October 2002 • NREL/SR-560-32498

Subcontractor Report

State Electricity Regulatory Policy and Distributed Resources: Distributed Resources and Electric System Reliability

R. Cowart, C. Harrington, D. Moskovitz,
W. Shirley, F. Weston, and R. Sedano
The Regulatory Assistance Project
Gardiner, Maine
Montpelier, Vermont

National Renewable Energy Laboratory
1617 Cole Boulevard
Golden, Colorado 80401-3393

NREL is a U.S. Department of Energy Laboratory
Operated by Midwest Research Institute • Battelle • Bechtel

Contract No. DE-AC36-99-GO10337

October 2002 • NREL/SR-560-32498

State Electricity Regulatory Policy and Distributed Resources: Distributed Resources and Electric System Reliability

R. Cowart, C. Harrington, D. Moskovitz,
W. Shirley, F. Weston, and R. Sedano
The Regulatory Assistance Project
Gardiner, Maine
Montpelier, Vermont

NREL Technical Monitor: Thomas Basso

Prepared under Subcontract No. NAD-1-30605-03

National Renewable Energy Laboratory

1617 Cole Boulevard
Golden, Colorado 80401-3393

NREL is a U.S. Department of Energy Laboratory
Operated by Midwest Research Institute • Battelle • Bechtel

Contract No. DE-AC36-99-GO10337

Available electronically at http://www.osti.gov/bridge

Available for a processing fee to U.S. Department of Energy
and its contractors, in paper, from:
U.S. Department of Energy
Office of Scientific and Technical Information
P.O. Box 62
Oak Ridge, TN 37831-0062
phone: 865.576.8401
fax: 865.576.5728
email: reports@adonis.osti.gov

Available for sale to the public, in paper, from:
U.S. Department of Commerce
National Technical Information Service
5285 Port Royal Road
Springfield, VA 22161
phone: 800.553.6847
fax: 703.605.6900
email: orders@ntis.fedworld.gov
online ordering: http://www.ntis.gov/ordering.htm

Printed on paper containing at least 50% wastepaper, including 20% postconsumer waste

Foreword

This report is one in a series of four that discusses aspects of state regulatory policy and the potential development of cost-effective distributed resources. These reports were prepared by The Regulatory Assistance Project under contract to the National Renewable Energy Laboratory (see Annual Technical Status Report of the Regulatory Assistance Project: September 2000-September 2001, NREL/SR-560-32733). The work is a part of a larger U.S. Department of Energy initiative designed to further the development and safe and reliable deployment of distributed resources within the nation's electricity system.

Distributed resources offer many economic and reliability benefits to customers, utilities, and society as a whole. But in some very important ways, our state regulatory practices inadvertently have made it difficult for these resources to be deployed. Understanding the existing regulatory barriers may lead to their removal. States such as Texas, New York, California, and others have already undertaken new regulatory approaches that simplify the technical integration of distributed resources into their local distribution networks. We encourage regulators and interested parties to become familiar with the work now under way in these states and to take steps to ease the integration of small-scale resources into local distribution systems.

The papers in the State Regulatory Policy and Distributed Resources series may be found at www.nrel.gov/publications under the following titles:

- Accommodating Distributed Resources in Wholesale Markets, NREL/SR-560-32497
- Distributed Resource Distribution Credit Pilot Programs — Revealing the Value to Consumers and Vendors, NREL/SR-560-32499
- Distributed Resources and Electric System Reliability, NREL/SR-560-32498
- Distribution System Cost Methodologies for Distributed Generation, NREL/SR-560-32500
- Distribution System Cost Methodologies for Distributed Generation Appendices, NREL/SR-560-32501.

These reports, along with previous reports that address related distributed resource issues, can also be accessed on line at www.raponline.org.

Table of Contents

1. The Setting: Reliability Challenges Today

The U.S. electric system is in the midst of a transformation as profound as any change it has experienced since the emergence of the franchise system early in the past century. The nation is now dealing with the consequences of this transformation, and not all of them were anticipated by the advocates of reform. In particular, the reliability of electric supply, long taken for granted by most citizens and governmental officials, is now a matter of increasing national concern. Rolling blackouts, electric price spikes, and power quality issues have become topics of daily news coverage, private conversation, and public debate.

As summer heat waves and winter cold snaps drive the demand for power to new peaks and tax an already constrained electric grid, policymakers are considering what steps can be taken to ensure system reliability in competitive markets in which traditional utility rules of price restraint and mutual aid are under siege. The California power crisis of 2000-2001 commands national attention, but reliability problems in various forms are arising in almost every region of the country.

Although new investments in central station generation and transmission are obvious reactions to reliability challenges, often overlooked are the very real reliability benefits that can be captured from distributed energy resources: end-use efficiency and demand management, customer-owned generation, customer-supplied ancillary services, and customer responses to improved pricing signals in wholesale and retail markets. How can these distributed resources enhance electric system reliability?

1.1. Underlying Trends

To begin, it's useful to understand that the "reliability problem" is not a single problem but a cluster of challenges that arise at the intersection of at least three critical trends:

- The power quality demands of the digital economy
  First, there is a growing awareness that continuous power supply and improved power quality are critical underpinnings of the nation's post-industrial, digital economy. Our economy is increasingly based on the continuous real-time flow of information and increasingly dependent on machines controlled by computer chips. For many high-tech businesses, power outages are unacceptably expensive.[1] And for many electric applications, from home computers connected to the Internet to commercial banking networks to multi-million dollar industrial machines controlled by computer chips,

1. For example, according to Larry Owens of Silicon Valley Power, a blackout costs Sun Microsystems "up to $1 million per minute." Mike Wallach of Oracle states, "The impact of momentary interruptions of power is extremely costly in terms of lost productivity and potentially damaged equipment at Oracle... . Whether the electricity was free or cost three times as much would have absolutely no effect on the cost of our product." Quoted in: Stahlkopf, Karl. *Consortium for Electric Infrastructure to Support a Digital Society (CEIDS)*. Forth Worth, Texas: Electric Power Research Institute, November 2000.

even very small variations in power quality can cause troubling and expensive disruptions.[2] The United States Department of Energy (US DOE) now estimates that power outages and other fluctuations in power delivery cost at least $30 billion a year in lost productivity.[3]

- The effects of persistent load growth
  Second, load growth in the United States, and particularly peak load growth, has been proceeding at a pace that has put great strains on our power system infrastructure. Between 1993 and 1997, noncoincident summer peak load in the United States rose from roughly 581,000 MW to 638,000 MW — an increase of more than 56,000 MW in four years.[4] This is the equivalent of adding a new, six-state New England to the nation's electrical demand every 18 months. Between 1997 and 2000, the rate of increase was even more rapid. Nationwide, electric consumption grew 31% in the decade between 1988 and 1998.[5] Consumption grew 278,000 GWh (or about 9.7%) between 1993 and 1997 alone.[6]

  According to many estimates, shortages are likely to develop in almost every one of the nation's 10 regional reliability councils in the next five to seven years.[7] Regulators, legislators, reliability managers, and energy markets are now calling forth a huge wave of new construction in central station power plants. The DOE now estimates that meeting the needs of demand growth and plant retirements will require the construction of more than 300,000 MW of new capacity in the next 20 years.

- The abandonment of integrated resource planning
  Changes in the economy and continued widespread load growth have been accompanied by another very significant change in the electric industry: the de-integration of functions that formerly occurred within tightly woven franchise operations. There are at least two critical reliability consequences. First, transactions that formerly occurred within integrated franchises are now increasingly occurring in the regional wholesale marketplace, placing greater demands on transmission grids and undercutting the industry's traditional ethic of cost-based mutual support. And second, in most of the United States, the process of integrated resource planning, which

---

2. *Id.*

3. Environmental Media Services. "Widespread Reliability Problems Produce Huge Disruptions, Great Cost." *Lighten the Load*, 2000.

4. US Energy Information Agency. "Electricity End Use (1949-1999)." Table 35, Noncoincidental Peak Load.

5. *New York Times.* Sept. 13, 1999.

6. US Energy Information Agency. "Electricity End Use (1949-1999)." Table 8.9, Electric Utility Retail Sales.

7. "Nationwide Capacity Shortage by 2007?" *Electricity Daily*. June 4, 1999.

contributed greatly to balancing demand and supply after the energy crises of the 1970s, has now been abandoned. This has led to greater pressures on the entire electric infrastructure, less controlled peak load growth, and, thus, increased market power of generators, thin reserve margins, and higher power costs generally.

1.2. The Potential Contribution of Distributed Resources

Although the three trends noted above present serious challenges to electric systems, concurrent changes in technology and policy are creating new opportunities for nontraditional electric resources to meet the needs of customers, electric systems, and the broader economy. In particular, distributed electric resources can address the needs of customers, meet load growth, and help fill the reliability gaps left by the erosion of franchise planning and regulation.

What is meant by distributed resources (DR) in this discussion? DR are the large set of electricity-generating and electricity-saving measures that are located near or on customer premises — that is, are *distributed* throughout the network, close to customers and load centers. DR include both demand-side and supply-side resources. DR include smaller-scale generation, energy storage, load management, and energy efficiency as well as wires solutions. For reliability purposes, the contribution of demand-side and supply-side resources are often very similar. There is no established measure for the size of distributed resources. Typically, they are thought to include technologies of up to 10 MW, but some customer-owned generation is as large as 100 MW. DR can be owned by a customer (load), a utility, or a third party (e.g., an ESCO performing load reduction contracts or an independent power producer). Efficiency and load management resources are usually "found" on a customer's premises. Generation and storage resources, however, can be located on either side of the utility meter — at customer's facilities, at utility substations, or elsewhere in the community on the lower-voltage system.

