T&D Reliability: The Next Battleground in Re-Regulation

PUCs turn their attention to what they can still control.

By Dan O'Neill

THE BATTLEGROUND HAS SHIFTED. UTILITIES THAT LAST year worried about winning customers in pilot programs for retail choice now face public audits on the reliability of transmission and distribution.

With rate cases in remission, no nukes on order and generation planning left to the market, public utility commissions are turning their attention to what they can still regulate. That means service quality. Nor are PUCs the only ones involved. In some states, public officials up for re-election are making political hay of each major outage and playing on fears of post-deregulation reliability meltdowns. Consumer advocates and watchdogs also are protecting their interests.

Beyond the posturing, however, lies a genuine policy issue. How should utilities balance cost-cutting with improved reliability? Any serious discussion of performance-based ratemaking, or PBR, cannot avoid this issue.

Rising Scrutiny

The pace of regulation for T&D reliability and service quality is accelerating (*see figure*, Increase in States with New Rules). A closer look (*see Table 1*, New Reliability Regulations by State) reveals two major causes:

- public reaction to unusually severe outages; and
- public concern about competition-induced cost cutting.

Mergers only exacerbate this acceleration in rules and regulations. Merger reviews may include a special focus on post-merger reliability. Even an internal but very public restructuring could lead to the same result.

CONCERN OVER SEVERE OUTAGES. While PUCs for years have allowed and even encouraged utility companies to report their outage data on a storm-adjusted basis for better trend-spotting, there is no surer way for a utility to invite scrutiny than by mishandling a major outage, especially in unusual cases. If the cause is familiar, like hurricanes or tornadoes in states prone to such calamities, the public appears more likely to be forgiving, but when an ice storm hits the Gulf Coast or a hurricane hits New England, then any problems in service restoration seem quicker to promote a reaction.

For example, New England utilities still provide their PUCs with an unusually large amount of reliability detail that began as a reaction to outages that followed hurricane Gloria in 1985. Another example is Entergy, which suffered from a triple-jeopardy situation when, in early 1997, on the heels of its acquisition of Gulf States Utilities in 1995 and with deliberation of a deregulation bill for Texas underway, an unusual ice storm hit the Texas Gulf Coast. The resulting public reaction spurred the Texas PUC to fine Entergy 60 basis points against return on equity (with an opportunity to earn half back) and to mandate a service quality assessment by an external auditor.

In short, expectations define performance. Storm response, then, must pay heed to this rule. Second, it is better to avoid regulatory problems than to fight them. As any utility knows that has a nuclear plant on the NRC's watch list, more money may be spent responding to auditors (and intervenors, whistleblowers, etc.) than on assuring performance in the first place.

FEAR OF COST CUTTING. Here, what is interesting is how the discussion confuses reliability with supply adequacy. Even when deregulation extends to retail customers, the choice of energy supplier will not much affect the means of energy delivery. Unfortunately, when the industry and regulators think of supply adequacy, they often use the term reliability (as in the North American Electric Reliability Council, or NERC), and its regional counterparts.

As generation is unbundled and reserve margins in control areas are set by independent system operators or other quasi-public entities, regulators will lose much of their ability to control supply adequacy. But distribution and subtransmission reliability, as measured by outage frequency and duration, will continue to be heavily regulated. In fact, as the figure, Increase in States With New Rules, indicates, such regulation will expand.

Consider this story. When a certain big city mayor was told by the local utility that, under the state's deregulation plan, no single entity would be responsible for ensuring supply adequacy to his city's customers, the mayor was overheard to ask his staff advisor, "Is that right?" to which he received a concerned nod, "Yes."

