NEW ENGLAND DEMAND RESPONSE INITIATIVE

Dimensions of Demand Response: Capturing Customer Based Resources in New England's Power Systems and Markets

Report and Recommendations of the New England Demand Response Initiative

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NEDRI's able technical consulting team consisted of nationally-recognized experts including: Charles Goldman of Lawrence Berkeley National Laboratory who took the lead on the Regional Demand Response Chapter and prepared the final Contingency Reserves Chapter. Rick Weston of RAP took the lead along with independent consultant Jim Lazar on the Pricing and Metering Chapter. Independent consultant Jeff Schlegel took the lead role on the Energy Efficiency Chapter. Brendan Kirby of Oak Ridge National Laboratory and independent consultant Eric Hirst developed the initial scoping papers for the Contingency Reserve Chapter. Finally, Richard Cowart drafted Chapter 1, and he and Richard Sedano took the lead in drafting the Power Delivery Chapter.

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We are grateful for all of these contributions. Congratulations to everyone for a job well done.

Richard Cowart, NEDRI Policy Director
Jonathan Raab, NEDRI Facilitator
July 2003

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NEDRI Members

State Utility Commissions (NECPUC members)

Connecticut Department of Public Utility Control
Maine Public Utilities Commission
Massachusetts Department of Telecommunications and Energy
New Hampshire Public Utilities Commission
Rhode Island Public Utilities Commission
Vermont Public Service Board

System Operators

ISO New England, Inc.
New York Independent System Operator
PJM Interconnection

Environmental Regulators

Connecticut Department of Environmental Protection
Massachusetts Department of Environmental Protection
Northeast States for Coordinated Air Use Management
U.S. Environmental Protection Agency

State Energy Offices

Massachusetts Division of Energy Resources
Vermont Department of Public Service

Utility, Demand Response and Market Participants

Demand Response and Advanced Metering Coalition (DRAM) (by Peregrine)
Green Mountain Energy*
Joint Demand Response Resource Supporters (by The E Cubed Company)
Mirant*
Massachusetts Technology Council
National Association of Energy Service Companies (NAESCO)
National Grid
Northeast Energy Efficiency Partnerships, Inc.
Northeast Utilities
PG&E Energy*
PowerOptions/Massachusetts Health and Education Facilities Authority
Price Responsive Load Coalition
Sithe*
United Illuminating
Vermont Energy Investment Corporation

Consumer and Environmental Advocates

Connecticut Office of Consumer Counsel
Environment Northeast
Maine Public Advocate
Pace University Energy Project
Union of Concerned Scientists (by Synapse)

Federal Agency (non-voting) Members

Federal Energy Regulatory Commission (FERC)
U.S. Department of Energy

*These NEDRI members actively participated in the NEDRI discussions in 2002 that laid the foundation for this Report, but did not participate in drafting the final Report and recommendations after January 15, 2003. The majority of the recommendations in Chapter 2 were finalized on January 15, 2003.

Acronyms

AM	Advanced Metering
CBL	Customer Baseline Load
CPP	Critical Peak Pricing
CPS	Control Performance Standard
CSP	Curtailment Service Provider
DADRP	Day-Ahead Demand Response Program
DADRP-E	Day-Ahead Demand Response Program-Economic
DADRP-R	Day-Ahead Demand Response Program-Reliability
DCS	Disturbance Control Standard
DISCO	Distribution Company
DOE	Department of Energy
DR	Demand Response
DRP	Demand Response Provider
DSM	Demand Side Management
DSP	Default Service Providers
EPACT	Energy Policy Act of 1992
ESCO	Energy Service Company
ESP	Electric Service Provider
FERC	Federal Energy Regulatory Commission
ICAP	Installed Capacity
ISO-NE	ISO New England, Inc.
LSE	Load Serving Entity
MCP	Market Clearing Price
NECPUC	New England Conference of Public Utility Commissioners
NEDRI	New England Demand Response Initiative
NEPOOL	New England Power Pool
NERC	North American Electric Reliability Council
NPCC	Northeast Power Coordinating Council
NTGS	National Transmission Grid Study
NYISO	New York Independent System Operator
PCLB	Price Capped Load Bidding
PJM	PJM Interconnection, Ltd
PUC	Public Utility Commission
RDR	Regional Demand Response
RT-EDRP	Real Time Emergency Demand Response Program
RTEP	Regional Transmission Expansion Plan
RTO	Regional Transmission Operator
RTP	Real Time Pricing
SBC	System Benefits Charge
SMD	Standard Market Design
TOU	Time of Use

CHAPTER 1: INTRODUCTION AND OVERVIEW

Demand Response Resources in Context

The **New England Demand Response Initiative** (NEDRI) was established to develop a comprehensive, coordinated set of demand response (DR) programs and policies for power markets and systems throughout the New England region. This effort grew out of a growing realization among market participants and policy makers that the efficient integration of demand response resources (DRR) would be central to the long-term success of restructured electricity markets, power portfolios, and delivery systems. This realization was based in part on early experience with wholesale power markets in New England, but to a greater extent was based on market and reliability problems in other regions, especially those in 2001-02 throughout the Western United States.

National setting. For much of the past decade, the U.S. electricity sector has been engaged in a complex process to bring increased competition to the business of electric generation, sales, and service delivery. The objectives of electric industry restructuring have been to harness the forces of competition to increase the efficiency of the electric system, to reduce costs, and to improve the services and choices offered to consumers. Initial legislative and regulatory efforts to promote competition have focused on the supply side of the market: creating trading floors for energy and capacity sales, removing barriers to independent generators and marketers, and promoting open and non-discriminatory access to the transmission grid. It was assumed by many that robust competition among a variety of **suppliers** would be sufficient to ensure reasonable electricity rates and service options to customers.

However, the nation's experience to date with the introduction of supply-side competition has been mixed. On the positive side, competitive wholesale transactions and investment in independent generation have advanced rapidly, and some regions have seen competitive wholesale markets with a healthy balance of longer-term bilateral and short-term spot trading arrangements. But there have been problems as well, including unwanted price volatility, supplier market power, a boom-bust cycle in generation investments, little retail competition, heavy reliance on default pricing, and an underinvestment in energy efficiency and renewable supply technologies.

Lessons. A principal lesson from this experience is that competition among electricity suppliers alone (without an active demand response) is not enough to create efficiently competitive electricity markets. Electric systems face two challenges not faced by other commodity markets: (a) because storage is impracticable, load must be served instantaneously, even though demands on the grid vary considerably across time and geography; and (b) because customers are physically interconnected, and because electric service is central to economic and social well-being, continuous, universal service without interruptions has an extremely high value. Thus, the balance between demand and supply is critical *at all times*, and this balance must be assured over a *sustained period of time*. Moreover, the electric power system has a large environmental footprint, and is crucial to the general public good. Demand response resources are an important response to these essential features of electric systems

Volatility, price spikes, worsened environmental impacts, and diminished reliability can be moderated through **actions on the demand side** of the market. Actions are needed to address two complementary needs: First, it is essential to develop active responses to market prices and system conditions on the demand side in order to enhance market efficiency and system reliability – that is, ***active load management*** by customers. Second, enhanced ***energy efficiency investments*** could lower market clearing prices, improve reliability and environmental quality, and lower the region's total cost of electric service over the long term. Furthermore, significant market barriers to cost-effective *active load management* and *energy efficiency investments* will remain, even in conditions of active wholesale competition. Thus, market and policy reforms that will call forth economic demand responses – both short-term load curtailments and longer-term reductions in consumption patterns – are needed.

NEDRI's Structure and Process

NEDRI builds upon the considerable experience of utilities, customers, service providers and governments in each of the region's states with demand-side management (DSM) over the past two decades. That experience had demonstrated the large potential for energy efficiency and demand response resources in the region, and the value of capturing those resources to serve consumers better, to reliably balance power systems, and to lower power system costs. NEDRI was created to develop DR programs and policies that would be appropriate in the region's new wholesale market structures, and within the retail structures evolving in each of the region's six states.[1] The recommendations embodied in this Report would affect both wholesale and retail markets and should result in lower prices, enhanced reliability, market power mitigation, and environmental enhancement.

The NEDRI Group's (Group) recommendations are the result of a broad-based, facilitated process involving more than 30 stakeholders representing all key electric market interests. Members that participated include ISO New England (ISO-NE), consumers, environmental and utility regulators, generators, utility companies, state energy offices, and other interested

[1] Five states (Maine, New Hampshire, Massachusetts, Rhode Island and Connecticut) have adopted retail competition policies, with some similarities but important differences among them, while one state (Vermont) retains its historic franchise system. The entire region is served by ISO-NE, which operates the region's wholesale power markets, and conducts dispatch, operations, and reliability functions, and conducts a regional system planning process.

organizations (see Appendix A). The region's two neighboring ISOs (NYISO and PJM) and the key federal agencies – the Federal Energy Regulatory Commission (FERC), the U.S. Environmental Protection Agency, and the U.S. Department of Energy – also supported the process.

NEDRI first convened on February 26, 2002 and held 16 plenary meetings over 17 months, concluding in July, 2003. In addition to the plenary meetings, the Group convened several ad-hoc working groups to refine and prepare more detailed recommendations and supporting text for consideration by the full Group. In September 2002, in cooperation with the FERC and ISO NE, NEDRI also convened a national workshop on demand response. This workshop focused on the needs and suggestions of DR providers and end-use customers, and provided valuable insight on DR policy topics from many market participants from across the nation.

The Group studied, discussed, and created program recommendations in numerous areas including: regional reliability, regional (short-term) demand response programs, retail pricing and metering, energy efficiency, load participation in providing contingency reserves, and power delivery. For each program area, the Group first established basic principles around which programs should be designed. It then deliberated and sought consensus on specific policy recommendations and program features.

