SYSTEM RELIABILITY REGULATION: A JURISDICTIONAL SURVEY

Pacific Economics Group Research, LLC

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1. Introduction and Executive Summary

1.1 Introduction

Service quality is an increasingly important issue in utility regulation. In addressing this topic for all regulated industries, a report by North American regulators stated that "attention to service quality will be of greater importance as competitive markets proliferate and financial regulation diminishes."[1] Service quality issues have become especially prominent in the electric power industry, partly because advanced industrial economies like Canada are more dependent than ever on reliable power supplies.

Some observers have questioned whether traditional regulation is best suited to this new environment. One early statement of this view comes from a Power Outage Study Team (POST) commissioned by the US Department of Energy (DOE) to investigate several prominent power outages in the US in 1999. In addressing the relationship between regulation and appropriate reliability, DOE POST wrote:

> '(I)s the existing regulatory policy package adequate in light of the new demands on electricity delivery companies? Additional regulatory measures and increased incentives, including performance-based standards, may be required to assure that the necessary actions are taken to provide the proper level of reliability.'[2]

Throughout the world, a number of jurisdictions have implemented policies that are designed to ensure that electric utilities provide appropriate service reliability. For example, the vast majority of US States require companies to provide information on

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[1] The National Regulatory Research Institute, (1995), *Missions, Strategies, and Implementation Steps for State Public Utility Commissions in the Year 2000: Proceedings of the NARUC/NRRI Commissioners Summit*, Columbus, Ohio, p. 4.

[2] US Department of Energy Power Outage Study Team, (2000), *Interim Report of the U.S. Department of Energy's Power Outage Study Team: Findings From the Summer of 1999*, p. 2.

[6] These papers are *Service Quality Regulation for Ontario Electricity Distribution Companies: A Discussion Paper*, September 15, 2003; and *Staff Discussion Paper: Regulation of Electricity Distribution Service Quality*, EB-2008-11, January 4, 2008.

service reliability metrics and monitor utilities' performance on the selected indicators. A significant number of incentive mechanisms have also been approved for US utilities, which penalize (and sometimes reward) utilities based on how their measured service reliability performance compares to established benchmarks. In Europe, many countries require reporting on reliability metrics, and some like Norway and Sweden have established sophisticated regulatory arrangements that penalize or reward distributors depending on how their measured reliability compares with established industry benchmarks. Some of the world's most comprehensive and rigorous service reliability regulatory regimes can be found in Australia/New Zealand where, in some jurisdictions, regulators have established benchmarks for system-wide reliability and performance on relatively poor-performing circuits in the network. Utilities are penalized or rewarded depending on their measured performance relative to these benchmarks, with penalties and reward rates linked to customer valuations of reliability.

System reliability has also been regulated in Ontario since the "first generation" incentive regulation plan approved for electricity distributors in 2000. Distributors are required to monitor their system average interruption frequency index (SAIFI), system average interruption duration index (SAIDI) and customer average interruption duration index (CAIDI) monthly and report on them annually to the Ontario Energy Board (OEB, or Board). Distributors are also required to report these reliability indicators in their distribution rate applications.

In general, the Board's approach to regulating system reliability has been relatively informal. It is expected that a distributor with at least three years of reliability data "should, at a minimum, remain within the range of its historical performance," although in practice this "range" has not been precisely defined. The Board may also ask utilities to provide information on the causes of the interruptions.

The OEB Staff has previously prepared two discussion papers on service quality regulation in the Province. The first was issued in September 2003 and the second was released in January 2008.[6] Following the January 2008 paper, the Board did make some amendments to the Distribution System Code that affected the regulation of customer service indicators. However, there have not been any substantive changes to the system reliability regulation approach that was originally adopted in early 2000.

In March 2010, the Staff began a new consultation process regarding reliability regulation for electricity distributors in the Province. The consultation will address whether changes should be made to the current regulatory arrangements that apply to system reliability. Attention would be restricted to system reliability *per se* and not address other aspects of distributors' service quality.

The Staff hired Pacific Economics Group Research (PEG) as an advisor during this consultation. PEG has worked on a significant number of service quality regulation projects throughout the world. We have also worked with OEB Staff on a number of regulatory issues for Ontario's gas and electric distributors. PEG's consulting team also includes John Rich from Rich Consulting, a well-respected engineering consultant who has advised many leading North American utilities on reliability issues.

An important component of our work was to prepare a jurisdictional survey on system reliability regulation. PEG was asked to survey the regulation of system reliability in Canada, the US, Europe, Australia and New Zealand. The purpose of this survey is to inform Staff and stakeholders on current system reliability regulatory practices and thereby focus stakeholder deliberations on these issues.

This report presents PEG's jurisdictional survey and related analysis. It is supplemented by a chapter written by Rich Consulting that discusses two case studies on system reliability regulation for particular North American utilities and how those utilities responded to regulatory mandates. Although time and resource constraints did not allow our survey to be all-inclusive, we believe that this is the most comprehensive survey of system reliability regulation that is available.

1.2 Executive Summary

The results of this report can be briefly summarized. There are many dimensions of the service quality provided by utilities to retail customers. Service reliability metrics are almost invariably collected directly within the utility itself. Most utilities have historically collected and monitored these data primarily for internal management rather than external regulatory purposes. Accordingly, until recently, there have been few attempts to standardize the definition and measurement of service reliability indicators across utilities. It is therefore common for the measurement of service reliability indicators such as the system average interruption frequency index (SAIFI), system average interruption duration index (SAIDI), and customer average interruption duration index (CAIDI) to differ across utilities.

The measured reliability of utility service can also vary because of external business conditions that are beyond managerial control. Utilities have an obligation to provide service to customers in assigned territories. Power delivery requires direct connection and delivery into the homes and businesses of end users. The conditions of a utility's service territory and customer base can therefore affect the cost and measured reliability for power delivery networks. These business condition variables often differ substantially among companies. In addition to varying across distributors, some of these business conditions (particularly weather) are quite volatile and unpredictable over time. As a result, external business conditions lead both to systematic differences in measured reliability across companies and year-to-year fluctuations in reliability.

Measured service reliability is not determined entirely by external conditions but also depends on a distributor's behavior. In evaluating work practices and investments that can enhance quality, it is usually rational from both a shareholder and customer perspective to balance cost and reliability considerations. It is often not cost effective to have the same reliability levels in service territories with markedly different business conditions. Differences in measured reliability across utilities are therefore not necessarily evidence of either good or bad service reliability performance. In addition, it should be recognized that distribution systems are rationally designed to deliver fluctuating reliability levels. A short-term decline in reliability is not necessarily cause for concern.

The analysis of service quality economics in competitive markets provides an important guide for evaluating how best to regulate the reliability of regulated services. Supply and demand conditions are distinct aspects of any marketplace. For most goods and services, the market forces of customer choice and competition among firms induce companies to make supply decisions that reflect consumer demands for product quality, including the willingness to pay for quality. These same forces are not operative for power delivery and related services which, even in a market where retail competition has been introduced for power supply services, will overwhelmingly be provided by regulated utilities that have a monopoly over power distribution in designated service territories. In principle, regulation will be more effective if it replicates the market-like incentives that move the quality of utility services towards optimal levels that reflect customer demands and willingness to pay. However, service quality approaches that tend to promote optimal quality are much more information-intensive than other, simpler regulatory approaches.

Three broad approaches have been taken towards service quality and system reliability regulation. Under service quality monitoring, utilities are required to report their performance on defined indicators to regulators, and perhaps other parties, at defined intervals. A service quality target regime is one where companies are expected to achieve established, targeted levels of performance on a series of identified performance indicators. This approach requires setting one or more benchmarks for each of the indicators and providing information on how the Company's current performance compares with those benchmarks. If utilities fail to achieve a given benchmark, they may be compelled to present action plans on how they plan to boost performance to the benchmark level. Service quality penalty/reward mechanisms automatically penalize, and sometimes reward, companies depending on how their measured service quality performance compares with established performance benchmarks. The main idea behind penalty/reward plans is to establish rules that create inherent incentives for utilities to meet desired regulatory objectives. A well–designed penalty/reward plan will create incentives for the utility to operate in an efficient and effective manner for the benefit of customers, so there is less need for continuous and detailed regulatory scrutiny of utility operations.

System reliability regulatory practices were surveyed in Canada, the US, Europe, Australia and New Zealand. Information was compiled on system reliability indicators, circuit indicators, and severe storm restoration indicators. The survey also considered the alternative methods used to "normalize" reliability data to exclude the impact of service storms, different approaches that are taken towards setting benchmarks, and the variety of regulatory responses to measured reliability metrics (and perceived reliability problems). This survey showed that there is a wealth of information available on system reliability regulation throughout the world and a considerable diversity of approaches that have been taken towards regulating system reliability.

To provide greater depth on how reliability regulation impacts companies, we examined two case studies. One was for Consolidated Edison in New York, the other for Dayton Power and Light in Ohio. Details are provided on the history and evolution of reliability regulation for each company, and a discussion of how each company responded to its changing regulatory environment.

Going forward, one issue to be addressed in Ontario is the choice of system reliability indicators. Currently, the OEB monitors a distributor's performance on three indicators: SAIDI, SAIFI, and CAIDI. It should be recognized, however that monitoring all three indicators is redundant, since SAIDI is the product of SAIFI and CAIDI. SAIFI and SAIDI also represent the overall frequency and duration of interruptions for customers on the system, and it is possible that measured CAIDI performance could deteriorate despite improved performances in both SAIDI and SAIFI.

Previous Staff papers have also discussed the possibility of adding MAIFI and circuit indicators. No utility in Canada currently monitors or regulates MAIFI, although this is becoming more common in other jurisdictions. One reason is that increasing digitalization and use of computers means that even momentary power interruptions can lead to significant economic losses. Circuit indicators are also fairly prevalent.

Another issue is whether and how to normalize reliability data. There is a noticeable move towards using the IEEE 1366 standard for such normalizations. The costs and benefits of adopting this standard in Ontario merit attention.

The consultation will also consider whether more formal benchmarks should be established. A relatively simple, but still "rule-based," approach for setting benchmarks comes from Massachusetts. A more sophisticated, but complicated, approach may be that adopted in Norway, which sets more objective benchmarks for each distributor based on econometric methods.

The potential relationship between measured reliability and the ongoing introduction of smart metering in Ontario should also be considered. When the shift to a smart metering-based reporting system occurs, an initial decline in reliability results may result due to the significantly greater quantities of outage information (all outages will be definitively known). Since the Ontario government has mandated that all distributors in the province implement smart metering systems, this proceeding may provide an opportunity to review any issues that may arise regarding reporting and measuring reliability during the transition to smart meter-based reporting.

The plan for this report is the following. Chapter Two briefly describes the power distribution business, the type of system reliability information that distributors often collect, and how companies may respond to system reliability regulation. Chapter Three provides a conceptual framework for analyzing service quality and system reliability issues. This framework considers both the "supply side" and the "demand side" of electric utility service quality. Chapter Four discusses various options for service reliability regulation. Chapter Five surveys current system reliability regulation practices in the US, Canada, Europe, Australia and New Zealand. Chapter Six discusses the system reliability case studies. Chapter Seven presents brief concluding remarks.

2. The Electric Utility Business and System Reliability

2.1 Power Distribution and System Reliability

The main function of local distribution companies (LDCs) is to receive power in bulk from points on high-voltage transmission grids and distribute it to consumers in assigned territories. Delivery involves reducing the voltage of bulk power supplies to the levels used in end-use electrical equipment. Delivery is achieved via conductors that are usually held above ground but pass underground in some areas through conduits. Important LDC facilities include conductors, line transformers, station equipment, poles and conduits, computer systems and software, transportation equipment, storage areas, and office buildings. LDCs commonly construct, operate, and maintain such facilities but may outsource certain functions.

Continuous use of electric power is essential to the functioning of modern homes and businesses. Power storage, self-generation and self-delivery from the grid are generally not cost competitive with power delivered by LDCs. End users therefore want power delivered to their premises and must be physically connected to the distribution system. To satisfy consumer demands, LDCs construct and maintain power delivery networks that establish physical contact with almost every business and household in their service territory.

The essential nature of power demand also makes interruptions in power delivery costly to customers. LDCs are therefore expected to design and operate distribution networks to assure reliable deliveries. One important design requirement is that the capacity of the delivery system must be able to accommodate the peak demands in the territory. LDCs must also endeavor to connect customers rapidly to the network. End use electrical equipment is also designed to operate within a narrow range of voltage levels. Thus in addition to providing power supplies that are as continuous and uninterrupted as possible, LDCs must attempt to conform to technical standards affecting the quality of power deliveries (*e.g.* regarding voltage, waveform, and harmonics).

Even well-built delivery systems are subject to disruption from accidents and weather conditions. When disruptions occur, LDCs are expected to restore service promptly. LDCs can maintain system reliability in a number of ways. Important facilities that promote continuous and high quality power supplies are protective devices such as fuses and circuit breakers, switchgear, automatic reclosers, voltage regulators, capacitors, and cable insulation. Supervisory control and data acquisition (SCADA) and distribution automation systems also permit more centralized monitoring and control of power distribution systems, thereby reducing the extent and duration of interruptions experienced by customers in the event of equipment failure.

In addition to these capital assets, the quality of delivery services depends on a LDC's operation and maintenance (O&M) activities. Vegetation management and tree trimming can reduce the likelihood of contact between foreign objects and power lines that lead to interruptions. More frequent washing of insulators can reduce contamination and enhance reliability. Wood pole wraps and other pole maintenance also promote system integrity. When outages do occur, the size and deployment of restoration crews affects the duration of interruptions that customers experience.

2.2 System Reliability Measures

Reliability indicators measure the continuity of the basic power delivery service. Electric utilities are expected to provide a continuous power supply at all times, so interruptions in power supply constitute a diminution in service quality. Reliability is often measured by the frequency and duration of power interruptions. Reliability is most often measured at the level of the entire system, although it can also be measured for subsets of the network such as for operating areas or specific circuits. The most typical measures used in utility regulation are:

- the System Average Interruption Frequency Index (SAIFI), or the number of sustained interruptions that is experienced annually by an average customer on the system

- the System Average Interruption Duration Index (SAIDI), or the number of minutes of sustained power interruptions that are experienced annually by an average customer on the system
- the Customer Average Interruption Duration Index (CAIDI), or the average duration of a sustained interruption experienced annually by a customer on the system[7]
- the Momentary Average Interruption Frequency Index (MAIFI), or the number of momentary interruptions that is experienced annually by an average customer on the system

The definition of "sustained" and "momentary" outages differs among utilities, but in most cases a sustained outage is either one that lasts at least one minute or five minutes; a momentary outage is any loss of power experienced by a customer that is not "sustained." There are also analogues of each of the reliability measures above for subsets of the network. An example might be a "circuit SAIFI," which measures the number of annual outages experienced by an average customer on a specific circuit. Reliability indicators can also focus on thresholds for restoring power to customers.

These service reliability metrics must generally be collected directly within the utility itself. There is considerable variation in how reliability measures such as SAIFI and SAIDI are defined and calculated across utilities. Sources of difference include:

- *Which interruption events are excluded from the metrics* Utilities can differ in which outages are included or excluded from SAIFI and SAIDI statistics. For example, four Australian jurisdictions (the Australian Capital Territory, New South Wales, South Australia, Victoria) exclude planned outages while it is rare for planned outages to be excluded in Canada, the US, and Europe. In Ontario, planned outages are not excluded from the metrics. Some electric utilities are still vertically-integrated, and their reliability measures will

[7] SAIDI is equal to the product of SAIFI and CAIDI, so if any two of these indicators are measured the third can be computed.

include generation, transmission and distribution outages, while others are stand-alone distributors and their outages reflect only outages at the distribution level. While vertically-integrated reliability measures can be separated into those resulting from the generation, transmission and distribution systems (and most are usually distribution-related), a failure to do so will lead to inherently misleading comparisons among some utilities' reliability measures.

The largest source of discrepancies in outage exclusions across utilities concerns major event days. In Ontario, there are no standardized rules for excluding major events from reported reliability metrics, and some LDCs do not exclude any events. In most jurisdictions, however, nearly all utilities exclude these events from recorded reliability statistics because major events and storms are atypical and idiosyncratic, so including them can lead to a distorted perception of the utility's underlying reliability performance. However, utilities have adopted different definitions of what qualifies as "major" or "catastrophic" events. One traditional approach that has been adopted in a number of jurisdictions is to define any event as exceptional if at leads to interruptions for at least 10% of customers on the system. Any such widespread outage would accordingly be "normalized" out of reported, system-wide reliability indicators. This standard currently applies to the measured reliability of Maritime Electric, San Diego Gas & Electric, Kansas utilities, and Pennsylvania utilities, among others.

In 2002-2003, there was an effort by the Institute for Electrical and Electronic Engineers ("IEEE") to standardize the definition of major event days across utilities. This culminated in IEEE Standard 1366, which is sometimes referred to as the "Beta Method."[8] This standard has been promulgated

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[8] The main steps for identifying an major event day under Standard 1366 are the following:

- A major event day is a day in which daily SAIDI exceeds a threshold value $T_{MED.}$

worldwide, and an increasing number of utilities are adopting it as a basis for their officially reported reliability statistics. This standard does lead to greater comparability of reliability statistics among utilities, but there are still a number of factors that can lead to differences in reliability measures.

- *Step restoration* When utilities restore power after widespread outages, restoration typically proceeds in "steps," where some phases of a circuit are restored before others. Companies vary in the extent to which they track customer minutes of interruption in response to partial restoration of circuits. This can affect both the "start" and "stop" times of a given interruption and the total minutes of the recorded outage.