A Pattern Emerges

My firm has reviewed in detail the new regulations relating to T&D reliability and service quality[1]. From our review a pattern is clear. The new regulations tend to have five focus areas:

1. SYSTEM MEASURES—the usual measures of system interruption frequency and duration;

2. PUBLIC EVENTS—hour-by-hour reporting and coordination during major storms and events;

3. WORST CIRCUITS—frequency and duration measures for the worst five percent or so of circuits;

4. RELIABILITY PROGRAMS—activities and spending associated with preventing outages and restoring service; and

5. CUSTOMER SERVICE—other service quality measures for things like call handling and new service connections.

In each of these focus areas (*see Table 2*), we have identified different degrees of

New England utilities report reliability data with unusual detail—which began as a reaction to hurricane Gloria in 1985.

regulatory control: (A) Mandatory Reporting (often in prescribed format); (B) Standards (prescribed performance minimums, involving averages, percentiles or benchmarks); and (C) Incentives (with fines for missing targets, or occasional upside rewards).

1. SYSTEM MEASURES. Many utilities for years have had to report average system interruption performance, with the most common measures being SAIDI, SAIFI and CAIDI (*defined in the sidebar,* Performance Measures). All of these measures are derived from a database that each utility must maintain. For each outage lasting more than a few minutes (typically, five, but sometimes less), the utility estimates the number of customers interrupted and the duration for which each was interrupted. Some types of outages may be excluded, as in supply-caused outages or planned outages for making new service connections or disconnecting service to a building on fire, etc. The data are typically reported with and without major storms. Note that momentary interruptions, often caused by a temporary fault that can be cleared by the operation of an automatic recloser or feeder circuit breaker, are not counted, although some commissions have begun to ask that a frequency measure for such interruptions (MAIFI) be included as well, since customers increasingly complain about their digital clocks blinking when they return home.

Among other points, an audit might examine whether the utility is properly reporting its reliability data. For the typical outage, a customer calls in and says his lights are out. The duration clock starts at that time. If no other customer nearby calls in the next few minutes, then a truck is dispatched to that customer to fix what is probably a blown fuse on his transformer. If that is the case, then when the fuse is replaced and service restored, the duration clock stops for that interruption. If any other customers are served by that transformer, they are counted, too, even though they may not have called. If the troubleman who restored the service can guess the cause (a "fried" squirrel at the base of the pole, a broken tree branch or lightning in the area), he will note it on his trouble report, along with his estimates of the number of customers and the time of restoration. If three customers are interrupted for 30 minutes, then the system will record one *outage,* three *customer interruptions* and 90 customer interruption *minutes.*

Where the possibility for error enters is that the actual outage may have started some time before the customer called, especially if it is in the middle of the night. So utilities that install automatic detectors that seize the customer's phone line and call in for him will find their measured performance deteriorates even though their actual service restoration time has improved. The next cause of error is the estimate of how many customers are interrupted. If the

Performance Measures

For interruptions, excluding momentaries and certain sustained outages.

SAIDI — System Average Interruption Duration Index. The average number of minutes in a year that the typical customer is interrupted. The ratio of total minutes divided by the average number of *customers.*

SAIFI — System Average Interruption Frequency Index. The average number of times per year that the typical customer is interrupted. The ratio of total customers interrupted divided by the average number of *customers.*

CAIDI — Customer Average Interruption Duration Index. The average duration of a customer interruption. The ratio of total *minutes* divided by the total number of *customers interrupted.*

ASAI — Average System Availability Index. The number of SAIDI minutes divided by the total number of minutes in a year, subtracted from 100 percent, to yield a positive measure. A typical transmission system accounts for less than ten minutes of interruption per year, so ASAIs for transmission are typically greater than 99.998 percent.

Example: SAIDI is the product of SAIFI and CAIDI, so if the average customer sees 1.5 interruptions per year and the average duration of each interruption is 90 minutes, then the average number of minutes of interruption experienced is 135 minutes. In this case ASAI would be 99.974 percent.—Author utility uses an automated system with accurate customer counts for each potential interrupting device (fuse, recloser, switch), then the count can be fairly accurate, but if the lineman makes an estimate based on his knowledge of the system, possibly checked by the dispatcher, it could be quite wrong. One auditor's test: Have the system print the number of customers interrupted for each device that has been interrupted more than once. If the numbers vary widely, the company's only defense is to see if the errors are due to switching changes.

