EFFICIENT RELIABILITY

THE CRITICAL ROLE OF DEMAND-SIDE RESOURCES IN POWER SYSTEMS AND MARKETS

Prepared for
The National Association of Regulatory Utility Commissioners

Richard Cowart
Regulatory Assistance Project

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EXECUTIVE SUMMARY

The reliability of electric supply, long taken for granted by most citizens and governmental officials, is now a matter of increasing national concern. Economic growth, heat waves and cold snaps are driving the demand for power to new peaks and taxing an already-constrained electric grid. Policymakers are considering what steps can be taken to assure system reliability during the transition to competitive markets, where 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.

As the recently-released National Energy Policy states, **"A fundamental imbalance between supply and demand defines our nation's energy crisis."** New investments in generation and transmission are obvious reactions to reliability challenges, but we must also consider the very real reliability benefi that can be captured from energy resources held by customers: efficiency and load management, customer-owned generation, and customer responses to market prices.

The nation's utility regulators have also recognized the importance of demand-side resources for reliability. They have by resolution urged state regulators, power pools, and Congress to "encourage and support programs for cost-effective energy efficiency and load management investments as both a short term and long-term strategy for enhancing the reliability of the nation's electric system.." This report explores the role that those resources can play in restoring the demand-supply balance in electricity. It concludes that as much as 40% to 50% of expected load growth over the next 20 years can be met through end-use efficiency and load management, cost-effectively and reliably. It sets out a menu of regulatory and policy solutions to achieve that potential.

The Benefits of Demand-Side Resources

A narrow focus on fixing today's weakest links in supply and delivery alone will ultimately be less resilient and more expensive than a strategy that also targets reliability-enhancing demand-side investments. Utility managers and regulators are often called on to identify the immediate causes of eac reliability event of public concern. It is usually possible to identify the weak link in the chain that links generation, systems operation, transmission, and distribution to customer load. And, certainly, inadequate generation capacity, aging distribution infrastructure, and overloaded transmission links mus be addressed to ensure reliable, high-quality service. But there are powerful reasons that reliability policy should also focus on, and seek to capture, demand-side solutions to reliability problems:

- **Avoiding new weak links:** By accepting load growth and demand spikes as givens, and attempting to meet them through an exclusive wires and turbines policy, reliability managers can fix each "weakest link" in the supply chain as it appears. But once one upgrade is completed, the next weakest link will then emerge. For example, when load growth is met through increased generation, it is likely that transmission links and gas pipeline capacity will be more stressed, particularly in peak periods. Unless electric and gas transmission upgrades are also secured, the resulting degradation in transmission and fuel supply reliability may offset the gain in reliability (to the new generation. Demand-side resources, 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 th entire chain, from generation adequacy and fuel supply all the way through to the local distribution network.

- **Matching needs and resources:** Energy efficiency load reductions follow the load profile of the end-uses that set the system load curve during critical hours. For example, in most regions, air-conditioning load accounts for a major portion of daily system load swings on peak days. Improving air-conditioning efficiency automatically generates savings that lighten the system loa during the most critical periods.

- **Economic benefits:** Enhancing reliability through demand side measures can also lower the nation's electric bill. Many efficiency measures are simply less expensive than the costs of generation, delivery, and reserves that they displace. Moreover, persistent high demand and high peak loads are principal drivers of the price spikes and growing market power exercised by generators in wholesale power markets. Lightening the load can widen the margin between demand and supply, moderating generator market power and lowering wholesale market prices.

- **Environmental benefits:** Demand-side measures also lower the environmental footprint of the electric industry, one of the most significant sources of pollution in modern society. Load management and load response programs lessen the need for new power plants and transmission lines, while efficiency measures lower total fuel consumption and the related costs of air pollution, fuel extraction, and waste disposal. By lowering the risk of future environmental problems, demand-side measures also improve the long-term reliability of the electric system.

How Did We Get Here? Load Up, Efficiency Down

Load growth in the United States, and particularly peak load growth, have been proceeding at a pace that has put great strains on our power system infrastructure. Between 1994 and 1999, non-coincident summer peak load in the U.S. increased by 95,000 MW. This is the equivalent of adding a new, 6-state New England to the nation's electrical demand every 14 months. The Bush Administration's National Energy Policy now estimates that electricity demand will increase 45% by 2020, requiring the addition of 393,000 MW of new generating capacity. This is roughly nine times larger than California's recent peak load.

Meanwhile, unfortunately, the contribution of utility-sponsored demand-side management programs (DSM) to meeting the nation's load growth needs has been in decline. In the early 1990's, utility DSM programs saved a total of 29,000 MW at a cost of about 3 cents per kWh saved. Despite this generally solid record of success, since the passage of the Energy Policy Act and the national move to retail electric competition, utility-sponsored DSM programs have been cut back sharply. Total utility DSM spending has declined by about 50% since 1993. Urgent efforts to restore those programs under crisis conditions are now underway in some states, with attendant logistical, marketing, and cost problems of off-again, on-again operations.

"Wires and Turbines" Reliability -- Some Practical Considerations

Undoubtedly, significant new investment in generation and transmission is justified on both on econom and reliability grounds. Economic growth, changes in settlement patterns, and the emergence of superio technologies all support a conclusion that many investments in generation and transmission are needed and should be supported in new markets and regulatory systems.

However, a national generation expansion program that overlooks cost-effective efficiency and load-management resources will be more expensive and less reliable than a program that is more balanced and more flexible. A supply-side strategy will require a very large commitment of investment capital in generating plants, gas pipelines, and electric transmission and distribution lines. It will also pose significant new challenges for natural gas supply, increasing total annual demand by as much as one-thir and place upward pressure on gas prices. Finally, electric generation and transmission facilities bring wi them very substantial environmental costs, which must be absorbed or offset through additional mitigation measures.

The Demand-Side Reservoir is Very Large

Over the past two decades, there have been numerous studies, experiments, and programs aimed at improving the efficiency of electricity use in the United States. The central lesson of these studies and initiatives is that very large reservoirs of low-cost energy and capacity resources on the customer side o the electric meter are still untapped today. **A careful review of past programs and current market data support a conclusion that a large fraction -- as much as half -- of the nation's anticipated load growth over the next decade could be displaced through energy efficiency, pricing reforms, and load management programs.**

- In the decade up to 1994, utility-sponsored efficiency and load management programs avoided a total of 29,000 MW, and avoided electric consumption at a utility cost of less than $0.03 per kWh. The DOE's five National Energy Laboratories concluded in 1997 that cost-effective energy efficiency investments could displace 15% of the nation's *total electrical demand* by the year 2010. This result is consistent with the experience of many utilities as well as several other large-scale studies.

- Customer market studies and load-response pilot programs demonstrate that the potential for load management is also quite substantial. While most of the load of most large customers is constrained by commercial and production needs, approximately 15% to 17% of their total load could be managed in response to short-term price signals. A relatively modest load response would lower peak demand, improve reliability, and lower power costs across regional power markets.

Historic Market Barriers and New Market Flaws Block Demand-Side Responses

Cost-effective energy efficiency investments are often untapped in the U.S. economy due to a number o market imperfections and market barriers faced by individual customers. Even in the fluid and price-responsive electricity markets envisioned by restructuring advocates, most of the well-known and widely-documented barriers to efficiency investments will remain. Moreover, the reduced sweep of utility integrated resource planning (IRP), and new market rules and utility incentives have created new impediments to market-based efficiency and load management.

In a competitive generation market, generators have no financial incentive to promote either efficiency load management, and they profit handsomely from high peak prices. And under the rate designs commonly in use, wires companies profit from increased throughput, and find their profits harmed by energy efficiency programs.

Nor are today's wholesale power markets structured to overcome these barriers or to reveal the value of demand-side resources to market participants. While market advocates sometimes assume that demand-side responses can be "left to the market," current market structures actually block price signal from reaching service providers. Because of these structural barriers, neither providers, nor load-servin entities, nor end-users see the real value that demand-side resources can provide to the market and the grid. Thus, the U.S. wholesale electric markets are more expensive, more volatile, and less reliable than they should be.

Tapping the Demand-Side Reservoir: A Solution Menu for Decision-makers

Our nation now has nearly twenty years' experience with utility-sponsored energy efficiency programs, and has been engaged for several years in developing wholesale and retail markets in electricity. These experiences lead to the central conclusion of this report:

Cost-effective efficiency and load management investments 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.

While the advantages of demand-side resources are widely recognized, there is no single "silver bullet" mechanism for capturing all of those benefits for electric systems and customers. Rather, the challenge facing decision-makers is to examine each market component, and each important market or regulatory rule with the following questions in mind:

Could the function of this market or the purpose of this rule be served at lower cost and/or lower risk through demand-side resources? And if so, how can we organize this market or structure this rule to ensure that high-reliability, low-cost solutions are in fact developed?

Throughout the many markets and franchises operating in the U.S. today there are three major venues for discovering and deploying cost-effective efficiency resources:

A. Wholesale Market Structures:

Wholesale markets should be designed to invite demand-side price responses to bid against supply on the trading floors of new electricity markets, and should permit demand-side resources to compete with transmission and generation investments to meet system needs. The report sets out four policy reforms in this area:

- **Demand-side Bidding:** Early wholesale power markets have treated the demand side of the market as essentially inelastic, and have focused on promoting competition among bidders only on the supply side. It is essential to open the trading floor to the demand side, and reveal the slope of the demand curve. Markets will clear at lower quantities and lower prices, especially in peak periods, when this curve is exposed.

- **Reforming Load Profiles**: An essential step in promoting meaningful demand-side bidding is the reform of the system of load profiles used by wholesale markets and wires companies to assign load responsibility among load-serving entities. With alternative load profiles in place, service providers would have an incentive to seek out customers who have less expensive (off-peak) consumption patterns, and to invest in equipment and rate plans that would move customers to more advantageous load profiles.

- **Multi-Settlement Markets:** A second needed reform in wholesale markets extends the potential of demand responsiveness by recognizing the differences between projected market conditions and real-time events. Bidding rules should permit market participants to plan consumption and generation decisions in advance, but they should also permit additional adjustments to those plans in response to real-time conditions. This is one of the principal advantages of “two-settlement” or “multi-settlement” systems.

- **“Dispatchable Load” and Integrated Reserves Markets**: From the perspective of the system as a whole, controllable load can provide most balancing services just as well as controllable generation. Wholesale markets for ancillary services should permit demand-side resources to bid their services on a technology-neutral basis in ancillary service markets.

- **Efficient Reliability Standard:** System managers may propose generation and transmission investments, supported by broad-based charges, to improve reliability. Those proposals should be tested against demand-side and distributed resource options to see whether they are the lowest-cost, reasonably-available means to correct a reliability problem.

B. Rates and Rules for Wires Companies:

- **Transmission Congestion Pricing**: Transmission constraints impose significant costs on electric systems, but those costs have often been hidden in averaged rates, or paid for in uplift charges on all buyers in a region. Locational pricing can reveal the cost of congestion and thus the value of demand management and distributed resources to enhance reliability in constrained areas.

- **Enhancing Reliability Through Retail Rate Design**: Rate design is still a critical function of regulation -- almost all electricity is delivered on monopoly wires systems, and the vast majority of energy sales are still made at regulated rates by regulated franchises or default service providers. Administrative and legislative rate designs for power prices and wires services should be re-examined for their effects on consumption, peak demand, and reliability. Retail rate caps should be modified to better align rates and power costs, and to encourage customers to better manager their loads. Wires company rates should not be based on per-unit price caps, which promote throughput and impair reliability, but on performance-based, per-customer revenue caps.

C. Promoting End-Use Efficiency:

Broad-based energy efficiency measures provide multiple reliability benefits to electric systems. They can reduce load, fuel use, equipment maintenance, and environmental impacts throughout the entire electric system. Moreover, efficiency measures now have a very valuable role to play in lowering power market clearing prices. The savings resulting from energy efficiency are obviously very high at peak, but they are also surprisingly high when all other hours of the year are considered. The "public" benefits of energy efficiency investments to customers in a market may substantially exceed the private benefits of efficiency to those who install efficiency measures. The report recommends several mechanisms for delivering broad-based efficiency measures to electric networks.

- **System Benefit Funds:** Broad-based wires charges can support efficiency and load management measures that enhance system reliability and lower market prices. Small, non-bypassable charges are competitively neutral and can provide adequate funding for programs to serve all customer classes. At least 19 states have established statewide funding mechanisms for efficiency programs, supervised by state agencies with a mandate to improve reliability and save energy cost-effectively.

- **The Energy Efficiency Utility:** One important variant on the statewide public benefits fund is the Energy Efficiency Utility, which is awarded a franchise in order to deliver efficiency service to customers across a state or region. The first such utility was chartered by the Vermont Public Service Board, with a statewide franchise, supported by a wires charge in each franchise territory in which it delivers services.

- **System Benefit or Uplift Charges at the Power Pool Level:** Power pools and RTO'S with authority to impose tariffs for supply-side investments should also have authority to support cost effective demand-side programs on a regional basis. One option is a wires charge collected on the same basis as other reliability and uplift charges collected by regional pools and reliability managers.

- **Complementary policies for energy efficiency**: Building codes, appliance and equipment standards, and financial policies are all important tools to advance energy efficiency in the power sector. Higher air conditioning standards alone could save over 40,000 MW over the next two decades. Better building codes, expansion of the Energy Star labeling program, and new tax and finance mechanisms would add measurably to a more reliable electric system.

Conclusion

Heat waves are natural events, but blackouts and price spikes are the result of governmental and private choices. Heat waves and cold spells are as predictable as snowstorms and hurricanes. The resulting outages and price spikes are not “caused” by the weather, they are the consequence of our policy decisions. After a recent hurricane, Floridians learned that low-cost investments in roofing tie-downs would have kept many roofs intact in high winds. In a similar manner, energy efficiency investments can be viewed as a low-cost means of “peak-proofing” the electric system, keeping the electric grid intact during heat waves, cold snaps, and other challenging events. The means of providing this added measure of reliability are well within the grasp of utilities, governments, system operators and customers.

I. INTRODUCTION

In the present movement towards competitive electricity markets, it is important to remember that electric system reliability is, in many respects, a classic public good. By the laws of physics, the essent attributes of adequacy, voltage, and frequency are available to all interconnected users simultaneously. As one prominent marketer put it, "I tell all my prospects, as long as you're connected to the grid, your reliability will be just the same as your neighbors', no matter who you buy your power from." Like the textbook examples of lighthouses and national defense, most aspects of electric reliability are provided to everyone or to no one, and everyone is required to pay for them. Public rules, imposed by governments, utilities, reliability councils, or power pools, will determine the costs of reliability measu and the means of paying for them. In this environment, least-cost thinking can provide substantial benefits to the public and the economy.

In response to recent reliability and price events, it is common for customers, politicians, and industry participants to conclude that outages and shortages are the result of a failure to build sufficient new generation, and/or too little investment in transmission and distribution facilities. It is, of course, often case that additional investments in generation and delivery facilities would improve reliability, and such investments are often needed.

But this narrow focus overlooks the essential fact that reliability is a function of ***the relationship among generation, wires, and load.*** When the relationship is out of balance, the search for solutions must consider new generation, investments in wires, or accelerated load management and efficiency measure or a combination of the three. A persistent feature of the public dialogue on this critical topic has been the repeated refrain that reliability problems have been "caused by a failure to invest in generation (or transmission)" rather than the equally logical observation that they have been caused by a failure to inve adequately in cost-effective efficiency and load management, or to stimulate such investments through better pricing and more efficient markets.

Analysis of the current and emerging conditions of America's electric grids reveals the following conclusions:

- Rapid demand growth, the break-up of electric monopolies, and a critical decline in efficiency and demand-side management programs are undermining the reliability of America's electric grids and now present a growing challenge to public decision-makers;

- In many locations, additional generating and transmission capacity will be needed to maintain reliable and efficient service. However, maintaining reliability exclusively through a "turbines ar wires" policy will be unnecessarily expensive, and unnecessarily harmful to the environment;

- Energy efficiency and load management can add enormous value to the nation's electric system, lowering the cost of electric service, mitigating capacity crunches, and cost-effectively improvi system reliability. Responsible estimates of the demand-side potential conclude that as much as 40%-50% of the nation's peak load growth over the next twenty years could be met through energy efficiency, price-response, and load management measures that would be less expensive than their supply-side substitutes;

- Demand-side resources can provide reliability and price benefits both in electricity markets, and in franchise or monopoly service situations:

  Where services are provided through competitive markets, those markets should be structured to give demand-side and supply-side resources equal opportunity to supply energy, capacity, and reliability requirements.

  Where electric services are provided through historic franchises or new default service providers, demand-side resources should be built into the portfolio of resources assembled for the benefit of customers.

- Integrating demand resources into electricity markets will lower the cost of reliable service, mitigate the market power of concentrated supply-side generation owners, and lower market clearing prices and price spikes at times of peak demand.

- Energy efficiency and load management programs can also lower the cost of distribution service and improve distribution reliability by accommodating load growth and high-demand situations below the load tolerance levels of the existing distribution network.

The foundations for these conclusions are set out in the sections following. This paper begins by examining the unwelcome trio of problems now facing electricity markets: reliability challenges, price spikes, and market power problems. It then examines the premises and risks of an exclusive, supply-side,"wires and turbines" approach to these problems, and examines the potential for demand-side resources to contribute to their resolution. The paper concludes with a series of policy recommendatio in three areas: (A) measures to incorporate demand responses and demand-side resources into modern electricity markets, (B) policies for the rate structures and operations of wires companies in order to remove regulatory barriers to demand-side resources, and (C) measures to support investments in efficiency and load management where market barriers continue to stand in the way of cost-effective efficiency investments.

II. The Unwelcome Trio in Today's Power Markets: Reliability Challenges, Price Spikes, and Generator Market Power

It is now an understatement to observe that power markets throughout the United States are undergoing a dramatic transformation. The crises in California and the West in 2000-2001 dominate the national debate, but several less dramatic processes are also underway: the rise of wholesale competition, transmission open access, and the creation of Regional Transmission Organizations; the move to retail competition in many states; the unprecedented pace of consolidation among utility companies; the rise of the merchant plant industry, based in part on the reshuffling of the nuclear industry and in part on the ris of efficient natural gas generating options.

Along with all of these changes has come the de-integration of functions that formerly occurred within tightly-woven franchise operations. 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. Acros the nation, significant and persistent load growth, particularly at peak, is placing ever-greater demands on electricity networks. As a consequence, supply adequacy, price spikes and electric system reliability have become major public policy challenges in many regions. These new problems are introduced in the following section.

A. Reliability Challenges Expose the Value of Demand-Side Resources

The reliability of electric supply, long taken for granted by most citizens and governmental officials, is now a matter of increasing national concern. This increasing concern has two dimensions. First, there i a growing awareness that continuous power supply and improved power quality are critical underpinnings of the nation's post-industrial, digital economy. That economy is increasingly based upo 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, even very small variations in power quality can cause troubling and expensive disruptions.[2] The U.S. DOE now

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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 Karl Stahlkopf, Consortium for Electric Infrastructure to Support a Digital Society (CEIDS), Electric Power Research Institute (November 2000, Forth Worth, Texas).

2. *Id.*

estimates that power outages and other fluctuations in power delivery cost at least $30 billion a year in lost productivity.[3]

Second, over the past four years, managers and consumers across the nation have seen a significant rise in the number of important reliability events, including power alerts, voltage reductions, power outages and other system disturbances. The most significant reliability 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, and that "the necessary operating practices, regulatory policies, and technological tools for assuring an acceptable level of reliability were not yet in place" [4] t support changing industry conditions.

This view is echoed by the North American Electric Reliability Council (NERC), which testified in Congress during the year 2000 that reserve margins were shrinking, transmission lines were becoming overloaded, and reliability challenges were greater than at any other time in recent history. By far the most significant series of events has been the continuing crisis in California, and its effects throughout Western Interconnection. The unprecedented series of rolling blackouts, power alerts, and price spikes in this region have many causes, which are the subject of intense debate. While the focus on California i understandable, it is important not to overlook conditions and events in other regions.

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

Reliability problems have become so widely known that there is little need to document them here. Wha is not so well known, however, is the role of demand growth in causing those problems, and the role that demand-side responses can play in addressing them.

Review of the major reliability events of the last four years reveals a single key observation:

While the immediate system failure or technical problem involved in theses events varies from case to case, the underlying cause of these reliability problems is most often the high loads the system was required to serve at the time of failure.[5] Demand-side resources can enhance reliability by moderating those challenging high loads.

3. Environmental Media Services, "Widespread Reliability Problems Produce Huge Disruptions, Giant Costs," (Lighten the Load, 2000.)

4. US DOE, *Report of the US Department of Energy's Power Outage Study Team* (March 2000 Final Report), at S-2. The POST Report recommends 12 policies to promote reliability, including several that are consistent with the recommendations contained in Section V of this report.

