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Technical Potential For Peak Load Management Programs in New Jersey

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ABBREVIATONS AND ACRONYMS

ACP	appliance cycling program
ALM	active load management
BGS	basic generation service
C&I	commercial and industrial
CAC	central air conditioners
CHP	central heat pump
CRA	comprehensive resource analysis
CSP	curtailment service provider
DLC	direct load control
DSM	demand side management
DSR	demand side response
ECAR	East Central Area Reliability Coordination Agreement
EE&RE	energy efficiency and renewable energy
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
FRCC	Florida Reliability Coordinating Council
FSL	firm service level
FTR	financial (or firm) transmission rights
GLD	guaranteed load drop
HVAC	heating, ventilating, and air-conditioning
ISO	independent system operator
JCP&L	Jersey Central Power and Light Co.
LIPA	Long Island Power Authority
LMP	locational marginal price
LSE	load serving entity
MAAC	Mid-Atlantic Area Council (PJM)
MAIN	Mid-America Interconnected Network
MAPP	Mid-Continent Area Power Pool
MM	maintenance mode
NEEC	Northeast Energy Efficiency Council
NERC	North American Electric Reliability Council
NJBPU	New Jersey Board of Public Utilities
NJCEC	New Jersey Clean Energy Collaborative
NPCC	Northeast Power Coordinating Council
NRDC	National Resources Defense Council
NYISO	New York Independent System Operator
NYSERDA	New York State Energy Research and Development Authority
OASIS	Open Access Same Time Information Systems
PEPCO	Potomac Electric Power Company
PJM	PJM Interconnection LLC
PSE&G	Public Service Electric and Gas
PTAC	packaged through the wall air conditioner
SERC	Southeastern Electric Reliability Council
SPP	Southwest Power Pool
TED	The Energy Detective
VLR	voluntary load reduction
WECC	Western Electricity Coordinating Council
WSA	weather sensitive adjustment

WSCC	Western States Coordinating Council – Now WECC

1. INTRODUCTION

Restructuring is attempting to bring the economic efficiency of competitive markets to the electric power industry. To at least some extent it is succeeding. New generation is being built in most areas of the country reversing the decades-long trend of declining reserve margins. Competition among generators is typically robust, holding down wholesale energy prices. Generators have shown that they are very responsive to price signals in both the short and long term. But a market that is responsive only on the supply side is only half a market. Demand response (elasticity) is necessary to gain the full economic advantages that restructuring can offer.

Electricity is a form of energy that is difficult to store economically in large quantities. However, loads often have some ability to (1) conveniently store thermal energy and (2) defer electricity consumption. These inherent storage and control capabilities can be exploited to help reduce peak electric system consumption. In some cases they can also be used to provide system reliability reserves.

Fortunately too, technology is helping. Advances in communications and control technologies are making it possible for loads ranging from residential through commercial and industrial to respond to economic signals. When we buy bananas, we don't simply take a dozen and wait a month to find out what the price was. We always ask about the price before we decide how many bananas we want. Technology is beginning to allow at least some customers to think about their electricity consumption the same way they think about most of their other purchases. And power system operators and regulators are beginning to understand that customers need to remain in control of their own destinies. Many customers (residential through industrial) are willing to respond to price signals. Most customers are not able to commit to specific responses months or years in advance. Electricity is a fluid market commodity with a volatile value to both producers *and* consumers. Fortunately too, only a percentage of loads need to respond elastically for all customers to benefit.

This report explores mechanisms to reduce, when necessary, the peak load in New Jersey's electricity market. It examines load pricing and technical load reduction programs used in recent years in New Jersey and discuss how they can be made more effective in controlling summer peaks and attendant high prices of electricity. Particular attention is given to load curtailment programs now in place and utility opinions relating to them.

2. BACKGROUND ON LOAD CURTAILMENT PROGRAMS

This section considers the need for load curtailment and how the current electricity market makes load programs absolutely essential. Some background discussion of the market and capacity reserve is presented since both must be understood and managed effectively.

2.1 Market Considerations

Electricity price spikes experienced in California during the summer of 2000 were painful indicators of the value that demand-side load responses could bring to the restructuring U.S. electricity system. Review of the aggregate offers made by suppliers confirms that even a modest increase in demand elasticity could dramatically reduce these extremes in price volatility. There is a strong need for dramatically increased customer participation in electricity markets to enhance system reliability and reduce price volatility.

Most would agree that meaningful load responses to price are the hallmark of a well-functioning competitive market [1]. Yet, in today's markets for electricity, only modest levels of such response are evident. Figure 2.1 illustrates how, at high levels of demand, the inelasticity of demand (i.e., vertical line at right in figure) in the PJM market leads to very volatile and high market clearing prices for electricity. These high prices are an attractive benefit to potential responsive loads. As a result, responsive loads become active (i.e., slanted dashed line), and there results a significant price drop, as indicated. This price drop benefits both the responding and non-responding loads. Introducing demand elasticity or responsive load moderates price spikes and benefits. Keep in mind that the responsive loads must see the real-time prices to be able to respond to them. Figure 2.2 shows the same relationship in the New York market. In this case, the reduction in prices is more modest due to reduced levels of responsive load (i.e., a more vertical slope) and a more gradual increase in the real-time price curve.

If electricity suppliers and the market routinely permitted the California process to repeat, the high price peaking would become more frequent around the country and many new generation facilities would spring up. The market *might* fix itself – but only at a severe price that would be paid in terms of reliability/availability [2, 3].

Certain kinds of load response also interact with capacity requirements, helping to control electricity price volatility and improve reliability. Mandatory capacity requirements are often imposed by the regulator or independent system operator (ISO) on the various load serving entities (LSEs) based on the load requirements of their customers. Meeting the mandatory capacity requirements forces the LSE to purchase generation capacity or pay high deficiency charges. Loads that commit to curtail under specific conditions reduce the LSE's capacity requirements and should be compensated.

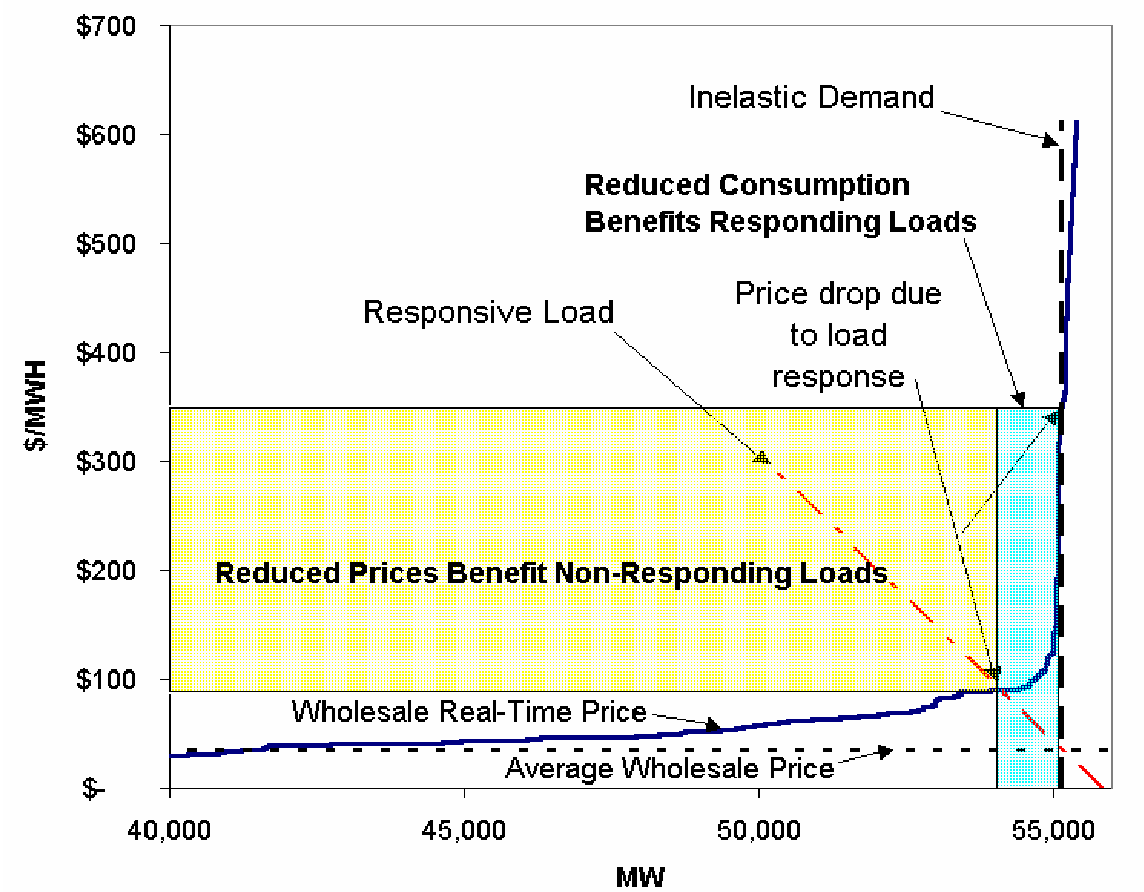

Fig. 2.1. Current relationship between electricity supply and demand in the PJM Market (2001)

2.1.1 Penalties

Load's needs, and ability to respond, vary from day-to-day and hour-to-hour. A manufacturer, for example, may normally be very willing to delay production a few hours or a day for an attractive reduction in electricity price. That same load may be unable to reduce power consumption if it has a pressing delivery schedule to meet. As with the sale of most products, a free market, based on real-time prices, with voluntary response and without penalties is best for many transactions. Alternatively, mandatory response with penalties for failure to respond should receive capacity payments.

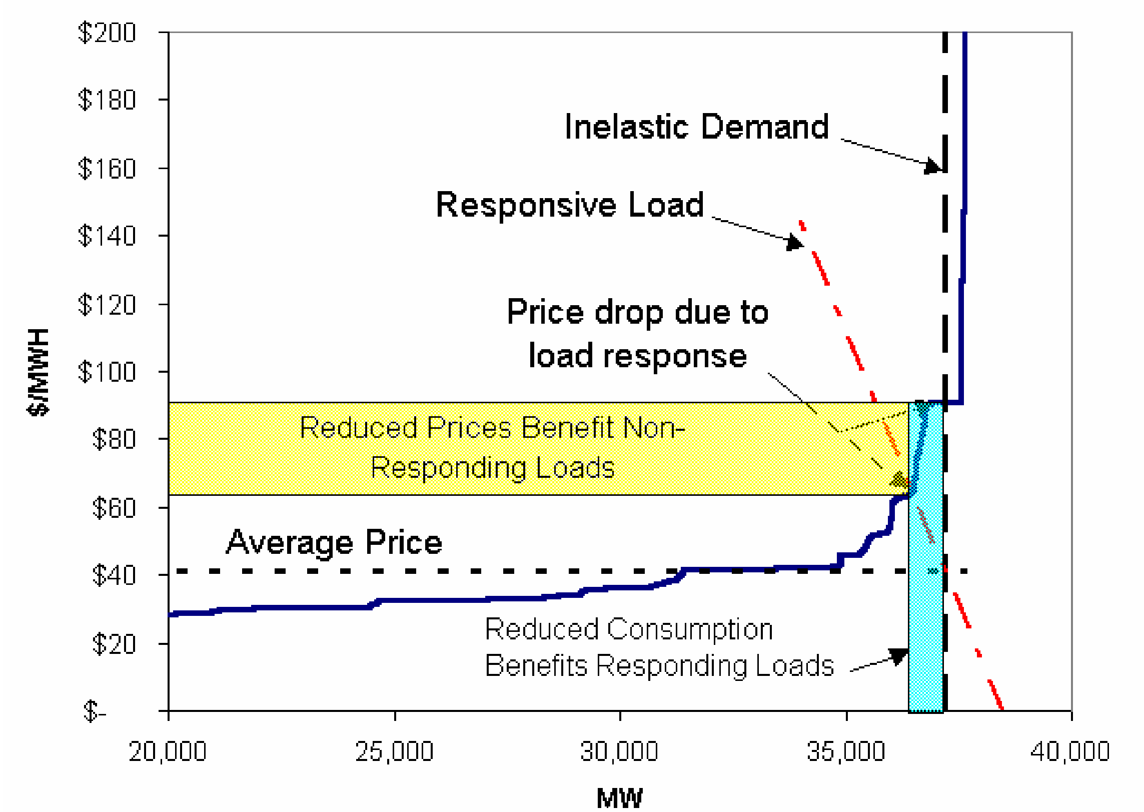

Fig. 2.2. Current relationship between electricity supply and demand (comparison for the New York market)

2.1.2 Sources of Funds

Several sources of funds are available to compensate responding loads. These are not necessarily mutually exclusive.