- *Degree of automation* Companies differ in the extent to which they rely on manual or automated systems (such as outage management systems, or OMSs) to record reliability data. It is quite common for companies' measured

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- o In calculating daily SAIDI, interruption durations that extend into subsequent days are assigned to the day on which the interruption begins. This technique ties the customer-minutes of interruption to the instigating events.
- o The major event day identification threshold value T_{MED} is calculated at the end of each reporting period for use during the next reporting period. For utilities that have six years of reliability data, the first five are used to determine T_{MED} and that threshold is applied during the sixth year.
- o The methodology for calculating T_{MED} is as follows:
  - Values of daily SAIDI for a number of sequential years, ending on the last day of the last complete reporting period, are collected.
  - If any day in the data set has a value of zero for SAIDI, those SAIDI data are excluded from the analysis.
  - The natural logarithm of each daily SAIDI value in the data set is calculated.
  - The average of the logarithms, α , of the data set is calculated.
  - The standard deviation of the logarithms, β , of the data set is calculated.
  - The major event day threshold, T_{MED}, is calculated by using the equation (this value should in theory give an average of 2.3 major event days per year)

    $$T_{MED} = e^{\alpha + 2.5\beta}$$

  - Any day with daily SAIDI greater than the threshold value T_{MED} is designated a major event day, and data for this day is removed from SAIFI and SAIDI performance to provide a "normalized" measure of performance.

frequency and duration of outages to rise substantially after they move to more automated recording systems. This implies that manual systems for measuring interruption data tend to miss or undercount the frequency and duration of outages.

For these and related reasons, there is often significant variation in how companies measure and record reliability indicators. 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.

2.3 Business Conditions and Measured Service Quality

The measured reliability of LDC service can also vary because of external business conditions that are beyond managerial control. LDCs have an obligation to provide service to customers in assigned territories. Power delivery also requires direct connection and delivery into the homes and businesses of end users. The conditions of a utility's service territory and customer base can therefore affect the cost and measured quality of service for the delivery networks that LDCs construct and maintain. These business condition variables can also vary considerably among companies. The list of relevant business conditions that can impact different aspects of service quality includes:

- weather (*e.g.* winds, storms, lightning, extreme heat and cold)
- vegetation (contact with power lines)
- the amount of undergrounding mandated by local authorities (reducing the contact of power lines with foreign objects but typically increasing the duration of interruptions that do occur)
- the degree of ruralization in the territory (typically increasing the exposure of feeders to the elements and lengthening response times when faults occur)
- the difficulty of the terrain served

- the mix of residential, commercial, and industrial customers (*e.g.* industrial and large commercial customers value power reliability more than smaller customers and are often willing to pay more for it; a greater share of such customers may therefore be correlated with better reliability indices)
- in the short run, it should also be noted that the age of the utility's network can also affect its reliability performance, although in the longer term this variable is subject to managerial control

In addition to varying across distributors, some of these business conditions are quite volatile and unpredictable over time. This is particularly true for weather. This implies that business conditions can lead not only to systematic differences in measured quality across companies, but year-to-year fluctuations in some quality indicators.

Of course, a LDC's measured system reliability is not determined entirely by external conditions but also depends on the distributor's own behavior. This behavior will include work practices, worker training, and capital investment that impact measured reliability. Relevant work practices include power line maintenance procedures such as tree trimming. Relevant capital investments include the size and sophistication of OMS and communications equipment and software.

In evaluating work practices and investments that can enhance quality, it is rational from both a shareholder and customer perspective to balance considerations of cost and quality. It is generally not cost effective to have the same quality levels in service territories with markedly different business conditions. For example, most will agree that it would be cost prohibitive for LDCs serving highly rural territories to have the same SAIFI as an urban distributor.[9] Australian jurisdictions commonly separate the standards for utilities by the level of urbanization. Some Australian plans have separate

[9] Circuits in rural areas are longer and more exposed to a variety of factors that can lead to outages. Rural utilities can thereby maintain the quality levels of more urbanized utilities only by incurring extra costs, such as additional protective devices or maintenance. By the same token, the extensive underground systems of highly urbanized utilities are much less exposed to contact with foreign objects than overhead networks. LDCs in such areas may be forced to underground much of their systems to comply with local ordinances.

reliability targets/benchmarks for central business districts, urban areas, and rural areas given some Australian LDC service territories contain all these areas.

The appropriate balancing of cost and external business considerations implies that differences in measured quality across LDCs are therefore not necessarily evidence of either good or bad reliability performance. Robust inferences on the effectiveness of a utility's service quality effort are only possible if comparisons control for differences in business conditions across utilities. In addition, it should be recognized that distribution systems are rationally designed to deliver fluctuating quality levels. A short-term decline in service quality performance is not necessarily cause for concern. It is important to keep these points in mind when formulating regulatory policies for system reliability.

2.4 Employing Reliability Metrics in Asset Management Decision-Making

There are a number of strategies utilities can employ to address reliability issues, such as focusing remedial attention on the worst-performing feeders (to be described in more detail in Chapter Six for Dayton Power & Light) or by focusing on specific system components that have a high risk and a high consequence of failure (as will be described in more detail for the Con Edison in Chapter Six). Broader strategies may also include:

- Increasing the use of distribution automation to improve response times.
- Changing design standards to improve feeder sectionalizing and control.
- Upgrading poles and basic infrastructure to reduce vulnerability to storms.
- Expanding inspection and maintenance programs to reduce risk of failure.
- Increasing vegetation management frequencies or clearance standards to reduce the number of tree-related failure events.

Choosing the right strategies, and making effective asset management decisions, requires a method for evaluating the costs and benefits of potential reliability improvement programs or project. Funding can then be allocated in a manner which will optimize the overall result.

There are a number of costs associated with reliability performance issues. These include the direct costs of restoring power, repairing infrastructure, settling customer claims and paying penalties (in certain jurisdictions). Indirect costs, which may appear after a prolonged period of under-performance, could include customer satisfaction issues, which may lead to audits, increased regulatory reporting requirements, and reductions in approved ROE.

To facilitate effective asset management decision making, it is suggested that the analysis of potential reliability improvement programs and projects start with the direct costs and benefits which can be quantified. Indirect costs and benefits can be identified and incorporated in subsequent discussions, but the effort to optimize the portfolio of improvement initiatives is best served by starting with a quantitative analysis. This requires a method for quantifying the reliability benefits associated with potential reliability improvements.

One way to determine the potential reliability benefit is to establish the cost of outages or customer interruptions. Reliability improvements can then be evaluated in terms of the *Avoided Cost of Customer Interruptions,* which can be quantified as $ / Customer Interruption (CI). Incentive mechanisms that were implemented in certain jurisdictions can provide a convenient basis for such calculations, which can be used to establish one end-point in a range of reliability values.

The State of California had for several years maintained a reliability SQI regime for the major utilities operating in the state. In the case of San Diego Gas & Electric, a targeted SAIFI range of 0.59 – 0.63 had been established. An Award (or Penalty) of $250,000 was provided for each .01 variation below 0.59 (or above .63). This data can be used to calculate a value for each Customer Interruption (CI):

Sample Calculation - Incentive Rate Basis

No. of Customers		SAIFI Range	Award/Penalty Provision	CI for .01 variation	$ Penalty	$/CI
1,200,000		0.59-0.63	.01 +/- $250,000	12,000	$250,000	$20.83

Another means for estimating the CI cost to the utility can be calculated on an event basis. An example is shown below:

Sample Calculation - Event Basis

Event	Year	Duration (Hours)	No. of Cust. Affected	Lost Revenue	Restoration Cost	$/CI
ABC Substation Failure	2007	10	22,000	$11,000	$3,000,000	$136.86
TUV Storm	2008	31	85,000	$129,625	$7,500,000	$89.76
XYZ Storm	2009	20	48,000	$48,960	$5,600,000	$117.69
Major Storm Average						*$114.77*

It should be noted that these costs do not include the outage-related costs which may be incurred by customers such as the loss of production, since these are not easily quantified by the utility. But the calculations above can define a range of reliability values for a utility, and a median or weighted average value can then used in evaluating various reliability program alternatives. While there is obviously some subjectivity in determining the $/CI value to be used, this approach clarifies the basis for decision-making. Sensitivity analyses can also be run to determine the effect of varying the $/CI value on an optimized portfolio of initiatives.

To illustrate the use of this approach, a simplified analysis for evaluating improvements to a group of worst performing feeders is provided below. In this case, a value of $40/CI was used to compare the potential benefit and approximate ROI of each feeder improvement project. (Note, a more accurate comparison could be provided by calculating the NPV of each of the potential feeder improvement projects.)

Sample Calculation - Worst Performing Feeders

Feeder Number	Feeder SAIFI	No. of Customers	No. of CIs	Estimated CI Reduction	Annual Benefit*	Estimated Cost	Approx. ROI
123	5.2	2,500	13,000	2,500	$100,000	$1,200,000	8.3%
457	3.1	3,250	10,075	3,000	$120,000	$2,000,000	6.0%
628	4.6	1,750	8,050	2,000	$80,000	$850,000	9.4%

* Based on Avoided Cost Benefit of $40/CI

The same type of analysis could be used to optimize the annual investment in a URD cable replacement program, for which the calculations would be performed on a segment basis. A similar analysis could also be developed for various component replacement programs. In all cases, there would likely be many individual feeders, cables or components to consider, but this type of analysis provides a rational basis for ranking individual projects and optimizing the total portfolio of reliability improvement programs and projects.

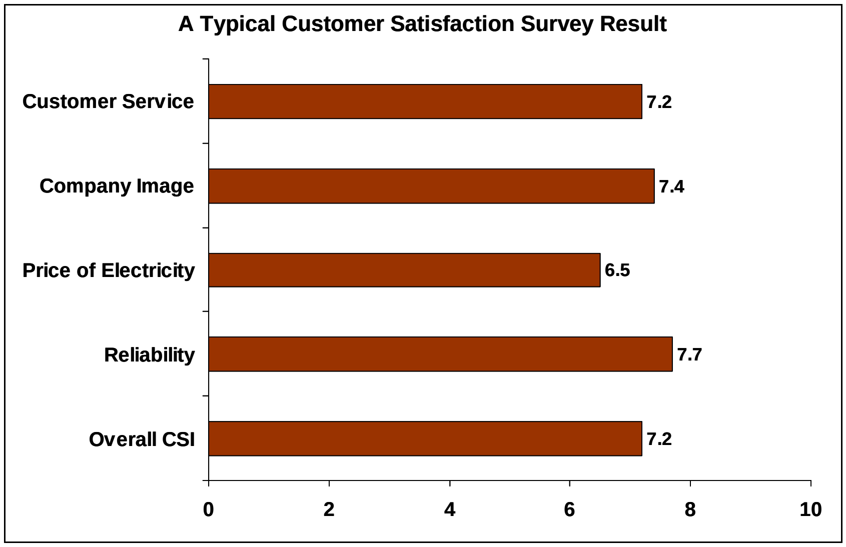
Many utilities have already adopted such analytical tools and have developed further refinements to advance the true optimization potential. This has happened in many jurisdictions in the US without a specific regulatory requirement, due to the fact that most utilities are keenly aware of the direct and indirect costs of poor performance and have taken a proactive approach to optimizing their portfolios of reliability improvement programs.

The current economic climate, with limited growth and tighter spending constraints, has added further impetus to investment optimization. Performance improvement or asset replacement projects that would have been funded in prior years may not longer make the cut, which means a sharper pencil – i.e., better tools and a more rigorous analysis and selection process – is required. Nonetheless, the current economic conditions and the resulting spending constraints means critical programs will likely be under-funded, which implies that reliability performance will likely decline. The use of sound analytical tools and procedures are now essential in minimizing the impact of under-funding.

2.5 The Impact of Reliability on Customer Satisfaction

Reliability is typically an important component of customer satisfaction surveys conducted for distribution utilities. The example below shows the scoring of four dimensions of customer satisfaction on a 10 point scale, with the overall Customer Satisfaction Index (CSI) calculated as a simple average. In some cases, utilities prefer to use a weighted scoring system by including a series of questions that determine the relative importance of each dimension to the customer being surveyed. But with either approach, it is often found that respondents react most strongly to recent events that have affected their perception of utility performance.

For example, a recent storm that resulted in a significant number of outages will typically have a negative impact on the reliability score. Similarly, a recent rate increase will negatively impact the price score. These movements tend to be temporary, unless reinforced by an ongoing series of events.



For the purposes of this study, it is useful to explore the underlying questions that are asked of customers to determine the reliability score. Key questions are likely to include some or all of the following:

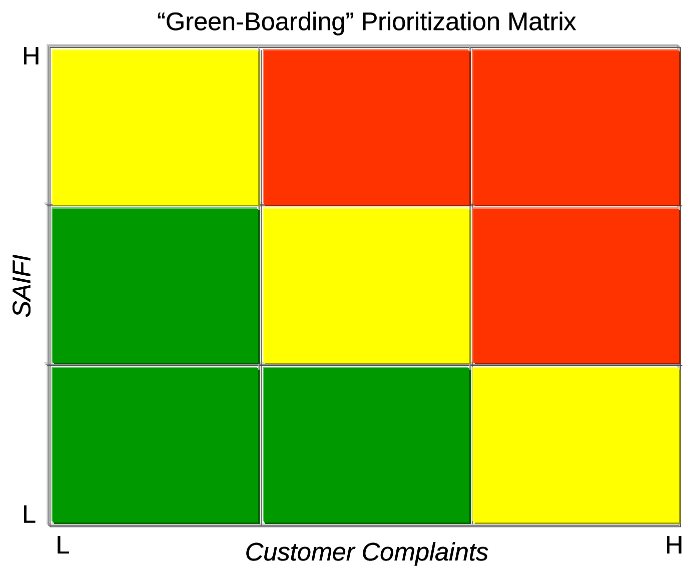
- How do you rate the utility in providing reliable service?
- Does the utility restore power quickly after an outage occurs?
- Are momentary power outages kept to a minimum?
- Are longer power outages kept to a minimum?
- Are power quality problems kept to a minimum?
- Does the utility keep you informed during an outage?
- Are reliable restoration estimates provided during an outage?

Note, there is no reference point or baseline presented with any of these questions, so the score the customer gives is relative to her expectations of utility performance. A high score for any question therefore mean expectations are being met, while a low score indicates the opposite.

It is also interesting to note how often the word "outage" appears, and that all aspects of the outage experience – frequency, duration and restoration times - are explored. The answers can be used to focus reliability initiatives where they will yield the greatest customer benefit. For example, if customers generally believe that restoration times are longer than they should be, specific activities such as installation of fault locating devices, improved dispatching of restoration crews, improved training and switch maintenance, etc. can be initiated to directly address this perception.

Another useful but contrary indicator of customer satisfaction is the number of complaints received. The number of complaints received can be used as an alternative means to prioritize reliability improvements initiatives (or to confirm the priority established via the $/CI method above). Feeders can be plotted in a *SAIFI vs. Customer Complaint Matrix* as shown below, and reliability improvement initiatives can then be focused on those feeders in the red sections of the matrix. By doing so, problem feeders are moved to a green section of the matrix (hence the term "Green-Boarding").

Some utilities use this technique on an area basis, since there are often synergies is upgrading a group of interconnected or proximate feeders at the same time. In either case, this is a useful way to convert complaints into action plans, which can be a very positive response in the eyes of customers. Consequently, it is suggested that utilities communicate actions such as these to their customers and stakeholders to reinforce their commitment to system reliability and customer satisfaction.


"Green-Boarding" Prioritization Matrix
H
SAIFI
L
L
Customer Complaints
H

3. Service Quality Economics

To provide context for the discussions that follow, this chapter discusses service quality economics for power distribution services. We begin with a general analysis of service quality economics. We then consider the regulation of the quality of power distribution services more specifically.

As one author has stated, "when one investigates quality in economics, one is asking, in effect, what is it about a good or service that makes it more desirable?"[10] Economists make this open–ended question more manageable by conceiving of products as a (finite) bundle of attributes or characteristics. Each characteristic is desirable in the sense that it satisfies consumer tastes and preferences. Since all characteristics are valuable to consumers, consumers generally prefer 'more' rather than less of each.

However, higher quality comes at a price. It is typically costly to add quality characteristics to a product or to provide 'more' of any given attribute. The amount and number of quality attributes that firms choose to bundle with their products is ultimately limited by consumers' willingness to pay. Economists therefore believe that each quality attribute carries an implicit price that, in turn, is reflected in the overall price of the product or service in the marketplace.[12]

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[10] Payson, S., (1994), *Quality Measurement in Economics: New Perspectives on the Evolution of Goods and Services,* Edward Elger, p.2.

[12] The implicit prices for various quality attributes can be quantified through statistical methods and aggregated in so-called hedonic price indexes that summarize overall quality differences between products. Clearly, quality attributes are rarely priced explicitly in the marketplace, but it does not follow that the estimation and use of hedonic prices is simply an academic exercise. One example where these economic concepts are applied is by the Bureau of Labor Statistics of the US Department of Labor, which computes hedonic prices indices and adjusts for changes in the quality of some products when it computes the U.S. Consumer Price Index (CPI). For example, CPI calculations control for quality changes in personal computers. The quality of PCs has been increasing at the same time that their prices have fallen. The real decline in PC prices is, therefore, even greater than reflected in their list prices, since consumers are getting more for their money. Alternatively, if a firm were to offer a new PC that had quality levels equal to those of a PC ten years ago, it would certainly fetch a lower price than the higher-quality new models that are available. Hedonic price indexes adjust PC prices so that they reflect the price declines associated with a PC of constant quality.

It is also important to recognise that preferences differ among customers. Consumers naturally have different tastes regarding the quality characteristics that they find desirable in a given product or service. Just as importantly, customers differ in their willingness to pay for quality (for absolute quality levels and in the relative valuation of different quality attributes). These differences stem from differences in income as well as heterogeneous tastes and preferences.

Firms in competitive markets have strong incentives to meet customers' demands for quality. Because consumer preferences are heterogeneous, firms are financially motivated to offer an array of products that cater to customers' different tastes and willingness to pay for quality. This can result in firms choosing to compete in different segments or 'niches' in the marketplace. A simple example is the distinction between 'high end" (*e.g.* Holt Renfrew) and 'low end' (*e.g.* WalMart) general retailers. The abundance of quality–differentiated products observed in most markets, therefore, reflects differences in product attributes that are bundled together to appeal to the multiplicity of consumer tastes, preferences and price–quality tradeoffs.

Firms' choices on quality levels, and the implicit prices they charge for quality, can have important financial consequences. Consumers choose among goods and services available in the market based on their price and quality. If customers believe that a product does not offer good quality for the money, they will purchase other products that offer more appropriate price–quality terms. Firms providing poor quality products (at a given price), therefore, suffer financially as sales are lost to competitors. By the same token, firms providing superior quality for the money are rewarded with additional sales and profits. Firms in competitive markets, therefore, have powerful incentives to provide appropriate quality levels on the products that customers demand.