Since DR resources necessarily involve the participation of a broad range of market participants and involve both wholesale and retail issues regulated by federal and state regulators, it is essential to coordinate the development and implementation of DR programs. NEDRI intends that these recommendations, most of which bear the consensus seal of approval of the NEDRI stakeholders, could serve as a model for other regions to follow

Throughout the process, NEDRI's work was supported by a team of expert advisors, who developed Framing Papers, draft recommendations and other guidance documents for the Group's consideration; a professional facilitation team who framed and guided deliberations; and a dedicated website which served as an archive and clearinghouse for all project-related documents. An extensive collection of materials related to Demand Response has been developed for this project.[2]

Principles for Demand Response Resources

The overall objective of NEDRI has been to devise an effective long-term strategy for demand responsiveness, which includes load response resources and efficiency investments, in New England's power systems and markets. The NEDRI members agree that such demand responsiveness is an essential component of the wholesale market, and can be compatible with both competitive and franchise retail markets. NEDRI participants envision a regional economy and environment enhanced by a more productive and less wasteful electricity system, and one that is more reliable and more vigorous due to broad-based competition among both supply-side and customer-located resources.

[2] The most important background materials and supporting documents are set out in Appendix C.

At the outset of the NEDRI process, the Group discussed in general terms the goals of demand response, and general principles that should guide policy and program development. The cross-cutting general principles that NEDRI concludes should inform the design and implementation of a wide range of demand-response programs and resources are set out below:

- **Efficiency and productivity:** New England's electric system is a complex web that includes generation, transmission, and distribution services, together with end-use applications and equipment at customer locations. The overall efficiency of this *entire* network is a principal focus of public energy policy. The overriding objective of the NEDRI process is to develop energy markets and public policies that will maximize the value of electricity services in the region, while minimizing the total societal cost of electricity production, delivery, and use.

- **Using market forces:** As historic aspects of the vertically-integrated electric system decline, electricity markets in New England have become more competitive. The region's basic markets for electrical energy, capacity, and ancillary services should be designed so that they are workably competitive, and open to comparable demand-side resources on a level basis with more traditional supply-side resources. Wherever possible, end-use customers should be empowered to deliver distributed resources, including load management, energy efficiency resources, and clean distributed generation to regional electricity markets, at prices that reflect the value of those resources to the grid.

- **The role of public policy.** While the region's emerging electricity markets hold great promise in certain areas, market outcomes alone are not a substitute for public policy. Lacking a well-developed demand response, and with only modest retail competition, the region's power markets are not yet fully developed. In addition, market barriers still block many cost-effective end-use investments in load management and energy efficiency, and certain public costs, including environmental and reliability costs, are not fully reflected in today's market prices. For these reasons, public policy should intervene when market mechanisms alone do not capture the full value of demand-side resources.

- **Comprehensiveness**: One critical lesson from the region's *historic* experience with utility DSM programs is that multi-faceted DSM programs are needed to tap the efficiency and load management resources that are embedded in numerous, diverse end-use technologies and locations. One critical lesson from the region's *recent* experience with regional power markets is that divestiture and default service plans can create new barriers between wholesale costs and the retail prices that customers face. To maximize the value of demand resources within the region, decision-makers must view the electric system comprehensively, consider market rules, tariffs, and policies at both the wholesale and retail levels; and employ a variety of tools to develop and deliver demand response resources to the system.

- **Environmental Protection.** Beyond its economic and reliability benefits, demand response has the potential to provide long-run environmental benefits through greater investment and innovation in energy efficiency, decreased peak load energy and transmission requirements, and increased use of low or non-polluting small-scale supply resources. However, because of the possibility that demand response resources could increase air emissions associated with the provision of electric services, environmental impacts and policies are of primary concern in shaping demand response programs and opportunities. Demand response programs should ensure no net environmental harm in the short run, and in conjunction with electric supply resources should contribute to improved air quality over time.

- **Administrative Simplicity.** Experience with regulated programs of many kinds, and with market-based demand management options, teaches us that both market and regulatory transaction costs can create barriers to a more efficient power system. An overemphasis on regulatory process, participation preconditions, or on complex market rules may, on the whole, be counter-productive. Demand response market rules and programs should be designed to minimize transaction costs and regulatory requirements, consistent with principles of overall cost-effectiveness, market sensitivity, public accountability, and consumer equity.

Dimensions of Demand Response – A Typology of Values and Resources

As noted above, a principal lesson of NEDRI's investigations is the realization that "demand response" is not a one-dimensional concept, but rather a multi-faceted set of resources that can provide value to electric systems and markets in a variety of ways. The breadth of this resource mix is described briefly below, as a foundation for the recommendations in this report.

Most discussions of demand response begin with the observation that day-ahead and hourly electricity markets exhibit steeply inclining prices as load grows and reserve margins shrink on the system. In this market environment, a relatively small reduction in demand can yield a much larger percentage reduction in the market clearing price.[3] (See Figure 1-1.)

[3] "The few examples that have been observed indicate that when supply is scarce relative to expected demand a reduction in demand of 2-5 percent could reduce prices by half or more." M. Rosenzweig, et. al., "Market Power and Demand Responsiveness: Letting Customers Protect Themselves" (Electricity Journal May 2003, at p. 15).

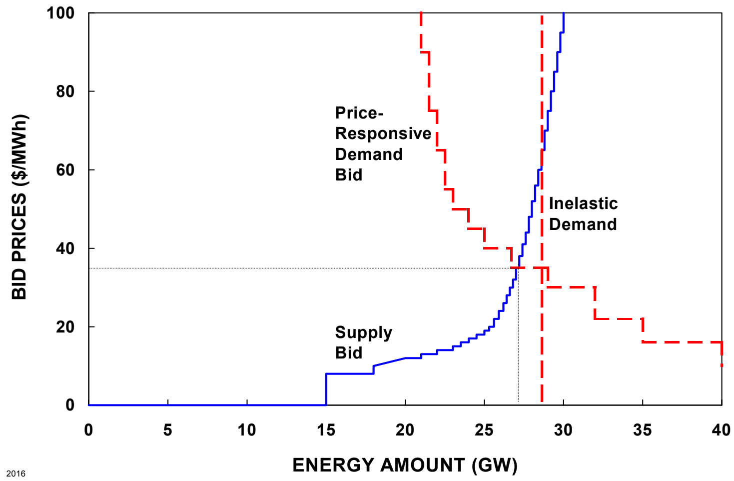

Figure 1-1. Wholesale electric market supply and demand curves. Revealing customers' willingness to pay yields a small reduction in demand (from 28 to 27 GW), and a large reduction in the market clearing price (from $60/MWh to $38/MWh).

Yet, without effective demand response opportunities, customers who would be willing to reduce their consumption and balance the system at a lower price are not given a market opportunity to do so. Because this problem has weakened the functioning of wholesale power markets, both market participants and regulators have focused a great deal of attention on the need for short-term, price-responsive load curtailments.

Wholesale market rules that support short-term, price-responsive load curtailments are an essential element of an efficient wholesale market structure.[4] However, the concept of "demand response" does not end there. A principal finding of NEDRI's inquiries is that the limited view of demand response is much too narrow. Broadly stated, Demand Response Resources (DR resources) include all intentional modifications to the electric consumption patterns of end-use customers that are intended to modify the quantity[5] of customer demand on the power system in total or at specific time periods. There are many opportunities for customer-based DR to add value to power systems and markets, and many types of DR resources to call upon.

This broad view of DR resources takes into account two kinds of resource attributes, which are set out in the typology below. First, we consider the *purposes and values* of different demand response resources as elements of power markets and power systems – what power system values are advanced, and what supply-side resources are affected? Second, we consider the

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[4] FERC has clearly and repeatedly made this point in its Standard Market Design proposals and in review of market rules in individual regions. By moving to a multi-settlements system that permits demand-release resales in the short-term market, ISO-NE has taken a major step in this direction as well.

[5] This includes both the level of instantaneous demand (capacity in kW or MW), and total consumption in kWh or MWh.

operational characteristics of the demand-response resource – how is it deployed and for how long; how is it called, and for what duration? The various types of demand response are set out in the tables below:

Types of Demand Response: Purposes and System Values

DR resources can be developed and deployed to meet system needs, to lower costs, and to add value to power markets in a variety of circumstances. The most important opportunities are:

- Economically balancing supply and demand in ***wholesale power markets*** (DR resources here include price-responsive curtailments, including demand-side bidding and demand release re-sales or sale-backs);
- Cost-effectively ***reducing long-term demand and lowering throughput***, both on the power grid as a whole, and within the resource portfolios of power suppliers, including individual standard offer/default service providers (DR resources here include broad-based energy efficiency investments, which can supply energy services with lower costs, risks, and environmental impacts compared to generation investments.)
- ***Moderating inefficient demand*** through more accurate retail pricing options and policies to permit retail loads to enroll in DR programs (DR resources here include pricing systems, price-responsive curtailments, and metering/communications infrastructure that call forth both long-term and short-term customer load responses);
- Enhancing ***regional power system reliability*** by using demand response resources to meet planning and operational reserves (DR resources here include ISO-level reliability-focused assets, providing emergency curtailments and/or routine contingency reserves); and
- Lowering the cost of ***power delivery***, reducing congestion, and improving the reliability of the delivery system (DR resources here include both short-term demand resources and long-term transmission and distribution congestion relief programs).

To provide for all of the resource values noted above, energy companies and end-use customers can call upon a rather wide range of technologies and behavioral responses, which are noted briefly below.

Types of Demand Response: Resource Characteristics

A Broad Potential Array of DR Resources: In considering the range of possibilities, it is helpful to view DR resources across at least three dimensions from the perspective of the system operator and the customer:

- **Term of availability**: some DR resources will be available to balance the grid only for short periods of time; others will be available over a period of years.

- **How deployed?** Some DR resources (e.g., interruptions or curtailments of industrial processes) are *dispatchable* by a system or utility operator. They can, and must actively be called in order to respond to system conditions on short notice. Other DR resources can be *scheduled* as load curtailments by system operators in day-ahead and real-time markets. Additional DR resources arise as a result of *customer response* (either manual or automatic) *to price* signals (e.g., TOU rates.) Finally, some demand-side resources (e.g., efficient air conditioners) can be *deployed* and are constant in nature. Once installed by the customer,[6] they can deliver value to the utility system wherever they are operating, without being called by ISO or utility operators.