- Electric power prices are inherently volatile. Load response can be compensated from the lower power prices, either directly from real-time prices or as a payment from the load aggregator.
- The capacity market can provide payments to loads that commit to respond. Payment can come from entities with capacity obligations that have to pay generators to provide capacity.
- State-approved system benefit charges, or state-approved tariffs, can also provide payments to responsive loads. This is reasonable if the regulator believes that the responsive load provides benefits to other customers or society at large that cannot be compensated in some other way. Responsive loads' influence on power prices (ancillary service prices as well as energy prices) for all other customers is one such benefit as are emissions reductions and the reduced need for new generators or transmission lines.

2.1.3 *Barriers to Response*

Historically, there have been many barriers to load management including:

- No access to a real-time prices and real-time market: restrictive tariffs
- Need for difficult contract negotiations that only large businesses would attempt
- Expensive metering, monitoring, communications, and control
- Belief that loads are unwilling or unable to respond
- Excessive forward-generation-capacity-reserve requirements that artificially suppress the value of responsive load
- Lack of information on opportunities and benefits from load response

More recently, some of these barriers are either gone or greatly reduced in magnitude. The barriers that exist for potential customers today are barriers that exist in many commercial markets, as suggested by the following questions:

- Is the financial incentive adequate for reducing commercial and industrial (C&I) loads?
- Does the financial incentive warrant purchasing control, metering, process response, or generation equipment?
- Does the financial incentive reflect the true long-term and short-term costs of inelastic demand?
- Will the program be around long enough to justify making investments and changing customer operations?
- Is the communication system effective and easy to base decisions on?
- How frequently will C&I processes be upset – how will it affect the business?
- Labor cost questions such as:
    - Who will review programs and make decisions?
    - Who will keep up with them?
    - Who will monitor prices, manage responses, & resolve problems?

2.1.4 *Metering & Communication Requirements*

You cannot sell or pay for something you that cannot be measured. This is why metering must be as fast as the response you are looking for (e.g., hourly or faster interval meters). Generally, there is no technical requirement to communicate the response to anyone in real-time. However, on a practical perspective, there can be real value to the customer to see their response verified and system operators often want to verify performance in real-time, at least until they develop sufficient confidence.

The regulator can potentially help in this area by establishing metering and communications standards that should ultimately reduce cost. Establishing metering requirements can stimulate response by reducing the metering barrier. Socializing the cost of interval metering may be justified since all customers benefit from the reduced market-clearing price. Some advanced metering technologies (those based on fixed-radio-networks, for example) are only cost effective only with high penetration rates.

Here too the regulators can help by selecting a specific technology and having it deployed regionally.

2.2 Methods for Eliciting Load Response

There are various types of responsive load programs that have been tried successfully and less formal methods for attaining reduced loads. Some examples follow:

- Moral suasion – One of the least-cost methods for a system operator to get loads to help reduce stress on the power system is to simply ask loads to curtail consumption "for the common good." Amazingly, this often works if it is not used too often and if loads believe that the problem they are helping to fix was caused by some external event (e.g., excessively hot weather, a drought, storm damage, etc.) and is not the result of corporate greed (the power supplier realizing that it is cheaper not to generate).
- Rolling blackouts – Another low-cost method for a system operator to obtain load response is to simply curtail service to some customers. Typically customers are not compensated for cost and inconvenience they experience. Fortunately, this option is exercised only in extreme cases; probably because the political cost is so high.
- Interruptible load programs – These provide the utility with the right to periodically reduce a customer's load in exchange for a continuous economic incentive, the lower "interruptible energy rate." Interruptible rates were often used as a veiled method to offer reduced rates to select loads with little or no intention of interrupting. In any event, these rates fundamentally provide the wrong economic signal. The load wants the reduced energy rate but hopes to never be called upon to interrupt. The load is likely to complain if interrupted too often.

The previous three methods of obtaining load response have been used by many utilities for decades. There are also methods where loads can voluntarily offer to adjust their consumption in response to price signals:

- Real-time pricing – simply exposing loads to real-time prices allows the loads to evaluate the relative value of consuming power now versus later. Theoretically, this lets generators and loads continuously optimize the combined generation/load system without the need for central load control.
- Buy back – an alternative to exposing loads to volatile real-time prices is to sell power at fixed rates (firm power contracts) but allow loads to sell power back to the power system at the market price when they are able and it is economically attractive for them to do so. This can be equivalent to real-time pricing but may be more palatable to some loads: high prices, price spikes and price volatility are an opportunity, not a burden. Determining how much power the load sold back to the power system requires effort but there are several ways this can be accomplished. Specific processes that consume known amounts of power can be controlled and monitored (e.g., residential

water heaters and air conditioners or specific industrial equipment). Alternatively, base-line consumption for the load can be established from a few previous days of operation (possibly with weather adjustments). Another alternative has loads reducing consumption to an agreed-upon level. Georgia Power has had considerable success with responsive load tariffs and programs, as have other utilities [4, 5, 6].

- Ancillary services and contingency reserves – loads can sell contingency reserves to the power system. These ancillary services are a firm commitment by the load to reduce consumption within a specific amount of time if a reliability problem occurs on the power system. The faster the response the higher the price. The commitment to respond must be made ahead of time. The advent of day-ahead and hour-ahead markets for ancillary services allow loads (and generators) to participate only when it is economically attractive for them to do so.

2.3 Need for Load Response Programs in New Jersey

In New Jersey, and PJM as a whole, load demand is growing. Figure 2.3 shows the peak summer and winter load demands for PJM since 1989 [7].

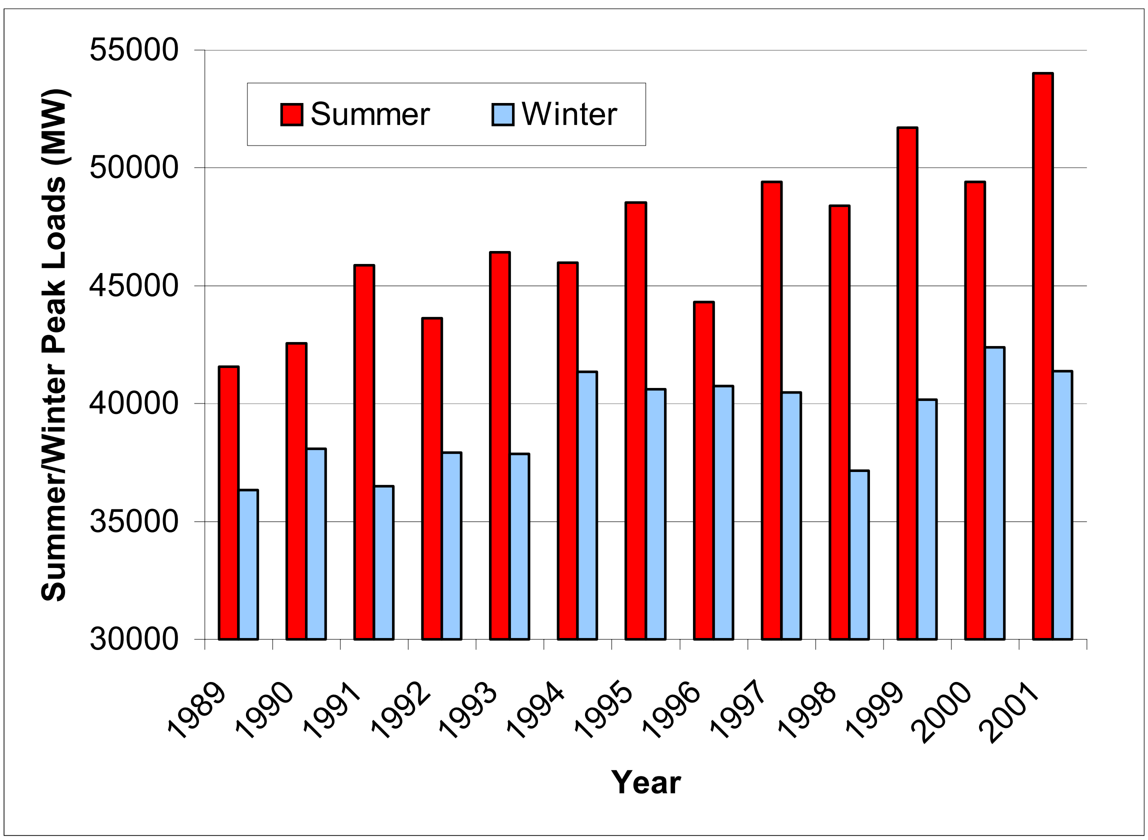

Fig. 2.3. PJM Peak Loads (1989-2001)

Figure 2.4 shows the PJM Load profile for the summer of 2001 [7]. The bold line shows load levels at 3 pm and the lower line at 6 am. The four-month period from June through August show load levels far beyond what was encountered during other months. For the market to reliably accommodate this period, some level of self-regulation (i.e., mandatory requirements) has been found to be necessary.

PJM high load, high demand operations in 2001 are summarized in a histogram (Fig. 2.5). The number of hours of operation with load in excess of 40,000 MW is significant in June through August due primarily to air conditioning demand. The PJM load exceeds 50,000 MW in July during 12 hours and in August during 40 hours.

Figure 2.6 shows not only the load levels but also the very high price spiking that occurred in the PJM market during the summer of 2001. Figure 2.7 makes clearer just how long the high prices lasted during 2001. The figure shows that the PJM wholesale price was above $100 for only about 200 hours during the year and above $200 for about 50 hours. Another view of price duration is seen in Figure 2.8 where the number of wholesale price excursions above $60, $80, $100, $200, and $800 are clearly seen by time duration (i.e., number of hours up to 12 hours and above 12 hours). For instance, greater than $80 excursions lasting an hour occurred about 100 times during the year and greater than $80 excursions lasting for 2 hour periods occurred only about 30 times.