These same forces are weaker for regulated monopoly services. Consumer choice is rarely possible for power distribution. Regulation, therefore, does and should play an important role in ensuring that utility customers receive appropriate service quality.

This discussion naturally raises the question of what constitutes 'appropriate' quality for a given price. From the customer's perspective, the quality of any given attribute will be appropriate as long as the (implicit) price at which it is offered is no greater than his willingness to pay. Consumers' marginal willingness to pay for a quality attribute typically declines as the amount of quality increases. That is, as they attain higher quality levels, consumers place less value on additional quality improvements. This implies, for example, that customers are prepared to pay less to go from very good service to excellent service than they would be to go from poor to mediocre service.

Firms are willing to supply a quality attribute as long as the (implicit) price received is at least equal to the marginal cost of providing that attribute. Firms typically face increasing marginal costs of improving quality. That is, as quality levels increase, firms often must incur greater incremental costs to increase quality still further.

Consumption and production decisions for each quality attribute lead to a type of equilibrium, pictured in Figure 1 below. Customers' demand for quality will be given by plotting the willingness to pay for additional increments of quality. Therefore, going from one quality level to the next along the demand curve reflects consumers' marginal willingness to pay for quality. The firm's supply curve is given by the marginal cost of providing quality. Moving along the supply curve from one quality level to the next reflects the marginal cost of providing additional quality.

Consumers continue to demand quality, and firms continue to supply it, until the point where the demand and supply curves intersect. At this point, the marginal willingness to pay for quality is just equal to the marginal cost to firms of supplying it. This yields the (implicit) equilibrium quality indicated.[13] These equilibrium quality levels and implicit prices are appropriate in that they reflect customers' preferences and willingness to pay for quality and firms' willingness to supply it. The market equilibrium depicted in this diagram is also optimal, since it maximises the difference between

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[13] Rosen (1974, p.34) describes this equilibrium more formally as follows:

> 'A class of differentiated products is completely described by a vector of objectively measured characteristics. Observed product prices and the specific amounts of characteristics associated with each good define a set of implicit or "hedonic" prices. A theory of hedonic prices is formulated as a problem in the economics of spatial equilibrium in which the entire set of implicit prices guides both consumer and producer locational decision in characteristics space.'

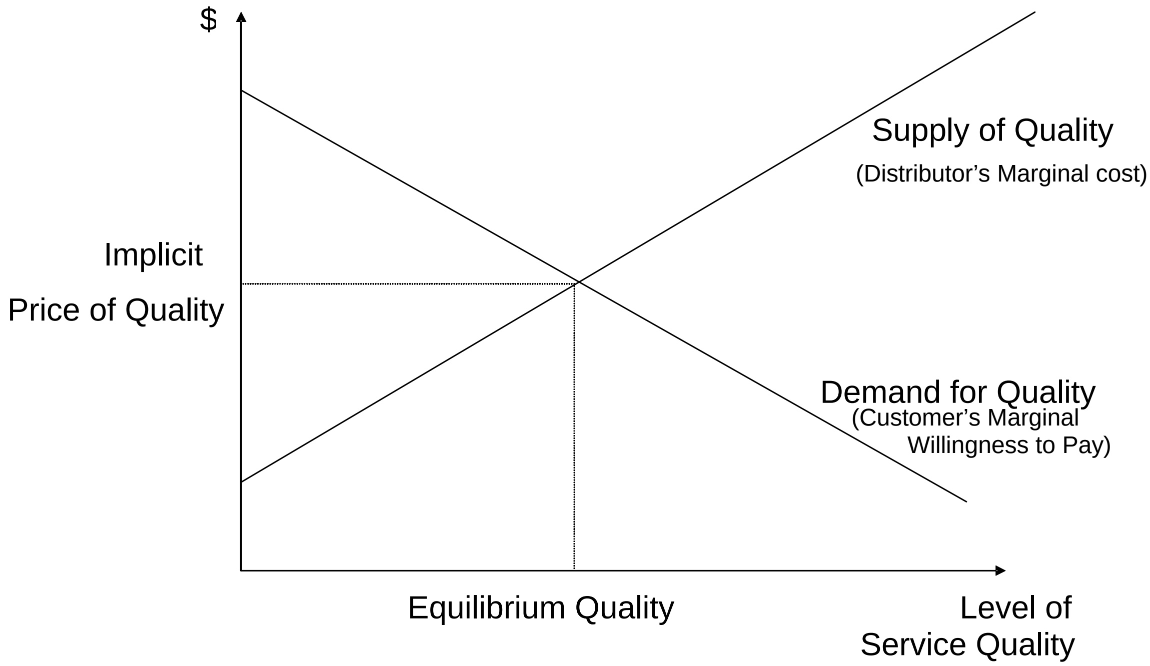

Figure 1: **The marginal benefits and costs of service quality**

customers' total willingness to pay for the quality attribute and firms' total cost of producing quality.

This treatment is, of course, highly stylized. Actual quality choices and implicit prices are more complicated since quality attributes are not supplied in isolation but rather are bundled with the basic product or service in question. Firms' decisions regarding quality attribute bundling depend on customer preferences, among other things. Consumer tastes, company costs, and marketplace conditions (*e.g.* general competitive pressures) can also change over time, and these factors naturally affect firms' behavior and the financial consequences of quality decisions.[14] Nevertheless, this analysis demonstrates that firms in competitive markets are driven to provide quality levels that reflect customer demands and their willingness to pay. Firms that meet these demands

[14] This discussion also abstracts from information available to consumers and producers and how this affects decisions, as well as the cost considerations of supplying multiple quality attributes jointly rather than in isolation.

most successfully are rewarded, while companies that fail to provide appropriate quality levels suffer financial penalties.

This analysis of service quality economics in competitive markets provides an important guide for evaluating how best to regulate the quality of regulated services. The supply and demand characteristics are distinct aspects of any marketplace, although for most goods and services, the market forces of customer choice and competition among firms induce companies to make supply decisions that reflect consumer demands. These same forces are not operative for the power delivery and related services which, even in a market where retail competition has been introduced for power supply services, will overwhelmingly be provided by regulated utilities that have a monopoly over power distribution in designated service territories. In principle, however, regulation will be more effective if it replicates the market-like incentives that move the quality of LDC services towards optimal levels that reflect customer demands and willingness to pay.

It should also be recognized that the desirability of enhanced quality ultimately depends on customers' preferences for quality vis-à-vis cost. Customers do not inherently demand "more" service quality from LDCs. Indeed, some customers may even prefer lower LDC quality in exchange for lower costs and prices.[15]

The following chapter will consider alternative approaches to service quality regulation. It will be seen that service quality approaches that tend to promote optimal quality are much more information-intensive than other, simpler regulatory approaches. The most reasonable regulatory approach in any jurisdiction depends on the objectives for service quality regulation, as well as parties' willingness to undertake the research necessary to increase assurance that regulation is moving quality towards optimal levels.

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[15] A good competitive market example where this was apparently true was for airline travel. After airline deregulation in the US, many customers chose to consume lower-price but lower-quality airline services compared with what prevailed under regulation.

4. Alternative Approaches for System Reliability Regulation

There are several broad approaches available for service reliability regulation. Some regulatory approaches are more suited for attaining certain regulatory objectives than others. These approaches also differ in the amount and complexity of the information that is required for implementation. This chapter will briefly describe the main approaches that can be taken towards regulating service reliability and some of the issues that need to be addressed to implement each of them.

4.1 Regulatory Objectives

Regulators try to achieve a number of different objectives through service reliability regulation. This report will not address all of these specific objectives that are manifested in service reliability regulations adopted in different jurisdictions. Rather, we discuss a few fundamental features that can be used to distinguish the approaches that are broadly used to regulate system reliability in the electric utility industry.

One issue is whether policies are designed to maintain or improve reliability levels. In many instances, regulators and other interested parties believe utilities' existing service reliability is generally adequate. Regulatory policy in these jurisdictions is therefore designed to maintain the status quo. One example of this is in New Zealand where the Commission "sought to develop quality standards that will promote an outcome of no material deterioration" for its LDCs.[16] In other cases, however, service reliability regulation is driven by a perception that quality levels have either been slipping or are otherwise inadequate. Service reliability regulation in these jurisdictions will therefore place more emphasis on the need to improve the reliability that utilities deliver to customers.

A second fundamental issue is whether policy should focus on "current" or "leading" measures of service reliability performance. Current service reliability

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[16] New Zealand Commerce Commission, (2009), *Decisions Paper: Initial Reset of the DPP*.

measures are those that reflect the reliability of service that is delivered to customers either contemporaneously or in the recent past (*e.g.* within the last year). A leading indicator is an activity variable that could be indicative of future service reliability problems. Examples of leading indicators may be tree trimming expenses or asset inspection cycles; delayed or declining expenditures on either activity could lead to conditions that lead to power interruptions in the future. Most jurisdictions have focused on current service reliability measures as the basis for policy, although some have established targets for activities such as inspection and maintenance. These approaches are also not necessarily mutually exclusive.

A third issue is whether regulation relies on pre-established rules or regulatory discretion as the means of responding to service reliability problems that do occur. Regulatory discretion utilizes regulatory judgment to evaluate and respond to service reliability problems, essentially on a case by case basis. For example, regulators could ask utilities to develop "action plans" that address observed service reliability concerns, which they would monitor until they were satisfied that the problems had been fixed. One example of the informal style of reliability regulation is in Newfoundland and Labrador, where Newfoundland Power explains variances between the current year performance and a five year average. If the performance is not judged to be sufficient, commission staff will meet with the utility and form an action plan.

In contrast, a "rule based" approach establishes known and automatic consequences for a given level of service reliability performance. An example would be financial penalties for service reliability performance that falls below specific benchmarks. Regulators often rely on rule-based approaches as a way to "countervail" or offset service reliability concerns that arise when companies have stronger incentives to cut costs, such as when mergers or incentive regulation plans are approved. Rule-based penalty/reward plans are often coupled with merger and performance-based regulation (PBR) plans to ensure that these cost savings are not achieved at the expense of service reliability. The recently approved plan for Enmax is a Canadian example of a PBR plan that incorporates a penalty/reward mechanism.

Before turning to the alternative regulatory approaches, it is worth making a few observations on these objectives. One is that it is generally more challenging to structure regulation to encourage service reliability improvements rather than simply to maintain reliability. Drawing on the conceptual framework presented in Chapter Three, service reliability will be substandard if the firm is inefficient in supplying service quality to customers, the service reliability delivered to customers does not reflect their preferences and willingness to pay, or both. The logical end point for "improving" service reliability is to move it to the optimal level. At the optimum, the utility is efficiently supplying service reliability to customers, and the amount of service quality provided just matches customers' willingness to pay.

However, determining whether and when customers' reliability levels are optimal is informationally demanding. Assessing whether companies are supplying service reliability efficiently, or what system reliability should be expected for a utility given its costs and operating conditions, involves benchmarking analyses. Evaluating whether reliability is consistent with customers' demands also involves research on valuing customers' willingness to pay for system reliability improvements, or their willingness to accept system reliability declines in exchange for lower prices. These types of analyses are complex and not necessary if the main objective is to maintain reliability.

Regulators can avoid undertaking this research and simply set arbitrary "stretch" goals for improved reliability performance that they expect utilities to attain. However, this approach is potentially risky and may be unfairly demanding for utilities if their system reliability performance is already good. Stretch goals that entail system reliability improvements may also not be in customers' interests if the costs of achieving the system reliability improvements are not at least met, and ideally exceeded, by customers' willingness to pay for the incremental system reliability gains. For these reasons, if a primary objective for system reliability regulation is to improve the reliability of service delivered to customers, this goal should ideally be matched with the necessary benchmarking and/or customer demand research that is needed to support rigorous "stretch" goals for a utility's system reliability performance.

Second, while the notion of using "leading" system reliability indicators may have some surface appeal, in practical terms there are both limits and certain disadvantages to this approach. All else equal, regulators and other parties would like to establish a regulatory framework that addresses system reliability problems before they occur rather than responding to them after the fact. Monitoring activity variables such as tree trimming expenses may be seen as a means for ensuring that reliability problems do not arise in the first place. However, there is typically a significant and unpredictable lag between declines in such activity variables and potential system reliability problems. Because parties cannot be certain how changes in such activity may impact future system reliability, there are limits to relying on these variables as the basis for system reliability regulation. Even more importantly, monitoring activity variables creates incentives for companies to maintain the associated spending on a continuous basis. Such incentives can be counterproductive and may prevent companies from adopting innovative strategies, such as "reliability centered maintenance" practices, which can lead to lower maintenance spending while not jeopardizing system reliability. A focus on "leading" system reliability indicators may therefore unintentionally create perverse incentives that run counter to the goal of supplying system reliability efficiently.

On the issue of using rules and discretion, it should be recognized that there are some advantages in principle with a rule-based approach. One is that rules are more predictable than discretion, so a rule-based approach tends to promote regulatory stability. All else equal, a stable regulatory framework fosters efficient utility behavior that can ultimately benefit customers. Establishing a rule-based approach does require some initial start-up costs, but once it is in place can operate more or less automatically. Rule-based approaches can therefore be easier to monitor and less burdensome than regulation which places more emphasis on regulatory discretion to identify and remediate problems. A rule-based approach can also alleviate concerns that may arise because of other regulatory changes, such as mergers or PBR plans, that may lead to unintended system reliability declines. A well-designed, rule-based system reliability plan can minimize those concerns and allow regulatory oversight and discretion to be more focused and efficient.

4.2 Approaches to System Reliability Regulation

Three broad approaches can be taken towards system reliability regulation. *System reliability monitoring* is where utilities are required to report their performance on defined indicators to regulators, and perhaps other parties, at defined intervals. Reporting can also include information on specific programs the company may be taking to maintain or enhance performance and spending on certain critical activities (*e.g.* tree trimming). Monitoring approaches are relatively unobtrusive. They can often satisfy regulators and other parties who simply want more information on a utility's current system reliability performance and comfort that the company is acting to maintain performance and address whatever problems may exist. Two jurisdictions using system reliability monitoring are Newfoundland and Labrador and the Yukon Territory.

System reliability targets is a regime where companies are expected to achieve established, targeted levels of performance on a series of identified performance indicators. This approach requires setting one or more benchmarks for each of the indicators and providing information on how the Company's current performance compares with those benchmarks. If utilities fail to achieve a given benchmark, they may be compelled to present action plans on how they plan to boost performance to the benchmark level. In some cases, regulators may also impose penalties if a company consistently fails to satisfy the benchmarks. Target approaches are usually designed to maintain rather than improve reliability levels, but they are more demanding than monitoring regimes since companies are expected to attain concrete performance standards. Because it can involve reporting on forward-looking action plans in addition to historical information, this can also be more administratively burdensome than quality monitoring. Jurisdictions using system reliability targets include Prince Edward Island, Ohio, and Pennsylvania.

System reliability penalty/reward plans are regulatory mechanisms that automatically penalize, and sometimes reward, companies depending on how their measured service quality performance compares with established performance benchmarks. Penalty/reward mechanisms are often included as a component of a broader PBR plan or as part of many merger agreements. In these cases, the potential for penalties is often viewed a kind of "countervailing" incentive to ensure that system reliability is at least maintained at the same time that the LDC is incentivized to cut costs. Jurisdictions using penalty/reward mechanisms include Hungary; Victoria, Australia; and Oregon.

The main idea behind penalty/reward mechanisms, like all incentive regulation plans, is to establish rules that create inherent incentives for utilities to meet desired regulatory objectives. A well–designed mechanism will create incentives for the utility to operate in an efficient and effective manner for the benefit of customers, so there is less need for continuous and detailed regulatory scrutiny of utility operations. An essential feature of such mechanisms is therefore the existence of well-defined rules that (1) provide clear guidance to the utility in structuring its operations to achieve the desired objectives, and (2) create a framework that allows for an objective evaluation of the distributor's performance, which is essential in minimizing administrative burdens for regulators and the distributor.

There are three basic elements in a penalty/reward mechanism: 1) a series of indicators of the utility's reliability of service, which are measured and monitored under the plan; 2) associated performance benchmarks, or the standards against which measured reliability is judged; plans also often include deadbands around those benchmarks, or a zone around the benchmarks within which utility performance is neither penalized nor rewarded; and 3) a mechanism which translates a utility's reliability performance into a change in utility rates or allowed returns via rewards or penalties. In general, measured performance that "exceeds" the benchmarks (or upper bands) signals superior quality and a possible reward. Performance below the benchmarks (or lower bands) indicates sub–standard reliability and a possible penalty. For example, in the most recent San Diego Gas & Electric (SDG&E) mechanism, the initial SAIDI and SAIFI benchmarks were calibrated using the Company's five-year average performance on each metric over the 2002-06 period. These values were 69 minutes for SAIDI and 0.61 interruptions for SAIFI. The SAIFI benchmark was set at the Company's 2002-06 average performance, while the SAIDI benchmark incorporated a one-minute "stretch factor" and was therefore set at 68 minutes. These benchmarks were then updated annually, over the remaining four years of the plan according to pre-established rules that incorporated additional "stretch" goals. The SAIFI benchmark was reduced by 0.03 each year while the SAIDI benchmark was reduced by 5% annually. Deadbands of +/- 2 minutes for SAIDI, and +/-0.02 for SAIFI, were also established and penalties and rewards levied for SAIDI and SAIFI performance beyond these bands.

Our survey found that reliability monitoring is the most commonly used regulatory approach and is used in 40 different jurisdictions. System reliability penalty/reward plans have been used in 27 jurisdictions while there are 12 system reliability target regimes.[17] Australia/New Zealand relies relatively more on penalty/reward plans than jurisdictions in either North America or Europe.

4.3 Implementation Issues

4.3.1 Reliability Indicators

One common element in all the service quality regulatory approaches is reliability indicators. To implement any service reliability regulation method, objective, quantifiable and verifiable performance indicators are required. We believe the service reliability indicators used in regulation should ideally satisfy four, common sense criteria:

- they should be related to the aspects of service that customers value;
- they should focus on monopoly services;
- utilities should be able to affect the measured reliability; and
- the indicators should be sensitive to "pockets" of system reliability problems.

