Regulatory Policies for Electricity Outages: A Systems Approach

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EXECUTIVE SUMMARY

This report focuses on outages that are of sufficient customer or system duration, frequency, or cost that regulatory intervention is desirable to determine whether the utility behaved efficiently in meeting its obligation to serve. This report presents a systematic regulatory approach for outage policies that uses of principles, logic, fact-gathering, standards, evaluation, and recalibration. The regulatory approach has four steps, shown in the diagram of Figure I.

Step One recommends principles for regulatory policy. Principles precede policy and link the statutory concept of "public interest" to the context at hand. In Step One, three regulatory principles, based on the obligation to serve, are appropriate for the outage context. Those principles are: encourage efficiency and discourage inefficiency (in both the regulator's policy and in the utility's performance), encourage adoption of all economically and technically feasible options, as those options grow through technological advances; and provide reasonable opportunity to recover prudent costs.

Step Two addresses fact-gathering on the costs and benefits relevant to outage prevention, management, and restoration. Reliability has value, but also costs. Any outage policy must have benefits in excess of costs. Regulators need facts on the value that the customer places on increased reliability as well as the cost to the utility of achieving increased reliability.

Step Three applies the regulatory principles to facts, describing how a regulatory commission should establish its utilities' pre-outage and post-outage obligations. Regulatory outage policy addresses outage prevention and outage mitigation. Each is examined in detail.

Finally, Step Four addresses evaluation of the utility's performance under commission policies as well as evaluation of the commission's own policies. Feedback from evaluation allows the commission to recalibrate the utility's obligations and the commission's policies and makes the approach dynamic in its response to changing facts, technologies and customer preferences.

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I. Introduction

Outages can be momentary, or could last for hours, days or (in extreme disasters) months; unnoticed or headline-grabbing; without consequence or equipment-destroying; household-based or regionwide; infrequent or daily. Electrical engineers measuring outage trends use one definition of a major outage. Regulators evaluating utility practices use another.

What state regulators consider an outage worthy of regulatory attention cannot be measured from a statistical formula based on historical outage data or from threats to reliability. This report focuses on outages that are of sufficient customer or system duration, frequency, or cost that regulatory attention is desirable to determine whether the utility behaved efficiently in meeting its obligation to provide reliable service. Outages worthy of regulatory attention include major events, major outages, and significant daily outages.

The diversity of effects, perspectives and definitions poses a challenge for regulators: in terms of duration, frequency or seriousness of effect, at what point do electricity outages warrant regulatory attention? What constitutes an outage worthy of regulatory attention changes over time and needs to be recalibrated to account for changes in the electric utility industry, including changes in customer expectations and tolerances to outages; and changes in utility infrastructure that affect the cost to utility of preventing outages or mitigating outage costs.

Outage policy has three main components: prevention, management and restoration. The regulatory approach to outages should be both dynamic and systematic: dynamic in its response to changing facts, technologies and consumer preferences; systematic in its use of principles, logic, fact-gathering, standards, evaluation and recalibration.

This report seeks to construct such an approach. The report has four steps.

Step I recommends principles for regulatory policies that encourage efficient and discourage inefficient utility behavior. Without explicit principles, regulators cannot determine what facts are relevant, define success, or fashion policies to serve the public.

Step II addresses fact-gathering: facts on the costs and benefits relevant to outage prevention, management and restoration. Section C, discusses the second step of the systems approach; namely, the utility gathers information about the costs and benefits of avoiding outages and mitigating outages that do occur.

Step III applies principles to facts, describing how a regulatory commission should establish its utilities' obligations relevant to prevention, management and restoration of outages.

Step IV addresses evaluation: evaluation of utility performance under commission policies, and evaluation of the policies themselves. Evaluation occurs after an outage that warrants regulatory attention has taken place. Periodic evaluation leads to periodic policy revision – a recalibration of utility obligations in light of newly gathered facts and feedback.

This systematic approach is displayed in Figure 1 below. The figure shows there are four steps in our approach. Rectangular boxes represent commission actions or evaluations. The circles in the figure represent information gathering. Arrows represent flow of information or decisions.

In the first step, the commission establishes regulatory principles. In the second step, the utility gathers facts about costs and benefits of utility actions to prevent or mitigate outages. In step three, the commission applies regulatory principles to the facts. The facts are those either garnered in step two or supplied from the commission's evaluation of the utility's performance and the commission's own policies (see Step Four). When applying regulatory principles to facts commissions can establish outage performance indices, prescribe pre-outage preventative and mitigative activities as well as prescribe post-outage activities aimed at outage mitigation. In step four, the commission evaluates the utility's performance and the commission's own outage policies. The occasion for step four is either an outage that warrants regulatory intervention or a periodic commission evaluation.

The dynamic systems approach, described in this report, allows regulators to set out their expectations about the utility's pre-outage preventative and mitigative activities as well as its post-outage obligations. Use of the dynamic systems approach will increase a commission's ability to measure and derive utility outage performance standards for major storms and events as well as daily outages that warrant regulatory attention.

II. Step One: Establish Regulatory Principles

Principles must precede policy. Principles link the statutory concept of "public interest" with the context at hand. Principles help regulators determine the extent and nature of regulatory involvement.

The development of regulatory principles starts with the utility's legal obligation to connect customers, and then provide them safe, adequate, and reliable service at reasonable prices. This obligation includes an obligation to provide service without unnecessary interruptions.

This general obligation includes five responsibilities:

1. Predict service territory load accurately.
2. Procure, through ownership or contract, infrastructure assets (generation, transmission, and distribution) sufficient to meet load at all times.
3. Operate the assets in a manner consistent with prudent utility practice; for example, make power available to all customers for a high percentage of time.
4. Undertake sufficient preventative measures to prevent avoid outages that are preventable at a reasonable cost.