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- **Nature of the response:** Here again, a variety of options should be considered. Some instances of demand response involve only *conservation*, a long-term reduction in use. In other cases, the customer *reduces load* in response to specific system conditions such as high prices or a reliability-threatening event, or *shifts load* from peak to off-peak (or higher-price to lower-price hours). And, in some instances, the demand response in question is actually accomplished, not through a reduction in the customer's electricity use, but by an increase in *on-site generation*, which reduces the customers demand on the grid.

Structure of This Report

In the following chapters, NEDRI addresses the broad range of DR resources set out above. Chapter 2 begins with detailed discussion of program design elements for *regional DR programs*, administered by ISO-NE to address acute reliability problems and mitigate high prices. Chapter 3 focuses on policies for *retail pricing and metering* that would enhance both short-term and long-term demand responses at the customer level. In Chapter 4, we examine the role of long-term investments in *energy efficiency resources*, and emphasize their contribution to both capacity and energy savings Chapter 5 addresses policies and programs that could call forth DR resources to provide reliability-based *contingency reserves*, which would enhance the reliability of the wholesale electricity system. Chapter 6 focuses on *power delivery systems*, and presents recommendations for tapping DR resources to relieve congestion and promote reliability across the region's transmission and distribution grids.

In these chapters NEDRI participants present a broad view of the potential for DR resources to improve the reliability of New England's power system, and to lower its financial and environmental costs, by making customer-based resources available to energy resource portfolio managers, to energy and capacity markets, and to system operators.

[6] Note that in the context of Demand Response policy, the *decision to install* more efficient end-use equipment in particular quantities and locations is a conscious resource deployment decision. The deliberate modification of customer load through investments in efficient end-use technologies, particularly those that affect peak power periods, is a valuable component of demand response policy. Strategies that support such strategic, long-term investments are discussed in Chapter 4, Energy Efficiency.

NEDRI has adopted a total of 38 recommendations to support the comprehensive development of cost-effective DR resources throughout the region. These recommendations represent the consensus of all NEDRI members except in limited circumstances noted in the text.[7] [8] However, beyond the 38 specific recommendations, as with any consensus process, individual stakeholders may not agree with each specific example, specific wording or with an unintended implication that might be drawn from a particular recommendation.[9] In adopting these recommendations the NEDRI members recognize that their implementation by the states, regulated utilities, ISO-NE or other affected parties is contingent upon approval by their respective governing agencies and that its members are free to present the particular views of their organizations in any proceedings in which these recommendations are being considered.

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[7] Consistent with NEDRI's ground rules, the following state agencies are abstaining from endorsing the final recommendations in the Report: Connecticut Department of Public Utility Control, Maine Public Utilities Commission, Massachusetts Department of Telecommunications and Energy, New Hampshire Public Utilities Commission, Rhode Island Public Utilities Commission, Vermont Public Service Board. See their letter of support in Appendix F.

[8] While unanimously supporting recommendation PD-6 in the Power Delivery chapter, NEDRI goes on to offer 3 alternative implementation paths supported by different members.

[9] National Grid, Northeast Utilities and United Illuminating have an overriding concern about statements in this report that can be interpreted to suggest that their independence could be compromised by directing their participation in demand response programs. See pages 122-123 for further details.

CHAPTER 2: REGIONAL DEMAND RESPONSE PROGRAMS[10]

Summary

Active demand response to market and power system conditions will play a critical role in creating an effective wholesale market and in sustaining the reliability of the grid in New England. NEDRI Participants and the NEDRI process have focused significant attention on improved program designs and policies that could attract a sufficient base of demand-side resources in short-term load response efforts. Based upon experience to date in New England, program experience in New York and PJM, and substantial input from participants in the NEDRI-FERC Focus Group on Demand Response, we conclude that the ISO New England's existing Regional Demand Response (RDR)[11] program designs should be strengthened in several ways.

In this chapter NEDRI participants summarize specific program design changes recommended to strengthen those programs and attract sufficient providers and customers to them; to ensure that RDR programs can be funded adequately; and to ensure that they do not impose undue environmental harms when implemented. We also recommend selected complementary policies at both the state and regional levels that will support active and effective Regional Demand Response programs.

The eleven recommendations below represent a consensus of NEDRI's diverse participants unless otherwise noted in the text.

[10] Recommendations RDR 1-8 were formally adopted by NEDRI in January 2003, were filed at FERC shortly thereafter, and in large measure were accepted by FERC in orders dated February 25, 2003 (Docket no. ER01-3086-001) and June 6, 2003 (Docket no. ER02-2330-004). No additional action on these recommendations is being taken by NEDRI in this Report. Recommendations #9-11 were approved at the June 18-19, 2003 NEDRI meeting.

[11] Throughout much of our discussion, NEDRI used the terms "Price Responsive Load Program" or "PRL program" to refer to these regional efforts. However, recognizing that the programs under discussion here have both reliability and price-response characteristics, the group adopted the general term "Regional Demand Response Programs" for them. That term is often used in this document. The program designs are not affected by this change in terminology.

Introduction

The Role of Short-term Demand Response in New England's Power Markets

Growing experience with regional power markets in New England and across the nation has led to an almost universal understanding that an active demand response is crucial to both market efficiency and power system reliability. Demand response resources can contribute to efficiency and reliability in several different ways.[12] One important opportunity is the role that short-term, price-responsive load can play in real-time and day-ahead power markets. The ultimate objective of efforts here is to create sufficient price-responsive load so as to improve the performance, efficiency and reliability of wholesale electricity markets. Several conceptual studies and actual experience in other regions (e.g., New York) have demonstrated that a relatively small amount of price-responsive load can enhance system reliability if there are reserve shortfalls and substantially reduce market-clearing prices during tight market conditions, producing significant benefits to consumers.

In its Notice of Proposed Rulemaking on Standard Market Design, FERC observes that "participation of demand in the market is critical for an effective wholesale market," and proposes policies and market rules to develop demand response resources across the energy, capacity, ancillary services, and transmission arenas. ISO-NE and the region's utility regulators have also embraced this goal; however, the ISO's DR programs over the past two years have attracted only modest enrollments, and have provided modest peak-load reductions to the grid[13]. Translating these broad principles into a set of specific programs and policy initiatives to develop demand response resources in New England has been a major challenge for participants in the NEDRI process.

The NEDRI Technical Consultants examined various options for demand response resources to provide load curtailments or decrements in response to system emergencies and market (price) signals in the day-ahead energy market as well as key policy and program design issues (see Framing Papers #1 and #2).[14] These papers also described the several elements of wholesale

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[12] E.g., through participation in ancillary service and resource adequacy markets, helping to resolve transmission and distribution congestion problems, moderating price spikes, and improving end-use efficiency. The means to deliver these values of short-term and long-term demand response are addressed in other chapters of this Report.

[13] In 2002, ISO-NE offered two Load Response Programs: a Demand Response Program (known as Class 1) that compensated users for reducing consumption at ISO-NE's direction and a Price Response Program (known as Class 2) that compensated users for monitoring and controlling their consumption in response to real-time market prices. The Demand Response Program (Class 1) had 112 MW enrolled and the voluntary Price Response program (Class 2) had 73 MW enrolled and was called 12 times during 2002. The ISO has acknowledged that these programs are very small in relation to the overall system demand, and that more robust programs are needed to resolve reliability and market needs.

[14] See Framing Paper #1 (Price Responsive Load) and Framing Paper #2 (Demand Side Resources and Reliability). In principle, these programs could also encompass customer load curtailments offered in short-term forward markets – e.g. several days to weeks.

electricity markets, identified barriers that currently limit participation in these markets by demand response resources, and summarized recent experiences and lessons learned from ISOs and utilities that have offered similar and related demand-response programs.

NEDRI's discussions and program recommendations assume that ISO-NE will be implementing a day-ahead market as part of its Standard Market Design and that for the foreseeable future FERC will continue to require ISO/RTOs to implement a set of demand response initiatives and programs that are consistent with Standard Market Design which will be included in a revised transmission tariff.

NEDRI Participants addressed several tough policy issues in assessing various program approaches, including the following:

- *What market mechanisms are needed or desired by end users and other market players in the price-responsive load area?*
- *Should Regional Demand Response (RDR) -type program activities be undertaken and supported by ISOs or should they be considered solely at the state/retail jurisdictional level?*
- *Under what conditions or circumstances are wholesale market RDR programs appropriate (e.g., would economic demand bidding programs be necessary if real-time pricing were widespread)?*
- *What is the relative magnitude of demand response resources needed to ensure efficient and well-performing wholesale electricity markets? Is Price-Capped Load Bidding (PCLB) likely to provide sufficient demand response or will other types of load reduction programs be necessary?*
- *How do you pay for the enabling demand response technology infrastructure necessary to capture consumer market benefits of Regional Demand Response?*
- *Is the provision of demand response resources an attractive business opportunity for potential load aggregators? Is it a viable "stand-alone" business"? Are there disincentives that limit the interest of potential load aggregators (e.g., utilities)?*
- *What types of demand-side resources should be eligible to participate, and how can program designs facilitate evaluation of environmental impacts?*

RDR program participants that curtail their loads are typically paid either the energy market clearing price (MCP), or a floor price that reflects an estimate of what that price would have been but for the availability of these resources. Some fraction or all of these gross benefits may be passed through to customers. From a participating customer's perspective, their net benefits depend on the costs they incur in undertaking curtailments (e.g., costs associated with rescheduling business activities, investments made in equipment and monitoring and control technology), compared with the price paid for the curtailment. Program designs and market rules must respect these customer realities.