First, indicators should be linked to aspects of utility service that customers actually value. This may seem obvious, but a strict application of this criterion excludes indicators that have been included in some plans. For instance, the reliability of service delivered to customers is an appropriate service quality indicator while tree trimming expenses generally is not. As discussed above, we believe that using activity variables

[17] It should be noted that in the United States and Canada, some jurisdictions use different system reliability regimes for different utilities in a jurisdiction or for different system reliability metrics. Jurisdictions with multiple system reliability regimes include the Delaware, Indiana, Maine, Minnesota, Washington, Alberta, and British Columbia. These jurisdictions have been counted more than once in the above tallies.

like maintenance expenses as reliability indicators has limited usefulness and may unintentionally create perverse incentives.

Notwithstanding these points, we have less concern with including utility “inputs” such as activity variables (*e.g.* tree trimming expenses) rather than the reliability “outputs” delivered directly to customers (*e.g.* SAIFI and SAIDI) in reliability monitoring approaches than in penalty/reward mechanisms. The reason is that under the latter approach, utilities can be penalized or rewarded depending on an indicator’s measured performance. Such penalties or rewards are usually levied as changes to customer rates. It is not appropriate to base changes in customer rates on changes in indicators that do not directly pertain to or reflect customer welfare.

Second, indicators should focus on the reliability of the activities for which there are few if any alternative suppliers. This is consistent with the principle that regulation, including regulation of service reliability, is less necessary in competitive markets. Market forces are likely to create acceptable quality levels when products are available from multiple providers.

Third, utilities should be able to influence measured reliability through their own behavior. It is nonsensical to evaluate a company’s reliability performance using indicators that are largely or entirely unrelated to management actions. As discussed in Chapter Two, the measured reliability of power distribution service is potentially influenced by a number of external factors that are beyond managerial control. These factors vary substantially between distributors and some are quite volatile. If random or unforeseen incidents can affect important quality dimensions, the impact of these events should ideally be eliminated from the indicators.

Fourth, it is often sensible to have indicators that are measured on less than a system-wide basis. This is because system-wide measures may mask persistent service quality problems for “pockets” of customers. An example may be circuit reliability performance standards.

Overall, the choices for reliability indicators should balance the needs of comprehensiveness and simplicity. The selected indicators should not focus on some areas while ignoring other reliability attributes that are important to customers, because performance may deteriorate in the non–targeted areas. Comprehensiveness can be achieved simply by adding indicators to a plan. However, regulatory costs also rise as the regulatory plan includes more indicators since more utility and regulator resources must be devoted to reliability monitoring.

4.3.2 Reliability Benchmarks

Reliability benchmarks are the standards against which measured reliability is judged. Reliability benchmarks are elements of both the target and penalty/reward approaches. Whenever benchmarks are established, it is also common to have 'deadbands' around the benchmarks, or a zone within which utility performance is neither penalized nor rewarded. As with the reliability indicators, some basic criteria can be used to evaluate the design of performance benchmarks and deadbands.

One important criterion is that benchmarks should be calculated on the same basis as the reliability indicators. If the data used to measure reliability are not comparable to those used to set the benchmark, the regulatory plan will not lead to an objective comparison of the company's measured reliability relative to the benchmark. This is almost literally a case of 'comparing apples to oranges'. Discrepancies between measured and historical benchmark performance can arise if utilities change the measurement systems used to record reliability data, such as installing a new OMS.

Benchmarks and deadbands should also reflect external business conditions in a utility's service territory. Chapter Two discussed these business conditions in some detail. A failure to control for these business conditions in a regulatory benchmark can expose utilities to arbitrary and unfair performance evaluations. For example, consider a plan where a utility is rewarded or penalized depending on how its measured reliability compares to that of another utility. Assume that both companies measure every reliability indicator in the same way. This plan would still lead to unreasonable penalties or rewards if one utility had a more demanding territory (*e.g.* more severe weather). Not controlling for the effect of business conditions in that service territory would tend to handicap the utility serving that territory and, over time, lead to penalties that did not reflect its real reliability performance.[18]

Third, all else equal, benchmarks should be as stable as possible during the regulatory plan. Stable benchmarks give utility managers more certainty over the resources they must devote to providing adequate system reliability, as reflected in those benchmarks. It is harder for managers to hit a 'moving target', particularly if operational changes can only be implemented over longer periods. Stable benchmarks therefore promote more effective, longer–term service quality programs.

In some cases, however, a lack of data available at the outset of regulatory plan may make it more difficult to set benchmarks that are viewed as reliable over the term of a multi–year plan. This would be true if the information systems used to record reliability data had changed recently or if there was little confidence that a short data series reflected typical external business conditions for the utility. If this is the case, benchmarks can be updated using data that becomes available during the term of the plan, but this should be done according to well–defined rules that are established at the outset of the plan. An example would be a benchmark equal to a ten year moving average of a company's historical performance on an indicator, until 10 years of historical data are available. This type of approach has been implemented in Massachusetts. Setting benchmarks according to such objective rules creates as much stability as is feasible given data constraints.

In practical terms, two main sources of information can be used to set benchmarks and deadbands in regulatory targets and penalty/reward plans. The first option is peer performance. In principle, peer–based benchmarks may be attractive since they are commensurate with the operation and outcomes of competitive markets, where firms are

[18] For example, suppose the company in the more demanding territory really had worse service quality performance than the other firm in a given year; this plan would lead to penalties both for worse performance and because one firm had more demanding conditions that made it more difficult to provide the same level of service as the other firm. In principle, a firm in a more demanding territory could also have better system reliability performance and yet still register worse measured reliability performance because of the impact of its more demanding business conditions. Here, the company is penalized even though it is a superior performer. In both cases the company's penalties do not reflect its real reliability performance unless adjustments are made to the plan to reflect differences in the companies' service territories.

penalized or rewarded for their price and reliability performance relative to their competitors. In practice, however, industry–based benchmarks are challenging. One reason is that uniform data are not generally available for utility reliability measures. Differences in measure definitions would make peer data difficult to compare and inappropriate as benchmarks. Even if measures are defined comparably across utilities, peer benchmarks should control for differences in utility business conditions that affect quality performance. Controlling for the impact of business conditions on expected system reliability performance is complex. While industry-based benchmarks are rare, this approach has been used in Norway, Sweden, and the Netherlands.

The alternative is the utility's own performance on an indicator. For example, benchmarks could be based on average performance on a given indicator over a recent period. Reliability assessments would then depend on measured reliability levels that differ either positively or negatively from recent historical experience. Historical benchmarks are used in a number of North American jurisdictions including Massachusetts and California.

The use of past utility performance to set benchmarks is appealing in many respects. Historical benchmarks reflect a company's own operating circumstances. Historical data will reflect the typical external factors faced by the company if the period used to set benchmarks is long enough to reflect the expected temporal variations in these factors. Longer periods are more likely to achieve this goal than shorter periods and are therefore preferred. As noted above, if only short time series are available at the outset of a (reliability target or penalty/reward) plan, benchmarks can be updated at the outset of future plans as more data become available. The rules for updating benchmarks should be spelled out clearly in advance to create the appropriate performance incentives and minimize administrative burdens.

A potential concern with using a company's past performance to set benchmarks will arise if the utility has historically registered substandard reliability performance. If this is the case, the benchmark would reflect a level of inefficiency in system reliability delivery. A more objective standard of system reliability performance may then be appropriate and would benefit of customers. However, evaluating whether a company's historical system reliability performance is substandard requires controlling for factors beyond companies' control that can impact their system reliability performance. This raises issues of performance benchmarking, which can be complex and will certainly entail greater administrative costs than simpler system reliability regulation approaches.

4.3.3 Controlling for Volatility

Although historical averages of company performance will reflect typical external factors faced by a company, they will not control for shorter–term fluctuations in external factors around their norms. As noted, some business conditions that can affect measured quality are quite volatile from year to year. Weather is the salient example.

One way to accommodate year–to–year fluctuations in external factors is by measuring indicators on a multi-year basis. For example, a regulatory plan could target a three-year moving average of SAIFI and SAIDI rather than the SAIFI and SAIDI values registered each year. Measuring indicators over multiple years will tend to smooth out the impact of random factors on indicator values and lead to a more reasonable measure of the company's underlying service quality performance. New Jersey LDCs and Alberta-based Enmax both use a 5 year rolling average to calculate their system reliability benchmarks.

Another way to accommodate year-to-year fluctuations in external factors is through deadbands. Suppose, by way of example, that the value of a reliability indicator is known to fluctuate in a certain range due to external factors. The mean value of this indicator over a suitable historical period would reflect the typical long run external business conditions faced by the utility. Variation in the company's performance around this historical mean will accordingly reflect short run fluctuations in those business conditions. Deadbands should therefore reflect the observed variability in measured system reliability performance. One straightforward measure of this year–to–year variability is the standard deviation of the reliability indicator around its mean. San Diego Gas & Electric, based in California has a deadband around their SAIDI and SAIFI performance before penalties or rewards begin to accrue. New Zealand has gone the furthest to minimize volatility in their SAIDI and SAIFI performance by incorporating a regime which uses both a deadband and even allowing an LDC to be non-compliant in one out of three years before penalties are considered.

4.3.4 Penalties and Rewards

Penalty/reward mechanisms naturally include rules for rewarding or penalizing a utility for its system reliability performance, while the other regulatory approaches do not. In some cases, however, regulators can levy penalties in target regimes for especially poor performance. The amount of these penalties is usually based on regulatory judgment, although it is sometimes constrained by law.

In a penalty/reward mechanism, established rules link a reliability assessment to a change in the utility's rates or allowed returns. A reliability assessment relates quality as measured by the indicators to the reliability benchmarks. In general, measured performance that "exceeds" the benchmarks signals superior reliability and a possible reward. Performance below the benchmarks indicates sub–standard reliability and a possible penalty.

One important design issue for a penalty/reward mechanism is whether the award mechanism will be symmetric (both rewards and penalties are possible) or asymmetric (penalty–only). Some parties believe that only asymmetric system reliability plans are appropriate. Proponents of this view contend that, in PBR plans, system reliability incentives are designed to prevent reliability declines that may result from the incentives utilities have to reduce costs. Penalties are sufficient to deter such behavior and rewards are therefore unnecessary.

This argument has some merit if the goal of regulation is to maintain system reliability levels. However, a strong case can be made that symmetric penalty/reward plans are more appropriate, particularly if there is uncertainty about customers' system reliability demands. Optimal regulation (discussed in Chapter Three) is not necessarily focused on keeping system reliability performance from slipping, but rather will encourage system reliability to be provided up to the point where consumers' marginal valuations of reliability gains equals a utility's marginal costs. An optimal provision of system reliability could entail service quality enhancements in at least some areas. Since just and reasonable prices and the reliability of service are both important to customers, symmetric plans are more effective than asymmetric plans in creating incentives to improve performance in all areas valued by customers.

Symmetric plans are also more consistent with the behavior of unregulated markets than are asymmetric plans. Customers in competitive markets routinely pay higher prices for higher quality products, and a symmetric service quality incentive reflects this phenomena. However, competitive markets usually offer an array of goods with varying quality levels, and not all customers choose to consume high quality goods. This will not be the case for power distribution services. Even if it is possible to provide premium quality services to some customers, it is not practical to tailor quality levels to every individual retail customer on a distributor's network. Symmetric plans could therefore lead to price increases on monopoly services. Because price- reliability tradeoffs differ among customers, such price increases imply that at least some customers will be paying for reliability improvements that they do not want.[19]

It should also be noted that, for some reliability indicators, it is possible to make penalty payments directly to affected customers whenever quality falls below the associated benchmark. This is sometimes referred to as a system of "performance guarantees". Targeting compensation directly to customers that directly experience system reliability degradations is generally desirable, since it establishes a nexus between penalties for poor service and those customers who actually experienced poor reliability. But while such guarantees can be effective when problems are customer-specific, this method is more difficult to implement and less appropriate for system-wide reliability measures such as SAIDI and SAIFI.

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[19] However, it should be noted that, depending on the other features of the regulatory plan, symmetric system reliability incentive plans may not lead to price increases even if the utility is rewarded under the plan. For example, if the regulatory plan also features an earnings sharing mechanism, the system reliability reward can take effect as an increase in the allowed return at which earnings are shared, rather than a price increase.

5. Survey of System Reliability Regulation

To inform the consultation in Ontario, PEG prepared a survey of system reliability regulation in Western countries. Our survey examined system reliability regulation in Canada, the US, Europe, Australia and New Zealand. By system reliability regulation, we mean those plans where a company's system reliability performance is routinely reported or monitored outside the scope of rate cases. While time and resource constraints prevented this survey from being all inclusive, we believe that it is the most comprehensive survey of system reliability regulation that is currently available.

Our survey showed that there were three broad categories of system reliability indicators (other than performance guarantees, which were not surveyed due to time constraints). *System* reliability indicators measure the reliability of power supplies over an LDC's entire delivery system. *Circuit* reliability indicators measure reliability over subsets of the delivery system, which in most cases refers to individual network circuits. *Severe Storm/*Restoration indicators measure the maximum duration of interruptions to customers during outage events. As discussed, severe events are often "normalized" out of commonly-reported system reliability metrics such as SAIFI and SAIDI. In some jurisdictions, however, regulators have deemed it important to regulate restoration times during these severe events separately.

PEG has also surveyed Regulatory Responses to utilities' measured reliability on each of these three broad metrics. In most cases, this regulatory response is categorized as service reliability monitoring, service reliability targets, or penalty/reward mechanisms. These terms were defined in Chapter Four.

It should be noted, however, that service reliability regulation can be idiosyncratic. Not all reliability indicators fall into our assigned categories. For example, in some instances, utilities' performance on certain operational metrics (as opposed to actual reliability performance) is subject to regulation. Regulatory responses also sometimes do not fit neatly into the three main categories. The summary tables that follow therefore occasionally include different indicators and other, miscellaneous aspects of the regulatory plans.

5.1 System Reliability

Survey information is summarized in four sets of Tables. The first three tables summarize information on System Reliability, Circuits, and Severe Storm indicators, respectively. Table Four summarizes information on Regulatory Responses to each of these three reliability categories. In all instances, we begin by summarizing information from US jurisdictions, then examine Canadian, European, and Australia/New Zealand jurisdictions in turn. It is natural to begin with the US since it has the most information available on system reliability regulation.[20]

Table One presents information on system reliability indicators. The columns in this table correspond to the jurisdictions surveyed; in some cases, information for specific companies within each jurisdiction; the system reliability indicators that are subject to regulation; the methods used to normalize reliability statistics; and benchmarks for the regulated indicators (if any).

We find the most common quality indicators that are reported are the system average interruption frequency index (SAIFI) and the system average interruption duration index (SAIDI). In most jurisdictions both are measured, although some use SAIFI and CAIDI instead. As a result, SAIFI is somewhat more widely reported. Thirty seven US states use SAIFI while 32 use SAIDI. Of the states that regulate SAIDI, SAIFI, and CAIDI, 11 states report both SAIDI and SAIFI, while 5 states report SAIFI and CAIDI and 22 states report SAIDI, SAIFI, and CAIDI. In Canada, four provinces and the Yukon Territory regulate SAIDI and SAIFI while three provinces and the Yukon Territory regulate CAIDI. Three jurisdictions report SAIDI and SAIFI and three more report SAIDI, SAIFI, and CAIDI, while only one province reports SAIDI and CAIDI.

In Europe, 16 jurisdictions regulate SAIFI and 14 regulate SAIDI. A total of 13 jurisdictions regulate both SAIDI and SAIFI, while no jurisdictions regulate SAIDI and

[20] The US survey does not include municipal or cooperative utilities because they are usually not formally regulated by state governments.