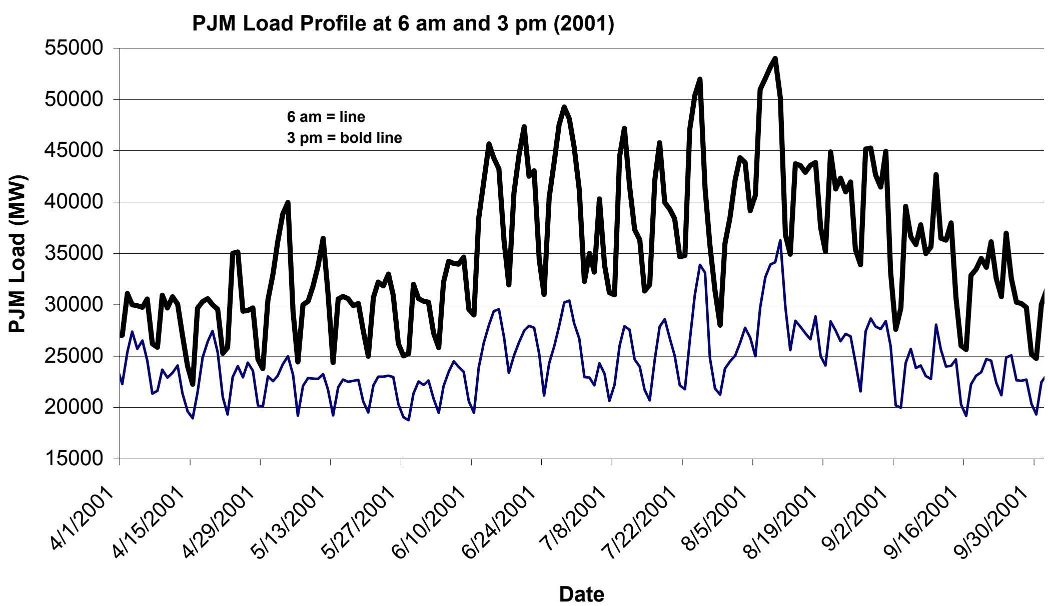

Fig. 2.4. PJM Load Profile from April 1 through September 30 (2001)

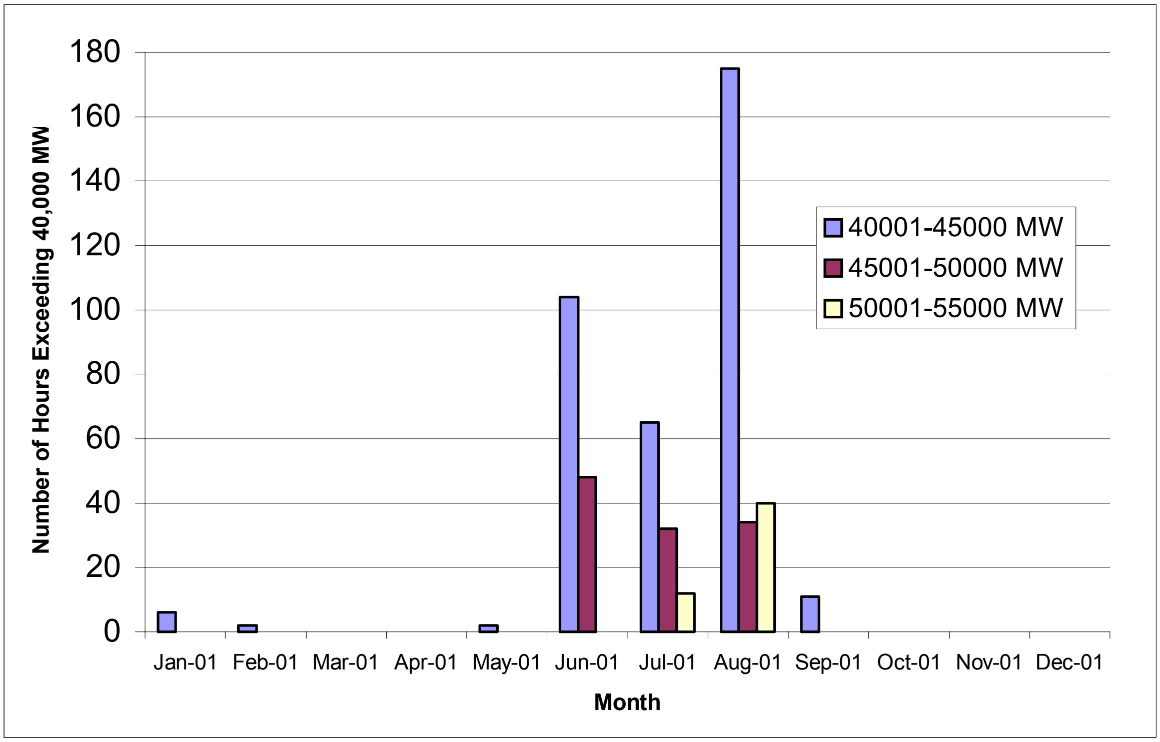

Fig. 2.5. Histogram of PJM High-Load Operations in 2001

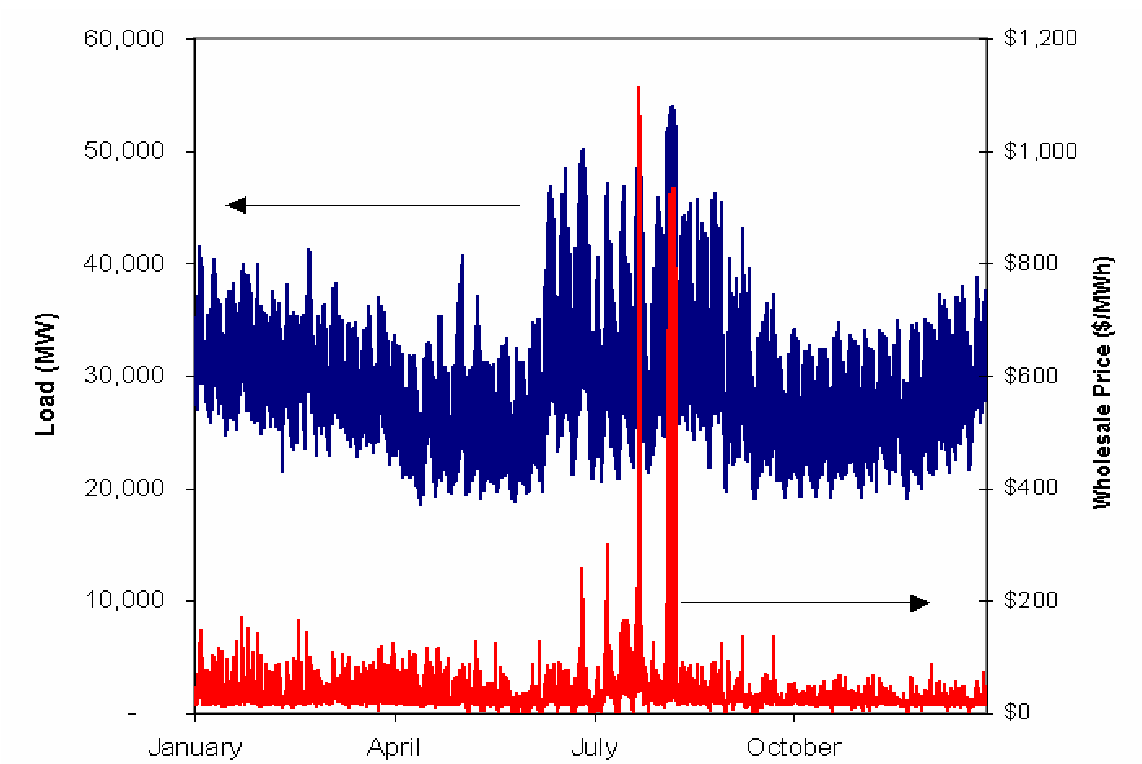

Figure 2.6. PJM Wholesale Price and Load in 2001

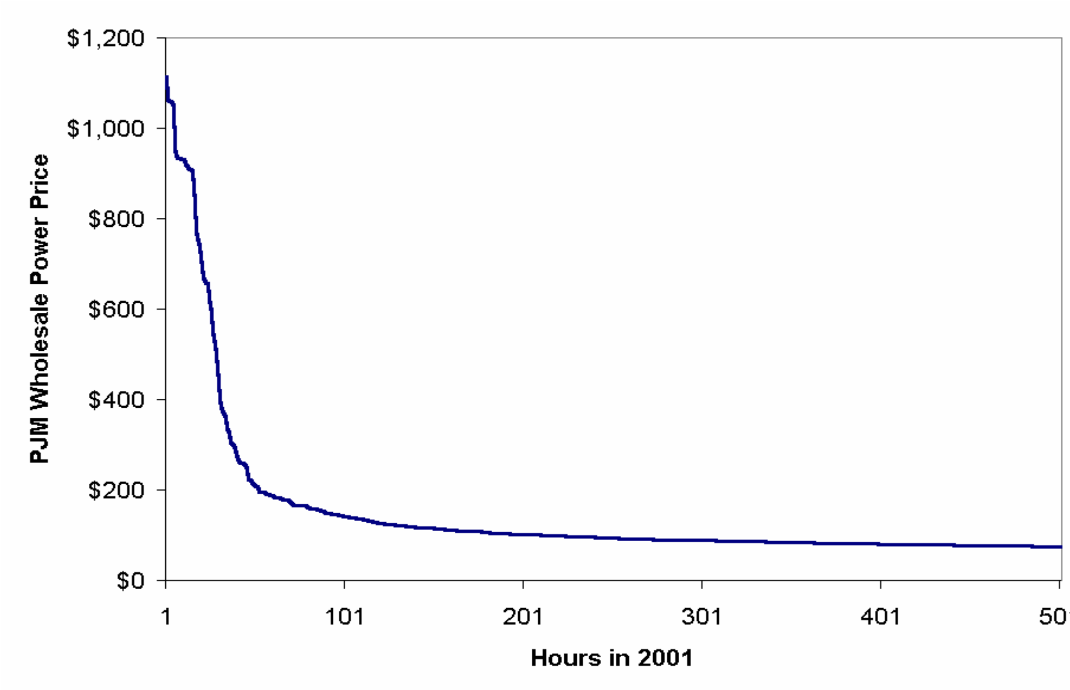

Figure 2.7. PJM Price Duration Curve for 2001

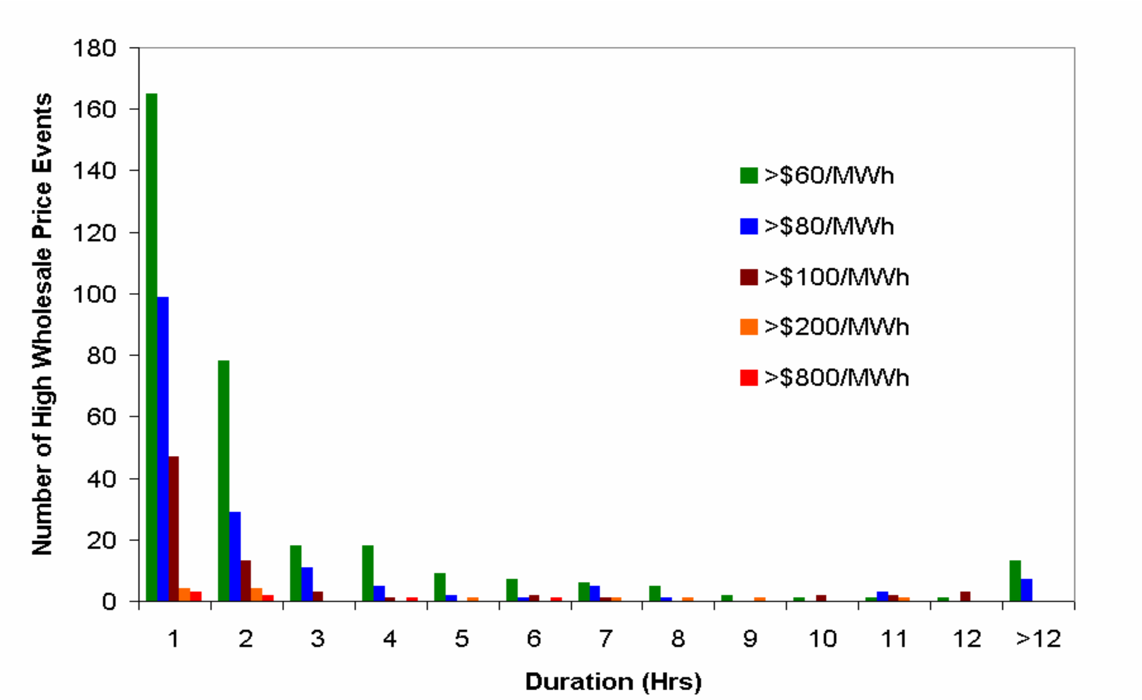

Figure 2.8. Duration of High Wholesale Price Events in PJM (2001)

PJM received an average 1200 MW of load reduction and an average $135/MWh power price reduction from the Active Load Management (ALM) and Pilot programs (see Sect. 3.1) when they were called. PJM calculated that there would have been a further $300/MWh price reduction if there had been an additional 2000 MW of responding load. Each 100 MW of load response would have provided $15-$16/MWh price reduction, providing a quantifiable benefit to all other customers [8, 9].