In addition to the benefits provided to participating customers, RDR programs are of interest to all customers (including non-participants) because of their effects on power markets and delivery systems. These effects include improved system reliability, lower wholesale electricity prices, and reductions in risk:[15]

- **System Reliability benefits:** When RDR resources are dispatched in response to operating reserve shortfalls, all end-use consumers benefit directly from the improvement in system reliability;
- **Collateral savings: downward pressure on market clearing price** - The RDR resources can place downward pressure on market clearing prices by displacing the highest priced units in the bid curve. The extent to which load curtailments dampen market prices depends on the steepness of the supply curve at the time: the steeper the curve, the greater the impact;[16] and
- **Hedging benefits:** Over the long-term, significant amounts of RDR resources may also be expected to impact price volatility and average market price.[17]

The NEDRI Process

The NEDRI stakeholders initially discussed Regional Demand Response load program and policy issues over an eight month period, beginning with Framing Papers (April 2002), discussions in working groups (June-Sept 2002), leading to "straw person" program design and policy proposals which were discussed and revised (Oct-Nov 2002). In addition, valuable feedback was received from over 100 market participants from across the nation on the design of Regional Demand Response programs at a Demand Response Focus Group jointly convened by FERC and NEDRI in September 2002. Finally, in a NEDRI meeting on January 15, 2003, NEDRI participants reviewed all of the program recommendations in light of the FERC's Order of December 20, 2002 on New England Standard Market Design issues, adopted additional recommendations, and approved the first eight recommendations for submission to ISO-NE,

[15] See Neenan Associates (2002) evaluation of the New York ISO PRL 2001 programs for an illustration of how these benefits can be determined and estimated for specific ISO PRL programs, both Emergency Demand Response Program (EDRP) and Day-Ahead Demand Response Programs (DADRP).

[16] These benefits include *settlement benefits,* which are the product of the price decrease resulting from the demand curtailments and the amount of load settled at real-time prices, and the *full market impact benefits*, which includes reduction in price volatility (which reduces the risks associated with load settled in the real-time market). The full market impact is a measure of this effect on bilateral prices as it reflects equilibrium market prices under more robust competitive conditions. These benefits are measured by the product of the price decrease caused by program curtailments and the total load served at the time.

[17] Reduction in average market price multiplied by amount of load traded under bilateral contracts provides an estimate of these benefits.

NEPOOL, FERC, as well as state utility and environmental regulators. In June 2003, NEDRI participants approved three additional recommendations on RDR programs; the 11 recommendations on Regional Demand Response programs are presented in the next section.

Recommendations

ISO-NE's Demand Response Program Designs

As part of its efforts to deepen the region's power market, strengthen reliability, and to implement the FERC Standard Market Design, ISO-NE and NEPOOL have proposed four Demand Response programs for 2003. These are:

- Real-Time Demand Response Program (RT-EDRP, an "Emergency" DR program),
- Day-Ahead Demand Response Program (DADRP),
- Real-Time Price Response (which is based on the current Class 2 program), and
- Real-Time Profiled Response (for customers without interval meters).

The NEDRI Participants have focused primarily on the first two of these program areas, the Real-Time (or "Emergency") Demand Response Program, and the Day-Ahead Demand Response Program.[18] The Group found the ISO's current working proposals to be a useful starting point for program design, and focused on ways to build on this existing framework, given time constraints. After detailed discussion, we recommend that ISO-NE amend and strengthen those programs in several specific ways as set out below. These recommendations go both to short-term improvements (e.g., for the programs for the Summer of 2003) as well as suggestions for 2004 and beyond.

Recommendation RDR-1: Strengthen the Real-Time Demand Response Program (RT-EDRP)

NEDRI recommends that ISO-NE file a revised real-time, "emergency" demand response program with FERC for adoption in 2003 (for program details, see Appendix 2-B, Program Strategy RDR #1: Real-Time Emergency DR Program). That program should incorporate the four specific features set out below, which were unanimously adopted by the large majority of the NEDRI Participants voting on them.[19]

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[18] Because of time and resource constraints and priorities indicated by NEDRI members, we have not devoted much attention to the ISO-NE's Real-Time Price Response (e.g. based on the existing Class 2 program) or proposed Real-Time Profiled Response program (for customers without interval meters).

[19] **YES** (24) Associated Industries of Massachusetts, Connecticut Consumer Counsel, Connecticut Department of Environmental Protection, Connecticut Public Utilities Commission, Demand Response and Advanced Metering Coalition , ISO New England, Joint Demand Response Resource Supporters/E-Cubed, Maine Public Advocate, Massachusetts Department of Environmental Protection, Massachusetts Division of Energy Resources, Rhode Island Public Utilities Commission, Northeast Utilities, National Grid, National Association of Energy Service Companies, Northeast Energy Efficiency Partnerships, Inc, Northeast States for Coordinated Air Use Management, Pace University Energy Project, PowerOptions/Massachusetts Health and Education Facilities Authority, Price

- *Higher minimum floor payments for called resources.* ISO-NE currently proposes to pay participants for their actual load reductions based on the higher of the hourly real-time zonal price or an established floor price of $100-150/MWh depending on the amount of advance notice required (2 hours vs. 30 minutes). The NEDRI participants believe that these floor payments are too low to elicit significant customer response. When called, DR resources should receive the higher of: the real-time LMP in their zone, or $500/MWH for 30-minute notice resources, or $350/MWH for 2-hour notice resources.
- *Lower entry barriers for Demand Response Providers*. Historic NEPOOL rules required Demand Response Providers to participate in the market as NEPOOL Participants, which required a minimum annual payment of $5,000, and potential exposure to other legal and financial obligations of NEPOOL. ISO-NE has since amended this requirement to permit program participation by DR program providers who are not NEPOOL Participants, but the annual fee was kept at $5000 for such participation. While an improvement, this financial requirement creates a barrier to participation by customers and small DRPs, which should be lowered to promote development of the DR market.[20] We conclude that the DR participation fee should be lowered to $500 annually.
- *A longer-term commitment to DR programs*. As DR providers and customers point out, DR programs must be in place for a sufficient period to support commercial development of the resource. The ISO-NE's current DR programs are slated to run for two years; we recommend that the programs adopted in 2003 be approved to run for at least three years, with the opportunity for extensions if they are operating successfully.
- *ICAP treatment that incorporates credit for reduced reserve requirements* (See discussion at Recommendation #5 below).

Recommendation RDR-2: Strengthen the Day-Ahead Demand Response Program (DADRP)

ISO-NE's proposed DADRP is a reliability-focused program, in contrast to the more price-driven day-ahead market programs in other regions. While we recommend that ISO-NE investigate development of a basic, economic, day-ahead market DR program (see Recommendation #3), we also recommend improvements to the reliability-oriented day-ahead market program planned for 2003. ISO-NE should file a revised "reliability-oriented" day-ahead demand response program (DADRP-R) for adoption in 2003. The DADRP program should

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Responsive Load Coalition, United Illuminating, Union of Concerned Scientists, United State Environmental Protection Agency, Vermont Energy Investment Corporation, Vermont Public Service Board; **ABSTAIN** (6) Constellation New Energy, Maine Public Utilities Commission, Mirant, New Hampshire Public Utilities Commission, PG&E Energy, PJM Interconnection; **NO** (0). National Association of Energy Service Companies.

[20] We note that the NY ISO permits DRPs to enroll customers and participate in the NY programs without such charges, and that a substantial fraction of the MWs actually enrolled in New York have been enrolled through such independent providers.

incorporate the following five features, which were supported by the large majority of NEDRI Members voting on them.[21]

- *Greater flexibility in bidding increments*. Due to limitations in ISO-NE's existing software, current rules require that DR resources be bid in whole increments no smaller than 1MW. This creates commercial barriers to DR providers and customers, whose resources are available in various smaller increments. We recognize that ISO-NE faces more critical software challenges, and that this particular problem will take some time to fix. However, even while the bidding software may require *bid* increments of 1 MW or greater, the DR program rules should be revised to permit providers to be *paid* for actual performance in smaller increments. In addition, ISO-NE should commit to the software changes needed for more flexible bidding increments as the program evolves.
- *Greater flexibility in bidding process*. This program currently requires DR bidders to post their bids daily, an unnecessary burden for small DR providers and customers. DR bidders should be given the option of posting a fixed bid each month or each Capability Period.

In addition to the two revisions above, NEDRI recommends three changes to the ISO-NE's Day-Ahead DR Program that are also recommended for the Real-Time Emergency DR Program. Those recommendations are:

- *Lower entry barriers for Demand Response Providers.*
- *A longer-term commitment to DR programs, and*
- *ICAP treatment that incorporates credit for reduced reserve requirements* (see discussion at recommendation #RDR-5 below).

Finally, after discussion of the FERC's Order of December 20, 2002 on New England market design issues, NEDRI participants recommends two additional changes for this program.[22] *Those recommendations are:*

- *Permit demand resources to enroll in both the Day-Ahead and Real-Time programs***.** Resources that participate in the Day-Ahead Demand Response Program whose offer is not accepted in the day-ahead market will be permitted to participate in the ISO's

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[21] **YES** (25) Associated. Industries of Massachusetts, Constellation/New Energy, Connecticut Consumer Counsel, Connecticut Department of Environmental Protection, Connecticut Public Utilities Commission, HEFA, ISO New England, Joint Demand Response Resource Supporters/E-Cubed, Massachusetts Department of Environmental Protection, Massachusetts Division of Energy Resources, Maine Public Advocate, National Association of Energy Service Companies, National Grid, Northeast Energy Efficiency Partnerships, Inc, Northeast States for Coordinated Air Use Management, Northeast Utilities, PG&E Energy, PowerOptions/Massachusetts Health and Education Facilities Authority, Price Responsive Load Coalition, Rhode Island Public Utilities Commission, Pace University Energy Project, United Illuminating, United States Environmental Protection Agency, Vermont Energy Investment Corporation, Vermont Public Service Board; **ABSTAIN** (4) Maine Public Utilities Commission, Mirant, New Hampshire Public Utilities Commission, PJM Interconnection; **NO** (0).

[22] On January 15, 2003, NEDRI participants unanimously approved these measures (with abstentions from PJM, ISO-NE, and the PUCs of MA, NH, and ME).

real-time DR programs, if qualified. The settlements process should ensure that a single curtailment is compensated in only one program.

- *Equal bid ceilings for demand and supply resources.* Permit bids in the Day-Ahead program up to the ceiling on supply-side bids ($1000).