5. As noted in the text below, California represents an important variation on this theme. The combined effects of a severe drought, reducing generating capacity in the Northwest, and rapid load growth in the states *surrounding* California have reduced the generation available to meet load in California. Those physical events have greatly enhance the opportunities of fuel suppliers and generators to exert market power in regional power markets.

It is important to note that reliability problems are not simply the result of inadequate generation capaci across a utility system or power pool, and they are not confined to a few high-growth states. As the following examples demonstrate, the problems caused by high loads can affect reliability at all points o the generation-transmission-distribution system, and they are occurring in all regions of the country.

- **Local distribution failures:**
  New York City and Chicago

On July 6 and 7, 1999 more than 200,000 people were left without power for up to 19 hours when Consolidated Edison lost 8 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.

Outages in Chicago have also been triggered by the failure of aging and overloaded local distribution systems due to 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 o 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, ComEd 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.

- **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 ISO was forced to institute rolling blackouts in San Francisco and surrounding areas in order 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 loac required to meet peak demand in the load pocket.

- **Regional transmission failure:**
  Western States (August 10, 1996)

On August 10, 1996 the largest regional blackout in the U.S. since the New York City blackout of 1965, cascaded across a multi-state region of the U.S. 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 protective equipment to protect them from failure, resulting in a series of outages that stretched across several states. Altogether, 30,000 MW of load was interrupted, and 7.5 million customers were affected, some unserved for as long as 9 hours. The California Energy Commission later estimated the economic cost of this outage to the California economy alone at $1 Billion.

- **Generation adequacy problems**:
  California Crisis (Summer 2000 and continuing)

Since June 2000, California has experienced an unprecedented power crisis, marked by power warnings, price spikes, rolling blackouts, and numerous days of extremely low reserve margins. While the crisis is associated with a supply-demand imbalance in California, for the most part, it has not been caused by high, in-state load growth.[6] Reserve margins have been dramatically cut by the effects of an extreme drought, reducing hydro capacity available in California and the Pacific Northwest. Moreover, many observers, including the California ISO, assert that reliability and price problems have been exacerbated by strategic withholding and other "gaming" behavior by generators. Load growth in California, which has been modest in comparison to the pace of growth in surrounding states, is probably not the principal cause of the state's reliability problems. However, load growth *throughout the region* has greatly reduced the ability of California's utilities to balance their systems with imports from other states.[7] The effects have been exacerbated by a substantial reduction in energy efficiency programs in California since 1994, adding about 1100 MW to the state's overall demand.[8]

New England (June 7 and 8, 1999):

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6. Between 1990 and 1999, California's load growth averaged 1.1 percent per year, about half the national average. Hal Harvey, Bentham Paulos, and Eric Heitz," California and the Energy Crisis: Diagnosis and Cure," Energy Foundation (March 8, 2001), at 1

7. For example, during the 1990's, load grew 83% in Nevada and 42% in Arizona. Ibid. at 11.

8. Ibid. at 10.

Record-breaking heat and humidity spread across the northeastern U.S. in June 1999, leading to operating emergencies in New England, Ontario, and New York due to shortages of reserve generating capacity. Many generating units were out of service for maintenance and refueling, in anticipation of hig 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 underway.

B. Compounding the Problems of Thin Margins: Price Spikes and Market Power

Deteriorating reliability is not the only consequence of declining reserve margins. In wholesale power markets in several US regions, system managers, load-serving entities, and customers are witnessing extraordinary price increases, particularly while reserve margins are thin. Meanwhile, it is apparent that generators have significant market power to affect price and supply quantities, power not available in purely competitive markets. As will be developed in Section V below, demand-management and energy efficiency investments hold significant potential both to improve reliability and to mitigate the undesira economic attributes of current power markets.

1. Price Spikes

Electricity prices in regional wholesale markets are volatile, perhaps more volatile than for any other commodity, . They are so variable because:

- Generators differ substantially in their costs to produce electricity (e.g., the running costs for hydro and nuclear units are typically well below $10/MWH, while the cost for an old combustion turbine might be $100/MWH or more);
- System loads vary substantially from hour to hour (e.g., by a factor of two to three during a single day);
- Electricity cannot easily be stored and therefore must be produced and consumed at the same time; and

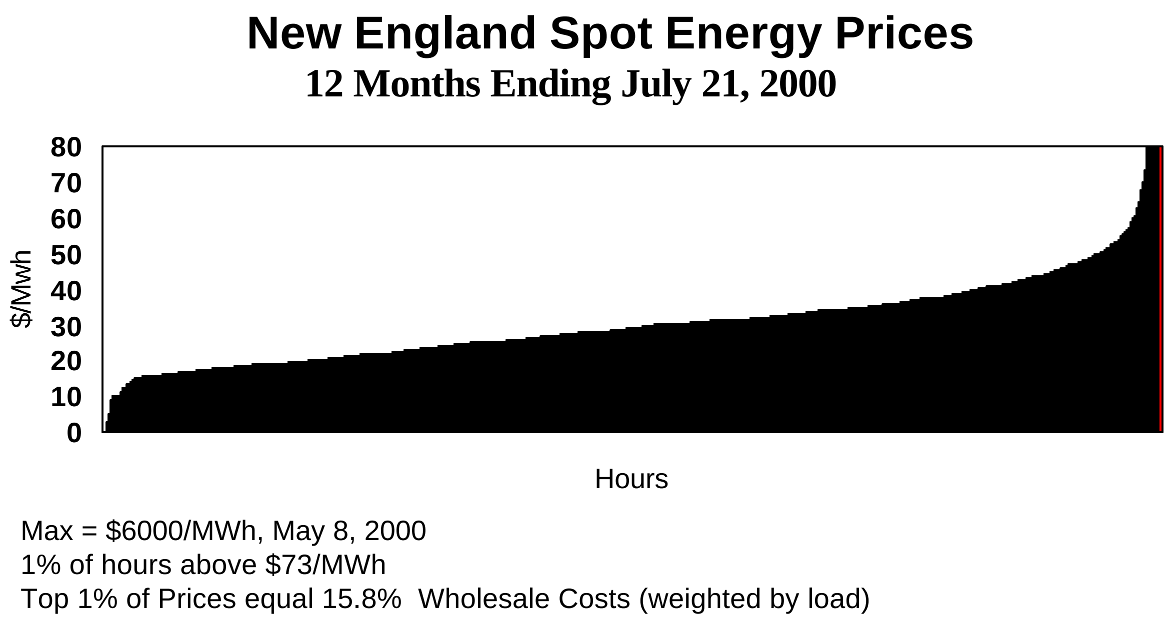

Figure 1: New England Price Duration Curve

- When unconstrained demand approaches available supply, reliability concerns lead system operators to call on generators charging prices well in excess of the running cost of the most expensive unit then on line.

In Figure 1 the market clearing prices for power on the New England ISO are arranged in ascending order for every hour of an extended market period. As this figure demonstrates, the distribution of price is relatively smooth across most hours of the year, but prices rise to extraordinary levels during a few hours of the year. Although recent (year 2000 - 2001) experience in California shows a much higher overall level of prices, price-duration curves in most U.S. power markets appear very similar to this figure.

While the annualized price-duration curves in power markets appear as relatively smooth functions, ther is in fact a very high degree of volatility in hourly prices, and in power markets'daily and weekly peaks.[9] Figure 2 below shows the hourly variation in prices in the PJM Interconnection for the week of December 8, 1997.

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9. For example, in New England between May 1999 and July 2000, weekly peaks varied by about 50%, while weekly spot prices varied by well over 1,000%. (In fact, in May 2000, the spot market price in New England reached $6,000/MWh, 200 times the usual market clearing price. This particular anomaly is unlikely to be repeated, but substantial price excursions are not unusual in regional power markets.)

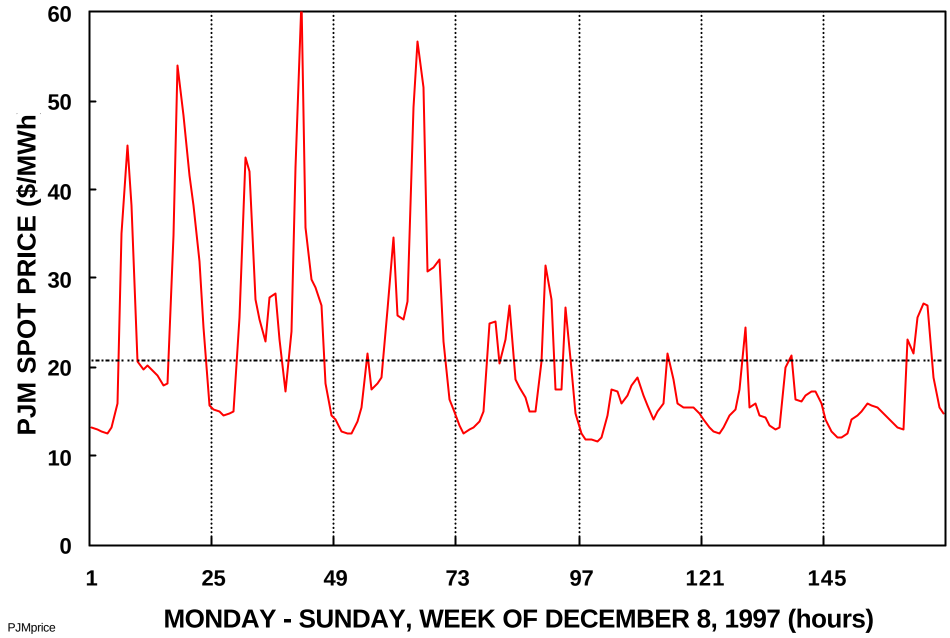

Figure 2: Hourly spot prices can be highly variable.

2. Market Power

The electric system's unique characteristics – delivery of an essential service which must be generated and consumed simultaneously, across an interconnected network where all users are affected by the consumption patterns of all other users – confer on generators a great deal of market power, particularly when the margin between generation and load is thin. The price spikes illustrated above are a direct consequence of this reality. When generating margins are thin, generators have been able to command very high prices on the spot market, and system operators have paid those prices in order to avoid brownouts, blackouts, and diminished power quality[10].

10. That generators may possess market power does not, in itself, mean that they are violating anti-trust statutes or engaging in unethical market behavior. Market power is simply the ability of a firm (or a group of firms acting together) to profitably raise prices above competitive levels and/or restrict output below competitive levels for a sustained period of time. From the point of view of consumers, however, this is not a neutral fact. Generators with market power will naturally raise prices above competitive levels, and/or reduce output below competitive levels, raising power costs and /or lowering the reliability of the electric system.

The market power possessed by generators is also enhanced by the rapid pace of consolidation among the owners of generation facilities in the United States, yielding fewer and fewer competitors in regional power markets. According to a recent EIA report on utility structure, in 1992 the 10 largest utilities, ranked according to generation capacity, owned just 36% of all non-customer owned generation capacity, but by the end of 2000 the 10 largest utilities controlled an estimated 51% of that capacity. During the same time period, the percentage of generation owned by the 20 largest companies rose from 58% to 72% of total IOU and IPP generating capacity.[11] The degree of concentration among the major utilities is now approaching the levels it had reached in 1935, before passage of the Public Utilities Holding Company Act.[12]

Serious concerns have been raised in several power markets, including California, New England, and New York[13] that generators are "gaming" the bidding rules and/or strategically withholding generation from the market in order to drive prices higher. Most notably, in early 2001, the California Independent System Operator (ISO) asserted that generators in that market had improperly manipulated bids and unit availability, raising total electricity costs in the state between May 2000 and February 2001 by $6.7 billion.[14] While allegations of strategic withholding have been vigorously disputed, the key point for the purposes of this report is not in controversy:

When the margin between available generation and load is thin, generators can require very high prices for supply-side resources. In this setting, demand-side resources have new value as a means of moderating the power of producers to raise the market clearing price well above the marginal cost of production.

C. Sources of Today's Reliability Problems

1. Capacity Crunches are Directly Related to Load Growth

In response to recent reliability and price events, it is common for customers, politicians, and industry participants to conclude that outages and shortages are the result of a failure to build sufficient new generation, and/or too little investment in transmission and distribution facilities. It is, of course, often case that additional investments in generation and delivery facilities would improve reliability, and such investments are often needed.

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11. Energy Information Administration, *The Changing Structure of the Electric Power Industry 2000: An Update*, at 97 (October 2000).

12. In 1935, 13 companies controlled more than 50% of all IOU generation. After the breakup of the major holding companies following passage of PUHCA, and for the decades between 1955 and 1995, one had to combine the assets of the 200 largest companies to cross the 50% threshold. Today, 10 companies own 51% of IOU generation.

13. The New York PSC concluded that "strong mitigation measures need to be in place to prevent abuse of market power." NY State Department of Public Service "Interim Pricing Report on New York State's ISO," December 2000.

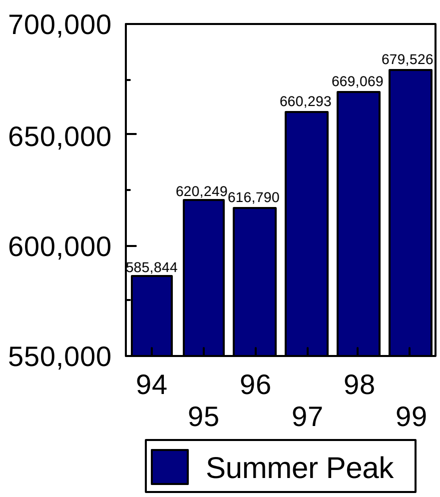
14. Will McNamara, "Energy Stocks Tumble in Response to Possible California Refunds," IssueAlert (June 25, 2001).

But this simplistic approach overlooks the essential fact that ***reliability depends on the relationship among generation, wires, and load.*** When the relationship is out of balance, the search for solutions must consider new generation, investments in wires, or accelerated load management and efficiency measures, or a combination of the three. A persistent feature of the public dialogue on this critical topic has been the repeated refrain that reliability problems have been "caused by a failure to invest in generation (or transmission)" rather than the equally logical observation that they have been caused by a failure to invest adequately in cost-effective efficiency and load management, or to stimulate such investments through better pricing and more efficient markets.

The undeniable fact is that load growth in the United States, particularly peak load growth, have been proceeding at a pace that has put great strains on our power system infrastructure.

- Between 1994 and 1999, non-coincident summer peak load in the US rose from roughly 585,000 MW to 680,000 MW — an increase of 95,000 MW in five years.[15] See Figure 3. This is the equivalent of adding a new, 6-state New England to the nation's electrical demand every 14 months.

- Nationwide, electric consumption grew 31% in the decade between 1988 and 1998.[16] Consumption grew 325,000 GWH (or about10.6%) between 1994 and 1998 alone.[17] See Figure 4.



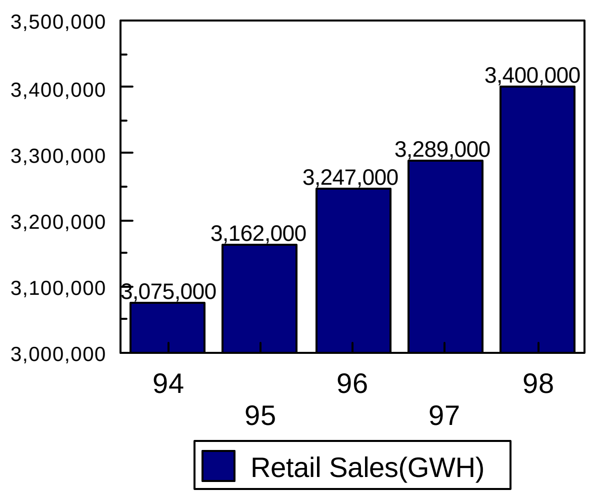


Figure 3: US Noncoincident Summer Peaks

Figure 4: US Electric Retail Sales

15. EIA , Electricity End Use (1949-1999) Table 35 Noncoincidental Peak Load
16. New York Times 9/13/99
17. EIA, Electricity End Use (1949-1999) Table 8.9, Electric Utility Retail Sales

Current estimates predict continued sustained growth in demand. Together with the need to replace retiring generating units, this demand growth has led many analysts to declare a nationwide need to construct hundreds of thousands of MW of new generating capacity in the next few years:

- The most well-known assessment was prepared by the Bush Administration's National Energy Policy Development Group in May, 2001, which concluded that electricity demand would increase by 45% over the next 20 years, requiring the addition of 393,000 MW of new generating capacity to the nation's electric grid.[18].

- A number of projected shortages are, in utility planning terms, almost directly in front of us. According to a study by Applied Energy Group, all but one of the nation's 10 regional reliability councils face a shortage of generating capacity by 2007.[19]

2. Successful Energy Efficiency Programs Have Been Cut Back

In the 1980s, U.S. electric utilities, regulators, and customers launched a serious effort to balance the industry's traditional focus on supply-side construction and rapid sales growth with a program of investments in demand-side resources, governed by the process of integrated resource planning. The overall performance of demand-side management (DSM) programs, even during a period of experimentation and start-up, was very encouraging. Efficiency and load management resources were often cost-effective, and could add stability and reliability to electric systems. DSM programs displaced the need to construct 29,000 MW of generating capacity. Overall DSM costs to utilities have been about 2.1 cents/kWh on a "simple" basis, and 2.9 cents including the time value of the invested capital.[20] These investments were also, by their nature, modular and dispersed. They could be targeted to stressed transmission and distribution (T&D) areas, and they have had almost no negative environmental impacts.

Unfortunately, the contribution of DSM to meeting the nation's load growth needs has been in decline. Today's capacity crunches and reliability problems have, in substantial part, been caused by a dramatic downturn in our nation's investment in these utility-sponsored energy efficiency programs following passage of the 1992 Energy Policy Act and the move toward competition in electricity markets.

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18. National Energy Policy, report of the National Energy Policy Development Group, May 2001 at p.1-4. This is roughly 9 times the current California system peak, and exceeds the existing generating capacity of Japan and Germany combined.

19. "Nationwide Capacity Shortage by 2007?" (Electricity Daily June 4, 1999). The WSCC could have a capacity shortfall of 17,200 MW, according to the study. MACC could fall short by 7100 MW, Ercot could have a 5,500 MW shortage, SPP could be short by 5,400 MW and ECAR 4,400. MAPP could be 3500 MW short, SERC 2,500 MW short, MAIN 2,400 MW short, and FRCC down by 500 MW. The NPCC was the only region not expected to be short, but this is because of significant new construction now being planned for that region See also, "TVA Warns of Long, Hot, Power-Short Summer" (Electricity Daily May 6, 1999.)

20. Fickett, Gellings, and Lovins, "Efficient Use of Electricity," *Scientific American* (1990).

Despite the generally solid record of success of utility DSM programs up to 1993-94, utility-sponsored DSM programs have since been cut back sharply. Total utility DSM spending has declined by about 50% since 1993. According to the EIA, utility spending for all DSM (efficiency and load management) totaled $2.7 Billion in 1993. Based on utilities' announced plans, EIA at that time projected a **20% increase** in DSM spending to about $3.5 Billion by 1998. Instead, spending has dropped to $1.5 Billion, a **decline of 45%** in four years, and a reduction of 57% as compared to the trendline of 1991-93.[21]

A look at the 15 largest utility programs confirms this trend. Utility DSM spending has declined by about 50% at those utilities since 1993. A modest fraction of that spending has been restored by public benefits programs in a few states.[22]

The abandonment of utility-sponsored DSM programs between 1994 and 1999 has dramatically reduced the contribution such programs could have made to meeting both energy needs and peak demands in recent years. By 1993, DSM-related peak load reductions and were growing by about 4,000 MW per year. However, this progress has been stalled, and total peak load reductions have been virtually flat since 1995. See Figure 5 below.

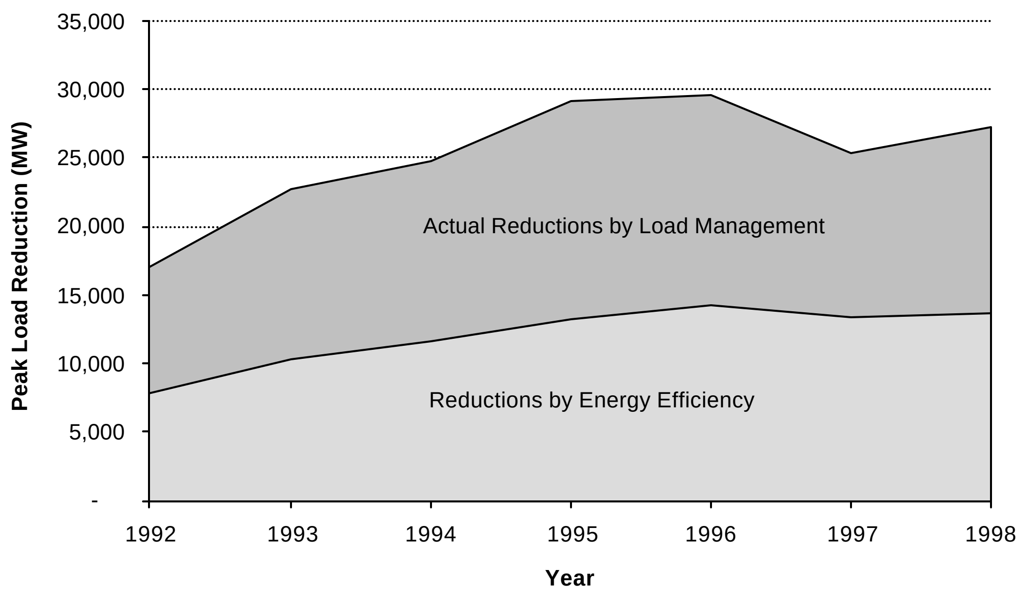

Figure 5: Peak Load Reductions from Efficiency and Load Management

21. Nadel and Kushler, "Public Benefit Funds: A Key Strategy for Advancing Energy Efficiency," *The Electricity Journal*; October 2000. (For efficiency programs alone, excluding load management, the drop has been steeper — as much as 67% compared to the 1992-93 trendline.).