1.3. Adequacy, Security, and Power Quality Events Across the Country

Throughout the summers of 1998 to 2000 and into the winter of 2000-2001, major reliability problems in many regions of the nation became so common that there is little need to document them here. Eight of the most significant events from the summer of 1999 were examined by the US DOE's Power Outage Study Team (POST), which concluded that the transition to more competitive wholesale markets and to retail competition in many states had undermined the industry's traditional reliability mechanisms. As the report stated:

> "The power outages and disturbances studied by POST served as a wake-up call, reminding us that reliable electric service is critical for our health, comfort, and the economy. While the new industry structure should improve reliability ... the transition to that new structure presents a risk... . (T)he reliability events of the summer of 1999 demonstrated that the necessary operating practices, regulatory policies, and technological tools for ensuring an acceptable level of reliability were not yet in place."[8]

---

8. US DOE. *Report of the U.S. Department of Energy's Power Outage Study Team*. March 2000 Final Report, at S-2.

A review of the major reliability events of the past four years reveals one key observation: although the immediate system failure or technical problem involved in these events varied from case to case, the underlying cause of these reliability problems was, in almost every case, the high loads the system was required to serve at the time of failure. And in most of these cases, distributed resources could have improved system reliability by moderating high demands or serving the system loads that caused the reliability problem.

The following leading examples will illustrate this point:

- Regional transmission failure
  Western states — August 10, 1996
  On August 10, 1996, the largest regional blackout in the United States since the New York City blackout of 1965 cascaded across a multi-state region of the West. This event began with a transmission line on the California-Oregon border that sagged under heavy load in high heat conditions and shorted out. Other facilities were taken out by system operators and equipment to protect them from failure, resulting in a series of outages that stretched across several states. Altogether, 30,000 MW of load were interrupted, and 7.5 million customers were affected, some unserved for as long as nine hours. The California Energy Commission later estimated the economic cost of this outage to the California economy at $1 billion.

- Generation adequacy problems
  New England — June 7 and 8, 1999
  Record-breaking heat and humidity spread across the northeastern United States in June 1999, leading to operating emergencies in New England, Ontario, and New York because of shortages of reserve generating capacity. Many generating units were out of service for maintenance and refueling in anticipation of high demand later in the season. Operators kept the system running with urgent calls for customers to curtail energy use and forced voltage reductions. They brought in emergency power from several neighboring systems, and from as far away as Michigan, until relief finally came in the form of cooler temperatures.

  South Central states — July 23, 1999
  At noon on July 23, Entergy — which serves 2.5 million customers in Louisiana, Arkansas, Texas, and Mississippi — discovered electric load was rising beyond forecast levels at the same time that its generating system was lagging behind projected capacity. Power imports expected from other generators disappeared as loads rose elsewhere. The company issued an emergency public request for conservation, only its third such appeal in 20 years, but this was not enough to prevent outages that affected 500,000 customers. Load growth in the region will continue to threaten reliability despite a multi-billion dollar investment program in new capacity now under way.

- Inadequate local transmission to serve a load pocket
  San Francisco Peninsula — June 2000
  The San Francisco Peninsula is a rapidly-growing load pocket, with inadequate local generation, served by limited-capacity transmission lines. In June 2000, during an early heat wave, the California independent system operator (ISO) was forced to institute rolling blackouts in San Francisco and surrounding areas to avoid uncontrolled overloads. This was the first time in modern history that intentional load losses were imposed on customers by system managers in California. Even though much of Northern California was experiencing record heat at the time of this event, there was sufficient generation capacity available to serve San Francisco. However, the transmission links serving the peninsula were unable to carry the load required to meet peak demand in the load pocket.

- Local distribution failures
  New York City — July 6 and 7, 1999
  On July 6 and 7, 1999, more than 200,000 people were left without power for up to 19 hours when Consolidated Edison lost eight of its 14 feeder cables serving the densely packed Washington Heights neighborhood in northern Manhattan. Among those blacked out was the Columbia University Medical Center, where years' worth of medical research was nearly lost when laboratory coolers failed. The loss of feeders occurred because of heat-related failures in connections, cables, and transformers and was triggered by high, persistent demand during hot weather. ConEd serves the most dense electric power load pocket in the world, with more than 3.1 million customers in a 604-square-mile area.

  Chicago — July 30 to Aug. 12, 1999
  Outages in Chicago have also been triggered by the failure of aging and overloaded local distribution systems because of high demand during sustained hot weather. Between July 30 and August 12, 1999, three major outages struck Commonwealth Edison's Chicago distribution network. Difficulties started late on the afternoon of July 30 after demand set record highs. Cable faults knocked transformers off line, sending automatic shutdowns cascading through the system. More than 100,000 customers suffered outages on July 30 and August 1. Later, on August 12, ConEd cut power to 3,300 customers, including the Chicago Board of Trade, served by a failed substation. Other firms closed their offices voluntarily out of fear that the collapse would spread.

- Power quality disruptions
  "This energy crisis is probably the most critical issue Silicon Valley has faced in last the 30 years," said Carl Guardino, president of the Silicon Valley Manufacturers Group, a powerful association composed of 190 of the largest companies in the high-tech corridor.[9]

---

9. Sanchez, Rene; Booth, William. "California's Energy Future Looks Dim – Problems Brought on by Deregulation Plan Defy Easy Solutions," *Washington Post*, Jan. 14, 2001, p. A01.

1.4. Distributed Resources and the Never-Ending Problem of Weakest Links

In the POST report, and in many other post-event analyses, utility managers, regulators, and other experts were called on to identify the immediate causes of the types of reliability problems noted above. Of course, in nearly every case, it is possible to identify the weak link in the chain that links generation, systems operation, transmission, and distribution to customer load. For example, in the 1996 West-wide outage, an overloaded transmission link near the Oregon-California border was identified as the weak link that started a cascade of problems. In Chicago and New York in 1999, aging and overloaded distribution facilities were the links that failed, and in California throughout 2000 and 2001, generation adequacy has been a major continuing problem.

Of course it is important, and often essential, to address resources and policy attention to the weakest links in the supply and delivery chain to improve reliability for customers. For example, aging distribution infrastructure in Chicago and New York must be maintained and replaced over a reasonable schedule to ensure high-quality service long into the future. However, a narrow focus on fixing today's weakest links in the supply/delivery chain will ultimately be less resilient and more expensive than a strategy that identifies reliability-enhancing distributed investments as well. There are several powerful reasons that reliability policy should focus intently on, and seek to capture, distributed generation and demand-side solutions to reliability problems:

- The untapped reservoir of distributed generation, energy efficiency, and load management options is both large and dispersed; these resources offer many ways to meet reliability needs. Moreover, by being dispersed and diverse, they are less "lumpy" and in a statistical sense and more likely to be available when needed than many supply-side resources are.[10]

- Demand-side resources, even if not fully coincident with peak demand, will provide an offset against load that would otherwise have to be served. "Lightening the load" moderates the problems that reliability managers have to solve.

- Cost-effective DR solutions are often less expensive than the central station and transmission-dependent solutions put forward to address reliability problems. DR solutions "at the end of the line" can avoid costs in system upgrades, operation, and maintenance all the way back through the system: distribution, substation, transmission, generation, fuel supply, and reserve margin requirements.

---

10. For example, a 100-MW peaking unit will frequently be available at its full rated capacity, but on occasion it will not be available at all. Most demand-management resources, on the other hand, are more likely to be available at some known discount below their technical capacity, but they will be reliably available at that discounted level consistently.

When reliability managers accept load growth and demand spikes as givens — and attempt to meet them through an exclusive, central station-focused, wires and turbines policy — they may fix each "weakest link" in the supply chain as it appears. But once one upgrade is completed, the next weakest link will emerge. For example, where reliability managers resolve load growth problems by building new central-station generation facilities, it is likely that transmission links will be more stressed, particularly at peak-load periods. Unless transmission upgrades are also purchased, the resulting degradation in transmission reliability will at least partially offset the gain in reliability because of the new generation. DR, on the other hand, can lighten the load at the end of the supply/delivery chain and thus simultaneously enhance the reliability of each link in the entire chain, from the local distribution network all the way through to generation adequacy.

2. Reliability Contributions of Distributed Resources

The reliability contributions of distributed resources must be considered from at least three points of view:

- Individual customers
- Groups of customers and their local distribution companies
- Wholesale market managers, reliability managers, and system operators.

In this section, we examine case studies in which DR have been considered or have been deployed to address the reliability objectives of one or more of those responsible parties.

DR may be tapped to address reliability challenges by:

- Improving power quality and ensuring uninterrupted power to individual customers
  DR can improve power quality in stressed service areas, at the end of long distribution lines, and in customer locations where especially high-quality power is needed. It can also provide on-site generation capability under the control of customers who demand uninterrupted service.

- Relieving distribution overloads and transmission congestion
  DR can lighten the load on stressed distribution systems and can relieve congestion on transmission systems, lowering the costs of serving load pockets and improving the resilience of transmission systems.

- Meeting generation adequacy requirements
  DR can lower system requirements on a "baseload" basis and can meet or shave peak loads so as to satisfy essential reserve margin requirements and avoid overloads and involuntary load-shedding.

- Providing ancillary services to the system
  DR can provide an array of ancillary services to system operators and reliability managers.[11]

The case studies in the sections below illustrate DR applications in each of these categories.

---

11. In addition to their reliability benefits, DR also may provide valuable financial benefits in wholesale power markets. Where distributed resources can participate in those markets freely, they can bid to provide services in response to changing market conditions, lowering the price curve, weakening the market power of conventional generators, and mitigating power market price spikes. These features are discussed in a companion paper and will not be developed here. Lowering the demand on conventional resources will, of course, also tend to improve reliability.

2.1. Improving Power Quality and Ensuring Uninterrupted Power Supplies to Individual Customers

2.1.1. Introduction

Customers who install distributed power on their own side of the meter usually do so for three reasons: cost reduction, improved power quality, and greater reliability. Old-fashioned altruism or the more modern impulse of early technology adoption can also play a role.