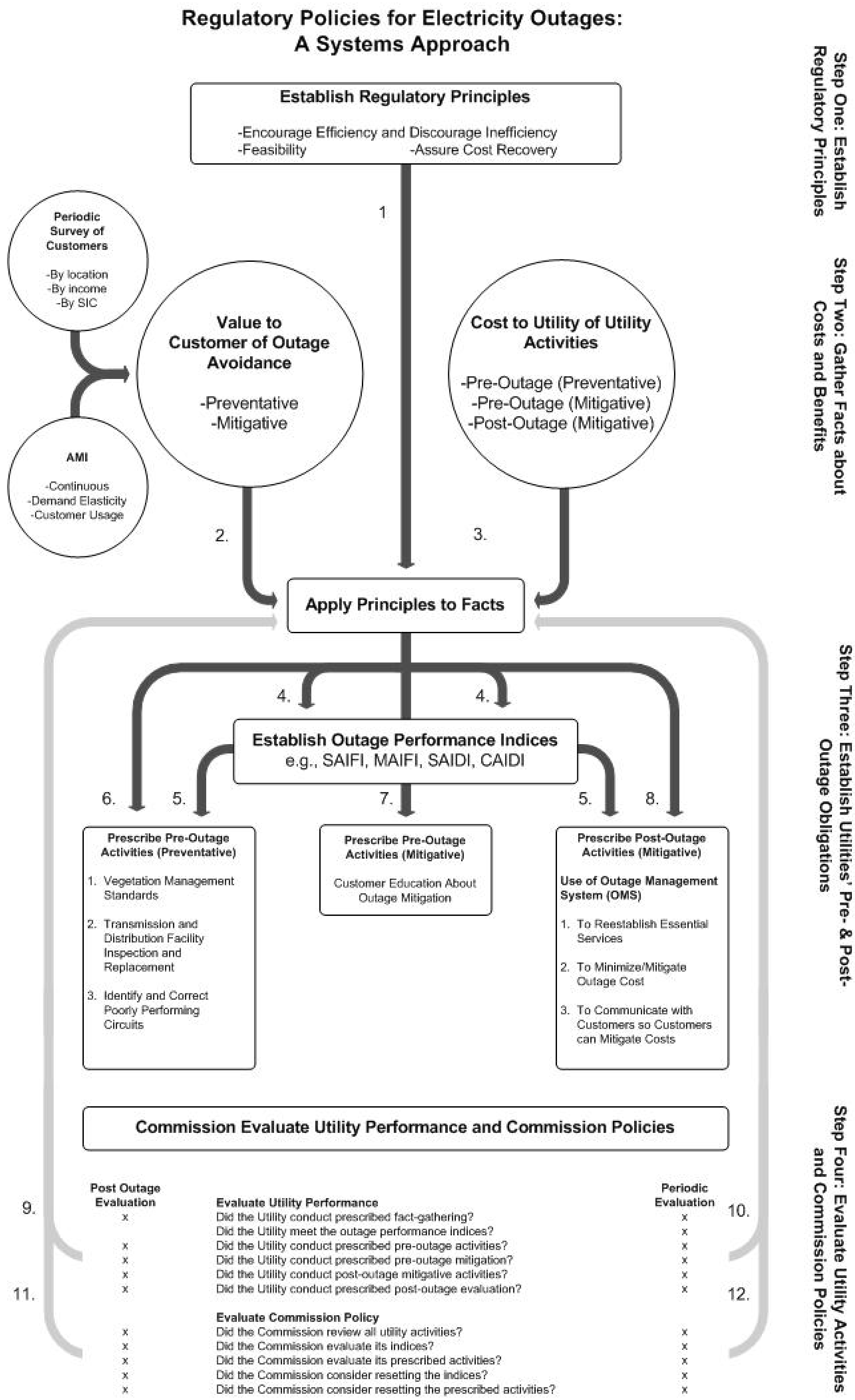

Fig. 1. Regulatory Policies for Electricity Outages: A Systems Approach

5. For outages that do occur, create and execute reasonable outage mitigation plans to minimize overall outage costs.

These five responsibilities – each rooted in the obligation to serve -- do not vary with asset ownership or the market structure in which the utility serves retail customers. Thus:

A utility that has divested its generation assets is still obligated to operate its transmission and distribution system reliably and to procure sufficient generation resources through purchase.

A utility that provides "last resort" or "default" service in a retail competition state usually has the same obligations that it had prior to the introduction of retail customers (although there can be some variation on this point, depending on the state's competition statute).

A utility that has transferred control of its transmission assets to a Regional Transmission Organization (RTO) still is responsible under state law to provide reliable service; the only limit on the state law is that state-level reliability actions not be "inconsistent" with standard promulgated by the FERC-certified Electric Reliability Organization.[1]

We turn now to three regulatory principles, based on the obligation to serve, that are appropriate for the outage context. As shown in Step One of the Figure I diagram, those principles are: encourage efficiency and discourage inefficiency (in both the regulator's policy and in the utility's performance), encourage adoption of all technically and economically feasible options, as those options grow through technological advances; and provide reasonable opportunity to recover prudent costs.

A. Encourage efficiency and discourage inefficiency

Accompanying the utility's obligation to serve is the obligation to serve efficiently. In the context of electricity reliability, there are two facts to efficiency: the efficiency of the policy itself, and the efficiency of the utility's performance under the policy.

The efficiency of the policy: A policy's benefits must be compared to its costs. A policy preventing all outages is too costly; one preventing no outages too unpredictable. The efficient outage policy depends on the value to customers of avoiding a utility outage, as well as the cost to the utility to take reasonable steps to prevent avoidable outages. And when outage does occur, the question then is the value to customers of minimizing its duration and extent, and the cost to the utility of doing so. Since we assume that all reasonable utility costs will ultimately be recoverable from customers, this cost-benefit tradeoff reflects the customer's perspective. This first principle, therefore, means that an efficient policy is one that reflects and achieves a reasonable relationship between customer benefit and customer cost.

[1] See Section 215(i) of the Federal Power Act, enacted by the Energy Policy Act of 2005.

Determining the reasonable relationship is easier said than done. How a customer values outage avoidance varies by many factors: the type of customer (industrial, residential, commercial); the customer's geographic location (e.g., urban, rural); the type of commercial customer (silicon chip manufacturer, bakery); and for residential customers, the customer's income level (reflecting perhaps the value of time lost or equipment not usable); the frequency of outages (particularly for manufacturing processes where a short outage results in an extended loss of production); time of the outage; electricity usage. As discussed in Part II below, uncovering the value of outage of avoidance requires granular, customer-level facts.

Turning from outage avoidance to outage duration: customers incur damages not only because an outage occurs, but also because of how long it lasts. Once an outage occurs, regulatory policy should induce the utility to manage the outage efficiently and to restore power to its customers expeditiously, subject to the constraint of reasonable cost. The goal is to minimize total outage costs (taking into account special circumstances like hospitals or traffic lights, where the requirement of continuity has special non-cost value).

The efficiency of the utility: The efficiency principle also requires the utility to behave efficiently in its actions to carry out the policy – whether that be incurring costs to prevent avoidable outages, or incurring costs to minimize the duration of outages that do occur. Assume that a utility were to incur costs in vegetation management (tree trimming) that were unnecessary and ineffective because a less expensive alternative was available to achieve the same result. Those expenditures would then be considered inefficient, even if the expenditure passes a cost benefit test.

B. Encourage adoption of all technically feasible options

Regulatory policies should encourage the utility to take advantage of technological advances. Devices and techniques to improve transmission and distribution reliability are constantly improving, in part, because of the use of digital technology as new equipment is deployed or existing equipment replaced, as well as wider use of advanced communications infrastructure. An example of an advanced communications infrastructure is the use of satellites for instant communication as part of the wide system monitoring of the western transmission system grid. Regulators should encourage utilities to take efficient actions in adopting technologies that improve reliability, particularly where the utility has the flexibility to take advantage of future technological improvements. Taking efficient actions in adopting technologies involves an assessment of the incremental cost and the incremental benefit of the new technology and adopting those technologies where the incremental benefit outweighs the incremental cost. Both incremental costs and benefits are not static and will change over time and will vary across utilities depending on customer characteristics.

C. Provide reasonable opportunity to recover prudent costs

Regulatory policies should provide utilities with a reasonable assurance of cost recovery for their investments and expenditures made to provide reliable service. When, however, there is an unusual level of outage related expenditures in a year because of factors outside the utility's control, the commission should consider providing a means of assuring the utility the recovery of its expenditures.

III. Step Two: Gather Facts about Costs and Benefits

Reliability has value, but it costs. Any outage policy, like any regulatory policy, must have benefits in excess of costs. Regulators therefore need facts on the customers' valuation of outage avoidance, as well the utility's cost of preventing or mitigating outages. This is shown in Step Two of the Figure I diagram. With this knowledge, regulators can establish economical practices and standards to prevent avoidable outages and to mange outages and restore power when outages occur.