Recommendation RDR-3: Develop an Economic, Price-Driven Day Ahead Market DR Program by 2004

Although ISO-NE has proposed an "emergency" and a "day-ahead" DR program for 2003, a close look at the way they would operate reveals that both are essentially reliability-focused programs. In contrast to NYISO and PJM, ISO-NE does not presently plan to offer a day-ahead, economic DR program in which DR resources would be called solely on an economic, bid-based basis. We recommend that ISO-NE commit to developing an "economic, price-driven" day-ahead market demand response program by summer 2004. In designing this program, ISO-NE should use the NEDRI program design as a starting place (see Appendix 2-C Program Strategy RDR #2 - Day-Ahead DR – Economic) and should draw upon best practices and recent experience in other regions of the country.[23]

Related Actions Needed to Support Regional Demand Response Programs

Our review of the proposed Real-Time and Day-Ahead DR programs has led NEDRI to the conclusion that crucial complementary actions by ISO-NE and state agencies are needed (outside of the narrow limits of those programs) if DR resources are to make a meaningful contribution to regional power markets. Some of those changes are well underway, and we have not attempted to capture all of those actions in this document.[24] However, the Group has considered some aspects of this problem, and recommends the following (see Recommendations 4-11 below):

Recommendation RDR-4: Monitor and Limit Environmental Impacts of Demand Response Programs

One potential problem with more robust demand-response programs is the possibility that they will lead to the more frequent use of relatively highly polluting, back-up generation by participating customers. Existing emergency generators were not permitted or installed with a market-driven dispatch in view, and even new generators could be more polluting than the central station facilities with which they may be competing during peak-load periods. For these reasons, it is important to consider the environmental attributes of customer-located back-up generation that may be associated with participation in the ISO-NE's RDR programs.

[23] This recommendation was adopted unanimously.
[24] As a principal example, the move to a two-settlements market with locational marginal pricing provides key features of a market supporting active demand-response. These changes are well underway.

NEDRI has the following recommendations on environmental eligibility and information requirement for Regional Demand Response programs, including ISO-NE's 2003 programs.

- *Adopt output-based, technology-neutral standards for new on-site generators.* NEDRI recommends that environmental regulators apply a stringent (but technology neutral) output-based environmental performance standard – such as has been proposed in the Regulatory Assistance Project's Model Rule for Distributed Generation – to new on-site generators participating in non-emergency based demand response programs at the earliest possible date. NEDRI recommends that environmental regulators, demand response providers, and the grid operator cooperate to mitigate environmental impacts and enhance information collection on ISO-NE's demand response programs.[25]

- *Update state regulations for existing generators.* NEDRI also notes that state air regulators need to update their regulatory requirements for existing on-site generators that wish to participate in non-emergency based demand response programs.[26] Over time, such standards should converge toward emissions performance levels achievable with modern new equipment and best available retrofit controls. The need for new regulation is particularly acute for smaller units that fall below current permitting thresholds.

- *Provide an information base for environmental analysis of DR program impacts*. NEDRI has developed specific recommendations (below) to enhance information collection and analysis of the environmental impacts of ISO-NE's Summer 2003 Day-Ahead and Real-Time Price Responsive Load Programs. NEDRI recommends considering the extension of these proposed requirements to all demand response programs in the future (2004 and beyond).

With respect to ISO-NE's Summer 2003 Day-Ahead Demand Response and Real-Time Price Response Programs, NEDRI recommends the following:

- ISO-NE should require Demand Response Providers (DRPs) to provide information on any on-site generators their customers plan to use in conjunction with load response events in the above-mentioned programs. Specifically, DRPs should be required to

[25] The net environmental impacts of enhanced RDR programs may be positive or negative, depending upon whether demand response resources can be used to meet reserve requirements and the extent and nature of backup generation used by customers. As the U.S. EPA noted in its study of the NEDRI proposals, "If demand response resources were not used to meet reserve requirements, emissions impacts would be much smaller, and emissions could increase or decrease depending on the amount of demand response generation and the fuel mix of that generation. More work is needed to assess the health risks posed by emissions from the on-site generators likely to participate in demand response programs." See Letter from EPA to NEDRI, Appendix E.

[26] Most states already have specific regulations in place for emergency back-up generators. Such generators are generally permitted to operate only during true emergency events – typically defined as requiring, at a minimum, that the grid operator has called for manual voltage reductions (e.g., OP 4, Action 12 in ISO New England's current operating rules).

declare that each of its customers' units has obtained an air permit or written waiver from their state air regulator before allowing such units to participate in these programs.

- Air regulators will work collaboratively with DRPs and others to develop a user-friendly interface and process for customers owning on-site generation to expedite processing of requests for permits and waivers (for those without permits). An illustrative draft of the questionnaire/information is included in Appendix 2-A.

- ISO-NE will make information on actual load response events available to air regulators for purposes of evaluating the potential environmental impacts of load response programs. This information will be disaggregated to the greatest extent possible while maintaining confidentiality of participant-specific information. ISO-NE anticipates that the information will include: specific dates during which these load response programs were in effect including the events' duration, and levels of actual load response by control area and specific load response event.

Recommendation RDR-5: Provide Location-Based Capacity Credits to DR Resources

- *That ISO-NE implement an effective, location-based ICAP resource credit for demand response resources as soon as possible.*[27]
- *Until ISO-NE implements locational ICAP, we recommend that ISO-NE continue to develop interim solutions to encourage demand response and supply resources in congested, constrained regions.*[28] *These interim solutions may include additional financial support from utility ratepayers or states, such as capacity reservation payments ($/kW), in order to address local reliability problems in constrained areas during the transition to effective location-based wholesale electricity markets (e.g., ICAP).*

Discussion:

Enrolled Demand Response resources (both load curtailment and DG) provide capacity and reliability benefits that should be reflected through the ICAP or other capacity obligations and credits imposed by the ISO. New England is proposing to continue an ICAP program for the near-term, and is considering other options for the longer term. If ICAP is continued in 2003, NEDRI concludes that ICAP credits should be available to enrolled DR resources, and should be location-based, to reflect the varying load/resource balance in the New England region and send

[27] National Grid and United Illuminating do not support the implementation of location-based ICAP in New England. Northeast Utilities believes that alternative solutions to location-based ICAP need to be explored.

[28] The second recommendation that NEDRI urge ISO-NE to develop interim solutions to encourage both demand and supply resources in congested, constrained regions if not able to implement a system-wide ICAP by summer 2003, did not receive any "no" votes, after inserting "and supply resources" after "demand response" in the sentence.

the appropriate signal for long-term investments in both supply and demand resources in capacity-constrained areas.

The eligibility of a DR resource for ICAP or other credits depends in part upon its availability to be called upon when needed. To the extent that certain resources, such as energy efficiency and CHP, are already producing savings that are reflected in reduced customer load profiles, then it is not appropriate that they should receive ICAP or related credits. However, insofar as incremental efficiency, DG, and CHP investments can serve longer-term resource adequacy needs, then they should be eligible for such credits.

Recommendation RDR-6: Provide Adequate Resources and Cost Recovery for DR Programs[29]

If Regional Demand Response programs are to succeed, they must be adequately funded, and those incurring costs must have a fair prospect of recovering them in rates. In addition, regulatory policy at the retail level should give potential competitive demand response providers a viable commercial opportunity to enroll customers in competition with default service providers and distribution wires companies. For these reasons, we recommend:

- *Allocate 2003 ISO RDR program costs to network load.*[30] Given the limited scale and objectives of the proposed 2003 price responsive load programs, NEDRI supports NEPOOL's proposal to allocate program costs to network load. NEDRI further supports recovery of these costs from ratepayers.

- *Review cost allocation alternatives for 2004 and beyond.*[31] However, NEDRI also recommends that ISO-NE's Regional Demand Response Working Group (see Recommendation #7 below) reconsider the cost allocation for the demand response programs. In further analyzing this issue, the Working Group should consider how programs should be designed and program costs allocated, consistent with the principle that comparable supply, transmission, and demand-side resources should be treated consistently.

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[29] To the extent the language in this recommendation expresses a preference for regulatory intervention in demand response, National Grid and United Illuminating do not support this recommendation and specifically do not support the allocation of these costs to network load. The other NEDRI members do not believe that this recommendation expresses such a preference.

[30] This recommendation was approved by the NEDRI Participants on January 15, 2003 (PJM and the PUCs of NH, MA, and ME abstained).

[31] This recommendation was approved unanimously by the NEDRI Participants on January 15, 2003 (PJM and the PUCs of NH and MA abstained).

- *New England state regulators should adopt retail tariffs and policies that support delivery of the ISO's Day-Ahead and Real Time (emergency) demand response programs.*[32] There are two aspects to this recommendation. First, as noted above, NEDRI participants recommend that state PUCs permit full recovery of net DR program costs from ratepayers. Second, we recommend that state PUCs permit regulated utilities and Default Service Providers to retain up to 30% of the ISO payments in these programs, rather than requiring a 100% pass-through of payments to end-use customers (see Appendix 2-D, Program Strategy RDR#3- Retail Delivery of ISO-NE RDR Programs). This will help to create an environment in which competitive DRPs can build a business enrolling and aggregating customers in load response programs. This sharing will act as a de facto maximum for the market. If DRPs can do better, they will capture more of the market and force default service providers to either reduce their share of the payments or cease providing the service.

Recommendation RDR-7: Evaluate and Improve Demand Response Programs33

- *Conduct an independent assessment and impact evaluation*. All parties involved in administering DR programs are still in a learning process. For these programs to succeed, ISO-NE, DR providers and customers, state officials, power suppliers, utilities, and others will need to learn a great deal about what works and what doesn't. NEDRI participants recommend that ISO-NE conduct an independent in-depth process and impact evaluation and market assessment of its 2003 demand response programs that would address, at a minimum, the following issues:

  - Discuss potential DR program targets and timetables that could achieve them,
  - Address barriers to participation by customers and market participants,
  - Assess the magnitude of price-responsive loads under SMD and current ISO-NE DR programs,
  - Estimate the impact on market prices and system reliability of 2003 DR programs,
  - Discuss their impacts on the environment, including timing and location of emissions, and

  Present recommendations on proposed DR program changes in order to achieve ISO-NE program goals for price-responsive load.