One cost reduction motive is the avoidance of high power costs, particularly generation costs such as demand charges or peak prices. (Businesses have only recently started to look for similar cost savings in avoiding distribution costs. See RAP's related papers on distribution costs.) However, the stronger cost reduction driver is more often the avoidance of lost business opportunities that arise from being unable to operate or operate fully because of power outages or receiving power of insufficient quality. The lost opportunity costs can be very large, greatly overshadowing the costs of electricity savings. This is particularly true for electronic and Web-based businesses. For example, the US DOE reports the following costs of power outages for several modern electronic communication-dependent businesses:

Industry	**Avg. Cost per Hour**
Cellular communications	$41,000
Telephone ticket sales	$72,000
Airline reservations	$90,000
Credit card operations	$2,580,000
Brokerage operations	$6,480,000

Source: US DOE Distributed Energy Resources Program and Strategic Plan, September 2000

Another cost avoided may be that of public safety. These are costs avoided by essential public facilities such as police, hospital, or airport facilities and the public they serve. Here, quantified costs of outages are not as readily available, but they are unmistakable.

For modern electronic- based businesses, it is not only outages that hurt but unstable power quality as well. Many high-tech businesses, from Web-servers to bio-tech laboratories, need a very high level of power quality. This level of quality is referred to as the "high nines." Most power is delivered to a reliability standard of 99.99% availability. For years, this was regarded as a very high standard and, in comparison with much of the world, is still a very high standard. Traditional manufacturing equipment is generally less reliable than the electricity system powering it. A business was more likely to suffer from the failure of its own equipment or processes than the failure of the electric system feeding it. Today, in the 24-hours-a-day, seven-days-a-week information age, many businesses operate computer-driven equipment with availabilities of 99.999% or even 99.9999%, where every added nine is a magnitude (10 times) greater than the previous level. In these cases, the electricity system is more likely to fail than the customer's equipment. Very brief sags in voltage or harmonic distortions that used to go entirely unnoticed by most customers can be devastating to customers using sensitive electronics. It takes as little as 8/1,000 of a second to crash a computer system, often destroying data at the same time.[12] Fixes to avoid power surges are usually cheap, but remedies for avoiding power sags are not so cheap. For these businesses, often redundant systems can be a very cost-effective means of ensuring the required power quality and reliability levels.

Some businesses install stand-alone systems that are not integrated with the grid, removing all or a segregated portion of their power needs from the grid altogether. Others keep their load connected to the grid but use distributed generation as emergency backup — or more recently in California, agree to run their distributed generation equipment to meet the needs of the grid in exchange for the distribution company's agreement not to subject the customers to a rolling blackout. It is important that regulation signal consumers to make the right decisions regarding whether to remain grid-connected or to cut the cord entirely.

2.1.2. Case Studies

2.1.2.1. Bank of Omaha

The First National Bank of Omaha in Omaha, Nebraska, began operating its carefully designed independent distributed power system for its power-sensitive credit card processing center in May 1999. The bank is the nation's seventh-largest credit card processor and the provider of similar services to many other banks in its region. It faces losses of about $6 million for every hour of power outage. Following the failure of a backup battery system in the early 1990s, the bank looked around for a better way to ensure itself of the continuous high-level power quality and reliability its 24-hour, uninterrupted operation required. The bank's critical computer operations are now served by two redundant sets of fuel cells (four in all) as well as a separate redundant set of diesel engines. The remainder of the building, with less critical operations, is connected to two separate electric feeders, installed from different substations.

The facility served is a 200,000-square-foot, three-story building with a 340-kW load. The distributed system, designed by HDR Architecture Inc. of Omaha, is powered by four 200-kW PC25™ natural gas-fired fuel cells. The fuel cells were manufactured by ONSI Corp. and supplied and operated by Sure Power Corp. of Danbury, Connecticut. The excess power generated by the two fuel cells serves the bank's noncritical power needs, which remain connected to the grid. The excess power from the distributed installation reduces the bank's demand charges. In winter months, recovered heat from the distributed system is used to heat the building and to melt ice and snow on its surrounding sidewalks. In the summer, the excess heat is dissipated. The overall efficiency of the system is 54.1%.

12. "Distributed Generation: Fuel Cells Deliver High-Quality Power." *American Gas Magazine*; Nov. 13, 200.

Customer satisfaction is reported to be very high. The bank's director of property management, Dennis C. Hughes, has cited competitive advantage as well as a cost advantage, as the system was less expensive on a life-cycle basis (20 years) compared with other available uninterruptible power configurations.

Source: "Distributed Generation: Fuel Cells Deliver High-Quality Power," *American Gas Magazine*; Nov. 13, 2000.

2.1.2.2. NYPD Central Park

The use of distributed power at the New York City Police Department Central Park Precinct highlights a much different need for electric reliability — that of maintaining public safety. The Central Park Precinct is housed in a 145-year-old historic building built originally as a horse stable and located deep within the park, a distance of several city blocks from the nearest electricity feeder lines. Like the rest of modern society, modern police equipment relies heavily on computers for information processing and communications. Central Park is in many ways a haven from modernity, where New Yorkers and visitors alike can enjoy peaceful retreat from the city, trading modernity for the older joys of strolling, picnicking, boating, and listening to concerts. But a vigilant police force connected with the modern world is a critical component of the park's peacefulness. When faced with the need to upgrade electrical service and the prohibitively high cost of trenching lines across the park for this satellite precinct, the New York Power Authority decided to place a distributed power source at the site. Because of the environmental sensitivity of the Central Park location and the protected historic nature of the building, neither gas-fired generators nor PV cells, which would have to be located on the building's exterior, were acceptable.

An ONSI 200-kW fuel cell was selected to upgrade the precinct's electrical power needs. The fuel cell not only runs the station's computers, lighting, and HVAC system, but it also serves as a refueling station for the NYPD's electric vehicles that patrol the park and elsewhere in the city.

Source: *Environmental Design & Construction Magazine*, May/June 1999.

2.1.2.3. North Central Bronx Hospital

Also in the public safety business, hospitals are typically high power factor customers with a variety of power needs. There are critical loads such as intensive care units and operating rooms that depend on sensitive electronic equipment as well as more ordinary needs such as heating, lighting, cooling, kitchen power needs for food preparation, and dishwashing and laundry.

The New York Power Authority added a 200-kW fuel cell to the roof of North Central Bronx Hospital to enhance its power quality. A fuel cell was a good match for this facility, which has an 85% load factor and a great need for power-source redundancy. The fuel cell allows the hospital to shave 200 kW off its peak demand, thereby lowering its demand charges by $6,102 (i.e., 200 kW x $30.51/kW demand charge) per month in summer months.

2.1.2.4. American Home Products

On a much larger scale, the Connecticut-based American Home Products, which manufactures a variety of pharmaceutical and consumer health products, installed its own diversified power system totaling about 15 MW at its Pearl River campus. The power plant commenced operation in January 1991. The campus contains 14 buildings, which house three divisions of AHP employing a total of 2,700 workers. It is AHP's largest integrated facility and accounts for $1.2 billion of total AHP sales of $15 billion. The combined heat and power system is centralized and consists of two Solar Mass 8-MW boilers and two steam turbines totaling 6.6 MW.

The power plant, which has been 97% available, has provided substantial power cost savings, operational flexibility, and a diversity of fuels.

Source: Forte, Al. "AHP," presentation at US DOE CHP Summit, Dec. 1998.

2.1.2.5. Web-Servers and Silicon Valley

A new end-use of electricity that emerged in the 1990s is that of powering Internet-server businesses. Many such servers exist in the states of California, Texas, and Washington and elsewhere. Web servers are essentially entire buildings, sometimes as many as 10 stories high, filled with computer servers and cooling equipment. Loads for these businesses can be in the range of 50 MW, with some approaching 100 MW, and they all require extremely high power quality. To convey a sense of the intensive power needs of these businesses, one would compare their demands of 120 W to 200 W per square foot with the more typical office building use of 10 W to15 W per square foot. Further, the computer equipment cannot perform its Internet support function if the power source is interrupted for even an instant of time. Outages can easily cost these Internet serving companies $1 million an hour. Not surprisingly, many of these businesses have installed diesel generators as essential emergency power sources, yet many of these same urban areas already have serious air-quality concerns.

Sources: *NY Times,* Jan. 12, 2001, and personal conversation with Tom Starrs.

2.2. Relieving Distribution and Transmission Overloads

2.2.1. Introduction

Public discussions on reliability have historically tended to focus on the relatively rare, major power outages that affect a large number of customers, even though approximately 90% of customer service losses result from distribution-level problems.[13] Maintaining and upgrading distribution systems are significant cost elements for utility companies, and the failure to upgrade local networks in response to rising loads can seriously impair reliability. The reliability problems of distribution networks are in some ways more difficult to deal with than generation adequacy problems. During peak periods, there may be many actions that system operators could take to provide more *generation* resources to the system, but there are few alternatives to the local distribution system — there is no spot market or reserve market to call forth additional wires in hours of peak need. Distributed resources can substitute for capacity on the wires, however, and thus, have particular value in supporting the reliability of local wires systems.

13. This is not an unusual phenomenon. Plane crashes make the national news while car crashes do not.

2.2.2. Case Studies

2.2.2.1. City of Chicago Energy Reliability and Capacity Account
Efficiency and Distributed Generation to Reduce Load on Stressed Distribution Network

Background
When Commonwealth Edison's franchise in the City of Chicago came up for renewal in 1992, problems with aging distribution infrastructure were known to be serious. Part of the 29-year franchise renewal was a commitment by the utility to spend $1 billion on transmission and distribution (T&D) upgrades over the next 10 years. When it appeared that the utility was not on schedule with these upgrades, the city sued and obtained a settlement that included, among other things, a commitment to spend $1.25 billion in T&D by the year 2004 and payments totaling $100 million to the City of Chicago for reliability-enhancing projects within the city.

Additional impetus for action by both the utility and the city came from a series of outages across Chicago neighborhoods, and including the downtown Loop, in July and August of 1999. An aging distribution plant, overloaded in the midst of a heat wave, repeatedly failed or was taken out of service to prevent failure. The resulting public outcry has led to an intense focus both on upgrading distribution facilities and on lowering growth in peak demand in stressed distribution areas.

The Chicago Reliability Fund
The $100-million Reliability Fund is administered by the Energy Division of the City's Department of Environment. The program has several major elements, enhancing reliability both through efficiency investments and investments in distributed generation.