22. (Chuck Goldman, Energy Analysis Dept, Lawrence Berkeley Lab, April 22, 1999). For additional information on state-level programs adopted since 1996, see Section V, below.

Incremental energy savings from utility energy efficiency programs (additional savings relative to saving achieved in the prior year) have also been cut in half, dropping from 8.6 billion kWh in 1994 to 4.3 billion kWh in 1996. [23]

3. The Efficiency Yo-Yo: Demand-Side Cuts and the Rush to Restore Programs

As power crises have mounted in California and the West, and reserve margins have narrowed in the East, demand-side resources have received renewed attention, and policy-makers have rushed to restore programs that had been abandoned or cut back sharply in prior years. California and New York provide similar lessons in this area.

In New York, utility spending on energy efficiency was cut by about 75% in the mid-1990's, despite projections by the Public Service Commission that increased demand would lower the reserve margin unacceptably by the year 2000.[24] By the summer of 2000, it became apparent that the combination of increased demand, limited transmission, and a lack of major new plants, particularly in New York City, was placing unacceptable pressure on reliable service. In response, the New York Power Authority launched an emergency program to site 11 new gas-fired generators in the New York City region, and the state legislature directed the Energy Planning Board to conduct a reliability study. That study found that demand-side measures, including energy efficiency measures, peak load shaving measures, and price-responsive load programs, would all have a positive effect on reliability.[25]The New York PSC subsequently doubled the funding given to utility efficiency programs through their System Benefit Charges, restoring a portion of the funding lost at the end of the 1990s. The New York ISO also launched an Emergency Demand Response Program, and a Day-Ahead Demand Bidding Program to address the reserve deficiency.[26]

In California, utility demand-side programs were cut in half following the PUC's initial moves to competition in 1994. (See Figure 6.) As a result, the state lost about 1100 MW in demand savings that would have been available to mitigate market power and avoid reliability crises in 2000 and 2001.[27] When those power shortages arose, the General Assembly, the state's utilities, and other agencies launched a portfolio of emergency demand-management programs to recapture some of

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23. ACEEE calculation based upon EIA data.

24. Neela Bannerjee, et al., "Power Politics: A Failed Energy Plan Catches Up to New York," New York Times (June 1, 2001).

25. "Report on the Reliability of New York's Electric Transmission and Distribution Systems," New York State Energy Planning Board (November 2000).

26. New York ISO, "Power Alert: New York's Energy Crossroads," March 2001 at 20-21.

27. Hal Harvey, Bentham Paulos, and Eric Heitz, "California and the Energy Crisis: Diagnosis and Cure," (Energy Foundation, March, 2001) at p.6.

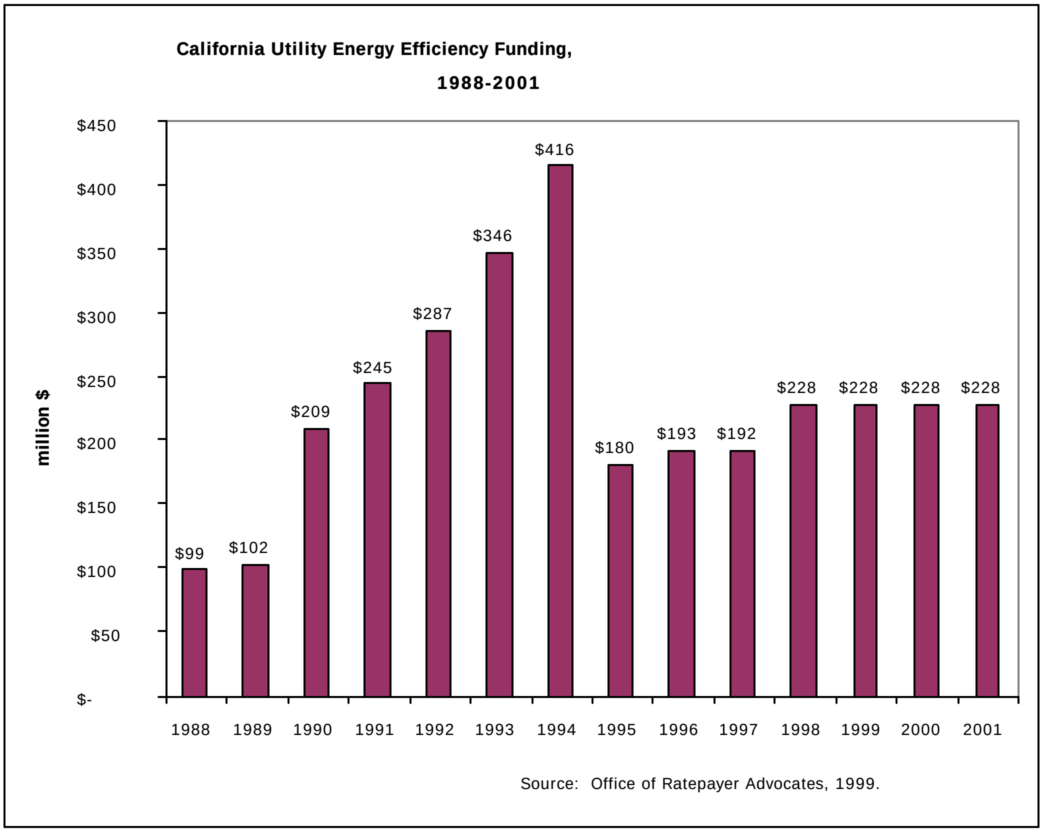

Figure 6: Reductions in California Utility Efficiency Programs, 1995-2001. These cut-backs added 1100 MW to the state's peak load in 2000-2001.

the ground lost over the preceding six years. More than $1 billion was authorized to be spent through a variety of programs, aimed at reducing demand by at least 1500 MW.[28] Implementing these programs on a crash basis, however, has presented numerous administrative and logistical challenges. Key personnel are no longer available, program designs are outdated, and stocks of energy efficient equipment are quickly depleted. Moreover, many savings opportunities arise infrequently (e.g., only when a building is built or major renovations are undertaken). On-again, off-again programs have missed those opportunities, and are now unable to recapture them. Finally, the emergency programs in California in 2001 have necessarily focused on immediate peak load reductions, even where long-term cost-benefit analysis would support investments with more sustained, but more gradual results.

28. See, e.g., Julie Tamaki, "Legislators to Promote Energy Conservation," LA Times (Feb. 6, 2001).

III. SUPPLY-SIDE AND DEMAND-SIDE RELIABILITY: THE PRACTICAL REALITIES OF EXISTING POLICY

Modern electric policy debates are often clouded by an inherent conflict between two competing economic objectives:

- On the one hand, advocates of competition and free markets in electricity often assert that the paradigm of utility integrated resource planning developed over the past decade has outlived its usefulness as a relic of "central planning," and that markets alone will call forth the most efficier combination of wires, turbines, and demand management services to meet the nation's electric service needs.

- However, at the same time, it is commonly observed, sometimes by the same advocates, that the increasingly sophisticated power demands of the growing digital economy require higher reliability standards, along with increased authority in the hands of network managers to enforce those standards, and to intervene in transmission and energy markets if necessary to protect against short-term and long-term network externalities.

While largely at odds, there is at least one point of reconciliation between these two positions. When regulators adopt system rules to structure electricity markets, and when reliability managers intervene i them, those actions are the hand of government at work, not the invisible hand of the market. Those government actions should be guided by the same principles that have long guided least-cost utility operations: they should capture the highest value for consumers over the long run, for the lowest reasonable cost. The challenge is to (a) discover how to structure those markets efficiently; and (b) understand where network externalities require regulatory interventions in addition to market solutions. Demand-side resources offer valuable solutions in both of these areas.

A. "Wires and Turbines" Reliability – Some Practical Considerations

The conventional and predominant response to the nation's current capacity/demand crunch is a focus on the construction of new power plants and major transmission lines.

Undoubtedly, significant new investment in generation and transmission is justified on both on economi and reliability grounds. Economic growth, changes in settlement patterns, and the emergence of superio technologies all support a conclusion that many investments in generation and transmission are needed and should be supported in new markets and regulatory systems.

However, major investment programs, particularly investment programs with large-scale and long-term financial and environmental consequences, should proceed only upon the conclusion that they are providing the nation the highest value service at the lowest reasonable cost. A massive national electrica building program, involving only central-station generation and transmission investments, and ignoring cost-effective efficiency and load-management resources, will be more expensive and less reliable than program that is more balanced and more flexible.

1. The Cost of New Generation

To begin with, a reliability policy that focuses on generation alone will be financially expensive. According to North American Electric Reliability Council data, generating capacity in the US will need to expand by about 12% by 2007, an increase of 91,000 MW of installed generation, in order to maintain adequate reserve margins.[29] DOE now projects a need for more than 390,000 MW of new capacity by 2020.[30] Although the capital cost of this new generating capacity is expected to be lower than the average cost of utilities' historic plant, it nevertheless represents a huge commitment of capital perhaps as much as $250 billion.[31] Informed observers also project the need for 38,000 miles of interstate gas pipelines (at a cost of $35 billion), 255,000 miles of gas distribution pipe (up to $100 billion), and 8800 miles of electric transmission lines ($5 billion) to support increased electric and gas consumption through supply-side measures.[32] In addition, of course, the fuel costs required to support generation from those units will greatly exceed the capital costs of the units themselves.

2. Increasing Demands on Transmission Networks

Significant capital expansion of the nation's transmission grids would also be required to meet continuin load growth through new generation, while supporting increasingly active regional wholesale power markets. According to many industry analysts, transmission grids are already strained. They could not support 200,000 to 400,000 MW of new generating capacity without substantial upgrades and new transmission links[33].

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29. Electricity Daily 6/4/99

30. "National Energy Policy" (May 2001) at p. 1-4.

31. This is a relatively low figure, assuming that new generation would be overwhelmingly combined cycle natural gas with an average capital cost of about $600/kW installed. Coal or nuclear facilities would, of course, involve much higher capital costs. Mike Kujawa, analyst at Allied Business Intelligence, states that over $100 Billion must be put into new power generation by 2010 to meet demand growth during the first half of the period in question. ("Power Generation Opportunities in a Restructured Environment," Reported in Deregulation Watch, July 15 1999 p. 7)

32. James Mahoney, PG&E National Energy Group, "Estimated Capital Needs for Electric Reliability (2000-2020)" presented at the 2001 Annual Symposium of the New England Conference of Public Utility Regulators (May 22, 2001).

33. Texas is a good example. Demands on the state's transmission system have increased by 32% in the past six years, with only minimal additions to transmission capacity. Thus, even though 10,000 MW of new generation is being built, "Texas' Achilles heel may be its transmission system, which is just as critical to a successful launch of deregulation as adequate power supply." Will McNamara, "Transmission Grid May Be Texas' Achilles Heel," IssueAlert (July 2, 2001).

As EPRI has reported, the value of bulk power transactions in the U.S. has increased four-fold in just the last decade, and about one-half of all domestic generation is now sold over ever-increasing distance on the wholesale market before it is delivered to customers. "This growth, however, comes at a time when many parts of the North American transmission system are already operating close to their stabili limits, as illustrated by recent widespread outages in the Western states....Traditionally, utilities would b adding new transmission capacity to handle the expected load increase, but because of the difficulty in obtaining permits and the uncertainty over receiving an adequate rate of return on investment, the total o transmission circuit miles added annually is declining while the total demand for transmission resource continues to grow."[34] While 10,000 circuit miles of transmission were added in the 1985-1990 period, only 4,000 circuit miles were added between 1990 and 1995.[35]

Industry leaders have recently evidenced increasing concern over the transmission situation, and many now propose statutory and regulatory interventions to enhance reliability through transmission investments. Proposed solutions include incentive rates for transmission investments, federal preempti of state and local siting laws,[36] and grants of authority to RTO'S to commission transmission facilities and pay for them through broad-based regional uplift charges.[37]

3. The Costs and Consequences of Overloaded Distribution Networks

Meeting load growth through a supply-side "wires and turbines" approach also entails investing in the distribution-level facilities necessary to reliably support increased load on local feeders and substation The capital cost of such upgrades can be very high, even when amortized over the long lifetimes of the facilities involved.[38] Across a wide range of utilities, companies spend an average of about $750 per kW of peak load growth on transformers, substations, lines and feeders.[39] In high cost areas, the required investment is several times greater.

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34. EPRI, "Electricity Technology Roadmap" July 1999 p.22

35. Ibid.

36. These are among the recommendations contained in the Bush Administration's National Energy Policy, (Report of the National Energy Policy Development Group, May 2001). Several bills have been introduced in Congress to provide federal preemption of state and local laws on transmission line siting.

37. See, e.g., New England ISO's decision to pay for more than $130 million for "Pool Transmission Facilities"throughout New England .

38. For example, Central Vermont Public Service reported that the marginal cost of transmission and primary and secondary distribution was more than $67.00 per kw/year. Testimony of Scott Anderson, Vermont PSB Docket 5835 (May 1995). Commonwealth Edison has committed to $1.5 billion in distribution investments as a condition of franchise renewal in Chicago.

39. Wayne Shirley, Regulatory Assistance Project, "Simplified Distribution System Cost Methodologies for Distributed Generation," (Discussion Draft, February 2001) at 17 and 19. Posted at www.rapmaine.org. This study analyzed data from FERC Form1 for 93 utilities for the period 1995-99. A portion of the investment is required to support facility replacements and customer growth rather than peak load growth alone, so demand management would not necessarily avoid the entire amount. Still, the author concludes that the cost of distribution system upgrades can rival the capital cost of generation required by load growth.

Increased demand on local distribution networks will also threaten reliability, sometimes in ways that ar unforeseen. Historically, more than 90% of all customer outages are caused by distribution-level problems. Many outages, such as those due to storm damage, are unrelated to load on the wires. However, local reliability problems are often the direct consequence of local load growth. For exampl the well-publicized failures in New York and Chicago in the summers of 1999 and 2000 were caused by distribution problems, not system generation inadequacy.[40] In both cases, the problem was an overloaded local distribution network due to high, sustained peak demand -- demand that might have been mitigated by more aggressive efficiency and load management programs in those areas.

4. Fuel Supply: Costs and Conflicts

The nation's currently projected **electric** load growth also brings with it considerable pressure on the nation's **natural gas** delivery system. As a recent trade press cover story puts it, "When Gas Sneezes, We All Catch Cold."[41] New electric generation, predominantly natural gas-fired, is expected to raise natural gas demand by as much as 20 billion cubic feet per day (BCF), a 30%+ increase over existing total deliveries of less than 60 BCF[42]. Several important consequences flow from this dramatic increase in gas demand. First, some experts now expect that the price of natural gas will be elevated to a new, higher plateau rate of $4 to $5 per mcf, rather than the $2/mcf rate the nation has enjoyed over the past few years.[43] Second, increased pressure is being placed on gas pipeline capacity. The National Energy Policy states that an additional 38,000 miles of new transmission pipeline will be necessary to meet increased gas demand over the next twenty years.[44]A shortage of pipeline capacity may also have serious market power implications for both natural gas and electricity markets.[45]

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40. See, E.g., "Oops! ComEd Throws Chicago for a Big Loop" (Electricity Daily 8/16/99) : "The catalyst for Daly's anger was the decision by ComEd to save transformers that were in danger of overheating because they were being overloaded after others failed. Saving the transformers meant cutting power to the Loop area in the heart of the city's business district....It was the third outage of the week...ComEd officials ...said more outages are likely because underground cables were damaged during July's heat wave and record power use."

See also, "Con Ed Fights Back After NY Blackout" (Electricity Daily 7/16/99) Con Ed spokesperson states, "There was no option of importing electricity from another community...The feeders in Washington Heights could only be repaired in Washington Heights."

41. John Herbert, "The Gas-Fired Future: Boom or Bust?" Public Utilities Fortnightly, April 1, 2001, at 20.

42. Presentation of James Mahoney, PGE National Energy Group, National Governors' Association Executive Policy Forum on Energy (April 5, 2001).

43. Presentation of Tom Robinson of Cambridge Energy Research Associates, National Governors' Association, Executive Policy Forum on Energy, (April 5, 2001). Natural gas prices averaged about $1.70 between 1986 and 1994, and rose to $2.26 between 1995 and 1999. The average almost doubled in 2000-2001, to $4.15. Even though gas drilling is proceeding at record levels, analysts now predict that the higher "price plateau" will continue, largely due to electric generation demands for gas. Ibid.

44. National Energy Policy, May 2001 at 7-12.

45. For example, California utilities have asserted that El Paso Natural Gas artificially limited gas throughput on its lines into Southern California, driving up power costs by $3.7 billion in 2000 and 2001. Will McNamara, "The Case Against El Paso Corp." IssueAlert, June 13, 2001.

Finally, dramatic increases in gas-fired electric generation raise reliability concerns within both the gas and electric markets. High summer gas demand (to fire electric generation) cuts into the gas industry's ability to transport and store gas in the summer to meet winter gas heating needs.[46] Serious reliability problems have also arisen due to competition between gas-for-electricity and gas-for-direct-heat during the winter.[47] Because electric generators cannot store large quantities of gas, pipeline interruptions will also directly and rapidly affect electric system reliability. For example, an explosion on the El Paso pipeline in Carlsbad, New Mexico early in 2001 took electric generation off line in California, and helped trigger rolling blackouts. In New England, which is now enjoying the addition of more than 10,000 MW of new capacity, 77% of the region's pipeline capacity may be consumed for power generation, and the potential loss of compression on the region's pipelines will soon become the largest single contingency that reliability planners must face in the region[48].

The existence of competitive markets for electric generating fuels will not resolve these reliability problem. Competitive markets will, of course, require suppliers and investors to make long-term decisions about price and availability trends for fuels and technologies behind their power supplies. Customers may choose among those suppliers based upon the price, environmental characteristics, or other attributes of those choices. However, when a supplier or class of suppliers is unable to supply power to the grid, their customer load will not be cut off -- those orphaned customers will, for all practical purposes, become the electrical security responsibility of the system operator. For this reason anyone's generation problem can become everyone's reliability problem[49].

5. Environmental Costs of "Wires and Turbines" Reliability

46. Few customers understand that high summer electric demand has the effect of raising winter heating bills and raising the risk of insufficient gas supply in the winter months.

47. When cold spells correspond with electric system peaks, (as occurs in winter peaking or dual-peak systems) there has to be enough gas and pipeline capacity to serve both firm gas load and electric generation loads, as evidenced in California and the Pacific Northwest in the fall and winter of 2000-2001. Cold weather throughout the region placed high demands on the natural gas supply to serve direct heat loads; electric generation facilities were left without sufficient natural gas to supply electrical demand. This situation resulted in repeated interruptions, region-wide power warnings, rolling blackouts in California, and has required extraordinary actions by system operators and federal officials.

This is not the first time that gas-electric capacity conflicts have led to major reliability problems, as hundreds of thousands of blacked-out PJM customers learned in the winter of 1994. Gas-fired generating stations were cut off during a cold spell, when natural gas supplies were needed by direct gas customers. Pennsylvania PUC Commissioner John Hanger pointed out after that event, "We cannot ignore the threat to reliability posed by plants that use only gas and are supplied with interruptible contracts, even though such plants amount to a small percentage of total capacity. When a system is stressed, reserve margins shrink precipitously...Every megawatt counts in an emergency." "Electric Reliability: How PJM Tripped on Gas-Fired Plants," Public Utilities Fortnightly, May 1, 1995.

48. Presentation of James Mahoney, (PGE National Energy Group) at the New England Conference of Public Utility Commissioners, May 22, 2001. A gas pipeline interruption or compressor failure can cause a greater loss of generation than a failure of New England's largest nuclear power plant or largest electric interconnection.

49. A reality demonstrated repeatedly during rolling blackouts in California in 2000 and 2001.

The environmental costs of electric generation and transmission are widely documented and do not require elaboration here. Nevertheless, this discussion would not be complete without recognition that those costs are substantial, and an increase of more than 300,000 MW of generating capacity and 40% or more in consumption will impose very serious environmental impacts. The environmental impacts fr construction of new transmission facilities are also likely to be significant, and it is unlikely that major transmission lines will escape citizen opposition in the siting process.