It will be necessary for ISO-NE to provide adequate funding for this thorough assessment, and for FERC to support the tariffs needed to provide those funds.

[32] This recommendation was unanimously supported by the NEDRI Participants. For additional information on this topic, see Program Strategy PM-1 (Retail Delivery of ISO Regional Demand Response Programs), which discusses actions and policies for retail regulators to consider, but does not offer definitive recommendations on all program design issues.
[33] NEDRI Participants unanimously approved the recommendations in this section.

- *Enhance effectiveness of the Regional Demand Response Working Group.* We recommend that ISO-NE seek more input from customers and DR market participants on DR policy and program designs using a Regional Demand Response Working Group.[34] To enhance effectiveness of the Regional Demand Response Working Group, the ISO-NE should commit to:
  - regularly scheduled meetings,
  - efforts to expand membership & participation by market participants, representatives of customer groups, and state regulatory staff,
  - input on the scope of program evaluation and market assessment activities, and
  - input on proposed changes to program design and rules.

Recommendation RDR-8: Adopt Performance-Based Metering and Telemetry Standards to Reduce Unnecessary Costs for Demand Response Resources

- *Metering and telemetry requirements for participating in demand-response programs should be designed to provide an appropriate level of accuracy, with a goal to minimize unnecessary costs for DR services. ISO-NE, in consultation with market participants and technology experts, should develop and implement such standards.*[35]

Discussion:

In its Order of December 20, 2002 on Standard Market Design issues in New England, FERC granted a request for rehearing on the topic of metering requirements for participation in demand response programs and directed "NEPOOL and ISO-NE to work with interested parties and experts at the Department of Energy, the Electric Power Research Institute and elsewhere to develop performance-based, rather than technology-based, standards for determining energy usage."[36]

Recommendation RDR-9: Ratepayer Funding to Overcome Market Barriers to and Increase Participation in Shorter-Term Demand Response

- *There is a need to overcome significant market barriers to increase customer participation in shorter-term demand response (both emergency and price-responsive*

[34] This would be an extension of the ISO's Load Response Working Group, renamed here for consistency with the terminology adopted by NEDRI for these regional DR programs.
[35] NEDRI Participants unanimously approved this recommendation on January 15, 2003.
[36] The Order goes on to state: "We require ISO-NE to engage in such consultations, develop performance-based standards, place those standards into the appropriate manual or manuals, and make an informational filing at this Commission within 180 days of the date of this order. As we underscored in the SMD NOPR, measures that facilitate a robust demand response are essential to the success of competitive wholesale markets. As markets mature in other regions, the Commission will insist on similar measures in all regional markets." (ISO-NE filed this report with FERC on June 18, 2003.)

> *programs) during the transition to effective competitive markets. NEDRI recommends that additional funds be made available to support enabling infrastructure, technical assistance, and customer education and information. Funding for these activities could come from regional and/or state sources should be relatively small in amount, and should preferably be incremental to existing state System Benefit Charge funding targeted at energy efficiency.*

Discussion

Funding Need: Why and For What

NEDRI supports use of NEPOOL funds through the regional shorter-term demand response programs to provide performance payments to compensate customers for their participation and load curtailments in emergency and day-ahead market demand response programs (see RDR-1 and RDR-2). NEDRI also recommends a location-based ICAP mechanism to provide the necessary location-specific capacity payment to provide an incentive for locating demand response in areas in which they are most needed (see RDR-5).

In this recommendation, NEDRI recognizes also the need to provide limited additional funding to support enabling infrastructure, technical assistance, and customer education to ensure the success and effectiveness of regional shorter term demand response programs, particularly during the initial years of program operation. Enabling infrastructure includes web-enabled energy information systems, advanced metering, communication and notification technology, and load control devices that support the customer's ability to reduce load and enable them to participate in shorter-term demand response programs.[37] Technical assistance and customer education/information includes facility audits, customer outreach, and education.

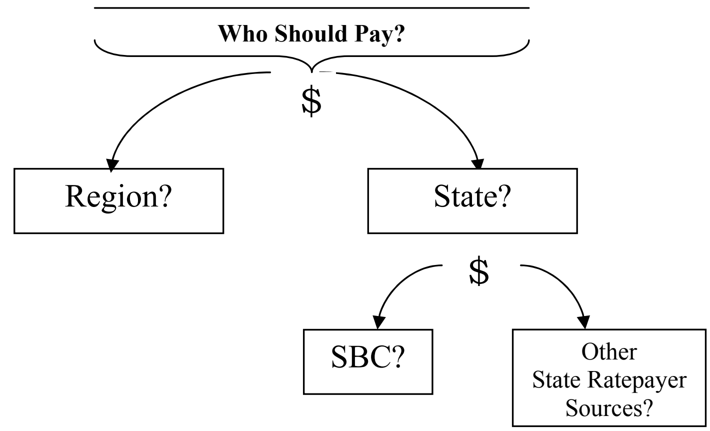
Funding Source

The source of funds for these supporting activities could come from regional sources or state sources (including SBC or ratepayer funding), as shown in Fig. 2-1. The funding source may vary by state and needs further careful analysis and discussion. However, in most, if not all cases state SBC funds are not adequate to fully fund cost effective energy efficiency. Thus, many NEDRI participants prefer that public funding of shorter term demand response infrastructure be incremental to existing state system benefit charges, while others believe that limited use of existing state system benefit charges for shorter term demand response is appropriate.[38]

[37] In the case of some demand response infrastructure (e.g. meters) a mass deployment of such infrastructure may provide benefits to certain parties (e.g. utilities) that are not related to demand response. These benefits should be taken into consideration in the funding of such infrastructure; in some cases it may be appropriate for only a portion of the cost to be funded according to this recommendation. See recommendations for advanced metering in Chapter 3.

[38] Utilities in Massachusetts and Connecticut have some SBC-funded efforts that support enabling infrastructure for shorter-term demand response programs [e.g., CT has a conservation and load management (C&LM) SBC fund including explicit authorization for load management, and there are shorter-term demand response pilots in MA].

Fig. 2-1. Additional Ratepayer Funding for Overcoming Market Barriers to Shorter-Term Demand Response



NEDRI further acknowledges that SBC allocations, if any, should be considered within the context of multiple objectives for SBC funding, and within the stated purposes and limitations for SBC funding in each state (e.g., whether the SBC funding is authorized only for energy efficiency, or has broader authorization that may include load management).

Amount of Funding

Experience in other states has shown that a small amount of funding for demand response infrastructure (an amount equivalent to 5-10% of SBC funding, but not necessarily allocated from SBC funds) is likely to increase demand response infrastructure deployment significantly. Experience in these states suggests that funding towards the higher end of the range may be appropriate only where a state is facing a major, immediate reliability problem. The funding amount (%) to be devoted to these activities is based on experiences of other states, specifically California and New York that utilized system benefit funds (NY) or general state funds (CA) to support ISO or utility DR programs.

Recommendation RDR-10: Distributed Generation: Clean and Behind the Meter

- *DG that is "clean,"[39] "behind the meter," is sized at, below, or modestly above the host load, and does not export power to the grid (i.e., is on the customer's side of the meter) should be able to participate in wholesale markets (e.g., day-ahead, real-time and ancillary services markets, and capacity markets) on a comparable basis to other forms of demand response.*

Discussion:

DG and CHP are integral components of a diverse energy supply. They can contribute to the efficient functioning of competitive energy markets, provide reliability services, reduce emissions (in certain instances), and improve the efficiency of energy production and delivery by reducing losses and congestion and by avoiding more costly infrastructure investment in transmission and distribution. NEDRI encourages states to adopt policies that will promote the deployment of clean, cost-effective distributed generation (DG) and combined heat and power (CHP).[40]

Stand-alone DG (that is, DG not serving a host load) was not considered and NEDRI makes no recommendations on how to treat stand alone DG with respect to the wholesale markets. NEDRI did not consider separate rules or markets that may be needed to foster development of new clean, stand-alone DG technologies.

Recommendation RDR-11: Support Participation by Clean DG in Real-Time Markets

- *NEDRI recommends that ISO-NE allow customer-located, clean DG units to sell energy in excess of customer or contract load without requiring such units to bid in the ISO markets.[41] The metered output of such DG units registered with the ISO as Settlement Only Generators receive compensatory real-time prices (note that all generators, including Settlement Only Generators, settle at the nodal level). They should also receive an ICAP credit.*

[39] By clean DG, we mean resources that at least meet the environmental requirements that are developed by state environmental regulators as a result of implementing Recommendation RDR-4. NEDRI urges the adoption of output-based, technology neutral standards for new on-site generators and the updating of state regulations for existing on-site generators toward emissions performance levels achievable with modern new equipment and best available retrofit controls.

[40] Unless the context clearly suggests otherwise, the terms "distributed generation" and "DG" refer also to CHP applications.

[41] This is consistent with ISO-NE's current practice.

Appendix 2-A. Draft Questionnaire/Information Request to be Used by Demand Response Providers

All participants in ISO New England's Summer 2003 Day-Ahead and Real-Time Demand Response programs would be asked the following questions:

1. Are your customers considering using any on-site electric generator(s) to supply power to your facility during demand response events?

If you answered NO to question 1: this section is complete, finish the rest of the application.

If you answered YES to question 1:

2. Are the electric generating unit(s) in question permitted to operate during demand response events by your state environmental agency?

If you answered NO to question 2 or if you are not sure whether your customers' unit(s) has or requires a permit, then the customers in question must follow this link and contact their state environmental agency. Your application can be processed only after you can declare the following regarding your customers: (1) they have a permit for each unit; or (2) they have a written statement from the environmental agency that they have complied with all necessary regulatory and informational requirements for each unit.