Table 1

System Reliability

US Jurisdiction[1]	Companies Involved	Indicators	Normalizing for Exceptional Events	Benchmarks
Alabama	All utilities	SAIDI, SAIFI, CAIDI, MAIFI	none	none
	Pacific Gas & Electric	SAIDI, SAIFI, MAIFI	major events that result in a state of emergency being declared by the government or that affect more than 15% of the system facilities or 10% of the utility's customers, whichever is less for each event; IEEE definition (& metrics) of major event days is also in effect	Based on historical performance: SAIDI=165, 161, 157 minutes, SAIFI=1.40, 1.33, 1.24 for 2005, 2006, 2007 respectively; benchmarks have not been set since then although application by PGE for new incentive mechanism is pending
	Southern California Edison	SAIDI, SAIFI, MAIFI	major events that result in a state of emergency being declared by the government or that affect more than 15% of the system facilities or 10% of the utility's customers, whichever is less for each event; IEEE definition (& metrics) of major event days is also in effect	Incentive mechanism for reliability was in effect from 1997 to 2006; from 2004 until the plan was terminated SAIDI benchmark = 56 minutes, SAIFI benchmark = 1.07 interruptions, and MAIFI benchmark = 1.26 interruptions per year
	San Diego Gas & Electric	SAIDI, SAIFI, SAIDET	an event is excluded if a state emergency is declared or it affects 15% of system facilities or 10% of customers, whichever is less	SAIDI=68+/-2 minutes, SAIFI=0.61+/-.02, SAIDET= 34, each escalated by stretch factor during plan
	Sierra Pacific Power	SAIDI, SAIFI, MAIFI	SPPCo excludable outages based on a subjective combination of (1) storm severity, (2) system design limits, (3) customers out and (4) total customer hours interrupted	none
California	PacificCorp	SAIDI, SAIFI, MAIFI	major events that result in a state of emergency being declared by the government or that affect more than 15% of the system facilities or 10% of the utility's customers, whichever is less for each event; IEEE definition (& metrics) of major event days is also in effect	none
	Black Hills/Colorado Electric Utility (Aquila)	SAIDI, SAIFI, CAIDI	IEEE standard, and planned outages, momentary outages of less than one minute in duration, and outdoor and street lighting outages	SAIDI = 101 minutes
Colorado	Public Service Company of Colorado	ODI (ordinary distribution interruption), SAIDI-ODI, SAIDI, SAIFI, CAIDI	IEEE standard, and extraordinary distribution interruptions prompted by generatio transmission and substation failures, planned outages, public damage, terrorism, safety, government order,emergencies	none
Connecticut	All utilities	SAIDI, SAIFI	whenever the number of trouble locations that result in outages exceed the 98.5 percentile of frequency over the preceding four years	none
D.C.	Pepco	SAIDI, SAIFI, CAIDI, CEMI8, CELID8	IEEE standard	Benchmarks for 2009: SAIDI=4.85 hours, SAIFI=1.18, CAIDI=4.85 hours (reset annually based on rolling 5-year average of O&M costs)
Delaware	Delmarva Power & Light	SAIDI, SAIFI, CAIDI	IEEE standard	SAIDI = 295 minutes
Florida	All utilities	SAIDI, SAIFI, CAIDI, MAIFI,CMI (customer minutes interruption), CI (customer interruption), CME (customer Momentary Events), CEMI5 (customers experiencing more than five interrutptions), N (number of outage events), L-Bar (average duration of outage events)	outage events caused by planned service interruptions; a storm named by the National Hurricane Center; a tornado recorded by the National Weather Service; ice on lines; generation & transmission disturbances; an event causing activation of the county emergency operation center	none
GA	All utilities	SAIDI, SAIFI, CAIDI	IEEE standard	none
HI	All utilities	SAIDI, SAIFI, CAIDI	normalization used to exclude abnormal situations such as hurricanes, tsunamis, earthquakes, floods, catastrophic equipment failures, and a single equipment outage that cascades into a loss of load that is greater than 10% of the system peak load	none
Idaho	Scottish Power-Pacificorp	SAIDI, SAIFI, CEMI (Customers Experiencing Multiple - Sustained and Momentary - Interruptions)	IEEE standard	SAIDI <= 30.5 minutes, SAIFI <= 0.297 by 2011
Illinois	All utilities	SAIFI, CAIFI, CAIDI	none	for service at <= 15 kV, <= 6 controllable interruptions & <= 18 hour for service at <= 69 kV & > 15 kV, <= 4 controllable interruptions & <= 12 hours for service at > 69 kV, <= 3 controllable interruptions & < = 9 hours
	Duke Energy	SAIDI, SAIFI, CAIDI	major events are storms or weather events that are more destructive than normal storm patterns	SAIDI=175 minutes, SAIFI=1.65, CAIDI=115 minutes
Indiana	Other utilities	SAIDI, SAIFI, CAIDI	major events are storms or weather events that are more destructive than normal storm patterns	none
Iowa	All utilities	SAIDI, SAIFI, CAIDI	based on severe weather event; wind that exceeds 90 mph; 1/5 inch of ice and wind that exceeds 40 mph; 10% of customers affected for more than 5 hours; 20,000 customers in a metro area affected for more than 5 hours	none
Kansas	All utilities	SAIDI, SAIFI, CAIDI	catastrophic event caused by forces that exceed system design limit and cause outage to more than 10% of a utility's customers within a 24-hour period	none
Kentucky	All utilities	SAIDI, SAIFI, CAIDI	IEEE Standard	none
Louisiana	All utilities	SAIDI, SAIFI	events caused by non-distribution system functions & catastrophic events that lea to loss of service to 10% or more of customers in a region requiring restoration tha takes more than 24 hours	SAIDI = 2.87 hours; SAIFI = 2.28

[1] US survey is limited to investor-owned utilities.

Table 1

US Jurisdiction[1]	Companies Involved	Indicators	Normalization for Exceptional Events	Benchmarks
Maine	Central Maine Power	SAIFI, CAIDI	IEEE Standard	CAIDI=2.18 hours; SAIFI=2.1 (2009), 2.08 (2010), 2 (2011), 1.92 (2012), 1.89 (2013)
	Bangor-Hydro Electric	SAIFI, CAIDI	IEEE Standard	none (had benchmarks and penalities under previous ARP that expired Dec. 31, 2007)
Maryland	Baltimore Gas & Electric	SAIDI, SAIFI, CAIDI	IEEE Standard	none
	Other utilities	SAIDI, SAIFI, CAIDI	events when more than 10% of a utility's Mary, or bordering jurisdiction, customers are without service and restoration takes more than 24 hours	none
Massachusetts	All utilities	SAIDI, SAIFI	events that lead to state of emergency declartion; event that causes unplanned interruption to 15% or more of a utility's customers; event caused by the failure of another utility's transmission or power supply	10 year average performance + 1 standard deviation
Michigan	Detroit Edison Co and Edison Sault Co	No regular indicators; instead uses service restoration factor & same-circuit repetitive interruption factor	severe weather conditions that result in the interruption of service to 10% or more of a utility's customers; events that lead to the issuance of state of emergency	catastrophic & all conditions, respectively, and no more than 5% of circuits experiencing 5 or more same-circuit repetitive interruptions/year
Minnesota	Xcel (Northern States)	SAIDI, SAIFI, CAIDI	IEEE Standard	SAIDI=98 minutes, SAIFI=1.00 interruption
	Interstate Power (Alliant)	SAIDI, SAIFI, CAIDI	IEEE Standard	Benchmarks for SAIFI, SAIDI & CAIFI set using pervious five years' performance data
	Minnesota Power (Allete)	SAIDI, SAIFI, CAIDI	IEEE Standard	Calculated as an average of the last five years' actual performance data
	Otter Tail Company	SAIDI, SAIFI, CAIDI	IEEE Standard	2009: SAIDI=74 SAIFI=1.3 CAIDI=56.92; Calculated as either an average of last five years' data (SAIFI) or based on internal KPI - Key Performance Indicators (SAIDI); CAIDI benchmark calculated from these
Missouri	All utilities	SAIDI, SAIFI, CAIDI, CAIFI	IEEE Standard	none
Nevada	All utilities	SAIDI, SAIFI, CAIDI, MAIFI	catastrophic event that results in a simultaneous sustained interruption to more than 10 percent of the customers in an operating area and requires longer than 24 hours for full restoration of service to customers	none
New Jersey	All utilities	SAIFI, CAIDI	a sustained interruption of service resulting from conditions beyond the control of the utility, which affect at least 10% of customers in an operating area	5-year rolling average
New Mexico	All utilities	SAIDI, SAIFI, CAIDI, ASAI (Average System Availability Index)	IEEE Standard	none
New York	Rochester Gas & Electric	SAIFI, CAIDI	outages caused by major storms, major catastrophic events (such as plane crashes), and events that result from the orders of NYISO	CAIDI = 1.90 hours; SAIFI = 0.9
	Con Edison	SAIFI, CAIDI	outages caused by major storms, major catastrophic events (such as plane crashes), and events that result from the orders of NYISO	Network benchmarks: CAIDI = 3.74 hours; SAIFI = 0.015 Radial benchmarks: CAIDI = 1.85 hours; SAIFI = 0.530
	Niagara Mohawk (National Grid)	SAIFI, CAIDI	outages caused by major storms, major catastrophic events (such as plane crashes), and events that result from the orders of NYISO	CAIDI = 2.07 hours; SAIFI = 0.93
	Central Hudson Gas & Electric	SAIFI, CAIDI	outages caused by major storms, major catastrophic events (such as plane crashes), and events that result from the orders of NYISO	CAIDI = 2.50 hours; SAIFI = 1.45
	New York State Electric & Gas	SAIFI, CAIDI	outages caused by major storms, major catastrophic events (such as plane crashes), and events that result from the orders of NYISO	two-tiered system: CAIDI = 2.08/2.18 hours; SAIFI = 1.20/1.26
	Orange & Rockland	SAIFI, CAIDI	outages caused by major storms, major catastrophic events (such as plane crashes), and events that result from the orders of NYISO	CAIDI = 1.70 hours; SAIFI = 1.10

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Table 1

US Jurisdiction[1]	Companies Involved	Indicators	Normalization for Exceptional Events	Benchmarks
North Dakota	Montana-Dakota Utilities Company	SAIDI, SAIFI	IEEE Standard	none
Ohio	Cleveland Electric Illuminating (First Energy)	SAIDI, SAIFI, CAIDI, ASAI	event caused by a major storm, or comparable term as defined by the utility, and also by the transmission system	Company proposed standards: SAIFI (1.72) CAIDI (144) Commission proposed standards: SAIFI (1.28) CAIDI (132.72)
	Ohio Edison (First Energy)	SAIDI, SAIFI, CAIDI, ASAI	event caused by a major storm, or comparable term as defined by the utility, and also by the transmission system	Company proposed standards: SAIFI (1.31) CAIDI (121) Commission proposed standards: SAIFI (1.09) CAIDI (114.37)
	Toledo Edison (First Energy)	SAIDI, SAIFI, CAIDI, ASAI	event caused by a major storm, or comparable term as defined by the utility, and also by the transmission system	Company proposed standards: SAIFI (1.28) CAIDI (134) Commission proposed standards: SAIFI (.8) CAIDI (112.33)
	Columbus Southern Power (AEP)	SAIDI, SAIFI, CAIDI, ASAI	event caused by a major storm, or comparable term as defined by the utility, and also by the transmission system	Company proposed standards: SAIFI: 2009 (1.68) 2010 (1.63) 2011 (1.58) CAIDI: 2009 (136.1) 2010 (135.1) 2011 (134.4) Commission proposed standards: SAIFI: 2009 (1.66) 2010 (1.61) 2011 (1.56) CAIDI: 2009 (137.42) 2010 (136.19) 2011 (135.36)
	Ohio Power (AEP)	SAIDI, SAIFI, CAIDI, ASAI	event caused by a major storm, or comparable term as defined by the utility, and also by the transmission system	Company proposed standards: SAIFI: 2009 (1.3) 2010 (1.26) 2011 (1.23) CAIDI: 2009 (186.0) 2010 (184.5) 2011 (183.5) Commission proposed standards: SAIFI: 2009 (1.35) 2010 (1.30) 2011 (1.26) CAIDI: 2009 (172.29) 2010 (170.40) 2011 (169.22)
	Dayton Power & Light	SAIDI, SAIFI, CAIDI, ASAI	IEEE Standard	Standards based on Stipulation and Recommendation of the company, the Office of the Ohio Consumers Counsel (OCC) and the commission staff: SAIFI: (1.07) CAIDI: (125.51)
	Cincinnati Gas & Electric (Duke Energy-Ohio)	SAIDI, SAIFI, CAIDI, ASAI	event caused by a major storm, or comparable term as defined by the utility, and also by the transmission system	Company proposed standards: SAIFI 2009 (1.5) 2010 (1.44) 2011 (1.38) 2012 (1.31) 2013 (1.24) 2014 (1.17) 2015 (1.1) 2016 and forward (1.1) CAIDI (140.4) Commission proposed standards: SAIFI: 2010 (1.44) 2011 (1.38) 2012 (1.31) 2013 (1.24) 2014 (1.17) 2015 (1.1) 2016 and forward (1.1) CAIDI: 2010 (101.92) 2011 (106.42) 2012 (110.92) 2013 (115.42) 2014 (119.92) 2015 (124.37) 2016 and forward (124.37)

[1] US survey is limited to investor-owned utilities.

Table 1

US Jurisdiction[1]	Companies Involved	Indicators	Normalization for Exceptional Events	Benchmarks
Oklahoma	Public Service Company of Oklahoma and Public Service Company of Oklahoma	SAIDI, SAIFI, MAIFI	a catastrophic event that exceeds system design limits and causes loss of service to 10% or more of the customers in a region for more than 24 hours	none
Oregon	Pacific Power & Light	SAIDI, SAIFI, CAIDI, MAIFI	a catastrophic event that exceeds limits of electric power system, causes extensive damage to the system and results in outage to more 10% of metering points in an operating area	2009 R1 (SAIDI) = 2.8 hours R2 (SAIFI) = 1.5 R3 (MAIFI) = 6 occurences R4 (CAIDI) = 2 hours
	Portland General Electric	SAIDI, SAIFI, CAIDI, MAIFI	a catastrophic event that exceeds limits of electric power system, causes extensive damage to the system and results in outage to more 10% of metering points in an operating area	2009 R1 (SAIDI) = 1.33 hours R2 (SAIFI) = 1.0 occurences R3 (MAIFI) = 3 occurences R4 (CAIDI) = 2 hours
Pennsylvania	All utilities	SAIDI, SAIFI, CAIDI, MAIFI	an abnormal event that results in service interruption to at least 10% of customers in a utility's service territory; or an unscheduled interruption undertaken to maintain the adequacy and security of the system	3-year rolling averages
Rhode Island	National Grid	SAIDI-Coastal, SAIDI-Capital,SAIFI-Coastal, SAIFI-Capital	IEEE Standard	SAIDI-Coastal: Penalty over 82.7/Bonus under 52.7 SAIDI-Capital: Penalty over 70.3/Bonus under 44.7 SAIFI-Coastal: Penalty over 1.43/Bonus under 0.99 SAIFI-Capital: Penalty over 1.27/Bonus under 0.83
Texas	All utilities	SAIDI, SAIFI	interruptions that result from catastrophic events that exceed system design limits and cause loss of power to at least 10% of customers in a region for more than 24-hours	SAIDI, SAIFI values not to exceed 5% of a standard based on 1998-2000 values or the first 3 reporting years the utility is in operation
Utah	Rocky Mountain Power (PacifiCorp Utah)	SAIDI, SAIFI	IEEE Standard	SAIDI = 217 minutes SAIFI = 2.21 interruptions
Vermont	Central Vermont Public Service	SAIFI, CAIDI	severe weather event that causes outage to more than 10% of customers in the service territory, or outage that lasts more than 24-hours to at least 1% of customers in the service territory	SAIFI = 2.5, CAIDI = 3.5
	Green Mountain Power	SAIFI, CAIDI	severe weather event that causes outage to more than 10% of customers in the service territory, or outage that lasts more than 24-hours to at least 1% of customers in the service territory	SAIFI = 1.7, CAIDI = 2.2
Virginia	All utilities	SAIDI, SAIFI, CAIDI	no commission guidelines on major events, but two utilities use the following definitions: outages requiring restoration efforts greater than 24 hours; outages that affect more than 10,000 or 10% of the customers in a local service area	none
Washington	Avista	SAIDI, SAIFI, CAIDI, MAIFI	An event that impacts more than 5% of the Company's customers and causes outages of more than 24 hours in duration in any given division withi its territory	none
	Scottish Power-Pacificorp	SAIDI, SAIFI, CAIDI	A catastrophic event that exceeds design limits of the electric power system and is characterized by more than 5% of the customers out of service during a 24-hour period	none
	Puget Sound Energy	SAIDI, SAIFI	major events defined to be 5% or more customers out of service during a 24-hour period and the associated carry-forward days; IEEE definition (& metrics) of major event days is also in effect	SAIDI = 136 minutes; SAIFI = 1.30 interruptions
Wisconsin	All utilities	SAIDI, SAIFI, CAIDI	outages caused by major storms & catastrophic events that affect at least ten percent of the customers in the system or in an operating area and/or result in customers being without electric service for durations of at least 24 hours	none

[1] US survey is limited to investor-owned utilities.

Table 1

Canadian Jurisdiction	Companies Involved	Indicators	Normalization for Exceptional Events	Benchmarks
Alberta	All utilities except Enmax	SAIDI, SAIFI, CAIDI	Varies by company	No explicit benchmarks, however, reported indicators are compared to prior year performance
	Enmax	SAIFI	IEEE 2.5 beta method	30 minutes (five year rolling average)
		SAIDI	IEEE 2.5 beta method	1.00 interruptions (five year rolling average)
British Columbia	BC Hydro	SAIFI, CAIDI, CEMI-4	Reports using own exclusion criteria and CEA's; BC Hydro's adjustment for uncontrollable events are for those that result in 70,000 or more lost customer hours or losses of more than 1% of customer hours on the system	No regulatory benchmarks
	Fortis BC	SAIDI	IEEE 2.5 beta method	Based on average of prior 3 years, 2010 target: 2.40 (excluding major events), 3.59 (including major events)
		SAIFI		Based on average of prior 3 years, 2010 target: 2.17 (excluding major events), 3.19 (including major events)
Manitoba	None	None	None	None
New Brunswick	None	None	None	None
Newfoundland & Labrador	Newfoundland Hydro	SAIFI, SAIDI	None	No explicit benchmarks, however, reported indicators are compared to a composite of CEA member companies
Nova Scotia	None	None	None	None
Prince Edward Island	Maritime Electric	SAIDI	Excludes events that affect more than 10% of customers for more than 10 minutes	Including Major Events: Target <6 hours, Maximum 9 hours; Excluding Major Events: Target <5 hours, Maximum 7 hours
		SAIFI		Including Major Events: Target <4 times, Maximum 7 times; Excluding Major Events: Target <4 times, Maximum 6 times
		CAIDI		Including Major Events: Target <1.5 hours, Maximum 3.5 hours Excluding Major Events: Target <1 hour, Maximum 3 hours
		Service Level Index	None	Target service level of 99.9%; Minimum service level 99.70%
Quebec	None	None	None	None
Saskatchewan	None	None	None	None
Yukon Territory	All	SAIDI, SAIFI, CAIDI, Index of Reliability	None (Yukon Electric excludes loss of supply from Yukon Energy Corp.)	No explicit benchmarks, however, reported indicators are compared to a composite of CEA member companies

Table 1

European Jurisdiction	Companies Involved	Indicators	Normalization for Exceptional Events	Benchmarks
Austria	132 Distribution System Operators (DSOs)	ASIDI (Avg system interruption duration index), ASIFI (Average system interruption frequency index), ENS (Energy Not Supplied)	Natural disaster where a crisis situation is declared by a local authority and/or the federal or provincial government takes measures aimed at providing financial support (e.g. catastrophe funds)	none
Belgium	27 Distribution System Operators (DSOs)	SAIDI, SAIFI, CAIDI (regional level) AIT (Avg Interruption Time), AIF (Avg Interruption Frequency), AID (Avg Interruption Duration) (federal level)	Force majeure defined as all reasonably unforeseeable situations such as natural disasters, strikes, computer viruses, fire, sabotage, war	none
Czech Republic	3 Distribution System Operators (DSOs)	SAIDI, SAIFI	none	none
Denmark	89 Distribution Network Companies	SAIDI, SAIFI, ENS	Exceptional events: Hurricanes and floods	none
Estonia	40 Distribution Network Operators	SAIDI, SAIFI, ENS	Force majeure: interruptions caused by events of long duration, such as natural disasters, heavy winds or glazed frost that exceeds design norm, wars	none
Finland	88 Distribution Network Operators	SAIDI, T-SAIDI (Transformer SAIDI), T-SAIFI (Transformer SAIFI)	none	none
France	EDF and 170 other Distribution System Operators	SAIFI, ENS, AIT, MAIFI	Exceptional event as defined by a simultaneous interruption of service to more than 100,000 end users; caused by a climatic event that whose probability of occurrence is less than 1/20 years	none
Germany	256 Distribution Network Operators	SAIDI, SAIFI	Force majeure: an interruption caused externally as a result of elemental natural forces (natural disasters) or by actions of a third party (such as strikes, terrorism, war), which cannot be foreseen	none
Hungary	6 Distribution Companies	SAIDI, SAIFI, MAIFI	Exceptional events as defined by service interruptions that affect more than 50,000 customers; caused by system collapse, terror attacks etc.	3-year rolling average
Ireland	1 Distribution System Operator (DSO)	CML (Customer minutes lost), CI (Customer interruptions)	Storms and exceptional events: where outage is more than 2 standard deviations from the 1999,2000, and 2001 mean on a national basis	Benchmarks for CI of and CML set by the regulator for each year of the 2006-2010 price control period
Italy	more than 300 territorial districts served by the 24 major distribution companies	SAIDI, SAIFI, MAIFI	Exceptional condition periods - a reliability indicator that exceeds a statistically-derived threshold based on a function of the average number of faults in a 6-hour time interval as observed in the three year time period preceding the reference year	For each district a “reference level” of continuity of supply to be reached after 2012 has been defined by the regulator.