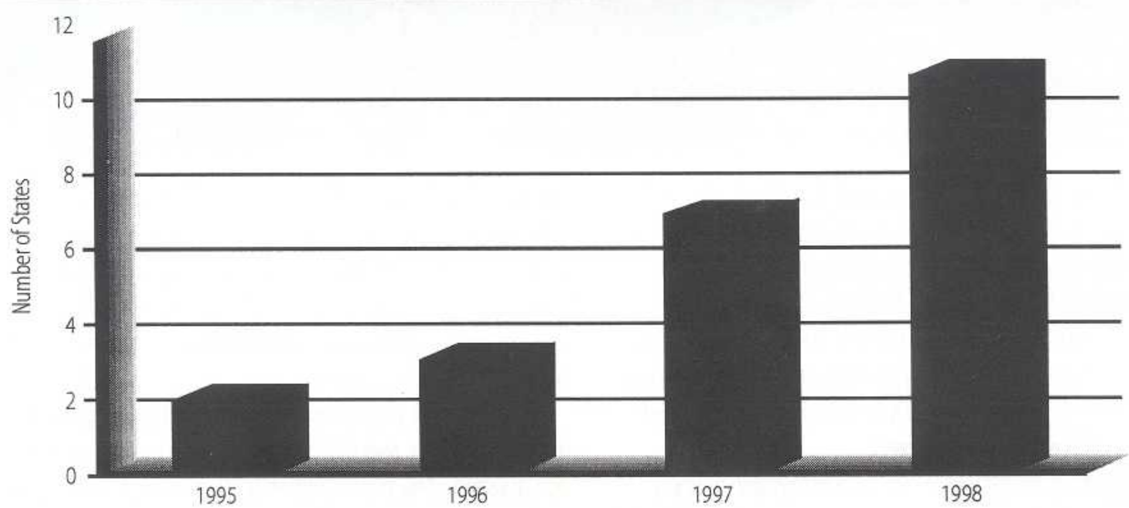
Moreover, these are just the easy cases. With such complications as calls not getting into the call center, partial restoration of circuits through temporary switching and the possibility of additional problems downstream of what was thought to be the offending device, counting customer interruptions and minutes gets tricky. There is a general sense among those of us who have worked with these data that utilities' manual systems tend to understate the actual number of overall minutes. There also is a general understanding that in a major storm with hundreds or thousands of outages, the systems are sorely taxed, and with accuracy of reporting being secondary to restoration of service, the numbers suffer.

Nevertheless, look for PUCs and their reliability auditors to ask for improvements in outage reporting systems, in part to improve their ability to monitor performance but also on the theory that in order to manage the problem, the utilities themselves need good information. At the very least, PUCS are requiring annual reporting of outages, customer interruptions, customer minutes and the various ratios, with and without storm adjustment. In some cases, PUCS have set standards and have threatened penalties for failure to meet the standard for system average performance.

2. PUBLIC EVENTS. Regulators and politicians alike are anxious to stay on top of what they know to be one of the most public aspects of reliability—storm restoration. For reporting purposes, the focus centers on the prudence and adequacy of a utility's service restoration efforts, i.e., the duration rather than the frequency. Regulators may require hourly status reports and ask for an account of the efforts after the fact. The prudent utility will prepare itself for scrutiny after a major storm.

The typical utility is not staffed to handle a major storm with internal resources. After diverting most of its construction crews to service restoration, it must call in its own non-construction personnel, outside contractors and other utilities. In fact, one utility that had done some downsizing in an area later hit by a major storm responded to bargaining unit criticism of its storm restoration

Increase in States with New Rules



* New rules refers to adopted or proposed reliability rules or an annual process of reviewing utility distribution service performance outside of simple compliance with the National Electric Safety Code.

performance by showing that, while the downsizing may have reduced its available force in the area by about 10 *percent*, the resources it tapped to handle the crisis were more on the order of 10 *times* the local force, even before the downsizing.