For each on-site generating unit without a permit, the state air regulators will likely require the following information from customers:

Owner of the unit
Location of the unit (address)
Manufacturer
Model number
Date of manufacture/purchase (if known)
Heat input capacity
Electrical output capacity (KW)
Fuel type(s)
Current use: Emergency only or Other
Current annual hours of operation: 0-500, 500

Appendix 2-B. Program Strategy RDR-1: Real-Time, "Emergency" Demand Response Program (RT-EDRP)

The Real-Time, "Emergency" Demand Response Program (RT-EDRP) provides ISO-NE with a demand response resource to dispatch during periods of capacity deficiency or system emergency.[42] The goal of the program is to create a demand response resource equal to at least ~3% of peak demand.[43] The program is a short notice program relying on the ability of customers who are willing and able to reduce demand for short time periods in exchange for compensation. Reductions are mandatory when the customer is instructed to interrupt by ISO-NE.

Program Duration: The program would begin with the implementation of Standard Market Design. The RT-EDRP program would be authorized for three years, with annual program modifications, as necessary. ISO-NE may request that the program be continued from FERC, including any changes determined to be necessary for 2005 and beyond.

Criteria for Eligible Participants: Individual end-users may participate in the program either directly or through a Load Serving Entity (LSE) – e.g., the customer's utility under Default or Standard Offer Service or competitive retail energy suppliers – or Demand Response Provider (e.g., third party providers that offer load response services but are not the customer's LSE). DRPs that do not participate in the NEPOOL market other than as permitted in the Load Response programs are subject to a nominal annual registration fee of $500.

End-User Requirements: The minimum aggregated size is 100 kW. Participants may provide this load reduction through any combination of load curtailment and operation of onsite generation. Interval metering is not necessarily required. Metering and telemetry requirements for participating in demand-response programs should be designed to provide an appropriate level of accuracy, with a goal to minimize unnecessary costs for DR services. ISO-NE, in consultation with market participants and technology experts, should develop and implement such standards.

Environmental Eligibility Criteria: All participants utilizing onsite generation must comply with local, state, and federal environmental permitting requirements. Emergency generators may not be operated under this program until ISO-NE has called for voltage reductions (historically, Action12 of OP 4, or its equivalent).

ISO-NE will require DR providers to provide information on any on-site generators their customers plan to use in conjunction with load response events in this program. Specifically, each DR provider will be required to declare that each of its customers' units has obtained an air

[42] This program strategy is discussed generically in the NEDRI Framing Paper #2: Demand Side Resources and Reliability.
[43] System operators often target a capability of 3-5%. As of August 2002, NYISO had more than 1,400 MW enrolled in its EDRP, equal to approximately 4.5% of system peak.

permit or written waiver from their state air regulators before being allowed to participate in the program.

Advance Notice: Customers may elect to participate in one of two program options, based on the advance notice they require before implementing a load reduction: a 30-minute option and a 2-hour option.[44]

Compensation: Participants in the emergency program are required to interrupt and are paid for their actual load reductions during an event based on the *higher* of the hourly real time zonal electricity price or an established floor price. For the 30-minute advance notice option, the floor price is $500/MWh; for the 2-hour option, it is $350/MWh.[45] Performance is measured on an hourly basis. Participants in the RT-EDRP are eligible to receive ICAP credit.

Customer Baseline Load (CBL): Participants will use the standard baseline methodology proposed by ISO-NE.[46] The baseline is developed as hourly averages of interval load data over the last ten (10) business days excluding response days and adjusts actual usage for the two hours preceding the interruption.

Penalties: Since participants receive ICAP credit for their load reduction capability, they are subject to non-compliance penalties if they do not fulfill their load reduction obligation. The penalty in this program is limited to reduction in their future ICAP credit.

Participation in Other Demand Response Programs: Resources that participate in the Day-Ahead Demand Response Program whose offer is not accepted in the day-ahead market will be permitted to participate in the Real-Time Demand Response program, if qualified. The settlements process should ensure that a single curtailment is compensated in only one program.

ICAP Credit: Participants in the RT-EDRP are eligible to receive ICAP resource credit. ICAP Resource capability will be set equal to their contract amount initially and will be adjusted based on actual performance. Loads should also receive a Reserve Component credit as part of ICAP to reflect the reality of reduced reserve requirements placed on the system.

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[44] These options correspond to those adopted by NEPOOL in their proposed Market Rule 1, submitted to FERC. Several studies discuss the varying abilities of end-users to provide rapid load response, and the corresponding importance of providing program options to accommodate these needs (e.g., ICF Consulting, *Policy and Technical Issues Associated with ISO Demand Response Programs*, report submitted to NARUC 2002).

[45] Neenan Associates' evaluation of NYISO 2001 Price Responsive Load Program found that a $500/MWh floor price helped to induce a substantial market response. Rationale for a high floor price is also based on the value of lost load to customers or their willingness to curtail in order to prevent rotating outages; see Steve Stoft, *Power System Economics* for discussion of valuation issues.

[46] A taxonomy of CBL methods and options is developed in XENERGY (2002), *Protocol Development for Demand Response Calculation: Draft Findings and Recommendations*, Prepared for the California Energy Commission. CBL methods can be characterized by three components: data selection criteria, estimation method, and adjustment method. The report recommends as the default method to average previous ten days, and adjust based on two hours prior to the curtailment event. NYISO uses a modified version of this method that caps the adjustment at 120% of unadjusted profile, which places an upper limit on any gaming opportunity.

Program Operation/Activation: The program is activated as part of Operating Procedure No. 4, *Actions During A Capacity Deficiency* (OP 4).[47] Program participants can either be dispatched on a system-wide or zonal basis. In addition, to ensure that RTDRP resources are called in controlled amounts to address specific system conditions. Program participants within a zone are assigned to Curtailment Blocks by the ISO.

[47] During OP 4 when any of Actions 3 through 5, 7 and 8 are implemented (2-Hour Notice RT-EDRP), or when OP 4 Actions 9 or 12 is implemented (30 Minute Notice RT-EDRP).

Appendix 2-C. Program Strategy RDR-2: Day-Ahead Demand Response Program - Economic (DADRP- E)

The Day Ahead Demand Response Program - Economic (DADRP -E) enables electricity end-users to offer load reduction bids into the day-ahead wholesale energy market a day in advance, in direct competition with supply bids.[48] These load reduction bids would be fully integrated into the scheduling and settlement processes of ISO-NE, and can set the day-ahead zonal electricity price just as would a comparably bid generator. ISO-NE would use this program strategy and “best practices” in “price-driven, economic” programs as the starting place for an “economic” DADRP program to be implemented by summer 2004.

Program Duration: The DADRP-E program would be implemented by summer 2004. The DADRP-E program would terminate at the same time as other programs proposed herein, with annual program modifications, as necessary. ISO-NE may request program continuation of the program from FERC, including any changes determined to be necessary for 2005 and beyond.

Criteria for Eligible Participants: Individual end-users may participate in the program through a Load Serving Entity (LSE) – e.g., the customer’s utility under Default or Standard Offer Service or competitive retail energy suppliers – or Demand Response Providers (e.g., third party providers that offer load response services but are not the customer’s LSE). DRPs that do not participate in the NEPOOL market other than as permitted in the Load Response programs are subject to a nominal annual registration fee of $500.

End-User Requirements: The minimum aggregated size is 1 MW. Participants may provide this load reduction through any combination of load curtailment and operation of eligible onsite generation. Interval metering is not necessarily required. Metering and telemetry requirements for participating in demand-response programs should be designed to provide an appropriate level of accuracy, with a goal to minimize unnecessary costs for DR services.

Environmental Eligibility Criteria: ISO New England will require DR providers to provide information on any on-site generators their customers plan to use in conjunction with load response events in this program. Specifically, each DR provider will be required to declare that each of its customers’ units has obtained an air permit or written waiver from their state air regulators before being allowed to participate in the program.[49]

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[48] This program strategy is discussed generically in the NEDRI Framing Paper #1: Price Responsive Load as Option 2, May 2002.

[49] We note that participants in the NEDRI process have also recommended that environmental regulators apply a stringent (but technology neutral) output-based environmental performance standard – such as has been proposed in the Regulatory Assistance Project’s Model Rule for Distributed Generation – to new on-site generators participating in non-emergency based demand response programs at the earliest possible date. NEDRI recommends that environmental regulators, demand response providers, and the grid operator cooperate to mitigate environmental impacts and enhance information collection on ISO New England’s demand response programs.

Bidding Process: The participant submits day-ahead bids indicating their load reduction amount (MW), bid price ($/MWh), and the contiguous period over which the load reduction will be provided – i.e., a load reduction strip. Participants may also include in their bids a curtailment initiation (i.e., start-up) cost and a minimum run-time. Bids may be made for any load reduction amount above the 1 MW minimum – i.e., bids are not required to be in any particular increment. The minimum bid price for any hour is $50/MWh.[50] The maximum bid is the same for demand and supply-side resources, $1000/MWh.

Customer Baseline Load (CBL): Participants may choose to adopt either a standard or a temperature-sensitive baseline methodology.[51] Both options are based on an average of interval data over the designated timeframe. The baseline is developed as hourly averages of interval load data over the last ten (10) business days excluding response days.

Compensation: Customers whose bids are accepted and scheduled in the day-ahead market are paid for their load reductions, based on the higher of the day-ahead market-clearing zonal electricity price or their accepted bid price.[52]

Penalties: Any difference between the customer's actual load reduction and their scheduled load reduction is settled at the zonal real time price.[53]

Participation in Other Demand Response Programs: Customers in this program may not provide or commit the same loads for multiple load response programs.

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[50] The purpose of establishing a minimum bid price is to limit the potential for participants to make low bids (which are likely to be accepted) for periods during which planned customer facility shutdowns are to occur.

[51] A taxonomy of CBL methods and options is developed in XENERGY (2002), *Protocol Development for Demand Response Calculation: Draft Findings and Recommendations*, Prepared for the California Energy Commission. CBL methods can be characterized by three components: data selection criteria, estimation method, and adjustment method. The report recommends as the default method to average previous ten days, and adjust based on two hours prior to the curtailment event. The issue for the DADRP program is that this adjustment may be susceptible to gaming: participants would know if their bid was accepted, and could artificially inflate load during two hours prior to curtailment. NYISO uses a modified version of this method that caps the adjustment at 120% of unadjusted profile, which places an upper limit on any gaming opportunity.