Table 1

European Jurisdiction	Companies Involved	Indicators	Normalization for Exceptional Events	Benchmarks
Lithuania	7 Distribution Network Operators (DNOs) - 2 regional and 5 local	SAIDI, SAIFI, MAIFI	Force Majeure: natural disasters, fires, war, terrorist acts, activities of a third person, actions of the State or conditions of the state of necessity	none
The Netherlands	9 Regional Network Operators	SAIDI	Force majeure: incidents caused by infrequent events that are uneconomical to take into account in the regulatory system and that are beyond the control of the grid manager, such as powerful earthquakes, major floods, wars	The average SAIDI of all regional network operators over M years prior to the current regulatory period, where M is the length of the current regulatory period
Norway	7 main Distribution System Operators (DSO's)	SAIDI, SAIFI, CAIDI, CTAIDI (Customer total average interruption duration index), CAIFI, ENS	Extraordinary situations: defined on a case-by-case basis, but these are not usually excluded from reliability metric calculations	"Expected total interruption" calculated from a regression model
Poland	14 Distribution System Operators (DSOs)	SAIDI, SAIFI, MAIFI	Force majeure: outages caused by events beyond the control of the utility including natural disasters (e.g. earthquakes), acts of state (e.g. martial law), sabotage, war, terrorism, strikes or social unrest	none
Portugal	The main Distribution Distribution Operator & 10 other small DSOs	SAIDI, SAIFI, TIEPI (Interruption Time Equivalent to Installed Capacity)	Force majeure: outages caused by unpredictable events beyond the control of the utility Security situations: supply interrupted to ensure the safety of people and goods	Energy Not Supplied (ENS) Reference = 0.0004 x ES (Energy supplied in the year)
Romania	35 Distribution Operators (8 of which are major)	SAIDI, SAIFI, ENS, AIT	Force majeure: Incidents beyond the utility control, and certified by competent authority in accordance with the law, such as strikes, wars, embargo, revolutions, earthquakes, fires, floods or other natural disasters	none
Slovenia	5 Distribution Companies (run by 1 distribution system operator)	SAIDI, SAIFI	Force majeure: outage caused by forces that exceed system design limit	none
Spain	5 Distribution System Operators	TIEPI, NIEPI (Equivalent number of interruptions related to the installed capacity)	severe by a compotent administration or by events that are not statistically common	benchmark for each reliability measure for urban, semi-urban, rural and scatter rural areas
Sweden	174 Electricity Network Companies	SAIDI, SAIFI, ENS, AIT	none	"Expected total interruption" computed using a Network Performance Assessment Model (PAM)
United Kingdom	14 Distribution Network Operators (DNOs)	CML, CI, SI (short interruptions)	Exceptional events: weather related events that result in more than eight times the daily average fault rate on higher voltages and non-Weather related events that are outside of the DSOs control that result in more than 25,000 customers interrupted and/or 2 million customer - minutes lost	Benchmarks set using the typical performance of 22 circuit groupings

Table 1

ANZ Jurisdictions	Companies Involved	Indicators	Normalization for Exceptional Events	Benchmarks
Australian Capital Territory	All	Unplanned SAIDI, Unplanned SAIFI, MAIFI	IEEE 2.5 beta method, load shedding and load interruptions outside distributors' control	None
New South Wales	All	Unplanned SAIDI, Unplanned SAIFI, MAIFI	IEEE 2.5 beta method, load shedding and load interruptions outside distributors' control	None
Northern Territory	All	SAIDI	Exclude load shedding	Darwin: 219.9 minutes; Katherine: 401.0 minutes; Tennant Creek: 411.0 minutes; Alice Springs: 108.0 minutes
		SAIFI		Darwin: 4.2 interruptions; Katherine: 9.6 interruptions; Tennant Creek: 9.8 interruptions; Alice Springs: 2.9 interruptions
		CAIDI		Darwin: 52.0 minutes; Katherine: 42.0 minutes; Tennant Creek: 41.8 minutes; Alice Springs: 37.2 minutes
Queensland	All[1]	SAIDI	Exclusion of interruptions caused by generation or transmission sources, customers, or occurring during a major event day as defined by the IEEE 2.5 beta methodology	CBD: 15 minutes; Urban: 106 minutes; Short Rural: 218 minutes
		SAIFI		CBD: 0.15 interruptions; Urban: 1.26 interruptions; Short Rural: 2.46 interruptions
South Australia	All	unplanned SAIDI	None	Adelaide Business Area: 25 minutes; Major Metropolitan Areas: 115 minutes; All other areas: range between 240 minutes and 450 minutes
		unplanned SAIFI		Adelaide Business Area: 0.3 interuptions; Major Metropolitan Areas: 1.40 interruptions All other areas: range between 2.1 and 3.3 interruptions
Tasmania	All	SAIDI (planned and unplanned)	Generation, transmission, third party caused outages, load shedding	Critical Infrastructure: 30 minutes, High Density Commercial: 60 minutes, Urban and Regional Centres: 120 minutes, High Density Rural: 480 minutes, Lower Density Rural: 600 minutes
		SAIFI (planned and unplanned)		Critical Infrastructure: 0.2 interruptions, High Density Commercial: 1 interruption, Urban and Regional Centres: 2 interruptions, High Density Rural: 4 interruptions, Lower Density Rural: 6 interruptions
		MAIFI		None
		CAIDI (planned and unplanned)		
Victoria	All[2]	SAIDI (unplanned outages only)	Exclusion of major events based on SAIFI based on a once in five year major event, load shedding due to shortfall in non-embedded generation or DSM activities; Companies report normalized values for penalty/reward targets and unnormalized values for monitoring purposes.	Urban: 73.0; Rural: 113.0
		SAIFI (unplanned outages only)		Urban: 1.27; Rural: 2.25
		MAIFI		Urban: 0.8; Rural: 2.6
		SAIDI (planned outages only)	None	Urban: 6.0; Rural: 14.0
		SAIFI (planned outages only)	None	Urban: 0.03; Rural: 0.08
Western Australia	Western Power[3]	SAIDI	IEEE 2.5 beta method, outages caused by fault on transmission or third party system, planned outages, force majeure events	CBD: 38; Urban: 162; Rural Short: 253; Rural Long: 588
		SAIFI		CBD: 0.24; Urban: 1.89; Rural Short: 3.06; Rural Long: 4.85
New Zealand	All	SAIDI, SAIFI	IEEE 2.5 beta method, deadband added to reduce likelihood of "false positives"	Varies by company but benchmarks based on average performance between 2004 and 2009

[1] The benchmarks vary by company, by year, and by whether the area is urban or rural. The standards for Energex are listed here for the year starting July 1, 2010.
[2] The benchmarks vary by company and by whether the area is urban or rural. The standards for Australia Gas Light are listed here.
[3] Western Power is the largest distributor in Western Australia. Benchmarks for Western Power change from year to year. Benchmarks listed here are for the year starting March 1, 2010.

CAIDI and two regulate SAIDI, SAIFI, and CAIDI. Another somewhat commonly-regulated metric in Europe is Energy Not Supplied (ENS), which is a measure of the power would have been supplied during interruptions and is regulated in seven jurisdictions. Since ENS reflects the energy that is lost during outages, when this indicator is multiplied by an estimate of customers' valuation of reliability, the result is an estimate of the economic losses to customers from power interruptions. The ENS indicator is therefore potentially useful for levying penalties and rewards. In Australia, all eight States and Territories regulate both SAIFI and SAIDI, as does the country of New Zealand. No Australian jurisdictions regulate SAIFI and CAIDI and two regulate SAIFI, SAIDI, and CAIDI. The table below provides summary information on the frequency of system reliability indicators in different jurisdictions.

Frequency of Jurisdictional Use of Service Reliability Indicators

	US	Canada	Europe	Australia/New Zealand
SAIDI only	0	0	1	0
SAIFI only	0	0	1	0
SAIDI and SAIFI	11	3	13	7
SAIFI and CAIDI	5	1	0	0
SAIDI, SAIFI, and CAIDI	22	3	2	2
Total	38	7	17	9

Washington, Alberta, and British Columbia are counted in multiple categories as they have separate plans that use different reliability indicators.

The momentary average interruption frequency index (MAIFI) is regulated much less frequently than the sustained interruption metrics SAIFI and SAIDI. We identified eight US States, five European countries and four Australian jurisdictions that regulate MAIFI. No jurisdiction in Canada currently regulates MAIFI, to the best of our knowledge. One reason MAIFI is regulated less often is that more sophisticated and costly equipment and information systems are needed to measure MAIFI.

Increasingly, the IEEE 1366 standard is being used as the basis for normalizing reported reliability measures, at least in the English-speaking world. In the US, 12 States use the IEEE standard, although 16 still use the more traditional metric of excluding events where at least 10% of customers on the network are interrupted (5% in Washington State). The IEEE standard is also used by Enmax, Fortis, and in Quebec;

Maritime Electric uses the 10% of customers interrupted standard. The IEEE standard is also used in four Australian States and New Zealand. Somewhat surprisingly, however, the IEEE Standard is apparently not used in Europe, which instead excludes "force majeure" events that are typically defined and determined on a case-by-case basis.

In the US, Europe, and ANZ, system reliability benchmarks are relatively common. These benchmarks can be the basis for more formal penalty/reward mechanisms. In many cases, these penalty/reward regimes have been implemented in jurisdictions where there is a long history of PBR (*e.g.* California, Massachusetts, Maine), while in others, penalty mechanisms have been implemented in conjunction with merger agreements. In the US, eight States and the District of Columbia have system reliability targets for some of the utilities in the State, while 12 States have penalty/reward mechanisms for at least some utilities in the State. Seventeen US States have system reliability monitoring regimes. In Europe, there are nine countries with penalty/reward mechanisms, 12 with system reliability monitoring, and no system reliability targeting regimes. In ANZ, there are four penalty/reward plans (including all of New Zealand, which is penalty-only), two service target regimes, and three monitoring regimes.

The situation is somewhat different in Canada. Ontario has what we would deem a target regime, although the target is not clearly defined; utilities are expected to maintain a three-year moving average of their system reliability performance within historical levels. Outside Ontario, PEG was able to identify only three utilities that use system reliability benchmarks: Enmax in Alberta (which is subject to a penalty regime); Fortis in British Columbia (where penalties can be imposed); and Maritime Electric in Prince Edward Island (a targeting regime). The benchmarks for Fortis are based on the company's own three-year moving average performance. For Enmax, the benchmark for SAIDI is given by the company's three-year moving average, while the SAIFI benchmark is equal to the five-year moving average. The bases for the Maritime Electric benchmarks are not clear.

Like Canada, in most other jurisdictions, approved benchmarks for system reliability are based on the company's own historical performance. A particular, "rule-based" example of this approach comes from Massachusetts. A statewide, generic review of service quality issues in 2000 established benchmarks for each Massachusetts gas and electric power distributor based entirely on the company's past performance on a service quality indicator. For all electricity indicators except SAIFI and SAIDI, benchmarks were based on 10 years' worth of data. Benchmarks for SAIFI and SAIDI were originally based on five years' worth of data.[21] However, Massachusetts' service reliability standards were reviewed in 2006, and this update revised the calculation of SAIFI and SAIDI benchmarks in the State so that they were based on ten years' worth of data.

Benchmarks in New Zealand are also based on each company's average, multi-year performance. Reliability benchmarks in Australia also depend on historical performance, although they are ultimately based on negotiation rather than through moving-average formulas. One interesting aspect of Australian regulation is that there are often separate benchmarks for urban, rural, and central business district areas. One reason is that, compared with most jurisdictions, Australian electricity distributors often serve very large territories that contain both urban and very remote rural areas.

In contrast, in Europe, there are several examples of more "external" system reliability benchmarks that are not linked directly to a company's own historical performance. Such comparisons can be to a "peer" utility or a "peer group." These benchmarks can also be constructed through econometric or engineering models.

In the Netherlands, for example, the 2007-2010 distribution price controls reflect differences between the SAIDI of a given company and the average SAIDI of the power distribution industry. The SAIDI benchmark was set using 2004-05 data since 2003 reliability data were not available for all distributors. After 2010, however, the SAIDI benchmark will be set using three-year averages (*i.e.* 2006-08) of SAIDI for the Netherlands' entire power distribution industry.

Norway has also implemented an innovative approach to setting service quality benchmarks for power distributors. Beginning in 2001, prices for each distributor were

[21] If a company did not have ten years of data on an indicator, new data would be used to update benchmarks until 10 years of data were available.

adjusted to include an allowance for energy not supplied. An *expected* value for ENS was determined for each distributor. The expected ENS was generated using an econometric model in which ENS is a function of a variety of business condition variables, including weather and the length of the network. Model parameters were estimated using historical data from the Norwegian power distribution industry. Each company's expected ENS was then determined by multiplying the parameter estimates by the average values of the business condition variables expected for a given company.

Each year, the distributor's annual ENS is compared to the benchmark, expected value. This difference is then multiplied by the value of reliability. This valuation of reliability is also tailored to each distributor to reflect its customer mix. If the difference is positive (*i.e.* reliability has been better than expected), it is added to the company's capped revenue for the following year. If the difference is negative (*i.e.* reliability has been worse than expected), it is subtracted from the company's capped revenue for the following year. This is a type of "Q factor" adjustment to allowed revenues, although it is not based explicitly on a comparison between company and industry reliability measures (as in the Netherlands). Rather, the target is determined using industry data and regression methods that establish a benchmark level of reliability that is expected if an average firm in the industry operated under the specific business conditions of the company in question.

A broadly similar approach has recently been adopted in Sweden. However, the benchmarks for the Swedish distributors are determined through a Network Performance Assessment Model (PAM), which is calibrated using engineering rather than econometric techniques. Generally speaking, the PAM determines the optimal network design and predicted reliability levels depending on a variety of network design features. Similar engineering-based models have been used to assess network cost efficiency in Spain and Chile, although they have not (to the best of our knowledge) been applied to assessing system reliability performance.

5.2 Circuits and Restoration Standards

Table Two shows examples of circuit reliability indicators that are regulated. Such indicators are relatively common in US regulation. Twenty eight states include

Table 2

Circuit Indicators

US Jurisdiction	Circuits Reported
Alabama	Worst 10
California	Any with SAIFI above 12
Colorado	Aquila reports 10 worst by SAIDI Reliability Warning Threshold (RWT) for SAIDI-ODI & 5 ODIs/year for each of PSCO's nine regions
Connecticut	Worst 100
Delaware	Worst 10
DC	Worst 3% by CAIDI
Florida	Worst 3% by SAIDI
Idaho	Pacificorp reports worst 5 by CPI (Circuit Perfomance Indicator): Weighted avg of SAIDI, SAIFI, MAIFI and cirucit breaker lockouts
Illinois	Worst by SAIDI, SAIFI, CAIDI. Targets for SAIFI of 6 and CAIDI of 18 set.
Kansas	Worst 10 by SAIDI, SAIFI
Louisiana	Worst 5% by SAIDI and SAIFI
Maryland	Worst 2%
Massachusetts	Worst 5% by SAIDI or SAIFI. Compare averages of worst circuits to rest.
Michigan	No more than 5% of circuits should have 5 outages/year. No circuits should have 8 or more outages/year.
Minnesota	Worst circuits
Nevada	Worst 25 by CAIDI, SAIDI, SAIFI
New Jersey	Worst 5 by SAIFI or CAIDI
New York	Worst 5% by SAIFI or CAIDI
Ohio	Worst 8% for all utilities AEP reports SAIDI for all circuits.
Oklahoma	Worst by SAIDI, SAIFI
Oregon	Worst 5
Pennsylvania	Worst 5% by SAIFI, CAIDI
Rhode Island	Worst 5% by SAIFI
Texas	Worst 10% by SAIDI, SAIFI. Compare one year's "worst list" to next. Note if any are above 300% of sample average.
Utah	Pacificorp reports worst 5 by CPI: Weighted avg, SAIDI, SAIFI, MAIFI.
Vermont	Worst 10
Washington	Pacificorp reports worst 5 by CPI: Weighted avg, SAIDI, SAIFI, MAIFI.
Wisconsin	Worst by SAIDI, SAIFI, CAIDI

Table 2

All Other Jurisdictions	Circuit Reporting & Performance Standards
Alberta	3% worst performing circuits based on each distributor's formalized evaluation process
Ireland	worst 15 MV feeders
South Australia	Identify worst performing feeders in each region each year
Tasmania	No more than 5% of all feeders shall exceed total interruption time of 60 minutes in the Central Business District, 240 minutes for other urban feeders, and 720 minutes for rural feeders
	No more than 5% of all feeders shall experience more than 2 interruptions in the Central Business District, 4 interruptions for other urban feeders, and 9 interruptions for rural feeders
Victoria[1]	Worst 5% of feeders are reported, Targeted levels of SAIDI for worst served 15% of customers no more than 267 minutes.
	Worst 5% of feeders are reported, SAIDI of CBD feeders over 70 minutes (>1 interruption) SAIDI of Urban feeders over 270 minutes or a MAIFI over 5 SAIDI of short rural feeders over 600 minutes or MAIFI over 12 SAIDI of Long rural feeders over 850 muinutes or MAIFI over 25

[1] This number varies by company. We report here the values for Australia Gas Light.

some type of regulation of worst performing circuits on the system. For example, Massachusetts measures SAIFI and SAIDI performance for the worst 5% of each LDC's circuits and compares these worst-performing circuit averages to system-wide SAIFI and SAIDI, respectively. In Texas, the worst 10% of circuits are reported for SAIFI and SAIDI performance, and the list of "worst" circuits is compared to that of the previous year. Regulatory attention is particularly focused on any circuit in excess of 300% of system-wide SAIFI or SAIDI performance. Three of the eight States or Territories in Australia also have worst circuit regulation, although New Zealand does not. In contrast, there is only example of worst circuit regulation in Canada (Alberta) and one example in Europe (Ireland).