Based upon established needs of a load curtailment program, PJM identified a number of goals/principles that they desired to adhere to during the preparation and implementation of various load management programs. A PJM task force documented these goals/principles and prepared a short set of governing principles; the portion of this pertaining to demand side response (DSR) programs is summarized in the *text box*. This is a good list and, more importantly, moving in the correct direction. It aims at technology neutral market response that symmetry between the supply and demand sides.

PJM Demand Side Response (DSR) - Governing Principles

1. DSR programs should be market-based and avoid command and control, penalties, or subsidies. Eventually, load response should become purely market-driven.
    a. Price: Payments/revenues under an economic load response program should reflect response to day-ahead or real-time price and under an emergency program should reflect the value of the reduction to the system.
    b. Load response programs should not supercede contractual obligations.
    c. Price-responsive load should have the same ability as generation to submit three-part bids and operating restrictions; similar bidding incentives are needed.
    d. Market-based penalties may be appropriate only when compensation for capacity is an element of load response payments/revenues.
2. An emergency load response program is necessary (should be assessed periodically).
    a. The program should address the needs of customers that are only able to respond during emergencies.
    b. The need for an alternate payment mechanism, including alternate cost allocation is needed to achieve both load reduction *and* improved reliability.
    c. Any emergency payment mechanism should not discourage participation in an economic program or facilitate gaming.
    d. Ease of participation &limitation of liability are needed for strong participation.
3. Interactions between ALM and DSR programs need to be addressed.
    a. Payments must be synchronized between all programs (e.g., customers cannot be compensated under multiple programs for the same reduction).
    b. ALM requirements are always satisfied first, as long as the ALM commitment is active.
    c. Measurement of load reductions should be consistent among all programs.
4. Market participants should be treated fairly and equitably, and be permitted to participate openly in all PJM markets. All participants need not be treated identically.
5. PJM should be proactive in publishing open standards with regard to interfaces necessary for DSR market participation that are as technology neutral as practicable.
    a. PJM should make standards compatible with other ISO programs when possible
    b. PJM should be responsive to customer needs while protecting membership from significant cost incurred to satisfy the request of a single participant.
6. DSR programs should identify/resolve current issues in the near term, such as:
    a. Retail rate caps and EDC recovery of fixed costs,
    b. Lack of hourly meters,
    c. Fixed load profiling,
    d. Difficulty in measuring actual load reduction,
    e. Tariff inconsistencies and incompatibilities,
    f. Lack of economic incentives to develop a market structure.
7. Identify sensitivities to direct, end-use customer participation in wholesale markets
    a. Address the need for EDC cost recovery and agree on method
    b. State commission/board representative participation in development of DSR programs will be requested
    c. PJM should discuss jurisdictional issues with state commissions/boards
8. DSR programs should clearly indicate the value of the product and ensure symmetry between supply and demand sides
    a. PJM should first look to alter existing markets to incorporate DSR.
    b. PJM should facilitate the development of new markets if necessary.
9. The roles of all participating entities should be clearly defined, including such tasks as verification of metered reductions, tracking of ALM customers, etc.

3. REVIEW OF NEW JERSEY LOAD PROGRAMS

This section summarizes electrical peak load management and general load control programs in effect in New Jersey during 2001 and 2002 (in some cases beginning in the early 1990s). Programs developed and implemented by PJM and the State's four utilities were reviewed.

3.1 PJM Programs

PJM has prepared an implemented a number of load management related programs including three current programs: the Economic Load Response Program, Emergency Load Response Program, and Active Load Management (ALM) Program.

The forerunner of the 2 PJM load response programs was the "Customer Load Response Pilot Program" begun during the summer of 2000 to encourage demand-side response during emergency conditions. PJM did not experience any high demand conditions during that summer, however, and did not call for response. PJM expanded the program in 2001 to also pay for load response during times of high-energy prices in addition to response during emergencies [8, 9]. Participants must be able to reduce load by at least 100 kW, be available between 9:00 and 22:00 on "any or all days of the week," be able to reduce load within 1 hour of notification, and be able to respond for at least 10 hours over the 2001-2002 program term. This wording is perhaps more restrictive or declarative than necessary. The program was, after all, a voluntary program and the intention was simply to inform customers at what times or days they might be called upon.

Money to pay for the load response is collected from all PJM customers in proportion to their energy consumption during each hour response is required.

PJM allows the load to either directly meter the specific process or load that is shut down to provide the load reduction or to negotiate a method to establish a load profile as a baseline to judge load reductions against. To date all participants have elected to negotiate a baseline method.[1]

Loads and load aggregators must keep PJM updated concerning the amount of load response and the price at which load will respond.

3.1.1 PJM Economic Load Response Program

The PJM Economic Load Response Program represents PJM's most basic approach to load control. It represents a very attractive program intended to "jump-start" load control in New Jersey, a process which in many locations tends to be a slower process than

[1] PJM recognizes that a standard approach must be developed for establishing customer-specific load profiles.

energy supplier entities desire. PJM provides a program description on their Internet site [10].

The PJM Economic Load Response Program provides opportunities to end-use customers via three paths, (1) load serving entity (LSE), (2) curtailment service provider (CSP) or (3) their PJM membership. The program provides incentives for reduction of consumption when PJM Locational Marginal Prices (LMP) are high. It represents a temporary program with artificially-high incentives (i.e., payments beyond what is justified by the market). It is designed this way to encourage sign-up and high participation.

The program is design to attract and accommodate two types of distributed resources, (1) those having generators (for exporting power to the grid) and/or (2) those able to provide measurable and verifiable load reduction. Thus, the program is intended to encourage broad participation by any hourly interval revenue metered curtailable loads.

Settlements are based on real-time or day-ahead program options. In the case of real time, if the real time LMP is less than $75/MWh, the end-use customer (or LSE representative) that curtails load is paid real time LMP less an amount equal to the applicable generation and transmission charges. If the real time LMP is equal to or greater than $75/MWh, the payment is the real time LMP without any extra charges. The payments for the day-ahead option are the same as above but based on "day-ahead LMP."

The Plan is effective from June 1, 2002 until December 1, 2004 (may be renewed beyond that date by vote). The program duration was intentionally set fairly long in order to provide assurance to loads that investments in time and equipment were justified to become involved in the program. The plan is *in addition to* PJM's ALM program however participants cannot also be in the emergency program (described below).

It is difficult to assess either the past success or the potential of the PJM program. As a pilot program in 2001, the potential curtailable load was only 65 MW (out of 25,000 MW total for PJM). The average actual curtailed load was *only* 2 MW and the number of days of operation in 2001 was only 5 [11]. This is not to say that the PJM Load Response Pilots (2001) were not successful as a "Proof of Concept." They did attract some very large industrial customers and, in fact, greater than 90% were larger than 1 MW in size [12].

In order to improve the program, PJM proposed substantial modifications to the 2002 program, which included (1) extend the program effective data to December of 2004 (so customers could see more certainty if they were to join), (2) paying full LMP when it is $75/MWh or greater, (3) providing real-time and day-ahead options, (4) offering the program to non-hourly metered customers [11].[2] Although the non-hourly metered customers could be residential customers, plans were for load reduction verification methodology being customized for each participant.

[2] This element was not actually implemented. Instead, the 2002 Emergency Load Response Program allows for 3rd party PJM members to enable non-members to participate.

It should also be mentioned that the program helped identify significant barriers that would have to be addressed. One was the need for additional interval meters so that such a relatively small concern would not prevent sign-ups. The other barrier was environmental restrictions for use of backup generators that prevented a number of interested and/or registering customers from actually becoming participants.

3.1.2 PJM Emergency Load Response Program

PJM's Emergency Load Response Program is an alternative plan that some end-use customers may prefer because it is used less frequently but has attractive incentives that are designed to encourage customers to sign up and make the necessary preparations so that they can reliably curtail load and/or generate power. PJM provides a program description on their Internet site [10]. The following summarizes the key elements of the PJM Emergency Load Response Program.

In the Emergency Load Response Program, end-use customers are compensated by PJM for voluntarily reducing load during emergency events by the higher of two prices, LMPs or $500/MWh. The program includes incentives for particular end users that have generators (i.e., for exporting power) and those who can provide significant load curtailment by reducing consumption.

Those with generators must meet requirements including certain interconnection agreements and transmission tariff provisions. PJM membership is *generally* required to participate however members may act as 3rd parties to allow non-members to participate. Metering requirements are similar to those in the economic program (described above).

Customers must meet the basic requirements of being capable of providing at least a 100 kW reduction and receiving PJM notifications. Participants *cannot* participate both in this program and in the economic program.

3.1.3 PJM Active Load Management (ALM) program

The ALM program began in the early 1990s – years before the economic and emergency load programs. It is essentially an emergency response program but it relies on economic choices made by loads. Participation is voluntary but participating loads are obligated to respond when called on. This obligated response allows ALM to be counted as capacity, reducing the load serving entity's capacity obligations and associated costs. This cost savings can be shared with the responsive load.

ALM provides the ability to reduce metered load by customer action taken after a request from the LSE, which holds the ALM rights or its agent. Alternatively, the ALM process may occur automatically in response to a communication signal from the LSE which holds the ALM right or its agent. The manual process is *Contractually Interruptible* and the automated process is *Direct Load Control*.

As opposed to the other PJM programs described above, actual payments are not made to the customer. In the case of ALM, the incentive is capacity credits for the LSE that purchases demand. Another important difference is that response is not voluntary; the LSE must respond to an ALM event or pay a significant penalty.

There are three types of ALM services that are recognized. The first is direct load control (DLC), which is initiated by the LSE or its agent. DLC uses a signal to control cycling equipment (e.g., water heaters). Next is the firm service level (FSL) option in which the customer reduces the load to a pre-determined level. Notification of the ALM event comes from the LSE or its agent. The last type is the guaranteed load drop (GLD) where the customer reduces the load by a pre-determined amount. Notification comes from the LSE or its agent. The service is generally accomplished by two methods, running generators or shutting down process equipment.