- The Rebuild Chicago program assists commercial and industrial firms to upgrade the efficiency of their facilities. As of early 2001, 1 million square feet of C&I space had been upgraded under this program, with 25 million square feet enrolled and being treated. In addition, 15 million square feet of public facilities are targeted for efficiency-related upgrades.
- There is also a distributed generation program. In preparing to deal with electrical outages, the city constructed a list of all "critical facilities" that would need attention; more than 8,000 sites were on the list. About 6,000 of these involved stoplights at key intersections, but there are also 2,000 critical buildings including schools, high rises, police stations, hospitals, and so on. An inventory of these facilities revealed a large number of backup on-site generators. Although most of these generators are diesels that the city does not want to deploy regularly, there are also a total of 13 MW of natural gas-fired backup generators in public buildings (12 MW in units more than 400 kw each). To make these units available as a network of distributed generators, the city developed a SCADA system to link them to a central operating post and is now connecting them. The network is expected to be operational by the summer of 2001. It will provide a dispersed network of reliable distributed generators for use in system emergencies; the city also expects to dispatch the units, to the degree permitted by air quality permits, at periods of high system prices. Income from power generation at peak periods will help to pay for the costs of the program.

- Finally, the Chicago Reliability Fund is supporting development of distributed renewable resources within the city. The leading initiative here is in photovoltaics. The Energy Division negotiated an arrangement with Spire Corp., a PV manufacturer, to locate a manufacturing plant in Chicago and has agreed to purchase 250 kW in PV arrays at six schools (10 kW each) and several prominent museums (approximately 50 kW each) throughout the city. Commonwealth Edison also committed to purchase $12 million in PV arrays for deployment in Chicago. The department recently announced plans for a “Renewable Energy Farm” on a brownfield site, which will host a wind turbine, an advanced fuel cell, and a large PV array — that at 2.5 MW is said to be the world’s largest PV installation.

2.2.2.2. Mad River Valley Project (Vermont)

Load Management and Energy Efficiency by Customer and Utility to Defer Need for Distribution Line Upgrade

Background

The Mad River Valley is a mountain/valley region in central Vermont and home to growing resort developments associated with three ski areas — two operated by Sugarbush. The valley is served by Green Mountain Power (GMP) by way of a 34.5-kV distribution line extending in a long “U” down one valley, across a ridge, and back along the highway on the other side of the ridge. Sugarbush, the largest load on the line, is located at the base of the “U,” its weakest point. The ski area was engaged in a major expansion project and informed GMP that it was planning to increase its load by up to 15 MW to accommodate a new hotel and conference center and significant new snowmaking equipment. The reliable capacity of the 34.5-kv line was 30 MW, and a 15 MW increase in load at that location would impair reliability of the line or require an upgrade. Utility studies concluded that the appropriate upgrade would be a parallel 34.5-kv line down the valley, at a cost of at least $5 million.

Process

The customer’s initial request was for an upgrade by the utility at utility expense. But under Vermont’s line extension rules, it was likely that a major portion of the cost of the upgrade would be charged to the customer. Neither the customer nor the utility wanted to pay for the line. (Sugarbush is owned by SKI, Ltd., one of the largest resort operators in the United States, but like most customers, it would rather focus capital on its core business, not electrical supply.) Thus, the stage was set for alternatives, which were negotiated among the utility, the customer, and the public advocate and later approved by state regulators.

Solution

The unique solution worked out in this case has two major elements:

(a) Customer load management commitment

Sugarbush and GMP entered into a customer-managed interruptible contract, under which Sugarbush committed to ensure that load on the distribution line, as measured at the closest substation, will not exceed the safe 30-MW level. Sugarbush has installed a real-time meter at its operations base and telemetry to monitor total local load (at the substation). Sugarbush must manage its resort and snowmaking operations so as to keep total local load at all times below 30 MW. Unlike the other interruptible contracts for snowmaking in effect at most of Vermont's ski areas, this contract requires the customer to manage its own load while taking the load of all other customers on the substation into account. In addition to avoiding the cost of the power line upgrade, Sugarbush receives value for load management in the form of a rate discount for the electricity it purchases.

(b) Targeted utility efficiency program in the valley
As noted above, the Sugarbush expansion plan uncovered a reliability concern with continued load growth throughout the Mad River Valley. The second part of the MRV program was a concentrated effort by GMP to improve efficiency and lower peak demand in the community. At the urging of the public advocate, GMP focused some of its demand-side management (DSM) programs on this area. Over a period of 18 to 24 months, the utility delivered a variety of DSM measures across all customer classes. The largest savings came from numerous conversions of electric hot water heaters and electric space heaters in buildings to alternative fuels, but many other measures were installed.

Lessons
Although the situation presented here seems unique, its principal elements could be applied in many other circumstances. First, a combination of load management and efficiency has avoided an expensive upgrade and maintained reliable service in a rapidly growing resort community. Moreover, the customer's load management efforts reduce the utility's peak power loads. In general, Sugarbush manages load to move snowmaking operations off the valley's winter peak hours, which are coincident with the utility's and the state's peak load hours.

One criticism of the MRV program is that the utility largely abandoned the follow-on DSM work once the reliability challenge was met and may have missed additional cost-effective efficiency opportunities. A singular focus on DSM for reliability may lead to lost opportunities for other efficiency savings if not combined with a broad program design for energy efficiency generally. The ground rules for dual-purpose DSM programs must be carefully worked out with regulators or other program advisors.

Participants in this process have also observed that the cost-effective solution to the valley's reliability problem came about only when it was clear that much of the cost of the upgrade would be charged to the customer driving the need for it. If the cost of this reliability upgrade had been socialized through the utility's tariffs, it is much less likely that the utility would, on its own, have negotiated the unique load management contract with the customer, regardless of its cost-effectiveness.

2.2.2.3. Kerman Substation (PG&E)
Project to Demonstrate the Value of Distributed Generation

One of the nation's leading examples of the value of distributed utility planning was the Kerman Substation, near Fresno, California, where PG&E deployed 500 kW of photovoltaic power to demonstrate the value of distributed generation. The project studied the benefits PV could provide to the distribution network: var support, line support, extending transformer life, and reducing capacity needs, all of which can promote reliable distribution service. Between 1993 and 1995, PG&E documented numerous benefits from distributed generation of this type; however, in 1996, the project was quietly ended.

According to news accounts, PG&E abandoned the project because of its maintenance costs (about $20,000 per year). PG&E may also have had problems selling the facility's output at market prices because of California's restructuring rules largely excluding franchise utilities from the generation market. Critics point out that in recent California power markets the value of the unit's energy output alone would greatly exceed the project's maintenance costs, without accounting for the reliability benefits or for the benefits that load reduction brings to wholesale markets by lowering the overall market clearing price.[14] For these reasons, it will be important for distributed resource analysts to examine the history of this project to understand the cost and market barriers that may have led to its abandonment.

2.2.2.4. Sand Bar Tie (VELCO)

Distributed Generation to Support Transmission Reliability

Distributed resources can also be used to address reliability concerns of transmission systems. One of the major transmission links between the New York and New England Power pools is the PV-20 line across Lake Champlain. This line is owned and operated by VELCO, the transmission utility that provides backbone transmission services to all of Vermont's public and private distribution companies. Historically, PV-20 provided a path for public preference power from the Niagara and St Lawrence power projects to eligible customers in Vermont. It now provides a transmission path and reliability support to both the New York and New England Power pools.

A serious problem arose on this line in March 2000 when a phase angle regulator on the Plattsburg, New York, end of the line failed and the line had to be derated to ensure its reliable operation. Maintaining even a modest power flow over PV-20 required installation of large inductors, along with a means of supplying voltage control on the Vermont end of the line. In May 2000, VELCO installed a 7-MW gas turbine generator (running, in this case, on distillate fuel oil) to supply the voltage support needed to maintain operation of the transmission link. The turbine can run either in generation mode or as a synchronous condenser, providing or absorbing vars as needed to maintain voltage on the power flows across the line.

Between May 2000 and February 2001, when the New York phase angle regulator was restored, the 7-MW turbine provided essential support to maintain the operation of the PV-20 transmission link. Whether this project illustrates the reliability benefits of distributed generation or is simply an example of traditional utility management may be debated. On the

---

14. At a 20% capacity factor and an average market price of 10¢ per kWh, 500 kW of PV would produce nearly $90,000 of power output annually. In addition, the project lowers the wholesale clearing price and provides reliability and other benefits to the distribution company.

one hand, because of the nature of its operation (principally run as a synchronous condenser providing var support) and its deployment by a transmission utility, this may not be judged as a distributed generation facility. On the other hand, from a physical point of view, this small, distributed unit obviously provided important reliability benefits to the New York and New England power pools and illustrates the high value that can sometimes be obtained from a small, strategically located generation facility.

2.3. Generation Adequacy and Peak Shaving

2.3.1. Introduction

In response to rising power costs, wholesale price spikes, and numerous power warnings and close calls experienced in many regions of the country, many utilities have launched programs to purchase curtailments and customer-owned generation at periods of peak demand and high prices. In most cases, it is difficult to separate the economic, market basis for a program from its physical reliability purposes; most programs serve both goals.

How large is the resource base that these programs can call on? The savings levels attributed to historic load-management programs cannot simply be assumed to continue in new energy markets. On the one hand, it appears that many industrial and commercial customers were willing to enroll in rate discount programs with the understanding that they would, in fact, rarely be interrupted. On the other hand, market studies suggest that many customers would willingly reduce at least some of their consumption during high-priced power periods in return for market-based savings, which might well exceed the savings obtained under the historic utility tariffs.

Because there are many barriers today to the deployment of price-responsive load management, it is too early to know for certain how deep that response will be under different market rules and prices. However, limited market tests suggest that the potential is quite significant when compared with the levels of response needed to moderate price spikes and meet reliability concerns.

- A customer market study by E-Source gives some dimension to the potential. After interviews with energy managers of more than 100 large companies, this study found that although most of the load of most large customers was constrained by commercial and production needs and would be largely fixed in the short term regardless of price, approximately 15% of their loads could be managed in response to short-term price signals.[15] As shown in Figure 1, some loads are currently able to tap bulk power markets and significantly reduce their power costs by managing their electric loads in response to bulk power market price signals. As power prices rose in the summer of 1998 (dark curve), the customer significantly cut power demand (gray curve).