Table Three shows examples of Severe Storm/Restoration indicators. These indicators are relatively uncommon. There are eleven severe storm/restoration indicators in the US and seven in Europe. In contrast, there are none in Canada or ANZ. The indicators that do exist usually pertain to connecting all or nearly all customers within a defined interval. In the US, this interval is usually 24 hours; in Europe, this interval is lower in four cases, and similar or longer in three instances.

Most restoration indicators set standards regarding the maximum amount of time it takes to connect all (or nearly all) customers after any outage event. For example, Pacificorp in Utah is expected to connect customers and end repair on 80% of circuits within 3 hours, and connect customers within 24 hours, in all instances. In some instances, restoration indicators also extend to severe storm situations. For example, in Michigan, the standard is to end repair in 16 hours in most situations, or 120 hours in emergencies.

Whether or not restoration indicators include severe storms, one reason for including them is that "standard" system metrics like SAIFI and SAIDI can mask substandard reliability performance. In the case of severe storms, this is because severe events are typically normalized out of reported SAIFI and SAIDI. More generally, it is simply because the outage experience of an individual customer will have an insignificant impact on the measured system-wide reliability performance. These indicators are therefore designed to supplement system-wide reliability metrics to ensure that "pockets"

Table 3

Severe Storms/Restoration Standards

Jurisdictions	Company	Standard
Arkansas	Statewide	End repair on all circuits within 24 hours
California	Statewide	System-wide CAIDI
Colorado	Public Service of Colorado	End repair in 24 hours
Delaware	Statewide	Begin repair within 2 hours
Idaho	Pacificorp	End repair in 24 hours
		End repair on 80% of circuits within 3 hours, all within 24 hours
Michigan	Statewide	End repair on 90% of circuits in 8 hours (normal), 60 hours (emergency), 36 hours (total)
		End repair in 16 hours, or 120 in case of emergency
New York	Con Edison	Penalites for any outage lasting more than 3 hours
New Jersey	Atlantic City Electric	End repair in 24 hours
	Statewide	Begin repair within 2 hours
Utah	Pacificorp	End repair in 24 hours
		End repair on 80% of circuits within 3 hours, all within 24 hours
Washington	Pacificorp	End repair in 24 hours
		End repair on 80% of circuits within 3 hours, all within 24 hours
Wyoming	Cheyenne L&P	End repair on all circuits within 24 hours

Table 3

Severe Storms/Restoration Standards

European Jurisdiction	Companies Involved	Standard
Austria	132 Distribution System Operators (DSOs)	NA
Belgium	27 Distribution System Operators (DSOs)	NA
Czech Republic	3 Distribution System Operators (DSOs)	NA
Denmark	89 Distribution Network Companies	NA
Estonia	40 Distribution Network Operators	power restored within 3 days
Finland	88 Distribution Network Operators	power restored within 12 hours
France	EDF and 170 other Distribution System Operators	80% of affected customers within 24 hours, and 95% in 120 hours
Germany	256 Distribution Network Operators	NA
Hungary	6 Distribution Companies	power restored within 18 hours
Ireland	1 Distribution System Operator (DSO)	NA
Italy	more than 300 territorial districts served by the 24 major distribution companies	LV customers: power restored within 8-16 hours MV customers: power restored within 4-8 hours
Lithuania	7 Distribution Network Operators (DNOs) - 2 regional and 5 local	NA
The Netherlands	9 Regional Network Operators	NA
Norway	7 main Distribution System Operators (DSO's)	NA
Poland	14 Distribution System Operators (DSOs)	NA
Portugal	The main Distribution Distribution Operator & 10 other small DSOs	NA
Romania	35 Distribution Operators (8 of which are major)	NA
Slovenia	5 Distribution Companies (run by 1 distribution system operator)	NA
Spain	5 Distribution System Operators	NA
Sweden	174 Electricity Network Companies	power restored within 12 hours
United Kingdom	14 Distribution Network Operators (DNOs)	power restored within 24 hours (intermediate events) and within 48 to 141 hours (large/more severe events)

of reliability problems that may not be captured in SAIFI and SAIDI are nonetheless addressed through regulation.

5.3 Regulatory Responses

The survey of Regulatory Responses to system reliability performance, and potential problems, is presented on Table Four. PEG has identified 12 US states that levy penalties and/or rewards based on system reliability and/or circuit performance. Most of these penalties or rewards take place through rule-based mechanisms that compare measured reliability to a benchmark, plus or minus and deadband. Six US states have service reliability targeting mechanisms, and 14 states have service reliability monitoring. Penalty and reward regimes are at least as prevalent in Europe and ANZ. Nine European jurisdictions levy penalties and rewards for system reliability performance, while 12 undertake system reliability monitoring. In Australia, three states have penalty and/or reward mechanisms, two have system reliability targets, and three have system reliability monitoring. New Zealand also has a penalty regime. In Canada, outside Ontario there are two penalty regimes (Enmax in Alberta and Fortis in BC), and one target regime (Maritime Electric). Both of the approved penalty regimes were part of a broader PBR plan for the company. System reliability monitoring takes place for other electric utilities in Alberta, British Columbia, Newfoundland and Labrador, and the Yukon Territory. System reliability regulation is largely absent in other Provinces, although reliability performance can be considered at rate reviews. It is notable that while Quebec does not regulate system reliability. Hydro Quebec's relative cost and reliability performance is considered at rate reviews.

An example of a European system reliability incentive plan is in the Netherlands, where the "CPI-X" price cap includes a "Q-factor". The Q factor compares each company's SAIDI performance to a benchmark equal to the average SAIDI value for *all* Dutch distributors for the 2004-05 period. The Q factor adjustment will take place at the end of the three-year regulatory period based on each company's SAIDI performance over the entire 2007-2010 period. This is being done because SAIDI values can fluctuate from year to year because of factors beyond company control. The actual value of the Q

Table 4

Regulatory Responses

US Jurisdiction	Companies Involved	System Reliability	Worst Circuits	Severe Storm Restoration
Alabama	All utilities	Service Reliability Monitoring	Plan for future action	none
Arkansas	All utilities	none	none	Explanation
California	Pacificorp, Sierra Pacific Power	Service reliability Monitoring	Explanation	Explanation
	San Diego Gas & Electric, Southern California Edison, Pacific Gas & Electric	Penalty/Reward		
Colorado	Public Service Company of Colorado, Aquila	Penalty/Reward (SAIDI)	Explanation (Aquila only)	Penalty per customer of $50, capped at $1M. (Public Service Company of Colorado only)
Connecticut	All utilities	Service Reliability Monitoring	Explanation	none
D.C.	Pepco	Service Reliability Target	Plan for future action	none
Delaware	Delmarva Power & Light	Penalty/Reward (SAIDI)	Plan for future action	Explanation
	Delmarva Power & Light	Service Reliability Monitoring (SAIFI, CAIDI)		
Florida	All utilities	Service Reliability Monitoring	Report actions undertaken	none
Georgia	All utilities	Service Reliability Monitoring	none	none
Hawaii	All utilities	Service Reliability Monitoring	none	none
Idaho	Scottish Power-Pacificorp	none	Penalty up to $1/customer if average CPI of each worst circuit not 20% better in two years.	Penalty per customer of $1 paid directly to customers Penalty per customer of $50 + $25/each incremental 12-hour interval
Illinois	All utilities	Service Reliability Target	Utility reports past and future action.	none
Indiana	Duke Energy	Service Reliability Target	none	none
	Other Utilities	Service Reliability Monitoring		
Iowa	All utilities	Service Reliability Monitoring	none	none
Kansas	All utilities	Service Reliability Monitoring	Plan for future action	NA
Kentucky	All utilities	Service Reliability Monitoring	none	none
Louisiana	All utilities	Penalty/Reward	Report actions undertaken	none
Maine	Central Maine Power	Penalties	none	none
	Bangor-Hydro Electric, Maine Public Service Co	Service Reliability Monitoring		
Maryland	All utilities	Service Reliability Monitoring	Explanation	none
Massachusetts	All utilities	Penalties	Penalty proportional to gap of averages up to 0.45% of company revenue	none
Michigan	All utilities	Penalties	Report cause of performance and past remedial actions; Penalties	Report problems, explain past actions, penalties

Table 4

US Jurisdiction	Companies Involved	System Reliability	Worst Circuits	Severe Storm Restoration
Minnesota	Xcel Energy	Penalty/Reward	Plan for future action (All Utilities)	none
	Other utilities	Service reliability Target		none
Missouri	Utilicorp (Aquila)	Service reliability Monitoring	none	none
Nevada	All utilities	Service reliability Monitoring	Explanation	none
New Jersey	Atlantic City Electric	Service reliability Monitoring	Plan for future action	Penalty of $50 per customer per 24 hours
	Other utilities	Service reliability Monitoring		Penalty of up to $25K/violation
New Mexico	All utilities	Service reliability Monitoring	none	none
New York	All utilities	Penalties	Plan for future action	Separate penalties network and radial performance
North Dakota	Montana-Dakota Utilities	Service reliability Monitoring	none	none
Ohio	All utilities	Service reliability Target	Explanation, AEP has SAIDI targets for each quartile of circuit	none
Oklahoma	All utilities	Service reliability Monitoring	Report actions undertaken and plan for future action	none
Oregon	Portland General Electric, Scottish Power-Pacificorp	Penalty/Reward	Plan for future action	none
Pennsylvania	Exelon	Service reliability Target	Explanation, requirement to improve worst circuits for next year	none
	Other utilities	Service reliability Target	Explanation	none
Rhode Island	National Grid	Penalty/Reward	Explanation	none
Texas	All utilities	Service reliability Target	Penalty of $50/customer for outlier performance, and $20/customer if two consecutive years in worst group. Each violation's loss capped at $9.1M/year.	none
Utah	PacifiCorp	Service reliability Target	Penalty up to $1/customer if 3-year average CPI of each worst circuit not 20% better in two years.	Penalty per customer of $1 paid directly to customers.
				Penalty per customer of $50 + $25/each incremental 12-hour interval
Vermont	All utilities	Penalties	Plan for future action	none
Virginia	All utilities	Service reliability Monitoring	none	none
Washington	Scottish Power-Pacificorp	Service reliability Monitoring	Penalty up to $1/customer if 3-year average CPI of each worst circuit not 20% better in two years.	Penalty per customer of $1 paid directly to customers.
				Penalty per customer of $50 + $25/each incremental 12-hour interval
	Puget Sound Energy	Service reliability Target	none	none
Wisconsin	All utilities	Service reliability Monitoring	Report actions undertaken and plan for future action	none

Table 4

Canadian Jurisdiction	Companies Involved	System Reliability	Worst Circuits	Severe Storm Restoration
	All utilities except Enmax	Monitoring and Explanation		
		Penalty		
Alberta	Enmax	Penalty	Monitoring and Explanation	None
	BC Hydro	Monitoring		
British Columbia	FortisBC	Explanation and possible penalty if financial incentive earned due to deteriorating reliability	None	None
Manitoba	Manitoba Hydro	No formal regulation of reliability	None	None
New Brunswick	NA	No formal regulation of reliability	None	None
Newfoundland & Labrador	All	Monitoring	None	None
Nova Scotia	Nova Scotia Power	No formal regulation of reliability	None	None
Prince Edward Island	Maritime Electric	Targets	None	None
Quebec	Hydro Quebec	No formal regulation of reliability	None	None
Saskatchewan	SaskPower	No formal regulation of reliability	None	None
Yukon Territory	All	Monitoring	None	None

Table 4

European Jurisdiction	Companies Involved	System Reliability	Worst Circuits	Single-Customer Standards	Severe Storm Restoration
Austria	132 Distribution System Operators (DSOs)	Service Reliability Monitoring	NA	none	NA
Belgium	27 Distribution System Operators (DSOs)	Service Reliability Monitoring	NA	Damages paid only if interruptions are distributor's fault; amount not specified	NA
Czech Republic	3 Distribution System Operators (DSOs)	Service Reliability Monitoring	NA	compensation equal to 10% of yearly payments for distribution, maximum 150€ for LV and 300€ for HV	NA
Denmark	89 Distribution Network Companies	Service Reliability Monitoring	NA	none	NA
Estonia	40 Distribution Network Operators	Monitoring	NA	LV: from 8€ (excess up to 48 hours) to 24€ (excess more than 96 hours) paid in compensation MV: from 0.77 to 2.3 €/kW according to the excess time paid in compensation	50,000 kroons (3195€) for a single violation
Finland	88 Distribution Network Operators	Service Reliability Monitoring	NA	paid in compensation; interruption 24-72 h: 25% of customer's annual network charges paid in compensation; interruption 72-120 h: 50% of customer's annual network	interruption 24-72 h: 25% of customer's annual network charges; interruption 72-120 h: 50% of customer's annual network charges; beyond 120 h: 100% of customer's annual network charges; Max 350€/interruption
France	EDF and 170 other Distribution System Operators	Service Reliability Monitoring	NA	For each range of 6 hours interruption, 2% of the fixed tariff (4% after 12 hours etc.) paid in compensation	For each range of 6 hours interruption, 2% of the fixed tariff (4% after 12 hours etc.)
Germany	256 Distribution Network Operators	Service Reliability Monitoring	NA	none	NA
Hungary	6 Distribution Companies	Penalty/Reward	NA	Household consumers: 8€-20€ paid in compensation Others: 12€ (LV) - 120€ (MV) paid in compensation	Household consumers: 8€-20€ Others: 12€ (LV) - 120€ (MV)
Ireland	1 Distribution System Operator (DSO)	Penalty/Reward	Report	none	NA
Italy	more than 300 territorial districts served by the 24 major distribution companies	Penalty/Reward	NA	150€ for LV or MV domestic customers with <= 100 kW 2 €/kW for LV customers with > 100 kW; maximum 3000€ 1.5 €/kW for MV customers with > 100 kW; maximum 6000€ these values are increased by 50% every 4 hours	varies; for domestic customers, the compensation = 30€ pus 15€ for each additional 4 hours

Table 4

European Jurisdiction	Companies Involved	System Reliability	Worst Circuits	Single-Customer Standards	Severe Storm Restoration
Lithuania	7 Distribution Network Operators (DNOs) - 2 regional and 5 local	Service Reliability Monitoring	NA	not defined	NA
The Netherlands	9 Regional Network Operators	Penalty/Reward	NA	none	NA
Norway	7 main Distribution System Operators (DSO's)	Penalty/Reward	NA	none	NA
Poland	14 Distribution System Operators (DSOs)	Service reliability Monitoring	NA	discount = 5*electric energy price/unit of undelivered energy	NA
Portugal	The main Distribution Distribution Operator & 10 other small DSOs	Penalty/Reward	NA	varies	£ 50 (domestic customers) or £ 100 (non-domestic customers)
Romania	35 Distribution Operators (8 of which are major)	Service Reliability Monitoring	NA	none	NA
Slovenia	5 Distribution Companies (run by 1 distribution system operator)	Service Reliability Monitoring	NA	none	NA
Spain	5 Distribution System Operators	Penalty/Reward	NA	Discount=PW*DH*5*P PW = billed annual average power DH = interrupted hours - hours set by the standards; P = kWh price	NA
Sweden	174 Electricity Network Companies	Penalty/Reward	NA	for outages between 12 & 24 hours, penalty of 12.5% of annual fee equaling at least €100 for each range of outage > 24 hours, additional 25% of annual fee	for outages between 12 & 24 hours, penalty of 12.5% of annual fee equaling at least €100 for each range of outage > 24 hours, additional 25% of annual fee
United Kingdom	14 Distribution Network Operators (DNOs)	Penalty/Reward	NA	£50 for domestic customers and £100 for non-domestic paid in compensation, plus £25 for each further 12 hours	for each further 12 hours up to maximum of £200 intermdiate events: above plus £ 50 (domestic customers) or £ 100

Table 4

ANZ Jurisdictions	Companies Involved	System Reliability	Worst Circuits	Single-Customer Performance Guarantee	Severe Storm Restoration
Australian Capital Territory	All	Monitoring	NA	$20 payment to customer	NA
New South Wales	All	Monitoring	None	Payment to customer of $80 per violation (only 1 violation counted under 4 interruptions lasting longer than 4 or 5 hours per year)	NA
Northern Territory	All	Monitoring	Monitoring	Monitoring	NA
Queensland	All	Target	None	Payment to customer of $104	NA
South Australia	All	Monitoring, possible penalty	Monitoring, explanation, plan for remediation	Interruption frequency payable to customer escalated CPI between 2005 and 2010 rounded to nearest $10 plus: $80, $120, $160 Interruption duration penalty payable to customer escalated by CPI growth between 2005 and 2010 rounded to nearest $10 plus: $80, $120, $160, $320	NA NA
Tasmania	All	Target	Monitoring, Explanation	Payment to customer of $80 Payment to customer of $80 Payment to customer of $160	NA
Victoria	All	For unplanned SAIDI, SAIFI, and MAIFI: Penalty/Reward, "S-bank" allows a distributor to bank all or part of S-factor between two consecutive years.	Monitoring, plan for remediation	Payment to customer of $100 Payment to customer of $150	NA
Western Australia	Western Power	Penalty/Reward based on variance from benchmark * incentive rate varying from $8,200 per minute to $220,000 per minute, variance from benchmark is calculated over the entirety of the price control period Penalty/Reward based on variance from benchmark * incentive rate varying from $450,000 per interruption to $10,300,000 per interruption, variance is calculated over the entirety of the price control period	None	Payment to customer of $80	NA
New Zealand	All	Penalties possible if company is non-compliant in two years out of three during plan	None	NA	NA

factor will be determined by first calculating the difference between the company's average SAIDI performance and the SAIDI benchmark (*i.e.* the industry's average SAIDI value in the preceding regulatory period), and multiplying this difference by an estimate of the value of system reliability to customers.