In addition to the obvious direct environmental impacts, an electric service policy that depends exclusively on supply side solutions runs the risk of threatening reliability in two ways. First, it may overextend environmental loading capacities, which could lead to strict future operating limits, or restrictions on future capacity expansions in locations where they may be particularly needed. In the fall and winter of 2000-2001, generators in California, running out of NOX allowances, were sometimes in danger of having to shut down even though their generation was needed to support the system.[50] Second, reliance on "lumpy" supply-side solutions to the exclusion of dispersed demand-side options may can create reliability problems as generation and transmission reserve capacities are eroded. Then, when a new capacity addition is critically needed, it may fall victim to public resistance, environmental siting problems. At that point, a long-term reliability challenge has been converted into a short-term reliability crisis.[51]

6. Lessons Learned – The Never-Ending Problem of Weakest Links

In the POST Report, and in many other post-event analyses, utility managers, regulators, and other experts are called on to identify the immediate causes of the types of reliability problems noted above. nearly every case it is possible to identify the weak link in the chain that connects 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. In California throughout 2000 and 2001, generation adequacy has been a major continuing problem.

Of course it is important to address the weakest links in the supply and delivery chain in order to improve reliability. For example, aging distribution infrastructure in Chicago and New York must be

50. "California's power plants, running hard to fend off a chronic electricity shortage, are themselves running out of pollution credits, forcing some to shut down..." The price of NOX emissions credits soared from $4 to $50 a pound, and the California ISO was forced to negotiate with state air regulators to allow units to run under emergency orders. "California Power Plants Run Out of Pollution Credits," *USA Today*: November 30, 2000. While the need to purchase emission credits has sometimes been costly, California officials assert that generators have usually been able to run when needed, despite air quality impacts. Marla Cone et al, "Bush's Idea of Easing Smog Rules Won't Help, Experts Say" *LA Times,* January 25, 2001.

51. A recent case in point is the plant proposed for Coyote Valley, in California's Silicon Valley, which waited for many months for siting approval notwithstanding the state's ongoing reliability crisis and the rapid demand growth and reliability needs of the local high-tech industry.

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 demand-side investments as well.

By accepting load growth and demand spikes as givens, and attempting to meet them exclusively through a wires and turbines policy, reliability managers can fix each "weakest link" in the supply chain as it appears. But once one upgrade is completed, a **new** weakest link will often emerge. For example, once load growth is addressed by siting new generation facilities, it is likely that transmission links will be more stressed, particularly at peak-load periods. Unless transmission upgrade are also purchased, the resulting degradation in transmission reliability will offset the gain in reliability to the new generation. Similar problems may well arise in other areas, such as electric distribution capacity, gas supply, pipeline capacity, and environmental loading limits.

Demand-side resources, 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 fuel supply and generation adequacy all the way through to the local distribution network. The potential for enhancing reliability through demand-side resources is the focus of the next section.

B. The Untapped Potential of Efficiency and Load Management – How Large is the Reservoir?

In setting out the first of five specific goals, the recently-released National Energy Policy states:

> "Americans share the goal of energy conservation. The best way of meeting this goal is to increase energy efficiency by applying new technology -- raising productivity, reducing waste, and trimming costs...America has made impressive gains in energy efficiency...We must build on this progress and strengthen America's commitment to energy efficiency and conservation."[52]

This recent statement echoes the conclusions of the nation's utility regulators. In a Resolution formally adopted in 1999, NARUC found that

> "Energy efficiency and load management programs are proven, cost-effective means of managing load and enhancing reliability by matching electricity demand with the system's generation, transmission, and distribution capacity constraints...."
>
> and urged state regulators, power pools, and Congress to

52. National Energy Policy (Report of the National Energy Policy Development Group, May 2001) at p. xi.

> "encourage and support programs for cost-effective energy efficiency and load management investments as both a short-term and long-term strategy for enhancing the reliability of the nation's electric system..."[53]

The challenge is clear, but the question still remains: how large is the reservoir of cost-effective efficie opportunities? How high should be set our sights? Over the past two decades, there have been numerous studies, experiments, and programs aimed at improving the efficiency of electricity use in the United States. The central lesson of these studies and initiatives is that very large reservoirs of low-cost energy and capacity resources on the customer side of the electric meter are still untapped today. **A careful review of past programs and current market data supports a conclusion that a large fraction -- as much as 40 to 50 percent-- of the nation's anticipated load growth over the next two decades could be displaced through energy efficiency, pricing reforms, and load management programs.** This conclusion is based upon a number of leading indicators:

1. Utility DSM Experience

First, the nation's experience with utility-sponsored DSM strongly suggests that concerted efforts to capture customer-side resources can succeed. By 1996, DSM programs at over 500 utilities had lowered peak demand by 29,000 MW, and were saving customers more than 61 billion kWh annually.[54] Even in a period of start-up and experimentation, utility DSM programs were relatively inexpensive, with utility program costs averaging between 2 and 3 cents per kWh saved.[55] By 1995, when EPAct and utility restructuring initiatives began to undermine support for utility DSM programs, DSM savings were growing at the rate of 18 percent annually. Based upon a compilation of utility filing EIA expected these double-digit savings growth rates to continue.[56] Leading utilities, those with the greatest DSM program experience, reported in many states that by the year 2000, their programs could lower peak demand by 10 to 14 percent.[57]

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53. National Association of Regulatory Utility Commissioners, *Resolution Supporting Energy Efficiency and Load Management As Cost-Effective Approaches to Reliability Concerns* (Adopted July 23, 1999). The full text of the Resolution is contained in the Appendix.

54. To put these figures in perspective, the capacity savings exceeded the total peak demand of the six New England states, while the energy savings were equal to the annual consumption of 6.2 million average homes.

55. Fickett, Gellings, and Lovins, "Efficient Use of Electricity," *Scientific American* (1990).

56. In 1993, utility estimates compiled by EIA projected peak load reductions of 55,000 MW by 1998. Due to program cutbacks later in the decade, savings peaked at 29,000 MW, and then fell to 25,000 MW.

57. As early as 1988, utility projections of the peak-reduction benefits of DSM averaged 3% nationwide. U.S. DOE, *Electric Supplies for the 1990's: Growing Reliance on Demand Management and Third-Party Suppliers*, (1988) at ES-3. After gaining experience with more active DSM programs, leading utilities saw much greater potential for demand reductions. For example, the following utilities projected double-digit capacity savings by the year 2000: Boston Edison (10.5%); ConEd (13.8%); PG&E (10.9%); Northern States Power (17.0%).

The overall national experience is reinforced by the progress of efficiency and load management programs in individual states that made a continuing commitment to DSM. For example, between 1980 and 1999, California's efficiency programs avoided 4,400 MW of demand; this is equal to nearly 10% of the state's 1999 peak, and a very large fraction of the state's overall demand growth in those two decades.[58] New York's experience is also instructive. Between 1990 and 1996, efficiency programs in New York saved 5.7 billion kWh, and avoided 1,374 MW of generating capacity, also a large proportion of total load growth in the state in those years.

2. Non-Utility Studies

The extent of the efficiency and load-management reservoirs has also been the subject of concentrated, thorough assessments by a number of non-utility experts:

- The leading governmental assessment is the well-known "Five Labs Study," prepared by the US Department of Energy's five National Energy Laboratories in 1997.[59] That study found that cost-effective energy efficiency investments could displace 15% to 16% of the nation's *total* electrical consumption by the year 2010.

- This was not the first time that the U.S. DOE had recognized the potential of customer-side resources. In its *National Energy Strategy,* the (first) Bush Administration concluded that widespread adoption of efficiency and load management measures through IRP could lower demand by about 7%, avoiding 45,000 MW of generating capacity by 2010, and 90,000 MW by 2030.[60]

- The magnitude of the efficiency resource potential is also indicated by the magnitude of the savings projected for particular end-use technologies by the DOE when setting appliance efficiency standards, and by the EPA in its Energy Star programs.

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58. By early in the year 2000, the net financial benefits of these programs were projected to exceed $2.7 billion. In view of the high prices and reliability crises seen in California in 2000 and 2001, the actual benefits are undoubtedly very much higher.

59. Interlaboratory Working Group, *Scenarios of U.S. Carbon Reductions: Potential Impacts of Energy Technologies by 2010 and Beyond* (September 1997), at pages 3.11 and 4.9. The five National Labs involved were: Oak Ridge National Laboratory, Lawrence Berkeley National Laboratory, Pacific Northwest National Laboratory, Argonne National Laboratory, and National Renewable Energy Laboratory.

60. U.S. DOE, *National Energy Strategy, First Edition 1991/1992* (February 1991) at 36. The Strategy also found that these reductions would save money: "The net economic benefit is estimated to be about $35 billion for the 1990-2030 period." Ibid.

- The Electric Power Research Institute concluded in 1990 that the nation's low-cost energy efficiency potential was at least 15% of total electric demand.[61]

- More recently, the American Council for an Energy-Efficient Economy (ACEEE) concluded that low-cost efficiency programs could displace approximately 64,000 MW of generation capacity within a decade nationwide, by focusing on just four key areas of opportunity[62]: Improving installation and maintenance of residential air conditioners (40,000 MW savings)[63]; Commissioning existing commercial buildings (20,000 MW savings)[64]; Higher efficiency standards for air conditioning (30,000 MW savings)[65]; and Efficient commercial lighting system (up to 20,000 MW savings).[66] ACEEE concludes that these four programs alone could meet approximately half of the total load growth now projected for the nation over the next 15 to 20 years.

3. Potential for Price-Responsive Peak Reductions by Customers

Utility DSM programs have traditionally pursued peak load management as well as overall energy efficiency gains, and load-management programs historically accounted for about half of the overall capacity savings attributed to utility DSM efforts. As electricity markets evolve, it is essential to assess the potential for customer-managed load as a resource to lower system peak loads and improve reliability.

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61. Fickett, Gellings and Lovins, "Efficient Use of Electricity" *Scientific American*, (1990). A contemporaneous study for EPRI by Barakat and Chamberlain put the technical potential as high as 40%, but recognized that much of this would be too expensive to secure.

62. Nadel, et al, *Using Targeted Energy Efficiency Programs to Reduce Peak Electrical Demand and Address Electric System Reliability Problems*, ACEEE, Washington, DC (2000).

63. Correcting routine problems could reduce air conditioning peak demand by 14 percent in existing homes, and 25 percent in new construction. Neme, Proctor, and Nadel, *Energy Savings Potential from Addressing Residential Air Conditioner and Heat Pump Installation Problems*, ACEEE, Washington, DC (1999).

64. "Commissioning" is the process of carefully examining the energy needs of buildings as they have changed over time, adjusting HVAC and other systems in line with those changes, and tuning up those systems to make them more efficient. A recent pilot project in Chicago by Commonwealth Edison suggests the magnitude of the potential savings from these efforts. Commissioning just eleven buildings, Edison reduced peak demand by 2 MW, with annual energy savings of more than 6 million kWh, and bill savings of nearly half a million dollars. See Kessler, Hill, Philbrick and Malek, "Maintenance, Operations and Repairs (MORES) - A Utility Recommissioning Program" in *Conference Proceedings 7th National Conference on Building Commissioning*, Portland Energy Conservation, Inc., Portland OR (1999).

65. US DOE is in the process of setting new efficiency standards for air conditioning, which could boost efficiency by 20 to 30 percent in residential units, and 10 to 20 percent for small commercial systems. These standards could eliminate the need for approximately 26,000 MW of peak generating capacity by 2010, and more than twice that by 2020. Appliance Standards Awareness Project, *Opportunity Knocks: Capturing Pollution Reductions and Consumer Savings from Updated Appliance Efficiency Standards,* ACEEE, Washington, DC (2000).

66. Lighting accounts for about 25 percent of summer peak demand in the commercial sector, and lighting energy use in most buildings can routinely be cut 30 to 50 percent through a combination of improved technology, automatic controls, and better lighting design. Lighten the Load, *Opportunities to Lighten Utility Load with Money Saving Energy Efficiency Investments,* Environmental Media Services, Washington, DC (2000).

How large is the responsive load reservoir? The savings levels attributed to historic load-management programs cannot simply be assumed to continue in new energy markets. On the down side, it appears that many industrial and commercial customers were willing historically to enroll in rate discount programs on the understanding that they would in fact rarely be interrupted. On the other hand, market studies and a number of pilot programs suggest that many customers would willingly reduce 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 toc early to know for certain how deep that response would be under different market rules and prices. However, analysts reasonably conclude that the potential is quite significant when compared to the level of response needed to moderate price spikes and meet reliability concerns.[67] Some leading indicators:

- Georgia Power, which operates the largest dynamic pricing program in the nation, gives us a good idea of the load-response potential. About 1600 of Georgia Power's large industrial and commercial customers, representing about 5000 MW of load, are enrolled in an hourly pricing program. These customers historically reduced their loads by a total of about 500 MW when prices reached $500/MWh or higher. In August 1999, when prices spiked at more than $1000/MWh, customer response reached 800 MW, which was about a 20 percent load reduction at that time[68].

- A customer market study by E-Source yields similar estimates. After interviews with energy managers of more than 100 large companies, this study found that while most of the load of mos 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 load could be managed in response to short-term price signals.[69]

- A 1995 study by Science Applications International Corp. reached much the same conclusion, finding that about 17% of customer load was typically discretionary, and could respond to price signals in short-term power markets[70].

4. How Large Does the Customer Response Need to Be?

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67. An excellent review is Hirst and Kirby, *Retail-Load Participation in Competitive Wholesale Electricity Markets*, prepared for the Edison Electric Institute and the Project for Sustainable FERC Energy Policy (January 2001).

68. S. Braithwait and M. O'Sheasy, "Customer Response to Market Prices -- How Much Can You Get When You Need It Most?" EPRI International Energy Pricing Conference 2000, Washington, DC, July 2000.

69. Adam Capage, et al "The Dawning of Market-Based Load Management," ER 99-18 (November 1999).

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

Importantly, a fairly modest load response to price can have very large effects on both reliability and price in constrained power markets. As Hirst and Kirby conclude, "when supplies are tight, small changes in the amount of power demanded can have dramatic effects on market-clearing prices."[71]

- A 1999 study by the Electric Power Research Institute, 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 percent.[72] Robert Levin, Vice-President of the New York Mercantile Exchange, was even more optimistic, testifying before Congress that "a 5 percent reduction in demand during the peak prices in the Midwest in 1998 could have dropped some of these prices 80 or 90 percent."[73]

- EPRI reached a similar conclusion after 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 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.

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71. Hirst and Kirby, supra, at p. 6.

72. Renee Guild, "EPRI's Response to Reliability Problems" presented at NARUC, November 8, 1999.

73. Hearing Before the Subcommittee on Energy and Power of the Committee on Commerce, House of Representatives (July 15, 1998), serial no. 105-115, p.45.

IV. WHY DON'T ELECTRICITY MARKETS SUPPORT EFFICIENCY AND LOAD MANAGEMENT? MARKET FLAWS AND MARKET BARRIERS IN TODAY'S POWER MARKETS

A. Historic Barriers to Energy Efficiency Remain

As utility regulators and demand-side professionals have long been aware, cost-effective energy efficiency investments are often untapped in the U.S. economy due to a number of market imperfection: and market barriers faced by individual customers.[74] Even in the fluid and price-responsive electricity markets envisioned by restructuring advocates, most of the well-known and widely-documented barriers to energy efficiency investments will remain. Those problems include:

- the gap between the private and social discount rates for efficiency investments;
- lack of customer information about efficiency technologies and costs;
- transaction costs for delivering and installing many small efficiency improvements;
- first-cost problems and the customer's limited access to capital;
- builder/buyer, landlord/tenant, and other split-incentive problems;
- environmental costs not included in the cost of power; and
- masking of real-time costs through customer aggregation, average billing, and regulated rate plans.

Utility DSM programs and energy efficiency standards have been designed to overcome those barriers, and have demonstrated their utility in doing so. To appreciate the contribution that demand-side options can make to improving reliability, it is critical to understand that the nation's current, halting transition t electric competition has not resolved those market barriers. Individual customers still face those barrie and the reliability of the electric system is being eroded as a consequence.

B. The New Efficiency Vacuum: How Efficiency Harms Utility Profits

For more than a decade, advocates of utility-sponsored efficiency programs have understood that historic rate-making practices created a strong disincentive for franchise utilities to invest in energy efficiency programs, even when they would be beneficial for customers.[75] Utility regulators created bot IRP mandates and lost-revenue adjustment mechanisms to resolve this problem.

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74. A large body of theoretical and empirical literature, and numerous orders by public utility commissions have documented these barriers; it is not our intention to restate these conclusions here. The essential point is that the barriers remain, while utility DSM programs have been reduced, and as a consequence the efficiency of the nation's electric system is compromised.

75. David Moskovitz, "Profits and Progress Through Least Cost Planning," National Association of Regulatory Utility Commissioners (1990).

The happy conjunction of responsibility and incentive that existed under many state IRP regimes has disintegrated with the transition to competition. Even in states that have not restructured, utilities have little incentive to pursue efficiency programs. Concerns about the prospects for competition in the futu about potential stranded costs, and about average rates combine to create powerful disincentives to efficiency programs, which lost-revenue mechanisms do not sufficiently erase. In states that have restructured, under many restructuring plans, the traditional utility responsibility to engage in integrated resource planning and to deliver DSM programs has been lost, while the problem of lost revenue remains. As a consequence, in most states, none of the successor functional elements of the historic utility has the mandate to pursue cost-effective efficiency measures[76]. And none of the entities succeedi the vertically integrated utility has a financial incentive to promote cost-effective energy efficiency for benefit of customers, the environment, or overall grid reliability.

1. Competitive Generation Incentives

In a competitive generation market, generators have no financial incentive to promote either efficiency load management. Base-load and intermediate units benefit from being able to sell all of their output, preferably at high market clearing prices. Peaking units will be profitable only if peak-load conditions obtain many hours of the year, or if peak-load clearing prices are high enough to cover the all-in costs o the unit. [77] In either event, efficiency and load-management measures that lower demand, lower market clearing prices, and mitigate generators' market power, will lower Genco profits.

2. Wires Company Revenues and the Problem of Lost Profits Math

It was a common assumption during restructuring debates in many states that wires companies, once deprived of the generator's natural desire to promote sales, would be able to promote cost-effective efficiency measures that would lower sales and customers' bills. While the assumption is superficially appealing, the opposite is true. Under the rate designs commonly in use, the financial disincentives to lower sales are worse for wires-only distribution or transmission companies than they are for integrated utility franchises.

The central problem with wires-company rate design is the predominant use of sales-based revenue formulas, particularly when per-kWh delivery prices are fixed for a long period of time, as with most wires company price cap plans. Under this method of rate-making, once a wires company's rates are set in a rate case, all changes in sales will directly affect the company's profitability. Since, in the short

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76. A notable exception is California, where the incumbent wires companies still retain responsibility for DSM programs. As noted in Section II above, however, utility spending and performance have dropped significantly since 1994.

77. Some investors and generators have argued that little-used peaking units will not be profitable (and thus, will not be built) without broad support payments or very high peak-load prices ($1200 to $5000 per MWH). Enron Power Marketing, Inc., "Analysis of the Midwestern Electricity Price Spikes of Late June 1998" (September 1998) at p.8.

term (i.e., between rate cases), most wires company costs are fixed, delivery charges from increased sales flow directly to the profits of the firm.

Table 1: Lost Profits Math: Impacts of Efficiency on Utility Profits

		Vertically Integrated Utility	Distribution-Only Utility
(a)	Average Retail Rate/kWh	$0.08	$0.04
(b)	Annual Sales, kWh	1,776,000,000	1,776,000,000
(c)	Annual Revenues, (a) * (b)	$142,080,000	$71,040,000
(d)	Rate Base	$284,000,000	$113,600,000
(e)	Authorized Rate of Return on Equity	11.00%	11.00%
(f)	Debt/Equity Ratio	50.00%	50.00%
(g)	Net income, (d) * (e) * (f)	$15,620,000	$6,248,000
(h)	% Reduction in Sales	5%	5%
(i)	Reduction in kWh Sales, 0.05 * (b)	88,800,000	88,800,000
(j)	Associated Revenue Reduction	$7,104,000	$3,552,000
(k)	Average Power Cost/kWh	$0.04	na
(l)	Power Cost Savings from Reduction in Sales	$3,552,000	na
(m)	Net Revenue Loss after Power Cost Savings	$3,552,000	$3,552,000
(n)	Reduction in Net Income, (m)/(g)	(22.74%)	(56.85%)

Table 1, above illustrates how the profit erosion from energy efficiency is **worse** for a wires-only distribution company than it is for an integrated utility. In this case, the integrated utility with total rates $0.08 per kWh will experience a 23% decrease in profits from a 5% decrease in sales. For the wires-only company, the impact in percentage terms is much worse. For a wires company with a rate of $0.04 per kWh delivered, the same 5% decrease in sales can, between rate cases, drop the return on equity by more than 50%.[78] The disproportionate impact works in the other direction in the event of an increase in throughput. The arithmetic of lost profits helps to explain the decline in utility support for energy efficiency programs in recent years, and should be an important factor in designing new efficien delivery mechanisms.