15. Capage, Adam; et al. "The Dawning of Market-Based Load Management." *ER* 99-18, November 1999.

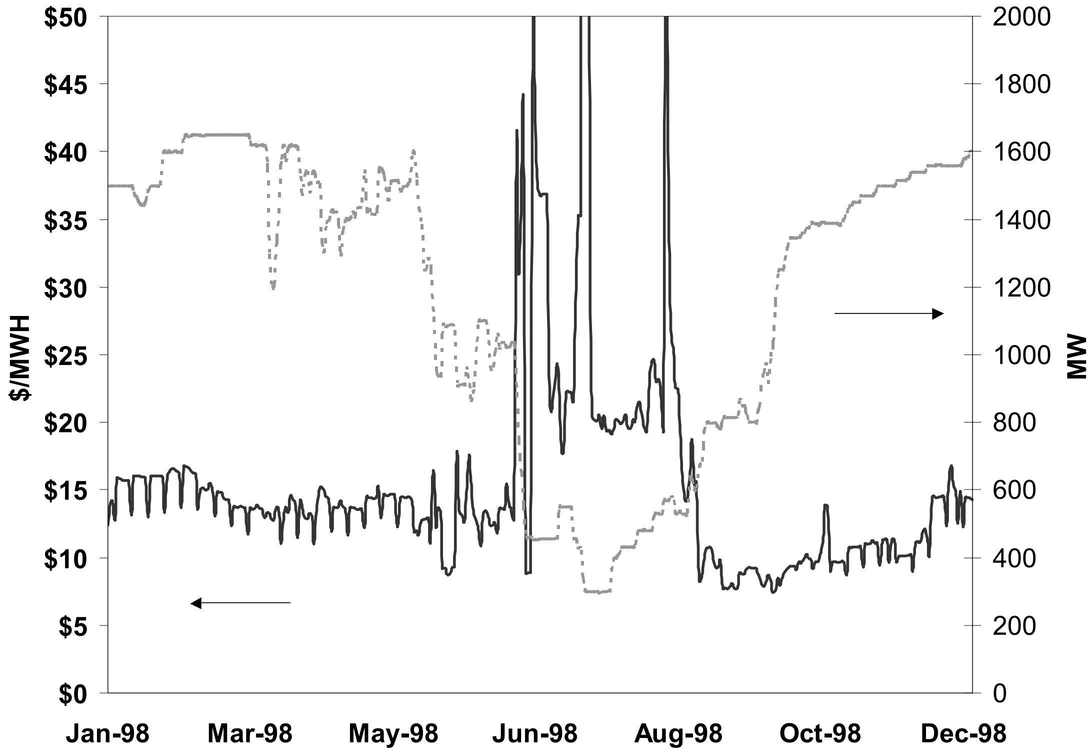

Figure 1 Resources that can respond to fluctuating prices should be allowed to participate in bulk power markets for energy and reliability as this large load does.

- A 1995 study by Science Applications International Corp. reached similar conclusions, finding that about 17% of customer load was typically discretionary and could respond to price signals in short-term power markets.[16]

- More recently, an ELCON survey of its members found that there was very strong interest in participating in price-responsive load management programs through both demand reductions and on-site generation alternatives.

2.3.2. Case Studies

2.3.2.1 Pacific Power and Light
Demand Exchange Program

In December 2000, Pacific Power and Light (PP&L) announced the Demand Exchange Pilot Program as optional, supplemental service that allows customers to voluntarily reduce usage at times of high load or high prices. The program is open to customers with at least 1 MW of

16. Kiernan, Brendan. "From RTP to Dynamic Buying: Communication, Analysis, and Control Tools for Managing Risk." *E Source Energy Information and Communication Series* EIC-7, October 1999, p. 7.

onsite generation or a demand peak exceeding 4 MW. The company will send a market price signal (MPS) when it seeks to repurchase customer load and will offer to compensate the customer by repurchasing demand at a net price that reflects a constructive sale of the power and a constructive resale by the customer at market-based prices. A customer participating in an exchange event must maintain electric usage at or below the customer's baseline service level, which is the average usage of each hour for a minimum of 14 consecutive days just preceding the exchange event. An Internet Web site will be used to notify customers of exchange opportunities. Participating customers will be required to install and maintain the necessary communications system.

2.3.2.2. NYSERDA

Distributed Resources Installation Support Program

In 2001, New York will be about 300 MW short of the 18% reserve margin that the New York ISO seeks to maintain. Using wires charge receipts from the state's system benefit charge, NYSERDA has announced a $10.4 million program to support the installation of distributed resources. One particular element is PV support, at the rate of $6 per watt installed. The program will subsidize distributed generation and curtailable load installations made before May 1, 2001, at the rate of $150 per kilowatt installed in return for a promise to generate or reduce load upon declaration of a need for interruptions by the New York ISO. Customers must commit to respond to the ISO request up to 15 times per year, up to a total of 50 hours.

2.3.2.3. Long Island Power Authority

Supplemental Service Program

In February, 2001, the Long Island Power Authority (LIPA) announced the Supplemental Service Program, an offer to business and governmental customers who can generate a portion of their own electric needs from June through September. Although described publicly as a means of promoting conservation, the program is actually intended to bring on customer self-generation resources at times of highest system demand.[17] This move aims at using self-generation to free up a portion of LIPA's on- and off-island electric supply for use by customers who cannot generate their own electricity.

According to a LIPA survey, there are only about 100 MW of self-generation capacity in the authority's region, and LIPA expects to capture only a relatively small fraction of it for the program. However, LIPA states that the existence of the program may also encourage new customers to add on-site generation that could be enrolled. The Supplemental Service Program works by providing self-generators a discounted rate for electricity, including "nonsummer" months, intended to help those companies see an overall savings in total annual energy costs. In

---

17. "We only need to look at California to see how life can be dramatically impacted by the lack of an adequate electric supply," said LIPA Chairman Richard M. Kessel in announcing the conservation initiative. "Since 1998, LIPA has been saying that Long Island's electric supply is tight. We've repeatedly indicated that we need to conserve, use our electric supply efficiently, and add new resources including renewable energy technologies."

return, the self-generators are required to use their own generating capability during the hours of 12 p.m. to 8 p.m. Monday through Friday, from June 1 through September 30.

2.3.2.4. Wisconsin Public Service
Uses Distributed Power to Meet Peak Demand

Wisconsin Public Service (WPS) used DR to meet peak demands during the summer of 2000 and expects to continue relying on distributed systems to hedge against high energy costs during seasonal peaks next year. Early in 2000, WPS leased 30 diesel-fired generators, adding a total of 34 MW of capacity to its generating portfolio to meet high summer energy demand. The units were removed in September. Given the uncertainties in regional generation and transmission capacity over the next year, WPS expects to rent an additional 24 MW (a total of 54 MW) of distributed capacity during the summer of 2001.

2.3.2.5. Illinois Municipal Electric Agency
Pays Customers for Backup Power

Illinois Municipal Electric Agency (IMEA), a wholesale power provider serving 39 municipalities in Illinois, has established a program that deploys backup generators to help meet peak summer demand. Through its *Just In Time Key Account* program, IMEA will pay customers for the right to "dispatch" backup generators during peak summer months. The cost-sharing arrangement is a way for IMEA to increase reliability and reduce costs while saving customers money on the purchase of emergency backup generators. IMEA hopes that the program will benefit manufacturing facilities that are the most vulnerable to power outages. To date, the program has led to the installation of generators in four cities. These systems will provide power when transmission lines are constrained, when market prices rise during peak periods, or in the case of generation-related curtailments. Based on its initial success, IMEA plans to expand the program to other customers.

2.3.2.6. Indianapolis Power and Light
Uses Distributed Power for Peaking Power

Indianapolis Power and Light (IPL) leased 85 diesel generators, representing a combined capacity of about 70 MW, to meet peak demand in the summer of 2000. IPL opted to lease the generators, rather than to purchase them new, because a large number of generators were left over from last year's Y2K concerns — a number of companies purchased generators to avoid Y2K-related difficulties only to find that they did not need them. As a result, IPL was able to arrange a favorable lease agreement for the distributed resources. Although the generators were to be removed in September 2000, it is likely that they will be needed to meet peak demands again next summer if in-state power plant construction does not keep pace with peak load growth. According to a Cummins representative, the company expects to provide about 100 MW of distributed generation capacity to IPL next summer.

2.4. Cost-Effective and Reliable Ancillary Services to Power Pools and Regional Transmission Operators

2.4.1. Introduction

Reliability of the power system is maintained by actively controlling some resources to continuously balance aggregate production and consumption. Historically, control was exercised only over large generators. Customers did whatever they wanted to meet their needs, while generation, under the control of the system operator, responded to the changing requirements imposed by customer loads. As restructuring progresses and regulated system operations are separated from competitive generation, new opportunities can emerge for distributed resources to participate actively in providing reliability resources to the power markets.

It will be important in this connection for system operators to articulate the requirements for reliability services needed to maintain the generation/load balance in technology-neutral language. That is, the required performance must be specified clearly enough that separate commercial entities can agree on what will be provided and at what price. The requirements must specify performance rather than the methods to yield desired outputs. For example, a system operator should request "100 MW of response that can be delivered within 10 minutes" rather than "100 MW of unloaded, on-line capacity from a large fuel-burning generator." FERC started this process by requiring the separation of six ancillary services from transmission in its Order 888; FERC expanded that process with its Order 2000 on regional transmission organizations (RTOs).

Table 1 presents eight ancillary services (reliability services) that DR owners might want to sell.