The notification periods for each type of ALM event begin with one of two process steps. The first is Step 1 (short lead time) where the ALM must be fully implemented in 1 hr or less from the time the PJM dispatcher notifies the market operations center of the curtailment event. The second process option is Step 2 (long lead time) where the ALM must be fully implemented in one to two hrs.

To become a qualified ALM participant, the LSE must supply information such as point of contact (with backup), supplemental status reports, customer-specific credit information, aggregated ALM nomination information, customer-specific compliance/verification information by event, and load drop estimates for all events.

The payments that are made to participants (ALM credit), depend on type of service (DLC, FSL, or GLD). The capacity credits or load reduction values due to FSL customers are based on the Peak Load Contribution for the customer with the maximum being equal to: Peak Load Contribution – Firm Contract Level. The credit for GLD customers is the guaranteed load drop amount established by the customer's contracts with the LSE. The credit for DLC customers is based on load research and customer subscription with the maximum being equal to: (the approved per-participant load reduction) X (number of active participants).

Over-compliance is rewarded with monies collected as penalties from other LSEs who fail to provide the curtailment targets as specified by the program.

3.2 Utilities' Tariffs/Load Programs

Currently New Jersey benefits from approximately 300 MW of directly curtailable demand from historic load control programs. New Jersey utilities are all participating in DSM programs where appliances such as central air conditioners (CACs), central heat pumps (CHPs), and/or qualifying water heaters are cycled during the afternoons on hot weather "event" days. The program's activity varies from no events during a year to several making it difficult to make general assessments, provide trends, make reference to average years, etc. The New Jersey Board of Public Utilities (NJBPU) Internet site provides information on the tariffs for the various utilities [13].

The DSM programs are presently in a "maintenance mode" (MM) and long-term prospects do not look good as will be discussed first. This section also will show that some utilities, such as Jersey Central Power and Light Company (JCP&L), are sponsoring other load management programs aimed primarily at larger customers. These programs are tied into PMJ programs such as the ALM.

3.2.1 Load Program Crises Affecting Utilities

All of the utilities presently have their DSM programs in a MM where new participants are sought only to make up for ones who have left the program. The "short reason" for this is because that is what the NJBPU has *approved* based on their review of data provided by the utilities. A more in-depth answer relates to a settlement process. Other parties wanted more money for other efficiency and renewable programs. The stipulation states that support from Comprehensive Resource Analysis (CRA) program funds (see Sect. 3.4) for these DSM programs should stop after 2003. Absent a new solution, or NJBPU direction that support from CRA funds should continue, this proven load management asset could be abruptly lost.

There are other fundamental problems looming for load management programs at the utilities. During the course of this study, utilities were asked whether they are interested in, and/or are pursuing, either expanded load management programs or new ones. The answers generally came back in the form of a question: Will the utilities in the future still have the opportunity to serve customers or will they be "wire utilities." This refers to a tendency in recent years for generation services to be sold or auctioned off to third parties and for these generation services to come under fixed price contracts (e.g., fixed supply prices for three or four years). Under such conditions a utility and its investors would never invest $50 million in a new load management program that controls the sales that some other entity is making (of course, the financial motivation would not be there to begin with).

Even the remote prospect of this happening at some time in the future paralyzes the implementation of new load programs. Thus, utilities are not pursuing programs for the fear of investing money only to be confronted with stranded cost in a year or two. What the utilities say they must have for new programs to develop and be implemented is, (1) assurance from the NJBPU that they will continue to have an obligation to serve customers, (2) assurance that their customers will not switch to another provider, (3) a guarantee that they will have an adequate number of customers to profit from the program over 15 to 20 years, and (4) assurance that they can retain rewards along with risks [14]. This last item refers to the utilities being able (perhaps through a holding company) to benefit from incentives/high rewards (e.g., extreme market price peaks) along with the accompanying formidable business risks without interference from price caps, such as the one that was in effect in New Jersey.

Another issue is increasing administrative complexity. For example, recently one utility auctioned off its basic generation service (BGS) and then the NJBPU ruled that the utility could no longer obtain rate recovery for its load reduction program. The utility then transferred its program customers to a PJM load program with an arrangement where PJM would attribute the load curtailment to the utility. The new generation services company would pay the bill. This is type of complexity is becoming increasingly common as "patches" are applied to old programs in a rapidly changing market.

Another issue is the relative profitability of load management with large customers versus with small customers. At one extreme, a utility may have a commercial investor program where they phone 80 to 100 large customers and simply request load curtailments when needed. The return on this small investment of effort may be huge. On the other extreme are residential programs (i.e., DSM) where considerable money is spent and the maximum that can be gained is about 1 kW/customer. The utility may have 50,000 customers and in 10 to 15 years be plagued by equipment failure, old technology, and the prospect of spending anther $50 million (i.e., $1K/customer) for new equipment.

3.2.2 JCP&L, First Energy Company

JCP&L designed and implemented two load management programs, the Appliance Cycling Program (ACP) and Voluntary Load Reduction (VLR) Program.

The ACP, which began in late 1992, is considered a successful program with roughly 100 MW participating. In this program, JCP&L installs the switch in the form of a programmable thermostat in each participant's home. Appliance switches are activated by JCP&L via a radio communication system to control CACs, CHPs, and qualifying water heaters (i.e., those water heaters accompanied by a CAC or CHP). The technology is now considered "old" and, as a result, it has become difficult to determine the status of operations. In order to validate both operations and the status of appliances (i.e., whether they still exist/function), time-consuming inspections must be made.

JCP&L offers a programmable thermostat as an incentive for enrolling new ACP participants (i.e., when necessary). Customers enrolled in the program, who have an outdoor control device (i.e., CAC or CHP), receive an incentive payment of $24.00 for each cooling season. An additional $6.00 annual incentive is paid if customers permit the utility to also cycle their electric water heater.

The VLR Program was filed for formal NJBPU approval in 2001; however, in the summer of 2002 a decision was made to discontinue the program after generation services were auctioned off to an independent group of suppliers. This program is designed for large customers and it is deemed a highly effective program. The program achieved a total of 55 MW of actual load reduction (46 MW in New Jersey alone) during 2001. The program provides considerable information to participants via an Internet-based system. This information includes metered load history, estimated hourly pricing/payments, target hourly loads, and near real-time performance.

Each VLR program event requires an offer from JCP&L and a reduction pledge by customer. There are day-ahead and day-of-event (i.e., real time) options. Day-ahead curtailment payments are based on load reduction and 80% of the real-time LMP's. Day-of-event curtailments are rare (i.e., emergencies) and bring 100% of real-time LMPs. Baselines are based on the average, hourly loads of the five highest-demand (non-event) days. Customers with weather-sensitive loads can have baselines weather adjusted for the season using the weather sensitive adjustment (WSA) procedure.

Three improvements were made to the VLR program for 2002, (1) simplification of day-ahead pledging, (2) improved Internet curtailment pledge management, and (3) improved Internet event performance monitoring.

In a recent auction, JCP&L sold the responsibility for basic generation service (BGS) to a group of suppliers. This will result in the utility having fixed-rate payments for generation supply beginning August 1, 2002. Unfortunately, that will remove all financial motivation for peak load curtailment programs. It is considered unlikely that the group of suppliers will come together and create any kind of load program. Without financial motivation, the difficult-to-manage JCP&L programs may be cancelled in 2003. The PJM programs may then be the only means of load control cost recovery in the areas served by JCP&L.

3.2.3 Conectiv Energy (Pepco)

The DSM program in New Jersey for Conectiv Energy is called the Peak Savers program. The program is similar to others in that it has radio receiver switches installed on CACs, CHPs, and water heaters. Residential customers receive $1.50 credit per appliance per month and the C&I customers receive monthly credit of $1.50 per KW of controlled load. These payments are made in June through September. When there is a cycling period (i.e., a rare event with the Conectiv program), the participants receive an additional $1.50 credit for that cycle period.

The status of Conectiv's DSM program is somewhat unique and difficult to characterize for the following reasons:

- Summary numbers useful in defining the program are several years old,
- No one at Conectiv is collecting data for current program parameters,
- The potential MW curtailment is not "approved" (i.e., recognized by PJM),
- The program was not used (i.e., no events) in 2001,
- The program is not likely to be used in the future,
- The program's use is determined solely by Conectiv,
- The program is in a MM, and
- Conectiv is completing a merger with the Potomac Electric Power Company (Pepco), which will direct the future course of the program.

Conectiv Energy does not have any other programs or tariffs effective in New Jersey for encouraging load curtailment.

The Pepco merger was approved by the NJBPU in June 2002. The new company will direct future load management initiatives, R&D, and implementation.

3.2.4 Public Service Electric & Gas Service (PSE&G)

PSE&G issued a 169-page tariff that was effective August 1, 1999. The tariff contains no discussion of load management or peak management; however, Chapter 16 discusses net metering installation and billing for renewable energy sources such as wind and solar.

PSE&G has an active DSM program, referred to as the AC cycling program, which began production in 1990. The program now has 140,000 radio-controlled switches on compressor circuits. PSE&G takes $6 off participant's monthly electric bills during the July through September months (4-mo period). The program is considered to be a success in significantly changing load profile however the program does not actually save energy (may even use a little more). The program is being "maintained" with the same MW load curtailment from year to year. As participants drop out, others are recruited and PSE&G does not have any problem recruiting participants, indicating that the level of payment may be adequate.

Switch maintenance was not performed for a number of years since the future of the program was in doubt. More recently, a decision to retain the program necessitated a QA program for switch maintenance. Switches are now being replaced and it is estimated that 30% are missing or inoperable. This situation has significantly degraded program savings and reduced load curtailment by the same percentage (i.e., 30%).

3.2.5 Historic Demand Response Program Summary

Historic demand response programs have had mixed results. Overall they have typically proven to be technically successful; they do reliably deliver the stated response. New communications and control technologies may help reduce maintenance requirements and reduce costs. They have also been of only limited size providing only limited system benefits. Restructuring has complicated the economic incentives for these programs leaving most in a state of limbo concerning their future. It *appears* that significantly greater response could be obtained if the correct market structure and incentives could be established. Greater response might be achieved if responsive load supplied contingency reserves in addition to or instead of peak shaving. Many (not all) loads' natural responses are better aligned with the rapid but short and infrequent contingency reserve requirements than with the slower but longer and more frequent peak usage reduction requirements.

3.3 Review of Key Parameters

This section considers the results of load management programs at PJM and the three utilities.

3.3.1 Overview

Table 3.1 presents summary information[3] regarding pertinent tariffs and load curtailment programs in effect at PJM and the utilities. Year 2002 data are current as of August 1, 2002. PJM data and much of the utility data are not limited to New Jersey but reflects multi-state operations. Nevertheless, the data reflects the performance of programs active in New Jersey that demonstrate effective load curtailment.

Much of the PJM data pertains to the 2001-2002 Pilot Program, which contained both the economic and emergency plans (that were similar to the plans described earlier for 2002). The 2001-2002 Pilot Program had 220 MW of load reduction approved. The approved load reduction figures shown for 2002 are as of July 16, 2002 and include a few that are pending.

For the PJM ALM program, the table indicates that the dropout rate depends on weather and the prior year. It has been observed that when long-range weather forecasts call for a hot summer, the number of customers signed-up may decrease since a large number of ALM events is feared. In addition, following a year where many events are called (e.g., 1999), there is a similar dropout in participation the following year based on the same concern. This may indicate that the incentives are not appropriately designed, as was the case with historic interruptible load tariffs, rather than that loads are unwilling or unable to respond.