Fact gathering must be continuous. Over time, customer expectations about outages change, affecting the value of reliability to customers. Changes in technology also affect the cost to the utility of its pre-outage and post-outage activities.

As all consumer sectors – industrial, commercial, and residential – have become more reliant on digital circuitry in their industrial processes, office equipment, and appliances, consumers have become increasingly cost-sensitive to disturbances in power supply. These power supply disturbances include power outages with a complete absence of voltage for a fraction of a second to hours or days. Alternatively, power supply disturbances include power quality problems that result from voltage sags, surges, transients, or harmonics.2 If the power quality problem is of sufficient duration, the consumer experiences an outage for that industrial process, equipment, or appliance.

Industrial and commercial customers tend to be more sensitive to and experience greater harm from outage frequency, while harm to residential customers depends more on outage duration.[3] Residential customer outages over eight hours result in loss of heat, air conditioning, and food spoilage.[4]

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[2] Voltage sag is when voltage is between 10 percent and 90 percent of normal operating voltage. Voltage surge or swell is voltage greater than 110 percent of normal operating voltage. A transient is a very short voltage event lasting under one-half cycle (1/120th of a second). Harmonics are integer multiples of the fundamental power frequency imposed on the fundamental frequency. Each of these is a power quality problem that can result in the customer experiencing an interruption of service. See Joseph Eto, Jonathan Koomey, Bryan Lehman, Nathan Martin, Evan Mills, Carrie Webber, and Ernst Worrell (2001, June 1). "Scoping study on trends in the economic value of electricity reliability to the U.S. economy". *Lawrence Berkeley National Laboratory*. Paper LBNL-47911. , 6-7. http://repositories.cdlib.org/lbnl/LBNL-47911

[3] Lawton, L., Sullivan, M., Van Liere, K., Katz, A., and Eto, J. (2003, November 1). "A Framework and Review of Customer Outage Costs: Integration and Analysis of Electric Utility

Because of changes in technology, the cost to the utility of its pre-outage prevention, pre-outage mitigation, and post-outage mitigation activities is also changing. Given the need to invest in new transmission and distribution, every utility faces choices, subject to regulatory oversight, concerning whether to invest in more advanced technologies and techniques. At the distribution level, outage management systems are available to identify outages, to manage outage recovery response, and to communicate with customers. Utility investment in outage management systems together with advanced metering infrastructure allows a utility to make better choices at reasonable costs to prevent outages and to mitigate those that occur.

A. The Value to Customers of Outage Avoidance

1. Why Determine Customer Value?

In 2003, a DOE study analyzed "what reliability costs consumers as well as how much they are willing to pay for reliability."[5] That study noted the need to "improve the quality and coverage of this critically important information" and recommended additional efforts to understand the value of electricity reliability.[6]

What value does an end-user place on reducing the likelihood of a service interruption? In other words, how much is a customer willing to pay to reduce the risk of an outage? What the customer is willing to pay is likely to be different from the actual cost of an outage. In theory, a risk-neutral customer would be willing to pay the product of the probability of an outage over a set period times the expected costs to that customer of an outage. Accepting this theory and ignoring practicalities, the regulator's determination of the utility's prudence in making a reliability investment or taking an outage-risk reduction action requires a simple calculation.

In practice, however, calculation of outage costs and outage probabilities is difficult. Different customers in the same class and use category may assign very different costs to outage. Customer surveys of outage costs are not sufficient to provide regulators with the accurate outage cost information necessary to make future improved outage and reliability investment decisions. Customer surveys reflect customer perception. Customer perception can diverge from reality in five areas: (1) the severity of risk, (2) the probability of risk, (3) the magnitude of

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Outage Cost Surveys." *Lawrence Berkeley National Laboratory*. Paper LBNL-54365. http://repositories.cdlib.org/lbnl/LBNL-54365, http://eetd.lbl.gov/EAP/EMP/reports/54365.pdf .

[4] Loss of heated or cooled air occurs gradually. In a closed residence, the speed at which heated or cooled air is lost depends on the R-value of the home's insulation.

[5] Lawton, L., Sullivan, M., Van Liere, K., Katz, A., and Eto, J. (2003, November 1). "A Framework and Review of Customer Outage Costs: Integration and Analysis of Electric Utility Outage Cost Surveys." *Lawrence Berkeley National Laboratory*. Paper LBNL-54365. http://repositories.cdlib.org/lbnl/LBNL-54365, http://eetd.lbl.gov/EAP/EMP/reports/54365.pdf.

[6] Id.

consequences, (4) the effectiveness of countermeasures at mitigating risks, and (5) the tradeoff between risk and countermeasures.[7]

For regulators to be able to apply the *probability times cost* formula without running the risk of over- or under-estimating the value of reliability, they must determine the true total costs of each type of service interruption to each customer group?. With accurate cost data, calculation of the value a customer places on a specific marginal decrease or increase in risk from the current level is possible.

2. Data for Determining Customer Value

To determine the value that customers place on reliable service, the utility should rely on both customer survey data and data from advanced metering infrastructure (AMI).

Customer survey data will provide the utility and the regulator with information about the customer's stated opinion on the value that they would place on the ability to avoid outages. AMI data provide the utility and the regulator with knowledge about actual customer behavior as to how much they value their power usage, particularly as customers change their usage patterns in response to time-of-use prices.

A customer survey would ask each customer about their electricity usage, specifying the end use and the time of day of usage. The survey would ask each customer whether they have experienced an outage and if so when and for what duration. The survey would also ask each customer whether they had experienced damage or loss (other an inconvenience) from the outage. The survey would also ask the customer several questions on how much the customer would be willing to pay for set increases in reliability that would decrease the frequency or decrease the duration of the outage. Each customer would also be asked their income and location and industrial and commercial customers would be asked for either their business type or their Standard Industrial Code.

AMI consists of advanced meters that can communicate with a data collection network for use in a data management system. AMI involves data collection at least hourly and data retrieval at least daily by means of a fixed network, such as broadband over power line, power line communications, fixed radio frequency networks, or systems utilizing public networks (landline, cellular, or paging). In supplying information on reliability, AMI provides validation or corrective information about the degree to which customers value power. For example, a utility might learn from AMI that a customer is willing to cycle air conditioning load, with a ten

[7] Bruce Schneier, "The Psychology of Security," http://www.schneier.com/essay-155.html, February 28, 2007.

minute interruption every hour. Through time-of-use pricing,[8] the utility would establish the value that the customer places on electricity service at different times of the day.

AMI also provides information about the location of outages, which allows the utility to identify which customers to survey after experiencing an outage. This information helps to determine the value the customers place on reliability.

As a fact-gathering tool, the commission should order the utility to employ AMI to the extent that the benefits of AMI outweigh its costs. Based on this cost and benefit tradeoff, the utility might fully deploy AMI, or might deploy AMI only for certain commercial and industrial customers, as well as for those customers that opt to for time-of-use rates. In addition, the utility might deploy AMI for other customers located in strategic geographic locations for outage monitoring purposes. Because the benefits of AMI depends on the value that customers place on reliability, which might not be known until AMI is already in place, AMI might first be deployed on a pilot basis or an independent estimate might be placed on the value of reliability based on pilot programs of other similarly situated utilities.