Table 1. Key Ancillary Services and Their Definitions

Reactive Supply and Voltage Control from Generation: Injection and absorption of reactive power from generators to control transmission voltages
Regulation: Maintenance of the minute-to-minute generation/load balance to meet NERC's Control Performance Standards 1 and 2
Load Following: Maintenance of the hour-to-hour generation/load balance
Frequency Responsive Spinning Reserve: Immediate (10-second) response to contingencies and frequency deviations
Supplemental Reserve: Response to restore generation/load balance within 10 minutes of a generation or transmission contingency
Backup Supply: Customer plan to restore system contingency reserves within 30 minutes if the customer's primary supply is disabled
Network Stability: Use of fast-response equipment to maintain a secure transmission system
System Blackstart: The capability to start generation and restore all or a major portion of the power system to service without support from outside after a total system collapse

These services are required to maintain bulk power system reliability and are being opened to competitive markets in regions where RTOs operate. Distributed generators, interruptible customers, and storage devices may best be able to provide load following and supplemental reserve services; they may not be able to sell reactive supply and voltage control from generation to the bulk power system depending on their size and location. Network stability is a service that both distributed generators and storage devices should excel at if they are connected to the power system through an inverter and are in the correct physical location. Blackstart appears to be a service that small distributed generators may be qualified to sell because many such generators are inherently capable of operating independently of the power system. To be useful to the power system, however, the blackstart units have to be located where they can be used for restarting other generators. Some DR generators are not large enough or located properly to be useful. For those that are big enough and in the correct location, this could be an excellent service to sell.

The five remaining services (regulation, load following, frequency responsive spinning reserve, supplemental reserve, and backup supply) deal with maintaining or restoring the real-energy balance between generators and loads. These services are characterized by response time, response duration, and communications and control between the system operator and the resource needed to provide the service. Figure 1 shows the required response for these five energy-balancing functions. Because regulation requires continuous (minute-to-minute) adjustments to real-power transfers between the resource and the system, loads may not want to provide this service. Load following could be provided directly or through the use of a spot market price response on a time frame of less than an hour, consistent with FERC's requirements that RTOs operate real-time balancing markets. The contingency reserves are especially amenable to being provided by distributed resources.

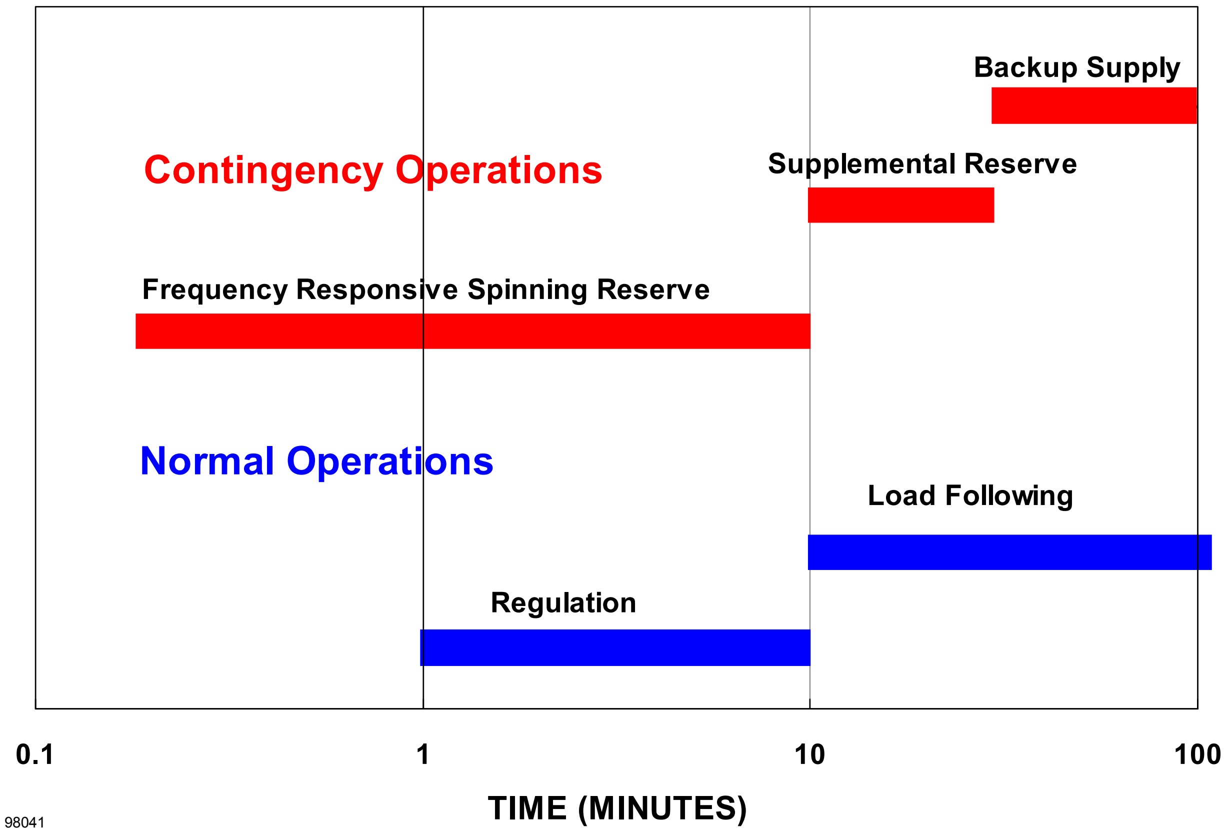

Figure 2: Real-power ancillary services are differentiated by the required response time and duration

Similar restrictions apply to DR supplying ancillary services as apply to central generation stations supplying those same services. For a generator to supply contingency reserves, it must have capacity available to respond to the contingency; the generator cannot be operating at full load. Similarly, a DR selling contingency reserves must have capacity it can make available when the contingency occurs, either by increasing its power output or by temporarily curtailing load.

Providing ancillary services from distributed resources should involve a careful integration of generation and load response. Because fast services generally command higher prices than slower services (as shown by Figure 3) it is desirable to sell the fastest service possible. At times, it may be faster to temporarily curtail load than to start generation. Load can be restored to service as additional generation is brought on line. It is also generally easier to incorporate energy storage on the load side in the form of thermal storage than it is on the power-supply side. Ten minutes of storage can be very valuable, as seen from the high prices paid for spinning reserves in Figure 3. It is worth noting that units operating just for reliability reasons often operate at partial capacity, which can result in higher air emissions per unit of energy produced than when operating at full capacity.

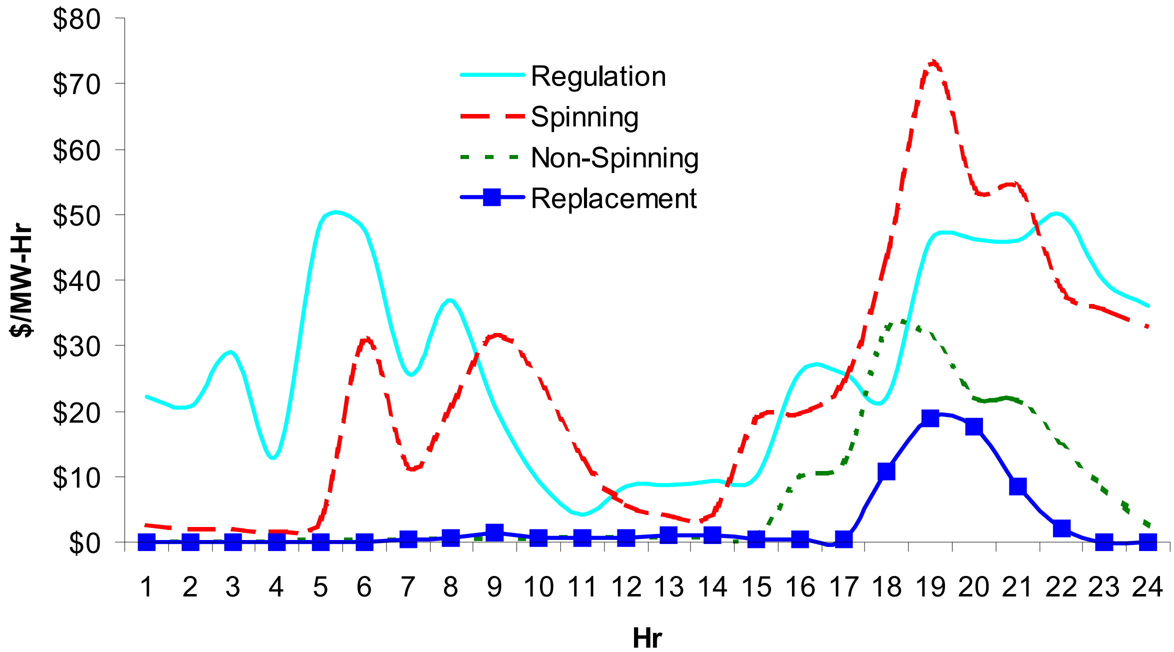

Figure 3: Real power reserve services requiring faster response command higher prices, on average, than do slower services in the California market as shown by this December 1998 weekday data

If ancillary markets are established so that demand-side resources can participate actively, load management resources benefit because they receive revenue from the sale of ancillary services as well as from energy production. The power system also benefits in several ways. FERC is encouraging open competitive markets for generation, in both energy and ancillary services. FERC ordered the unbundling of ancillary services from transmission to promote competitive markets, which should improve economic efficiency and lower electricity prices. These markets should be open to any technology capable of providing the service, not just to generators. This will expand supplies and reduce horizontal-market-power problems.

Beyond the argument of fairness, having additional resources participate as suppliers, as well as consumers, of electricity services improves utilization of generating capacity. Ancillary services consume generating capacity. When loads provide these reserves, generating capacity is freed up to generate electricity.

Smaller facilities may be able to respond more quickly to control-center requests than large generators. This will likely more than overcome the communications and control delays associated with their greater numbers (delays that will diminish with improved system communication protocols). DR should also be a more reliable supplier of ancillary services than

Exhibit 2. Reliability from Distributed Resources

When a system operator calls for the deployment of contingency reserves, there is always some chance that the resource that is supposed to supply the reserve will fail to do so. The small size of individual distributed resources reduces the consequence of this problem and makes them a more reliable source of contingency reserves. Take, for example, the case of a system operator purchasing 50 MW of supplemental operating reserve from a 50 MW fast-start combustion turbine. This turbine might start within the required time on 90% of its attempts. In one case in 10, the system operator is 50 MW short. It does the system operator little good to reduce its expectations to 45 MW, though that is the average response.