As a general matter, we find that the focus in target and penalty/reward plans is typically on service quality *trends* rather than inter-utility comparisons of benchmark *levels*. To the extent that benchmarks are used in such cases they pertain to a company's *historical* performance. This is commonly calculated by taking a simple average of the company's recent historical performance on the indicator.

Regarding penalty/reward rates, some regulators have recognized that customer value is important for designing appropriate penalty/reward regimes, but most North American regulators have not considered evidence on customer value.[22] Instead, these penalty/reward rates have been set either through negotiation between parties or through judgment. This likely reflects the cost and complexity of undertaking original research on the valuation of quality to a company's own customers.

This is somewhat less true overseas. The penalty/reward rates in Victoria and South Australia have both been informed by customer valuations of system reliability.

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[22] Although a complete discussion of the topic is beyond the scope of this report, two basic methods are used to estimate the value of system reliability. One method uses market-based measures for the value of service. The difference between firm and interruptible rates is one example of market-based data that reflects some customers' valuations of reliability. Another example of market-based measures is the use of hedonic price indexes, which are developed by regressing market prices on identifiable quality attributes. Hedonic price indexes reflect the notion that price differences are due to implicit markets for individual product characteristics. Some official statistics utilize hedonic methods; for example, the US Bureau of Labor Statistics adjusts for quality changes of some products when computing the Consumer Price Index. While market-based methods are often conceptually sound, they can be controversial, are often not well-understood, and can produce divergent estimates of underlying quality valuations. In addition, hedonic methods are less likely to capture the underlying quality valuations in utility markets since prices often reflect regulatory decisions rather than market forces.

Reliability valuations can also be obtained through customer surveys. An advantage of this approach is that surveys can focus on specific aspects of customers' reliability valuations, such as how the value of reliability changes depending on the duration of an outage, and can be tailored to different experiences with system reliability and customers demands for reliability. However, some survey results reflect subjective perceptions that may not be a good guide to customers' actual price-quality tradeoffs. Surveys can be structured to approximate actual consumer behavior more precisely, and thereby develop more accurate reliability valuations, but these types of surveys usually require larger surveys and more sophisticated econometric methods to estimate reliability valuations and are therefore more costly to undertake.

The value of energy not supplied has also been considered when setting penalty/reward rates in Norway.

Penalties are less common for regulating circuit performance. In most cases, regulators simply require companies either to report their performance or to develop remedial action plans. However, there are several examples of utilities that can be subject to penalties for how quickly they restore power to customers during severe storms. In some cases these penalties can be sizeable. One such case is for Consolidated Edison in New York, which is discussed in more detail in the following Chapter.

6. System Reliability Case Studies

To provide further context and detail on how service reliability regulation can impact the operations and decision-making of utilities, our survey also included two case studies in service quality regulation. These are: 1) the Reliability Performance Edison for Con Edison in New York; and 2) the Distribution System Reliability requirements for Dayton Power and Light in Ohio. Both of these utilities are clients of Rich Consulting, and John Rich prepared this chapter by drawing directly on his experience with these firms. The chapter deals with each of these case studies in turn, and then presents comments on two related topics: how reliability metrics are employed more generally in asset management decision-making; and the impact of reliability on customer satisfaction.

6.1 Case Study 1: Consolidated Edison (New York)

6.1.1 History of Reliability Regulation in New York

Reliability regulations have been in effect in New York since the early 1990's. The initial requirements directed utilities to track and report the annual number of outages and the SAIFI and CAIDI results. Reporting requirements were increased to provide additional information, after the Washington Heights Network outage event in 1999. This heat-related event initially affected 15,000 customers, but ultimately led to a complete network shutdown. The reliability reporting requirements implemented after that event are summarized in the table below, which presents information dating to 2001.

Sample Data, Statewide Electric Service Interruption Report, 2005 Prepared by NY PSC Office of Electricity and Environment						
Con Ed (Radial)	**2001**	**2002**	**2003**	**2004**	**2005**	**5YR AVG**
Excluding Major Storms						
Number of Interruptions	6,378	5,724	5,536	4,856	5,618	5,622
Number of Customer-Hours	616,053	773,879	652,341	536,776	814,921	678,794
Number of Customers Affected	380,642	392,439	405,641	328,002	426,742	386,693
Number of Customers Served	825,213	825,264	834,753	835,205	842,063	832,500
Average Duration Per Customer Affected (CAIDI)	1.62	1.97	1.61	1.64	1.91	1.75
Average Duration Per Customer Served	0.75	0.94	0.78	0.64	0.97	0.82
Interruptions Per 1000 Customers Served	7.73	6.94	6.63	5.81	6.67	6.76
Number of Customers Affected Per Customer Served (SAIFI)	0.46	0.48	0.49	0.39	0.51	0.46
Con Ed (Network)	**2001**	**2002**	**2003**	**2004**	**2005**	**5YR AVG**
Number of Interruptions	9,443	5,508	6,625	4,360	4,967	6,181
Number of Customer-Hours	89,024	526,854	66,219	44,195	59,566	157,172
Number of Customers Affected	21,832	81,110	20,131	12,138	13,406	29,723
Number of Customers Served	2,271,414	2,277,589	2,291,421	2,307,841	2,319,321	2,293,517
Average Duration Per Customer Affected (CAIDI)	4.08	6.50	3.29	3.64	4.44	4.39
Average Duration Per Customer Served	0.04	0.23	0.03	0.02	0.03	0.07
Interruptions Per 1000 Customers Served	4.16	2.42	2.89	1.89	2.14	2.70
Number of Customers Affected Per Customer Served (SAIFI)	0.01	0.04	0.01	0.01	0.01	0.01

Reliability regulation was substantially increased in subsequent years, with a "Reliability Performance Mechanism" (RPM) issued by the commission in October, 2003. In the next Con Edison rate order (March, 2005) the RPM was expanded to include:

> *Six performance metrics intended to ensure the Company (Con Ed) provides reliable service generally and with respect to several parameters of interest to one or more parties in this case… The two general parameters (system-wide frequency and duration of outages) are part of an existing reliability performance mechanism. The other four are new and include the repair of poles, the removal of shunts installed as temporary repairs, renewal of service to streetlights and traffic signals, and the replacement of circuit breakers with high fault current levels.*
>
> *In most instances where the Company fails to meet any of the general or detailed reliability criteria, and where one or more exclusions do not apply, it would be subject to a downward adjustment to revenues... The total amount of revenue at risk each year for this mechanism would increase from $22 million now to $56 million or more."*

6.1.2 The Evolution of Current Regulations

In July, 2006 Con Edison experienced a major outage of its Long Island City network which affected 25,000 of the network's 115,000 customers. In the subsequent rate case, which was settled in March, 2008, the NY PSC increased revenue adjustment penalties and added two new indicators to the Reliability Performance Mechanism. As a result of this settlement, Con Ed was required to defer up to $112 million for failure to meet RPM standards, which were divided into five categories: *System-Wide Reliability, Major Outage, Remote Monitoring System (RMS), Restoration, and Program Standards for Routine Work Activities.*

- The "*System-Wide Reliability Metric*" has four parts: Network Interruption Frequency, Radial Interruption Frequency, Network Interruption Duration, and Radial Interruption Duration. There is a $5 million revenue adjustment for failing to meet each of these four metrics.

- The *"Major Outage Metric"* for the network portion of the distribution system is the interruption of service to 10% or more of the customers in any network for 3 hours or more. The corresponding metric for the radial portion of the system is the interruption of 70,000 or more customers for 3 hours or more. There is a $10 million revenue adjustment for each major outage event, up to an annual cap of $30 million.

- The *"RMS Metric"* requires 90% of each network's Remote Monitoring System to report properly at the end of each quarter. Failure to comply results in a revenue adjustment of $10 million per network, with an annual cap of $50 million.

- The *"Restoration Metric"* establishes times for the return of customers' electrical service after the end of an outage event in the radial system. There is no revenue adjustment for failure to meet this metric.

- The *"Program Standards"* set required completion dates for repairs to damaged poles, removal of temporary shunts, repairs of street lights and traffic signals, and replacement of over-loaded circuit breakers. There is a maximum revenue adjustment of $12 million for failure to meet these program standards.

The Company is required to submit an annual compliance report which is then evaluated by commission staff. Any revenue adjustments resulting from the failure to meet specific RPM indicators are determined through this review.

6.1.3 Con Edison's Response

The company has tracked reliability indicators since the early 90's and has expanded its tracking and analysis program in recent years. For example, in addition tracking SAIFI and CAIDI, the company now tracks MAIFI (Momentary Average Interruption Frequency Index) for the radial portions of its distribution system. MAIFI was found to be a leading indicator of potential tree-related failures. By adjusting tree-trimming plans to focus on areas where MAIFI has been increasing, the company has been able to reduce both the frequency and duration of outages in the various radial segments of system.

The company uses both SAIFI and CAIDI indicators for investment planning in the radial portions of the system. For the network portions of the system, SAIFI and CAIDI are not relevant indicators. Rather, component failures, which can be precursors of broader circuit failures, are tracked and analyzed. An example is cable splicing joints. Failures are monitored to identify trends associated with specific splicing kit manufactures or installation conditions. Individual splice replacements are then prioritized based on the consequence of failure – i.e., the number of customers that could be affected by the failure of a specific splice.

Managing the reliability data and bi-annual reporting required by the commission is the responsibility of the Con Edison's Performance Engineering Group. The reliability data is a key input to a risk-based capital investment planning model which is used to optimize annual capital investment.

6.2 Case Study 2: Dayton Power and Light (Ohio)

6.2.1 History of Reliability Regulation in Ohio

The initiating event was the advent of electric de-regulation in the State of Ohio in 1999, which was implemented through Chapter 4928 of the Ohio Revised Code. This chapter established specific requirements for the certification of Competitive Retail Electric Service (CRES) providers in the state. It also established *"Minimum Service Requirements"* for the CRES providers which included Billing, Contract Disclosure, Disconnection, Service Termination and other commercial requirements.

Chapter 4928 of the code also includes a section entitled *"Minimum Service Requirements for Non-Competitive Services*", which are those provided by the electric distribution utilities. These requirements include service quality, safety, and reliability components. The Ohio PUC was directed to *"require each electric utility to report annually … to the commission on its compliance with the rules required under this section."* The legislation also authorized the commission to periodically review and modify these rules, which it has done every 5 years.

6.2.2 Overview of Current Regulations

The *"Distribution Service Reliability"* rule was promulgated under section 4901:1-10-10 of the Ohio Administrative Code. This rule *"prescribes the measurement of each electric utility's service reliability, the development of minimum performance standards for such reliability and the reporting of performance against the standard"*. The current rules, which became effective 6/29/2009, are summarized below

- *"Service reliability indices are defined as follows:*
    - *CAIDI = Sum of customer interruption durations / Total number of customer interruptions*
    - *SAIFI = Total number of customer interruptions / Total number of customers served.*
- *"Each utility shall file with the commission an application to establish company-specific minimum reliability performance standards.*

- *"Applications for approval of reliability performance standards shall include supporting justification for the proposed methodology and each resulting standard.*

- *"Performance standards should reflect historical system performance, system design, technological advancements, service area geography and customer perception survey results.*

- *"Each utility shall periodically (no less than every three years) conduct a customer perception survey. The survey results shall also be used as an input to the methodology for calculating new performance standards. The objective of the survey is to measure customer perceptions, including but not limited to, economic impacts of disruptions to electric service and expectations of electric service reliability in terms of the service reliability indices defined above.*

- *"Performance data during major events and transmission outages shall be excluded from the calculation of indices and proposed standards. "*

If annual performance does not meet a utility's performance standard for either index, the utility must submit an action plan for improving performance to the targeted level. Failure to meet the approved performance standard for two consecutive years constitutes a violation of the rule. In addition to undertaking additional corrective actions to achieve compliance, utilities may be subject to penalties of up to $10,000 per day for each day's violation.

A second rule was promulgated under Ohio Administrative Code section 4901:1-10-11 regarding *"Distribution Circuit Performance."* The key requirements of this rule are summarized below:

- *"Each electric utility shall submit, for review and acceptance, a method to calculate circuit performance, based on the service reliability indices defined above.*

- *"The worst performing eight percent of the electric utility's distribution circuits during the previous twelve month reporting period shall be identified with:*

    - *The circuit identification number and location.*
    - *The approximate number of customers on the circuit, by class.*
    - *The circuit ranking and the supporting data for SAIDI and CAIDI.*
    - *The number of safety and reliability complaints received.*

- *The number of outages experienced during the reporting period and the total number of out-of-service minutes.*
- *An identification of any major factors or events that specifically caused the circuit to be among the worst performing circuits.*
- *An action plan to improve the circuit performance to a level that removes the circuit from the worst performing list.*

The rule requires that *"electric utilities shall take sufficient remedial action to cause each of the circuits listed to be removed from the worst performing circuits list within 2 years. The inclusion of a circuit for three reporting periods shall be considered a violation of this rule."*

6.2.3 DPL Response

DPL originally proposed to define CAIDI and SAIFI targets based on the average result obtained over the previous 5 years, with exclusions for major storms and transmission outages. This year the company has proposed to a modification to those targets to minimize the impacts of random variations that occur from year to year. Specifically, DPL proposed that:

- CAIDI and SAIFI performance targets be calculated in accordance with IEEE Standard 1366, rather than defining a major event as an outage ≥ "25,000 Weighted Outage Hours".
- Secondly, DPL has proposed to define "Sustained Outage" as an outage lasting more than 5 minutes, rather than 1 minute.

The effect of these changes increases the targets as shown below:

	Current (5-Year Average)	**Proposed** (IEEE 1366 + 5 Minute Outage Duration)
CAIDI (Minutes)	114.82	131.95

SAIFI	0.97	1.11

DPL has recently reached a stipulation agreement with the Office of the Ohio Consumers Counsel (OCC) and Commission Staff which leads to slightly more demanding performance targets of 125.1 for CAIDI and 1.07 for SAIFI.

To comply with the worst performing feeder requirement, DPL has instituted the practice of examining failure records and system information to determine the underlying causes of poor performance and then develop circuit-specific work plans to eliminate those causes. In addition, all relevant maintenance, inspection and equipment replacement programs are coordinated for maximum impact. For example, circuit inspections are completed shortly after a vegetation management clearing has been completed to enable the best visibility of all circuit components. Similarly, pole replacement programs are coordinated with other remedial activities planned for the worst performing feeders. In this manner, DPL achieves the best synergies between related improvement activities. The result of this coordinated effort to monitor reliability performance and coordinate remedial activities has been an improving trend in SAIFI and CAIDI indicators.

7. Concluding Remarks

This report has provided an overview of system reliability regulation, including a survey of system reliability regulatory practices in Canada, the US, Europe, Australia and New Zealand. This survey has shown that there is a wealth of information available on system reliability regulation throughout the world, although assembling this information can be time-consuming. There is also a considerable diversity of approaches that have been taken towards regulating system reliability.

Compared with other Western countries, less attention has been devoted to system reliability regulation in Canada. It is not clear why this is the case, but there are only a small number of plans that go beyond simply monitoring system reliability information provided by utilities. Ontario has had a type of service target regime in place since 2000. Although this plan has been administered fairly informally, it is nevertheless one of the most comprehensive and 'advanced' Province-wide service quality regulation regimes in Canada.

In this consultation, one basic issue to be addressed is the choice of system reliability indicators. Currently, the OEB monitors an LDC's SAIDI, SAIFI, and CAIDI. It should be recognized that monitoring all three indicators is redundant, since SAIDI is the product of SAIFI and CAIDI. SAIFI and SAIDI also represent the overall frequency and duration of interruptions for customers on the system, while CAIDI represents the average duration of an outage that occurs. It therefore follows that CAIDI can increase in a year even though the total frequency and duration of outages have *both* declined.[23]

Previous Staff papers have also discussed the possibility of adding MAIFI and circuit indicators. No utility in Canada currently monitors or regulates MAIFI, although this is becoming more common in other jurisdictions. Circuit indicators are also fairly prevalent in North America and Australia.

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[23] This will occur whenever the percentage decline in SAIFI is greater than that for SAIDI.

Another issue is whether and how to normalize reliability data. There is a noticeable move towards using the IEEE 1366 standard for such normalizations. The costs and benefits of adopting this standard in Ontario merit attention.

The consultation will also consider whether more formal benchmarks should be established. A relatively simple, but still "rule-based," approach for setting benchmarks comes from Massachusetts, where benchmarks are based on a moving-average of the company's own reliability performance.[24] A more sophisticated, but complex, approach may be that adopted in Norway, which sets more objective benchmarks for each distributor based on econometric methods. PEG has already undertaken a considerable amount of econometric benchmarking for Ontario distributors, including some initial benchmarking of their reliability performance. This work could perhaps be examined further in this consultation.

The consultation may also provide an opportunity to consider the potential relationship between measured reliability and the ongoing introduction of smart metering in Ontario. When the shift to a smart metering-based reporting system occurs, an initial decline in measured reliability can result due to the significantly greater quantities of outage information (all outages will be definitively known). The conversion of manual to outage management system (OMS)-based reporting usually has the same effect - the volume and accuracy of information is much greater than previously available from manual reporting processes.

Since the Ontario government has mandated that all distributors within its jurisdiction implement smart metering systems, this proceeding may allow stakeholders to review options in terms of reporting requirements and any issues regarding measured reliability that may arise during the transition to smart meter-based reporting.

[24] Massachusetts also established a rules-based approach for setting deadbands around those benchmarks, based on the standard deviation of each company's system reliability performance.

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