The utility, in considering the overall benefits of advanced metering infrastructure, should take into account benefits other than outage detection and management that can accrue from AMI. Advanced metering infrastructure can create value for the utility and customers with the following additional features: it allows for remote connection and disconnection, collects data for load forecasting, provides the utility with data to reduce line losses, allows for price responsive demand response, provides information for asset management, provides power quality monitoring, and makes available time of use pricing and price responsive demand response.[9] The commission should review the utility's decision to deploy AMI to assure that the proper the utility properly weighed the costs and benefits of AMI for purposes of determining the extent of AMI deployment.

While a utility or regulatory commission would conduct a customer survey periodically, AMI collects information on a more continuous basis. AMI then allows the utility and regulator

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[8] Time-of-use pricing in this instance might include real time pricing, where the price of electricity changes in real time to reflect its costs, or critical peak pricing, where a utility sets a high price during critical peak periods when demand is at its greatest and supply is constrained.

[9] One study estimated that AMI benefits can amount to $1.35 and $3.00 per month per customer over the useful life of the meter. Gary Fauth and Michael Wiebe, "Fixed-Network AMR: Lessons for Building the Best Business Case" as cited in the Federal Energy Regulatory Commission Staff Report, *Assessment of Demand Response & Advanced Metering*, Docket No. AD-06-2-000 (August 2006), 38. In 2005 and 2006, the average hardware cost of advanced meters was $76. The total capital cost of AMI communications infrastructure has ranged between $125 and $150 per meter. Federal Energy Regulatory Commission Staff Report, *Assessment of Demand Response & Advanced Metering*, Docket No. AD-06-2-000 (August 2006), 34, 38. Distributed automation can provide another means to capture the same data as AMI. Correspondence from Joseph Eto, Lawrence Berkeley Laboratory. July 17, 2007.

to identify those customers that have had an outage, the frequency of outages, the day and time of day of the outage, and the duration of outages. This information allows the utility and regulator to categorize customers properly so that detailed facts about the value of outage avoidance can be gleaned from the customer surveys, validated by AMI data.

With information from both customer surveys and from AMI, both utilities and regulators can compare actual end-users' reported costs of historical outages and voltage interruptions with end-users' responses to inquiries of the value of preventing similar events in the future. An examination of end user value should include the value end users place on receiving electricity service at specific levels of reliability, including information on how much value end users place on differences in frequency and duration of power interruptions. The study, performed by the utility and independently assessed by the commission, should use the collected information to categorize the end-users' value of avoiding a power interruption to determine if values vary by customer class, SIC, socio-economical factors, geographic location, and other identifiable categorizations. The study would conclude with an analysis of response patterns the utility and regulators could use to understand the end users perception of the value of specific levels of reliability.

B. The Cost to Utility of Outage Prevention and Mitigation

The utility should also collect facts about its own costs of its pre-outage preventative, its pre-outage mitigation, and its post-outage mitigation activities. The utility should separately track these costs as part of its accounting.

The utility should collect data and develop estimates on an ongoing basis, compiled no less often than annually, that identifies the cost of pre-outage preventative activities, including vegetation management, transmission and distribution facility inspection and replacement, and identification and correction of poorly performing circuits. The utility should also collect data on the cost of pre-outage activities directed at mitigating outage costs, including customer education about outage mitigation.

The utility should collect data and develop estimates on the cost of maintaining its outage management system, assuming it has one. In the absence of an outage management system, the utility should keep separate track of its expenses incurred to shorten the duration of and mitigate the cost of an outage. After each outage, the utility should collect identifiable data on the cost to reestablish essential services, the cost to restore power to all customers, and the cost of communicating with customers during an outage.

C. Making Cost-Benefit Tradeoffs

With information about the value that customers place on avoiding outages, the regulator can use the cost-benefit tradeoffs that are integral to the regulatory principles for developing and establishing the utility's pre-outage and post-outage obligations. The customer benefit that we care about is the value a customer places on a marginal increase in reliability. That value varies according to whether the customer is risk averse, whether the customer is more sensitive to frequent outages or outages that are of long duration, the consequences of an outage, and the cost of self-help options available to the customer. The benefit of increased reliability is balanced against the marginal cost of the additional utility activities undertaken to increase reliability for the customer. These additional utility activities can increase customer value in three ways. They can 1) make an outage less likely (decrease its probability of occurring), 2) shorten the duration of the outage, thereby decreasing its consequences, and 3) enable the customer to exercise self-help measures to lessen an outage's consequences. The additional cost of utility activities should not exceed the additional benefit that customers receive from that activity. How this is applied to establish the utility's pre-outage and post-outage obligations is discussed next.

IV. Step Three: Establish Utilities' Pre-Outage and Post-Outage Obligations

Step Three of the Figure I diagram applies the regulatory principles to the gathered facts to establish the utilities' pre-outage and post-outage obligations. As shown in Step One of the diagram, the established regulatory principles are encourage efficiency, provide for a cost-benefit trade-off, encourage technologically feasible actions without foreclosing tomorrow's technology, and provide reasonable assurance of cost recovery; they also help to ensure, that state regulatory policies are not inconsistent with the policies of the ERO. Arrow #1 in the diagram represents the application of these regulatory principles to the gathered facts. The regulatory principles are applied to facts, gathered in Step Two, shown in the two circles from which arrows #2 and #3 lead. The gathered facts are the value to different customers of avoiding preventable outages and minimizing the consequences of outages that do occur, as well as the cost to the utility of its activities to prevent outages and to mitigate those outages that do occur.

With knowledge of facts specific to customer categories, the regulator can shape the utility's outage obligations to customer characteristics, such as customer location, demand elasticity, and usage. Each of these characteristics could affect the value to the customer of outage avoidance and minimization; this value, in turn, would affect the cost-benefit tradeoff.

As shown in Step Three on the table, the regulator can establish all or some of four types of obligations: outage performance indices, pre-outage preventative activities, pre-outage mitigative activities, and post-outage mitigative activities.[10] Each is discussed next.

A. Establish Outage Performance Indices

Pacific Economics Group conducted a March 2007 study showing that thirty-four states have adopted outage performance indices that establish regulatory expectations for the frequency

[10] An alternative approach would be to have utilities financially responsible for the consequences of not meeting their own performance indices. The utility would be responsible for the consequences if reliability suffers and would be required to pay customers value-based compensation for power interruptions. See L. Kaufmann, *Service Quality Regulation for Detroit Edison: A Critical Assessment* (Madison, Wisconsin: Pacific Economics Group, March 2007), pp. 33-36. A utility's potential liability under such an approach might be prohibitively high.

and duration of utility outages. The four outage metrics used most often as quantitative indicators are the System Average Interruption Frequency Index (SAIFI), the System Average Interruption Duration Index (SAIDI), the Customer Average Interruption Duration Index (CAIDI), and the Momentary Average Interruption Frequency Index (MAIFI). The definitions of these outage metrics follow:

System Average Interruption Frequency Index (SAIFI) is the number of sustained interruptions experienced by an average customer on the system.

System Average Interruption Duration Index (SAIDI) is the number of minutes of sustained interruption experienced by an average customer on the system.

Customer Average Interruption Duration Index (CAIDI) is the average duration of a sustained interruption experienced annually by a customer on the system.

Momentary Average Interruption Frequency Index (MAIFI) is the number of momentary interruptions experienced annually by an average customer of the system.