For the PJM economic and emergency load programs, the level of satisfaction is good however, as indicated in the table, the program is evolving (i.e., only last year, 2001, each were considered pilot programs). Ideas for improvements center around a more efficient means of declaring an event (i.e., a technology issue). Once the programs become larger it is expected that a staged implementation will be needed when events must be declared. Lastly, for the economic load program, a more market-based approach is needed.

The JCP&L VLR program experienced a significant shortfall in the actual MW response in 2002 due to basic implementation issues as indicated in the table. Not only were the prices down during the summer, but also many smaller problems emerged such as key customers personnel going on vacation without making arrangements for someone else to monitor and respond to the VLR program in their absence.

[3] The data shown in the table are the result of numerous contacts and discussions with PJM and the utilities. During the course of these contacts, numbers were revised repeatedly making it quite clear that this type of information is not well documented. Therefore, caution is advised regarding overall accuracy.

Table 3.1 Comparison of PJM and utility load programs (2001-2002)

	PJM Economic Load Response		PJM Emergency Load Response		PJM Active Load Management		JCP&L Appliance Cycling		JCP&L Voluntary Load Reduction		Conectiv Peak Savers Program		Public Service AC Cycling Program	
	2001	**2002**	**2001**	**2002**	**2001**	**2002**	**2001**	**2002**	**2001**	**2002**	**2001**	**2002**	**2001**	**2002**
Active?	Pilot	Yes	Pilot	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
No. of customers		60		53			76,300	78,235	51	38	~21,000	~21,000	140,000 switches	136,000 appliance
MW approved		265		400	1962		88	63	44	29	~21	~21	~120	116
MW response	6.2 (Aug 8)		62 (Aug 9)		1796 (Aug 9)		100		45 NJ only	7.6	No recent events/data		Full MW approved is expected	
Cause of shortfall					Was as expected		No shortfall		Implementa-tion – see text				No shortfall	No shortfall
Dropout rate	Voluntary (little or no drop-out)		Voluntary (little or no drop-out)		Depends on weather & prior year						Small		1.4 %	7% (3.4% net)
Sponsor's satisfaction	Evolving program		Evolving program		High		High		Very high		Satisfied		A success	
Expansion desired?	Yes		Yes		Yes		No, now in MM		Only up to 100 MW		No, now in MM		No, now in MM	
Comments	Pilot program began in '00		Pilot program began in '00		Program began in early 1990s		Program began in 1992/1993		Program is being cancelled		Future use is not likely		Program production began in 1990	

3.3.2 PJM 2001-2002 Load Programs [9]

A total of 24 companies from 50 locations applied for the 2001-2002 Pilot Program and all of the applicants were accepted. This represented a potential load reduction of 220 MW. Six percent (13 MW) were from participants with the ability to provide the load reduction via local generation. (Note: The 2000 Pilot program had 40 MW of local generation but since then, approved environmental permits became a requirement.)

PJM implemented the emergency option on three occasions (i.e., July 25, and August 8-9) in the summer of 2001 for a total of 17 hours. During the same summer, PJM implemented the economic program on five occasions - the above dates as well as August 7 and August 10. The load reductions for these events are summarized in Table 3.2.

Table 3.2 Load Curtailment in PJM Programs during 2001

	July 25		August 7		August 8		August 9		August 10	
	Pilot	ALM	Pilot	ALM	Pilot	ALM	Pilot	ALM	Pilot	ALM
Number of hours during event										
	5	11	4	12	11	11	11	11	4	9
Maximum Reductions (MW)										
	25	1481	0.3	390	39	1712	***62***	**1796**	1	1718
Total Daily Energy Reduction (MWh)										
	81	7565	1	2489	138	10973	***221***	**12385**	2	6780

The maximum load reduction and energy savings for both the Pilot Program and ALM occurred on August 9. During an 11-hour period on that day, the Pilot program produced 62.4 MW of load curtailment and 221 MWh of energy reduction. The 62.4 MW of load curtailment represented only 0.1% of the load. ALM produced 1796 MW of load curtailment and 12,385 MWh of energy reduction, a more substantial 2.9% of the load.

Table 3.3 shows the relative load reductions, energy reductions, and cost of the PJM economic and emergency programs during the summer of 2001. The emergency program reduced the energy consumption by 393 MWh, which is almost 8 times the reduction (49.5 MWh) from the economic program. To accomplish this, PJM had to pay a higher price for response in the emergency program ($731/MWh) than in the economic program ($283/MWh). Although energy consumption is of some interest in evaluating program effectiveness, the real goal (i.e., what is of monetary worth) is restoring the generation/load balance when generation capacity is scarce. The pilot program was able to produce only modest average daily reductions in load (i.e., less than 2 MW for the economic program and less than 40 MW for the emergency program). The cost per MW load reduction paid by PJM for the economic program was $8140/MW (i.e., to be precise, $8140 per average daily MW curtailment) and for the emergency program $7220/MW. These prices are more comparable than the $/MWh costs.

Table 3.3 Summary of PJM Programs during 2001

	Economic	Emergency
Average load reduction (MW)	1.72	39.8
Total energy reduction (MWh)	49.5	393
Total Payments to each	$14,000	$287,500
Capacity cost ($/MW)	$8140	$7220
Energy cost ($/MWh)	$283	$731

3.4 Comprehensive Resource Analysis (CRA) Programs

The CRA program was created by the NJBPU to increase assurance that the energy supply for New Jersey electricity customers will be adequate for years to come. On March 1, 2001, the NJBPU approved a plan for the electric and gas utilities of New Jersey that served to create both (1) a set of consistent, statewide energy efficiency programs and (2) shared strategies for promoting compact, clean and renewable sources of energy such as fuel cells, solar electric systems and wind generators. The above goals would be implemented through numerous State-wide energy projects by a collaborative of the electric and gas utilities. Additional details can be found at: http://www.njcleanenergy.com/

In the past, the utilities independently developed and delivered energy efficiency programs. Now, the CRA program enables them to offer programs that are uniform throughout the state. Program funding comes from a system benefits charge paid by all customers. The systems benefits charge is 3.76 mills/kWh (3.15 for energy efficiency, 0.16 for low income, and 0.45 for renewable energy). This charge rates as the highest in the country.

3.4.1 New Jersey Clean Energy Collaborative (NJCEC)

The NJCEC was created to assist the NJBPU in making the best use of CRA funds. The NJCEC's management consists of a representative from National Resources Defense Council (NRDC) and the Northeast Energy Efficiency Council (NEEC), a knowledgeable industry advisor (presently from Deloitte Touche Tohmatsu), and the seven electric and natural gas utilities in New Jersey. The voluntary collaborative holds monthly meetings to manage energy efficiency and renewable energy programs. Program Working Groups are set up for each project with a representative from each utility. NRDC assigns independent advisors, as required, for each technology. The NJCEC maintains a Regulatory Matters Team to perform technical evaluation and protocols development, cost effectiveness reviews, and reporting and tracking as the projects move forward.

The NJCEC reported that several significant milestones were reached in 2001 including the beginning of the renewable energy program in April and the beginning of the energy efficiency programs in May. Important goals of the NJCEC are insuring that energy efficiency and renewable energy (EE&RE) will be developed and used to [15]:

- Increase reliability,
- Increase source diversity,
- Improve choices,
- Produce energy independence, and
- Create environmental benefits.

Unfortunately, critics have claimed that the NJCEC has not been managed with full accountability and review [16]. For instance, many projects connected to their programs are executed without strategy or planning documents. The NJCEC, which began in about 1998, represents various interests but not necessarily those of local stakeholders. It is represented by consultants from the utilities and organizations that are mainly outside of New Jersey (e.g., NEEC, NRDC) and operates with economic ties to incumbent utilities.

The following improvements are envisioned for the CRA program [15]:

- Publicize an implementation strategy based upon informed goals and objectives
- Reassign program governance to an independent administrator to achieve accountability, transparency, information accessibility, and competition
- Pool CRA funds for accountability and administrative efficiency
- Develop program incentives tied to desired outcomes

An improved and successful organization would have a significant, beneficial effect on load reduction programs. Many such programs are included in the NJCEC programs and, with the growing difficulties the utilities are encountering in operating load reduction initiatives individually, the NJCEC programs may prove to be the best means of managing load in New Jersey.

3.4.2 New Jersey Clean Energy Collaborative 2001 Projects

The following is a complete list of collaborative programs based on a review performed by Davies Associates [16]:

<u>Collaborative programs in New Jersey</u>

- Residential Electricity HVAC
    - o Incentives for purchase of high efficiency equipment (heating, cooling and water heating) and for proper installation
    - o Consumer marketing campaign on key elements and benefits of efficiency (direct mail, bill inserts, radio and yellow pages offering brochure and video)
    - o Contractors training on key elements of quality installations (proper sizing, charge and air flow)
    - o Contractors Energy Star® sales training
    - o Promotion of HVAC technician certification

- Residential Gas HVAC (same features as for electrical counterpart)
- Residential Energy Star® Products
    - Program promotes the sale and purchase of Energy Star® rated and labeled residential products
    - Consumer marketing campaign
    - Sales training and marketing support to retailers and contractors selling Energy Star® products
    - Development of long term relationships with marketers of Energy Star® products
    - Co-op advertising
- Residential New Construction
    - Home owners receive energy ratings and Energy Star® certification
    - Program gives builders incentives to construct homes to program standards
    - Technical assistance to builders and their subcontractors
    - Marketing assistance to builders of efficient homes must meet performance standard of at least 30% improvement in energy efficiency
- Residential Retrofit Program
- Residential Low Income
    - Direct installation of cost-effective energy efficiency measures (e.g., insulation, compact fluorescent bulbs, efficient refrigerators)
    - Energy education
    - Installation of health and safety measures (e.g., CO Detectors)
    - Arrange reduction for participants who agree to payment plans
- Commercial & Industrial Energy Efficiency Construction
    - Prescriptive incentives for certain energy-efficient technologies
    - Custom measure incentives for more complex measures
    - Design support/technical assistance
    - Specialized program paths (e.g., chiller replacement and technical support for implementation of the new commercial energy code)
- Commercial & Industrial Building Operations & Maintenance
- Commercial & Industrial Compressed Air System Optimization
- **Residential AC Load Cycling Load Control Program**[4]
- School Energy Efficiency & Renewable Energy Education Program
- **Customer-Sited Clean Energy Generation Program**

The above programs are aimed at helping customers to reduce energy consumption and encourage EE&RE technologies. They make EE&RE technologies part of the New Jersey energy plan. The renewable resources that the program encourages attract high-tech industry, provide environmental benefits and reduce gas, oil, and coal imports into New Jersey. The programs also help to supplement and replace existing DSM programs, whose future is uncertain. The programs are useful in promoting competitive energy markets, improving system reliability, and adding alternative capacity. The NJCEC reported to the NJBPU in June 2002 that a large number of the EERE projects were

[4] Programs and objectives shown in bold are of high interest to load response programs.

attaining set goals. Table 3.4 lists the total expenditures, energy savings, and demand savings for NJCEC programs in 2001. These programs reduced emissions of CO_2 by 27,500 metric tons/yr, NO_x by 80 metric tons/yr, and SO_2 by 128 metric tons/yr.