C. Barriers to Efficiency in Wholesale Power Markets

Efficient prices result from the constant, well-informed interaction of supply and demand in an open marketplace. However, in today's electric power markets, the dynamic interaction between price, supply and demand is indirect at best. As a consequence it is simply not possible in electricity markets the U.S. today to conclude that "the market" is functioning so as to call forth an efficient level of load management and long-term energy efficiency. The failure of electricity markets has been most marked, course, in California and the West in 2000-2001, but the structural flaws noted here exist to a significar degree in all regions of the country.

The fundamental disconnection between cost and price in today's markets has many causes, but its roots lie in the way that historic franchise rate designs have been pushed forward into current electricity markets:

- The regulation of the monopoly franchise was historically based upon average prices, set in rate cases, and revealed to customers in monthly bills long after the hour of consumption. This is stil true for most customers today;

- Although the cost of consumption varies quite significantly over time, very few customers ever saw any resulting rate shifts through interval metering or real-time tariffs; this price-averaging policy continues today, even in markets where the hourly market clearing prices vary by factors of 100 or more;

- Under rate of return regulation, regulators and utilities found that the inefficiencies of inexact pricing could be moderated by rate regulations that required peak power to be sold at cost; by rate designs allocating costs among customer classes; and by utility planning decisions, includin explicit efforts to moderate demand through DSM programs and interruptible contracts. These policies and programs have not been carried forward in restructured markets.

As will be seen in the discussion below, market designs that simply carry franchise-style rates forward t competitive, volatile wholesale markets have stifled the development of cost-effective efficiency and load-management resources, and exacerbated the cost and reliability challenges of fluctuating demand.

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78. While perhaps not immediately apparent, the arithmetic is easily explained. A wires company has a relatively small equity rate base, while the short term profit loss from throughput reductions is relatively large, and not offset by power cost savings. The percentages shown here are illustrative -- percentages will vary with the rate design of each distribution company.

Despite considerable variability in wholesale costs, the price signals sent to retail customers have been muted by price caps and average cost rates. Only the supply-side is represented in any meaningful way in the emerging wholesale markets.

The demand-side of the wholesale market is essentially represented by a largely fixed, or price-insensitive, demand. As markets are developing, there is a gap between the wholesale and retail portions of the marketplace that inhibits the development of retail demand sensitivity. Variations in supply-side costs are simply not reflected in retail price signals.[79] Thus, the information and incentives necessary to stimulate demand-side responsiveness by ultimate consumers are masked.

1. Six Reasons the Demand-Side Lags in Wholesale Market Reforms

What is emerging with the development of wholesale markets is an electricity market with responsive supply resources, but without any significant price sensitivity on the demand-side. In economic terms, revealed demand is still inelastic. There are at least six reasons today's emerging wholesale markets demonstrate inadequate price sensitivity on the demand-side:

(1) Real wholesale costs are not reflected in retail tariffs seen by most customers;
(2) Wholesale energy markets have not built in a demand-side;
(3) Load profiles used to assign wholesale costs to load-serving entities fail to account for the actual costs of service to the LSE's customers;
(4) Demand-side resources are effectively excluded from the wholesale markets for reliability services;
(5) Transmission constraints have not been recognized in the pricing of wholesale energy services.
(6) The markets for innovative metering, reactive load management, and other demand-side services are immature, and will remain uncertain until equitable market rules are established.[80]

Wholesale costs and price levels have long been muted by the traditional system of pricing retail servic in the traditional vertically integrated utility system of regulation. This phenomenon continues in most markets today. Even areas that have or are opening markets have established rate packages that closely resemble the traditional utility service. Standard offer services in areas that have opened retail markets

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79. Even where there are straight pass through mechanisms, such as in San Diego, California, the retail market has not developed enough to respond effectively.

64. Development of advanced, interactive load management is hampered by several factors: RTO and market rules are uncertain; price patterns in new energy markets are not yet settled (quite the opposite!); customer responsiveness is blunted by poor market signals and rate designs; and neither market rules nor regulators offer successful load managers payments that would reflect the full value of their services to the utility system. These problems must be overcome in order to attract the capital and entrepreneurial talent necessary to launch this important new industry.

and the resistence to opening retail competition in other areas have perpetuated this phenomenon in the historical system. There is little relationship between high wholesale costs or prices (and correspondir relationships to system reliability), and retail demand in a given hour or day. Rather, retail prices were and are averaged over the year, the season, or for a specific period within a day.

When considering the overall success and critical challenges facing wholesale power markets in the United States, it would be difficult to overstate the significance of the six limitations listed here.

These structural market flaws are largely responsible for the price spikes and reliability challenges experienced in these markets, and contribute greatly to the market power increasingly exercised by generators. There are, however, realistic and workable solutions to these market design flaws, which, if adopted, could help to ensure more efficient and more reliable energy services. Those solutions are set out briefly in Section V, following.

V. Tapping the Demand-Side Reservoir : A Solution Menu for Decision-Makers

Our nation now has nearly twenty years' experience with utility-sponsored energy efficiency programs, and has been engaged for several years in developing wholesale and retail markets in electricity. These experiences lead to the central conclusion of this report:

Cost-effective efficiency and load management investments 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.

How can these benefits be obtained in today's electricity franchises and markets? While the advantages of demand-side resources are widely recognized, there is no single "silver bullet" mechanism for capturing all of those benefits for electric systems and customers. Rather, the challenge facing decision makers is to examine each market component, and each important market or regulatory rule with the following questions in mind:

Could the function of this market or the purpose of this rule be served at lower cost and/or lower risk through demand-side resources? And if so, how can we organize this market or structure this rule to ensure that high-reliability, low-cost solutions are in fact developed?

Throughout the many markets and franchises operating in the US today there are three major venues for discovering and deploying cost-effective efficiency resources:

> (1) **Wholesale Market Structures**: Wholesale markets should be designed to invite demand-side price responses to bid against supply on the trading floors of new electricity markets, and should permit demand-side resources to compete with transmission and generation investments to meet system needs;
>
> (2) **Rates and Rules for Wires Companies**: Regulators should seek to send accurate price signals to customers and load serving entities, and remove barriers to demand-side resources through reliability rules, rate designs for wires companies, and retail default service standards; and
>
> (3) **System Benefit Programs**: Legislatures and regulators should create funding mechanisms for efficiency and load management investments, recognizing their reliability benefits, as well as the significant market barriers that still block their efficient deployment.

In the sections below, we present brief description of workable mechanisms that meet these objectives. An "Efficient Reliability" program could well employ all of these means.

Efficient Reliability Solution Menu

<u>A. Wholesale Market Features</u>

(1) Demand-Side Bidding:

- **Price-sensitive load reveals a real demand curve**
- **Reform load profiles to support demand management**

(2) Multi-Settlement Markets:

- **Day-ahead financial settlement permits economic resales of load reductions in the spot market**

(3) Open Ancillary Services Markets to Demand-Side Resources:

- **Invite "dispatchable load" to bid into integrated reserves markets**

(4) Efficient Reliability Standard:

- **Demand-side resources should receive equal treatment with supply and transmission options in RTO and power pool initiatives that use uplift and other "socialized" support mechanisms**

<u>B. Rates and Rules for Wires Companies</u>

(5) Transmission-Level Congestion Pricing:

- **Locational pricing reveals the value of distributed resources across constrained interfaces**

(6) Enhancing Reliability Through Retail Rate Design:

- **Reform price caps and default service rates to reveal the value of efficiency and load response at different times and locations**
- **Use revenue caps, not price caps or high fixed charges, for wires company rate designs**

Efficient Reliability Solution Menu (con't)

C. Promoting End-Use Efficiency

(7) System Benefit Funds:

- **Broad-based wires charges can support efficiency and load management, enhance reliability, and lower market prices**
- **Assign efficiency programs to entities with incentives and ability to best succeed -- e.g., the Energy Efficiency Utility**

(8) Poolwide uplift charges and market transformation programs:

- **Widespread use of efficient technology will lower wholesale costs and enhance reliability across franchise and state boundaries**

(9) Complementary policies for efficiency:

- **Codes, standards, tax credits, and financing plans accelerate the use of efficient end-use technologies**

A. Demand-Side Resources in Regional Power Pools and New Electricity Markets

The focus of most decision-makers on supply-side solutions to meet load growth and reliability needs i perhaps a natural product of the manner in which franchises and electricity markets have evolved. Nevertheless, the demand side of these markets represents an enormous reservoir of untapped capacity available both as a moderating influence in the volatile wholesale electricity markets and as a resource i its own right in the markets for reliability services. Tapping these resources requires decision-makers t focus clearly on a simply-stated goal:

Every effort should be made to expose the value of demand response in the wholesale and retail markets to as many participants as possible.

It is becoming clear that a demand response has enormous value to consumers. The problem is that the structure of our markets hides that value from consumers, retail sellers, and innovative entrepreneurs who could develop new demand-side technologies and services. With the value of demand response so well hidden from those who could profit from it, it is no wonder that we see little demand response in these markets today. Regulators need to structure the market and market rules so customers, retail sellers, distribution utilities, and current and potential vendors of demand response have an opportunity to realize the value of the services they can offer[81].

Fortunately, the Federal Energy Regulatory Commission (FERC) has responded to this challenge, observing that "... a successful transition to competitive electricity markets will necessarily involve an increased participation of the demand side of the market in making resource decisions" and that demand-side participation "can serve to discipline prices by bringing supply and demand into balance."[82]

Four policy reforms for accomplishing these purposes are described below.

1. Demand-Side Bidding:
Price-sensitive load reveals a real demand curve

Under traditional franchise regulation, the financial relationship between electric demand and the cost o supply was indirect at best. In particular, the cost of maintaining reliability at peak was rarely reflected i peak period prices. The price signals delivered to both wholesale and retail customers were averaged over time and location, and bore only a general relationship to the cost of production. Supply was managed, not to match marginal cost and marginal "demand" from customers, but to meet the revealed load curve of customers who received only broadly averaged price signals. The "demand curve" in such circumstances was an engineering concept more than the revealed willingness-to-pay of the utility's customers. This is the vertical "assumed" demand curve shown in Figure 7.

81. For a summary of this analysis, see Regulatory Assistance Project, "Using A Demand Response to Stabilize Electric Markets" (February, 2001).

82. FERC Order in NSTAR v. NEPOOL (July 26, 2000).

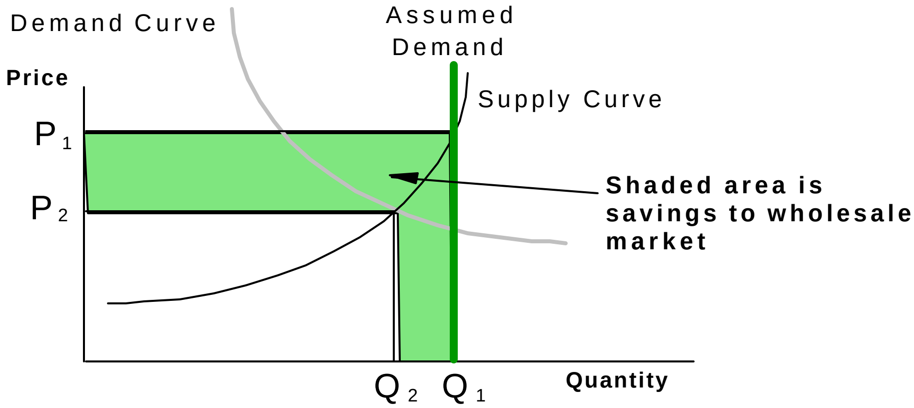

Figure 7: Assumed vs. Actual Demand Curves for Electricity. Revealing the actual demand curve would lower price and peak loads in the market.

Whatever the merits of this muted demand response in the franchise system, it has serious detrimental effects in electricity markets that are established to efficiently balance demand and supply. As recent price spikes, high prices, and reliability challenges of those markets reveal, efficient energy markets simply cannot be built on such a foundation. As noted in Section III, above, there is ample evidence that for many customers, demand for electricity is moderately elastic, and that at the high prices experience in tight market situations, customers with choices will respond by reducing demand, and/or shifting it to hours when prices are lower. Revealing the customers' real demand curve is now a critical challenge for the nation's electric policymakers. As shown in the second curve in Figure 7, markets will clear at lower quantities and lower prices when this curve is exposed[83].

The good news in this connection is that a relatively modest demand response during just a few hours of the year could make a very substantial contribution to lowering peak demand, and thus enhancing reliability -- and lowering overall power costs at the same time. In New England, for example, 9% of the capacity of the generating system is called on just 1% of the hours of the year, and the high cost of

83. This does not require a rate system that charges real-time prices to all customers, a policy that could be both expensive and politically difficult. Substantial progress would be made even if only the largest customers received real-time prices, and if customers and providers were rewarded for *selling back* high-value consumption avoided in peak periods.

power in the most expensive 1% of all hours accounts for 16% of the total annual power costs in the spot market. See Figures 8 and 9 below.

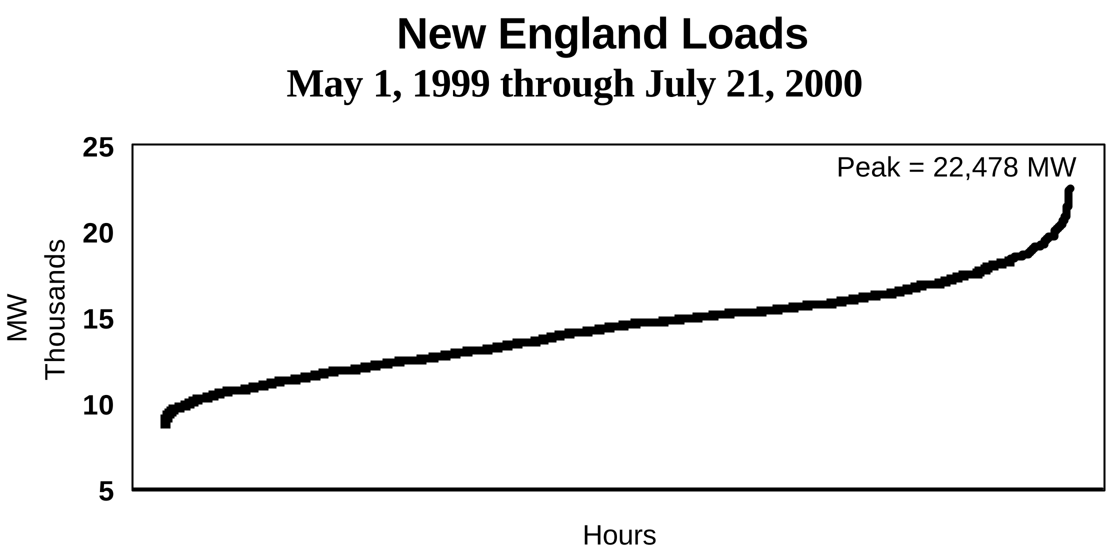

Figure 8: Load Duration In New England

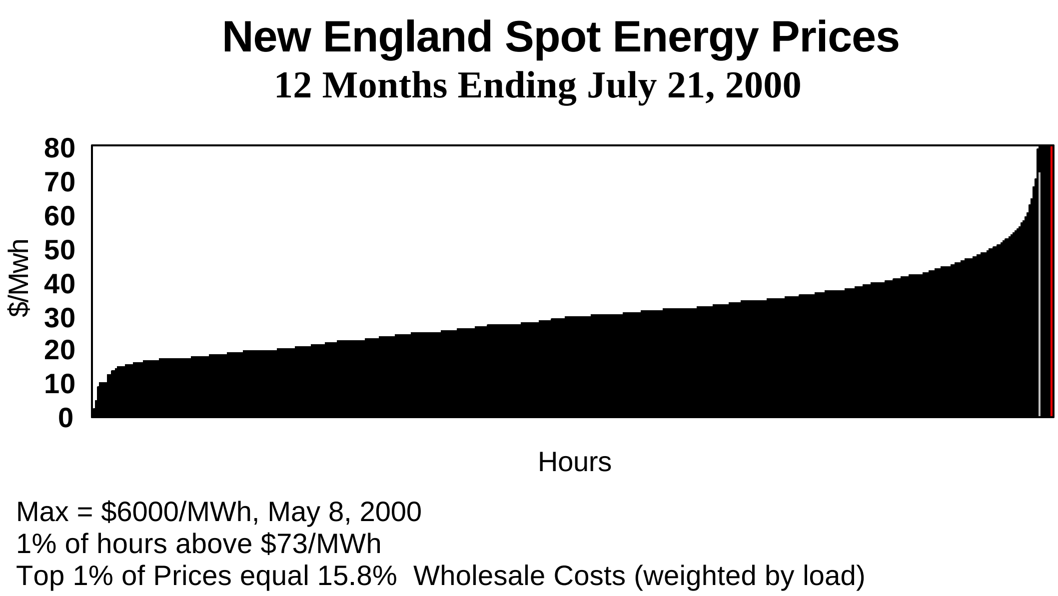

Figure 9: New England Price Duration Curve

Another important feature of electricity markets is that a very small fraction of the customer base accounts for a large fraction of total demand. Nationwide, the 538,000 industrial customers represent just 0.4% of total customers, but 30% of total demand,[84] equivalent to about 200 GW of demand at the time of summer peak. This is true for individual utilities as well; 1% of the customer base might well account for 50% of a utility's load.[85]

For those constructing wholesale electricity markets, the lessons suggested by these data are relatively straightforward: First, as Hirst and Kirby conclude:

> These results show that large benefits can likely be achieved by offering dynamic pricing and related programs to a tiny fraction of the nation's electricity consumers. In other words, your grandmother need not worry about responding to real-time pricing.[86]

Whether large customers bid their load directly into wholesale markets, or whether they are representec by franchise utilities or retail aggregators, bidding rules on the wholesale trading floor must be organize to reveal the customers' demand curve. The first step in this process is to require customers or their load-serving entities (LSE'S) to place binding bids into the market under the same general conditions as generators placing supply-side bids. Bidding rules should permit load to bid at multiple price points, stating how consumption will vary with different market prices.[87] Thus, when the market managers clear the market and set prices, both demand and supply bids will be involved in setting price and quantity in the settlement.

a. Reforming Load Profiles: An Essential Step for Demand-Side Bidding

An essential step in promoting meaningful demand-side bidding is the reform of the system of load profiles used by wholesale markets and wires companies to assign load responsibility among LSE'S. serving customers whose consumption is not measured by interval metering. Since the overwhelming majority of customers are not served by interval metering, the allocation of total sales to an LSE's customers has always been done through the use of load profiles -- assignments of a customer's monthl

84. Edison Electric Institute, *Statistical Yearbook of the Electric Utility Industry, 1999 Edition* (Washington, DC 1999)

85. Hirst and Kirby, *Retail-Customer Participation in Bulk-Power Markets* (Oak Ridge, November 2000) at 30-31. Without naming utilities, the authors give some examples: "We know of one utility with about 500,000 customers, for which the largest 600 customers (all of which have 5-minute interval meters) account for 60% of total load. We know of another utility, for which the largest 15 customers represent 20% of total load." (at 31). The Hirst and Kirby paper provides the reader with an excellent overview of this issue, supported by several useful examples.

86. Ibid.

87. Across narrow price bands, load may be a price-taker, but be willing to curtail consumption at high prices. Bids with different price-points will reveal whether this is the case, and the markets settlements software can recognize their effects when settling the market. For example, current bidding rules in the PJM energy market permit either load or supply to place bids with up to 10 specific price-points set out.

consumption among each hour of the month based upon assumptions of usage patterns among average customers in a particular class.

The widespread use of load profiles has a powerful dampening effect on demand-side responses to varying wholesale prices. Customers who modify their consumption in consideration of high peak-hour costs will never see the benefits of the change in their bills, unless the load profile that assigns their consumption to peak and off-peak hours also changes. Equally important, the LSE that serves such customers will never see the economic benefits of those shifts either. In these circumstances, neither th customer nor the LSE has the necessary incentive to manage load in response to changing market conditions, and the benefits of demand-side bidding are undermined for most customers.

Dealing with the problems created by load profiles requires action by state and federal regulators. Whil it is theoretically possible to require real time meters for all customers, advanced metering systems are still expensive and comprehensive deployment would take years to accomplish[88]. The simplest way to address the problem may be to require the use of multiple load profiles. In the residential class, for example, we know that two most readily controllable loads are water heating and air conditioning. At a minimum, regulators should require creation of alternative load profiles for customers with those loads controlled. With alternative load profiles in place, LSE'S and others would have an incentive not only to search out customers who have these load management opportunities but to actively invest in equipment necessary to move customers from one load profile to another.

2. Multi-Settlement Markets:
Day-ahead financial settlement permits economic resales of load reductions in the spot market

A second needed reform in wholesale markets builds upon demand-side bidding, and extends the potential of demand responsiveness by recognizing the differences between projected market condition and real-time events. Bidding rules should permit customers, generators, and reliability managers to pla consumption and generation decisions in advance. They should also permit additional adjustments to those plans in response to real-time conditions, such as changes in the weather, unplanned outages, changed consumer needs, or unanticipated price changes in the market. This is one of the principal advantages of "two-settlement" or "multi-settlement"[89] systems, discussed below.