Many states also consider a circuit-only index that measures the number or duration of outages experienced by an average customer on a particular circuit. This index helps to determine which circuits are the most poorly performing ones. (A circuit is a path over which power flows.)

The principle difference between SAIFI and MAIFI is that SAIFI measures the frequency of sustained outages, while MAIFI measures the frequency of momentary outages. The definition of what is a sustained outage varies from state to state. It can be as little as more than one cycle ($1/60^{th}$) of a second or as long as five minutes. Most states define a momentary outage as either less than one minute or of five minutes duration.[11] Outage performance indices are not comparable from state to state and sometimes not even comparable from utility to utility within a state.

Major storms or events are excluded from the outage indices in most, but not all states.[12] The definition of a major storm or event also varies by state and sometimes by utility. Definitions of a major storm include, for example, 10 percent or more of the customers out for 24 hours; hurricanes, tornados; earthquakes; storm-related outages are excluded on a case-by-case basis. Although most states exclude from their quantitative indicators outages caused by a major event or major storm, a few do not. Some states also calculate the indicators with and without the major event.

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[11] L. Kaufman, *Service Quality Regulation for Detroit Edison: A Critical Assessment* (Madison, WI: Pacific Economics Group, March 2007), 18.

[12] Different states use either the term major storms or major events. While definitions vary, the concept of excluding a major storm or event from an index is the same.

The Institute of Electrical and Electronic Engineers has issued an IEEE Standard 1366-2003 that seeks to standardize distribution reliability standards. It defines a major event day as one in which the SAIDI is more than 2.5 standard deviations greater than the five-year average daily SAIDI. All outage types are included in the initial calculation, whether or not the cause of the outage was within the utility's control. Then, major event days are excluded from distribution reliability calculations. The Engineering Program Staff of the Illinois Commerce Commission criticized how IEEE Standard 1366-2003 operates, particularly because of the exclusion of major event days. Outages that the utility could have avoided are excluded from the IEEE outage performance indices. The exclusion of major event days from these reported figures could limit commission oversight and lessen the utility's incentive to take actions, such as replacing aged, defective, or stressed plant before they cause an outage.[13] Unless supplemented by special examination or investigation of the circumstances surrounding all major event days, use of IEEE Standard 1366-2003 would compromise regulatory incentives to have the utility act in the public interest by taking actions to prevent avoidable outages.

State commissions differ in their use of outage performance indices. States can use these indices as a basis for service quality monitoring (without a target) for the sole purpose of being able to track a utility's reliability performance. They can also use the indices as the basis for a service quality target without necessarily having an automatic consequence for not reaching the target. Finally, states can also use the performance indices as the basis for penalties if the utility fails to satisfy the indicator. (It is also possible to reward the utility for exceeding the index standard, but this rarely occurs.) According to Kaufman, fourteen states use the quantitative indicators for monitoring, four use them for targets, and twenty have penalties for failing to meet the indicators.[14]

State commissions that use outage performance indices as a quantitative measure of the utility's performance for preventing outages (SAIFI and MAIFI) or for shortening the duration of an outage (SAIDI and CAIDI) should consider resetting their outage performance standards or targets for two reasons. First, examining the indices in light of the regulatory principles applied to state-specific specific facts might lead the regulator to set a higher or lower performance standard, because customers' demand for reliable power might differ from the utilities' historical

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[13] Phillip Roy Buxton, Engineering Program Staff, Energy Division, *Discussion of Ameren's Use of Major Event Days and IEEE Standard 1366-2003 in its Annual Reliability Reports* (December 2006).

[14] See L. Kaufman, *Service Quality Regulation for Detroit Edison: A Critical Assessment*, table 1, at p. 58. States that use outage metrics as quantitative indicators for monitoring service are Alabama, Arkansas, Connecticut, Hawaii, Illinois, Indiana, Iowa, Kansas, Kentucky, Maryland, Missouri, Nevada, Virginia, and Wisconsin. State that use outage metrics as quantitative indicator targets are District of Columbia, Ohio, Oklahoma, and Pennsylvania. States that have penalties for failing to meet the specified outage metrics are California, Colorado, Delaware, Florida, Idaho, Louisiana, Maine, Massachusetts, Michigan, Minnesota, Mississippi, New Jersey, New York, North Dakota, Oregon, Rhode Island, Texas, Utah, Vermont, and Washington.

levels of reliability. Second, utilities that have not yet adopted an outage management system, or have one not coupled with AMI, might suffer from a lack of information. This lack of information can produce inaccuracy in the reporting of outage frequency and duration.

A utility without an outage management system might be reluctant to adopt one, especially those coupled with AMI, even though the regulator's expectations include use of outage management systems. This reluctance would stem from a concern that better outage reporting from outage management systems with AMI could lead to penalties under the existing outage performance standard. A commission might reset the outage performance standard if a utility faces penalties for failing to achieve the required outage index standard. Alternatively, a regulator might suspend any penalties under the target for a period of one or two years. During this period, the utility could collect information that will allow the regulator to reset the standard with more accurate outage data from the utility.

When resetting the SAIFI and MAIFI outage performance standards, as shown in diagram arrow #4, regulators should apply the five criteria for regulatory policy to the gathered facts, taking into account the trade-offs between utility costs and the value that customers place on avoiding outages. Frequency of outages is more important for commercial and industrial customers, who are particularly sensitive to power quality problems. Because the mix of customer types varies on each circuit, the tradeoff between utility costs and customer benefits will vary as well. The regulator should consider whether to vary the SAIFI and MAIFI standards by circuit as well.

The SAIDI and CAIDI outage performance standards, as shown in diagram arrow #4, should reflect the utility's duty to act efficiently to manage the outage and restore power to minimize total outage costs when outages occur. The regulator should consider whether to exclude major events or major storms from the calculation of SAIDI and CAIDI indices. Major storms and other major natural disasters can cause widespread and prolonged outages. Because these major outages are not preventable, a statistical standard to determine whether to reward or penalize a utility might exclude them. In some cases, however, the failure to take pre-outage actions to prevent outages can make a utility system more vulnerable to outages due to major events or storms. A major-event exclusion, such as contained in IEEE 1366-2003, is divorced from an outage cause. That exclusion tends to separate reasonable regulatory expectations of utility behavior to prevent and contain outages from financial incentives.

Because the damage of an outage depends in part on its duration, a utility can take steps, such as using outage management systems, to manage outages better and restore power more quickly. A SAIDI and CAIDI outage performance standard that focuses on outages worthy of regulatory intervention might provide a utility with better incentives to prepare for outages

B. Prescribe Utility Pre-Outage Preventative Activities

State commissions can prescribe pre-outage utility activities that can prevent avoidable outages. As shown by arrow #5 in the diagram, outage performance indices, specifically SAIFI and MAIFI, provide a measure of a utility's success in avoiding outages. Nevertheless, historically regulators prescribe three activities, namely, vegetation management standards, transmission and distribution facility replacement, and identifying and correcting poorly performing circuits, to establish the utility's pre-outage obligations because of their impact on avoiding outages.[15] Regulators can address these three areas as they establish their regulatory expectations for utility pre-outage activities aimed at preventing outages.

As shown by arrow #6 in the diagram, regulators should apply the regulatory principles outlined in this report to gathered facts when they prescribe pre-outage activities aimed at preventing avoidable outages. In particular, the activities should be efficient and represent a reasonable cost-benefit trade-off. State regulators also need to make certain that their prescribed activities that deal with the bulk power portion of the system (transmission facilities) are not inconsistent with ERO requirements. More detail follows.