Table 3.4 Summary of Results for Utility-Administrated Programs (2001)

	Actual	Committed	Total
Total Expenditures	$57,520,000	$22,207,000	79,727,000
Energy Savings (annual MWh)	55,000	69,600	124,600
Demand Savings (kW)	223,500	21,700	245,000
Demand Cost ($/kW)	$257	$1,023	$325

Table 3.5 lists the energy efficiency projects and summarizes the success of each. A number of projects performed well in excess of the goal such as residential new construction and many of the non-residential energy efficiency projects.

Table 3.5 Goal attainment for NJCEC Projects in 2001

Program	Metric	Goal	Actual	% of goal realized
Residential Energy Efficiency				
Residential HVAC - Electric	Participants	15,600	15,113	97
	Trained Technicians	600	712	119
Residential HVAC – Gas	Participants	8,400	8,275	99
	Trained Technicians	50	77	154
Residential windows	Retailers	150	160	107
	Manufacturers	2	2	100
Residential low income	Participants	13,004	11,684	90
	(Electric only)	*6,100*	*5,848*	*96*
Residential new construction	Enrollment	3,472	6,956	200
Residential lighting	Retailers	165	170	103
	Sales Trainees	330	330	118
Residential appliances	Retailers	83	131	158
	Sales Trainees	110	195	177
Non-Residential Energy Efficiency				
Commercial/Industrial construction	Savings (MWh)	15,000	26,293	175
	Thermal savings (Dtherms)	100,000	338,020	338
	Core projects	625	5,867	938
	Chiller Option projects	4	1	25
	Tier II projects	100	194	194
Building Operating & Maintenance	Operators trained	30	27	90
	Committed Pilots	3	11	367
Compressed Air	Compressed air audits	5	11	220

3.5 Interval Metering

Three things are required for loads to be able to respond to electricity prices and reduce consumption when supply is scarce. The load must see the real-time price. The load must have some ability to adjust consumption. And there must be a way to measure the load response. Without performance metrics there is no incentive to respond. Interval metering is generally the most attractive method to verify performance. Two utilities in New Jersey offer customers interval metering:

> JCP&L – Customers who have interval metering pay an approved one-time fixed charge (i.e., not a monthly charge) specified by the utility to help offset the additional cost of the interval meter and its installation. Where interval meters are used, they are generally 15-minute type.
>
> Conectiv – For C&I sites consuming 1 MW or greater, 15-minute load interval recorders are used that can be read by Itron hand-held data collection devices. There is no direct charge for the meters since they are covered by the cost of service. If the customer who is purchasing an interval meter desires (i.e., for their own purposes) to have optional advanced metering, they must pay the difference in cost up front.

Meters differ in what they measure and how frequently they do. Meters for residential and small commercial customers usually measure single-phase real energy use only. Meters for large C&Il customers measure three-phase demand and energy and may also measure reactive-power consumption and power-quality characteristics. The traditional residential meter records cumulative electricity use, typically read once a month by a meter reader who walks from house to house. Advanced meters record and store (within the meter) electricity consumption at intervals of 5, 10, 15, 30, or 60 clock-synchronized minutes.

For residential and small commercial customers, it may be cost-effective to retrofit existing meters. These retrofits include a pulse initiator that generates an electrical pulse for every revolution of the meter disc, a data recorder that records the number of pulses, and a communication interface. These packages permit the capture of electricity-use data at 15-minute intervals with communication of that data to the LSE on a daily or weekly basis. The cost of such upgrade packages is $50 to $200.

For new installations, larger customers, or more sophisticated applications, a new electronic solid-state meter may be installed. Such meters range in cost from $200 to more than $3,000. The range is so large because these meters differ in the number of channels of data they record, the amount of data that can be stored within the meter, the number of communication ports, and the communication medium.

3.6 Capacity Market

The Federal Energy Regulatory Commission (FERC) approved the design and operation of the PJM capacity market and has also approved changes to that market in recent years. Companies that sell electricity through PJM are required to have capacity to ensure the reliability of electricity service. The PJM capacity market requires suppliers to procure capacity for peak summer periods from June 1 through September 30.

While capacity requirements can help assure supply adequacy and dampen energy price volatility they do this at a cost. Once capacity is available then real-time energy prices only reflect the generator's marginal production cost. Capital costs are recovered through the capacity market. The disadvantage of this system is that it spreads the cost of meeting the relatively few peak hours of highest demand over the entire summer. This greatly reduces the price signals that tell the true cost of serving load each hour. This is a disadvantage because it reduces the incentive that loads have to reduce consumption during those few peak hours.

One solution is to allow responsive loads to participate in the capacity market and receive payments for their commitment to reduce load when needed. While this does work well for some loads it has limitations for others. First, loads often need flexibility in how they interact with electricity markets. Unlike generators, electric power is not their primary business. Loads often need flexibility to respond to changing conditions in their business. These may be entirely unrelated to conditions on the power system. So some loads will have difficulty committing to guaranteed response months in advance. Second, individual loads are typically much smaller than individual generating units. Hence, the failure of a single load to respond does not have the impact on the power system that a generator's failure to respond can have. It is the load's aggregated response that has value to the power system. Capacity payments may be justified based upon the statistical behavior of a large collection of loads rather than on long-term deterministic commitments from each individual. Metering of individual loads is still required; without performance metrics, there is no incentive to ever respond. But the aggregation should still receive capacity payments based upon the reliable characteristics of the aggregation.

Capacity payments also keep valuable resources in the mix even if significant time elapses in which response are not required. A load may not continue to maintain the capacity to curtail if years go by when no response is called for or paid for. For example, generators that supply black start capability to the power system, and enable it to restart in the event of a complete system collapse, are not paid on a per-event basis. Actual deployment events are too infrequent (hopefully never) for event-only payments to work. Instead, black start capable generators are paid a capacity payment so that they stand ready to supply the service if it is required. Similarly, it may be advantageous to the power system for some of the responsive load compensation to come from capacity payments.

3.7 Transmission Congestion

Transmission congestion occurs when there is insufficient transmission capacity to simultaneously accommodate all requests for transmission service within a region. Electric power industry restructuring has moved generation investment and operations decisions into the competitive market but has left transmission as a communal resource in the regulated environment. This mixing of competitive generation and regulated transmission makes congestion management difficult. The difficulty is compounded by increases in the amount of congestion resulting from increased commercial transactions and the relative decline in the amount of transmission. Figure 3.1 shows that transmission capacity, relative to peak load, has been declining in all regions of the U.S. including PJM/MAAC for over a decade.[5] This decline is expected to continue [17].

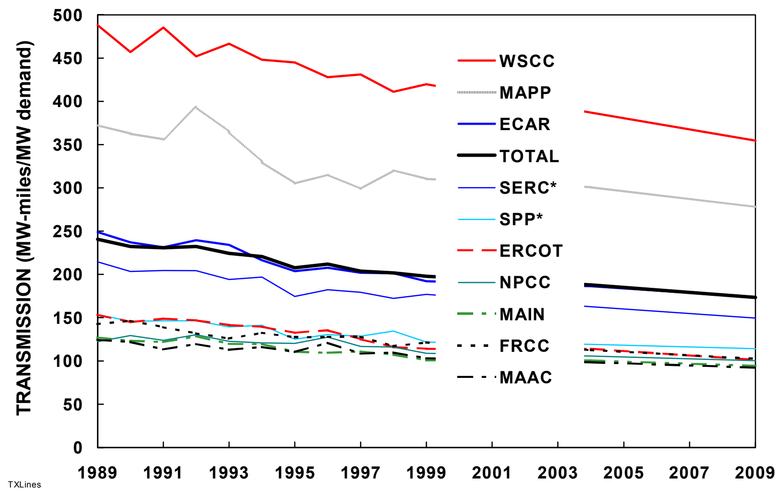

Figure 3.1 Transmission capacity relative to peak load has declined in every region of the U.S., including PJM/MAAC, for the past ten years and is expected to continue declining for the next ten.

PJM serves a large load relative to its transmission system; hence it is represented by the bottom line on figure 3.1. It has approximately 7.3 MW of demand per mile of high voltage transmission circuit (230 kV and above). This compares to 5.5 for the U.S. portion of the Eastern Interconnection and 2.1 for the Western U.S. Interconnection.

In recent years, New Jersey has experienced external transmission congestion in the PJM Eastern Interface between New Jersey and Pennsylvania. It represents the most important constrained interface in PJM. New Jersey also experiences internal transmission congestion at multiple locations caused by generation deficiencies [18].

The first responsibility of the transmission system is to maintain system reliability. This involves developing generation and load schedules that can be balanced in real time. Scheduling generators and loads must carefully consider any transmission link that could potentially become constrained. This consideration includes not only the current flows

[5] PJM is the MAAC (Mid-Atlantic Area Council) NERC reliability region.

on the system's lines and equipment, but it also must consider the post-contingency capacity. Each link on the transmission system must provide enough capacity that any single contingency within the system (and any credible multiple contingency) could be handled.

Although the transmission system operates according to the physical laws of power flow, the economic implications for congestion management are equally important. Transmission congestion can be easily managed by redispatching generators and curtailing loads but arbitrarily restricting generators and loads can have significant economic costs. Without congestion, the marginal cost to supply an increment of load is determined by the lowest marginal cost generator on the system and is the same for any load on the system. With congestion, however, the marginal cost to supply an increment of load is determined by location. The marginal cost for a given location is the lowest cost increment of generation supply with available transmission capacity between the generation source and the load.

PJM achieves congestion management through its centralized control of generation resources. The system operator utilizes a computer program that minimizes the cost of dispatching generation resources subject to the transmission constraints. Market incentives for power and transmission are combined through a system of LMPs. These LMPs are determined for 1,750 busses within the PJM system plus 5 interface busses with other control areas. Generation is redispatched and LMPs are calculated, based on the system marginal generating cost plus the "shadow price" on the transmission constraints specific to location of each generation and load buss, every 5 minutes. These LMPs are immediately posted on the Open Access Same Time Information Systems (OASIS) system (Internet) so they are essentially known in real time.

PJM provides a market that allows participants to financially hedge their transactions through Financial (or Firm) Transmission Rights (FTRs). The FTRs are initially auctioned and then traded in secondary markets. Their role is to provide a hedge against the uncertainty of high LMPs caused by congestion. The purchase of FTRs in effect guarantees the purchaser the LMP at the generation buss regardless of the LMP at the load buss.

In effect, PJM provides two types of incentives to account for congestion. The LMPs indicate the charge for congestion. These charges for congestion are only determined after the fact, however, they provide historical information that helps inform and indirectly provide incentives for future transactions to anticipate congestion costs. Market demand for FTRs corresponding to congested nodes or hubs (FTRs for hubs are created by a weighted average of an aggregation of nodal FTRs) will increase the cost to hedge a transaction and signal the anticipated cost of congestion.

Although congestion costs may be minimized by efficient congestion management strategies, an overarching concern is that the marginal cost of congestion should not be higher than the marginal cost of reducing congestion through investment in additional transmission capacity. In other words, high congestion costs should be a signal for expanding transmission capacity. Regulators must consider how the costs of congestion would be affected by increased investment in transmission facilities.

Determining the amounts and locations of congestion is relatively straightforward within the PJM system. Differences in LMPs show the location, duration and magnitude of congestion events. Historical price data for all busses within New Jersey, and the adjacent busses, can be analyzed.[6] Determining where future congestion will occur is somewhat more difficult as it requires making locational load and generation forecasts. Prices from FTR futures markets can add some additional insight.