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88. There are about 110 million residential electric meters in the U.S.. To date, there is only one large-scale system in place to measure residential consumption on a real-time basis. Puget Sound Energy has deployed 300,000 advanced meters to residential customers, who are billed on a simple peak/off peak tariff that varies the price by 15% above and 15% below the normal average residential rate. The program began in May 2001, so experience is still limited; however, it appears to have modestly affected residential consumption patterns without dramatic changes in prices to customers.

89. The terminology used varies by region. PJM has implemented the system described here, which is called the "Two-Settlements" system. The NE-ISO is developing a similar system, which it terms a "Multi-Settlements System."

In multi-settlement systems the market is “settled,” or cleared, more than once, generally through the following steps:

(1) First, in the “day-ahead” market, bids are taken both for loads and for supply resources.
(2) Using settlement software to rank both demand and supply bids at various price-points, the market manager clears the market at prices and quantities that are physically achievable.
(3) At the time of this first settlement (usually a day ahead), accepted bids are not merely hypothetical – they are firm financial commitments to buy and sell power at the market clearing price. In a financial sense, power is bought and sold in this settlement.
(4) Following the initial settlement, and up to a cut-point in the “day-of” market, buyers and sellers can seek to modify their commitments in a second settlement. Any adjustments made in this settlement are also financially binding.
(5) Discipline is imposed on bidders in these settlements by requirements that generation and purchases conform to the obligations of their bids. Any deviations from the settlements are presumed to be met by purchases from the spot market and are charged to suppliers and customers at spot market rates.

Multi-settlement systems can add both price stability and flexibility to electric power markets as compared with a single, real-time settlement, such as the market used to date in New England. The market for energy services operated by ISO-New England since May, 1999 has depended heavily on a single, after the fact, settlement, determined only after resources have been dispatched.[90] Day-ahead prices are forecast, but with fairly low confidence.[91] What has resulted is a structure in which neither supply nor demand-side resources have much opportunity to plan for and respond to volatile prices. By impairing the ability of demand-side resources to plan for load reductions, and to profit from re-selling demand at times of high prices, single-settlement systems reduce the ability of demand response to supply stability and reliability to the system.

In contrast, multi-settlement systems provide clear price signals to both suppliers and load in advance o physical generation and consumption activity. The first market in multi-settlement markets performs a hedging function for ultimate consumers and suppliers. (In effect, it reduces the exposure of load servi entities or retail customers to unexpected shortages in the real-time markets.) It also has the effect of reducing the potential windfall profits flowing to operating generators from unscheduled outages in oth

90. Peter Cramton and Robert Wilson (Market Design, Inc.), “A Review of ISO New England’s Proposed Market Rules,” Executive Summary at 2.

91. For example, In June of 2000, NE-ISO day-ahead **load** forecasts deviated from actual hourly loads by approximately 3.4% (roughly 440 MW). In contrast, hourly forecasted **prices** deviated from actual settlement prices by approximately 20% (or $8/MWH relative to the $39/MWh price for the month).

units. Used in conjunction with demand-side bidding, multi-settlements can also provide strong incentives to meet the supply resource commitments made in the day-ahead settlement.[92]

92. Properly structured, it reduces the secondary rent or market price premium that will inure to the benefit of other resources in a single market clearing price from actions to reschedule units (or declare a scheduled unit unavailable) in the real-time market. It may also strengthen the effective penalties from such rescheduling. (The unit that is declared out of service must pay the market clearing price for the resource that was no longer available.)

Profitable demand response in a multi-settlement system:

Multi-settlement markets support demand-side responses that can moderate the reliability problems anc price spikes associated with thin operating margins. This occurs in at least two ways. First, if prices clea at very high levels in the day-ahead market, LSE'S and their customers know in advance that it will be in their interest to reduce consumption and sell the released power back into the wholesale market in the "day-of" settlement. The same is true if the day-ahead market clears at normal prices, but prices spike the next day due to hot weather or unplanned outages. Anyone who purchased supply in the day-ahead market now has a clear opportunity to profit by reducing consumption and selling back their power purchases into the spot market.

Importantly, demand-side sale-backs of this type provide a virtually automatic profit incentive to load-side managers to reduce consumption at times of high peak load. And, because those sale-backs are re-sales of power actually purchased in the day-ahead market, in a settlement that satisfied the system's physical constraints, it answers the frequently-raised concern that purchases of demand reductions may merely be paying for reductions in "phantom load." Conversely, an LSE that finds its consumption exceeding its day-ahead purchases in this case will be obliged to pay the high spot prices for the deviation. Thus, LSE'S have an incentive to predict their loads accurately, and to control their loads in times of thin margins and high prices.

Effects on reliability:

As can be seen from the examples above, multi-settlements markets create important opportunities for demand-side as well as supply-side managers to meet the needs of the electric system during times of high prices. Such a system is both financially and physically more stable than a system that attempts to balance the market through ramping up and ramping down supply alone.

Mitigating market power and market "gaming":

Market power monitors have raised concerns that a single settlement approach increases supplier incentives to manipulate markets through the physical or economic withholding of assets (e.g., by declaring units unavailable in the short term market).[93] Well-functioning futures markets (including day-ahead markets) can reduce supplier incentives for gaming of this sort in the real-time market. In multi-settlement systems, units that suddenly become unavailable must purchase supply in the real-time marke to satisfy their output commitments; meanwhile, all other units that were cleared in the day-ahead marke

93. In some electricity markets, there may be a strong incentive for the physical withdrawal of generation resources when reliability is most threatened. For example, in the California and New England markets, only a few firms may set the clearing price when resources are limited (e.g., peak periods). The incentives for such gaming may be very strong in constrained load pockets. The combination of only a few suppliers and a single clearing price may create a strong incentive to withdraw or declare units "unavailable" when such an event can lead to a significant increase in the market clearing price that all producers will receive.

receive only their day-ahead prices, not the temporarily high spot prices. And demand-side resources can enter the market through sale-backs when prices rise, moderating the impact of temporary shortages. Under these conditions, the benefits to suppliers from short-term strategic withholding are greatly reduced.

Conclusion - Multi-settlements:

Effective advance markets can serve to help reduce the financial exposure of load serving entities (and their customers) as well as suppliers, to variations in real-time clearing prices. Forward markets can als help reduce the financial incentives for suppliers to manipulate short-term market clearing prices.[94] Th will also improve the strength and timing of price signals sent to end users to reduce loads when prices are high in real-time markets. Demand-side bidding and the multi-settlement process complement each other in each of these valuable functions. For these reasons, demand-side bidding and multi-settlement markets are important techniques to mitigate the reliability challenges, prices spikes, and market power problems seen in wholesale power markets in the U.S. in recent years.

3. Opening Ancillary Services Markets to Demand-Side Resources: *Invite "dispatchable load" to bid into integrated reserves markets*

As noted at the outset of this paper, electricity is a unique service in that production and consumption must be matched essentially instantaneously. Reliability of the power system is maintained by actively controlling some resources to continuously balance aggregate production and consumption. Historical this control was exercised only over large generators. Loads were most often free to consume electric on their own schedules to meet their needs, while generation, under the control of the system operator, responded to the changing requirements imposed by loads.

However, from the perspective of the system as a whole, controllable load can provide many balancing services just as well as controllable generation. And as wholesale markets evolve to provide competitio among generators, new opportunities can emerge for demand-side resources to participate actively in providing reliability resources to the power markets.

While FERC has recognized that competition will be desirable in setting the market values for different reliability services, those competitive reliability markets tend to be built on the same weak foundation a the market for wholesale generation generally. Because reliability has traditionally been viewed as a resource that, in periods of thinning reserve margins, could only be satisfied by bringing on more suppl resources, the reliability potential of the demand-side has often been overlooked. Resource adequacy

94. Arguably, it may simply shift the incentives for physical withdrawal of resources from the final market to the periods that are used for determining price levels in the advance or hedging markets. Gaming the advance markets, however, will present more modest reliability problems. The advantage of time and financial signals sent by these earlier advance-markets should increase the pool of available resources to meet service needs when the physical resources are needed in the final contingency market.

was considered only a matter or bringing forward robust administrative mechanisms or, in the emerging market world, adequate profit incentives to promote new generation so as to meet system margin requirements.

Individual ancillary services

As a practical matter, ancillary services can be provided by supply-side generation, distributed generation, or customer-side load management arrangements. Table 2 presents 8 ancillary services (reliability services) that end-users or their LSE'S might want to sell[95]. These services are required to maintain bulk power system reliability and are being opened to competitive markets in regions where RTO'S operate[96]. The most important opportunity to provide ancillary services on the demand side has been termed "dispatchable load" -- load that can be interrupted or reduced reliably to balance the system as load and supply conditions change. Thus, interruptible customers and storage devices may best be able to provide Load Following and Supplemental Reserve services. However, they are not likely to provide Reactive Supply and Voltage Control From Generation to the bulk power system. 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, but which cannot be provided by customer-side load management alone.

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95. This list is not exactly the same as FERC's. System Control is not included because DR owners can not sell that service. System Blackstart, Backup Supply and Network stability are included because DR owners might be able to sell these services even if FERC does not explicitly recognize them.

The services also do not exactly match the current NERC Interconnected Operations Services which currently split out Frequency Responsive Reserve. The precise definitions are still in flux though the concepts are well accepted.

96. FERC started this process by requiring the separation of six ancillary services from transmission in its Order 888; the Commission later expanded that process with its Order 2000 on regional transmission organizations (RTO'S).

Table 2: 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 Standard 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

Five of these 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 their response time and response duration, and by the communications and controls between the system operator and the resource needed to provide the service. Figure 10 shows the required response times for these five energy-balancing functions. Because regulation requires continuous (minute to minute) adjustment of real-pow transfers between the resource and the system, loads may not want to provide this service. Load Following, however, could be provided directly or through the use of a spot market price response on a time frame 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, including load management programs.

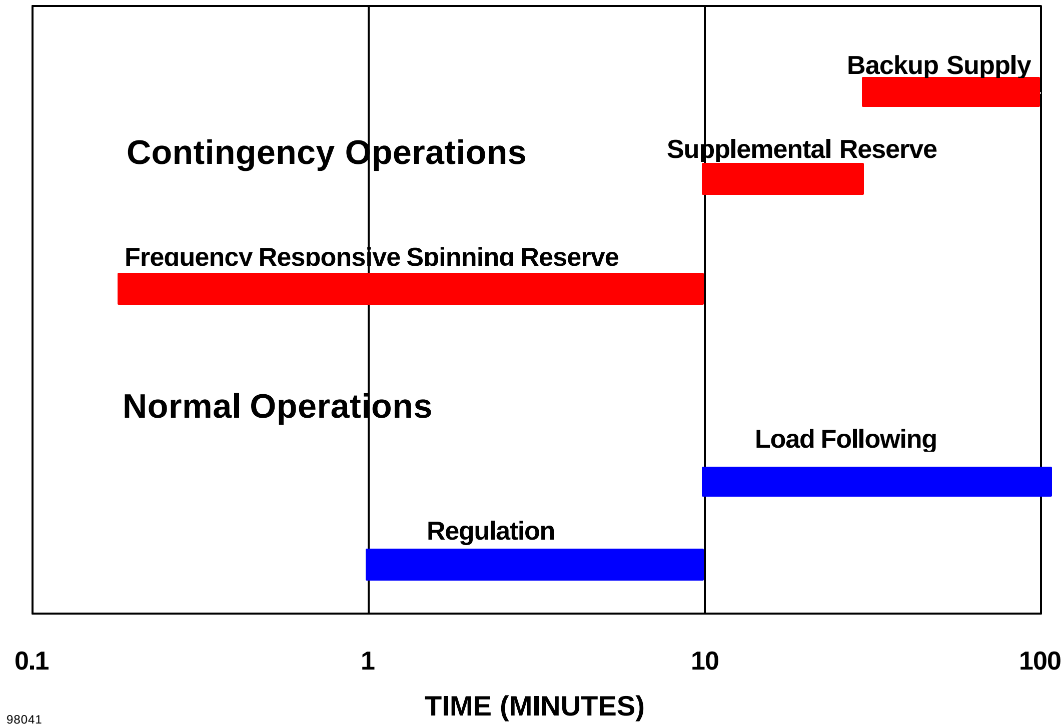

Figure 10: Real-power ancillary services are differentiated by the required response time and duration.

Some important considerations

While the benefits of dispatchable load as a reliability service are conceptually straightforward, it will require careful thought to create market rules that will permit demand-side resources to compete fairly ancillary services markets. To begin with, system operators must articulate the requirements for reliabil services 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, 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.”

In addition, system rules should respect the practical realities of distributed, demand-side resources, an not require the types of communications and controls traditionally used to control central station generators. Those who provide demand-side ancillary services should be permitted to demonstrate the availability and performance of aggregated, distributed resources through reliable statistical means, without the necessity of hooking up each customer to real-time meters and direct links to system contr room operators. It is not necessary to know exactly how each customer site is responding to system requests in order to rely on demand-side resources to help balance the system[97]. Indeed, in some respects, distributed resources may be more reliable than traditional supply-side units.(See Box --

Reliability from Distributed Resources

Whenever 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 100 MW of supplemental operating reserve from a 100 MW fast-start combustion turbine. This turbine might start within the required time on 90% of its attempts. In one case in ten the system operator is 100 MW short. It does the system operator little good to reduce its expectations to 90 MW, though that is the average response.

A collection of 12,500 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 100 MW response each time.

Reliability From Distributed Resources)

Conclusion - Ancillary Services:

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 valuable ancillary services The power system also benefits in several ways. FERC ordered the unbundling of ancillary services from transmission to promote competitive markets, which should improve economic efficiency and lov electricity prices. These markets should be open to any technology capable of providing the service, no just to traditional generators. This will expand supplies and reduce the horizontal market power of generators. Finally, because ancillary services consume generating capacity, providing reserves through demand-side resources also improves overall resource utilization and reduces the excess fuel use and pollution associated with spinning reserves that are not serving load. When loads provide these reserves, generating capacity is freed up to generate electricity.

97. This is not to argue that demand-side resources should be held to lower standards than supply-side providers of ancillary services. For example, 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 load manager selling contingency reserves must have capacity it can make available when the contingency occurs-- in this case by ensuring that there is active load in its portfolio that can actually be curtailed.

4. Efficient Reliability Standard:
Demand-side resources should receive equal treatment with supply and transmission options in RTO and power pool initiatives that use uplift and other "socialized" support mechanisms.

Resource adequacy and system reliability across electric networks are classic public goods, provided to all interconnected users on essentially the same basis. 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 and power market managers often find it necessary to take administrative action to promote reliability. And typically, they seek to recover the costs of these administrative actions in broad-based rates charged to all users of the grid. 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;[98]
- 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;[99]
- Identifying needed transmission links and supporting their construction through broad-based transmission tariffs or other forms of "uplift" assigned to users throughout the pool;[100]
- There are many other variations on this theme.

System operators have traditionally focused on supply-side resources in meeting reliability requirements for electric networks, especially in periods of stress. However, for many system needs, there is a demand-side corollary that could perform that same service at lower cost, provided that market rules were defined to include such resources, and broad-based funding were made available to support them on the same basis as the more traditional solutions.

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98. This has been the practice in New England for many years.

99. For example, in the summers of 1999 and 2000 the New England and California ISO's 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.

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

Energy efficiency, load management, demand-side bidding, and distributed resources are all potentially cost-effective means of meeting reliability needs identified by system operators and power pool managers.

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 decisior making. With the breakup of the franchise, the demise of IRP, and the assumption of new responsibilitie by RTO's and other regional organizations, there are now numerous occasions where broadly-funded interventions may be taken without serious consideration of less expensive and more reliable alternative based on distributed resources and demand-side alternatives.

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

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; and

(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 RTO'S when considering proposed reliability-enhancing rules and investments, it would provide a much-needed discipline in situations where expensive wires and turbines solutions are proposed to address reliability problems, an more robust, less expensive, distributed solutions are overlooked.[101]

101. A standard of this sort has been under discussion in at least one of the nation's ISOs. The Advisory Council to the Board of the New England ISO addressed this issue, concluding that it should be the responsibility of the ISO, as New England's RTO, to analyze feasible alternatives to transmission investments for reliability, and to present them as part of a regional reliability planning process. "The ISO should develop a regional plan for transmission, with updates and modifications as market participants provide market-driven proposals to relieve reliability and economic congestion conditions; this plan should identify high-value energy services and reliability needs that should be addressed, and which could be remedied through either a transmission, generation, distributed-

(continued...)

Opportunities to adopt and apply this principle arise in numerous circumstances. At the legislative level Congress and state legislatures have seen many proposals to amend underlying enabling legislation relating to reliability. Statutory revisions in this arena should adhere to the principle that demand-side ar supply-side reliability options should be treated equally in considering how best to address reliability needs. (See Box, Adding Balance to Reliability Legislation). FERC should also take the initiative on this point. Numerous state PUC's have long understood that least-cost principles should govern utility decisions to make investment decisions that they plan to recover from ratepayers. Increasingly, those decisions are being made by RTO's, ISO's, Transcos and wholesale power pools, subject to FERC jurisdiction. FERC should require RTO'S to ensure that decisions to socialize reliability improvements have been disciplined by a hard look at traditional, distributed, and demand-side alternatives.

101. (...continued)
generation, or demand reduction approach."

In addition, the Advisory Council concluded that the ISO should analyze alternatives to transmission, and make those analyses available in the public decision-making process on socialization proposals: "In situations where the ISO-NE is called upon to analyze transmission proposals whose costs are proposed to be socialized (that is, recovered through a broad-based mechanism paid for by captive ratepayers, as opposed to proposals to recover merchant transmission investments through market mechanisms), the ISO-NE should have a heightened duty to make sure that its analyses consider the impacts of the proposal and a broad array of practical transmission and non-transmission alternatives to it. These analyses should be designed to analyze whether the proposed transmission facility is needed and least-cost."(ISO-NE Advisory Committee, Comments to the ISO – New England Board Regarding the Design of a Regional Transmission Organization for New England, October 11, 2000.)

Adding Balance to 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 th 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; and

(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 distributed resources, energy efficiency, or load management whatsoever in this detailed legislative proposal. This oversight should be corrected in any legislation Congress considers on reliability 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 distributed resources for their economic and reliability benefits. This expanded mission should be part of the mandate of NAERO, FERC, and the nation's RTO'S, ISO'S 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 distributed resources in promoting the reliability the bulk power system. For example, the definition of the bulk power system (quoted above) should be amended by adding: "and (iii) 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.

B. Rates and Rules for Wires Companies

1. Transmission-Level Congestion Pricing:
Locational pricing reveals the value of distributed resources across constrained interfaces

Transmission congestion refers to the situation in which it is not possible to complete all the proposed transactions to move power from one location to another on the grid. Such commercial-transaction restrictions can arise because of thermal, voltage, or stability limits on transmission elements. Congest may occur even when the actual flow on a line is well below the line's capacity, whenever security-constrained dispatch requires modification of the economic dispatch. This situation occurs most frequently as the result of contingency analysis rather than because of steady-state line flows. The generation dispatch is modified because a line *will* overload *if* a specific contingency occurs (e.g., a generator or transmission line trips). Because there is often no time to take corrective action to prevent cascading failures if such a contingency occurs, it is necessary to preemptively modify the generation dispatch. It is this off-economic dispatch that results in locational price differences.

Transmission Resource Constraints are Not Fully Recognized in Wholesale Prices

As wholesale markets have restructured, and as load has grown, transmission congestion has become an increasing problem. The traditional vertically integrated utilities accounted for transmission constraints when they made their daily operating (unit-commitment) plans. Thus, they used their generating resources in ways that would not overload the network. However, in today's increasingly competitive environment, suppliers schedule resources without a detailed knowledge of or interest in transmission constraints.

Transmission constraints impose significant costs on electric systems. However, in most places, those costs have not been reflected in either wholesale or retail prices. They have typically been collected through a system uplift charge assessed on all buyers. This tradition must be changed in order to expose cost-effective solutions to congestion problems. The variability of wholesale costs caused by such constraints needs to first be recognized in wholesale prices. Financial congestion rights can assist transmission planners and potential generators looking for promising locations for new generation sources. Location specific pricing of energy services in the face of such constraints may provide the necessary incentives to LSE's and final consumers to manage loads during periods when transmission lines constrain access to the broader market.

In the long term, construction of new generators and transmission lines, or the addition of load reductio and load management programs, can reduce congestion. In the short term, system operators can treat congestion in three possible way: they can mandate engineering solutions; they can socialize the costs c congestion; or they can use prices to let suppliers and consumers decide where to make investments anc which transactions to forego.