1. Prescribe Vegetation Management

State commissions have historically required their utilities to engage in vegetation management and to meet the vegetation management standards set out in National Electric Safety Code (NESC) Rule 218, which states:

> A. General
>
> 1. Trees that may interfere with ungrounded supply conductors should be trimmed or removed. Normal tree growth, the combined movement of trees and conductors under adverse weather conditions, voltage, and sagging of conductors at elevated temperatures are among the factors to be considered in determining the extent of trimming required.
>
> 2. Where trimming or removal is not practical, the conductor should be separated from the tree with suitable materials or devices to avoid conductor damage by abrasion and grounding of the circuit through the tree.

The language in NESC Rule 218 is permissive, rather than mandatory. Without mandatory language, a regulatory agency will be unable to find that NESC Rule 218 as been violated. The California Public Utilities Commission and the Oregon Public Utility Commission took additional steps to make NESC Rule 218 mandatory.[16]

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[15] National Regulatory Research Institute 2000 and 2004 surveys on state public service commission reliability practices and policies identified vegetation management standards, inspection standards for transmission and distribution facilities, and identification and correction of poorly performing circuits as prescribed state commission practices and policies.

[16] Stephen Cieslewica and Robert Novembri, *Utility Vegetation Management Final Report*, (CN Utility Consulting, LLC: March 2004), 4.

For a majority of outages, including major outages of prolonged duration, a lack of proper vegetation management has been a principal cause.[17] Regulators should therefore require the utility to comply strictly with and execute its vegetation management programs. The cost-benefit trade-off between the value created by avoiding outages and the cost of the utility to prevent outages should lead regulators to establish utility obligations on utility vegetation management at a high level, particularly where gathered information shows that customers value outage avoidance highly.

On the other hand, vegetation management is also costly. Utility vegetation management is one of the largest expense items associated with maintaining transmission and distribution systems.[18] To be efficient and still effective, vegetation management should take into account local conditions, including precipitation patterns, types of vegetation, known vegetation growth rates, drought, and other relevant conditions.

ERO regulations address vegetation management standards for transmission facilities. A FERC-approved National Electric Reliability Organization standard addresses utility vegetation management for those lines at voltages of greater than 200 kilovolts and lower voltage transmission lines deemed critical to reliability by a regional reliability organization. The rule adopts IEEE Standard 516-2003 as the minimum clearance distance for vegetation. The FERC also directs the ERO to address and develop minimum clearances needed to avoid sustained vegetation related outages. The FERC also directs the ERO to develop appropriate inspection cycles based on local factors.[19]

State commissions should enforce reliability standards that are not inconsistent with ERO reliability standards.[20] Providing state standards that are consistent with or higher than the

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[17] Stephen Cieslewica and Robert Novembri, *Utility Vegetation Management Final Report* (CN Utility Consulting, LLC: March 2004), 1.

[18] Ibid.

[19] See Mandatory Reliability Standards for the Bulk Power System, Federal Energy Regulatory Commission Order 693, Docket RM 06-16-000 (March 16, 2007), para. 694-735.

[20] Energy Policy Act of 2005, section 1211, Federal Power Act 215(i)(3), which reads as follows: "(3) Nothing in this section shall be construed to preempt any authority of any State to take action to ensure the safety, adequacy, and reliability of electric service within that State, as long as such action is not inconsistent with any reliability standard, except that the State of New York may establish rules that result in greater reliability within that State, as long as such action does not result in lesser reliability outside the State than that provided by the reliability standards." The provision does not explicitly prohibit states from setting higher reliability standards, as long as they are "not inconsistent with" the ERO's standards. It is unclear whether "not inconsistent" with means "not different from" or "not incompatible with". A higher state standard would not be incompatible with the ERO standards because the affected entity could comply with both the state and ERO standard. Section 1211 mandatory reliability standards exclude Alaska and Hawaii. See Energy Policy Act of 2005, section 1211 (k).

applicable ERO standard should meet the test that state regulation is not inconsistent with that of the ERO. In particular, state commissions can require the utility to gather information on local factors and conditions that would lead to effective and efficient vegetation management.

2. Prescribe Transmission and Distribution Facility Inspection and Replacement

Regulators have also traditionally provided utilities with expectations about transmission and distribution facility inspection and replacement, which should be based on information on the value that customers place on avoiding outages. Current utility programs contain algorithms that predict when equipment will fail so that the utility can minimize equipment replacement costs. The goal is to replace aging equipment just before the likelihood becomes "too great" that a failure will occur, that is, just before a predicted equipment failure. Although these programs may appear efficient because they intend to minimize utility costs, they could fall short of regulatory expectations. Customers suffer damages and lose the value of avoiding a preventable outage when equipment fails before it is replaced. The proper utility objective is not to minimize utility costs of replacing transmission and distribution facility equipment, rather the objective is to balance and tradeoff the value customers place on increased reliability against the utility costs of inspecting and replacing transmission and distribution equipment.

The proper cost-benefit analysis compares (1) the cost of replacing equipment and (2) the benefits, which are measured as the product of the likelihood that the equipment will fail over the inspection timeframe and the total value to all potentially affected customers of avoiding the outage. As equipment ages and experiences stress from congestion or repeated voltage events, the likelihood of a future outage increases. Eventually at some point, the total value to all potentially affected customers of avoiding an outage exceeds the cost of replacing the equipment.

In contemplating the replacement of transmission and distribution equipment, the utility should consider how new equipment might enhance reliability on the system and create reliability value to customers. Depending on the type of equipment to be replaced, a utility might have to choose among a variety of options, including smart grid technologies. When choosing among technologies, the regulator should instruct the utility to consider whether a choice would foreclose efficiencies because of future improvements of technology. If possible, the choice of replacement equipment should not foreclose future improvements in technology.

3. Prescribe Identification and Correction of Poorly Performing Circuits

Twenty-four states require that poorly performing circuits be identified with a variety of consequences, ranging from providing an explanation, to planning for future action, to reporting corrective actions undertaken. [21]

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[21] L. Kaufman, *Service Quality Regulation for Detroit Edison: A Critical Assessment* (March 2007), 64-65.

Regulators can establish their expectations about the utility's obligations to identify and to correct or improve poorly performing circuits. With detailed facts about the value that customers place on avoiding outages, a utility has a standard by which it can judge whether circuits are performing poorly. Recall that industrial and large commercial customers tend to place greater value on avoiding frequent outages, while residential customers are less sensitive to outage frequency and tend to place a greater value on outages with a shorter duration. Currently, utilities rely on circuit-specific SAIDI and SAIFI outage metrics to identify poorly performing circuits. The current practice is to identify and correct the worse performing circuits measured by SAIDI or SAIFI, without regard to the value customers place on avoiding outages. With information about the types and mix of customers on each circuit and the value the customers as a group place on avoiding outages, the utility should correct circuits where the expenditures will achieve the greatest customer value.

The regulator can combine the SAIDI and SAIFI information for each circuit with information about the value each customer places on avoiding frequent outages or outages of a longer duration. With this combined information, the regulator should require the utility to identify the circuits that have the best benefit-cost ratio for corrective action. The information allows the utility to act efficiently correcting circuits to create the greatest value at the lowest cost.