A collection of 6,250 10-kW distributed resources that individually have only an 80% chance of responding each time makes a better aggregated resource. In this case 20% of the individuals fail to respond, but the system operator still sees the full 50 MW response each time.

conventional generators. Because each facility will be supplying a smaller fraction of the total system requirement for each service, the failure of a single resource is less important (see Exhibit 2). Just as a system with 10 100-MW power plants requires less contingency reserves than one with a single 1,000-MW plant, so too a system that utilizes a large aggregation of DR as a resource to supply reserves will require less redundancy than one that carries all its reserves on a few large generators. There can still be common-mode failures in the facilities of the aggregator (the aggregator's communications system could go down, for example), but it is easier and cheaper to install redundancy in this portion of the system than with an entire 1,000-MW plant.

2.4.2. Case Studies

2.4.2.1. Traditional Utility Load Curtailment Programs

Any discussion of the potential role of DR in providing reserve and other ancillary services should begin by recognizing the value that customer-side resources have long delivered within the franchise system. Interruptible contracts, off-peak tariffs, and other load management programs have enhanced utility system reliability for decades. In many cases, customer load reductions were backed up on-site by customer-owned generation; in other cases, they were not. But, whether linked to DR or not, customer-side load management provided about 13,000 MW per year in curtailable demand in the middle of the 1990s,[18] and many of those programs continue today. These programs, tariffs, and contracts represent perhaps the largest base of DR used for reliability purposes in the nation today.

Considering the wide experience with utility load management contracts and the large number of these programs, it is not necessary to present individual case studies here. However, it is important to note three important problems with traditional interruptible programs — problems that impair their functioning in today's competitive wholesale markets:

18. This is about half of the nation's total demand reduction due to all DSM program activities.

- First, many interruptible programs were, in essence, industrial discount programs entered into with the expectation that they would never, or almost never, be called on. They may represent a resource for use in a true emergency but not a reserve to be called on to balance the system routinely.

- Second, most interruptible contracts permit the utility to call on the resource only in the event of particular physical reliability problems and do not represent an economic resource supporting reliability on a least-cost basis.

- Third, the customer benefits in most of these programs create improper incentives to support needed curtailments. Customers generally receive a discount on energy they consume and are paid nothing for supporting an interruption when it occurs. This undermines the value proposition that curtailments are intended to promote. Enrolled customers would view interruptions quite differently if they were paid at the time of the curtailment for the value of their reduction (and they would value their consumption differently if they were charged the full cost of consumption at the time of use).

These limitations can be overcome and are addressed in some of the load curtailment programs now being set up by utilities and ISOs. These programs build on the generally unsatisfactory record of ISO-developed programs announced in 2000.

2.4.2.2. Cal ISO and NE-ISO
Summer 2000 DR Programs

Background
In the winter and spring of 2000, seeing the potential problems of the coming summer peaks, ISOs on both coasts announced their intention to run programs to sign up load management and distributed generation resources for direct control by the ISOs as ancillary resources. These programs were launched in part to respond to widespread criticism the ISOs received when they announced plans to pay for emergency generators on barges that would be moored for the summer in the Connecticut River and on the San Francisco Bay. In both cases, the barge proposals were later withdrawn. The ISOs announced they would accept proposals for customer-side resources and would pay relatively high values for them. Both proposals drew disappointing results.

Lessons
In some eyes, these results underscored the dangers of basing system reliability on unproven resources such as demand responses and customer-owned generation. However, particular attributes of these initial proposals are more likely to account for the low response rates. First, they were issued late in the year, with little time for ESCO or customer program development. Second, they typically excluded from participation any customer already enrolled in a utility interruptible load program (this was intended to avoid double-counting but may have excluded the most likely participants). And third, the ISOs required participating customers to install real-time meters and controllers that could be operated by the ISOs on a basis equivalent to the

controls installed at a central generating station. For most DR owners, the cost and maintenance requirements of these measures were serious barriers to participation in the programs.

2.4.2.3. New England ISO

Customer Reserves Program – 2001 Version

Background

The New England ISO is the system operator and market manager for the six-state New England region. Reliability standards for the regional power system require the pool to carry 2,100 MW of first contingency reserves divided between 10-minute and 30-minute reserve pools. In addition, to ensure the pool's capability to respond to subsequent events, an additional 1,300 MW of reserves must be carried. Because New England lacks much "quick start" capacity, this 1,300 MW has historically been provided by fossil units running at low operating limit levels, where the units are less efficient, more expensive to operate, and more polluting than would be optimal. The pool collects more than $30 million annually in uplift from all consumers for the support of this reserves program.

The Program

NE-ISO has initiated a new load response program to secure 300 to 600 MW of customer-based reserve resources. This program has been approved by most NEPOOL decision makers and is supported by the region's utility regulators. NE-ISO expects to file the program at FERC in February 2001, for operation beginning in June. This is intended as a demonstration phase of a permanent program, not a temporary response for the next summer or year. The principal elements include:

- Any pool participant (LSE, ESCO, or other) can sign up customers for the program, and the NE-ISO financial arrangements are with that participant, not the customer directly.
- The program is Internet-based. Enrolled customers will pay about $2,000 for the cost of communications and metering equipment and must provide an Internet connection. They will, while enrolled, see the regional real-time prices for power.
- Customers are compensated for enrollment by receiving the market value of 30-minute reserves all year around by being available for curtailment.[19]
- There is also a value-based payment for energy that is released by the customer during any curtailment. This release is treated as a resale into the spot market by the customer. Thus, the customer pays its LSE the tariff or contract price that would cover that consumption (it constructively buys the power), and then NE-ISO pays the customer the real-time market price for that amount of foregone consumption (the customer constructively sells the power).

19. NE-ISO actually pays the NEPOOL participant who enrolled the customer; payment levels to the customer are determined by arrangement between the participant and the end user.

Program Design Issues
NE-ISO proposes to make this program available to customers with a minimum load of 100 kW or greater. Because real-time communications and metering are required, the program will have limited appeal to smaller customers. However, a large number of small customers could be controlled through radio controllers, operated from a central point, and verified statistically. At this point, NE-ISO is excluding programs of this type, and it remains to be seen whether it should be extended to them, and if so, whether it actually will be extended..

One unique aspect of this reserve program is its overlay with the real-time energy markets. In addition to curtailments that are necessary to provide system reliability, customers in the program (who will have Internet access to the market and real-time meters) may wish to take advantage of the constructive "buy-resell" component of the program. In some essential elements, this approximates the demand resales that are operating in the PJM two-settlements market.

New England's air quality regulators have supported the capacity reserves aspect of this program, in part because it reduces the inefficient operation of central station plants at low operating limit levels and in part because the contingencies that would give rise to reserve calls will be rare. There is a greater concern with the energy market aspect of the program because resales might well be accompanied by self-generation with on-site diesel. Air regulators are considering a rule that would exclude such diesel-supported resales from participating in the program.

3. Conclusions and Policy Recommendations

Although the potential contribution of DR to power system reliability and power quality is substantial, this potential has been significantly underdeveloped. Industry traditions, reliability rules, costs and choices offered customers, and the rate structures and profit incentives of generators all stand in the way of more robust DR alternatives. Drawing on the case examples set out in this report, we conclude with a set of policy recommendations to enhance the contribution of DR to better power systems in the United States.

As an initial observation, it is important to recognize that the contribution of DR to the electric grid does not have to be very large to have a significant effect on market clearing prices and network reliability.

- A 1999 study by the Electric Power Research Institute (EPRI), based on customer-specific data from large customers in the Midwest, found that if only 10% of customer load had been exposed to real-time prices, the resulting customer demand reductions would have reduced the Midwest summer price spikes by 33% to 66%.[20] Robert Levin, vice president of the New York Mercantile Exchange, was even more optimistic, testifying before Congress that "a 5% reduction in demand during the peak prices in the Midwest in 1998 could have dropped some of these prices 80 or 90%."

- EPRI reached a similar conclusion after a study of the power markets in California in the summer of 2000. Here, it found that a 1% reduction in load during high peak periods could reduce market clearing prices by 10% and that a 5% reduction in load could reduce peak period prices by 19%, bringing down total power costs for the summer season by 5% to 16% overall.

Similar observations could, of course, be made about the reliability contributions of DR. In many instances over the past two years, power alerts and reliability events could have been avoided if relatively small distributed resources had been available to distribution companies or to system operators. (And those managers know of many instances in which power warnings and reliability problems were *avoided* because those resources were available).

After reviewing numerous reliability events from around the nation in the summer of 1999, the DOE's POST study team concluded that the federal government should:

- Support the development of market rules that allow customers to supply load reduction and ancillary services in competitive energy markets
- Encourage the development of demand management systems that support electric reliability
- Remove barriers to distributed energy resources
- Support state-led efforts to address regulatory disincentives for integrating customer supply and demand solutions

---

20. Guild, Renee. "EPRI's Response to Reliability Problems." Presented at NARUC, Nov. 8, 1999.

• Encourage energy efficiency as a means for enhancing reliability.[21]

Our research, review of reports such as the POST report, and review of the case studies discussed above leads to a central conclusion: cost-effective investments in load management, efficiency, and distributed generation could significantly improve the reliability of the nation's electric system and make electricity markets more competitive and more efficient while lowering the economic and environmental costs of electric service.

Many changes in public and regulatory policies are needed to capture the reliability benefits of distributed resources. We set out an initial list below.