The simplest (engineering) approach is to ignore congestion in setting energy prices (i.e., assume that a proposed transactions can be completed as if the amount of transmission capacity was infinite). If proposed transactions threaten to overload transmission lines, the security coordinator implements NERC's transmission loading relief (TLR) procedure. This procedure adopts an engineering approach to congestion relief. Transactions that contribute 5% or more to the congestion are cut. Many market participants oppose TLR because they believe that the incumbent utilities manipulate the TLR calls and implementation to favor their own transactions. In addition, FERC opposes the current TLR procedure because it is economically inefficient.

An alternative approach is to socialize congestion costs. With this approach, the system operator pays generators on either side of the constraint to increase output (constrained on) or decrease output (constrained off) to relieve the congestion. The system operator pays these generators for any opportunity or out-of-pocket costs associated with this uneconomic dispatch. The costs so incurred are then allocated to all transmission customers through an uplift charge. Although simple to implement, th approach is economically inefficient because it fails to send price signals to transmission users on the t costs associated with their transactions. The absence of location-specific prices also robs investors of important information on where to locate new generators or new demand management programs, and what transmission projects to build.

Finally, a more economically efficient way to deal with congestion is to use locational prices that provi signals to transmission users on the actual costs of transmission service. Because transmission constrai vary with time, and vary from location to location, pricing systems that value access to different transmission paths at different times can be complex.[102] The details of the method chosen in a region ar less important than the basic policy conclusion: locational transmission pricing reveals the costs of congestion, and thus reveals the value of demand-side measures that manage load and provide congestion relief.

Locational Pricing reveals the cost of congestion and the value of congestion relief

The preceding discussion of transmission systems and costs touches on two important features relevant to the role of demand resources: (a) Congestion on the transmission network raises very important reliability problems, not just for the load centers directly affected, but potentially for customers across the entire affected network; and (b) Congestion on the transmission grid is not even across the network, and it varies with time. For these reasons, energy efficiency and load management resources may have great value when they reduce load in the particular locations and at the particular times that congestion problems would otherwise arise..

102. For example, locational prices can be set on a zonal basis (as in California) or on a nodal basis (as in PJM). New York and New England plan to use a mixed system, in which generators will face nodal prices and consumers will face zonal prices.

The application of locational pricing is an important step in the development of competitive electricity markets. When congestion costs are assigned to the responsible load, a more accurate price signal is received within the load pocket. Thus, cost-effective means to reduce congestion will have the opportunity to compete to reduce the congestion and improve reliability.[103] Generation, transmission, and load management options will all have the incentive and the opportunity to offer cheaper solutions t customers and load-serving entities within the load pocket. Because locational pricing sets an appropriate "avoided cost" benchmark, replacing a system in which congestion costs are not revealed to customers, efficiency and load management investments can compete on a fair basis with transmission and generation options to provide reliability services in the load center.

2. Enhancing Reliability Through Retail Rate Design

At least since the passage of PURPA in 1978, utility managers and regulators have been aware of the important relationship between rate design and electric system reliability. Although it is little remarked today, one of the important provisions of PURPA was a requirement that state utility commissions examine the rate designs then in common use, and consider adopting rates that would better reflect the marginal costs of service, and promote load management, energy efficiency, and conservation.[104] A large number of rate design reforms were adopted across the nation, including: moving away from declining block rates for large customers, and moving toward two-part (demand and energy) rates, seasonal rates, time-of-use rates, rate discounts for controlled load, and interruptible rates.[105] These initiatives were aimed at sending better price signals to customers for at least three reasons:

(a) to better reflect the marginal cost of consumption in rates faced by consumers;
(b) to allocate more fairly the costs of the system among consumers; and
(c) to improve reliability and lower overall system costs by removing inefficient subsidies and inspiring changes in demand patterns due to those more accurate price signals.

The nation's recent focus on creating electricity markets has drawn attention away from the underlying fact that **rate design is still a critical function of regulation – almost all electricity is *delivered* on monopoly wires systems under regulated delivery charges; and the vast majority of *energy sales* are still made at regulated rates by regulated franchises or default service providers**.[106]

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103. Particularly if the Efficient Reliability Standard (discussed above) is applied to proposals that would socialize congestion relief and mute the signals sent by locational pricing. Locational pricing and the Efficient Reliability Standard work together to advance the most reliable and lowest cost solutions to congestion problems.

104. PURPA Sections 111 to 117, codified at 16 USC Sections 2601 et seq.

105. An EPRI survey in 1990-91 reviewed more than 1,000 "innovative rates" of these types, offered by 135 major utilities. EPRI, *Survey of Innovative Rates, 1991* (Palo Alto, April 1992) (In three volumes).

106. As of June, 2000 about 98% of the national load is still provided by incumbent franchises. XENERGY estimate, as reported in Restructuring Today, Monday, June 26, 3000 at 3.

Utility experience with cost-based and forward-looking rate design over the course of two decades demonstrated that the rate designs applied by wires companies and franchise service providers can have powerful effects on the reliability of electric systems. That hard-earned experience is now largely overlooked in the political debates surrounding restructuring. In part this is based on the misleading assumption that market prices would directly deliver the efficient pricing signals for which rate design was only a proxy. As it has worked out, this assumption is not even close to current reality. The reality is that over the past few years, fixed-price rate caps for utility service have become the predominant pricing option seen by customers both in traditional franchise states and in states moving to retail competition. This should lead regulators and reliability managers to the following conclusions.

Administrative and legislative rate designs for power prices and wires services should be re-examined for their effects on consumption, peak demand, and reliability, considering today's market conditions and power system technologies.[107] In particular:

- Rate caps for power sales should be modified to add meaningful incentives to customers to improve reliability through distributed generation and energy management operations; and
- Wires company rates should not be based on per-unit price caps, which promote throughput and impair reliability, but should ensure adequate support for the wires company through performance-based plans that reward efficiency in operations.

These two recommendations are addressed below.

a. Reforming Traditional Rate Caps and Default Service Rates

The theory advanced by market advocates in restructuring debates was deceptively simple: Competitive wholesale markets would reveal the true cost of electricity every hour of the year. Customers would see these transparent prices and would efficiently increase or decrease their consumption in response to changing prices. So much for the theory. In practice, hardly any customers have the metering needed to take advantage of real-time prices. Moreover, most states have adopted default service plans to protect customers from rate increases and rate volatility, which ensure that customers ***will not*** see variable prices as they occur in the wholesale market.[108]

The widespread adoption of low, fixed-price rate caps in default service plans has suppressed demand-side responses to wholesale market conditions in at least three ways.

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107. PURPA required each state regulatory body to examine its rate design practices within two years, and to re-examine them annually for a period of ten years. PURPA section 116(a). In view of today's rapidly-changing markets and technologies, and the nation's widespread reliability and market power challenges, it would be sensible to take a new hard look at rate design options for load management, efficiency, and reliability purposes.

108. California is the leading example. End-use customers protected by rate caps received no price signal at all from rapidly changing, volatile wholesale markets. The resulting disconnection between wholesale markets and retail rates was a major contributor to California's problems in 2000-2001: volatile wholesale markets, reliability threats, and generally elevated wholesale market prices.

- First, the price cap blinds individual customers to what is really going on in the wholesale markets, and thus blunts any short-term demand responses that would moderate wholesale price volatility;

- Second, low default service rates poison the market for creative load management. By artificially creating a "safe harbor" for customers, the default service price cap inspires the vast majority of customers to ignore potential choices in the market and to rely on the default service provider -- usually the incumbent utility. It becomes virtually impossible for innovative LSE'S or load aggregators to enter the market and profitably aggregate and manage customer load to the benefit of the overall power market;

- Third, unless very carefully designed, default service price caps will override or undermine the benefits of seasonal rates, time-of-use rates, credits for controlled loads, and other rate mechanisms previously used by utilities to manage load and account for the costs of peakload power. The system may end up with *less* load response under default service plans than it had under traditional regulation.

To reverse these effects, rate caps for power sales should be modified to add meaningful incentives to customers to improve reliability through distributed generation, energy efficiency, and load managemen

The problem exists both in traditional regulation and in retail competition

This observation applies just as well in states that are definitely moving to retail competition, in those th just thinking about it, and in those where retail competition is not being considered at all. Retail choice still not available in most states.[109] Of those states that have moved to retail choice, meaningful progre has been slow and most have made provision for a transition service or "standard offer" that resembles the former bundled and averaged retail rate. In the 27 or more states that have moved to open their markets, the standard offer is typically discounted through regulatory and accounting mechanisms in a manner that limits competition, at least in its early stages.[110] Current estimates are that only 2% of the national load has switched from the incumbent utilities.[111] The opening of retail markets will encourage

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109. As of May 2000, the U.S. DOE's Energy Information Administration reported that 25 states had passed restructuring legislation and that two states, Michigan and New York, were proceeding under comprehensive regulatory orders. Most states, however, are still in either the planning stages, pilot stages, or have only partially opened up their utility service territories. During 2001, in response to the California crisis, the pace of change in several states slowed down, leaving customers even more exposed to administratively set rates.

110. See Regulatory Assistance Project, "Setting Rates for Default Service: The Basics," *(*January 1999).

111. Based on estimates by XENERGY as reported in *Restructuring Today*, Monday, June 26, 2000 at 3.

price-responsive behavior on the demand side only if rate design permits wholesale market price signals to reach retail consumers.[112]

It is not the opening of the markets that is central here, but rather the pricing and service options that are presented to consumers, whether through traditional forms of electricity price regulation, through defa service plans, or through innovations that follow the opening and development of healthy retail markets. On the one hand, price innovation to support reliability can be encouraged within traditional regulation. And at the same time, the movement to retail competition will impair reliability unless customers receiv meaningful incentives to modify demand at peakload periods. Even where wholesale markets are regional, and regulated by FERC, this is a critical matter for state regulation. The rate designs and requirements imposed at the state level will determine how those wholesale market prices are delivered to retail customers.

Solutions to consider

Consumer and low-income advocates rightly point out that price caps and default service plans are important mechanisms to protect small consumers from utility company mismanagement (under traditional regulation) and from unpredictable and volatile wholesale markets (under retail competition) And it is hard to avoid the observation that most customers appear to prefer known, stable prices to flexible price plans, even where stable prices are somewhat more expensive. Thus, it is unlikely that the dream of market purists – changing wholesale market prices delivered directly to end-use customers every hour of the day – will ever attract a large following among end-users. It is certainly unlikely to attract political support.

But there are several other options that could significantly improve customer price-responsiveness. Utilities and state regulators in any jurisdiction facing reliability concerns should quickly examine the following:[113]

112. In California in 2000-2001, customer response to sharp price increases was initially weak. However, as the power crisis became more severe, and high prices continued, significant demand reductions began to occur. Political responses, on the other hand, were powerful and clear from the beginning. Meaningful end user response will most likely emerge first from larger customer loads, especially those with flexibility provided through alternative fuels or self generation capabilities. Advances in metering, telephony, smart appliances and end-user applications may also play a role over time.

113. This is by no means an exhaustive list. Many other innovations in rate design ought to be considered in the proceedings recommended above. Some of these innovations are relatively new, such as net metering; others have long been used, but may need revival and adjustment in light of current technologies and changes in market structure. For example, regulators in Vermont are moving away from seasonal rates, which have had a very large and beneficial effect on capacity factor and peak load exposure for the state's utilities over two decades. The move is based upon changes in the regional wholesale market, where winter power costs have moderated. But seasonal rates have not been replaced by any new rate design to reflect the newly-volatile, high costs of consumption in the wholesale market at peak periods, both summer and winter.

- **Time-differentiated default rates and price caps**: Customers may prefer rate stability to free-wheeling volatility, but they do not require a single rate for every hour of the year.[114] Considering the enormous costs and reliability concerns associated with seasonal peaks, any annual price caps adopted as part of a restructuring plan or utility rate freeze should include meaningful differences between peak and off-peak consumption. On an average annual basis, "the default price" might well be the same, but reliability will be improved when consumers see the cost of maintaining peak in the rates they pay during peak periods.

- **Deaveraged buy-back rates**: Despite the appearance that distribution costs do not vary directly with usage, in fact they do – particularly when viewed in the longer run or when demand presses up against the limits of capacity. At times of capacity constraint, the marginal costs of delivery rise very steeply – they are, in fact, the costs of new investment in wires, transformers, and substations. Moreover, as with transmission, the marginal costs of distribution can vary significantly by time and location.

  Where the marginal costs of distribution are high, the utility has a strong incentive to invest in le costly means of providing service: end-use efficiency, distributed generation, and load management, for instance. This is particularly true where, as in most areas, the retail rates for distribution service are averaged, and marginal on-peak costs exceed marginal revenues. In such circumstances, utilities have a strong profit motive to reduce costs. Customers, in contrast do not. They are not being given price signals that reflect the full marginal costs of service, at least at times of peak, and consequently their incentives to invest in load reduction, load management, and other distributed resources are muted. And, if they are paying fixed fees for distribution, the incentives are non-existent altogether.

  One response is to de-average distribution prices, according to location, charging low distribution rates to customers on circuits with low marginal costs, and much higher rates to customers served by expensive and overloaded substations and feeders. This policy might be efficient, but does not satisfy widely-held notions of equity and universal service.[115] Assuming that the geographic de-averaging of wires company rates is not possible, alternative approaches for promoting economically efficient outcomes must be developed. One such approach is the geographically de-averaged "buy-back" credit. The utility would establish financial credits for distributed resources, including efficiency and load management resources, installed in a given area. The credit amount would be a function of the distribution cost savings generated by the distributed resources. It would be highest in areas of greatest need and would be as low as

114. Seasonal rates and time-of-use rates have long been a feature in many jurisdictions, but their usefulness in controlling peak load has been eroded by inattention and the assumption that market prices would soon take over.

115. To the economist, differentiating prices according to geographic cost characteristics is no different than doing so according to time of use. However, in light of the potentially very great differences in rates from area to area, the administrative complexity of the rate structure, and universal service considerations, we are unlikely to see geographically de-averaged rates any time soon.

zero in low-cost areas, and could be set to share the system savings between the customer and the distribution utility.[116] For example, customers in an area with 20¢ distribution costs might b offered a 15¢ credit.[117] This would certainly produce a strong economic incentive for customers and others to invest in distributed resources.

b. Revenue Caps, Not Price Caps or Fixed Charges, for Wires Companies:

At first blush, the rate design for wires company services would not appear to raise significant reliabilit concerns. But it does. In a price caps environment, the "lost profits" problem will continue to undermin broad-based energy efficiency improvements in end-uses throughout the grid. This will raise overall consumption levels, erode reserve margins, and put increased stress on distribution and transmission systems. A system of high, fixed charges, as proposed by many utilities today, appears to address this problem, but it causes problems of its own. In this case, the wires company no longer has an incentive to promote high throughput. But, having paid a high fixed charge for access, the customer faces a much lower rate for incremental consumption. Since incremental consumption drives peak, high peak load prices, and reliability problems, high fixed customer charges can promote inefficient consumption and degrade reliability.

The solution to both of these problems is a **performance-based, per-customer revenue cap.**[118] It rewards a firm for increases in operating efficiency, while making it indifferent to the volume of throughput over its wires. Since, in the short run, a distribution company's costs vary more closely with the number of customers it serves than with throughput, a per-customer revenue cap would produce annual revenues that more closely track annual costs. To the utility, a per-customer revenue cap looks just like a fixed-price rate structure, and it removes the company's disincentive to support customer installations of efficiency and other distributed resources. However, the revenue cap enables prices for end-users to be set on a usage basis, enabling them to make consumption decisions and alternative energy investments that are, in the longer term, more efficient. In addition, if the per-customer revenue cap is modified by performance objectives, the resulting PBR plan can adjust rate levels automatically to encourage the utility to pursue cost-effective distributed resource options, and lower the overall cost of the

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116. Variations of the de-averaged distribution credits could be a sliding scale standby rate or a hook-up "feebate." For example, stand-by rates could be on a sliding scale ranging from high to negative. Negative stand-by rates, which look like distribution credits to customers, would be charged in high-cost areas. A hook-up feebate would be a revenue-neutral charge that collects from customers installing distributed resources in low-cost zones and pays to customers who install distributed resources in high-cost zones.

117. Demand-side resources are so much less costly that the winning bid prices would likely be far below 15¢.

118. See David Moskovitz, *Profits and Progress Through Distributed Resources*, NARUC, 2000 pp.16-18, 20-22, and Frederick Weston, *Charging for Distribution Utility Services: Issues in Rate Design*, NARUC 2000.

distribution system. The resulting savings can be shared between the company and its customers.[119]

C. Promoting End-Use Efficiency

Decision-makers addressing the reliability problems of emerging wholesale power markets may find, because they are focusing on the problems of peak load, that they are drawn particularly to load management solutions. Demand-side bidding, price-responsive load, and “dispatchable load” ancillary services are very important resources to electricity systems and to reliability managers. Broad-based energy efficiency options may thus be overlooked, despite their economic and reliability benefits. **A central conclusion of this report is that efficiency, load management, and price-responsive load are complementary and essential components of reliable power systems and efficient electricity markets.**

1. Energy Efficiency’s Multiple Reliability Benefits

Broad-based energy efficiency measures provide multiple reliability benefits to electric systems, even when they are not dispatchable at the discretion of operations managers. Energy efficiency measures:

- Reduce load, wear, and maintenance needs on the entire generation/transmission/distribution chain, even in hours when reliability problems were not anticipated by system managers;
- Reduce demand for generation fuels across both peak and non-peak hours, and thus improve fuel availability generally;[120]
- Reduce environmental emissions from generators, and thus conserve emissions credits to meet load at peak hours;
- Are modular, dispersed, and available in countless locations throughout electric grids, and thus, in a statistical sense are highly reliable in comparison with most generation resources;[121]
- Can reduce loading in strategic locations, and thus moderate transmission congestion and other system reliability problems whenever they might arise; and

119. A rate plan with most of the attributes described here is now in effect for Pacificorp in Oregon, and (before the reliability and financial crises of 2001) was being considered by the major distribution companies in California.

120. As the Western reliability crises of early 2001 illustrate, fuel availability can be a major reliability problem. With adequate storage, as in California, fuel not burned in off-peak hours will be available when it is needed.

121. 1,000 MW of energy efficiency and 1,000 MW of large-scale generation are not equivalent. For example, in early January, 2001, 30% of California’s generating capacity was unavailable because of heavy offshore waves, which threatened to block cooling intake pipes with kelp. On January 17-19, 11,000 MW of generation capacity was out of service for maintenance following heavy service in the previous summer. On those days the state was experiencing Stage III alerts, and 500,000 customers experienced rolling blackouts. Meanwhile, the installed base of efficiency resources was “on” and delivering significant benefits to the network.

- Are automatically dispatched (by customers) coincident with the use of the underlying equipmen or load, and thus are always “on” without any delay, intervention by system operators, or necessity to schedule or purchase the resource.

Economic benefits may be much larger in competitive wholesale markets

Utility DSM programs were always based on the knowledge that efficiency resources can often be acquired at relatively low cost, compared to the costs of generation, transmission, distribution, and reserves required to meet load growth. The benefits of cost-effective efficiency measures have been substantial. Significantly, in today’s electricity markets these benefits may be magnified many times. When deployed in markets subject to wholesale competition, efficiency measures may bring economic benefits greatly out of proportion to their costs.

In most regional electricity markets, investments in energy efficiency (and load management) are not or beneficial to those consumers who use the technologies, they also lower the wholesale market prices paid by ***all*** consumers. In competitive wholesale markets where all power plants receive the market clearing price for each hour of operation (which is how all four spot markets associated with regional ISO’s now operate), the ability to reduce peak demand reduces the power costs paid to every unit running at the time of the peak. This market-wide cost reduction greatly exceeds the savings previously achieved by demand reduction in fully regulated wholesale markets, where the only cost savings from reducing demand were those related to marginal unit(s) used to meet the peak. Suddenly, the value of demand reduction has jumped from the value of the avoidance of the marginal unit, to a system wide multiple of that number.

Massachusetts provides a clear example of this new value. The Massachusetts Department of Energy Resources concluded that the measures installed in their post-restructuring efficiency program lowere the participants’ electricity costs by \$20 million in 1999. The Department also concluded that, by lowering peak demand at high cost periods, the programs provided reliability and power cost savings to all customers, participants and non-participants alike. The benefit in just 13 hours on one high-cost day exceeded \$6 million. See Figure 11 below.