C. Prescribe Pre-Outage Mitigation Activities

As shown in arrow #7 in the diagram, the regulator should apply regulatory principles to the gathered facts to establish expectations about the utility's pre-outage activities that mitigate outage costs. The regulator should establish obligations for the utility to take pre-outage actions that educate the customer about self-help actions that the customer could take to help mitigate outage damage when outages occur. The regulator should seek to establish a pre-outage utility obligation to educate and encourage customers to take cost effective mitigative self-help actions.

Some utilities have established programs that remind customers of actions that they should take in anticipation of a major outage, particularly if the utilities know the type and occurrence of the major outage beforehand. For example, Gulf Coast and South Atlantic utilities can anticipate hurricane season each year and work to increase their customers' knowledge of what actions to take to minimize outage costs. Other types of natural disasters are known to recur in various regions of the country: ice storms and blizzard in the north, earthquakes in the west (and also in the New Madrid area), tornados in the Plains and Midwestern States; wildfires in the Southwest and other drought areas, for example. Many, but not all, of these natural disasters occur on a periodic basis during certain seasons, so that the utility can prepare its customers in advanced for possible outages. These programs do not need to be limited to residential customers.

The utility educational actions for residential might include information about maintaining a land-line phone connection for emergencies, because other phone systems might not work without power. The utility might also inform the residential customer to shut off large electric appliances to quicken the time for power restoration. The utility should also inform residential customers to keep refrigerators and freezers closed for a period of time or until power restoration in order to avoid food spoilage.

Utilities should be willing to engage in customer outage cost mitigation to the extent that the costs of the education meet a cost-benefit tradeoff. The cost of the consumer education should therefore not exceed the expected benefit from lower outage damages due to the customer education. Often, customer education can be done efficiently at little extra costs by adding educational material to customer bills.

D. Prescribe Post-Outage Mitigation Activities

Even in unavoidable situations, the utility has a duty to take post-outage actions to mitigate the total cost of the outage to its customers.

As shown in arrow #8 in the diagram, regulators should apply regulatory principles to gathered facts to establish the utility's post-outage obligations. As shown in arrow #5, the utility can also use SAIDI and CAIDI outage performance indices to help determine the utility's post-outage obligations. One objective of the utility's post-outage activities is to minimize the average duration of the outage.

Many state commissions use either the SAIDI or CAIDI standard, or both, as a means to measure the duration of outages, systemwide and sometimes by circuit. [22] Collecting SAIDI and CAIDI measurements systemwide and by circuit is also desirable. Because SAIDI and CAIDI measure the duration of outages, they indicate how well a utility has performed in preventing avoidable long-term outages in addition to taking post-outage restoration actions. When SAIDI or CAIDI link to a target or a set standard with a penalty for failure to meet the standard, the utility has an incentive to meet or slightly exceed the target or standard. The incentive for utility performance that meets or exceeds the standard is stronger as the penalties get larger for failing to meet the standard and as the rewards get larger for exceeding the standard.

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[22] L. Kaufman, *Service Quality Regulation for Detroit Edison: A Critical Assessment*, table 3, at 61-63. States using SAIDI as a quantitative indicator include Alabama, California (for San Diego Gas & Electric), Colorado (for Public Service of Colorado, Aquila), Connecticut , District of Columbia (for PEPCO), Delaware (for Delmarva Power & Light), Florida, Idaho (Scottish Power –Pacificorp), Indiana, Iowa, Kansas, Kentucky (for Duke Energy), Louisiana, Maryland, Massachusetts, Minnesota (for Xcel Energy), Missouri (for Utilicorp, Aquila), Nevada, Ohio, Oklahoma, Oregon (for Portland General Electric and Scottish Power-Pacificorp), Pennsylvania, Rhode Island (for National Grid), Texas, Utah(for Pacificorp), Virginia, Washington (for Scottish power – Pacificorp and Puget Sound Energy), and Wisconsin. CAIDI is used in Alabama, California, Connecticut, District of Columbia (for PEPCO), Delaware (for Delmarva Power & Light), Florida, Illinois, Indiana, Iowa, Kansas, Kentucky (for Duke Energy and AEP Kentucky), Maine (for Central Maine Power and Bangor-Hydro Electric), Maryland, Michigan (for Indiana-Michigan), Missouri (for Utilicorp, Aquila), Nevada, New Jersey, New York, Ohio, Pennsylvania, Vermont (for Central Vermont Public Service and Green Mountain Power), and Wisconsin.

Utilities increasingly are incorporating outage management systems (OMS) into their post-outage practices. OMS involves the use of computer software to assist the utility in identifying an outage, in locating the area of the outage, and in isolating the problem that caused the outage. The OMS software assists the utility in positioning and managing its restoration crews to make certain that crew response is done more quickly, without repetition, and without the need to double-back because of problems missed in an area where the crews undertook prior outage restoration efforts. The OMS program also helps the utility to determine whether it needs outside help for outage restoration. OMS allows the utility to prioritize restoration of service so that circuits to essential services are restored first, followed then by actions that restore service to as many customers as quickly as possible, consistent with the goal of minimizing customer outage damages and lost opportunity costs. An OMS also provides the utility with the capability of communicating with the customer on the expected time of service restoration. This communication allows the customer to make rational self-help decisions that can minimize the costs of the outage.

Without an outage management system, a utility will likely fail to minimize the customer cost of an outage because the duration of the outage will be longer than necessary. A utility should adopt an outage management system whenever the tradeoff between the cost of an outage management system and the value to customers of shortening the duration of outages favors the use of outage management system. Even so, the problem with current utility post-outage practices that incorporate outage management systems is that the regulator needs to know that the OMS is set to minimize overall outage costs to both the customer and the utility.

Regulators should establish their post-outage expectations, but without being overly prescriptive. Post-outage expectations should not prescribe precisely how a utility will respond to each outage as utility efforts must adapt to the particular facts of the particular outage. Regulators should encourage the utility to use the best technology available at a reasonable cost to manage the outage and restore power to its customers. Outage management systems that incorporate geographical information systems are critical for the utility to be able to know quickly the extent of the outage, to know whether essential services are involved, and to know the type of customer experiencing the outage as well as the costs that that customer incurs over a more extended outage duration. The regulator should make clear his or her expectations that the utility use outage management systems to minimize the total outage cost to customers.

V. Step Four: Commission Evaluation of Utility Performance and Commission Policies

In the fourth step, the commission evaluates both (1) the utility's performance in meetings its obligations under the outage policy and (2) the policy itself. The fourth step can occur after an outage that warrants regulatory attention has taken place or it can occur as a periodic review. As shown in arrows #9 and #10, the commission evaluation results in periodic updating of utilities' pre-outage and post-outage obligations as a result of newly gathered facts and feedback from commission evaluations of utility post-outage performance. As shown in arrows #11 and #12, the commission also evaluates its own policies to determine if those policies should be revised, in view of newly gathered facts and from the commission evaluation of the utility's post-outage performance.

A. Commission Evaluation of Utility Performance

In the event of an outage warranting regulatory attention, the commission should require the utility to conduct a post-outage evaluation. The commission should independently evaluate the utility's self-assessment of its pre- and post-outage performance. The regulator should also assign regulatory staff or independent consultants to participate in the evaluation to assess the utility's performance. The post-outage evaluation should address five concerns:

- Did the utility conduct prescribed fact-finding before the outage took place?
- Did the utility conduct the prescribed pre-outage activities to prevent the outage?
- Did the utility conduct the prescribed pre-outage activities to mitigate the outage costs?
- Did the utility conduct post-outage activities that mitigated outage costs?
- Did the utility conduct a post-outage evaluation to identify (a) the outage cause, (b) whether the utility could have taken any actions to prevent the outage, and (c) whether the utility managed the outage and restored power in a way that mitigates outage costs?