The utility will be judged on how well it had planned and arranged in advance to get extra resources. Many companies are enhancing their storm-watching ability, using not just the local weather service radar but also the National Lightning Detection Network to track the position and severity of oncoming storms. Dispatchers agonize over when to pull the trigger to mobilize massive resources in advance of a storm, and there are some examples of expensive false starts as storms changed direction and hit other areas. Sometimes the difference of a few degrees can determine whether an area sees harmless rain or a disastrous ice storm that loads up lines, poles and tree limbs with weight far in excess of even a conservative design criterion. The newspaper photo of a row of steel lattice transmission towers twisted like pretzels from last winter's Canadian ice storm comes to mind.

Regulators also will look for investments in automation. Call centers need to be able to handle many times their normal traffic, either through use of interactive voice response units or through outsourcing the overflow. Dispatchers must be able to diagnose properly the source of outages and the optimal way to restore service, while ensuring that restoring first the largest blocks of customers does not leave some isolated customers without service for too long. The utility that says it did not have enough resources to prevent harm to customers will not be heard. If help may be needed, the key is to recognize it soon and get it on its way.

3. WORST CIRCUITS. This area stands as the most predominant feature of the new reliability regulations. System averages can mask terrible service to small groups of customers. Utilities themselves long have recognized the value of outage frequency and duration data by circuit to prioritize their maintenance, on the theory that getting rid of the worst problems first is a good way to manage the

Table 1: New Reliability Regulations By State

State	Year Retail Choice Enacted	Year Reliability Rules Adopted	Comments
Arizona	N/A	N/A	Indices being considered as part of generic restructuring filing.
California	1995	1996	Comprehensive incentivized approach to enhancing reliability.
Connecticut	1998	1988, revised often	Reliability rules originated in response to storm Gloria (1985).
Florida	N/A	1997	Commission performed service audit in late 1997.
Illinois	1997	1998	Commission reliability activity spurred by legislation.
Kentucky	N/A	N/A	Spurred by merger activity in the state to ensure continued high-quality distribution service.
Massachusetts	1997	1997	Incentives for customer satisfaction and compliance with minimum reliability performance standards.
New York	1998	1991, revised in 1995	Implemented comprehensive program addressing customer care, circuit performance, remediation and reporting.
Ohio	Possible in 2001	1998	Proposed rules predominantly in line with what other states have opted for in terms of tracking reliability.
Oregon	Possible in 2000	1997	Reliability rules were adopted with the introduction of pilot choice programs in PGE's territory.
Texas	Possible in 2002	Proposed in 1998	Use indices for tracking reliability and the worst circuits semi-annually. Penalties for poor performance.
Wisconsin	Possible in 2001	1997	Adopted extensive annual reporting requirements for reliability performance as well as customer service.

total. The PUCs have jumped on this bandwagon *en masse* of late, probably because it appeals to their sense of protecting the individual customer.

The typical worst-circuit reporting requires that the utility provide the equivalent of SAIDI, SAIFI and CAIDI on a circuit-by-circuit basis, or at least for the worst five percent or so of circuits. Sometimes two lists are required, one ranked by frequency and one by duration. Typically, companies will be allowed to exclude circuits with less than five customers. Generally these programs address distribution circuits only.

One problem with worst-circuit reporting is that it aims at the wrong target. The definition of a distribution circuit can be a matter of convenience, and can even change seasonally for some utilities that use switching to maximize the use of their distribution plants (something we may begin to see more of as a cost-cutting measure). Moreover, by sheer accident of customer location and load growth, some rural feeders (circuits) may be more than 50 miles long, while their urban counterparts are less than 10 miles long. What is needed is an ability to focus on groups of say, 50 to 100 customers.

Many utilities that used circuit data to prioritize their maintenance now use their newly automated mapping systems to