Deciding on when and where to make transmission investments is harder still. Congestion can move rapidly from one location to another as generation and load patterns shift. Transmission investments, on the other hand, are exceptionally long lived and relatively inflexible. Facilities, especially lines, last 50 years or more with investment recovery typically spread over 30 years. Costs are predominantly capital, rather than operating, so there is little opportunity to reduce costs as use patterns change [19]. PJM uses a centralized process to plan transmission expansion. The costs plus a reasonable return are recovered through contracts and tariffs for use of the facilities. The Regional Transmission Owners must unanimously agree on the allocation of costs or costs are assigned based on the size or the voltage of the facility and the zone where the facility is to be located [20].

[6] Though determining congestion is not difficult, resources were not available to conduct such a study as part of this project.

4. EXAMPLE LOAD RESPONSE TECHNOLOGIES

There are a multitude of technologies available for controlling loads ranging from the very simple (public pleas for conservation, for example) to the very complex (industrial loads responding to the 10 minute spot power market). Most are directed at peak shaving and energy management though some are facilitating load's provision of ancillary services. Three example technologies for smaller loads that ORNL is actively working on are presented here.

Carrier Comfort Choice Controllable Thermostat

Carrier's programmable Comfort Choice residential and small commercial thermostat is centrally controllable, providing demand reduction when the power system is under stress. The power system operator communicates with the thermostat through the Internet and Skytel's paging network. The customer also uses the Internet-based communications network to manage their energy consumption, set temperature schedules, and monitor the home or small business remotely. This adds value for the customer and typically reduces or eliminates the need to pay the customer for utility-controlled load response [21].

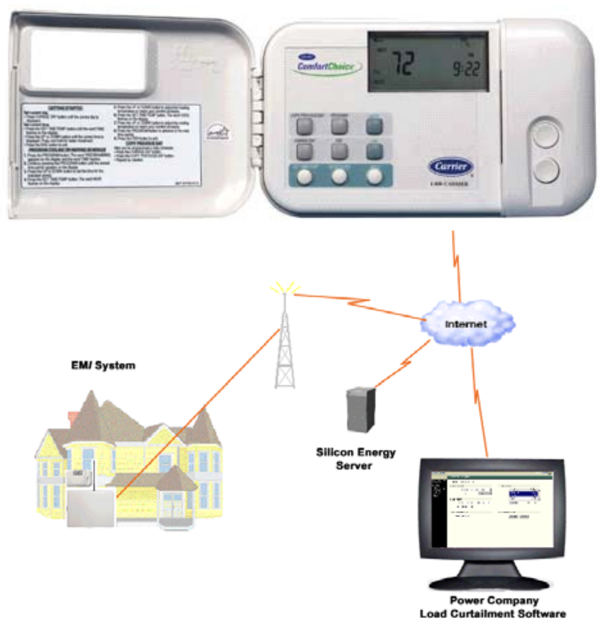

Figure 4.1 Carrier's Comfort Choice thermostat provides energy savings to the customer and demand relief to the utility.

One critical feature is that customer choice is retained. The customer has the option to override any curtailment. As theorized, this feature is important for retaining customer participation but it is infrequently used.[7]

[7] The system has the ability to issue a curtailment that the customer can not override. In that case the thermostat displays "critical situation" and does not respond to customer commands.

Two way communications and data logging are supported. Each thermostat acknowledges receipt of each schedule change or curtailment command. To avoid overloading the paging system with tens of thousands of immediate reply messages to a general curtailment, the thermostats stagger their responses over an hour or two. Each thermostat also retains, and reports back, hourly information on the actual temperature, heating/cooling system run time, and number of starts.

Communications from the utility to the thermostats and subsequent curtailment response is sufficiently fast (tens of seconds) that it is likely that they can meet the technical requirements to provide spinning reserves.[8] ORNL is working with Carrier, utilities, and the ISOs in New York and California to develop and demonstrate this capability.

The Energy Detective (TED)
The TED is a novel device that keeps customers informed about the cost of the electricity they are consuming, enabling them to make informed choices about energy use. Total home energy consumption is measured at the incoming feed and transmitted to the display unit which can be located anywhere in the home for convenient use.

Figure 4.2 TED provides information on the current cost of their electricity use allowing them to make informed choices and reduce demand.

The utility rate structure is programmed into the display unit which can then present current consumption in $/Hr or KW. Consumption for the day and month can also be displayed. The inclusion of the tariff information helps consumers quantify the increased benefit of controlling consumption on peak [22].

Adding the capability to receive real-time prices, coupled with having a real-time-tariff, will increase the value of TED to both the customer and the utility. Adding control

[8] Typically the system is used to schedule an upcoming curtailment event rather than to request immediate curtailment. The utility might issue a command at 9:00 am telling all thermostats to raise their air conditioning set points by 2 degrees starting at 1:00pm and returning to normal at 5:00 pm. The thermostats typically all respond by 10:30 am that they received the command.

capability that acts when costs exceed a customer-selected threshold will also increase its value. Finally, moving the voltage and current sensors from the circuit breaker panel where an electrician is required to install them and into a meter-base-collar where a utility meter technician can quickly plug them in may also reduce costs and increase acceptance.

This device is under development by Energy Inc. of Mt. Pleasant South Carolina and is ripe for a demonstration project.

PTAC Controllers for Energy Management and Spinning Reserve

Digi-Log has developed an add-on central control technology for hotel/motel packaged-through-the-wall-air-conditioners (PTACs). The front desk is then able to reduce the heating and cooling levels in unoccupied rooms and save significant amounts of energy (31% for occupied rooms and 43% for unoccupied rooms) and reduce peak consumption.

Figure 4.3 The Digi-Log PTAC controller (box below the PTAC and on right) adds central control capability to existing hotel/motel heating and cooling systems. An ORNL data collection box is located to the left.

ORNL has worked with Digi-Log to develop and test this technology. ORNL is now working with Digi-Log, the Long Island Power Authority (LIPA), New York State Energy Research and Development Authority (NYSERDA), and the New York Independent System Operator (NYISO) to add spinning reserve capability.

5. SUMMARY AND RECOMMENDATIONS

Restructuring of the electric power industry is challenging power system operators, customers and regulators alike. Markets are reasonably well developed (and getting better) on the supply side but are only beginning to develop on the demand side. Inherently, volatile real-time power prices provide valuable economic signals that potentially can allow loads, generators and system operators to continuously optimize the power system for everyone's benefit. Maintaining customer choice is fundamental to market operations; electricity is no exception. Advances in communications, control and metering technologies are helping to make this possible. Regulators play a critical role in assuring that markets are designed properly and that all players are treated fairly. They can also help by conducting research and demonstration projects that showcase new technologies and overcome barriers.

All customers benefit through dramatically lower prices when even a relatively few customers reduce consumption during times when the power system is heavily stressed. It may be desirable to socialize some of the costs of facilitating customer response in order to reduce barriers and encourage more loads to become responsive. Providing advanced metering to all customers might be one example.

Regulators must stay actively involved in the PJM planning process for both market design and the transmission system. It is natural, in a competitive environment, for individuals to advocate in their own self interests. Large entities with major economic interests, such as generators, will assure that their needs are known and addressed. Smaller individuals such as residential and commercial loads have less ability to participate even though, collectively, their economic interest is at least as large. State regulators are a natural advocate for these constituents.

Specific recommendations include:

Real-Time Pricing

Provide real-time price signals to *all* customers, at least as an option. Further, do not undercut the real-time prices by subsidizing a flat-rate offer. Flat-rates are a good financial tool that many customers will prefer to hedge the risk of price volatility. But that financial tool naturally carries an insurance premium and any flat-rate tariff should reflect this. Loads will then be able to optimally select what is best for each.

It is the real-time prices that best communicate the current condition of the power system and its need for demand relief.

Many options exist for how best to expose different types of customers to real-time prices. Some will prefer to see the real-time prices directly. Others will prefer to pay for firm service but have the option to sell back when real-time prices are high and they have the ability to reduce consumption. Two factors are critical:

- Maintain customer choice: always have the customer deciding when the customer can respond and when it can not.

- Expose all customers to real-time prices: let all customers know when the power system is under stress so that they can respond and help.

Ancillary Services
Many loads are inherently better able to provide ancillary services than they are to reduce their on-peak energy consumption. Advances in communications and control technologies allow them to (potentially) respond quickly enough to supply even the fastest spinning reserves. However, limitations in their own primary operations often restrict how long they can reduce their energy consumption. A 30-minute spinning reserve response may be possible when a 4-hour curtailment is not. New Jersey should pursue projects to educate loads and system operators about this opportunity and to encourage customers to participate. Opportunities exist for all classes of customers, from residential controllable thermostats to large industrial pumping loads.

Advanced Metering
Advanced metering is required to enable real-time energy pricing, customer choice, load response and load's provision of ancillary services. Promoting, providing, subsidizing, and/or standardizing short-interval revenue metering is helpful. Similarly, establishing standard communications protocols is helpful. Regulators can help in two critical ways:

- Many advanced metering technologies require high penetration rates to be cost effective. Regulators should select/approve advanced metering technologies for widespread deployment to reduce customer and utility investment uncertainty.
- Regulators can *require* advanced metering. High volumes will reduce the initial cost and encourage customers to take advantage of opportunities to become responsive. Socializing the cost of interval metering can be clearly justified by the fact that all customers benefit from the reduced market-clearing price.

Transmission Congestion and Expansion
The New Jersey regulators and utilities, and all others with a strong interest in electric power reliability, should participate fully in PJM's transmission planning activities. In addition, a study of transmission congestion within New Jersey should be conducted utilizing the 5 minute LMP data for all busses within New Jersey. This, combined with PJM transmission expansion plans, will provide a basis for determining what transmission enhancements will be of value to New Jersey for the extended future. The long life of transmission projects and high capital to operating cost ratio makes the planning process especially critical. The numerous externalities (visual impact, public interest, impact on interstate power flows, etc.) make this issue especially important for regulators.

Demand Response Programs
Traditional utility-led demand response programs were technically effective but limited in participation. Restructuring has made the utilities' market position and interest less clear. Existing programs have high utility effectiveness and customer satisfaction and a low dropout rate but are being canceled because of regulatory and market structure issues and uncertainty. This is unfortunate since advances in technology can now reduce costs,

improve response, increase the range of responses and provide customer choice. All of which will likely increase participation dramatically.

Regulators can help in three ways. They can increase regulatory certainty: make it clear who has the long term interest in serving load and facilitating demand response. They can also establish demand response programs, preferably coupled with real-time tariffs. Programs that demonstrate technologies are good; programs that sustain significant response capability are better. Demand response programs should be integrated with PJM programs but they need to extend down to the customers themselves. It may be useful to research tariff design opportunities to determine specifically what tariff offerings will work in New Jersey. Experience from other states will be useful but must be integrated into the PJM market design. Third, regulators can assure that demand response programs are compatible with those offered over a wide geographic area (the PJM region or greater). This will encourage the development of standard communications and response technologies that customers can easily purchase and implement.

Education and Outreach

Loads differ from generators in that electricity is not their primary business concern. Many loads are unaware of how they can adjust the electricity consumption in ways that benefit power system reliability and reduce costs. Educational programs that help loads understand the options they have are very useful. Research to identify load-specific response capabilities for specific industries and commercial enterprises can also be useful. Similarly, research to help system operators better understand the capabilities and limitations of load response would help. PJM is trying to design technology-neutral market rules and reliability service requirements but this is a difficult task and they could probably use help.

All of this is justifiably within the public interest because load response provides substantial reliability and price benefits to all power system users, not just the loads that respond.

The future of load response is bright. Technology is available. But much work remains to be done to capture the critically needed benefits for many years into the future.

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