Alternatively, a commission might require periodic evaluations of utility performance in meeting its outage obligation. In this instance, the commission would address the above questions and one additional one: did the utility meet its outage performance index?

The utility should establish at the outset that it has gathered facts about the value to customers of avoiding preventable outages and the cost to the utility of utility activities to avoid the outage or to mitigate the outage. If the utility cannot demonstrate that it has gathered facts about the benefits and costs of outage prevention and mitigation, then the utility cannot demonstrate that it acted efficiently by balancing costs with benefits.

The utility post-outage evaluation identifies the outage cause. In particular, the post-outage evaluation should consider whether the utility complied with vegetation management standards. If they were not, then the commission can require remedial action.

Similarly, the post-outage evaluation should consider whether the utility properly inspected and replaced transmission and distribution facilities. The failure to inspect such equipment can contribute to a major outage. Previously stressed and old equipment fail sometimes under stress; examples are previously stressed transformers failing in a heat wave and previously damaged poles failing in a major storm. If commission standards were not followed, the commission can again require remedial action.

If the utility were ordered to take remedial actions or to correct a poorly performing circuit to prevent a future outage but failed to do so, then a commission might penalize the utility as allowed by law. A failure to take commission-ordered remedial actions can constitute gross negligence or recklessness, which could also expose the utility to liability. At the end of the penalty spectrum is loss of the right to serve, if the utility persists in disregard of its obligations.

A post-outage performance evaluation also assesses the post-outage cost-mitigating actions of the utility. The evaluation examines whether the utility mitigated customer outage costs though its outage management and its power restoration efforts. Specifically, the commission evaluates the utility's actions to (1) reestablish essential services, (2) mitigate or minimize outage costs, or (3) communicate with customers on when they can expect power restoration.

Post-outage evaluations of utility pre-outage and post-outage actions are often case-specific. In some instances, however, a commission can compare the actions taken by two utilities reacting to the same major outage from the same natural disaster.

Periodic commission evaluations of utility performance also include the question whether the utility met or exceeded its outage performance indices. The commission evaluates, perhaps on an annual basis, whether the utility met is SAIFI, MAIFI, SAIDI, and CAIDI requirements.

If the commission's post-outage or periodic evaluation of the utility's performance finds that the performance is inadequate, then (following arrows #9 and #10, respectively) updating of the utility's pre-outage and post-outage obligations might occur. The process for such updating is discussed in the third subsection below

B. Commission Evaluation of the Commission's Policies

A commission should also evaluate its own policies periodically, and after an outage that warrants regulatory attention occurs. A commission should address five concerns:

- Did the commission review all utility activities?
- Did the commission evaluate its indices?
- Did the commission evaluate its prescribed activities?
- Did the commission consider resetting the indices?
- Did the commission consider resetting the prescribed activities?

The first three questions deal with whether the commission has conducted a comprehensive and complete post-outage or periodic evaluation. A commission should make certain that it has reviewed all utility activities and evaluated its outage performance indices and the prescribed pre-outage and post-outage utility activities.

A commission might consider resetting its outage performance indices if it is dissatisfied with the level of utility performance even though the utility met or exceeded its performance indices. The next subsection provides guidance on how this might be done.

Whether the utility followed its current vegetation management standard, whether the utility inspected and replaced transmission and distribution facilities, and whether the utility identified and corrected poorly performing circuits, a commission should address a second, separate question of whether one or more of these prescribed pre-outage standards should be revised. This question is considered in light of the outage evaluation or the results of the periodic review.

The commission might decide that the prescribed commission outage standard is too lax because the utility took inadequate actions to prevent or mitigate the outage. Alternatively, the commission might decide that its prescribed outage standards are too strict, inducing costly utility activities that are not justified in terms of the value to customer of avoiding the outage or mitigating outage costs. If the commission decides that the standard might need revision, then the standard is reconsidered in light of the previously discussed regulatory criteria set out in step one above. Arrows #11 and #12 in the diagram and the next subsection provide guidance.

C. Periodic Updating As a Result of New Information or Feedback

The systems approach to establishing regulatory policies for outages includes periodic revision and updating of outage performance indices metrics. In addition, it includes periodic revision and updating of the regulatory practices and standards that establish regulatory expectations on utility pre-outage and post-outage obligations. Updating occurs either when new detailed facts on the value that customers place on outage avoidance exist (arrow #2), when there is new information on the cost to the utility of its outage activities (arrow #3), or as a result of a post-outage or periodic commission evaluation (arrows #9, #10, #11, or #12).

The value that customers place on avoiding outages (arrow #2) changes over time. AMI data are collected continuously. That data is supplemented with data from periodic surveying of customers on the cost of actual outages and the value that they would place on avoiding outages. When combined with the AMI information, the survey data provides new information that can lead to new detailed facts about the value different customers place on outage avoidance.

The value of outage avoidance might increase for certain customers at particular times because of an increased reliance on sensitive digital equipment. On the other hand, other customers might have alternative, inexpensive self-help mechanisms that mitigate the cost of outages. This information can indicate that the value of outage avoidance might not be as great. As technology changes, and as customer uses and expectations change, the value of outage avoidance will change. Alternatively, the technology and software for outage prevention and outage management and power restoration could change.

Whatever the source of the new information, the regulator should use the new information in applying the criteria for regulatory policy. Assume that the new information shows that a new technology is available that would increase the customer's value of avoiding outages more than it would cost the utility to implement the technology (arrow #3). The utility should then adopt the new technology. If the utility fails to adopt the new technology, then the regulator should make explicit its expectations of the utility adopting the new technology consistent with the regulatory criteria.

If the new source of information involves resetting the value of outage avoidance at a higher level for particular customers because the customer has become more sensitive to outage frequency, then the regulator might apply the criteria to reset the SAIFI and MAIFI outage metrics to a higher level on circuits on which the particular customers take power. Alternatively, the regulator might prescribe stricter vegetation management standards for those circuits, or might require the inspection of transmission and distribution equipment for possible replacement more often.

If the new source of information shows that particular customers' value of outage avoidance rise as the duration of the outage increases, then the regulator might apply the criteria to reset the SAIDI and CAIDI metrics to a higher level for circuits on which the particular customers take power. The utility might also update its outage management system to reflect the new information. When an outage occurs, the utility will then give a higher priority to restoring service to these customers.

If the concern is that the utility did not take adequate action to mitigate the effects of a major outage that occurred (arrows #9 or #11), the regulator should use the criteria for regulatory policy to reset the SAIDI and CAIDI at a higher level. Alternatively, the regulator might conduct an inquiry or investigation to assure that the utility's outage management system reflects the regulator's expectations on post-outage mitigation through outage management and power restoration.

Through periodic updating (arrows #10 or #12), the systems approach we recommended in this report fills regulatory gaps and becomes self-re-enforcing. Each part of the outage regulatory policy re-enforces the other parts as an organic approach with systematic integrated parts, with outage regulatory policies changing over time to reflect changing customer expectations, as well as changing technology and infrastructure.

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