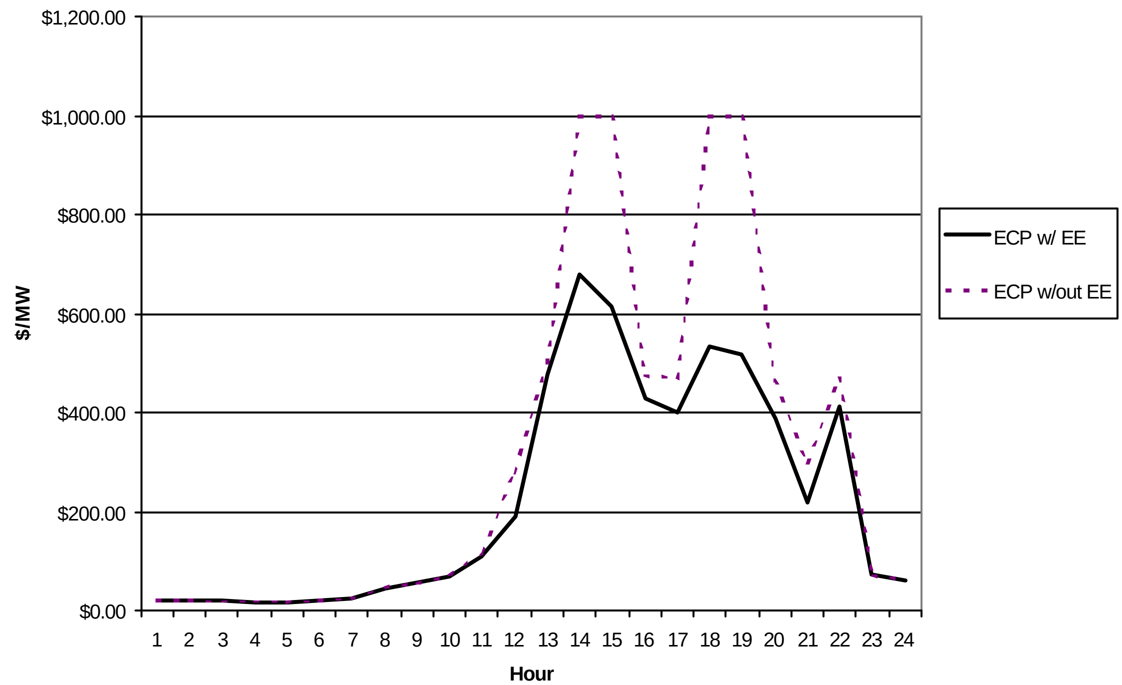

Figure 11: Impact of demand reductions (EE) on wholesale energy clearing prices (ECP) in the New England regional power pool on June 7, 1999

The savings resulting from energy efficiency are obviously very high at peak, but they are also surprisingly high when all other hours of the year are considered. Looking at the price curves in both California and the PJM region over every hour in recent years yields the conclusion that the benefits of energy efficiency investments to customers in the pool generally[122]substantially exceed the private benefits of efficiency to those who install efficiency measures.[123] For example, in the PJM market the value of load reduction was as high as $114 per MWh and averaged $67.67 per MWh (6.7 cents kwh) across all hours.. Enormous amounts of energy efficiency are available at far less than $67.67 per MWh

122. Even those whose consumption remains unchanged (in traditional DSM programs, the "non-participants.")

123. See Rich Ferguson, "The Public Value of Load Reduction in the California Market -- Preliminary Results" CEERT (July, 1999) (finding the public annual savings per MW of baseload reduction to be $650,000, or three times the direct power cost savings to conserving customers), and William Marcus and Greg Ruszovan, "Cost Curve Analysis of the California Power Markets" Testimony in App. 99-03-014, CA PUC (September 2000).

In a similar study done in California for the period June 1998 through May 1999, before the continuous high PX prices of 2000-2001, the savings per average kwh reduction across all hours was 7.51 cents.[124] With a great untapped reservoir of demand reduction available at less than 4 cents per kwh, customers exposed to market prices will be paying a high and unnecessary price when efficiency programs are not pursued in their market regions.

2. Capturing Efficiency Resources: Mechanisms for Today's Markets

As detailed above, broad-based programs to deploy efficiency resources can promote reliability and lower system operating costs. The challenge now is to create the mechanisms needed to deliver broad-based efficiency measures to electric networks. The most obvious opportunity would be to reinvigorate the practice of utility **Integrated Resource Planning**, particularly in those franchises that are not likely to face retail competition in the near-term -- which, for the next decade, may well be more than half of the nation. In those jurisdictions, legislators and regulators should seek to ensure, through careful reviev that utilities are delivering cost-effective demand-side services to their customers. While logical, this n not prove to be the most promising avenue. Many utilities in regions not yet open to competition are anticipating the *possibility* of retail competition in the future, and have been increasingly reluctant to invest heavily in efficiency measures.[125] Fortunately, regulators and legislators have other models to consider.

Among the most promising options:

a. System Benefit Funds: Broad-based wires charges can support efficiency and load management measures that enhance system reliability and lower market prices

In the absence of utility funding of efficiency programs in rates under integrated resource planning, it is possible to support them through broad-based System Benefits Charges (SBCs) – wires charges included in the electric bills of broad classes of customers. Because SBCs are non-bypassable, they apply to all sales, and no competitive provider is disadvantaged by the collection mechanism. At least 1ᐧ states, including California, Wisconsin, Ohio, New York, and Illinois have established statewide funding mechanisms for efficiency programs, supervised by state agencies with a mandate to improve reliability and save energy cost-effectively. Details vary from state to state; revenues for these programs totaled about $750 million per year in 2000 (about 25 percent of what the nation's utilities spent on demand-side management in 1993). Independent funding of efficiency and load-management programs is neede in order to continue the contribution of those measures to system reliability. See Table 3, below.

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124. Ferguson, supra.

125. On the other hand, a utility that invests wisely in efficiency in its home territory may be able to reap the benefits of off-system sales at high prices in wholesale markets, while saving on purchase power costs.

Table 3. Public Benefit Funds by State (mills/kWh)

Total Fund [3]		Energy Efficiency		Low Income		Renewable Energy	
State	mills [4]	State	mills	State	mills	State	mills
New Jersey	3.76	New Jersey	3.15	New Hampshire	1.50	California	0.80
Connecticut	3.75+	Connecticut	3.00	Wisconsin	1.30	Connecticut	0.75
Massachusetts	3.70+	Massachusetts	3.00	Maine	0.80	Massachusetts	0.70
California	3.00+	Vermont	2.50	Ohio	0.70	Rhode Island	0.50
Wisconsin	2.90	Rhode Island	2.10	Pennsylvania	0.70	New Jersey	0.45
Rhode Island	2.60	Maine	1.50	Illinois	0.60	Oregon	0.30
Vermont	2.50+	Wisconsin	1.50	Maryland	0.60	New Mexico	0.24+
Maine	2.30	California	1.30+	Oregon	0.60	Wisconsin	0.10
Oregon	1.90	Oregon	1.00	California	0.50	Illinois	0.04
New Hampshire	1.50+	New York	0.60+	Montana	0.19+	Delaware	0.03
Montana	1.10	Maryland	0.23+	New Jersey	0.16	New York	0.03
Maryland	0.83+	Delaware	0.18	Delaware	0.10	Pennsylvania	0.02
Pennsylvania	0.82	Ohio	0.10	New York	0.10	Maine	Dona-tions
New York	0.80+	Pennsylvania	0.10	Texas	0.07		
Ohio	0.80	Illinois	0.03+	New Mexico	0.03+	Arizona	TBD
Illinois	0.67+	Arizona	TBD	Massachusetts	Current levels	Montana	TBD
Delaware	0.31	New Hampshire	TBD			Nevada	TBD
New Mexico	0.30	Nevada	TBD	Rhode Island	In rates	Vermont	TBD
Texas	0.07+	Montana	TBD	Arizona	TBD		
Arizona	TBD	Texas	TBD	Connecticut	TBD		
Nevada	TBD			Nevada	TBD		
				Vermont	TBD		

Source: Nadel, Kubo and Geller, 2000, *State Scorecard on Utility Energy Efficiency Programs*, American Council for an Energy-Efficient Economy, Washington, DC.

Notes: 1) Mills = tenth of a cent.

2) TBD = To be decided.

3) The total is the sum of efficiency, low-income, renewables AND other programs not specifically listed such as R&D.

4) A plus sign next to a value means that additional funding may be added due to administrative determinations or municipal utility programs.

b. The Energy Efficiency Utility:

One important variant on the statewide public benefits fund is the Energy Efficiency Utility, which is awarded a franchise in order to deliver efficiency services to customers across a state or region. The fir such utility was chartered by the Vermont Public Service Board[126], with a statewide franchise, supported by a wires charge, averaging about 2.5 mills per kwh, in each franchise territory in which it delivers services. It was designed to eliminate the conflict of interest that wires companies have with respect to most efficiency services. It also minimizes the cost and complexity associated with regulatory scrutiny numerous utility DSM programs.

The Vermont Efficiency Utility franchise was awarded through an open solicitation conducted by the PSB, and is subject to a performance-based incentive contract that encourages the utility to maximize it cost-effective performance. The Efficiency Utility (called Efficiency Vermont) is supported with funds that formerly went to power company DSM programs. As a private entity with an efficiency mission, subject to regulatory oversight and a performance contract, Efficiency Vermont is expected to be more responsive and more nimble than either the franchise utilities had been, or a state-run public energy department could be.

After its first year of operation, Efficiency Vermont reported that it had met or exceeded all of the performance goals set out in its contract with state regulators, and had produced significant demand and energy savings at a cost of “approximately 2.6 cents per kWh at a time when the comparable price of wholesale electric supply is more than 5.2 cents per kWh.”[127] In effect, Efficiency Vermont is building a “invisible power plant” to help meet Vermont’s electric power requirements.

c. System Benefit or Uplift Charges at the Regional Level:

Historically, utility energy efficiency programs were administered at the franchise level. More recently noted in Table 3 above, states have recognized the value of statewide programs and funding sources. But there is no essential reason to draw the boundaries for efficiency programs at the state line. Power markets today are regional; transmission grids and system operations are regional; and reliability rules and the costs of reliability programs are imposed across franchise and state boundaries. Moreover, the markets and delivery channels for many end-use technologies (such as industrial motors, chillers, and household appliances) are regional in nature. Finally, the economic, environmental, and reliability *benefits* of improved electric efficiency flow to consumers across power pools and transmission grids, and do not stop at the state boundary. For all of these reasons, policy-makers should consider the merits

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126. The concept was developed in the Board’s Order in Docket 5854 (December 30, 1996) at pp.107ff, and in subsequent orders in Docket 5980 (January 19, 1999, and September 30, 1999). The franchise was awarded after competitive bidding in March 2000.

127. Vermont Energy Investment Corporation, Annual Report March 2001.

of broad-based, regional funding for efficiency programs that will benefit regional power markets, regional reliability, and regional transmission systems.

The benefits of regional energy efficiency programs have been recognized by energy professionals and decision-makers in a variety of contexts. The leading example has been the Northwest Power Planning Council, which has sponsored very significant programs throughout the multi-state region served by the Bonneville Power Administration. In recent years, multi-state programs in the BPA region have also been developed and funded through the Northwest Energy Efficiency Alliance, a non-profit corporation governed by a board of utility, government, and other stakeholder representatives. As of 1999 it had an annual budget of $22 million per year.[128] Regional efficiency organizations have also been established in the Northeast and the Midwest.[129]

While the current regional efficiency partnerships offer promise, they are both voluntary and relatively small. What is lacking is a consistent funding mechanism to support delivery of demand-side resources regional wholesale markets. Some modest load-management resources are now supported at the ISO level (see, e.g., the load-response programs sponsored by the New England, New York, and California ISOs in the summers of 2000 and 2001), but longer-term energy efficiency investments have been left t individual utilities and to state system benefit funds.

This is a missed opportunity for two reasons. First, regional power managers -- RTOs, ISOs, Transcos, and reliability organizations -- are engaged in the process of securing generation, ancillary services, reserves, and transmission projects on a regional basis. Where efficiency investments would meet those system needs at lower cost, the failure to invest in efficiency is driving up the *cost* of regional collectio mechanisms, and of reliable power for the region. Second, efficiency investments can provide benefits t consumers across a region by lowering the *price* of power in regional power markets. Evidence from existing regional markets in California, PJM, and New England supports the conclusion that modest regional wires charges supporting regional efficiency programs could be highly cost-effective.[130] Yet, in the absence of a regional, non-bypassable collection mechanism, individual utilities and states will continue to benefit from their neighbors' programs, whether or not they support equivalent programs of their own.

Wholesale markets could be designed to capture large consumer savings through broad-based market transformation or energy efficiency programs without much difficulty. With so much money to be save

128. Raab and Peters, "A Comparative Study of the Northwest Energy Efficiency Alliance and the Northeast Energy Efficiency Partnership," (NARUC 1998) at p.13.

129. The Northeast Energy Efficiency Partnership sponsors about $20 million per year in efficiency programs in the region stretching from Maine to Maryland. It is funded principally by utility contributions, but receives some federal and state agency support as well. Ibid. The youngest of these organizations is the Midwest Energy Efficiency Alliance, also founded in recognition of the regional nature of electricity markets and efficiency benefits.

130. These points are discussed in the sections on demand-side bidding and the Efficient Reliability Standard, above.

and so many reliabilty benefits to be acheived these questions should be high priority issues for FERC and state regulators.

d. Complementary Policies for Efficiency: Codes, standards, tax credits, and financing plans accelerate the use of efficient end-use technologies

The principal focus of this report has been on measures that should be taken within the utility system to support greater reliability and lower costs through demand-side resources. It is not intended as an exhaustive review of the means to promote more efficient end-use technologies in the economy. The most recent National Energy Policy states, "New technologies are proving that we can save energy without sacrificing our standard of living. And we're going to encourage it in every way possible."[131] Many complementary policies can, and should be, pursued to deliver those efficient technologies. The most important tool at present is the use of advanced building codes and appliance efficiency standards. Air conditioning provides an excellent example of the potential. It is estimated that DOE's recently-adopted standards for air conditioners will, over time, deliver more than 28,000 MW of savings nationally. If those standards were raised to the level proposed by the previous administration, an additional 13,000 MW of savings could be realized.[132] Taken together, improved air conditioner efficiency standards can lower the nation's load growth over the next two decades by 10% (41,000 MW saved as compared with about 400,000 MW of load growth projected by EIA). Savings from improvements in the standards for building shells, climate control systems, lighting, and motors are als potentially quite large.

Voluntary installation of high-efficiency technologies is also an important public policy goal. The EPA' Energy Star program, for example, has accelerated sales of high-efficiency products, and led to nationwide peak load reductions of as much as 10,000 MW.[133] Investments in Energy Star products and buildings can be encouraged through many means not yet widely used: sales tax exemptions, tax credits, favorable tariffs by electric utilities, and low-cost financing plans. One promising financing technique n under development is called PAYS -- Pay As You Save. Under the PAYS plan, a customer's investment in approved high-efficiency equipment is financed by a utility, an energy service provider, or public benefits fund. The investment is repaid through a charge on the customer's utility bill, which give the customer an easy means of repayment, and gives the financing entity a low-risk repayment schedule. If widely implemented, financing programs like PAYS could improve system reliability by stimulating deployment of high-efficiency technology, particularly in the residential sector.

131. National Energy Policy, op. cit., at p.xi (quoting Vice-President Richard Cheney).

132. "Supply and Demand in the National Energy Policy," PennFuture E-cubed (May 19, 2001) at p.3.

133. "Energy Star: The Power to Make a Difference in the Energy Crisis," Environmental and Energy Study Institute briefing (Washington, DC March 20,2001).

VI. CONCLUSION

The unwelcome trio of problems facing power systems in the U.S. today -- price spikes, generator market power, and degraded reliability -- are essentially three faces of the same underlying problem, the tightening margin between supply and demand. When the margin between available capacity and demand is thin, prices rise steeply and reliability is threatened. The principal response to these circumstances is often an assumption that additional generation and transmission facilities are the exclusive means of restoring balance to the grid. This assumption imposes unnecessary costs on customers, on the nation's economy, and on the environment. Lightening the load on the electric grid ca widen the margin, lowering costs and enhancing reliability at the same time. This report concludes that energy efficiency, load management, and price-responsive load programs can meet up to half of the nation's expected electric load growth over the next twenty years.

Finding a better balance between supply-side and demand-side investments for reliable grid managemen requires three basic public policy commitments:

- First, decision-makers should acknowledge that the reservoir of demand-side opportunities is a large and useful resource for grid management -- one that should be tapped when it is feasible and cost-effective to do so.
- Second, public policies should aim to capture the full range of demand-side resources available to the grid. Peak-load management and price-responsive load programs are valuable resources, but these short-term responses do not exhaust the cost-effective demand-side potential. There is a continuing need to promote investments in longer-term demand reduction through efficient end-us technologies. Programs that promote deployment of efficient end-use technology should not be sacrificed in favor of peak management programs. Long term energy efficiency and short term loa response are complementary resources, and both are needed.
- Third, there is no single "silver bullet" to ensure adequate development of demand-side options in today's power systems. There are many barriers to demand-side resources, while a variety of subsidies and traditions favor supply and power delivery options. Opportunities for improvement exist in many areas, from the tariffs and market rules governing operation of power pools and transmission systems, to the rate designs of local distribution companies. Decision-makers shoulc aim to develop a broad array of balancing solutions. Fortunately, there are many valuable ideas and models to draw upon. Many, but by no means all, of them are discussed in this report.

Heat waves are natural events, but blackouts and price spikes are the result of governmental and private choices. Heat waves are as predictable as snowstorms and hurricanes. When outages and price spikes follow, they are not "caused" by the heat wave, they are the consequence of our policy decisions. After Hurricane Andrew, Floridians learned that low-cost investments in roofing tie-downs would have kept a lot of roofs intact in high winds. In a similar manner, energy efficiency investments can be viewed as a low-cost means of "risk-proofing" the electric system, keeping the electric grid intact during heat wave demand spikes, and other reliability challenges. The means of providing this added measure of reliabilit are well within the grasp of utilities, governments, system operators and customers.

APPENDIX

Resolution Supporting Energy Efficiency and Load Management As Cost-Effective Approaches to Reliability Concerns

WHEREAS, Both utility-sponsored and market-based energy efficiency programs have a demonstrated record of lowering demand for electricity -- according to the U.S. Energy Information Administration, in 1997, cost-effective utility DSM programs provided over 25,000 megawatts of peak load reduction and saved more than 56 million megawatt-hours annually; and

WHEREAS, Despite energy efficiency's proven track record, utility spending on energy efficiency programs has been dramatically curtailed, falling from $2.7 billion dollars in 1993 to only $1.6 billion in 1997, according to the U.S. Energy Information Administration; and

WHEREAS, Several areas of the country have recently experienced electric distribution and supply reliability problems and major price volatility, for example:

- Utilities from Maine to Virginia cut the voltage they supplied to customers by 5 percent on at least one occasion during a five-week period in early summer, 1999, because their three regional power pools were approaching or exceeding their prior peak load;
- New England experienced its first power warning ever in June 1999, and experienced two more power warnings in the following five weeks;
- Delmarva experienced rolling blackouts that affected 400,000 customers in early July 1999;
- Utilities throughout the midwest lowered the voltage they supplied to customers in June of 1998 because of severe capacity constraints; and
- Denver experienced rolling blackouts on July 17, 1998, when demand exceeded electricity supply.

WHEREAS, During these distribution and capacity constraints, the spot market cost of power repeatedly rose to the range of $1,000/MWhr for one or more hours in the day; and

WHEREAS, According to the North American Electric Reliability Council, generating capacity additions are not keeping pace with demand growth - 24,400 MW of generation additions are planned by 2002, but demand is projected to increase by approximately 36,000 MW; and

WHEREAS, the North American Electric Reliability Council also reports that transmission systems are increasingly challenged to accommodate the demands of evolving competitive electricity markets, and

WHEREAS, According to a study performed by Applied Energy Group, Inc., nine of ten regional reliability councils in the United States will have a shortage of generating capacity by 2007; and

WHEREAS, Energy efficiency and load management programs are proven, cost-effective means of managing load and enhancing reliability by matching electricity demand with the system's generation, transmission, and distribution capacity constraints, and such programs help to avoid the need to rely upon excessively costly supply resources and strained transmission and distribution facilities; and

WHEREAS, For the last 15 years, NARUC has encouraged investment in cost-effective energy efficiency programs; *now therefore be it*

RESOLVED, That the Board of Directors of the National Association of Regulatory Utility Commissioners (NARUC), convened in its 1999 Summer Meeting in San Francisco, California, reaffirms NARUC's commitment to, and support for, cost-effective demand-side management measures, including both energy efficiency and load management measures, as a critical component of strategies to address electric system reliability concerns; *and be it further*

RESOLVED, That NARUC urges State public utility commissions to encourage and support programs for cost-effective energy efficiency and load management investments as both a short-term and long-term strategy for enhancing the reliability of the nation's electric system, and reducing its costs; *and be it further*

RESOLVED, That NARUC urges power pools and independent system operators to encourage and support market mechanisms that facilitate cost-effective energy efficiency investments, distribution enhancements, and load management by suppliers, marketers, and end-use customers; *and be it further*

RESOLVED, That NARUC urges Congress, as it considers legislation to restructure the nation's electric industry, to include in such legislation workable mechanisms to support cost-effective State, utility, and market participant energy efficiency programs in order to enhance the reliability of the nation's electric system.

Sponsored by the Committees on Energy Resources and Environment and Electricity

Adopted by the NARUC Board of Directors July 23, 1999