3.1. NERC Regional Reliability Councils, RTOs, and Other Reliability Institutions Should Recognize and Seek to Capture the Value of Distributed Resources in Their Rules and Operations

Resource adequacy and system reliability across electric networks have traditionally been viewed as public goods whose costs are recovered in broad-based rates charged to all interconnected users of the grid. Efficiently constructed wholesale electricity markets, including adequate demand-side bidding systems, can moderate volatile markets and, thus, the degree to which reliability managers must intervene in the market to ensure reliable service. Nevertheless, reliability managers, power market managers, utilities, ISOs, and RTOs are increasingly finding it necessary to take administrative actions to promote reliability, and these actions sometimes include implicit judgments about the financial responsibility for reliability. These administrative actions take many forms:

- Requiring the provision of specified ancillary services, by market participants by rule, and/or purchasing them on behalf of all market participants (and then imposing a tariff to pay for them)
- Socializing congestion costs, supported through uplift charges, so that customers in load pockets do not pay higher prices for power behind a constrained interface
- Entering the market directly through an RFP for the provision of reliability services, such as the emergency generators and dispatchable load contracts sought to be deployed in several power pools in recent summers[22]
- Identifying needed transmission links and supporting their construction through broad-based transmission tariffs or other forms of "uplift" assigned to users throughout the pool.[23]

---

21. US DOE. "*Report of the U.S. Department of Energy's Power Outage Study Team*." March 2000, pp. 19-28 (excerpts). These are some of the POST team's key recommendations.

22. For example, in the summers of 1999 and 2000, the New England and California ISOs proposed collecting pool-wide uplift charges to bring in and operate emergency generators on barges anchored in the Connecticut River and San Francisco Bay. Several pools have launched programs to acquire demand interruptions from customers who will agree to load controls directly from the ISO.

23. In 2000, the New England ISO accepted a recommendation to support the construction of several transmission upgrades throughout the region as "pool transmission facilities" because they would relieve transmission congestion in certain areas and improve the resilience of the transmission system. In NE-ISO parlance, the cost of these upgrades will be "socialized," that is, spread among all users of the regional transmission system

There will be many other variations on this theme.

System operators have, of course, traditionally focused on transmission and supply-side resources in meeting reliability requirements for electric networks, especially in periods of stress. For most of these system needs, however, there is a DR corollary that could perform that same service at lower cost, provided that market rules were defined to include such resources and broad-based funding was made available to support them on the same basis as the more traditional solutions. Energy efficiency, load management, demand-side bidding, and DR are all potentially cost-effective means of meeting reliability needs identified by system operators and power pool managers.

To capture the value of DR:

- RTOs and utility system managers should permit DR options to provide reliability services on an even competitive basis with conventional generation and transmission options.
- FERC should require RTOs to include DR options in ancillary service markets on an equivalent (but not straight-jacketed) basis with traditional generation and transmission options.
- RTOs should adopt demand-side bidding and two-settlement systems to permit capacity releases in response to market conditions.
- RTOs should adopt flexible load profiles to encourage and reflect responsive actions by load and distributed generators.
- Research institutions, power pools, and RTOs should adopt positive policies to support telemetry and metering as necessary to develop DR on the same basis as support has been provided for generation and transmission system software by the RTO.

3.2. Distributed Resources Should Receive Equal Treatment with Supply and Transmission Options in RTO and Power Pool Initiatives that Use Uplift and Other "Socialized" Support Mechanisms

So long as vertically integrated utilities were basing their investment decisions on the principles of integrated resource planning, many reliability-enhancing decisions were governed by least-cost decision-making. With the breakup of the franchise, the demise of IRP, and the assumption of new responsibilities by RTOs and other regional organizations, there are now numerous occasions in which broadly-funded interventions may be taken without serious consideration of less expensive and more reliable alternatives based on distributed resources and demand-side alternatives.

For this reason, reliability rules and investment decisions that will, by administrative action, impose costs on consumers and other market participants should first be tested by the following standard for the efficient provision of reliability:

---

through a regional "uplift" charge. More than $120 million in capital costs will be raised, under a NE-ISO tariff, for this purpose.

The "Efficient Reliability" Standard

Before "socializing" the costs of a proposed reliability-enhancing investment through tariff, uplift, or other cost-sharing requirement, FERC, the state PUC, and the relevant RTO should first require a finding:

(1) That the relevant market is fully open to demand-side as well as supply-side resources
(2) That the proposed investment or standard is the lowest cost, reasonably available means to correct a remaining market failure
(3) That benefits from the investment or standard will be widespread and thus appropriate for support through broad-based funding.

If this standard were adopted as a screening tool by FERC and the nation's RTOs when considering proposed reliability-enhancing rules and investments, it would provide a much-needed discipline in situations in which expensive wires and turbines solutions are proposed to address reliability problems, and more robust, less expensive, distributed solutions are overlooked.

3.3. NERC and Congress Should Embrace the Value of Distributed Resources in Enhancing Reliability in National Reliability Standards and Potential Reliability Legislation

Reliability crises across the country have brought increased attention to reliability issues in Congress, along with numerous legislative proposals. The leading legislation in the last session of Congress was the so-called "NERC Consensus Reliability Bill," which passed the Senate but died in the House. That bill would have given a new reliability organization, NAERO, extensive authority to promulgate rules to secure the reliability of the nation's bulk power system. The "bulk power system" was defined as including:

(1) High voltage transmission lines, substations, control centers, communications, data, and operations planning facilities necessary for the operation of all or any part of the interconnected transmission grid
(2) The output of generating units necessary to maintain the reliability of the transmission grid.

Even though reliability experts, including many at NERC, accept that demand-side options may be the best and least expensive means to resolve particular reliability problems, there is no mention of DR, energy efficiency, or load management whatsoever in this detailed legislative proposal. This oversight should be corrected in any legislation on reliability Congress considers in the next session. Congress should make clear that part of the mission of the nation's regulators, wholesale power markets, and reliability organizations is to structure electricity markets to enhance demand-side responsiveness and to support efficiency, load management, and DR for their economic and reliability benefits. This expanded mission should be part of the mandate of NAERO, FERC, and the nation's RTOs, ISOs, and Transcos.

Such legislation should contain a provision equivalent to the Efficient Reliability Standard discussed in the text, along with explicit recognition of the role of DR in promoting the reliability of the bulk power system. For example, the definition of the bulk power system (quoted above) should be amended by adding: "and (3) energy efficiency, distributed generation, and load management operations necessary to maintain the reliability of the transmission grid." Similar language placing customer-side resources on an even footing with generation and transmission resources would be appropriate in several other sections of the bill as well.

3.4. State Utility Commissions Should Adopt Regulatory Policies that Promote Reliability by Promoting Appropriate Use of Distributed Resources

Many of the policy bases for impeding or enhancing options for distributed resources lie within the jurisdiction and traditional practice of state utility commissions. State PUCs should:

- Support metering and interconnection policies that permit DR to participate appropriately in ancillary service and wholesale power markets
- Support broad-based energy efficiency programs. Apply a separate emphasis on efficiency and load management programs targeted to stressed distribution areas and the funding mechanisms to pay for those investments on the same basis as transmission and substation upgrades
- Adopt output-based emissions standards for DR to protect local environmental resources on a technology-neutral basis
- Promote the use of "distributed utility planning" by local distribution companies and the pursuit of least-cost distribution policies, including purchasing DR from customers when cost-effective.

REPORT DOCUMENTATION PAGE

Form Approved
OMB NO. 0704-0188

1. AGENCY USE ONLY (Leave blank)

2. REPORT DATE
October 2002

3. REPORT TYPE AND DATES COVERED
Subcontract Report

4. TITLE AND SUBTITLE
State Electricity Regulatory Policy and Distributed Resources: Distributed Resources and Electric System Reliability

5. FUNDING NUMBERS
CF: NAD-1-30605-03
TA: DP02.1001

6. AUTHOR(S)
F. Weston, C. Harrington, D. Moskovitz, W. Shirley, R. Cowart, and R. Sedano

7. PERFORMING ORGANIZATION NAME(S) AND ADDRESS(ES)
The Regulatory Assistance Project
177 Water Street
Gardiner, Maine 04345
207-582-1135
50 State Street
Montpelier, Vermont 05602
802-223-8199

8. PERFORMING ORGANIZATION REPORT NUMBER

9. SPONSORING/MONITORING AGENCY NAME(S) AND ADDRESS(ES)
National Renewable Energy Laboratory
1617 Cole Blvd.
Golden, CO 80401-3393

10. SPONSORING/MONITORING AGENCY REPORT NUMBER
NREL/SR-560-32498

11. SUPPLEMENTARY NOTES
NREL Technical Monitor: Thomas Basso

12a. DISTRIBUTION/AVAILABILITY STATEMENT
National Technical Information Service
U.S. Department of Commerce
5285 Port Royal Road
Springfield, VA 22161

12b. DISTRIBUTION CODE

13. ABSTRACT *(Maximum 200 words)*
Distributed resources can provide cost-effective reliability and energy services — in many cases, obviating the need for more expensive investments in wires and central station electricity generating facilities. Given the unique features of distributed resources, the challenge facing policymakers today is how to restructure wholesale markets for electricity and related services so as to reveal the full value that distributed resources can provide to the electric power system (utility grid).

This report looks at the functions that distributed resources can perform and examines the barriers to them. It then identifies a series of policy and operational approaches to promoting DR in wholesale markets.

This report is one in the State Electricity Regulatory Policy and Distributed Resources series developed under contract to NREL (see Annual Technical Status Report of the Regulatory Assistance Project: September 2000–September 2001, NREL/SR-560-32733). Other titles in this series are:

- Distributed Resource Distribution Credit Pilot Programs - Revealing the Value to Consumers and Vendors, NREL/SR-560-32499
- Distributed Resources and Electric System Reliability, NREL/SR-560-32498
- Distribution System Cost Methodologies for Distributed Generation, NREL/SR-560-32500
- Distribution System Cost Methodologies for Distributed Generation Appendices, NREL/SR-560-32501.

14. SUBJECT TERMS
distributed energy resources; DER; distributed power; wholesale markets; markets; electric industry restructuring; utility grids; ancillary services; rates; public utility commissions; regulatory policy; National Renewable Energy Laboratory; NREL

15. NUMBER OF PAGES

16. PRICE CODE

17. SECURITY CLASSIFICATION OF REPORT
Unclassified

18. SECURITY CLASSIFICATION OF THIS PAGE
Unclassified

19. SECURITY CLASSIFICATION OF ABSTRACT
Unclassified

20. LIMITATION OF ABSTRACT
UL