Table 2: New Regulations Sample language in several focus areas

	Reporting	Standards	Incentives
System Reliability	■ Report annually SAIDI, SAIFI, CAIDI, MAIFI and ASAI for the system and for each circuit (Wisconsin).	■ The minimum performance level shall be SAIDI = 3.58 and SAIFI = 2.84 … increasing at 5 percent per year for five years (Louisiana).	■ A utility may be fined up to $500,000 for failure to meet the minimum performance level for the reporting year (Louisiana).
Public Events	■ Customer interruptions that affect at least 10 percent of the customers in an operating area or durations of at least 24 hours (Wisconsin).	■ Not more than 30,000 customers interrupted for over 6 hours (Illinois).	■ Utilities shall design and implement an administrative procedure for resolving and paying claims for actual damages and replacement value (Illinois).
Worst Circuits	■ Report the 100 worst circuits on the system based on SAIDI and SAIFI ratings individually (Connecticut). ■ The worst 5 percent of the performing circuits in each region (Louisiana).	■ Improve the performance of its worst-performing feeders in stages so that by 2001, 98 percent of the utility's customers will receive service as good as 90 percent of its customers in 1999 (Texas).	■ A fine of 60 basis points of ROE, with the chance to earn back 30, based on improvement in worst circuits and customer service (Texas).
Reliability Programs	■ File with the Commission … programs and practices for the control of vegetation (Illinois).	■ Trees must be 4-15 feet from distribution lines, depending on voltage (California).	■ $1 million fine for violating tree clearance standards (California).
Customer Service	■ Customer satisfaction surveys must be reported annually … try to reach a benchmark of 92 percent responding "Very Satisfied" (California).	■ Maintain sufficient employees and equipment to achieve an average speed of answer of not > 90 seconds (Connecticut, Wisconsin).	■ If < 73 percent of customer calls are answered in < 30 seconds, a penalty will be imposed by the Commission (New York).

Regulators will look for improvements in automation.

provide data at the device level, allowing even better targeting of trouble spots, since devices (fuses) often exist for groups of 50 to 100 customers. PUCs would do well to heed this change, because a 50-mile feeder still can mask some serious problems for small groups of customers. In fact, some PUCs do require reporting of the customers who have been interrupted more than say, 10 times per year—data that depend upon the ability to record interruptions by device, not just by circuit. (Remember, even customers that do not call in are counted as interrupted if their service was cut, so customer call data alone are not sufficient to compute a 'worst-customers' list.)

Some PUCs require reporting only of worst circuits, whereas some set standards and impose incentives. Some emphasize that worst circuits should not repeat from one year to the next. Many that require reporting also require disclosure of remediation programs.

4. RELIABILITY PROGRAMS. The new emphasis on worst-circuit reporting opens the door to a greater degree of regulatory scrutiny and control. After asking utilities to report their worst circuits, it is natural to ask what efforts are being made to remediate those problems. The answer may invite a look at root causes—and then the specific project activity and spending designed to remediate the problem[2].

Once on that path, though, it is a short step to ask for detail on all reliability programs. This request typically will include: vegetation management; wood pole inspection, treatment and replacement; line rehabilitation; lightning mitigation; animal mitigation; underground cable maintenance; capacity reinforcement; substation maintenance; and sectionalizing. In large companies, these expenditures can total more than $100 million per year. Most of it is capital spending, except for tree trimming and the operations and maintenance charges associated with capital work.

Utilities may find that auditors look at the spending by category and relate it to outages by cause. Note the recent service quality assessment by the Florida PSC staff on the four major IOUs it regulates. Two of the four companies showed a pattern of falling expenditures on vegetation management and increasing vegetation-caused outages. Having noted the trend themselves, the companies volunteered to boost their spending by approximately 50 percent each.

This case underscores a nationwide trend: Companies that cut their tree trimming activity drastically in the last few years, in order to cut costs, are ramping back up in 1999. Of course, what matters is not just spending but the activity and its impact on reliability. Companies that cut costs through better management of contractors may find (if the contractors do not try to take back the savings in poorer service) that they can cut costs and still maintain reliability. One of the practice areas that we have developed in the last few years is the application of decision analysis tools to T&D reliability in order to optimize the "bang per buck" in reliability spending. With more than $100 million at stake in annual budgets, a little extra planning can go a long way. Regulators recognize this fact, and are beginning to ask not just how much is being spent, but how.

Here again, some commissions are satisfied with reporting on reliability programs, while others will insist on setting a standard and enforcing it with penalties. Of note is the recent $1 million fine levied by the California PUC for violations of its new tree-clearance standards.

5. CUSTOMER SERVICE. Some new regulations focus on efficiency of customer contacts, which may or may not relate to reliability. Call handling is one example. Rules may focus on the average speed of answers or the percent of calls answered within 15 seconds. A second example is new service connections—the cycle time between order and completion. Still a third example concerns billing errors—estimates or errors in reading or rating usage.

The Ratchet Effect

If the past is any indication, these changes in regulatory control are a ratchet. With a few exceptions, enhanced reporting requirements instituted years ago have not been relaxed. Perhaps what is needed is more and better dialogue between utilities and the public about what reliability is and how it can best be achieved. As traditional return-on-rate-base regulation gives way to rate caps and performance-based incentives, utilities and regulators must find innovative ways to insure that reliability is maintained without raising cost.

Recently, a New York PUC advisor commented that the commission first saw PBR as a two-way street, with upside rewards for better performance. He added, however, that when the commission polled customers and found no evidence they were willing to pay more for better service, the PUC dropped the upside incentive.

More information may come to light on this tradeoff, as competition moves beyond experiment. In the meantime, utilities can expect to be fined whenever their reliability frustrates customers' expectations, especially in a public way.

Dan O'Neill is vice president of Metzler & Associates, a management consulting firm headquartered in Deerfield, Ill. Research assistance was provided by his associate, Howard Friedman.

1 Source documents are available in electronic form from the author. He can be contacted at DONeill@MetzAssoc.com.

2 For examples, readers may request copies of reliability reports filed with the Illinois Commerce Commission or the Connecticut Department of Public Utility Control.

The California Case PG&E Outage Highlights Rule-Tightening

In its Jan. 25 report to the California Public Utilities Commission, Pacific Gas & Electric Co. attributes its Dec. 8 power outage to human error. But the incident—and the PUC's response in ordering a full investigation—highlight increasing state-level regulation of electric reliability.

INCIDENT. PG&E says the outage, which left more than 1 million of the utility's customers in San Francisco and San Mateo counties without power, occurred when a construction crew at the San Mateo Substation improperly removed temporary protective grounds. Separately, a transmission operator at the substation then energized the lines, but failed to engage protective relays. With the local protective system disengaged, electric current was sent to ground. The system took a half-second to isolate the fault instead of the one-tenth of a second that would be required normally.

REACTION. "The reliability of the transmission and distribution systems are crucial elements to our efforts in electric restructuring," noted assigned commissioner Richard A. Bilas in his initial ruling. He described the CPUC's work aimed at setting up a performance-based ratemaking mechanism for each investor owned utility, with standards for maintenance and repair and emergency response procedures and stricter tree-trimming rules.

Mark Ziering, the commission's Reliability Project Team manager, agrees that California's T&D systems are receiving more critical regulatory attention since deregulation. "The commission has full jurisdiction over distribution-level outages, which account for the vast majority of outages and outage-hours," he says. "The CPUC also is concerned about transmission outages because those can be the most catastrophic."

KEY POLICIES. Bilas also described the CPUC's efforts to prevent future incidents through new and tightened regulations. He cited Rulemaking 96-11-004, an ongoing proceeding to develop and refine standards to promote safety and reliability of the state's distribution system.

In addition, the commission has adopted incentives to encourage utilities to make investments that will prevent outages. "Every time a customer experiences an outage there's a \$15 penalty plus an additional \$15 for every hour they're affected," says Ziering. The incentives, which apply to Southern California Edison and San Diego Gas & Electric, reward utilities with SAIDI and SAIFI measures at or below a certain target value, and penalize utilities that exceed the value. "We understand SoCalEd is using this for planning," he notes.

Other key areas include:

- *Maintenance.* Decisions 96-11-021 and 97-03-070 establish inspection cycles and record- keeping requirements for utility distribution equipment.
- *Tree-Trimming.* Decisions 97-01-044 and 97-10-056 concern requirements for trimming trees near power lines.
- *Systems Jurisdiction.* In Decision 98-03-036, the CPUC asserted jurisdiction over the distribution systems of publicly owned utilities to oversee reliability.
- *Emergency Actions.* Decision 98-07-097 formalized the standards for operation, reliability and safety during emergencies and disasters.

—R.R.J.