[52] Participants can bid both an operating cost ($/MWh) and a startup cost, but the market-clearing price is based on the operating cost. Thus, in some cases, if the participant is only paid based on the market-clearing price, the payment may not cover the total value of their bid (operating cost plus start-up cost). Therefore, the payment mechanism must ensure that the participant recovers the full value of their bid.

[53] In their proposed Market Rule 1, NEPOOL has adopted this penalty mechanism for their day-ahead demand response program. Settling deviations between actual load reductions and accepted bids at the real-time price mirrors the risk/reward structure faced by generators. Based on survey analysis, end-use customers were deterred from participation in NYISO's 2001 DADRP, because of the program's penalty structure: participants were penalized for non-compliance based on 110% of the higher of real-time or day-ahead market prices. Statistical analysis suggests that the odds of participation increase substantially for variants of program in which participants are penalized simply based on the real time price (Bernie Neenan, Memo to NYISO price responsive load working group, June 7, 2002).

Appendix 2-D. Program Strategy RDR-3: Retail Delivery of ISO-NE's Regional Demand Response Programs

This strategy consists of the actions and policies necessary at retail to effect delivery of the ISO's Day-Ahead and Real-Time (Emergency) Demand Response Programs.

Delivery Mechanisms. Load Serving Entities (LSEs), competitive retail electric service providers (ESP), and Demand Response Providers (DRPs) may enroll customers.[54] The terms of the agreement are negotiated, are part of a standard product or products, or, in the case of regulated monopolies and default service providers (DSPs), are determined by PUC-approved tariffs or special contracts. LSEs and DRPs are notified by the ISO when interruptions are needed, and they in turn notify the customer. The ISO makes payments directly to LSEs and DRPs, who in turn pay the consumer for load reductions provided when called upon.[55]

Compensation. Compensation to LSEs and DRPs may take any of several forms. Typically, the ISO payment is shared between the LSE or DRP and the customer. If sharing is the only means by which payment is made, it must be sufficient to induce the desired behavior by the customer and cover the costs (including profit) incurred by the LSE/DRP to provide the service. In Connecticut, there is no sharing, but the DSPs (the distribution utilities) are compensated for their program administration and marketing costs in part with monies from the state's system benefits fund. The sharing ratios (where provided by DSPs or regulated monopolies) in three states are currently as follows:

	Customer	***Default Service Provider***	***Other***
NY	90%	10%	NA
VT	70%	30%	NA
CT	100%	0%	Some System Benefit funds for DSP admin/mkting

There are policy and market implications to the question of how the ISO payments are shared between customers and providers. In the case of competitive providers, the sharing percentages will be determined in the market -- by the price negotiated or offered through a standard product or contract (*i.e.*, the provider's share will be the margin between the price paid to the customer and the price paid by the ISO). In the case of regulated monopolies and DSPs, the sharing will

[54] LSE include vertically integrated monopolies and default service providers as well as competitive retail energy service providers (ESP) that provide electricity commodity to customers under contract.
[55] All payments are made to the Enrolling Participant who is either a NEPOOL Participant or DRP. Any ICAP credit belongs to the Enrolling Participant, but it is associated with specific DR resources. If the demand resource is eligible for ICAP then the enrolling participant would either sell the ICAP credit (either bilaterally or in the ICAP auction), or use the credit to offset the Enrolling Participants ICAP responsibility. The customer receives any contractually due payments from the Enrolling Participant since they are not contracting directly with the ISO. Thus, the Enrolling Participant may bear more of the price risk.

be determined by the PUC, taking into account traditional regulatory concerns – equity, efficiency, cost-allocation, and revenue collection.

Issue 1: Regulated pass-through of DR program payments: The ratio set by the PUC for *regulated* entities effectively determine the margins available to *competitive* Demand Response Providers and others who wish to market the ISO programs in those areas. The level of the utility/DSP share is a prime determinant of whether other providers will be able to enter those markets. A mandated, full (or nearly full) pass-through of the benefits to customers will inhibit competitive entry.

Issue 2: Reliance on DR program payments alone: Full cost recovery through sharing alone may be problematic if wholesale prices are low and there are too few curtailments to generate revenue sufficient to cover the direct costs of providing the program. To deal with this problem, some programs provide additional, basic support from system benefit funds or wires company revenues. While alternative funding through distribution rates or from system benefits charges will provide some stability of revenues for providers, it may also inhibit development of the retail market if just regulated DSPs, but not competitors, have access to those monies. This problem can be addressed by providing support equally to all enrolled participants or their DR service providers. The following table illustrates the trade-offs of various approaches to compensation.

Compensation Method	**SBC Funding or Covered in Rates**	**Sharing Allocation (Customer – LSE)**	**Impact on Competitive Market**
Alternative A	All admin. & Marketing Costs	100-0%	Inhibits competition because DRP and competitive ESP cannot cover costs or earn profits
Alternative B	Some Admin & Marketing Costs	90-10%	DRP and competitive ESP will be able to compete at best in limited circumstances
Alternative C	No Admin. or Marketing Costs	70-30%	More opportunities for DRP and ESP but reduced revenue stream during periods of low market prices

We recommend that state PUCs permit regulated DSPs and monopolies to retain up to 30% of the ISO payments. This should, in most cases, provide enough cash to cover DSP costs and yield a profit. This sharing will act as a *de facto* maximum for the market. If Demand Response

Providers can do better, they will capture more of the market and force DSPs to either reduce their share of the payments or cease providing the service. To the extent that the ISO payments include ICAP credits or reservation payments (which extend over a period of time), the revenue stability problem can be mitigated to some degree.

Other Regulatory Requirements. Regulatory oversight for transactions between customers and *competitive* providers is minimal or not required at all. The transactions are between willing parties, and they may (depending on state law and how the transaction is structured) not be subject to the jurisdiction of state utility regulators. Moreover, the activity should not affect the relationship between the customer and the regulated distribution company, except insofar as the LSE/DRP requires access to customer billing and related information. Protocols for providing that information – with the express permission of the customer – can be easily developed, while preserving the full range of consumer protections.

However, insofar as the programs are marketed by utilities and DSPs – *i.e.*, regulated entities – it is important that the programs be developed and filed for approval with sufficient lead time allow them to be properly reviewed and approved.

Eligibility. There are eligibility criteria for both customers and providers.

Retail Customers. Customer eligibility is defined in the strategy options for the "emergency" and day-ahead demand response programs. Distributed and self-generation resources and direct-serve customers are not eligible to provide load reductions under alternative performance measures. The aggregations must be at least 0.1 MW for the emergency program and 1.0 MW for the day ahead.

Providers. A variety of providers may market these programs: the customer's load serving entity (*e.g.*, vertically integrated monopoly, default service provider, competitive retail electric service provider) or a third-party Demand Response Provider (DRP) that is not a LSE (e.g., ESCO, vendor). State law will determine whether DRPs need to be certified by PUCs in order to provide service.

Programs can be crafted or modified to deal with localized distribution capacity constraints. The DSP may augment the offering by the ISO in local areas where demand response will provide distribution capacity relief in addition to generation.

CHAPTER 3: PRICING, METERING, AND DEFAULT SERVICE REFORM

Summary

A number of recommendations adopted by NEDRI in other chapters focus on developing administrative programs to encourage energy efficiency and ISO-based load response and interruptible programs. By contrast, Chapter 3 focuses on pricing and other policies that affect customer behavior at retail. Here, the fundamental premise is that there is a significant amount of demand response that time- and location-sensitive retail prices can inspire. Our essential recommendation is that policymakers should evaluate and adopt pricing structures (and their associated metering technologies) and other policies that will most cost-effectively capture that demand response, and do so in ways that are consistent with other stated objectives, such as consumer protection, economic efficiency, equity, and environmental protection.[56]

NEDRI has developed three sets of policy strategies (see Tables 3-1, 3-2, and 3-3) to achieve these ends. They approach the problem from several directions simultaneously, and in concert. The first set of strategies calls for changes in default service rate design, which remains effectively a monopoly service for the majority of customers. These rate proposals are intended to deliver to consumers better signals of the time- and (where appropriate) location-specific costs of electricity production and delivery. The next set of recommendations deals with actions and policies that can enhance the ability of mass-market consumers (*i.e.*, those currently lacking advanced metering capabilities), and of the market generally, to assess and capture the value of their demand responsiveness. The last two strategies suggest broader policy reforms for both default service and distribution company ratemaking, with the aim of increasing demand response through promotion of competitive markets and the removal of utility disincentives to customer reductions or shifts in usage.

The recommendations represent a consensus of the NEDRI participants, unless otherwise noted in the text.

The following section briefly describes the recommended strategies and the process that led to their adoption. Section III gives a general background of the current market conditions that the recommendations are intended to address. Section IV sets out the specific recommendations. Appendices 3-A, 3-B, and #-C describes the recommended strategies in more detail.

Introduction

[56] We should note that the goal is to encourage pricing structures which send customers efficient price signals and allow them to respond without regard to whether they meet the specific requirements for enrollment in a particular administrative program and without limiting their responses to those which fit within that program. It is not necessary to decide in advance whether to prefer administrative or price-based approaches. Indeed, they complement one another.

Experience in New England and across the nation has demonstrated that, to varying degrees, end-users of electricity can and often do modify their consumption in response to price signals.[57] The history of the electric industry is, in one measure, the history of experimentation with pricing, particularly so in the past three decades as policymakers and utilities began to confront the challenges of increasing energy costs and declining economies of scale. More recently, a number of forces, including new generation technology, the greater availability of natural gas, and a political preference for competition have led to the restructuring of wholesale markets, some retail competition, and advances in metering and data collection. This restructuring also has encouraged, to some degree, new ideas for how to use electricity and, perhaps more to the point, how to manage that usage. There are means available for creating closer linkages between the wholesale and retail markets, to allow end-users in retail markets to respond more quickly and efficiently to price changes in wholesale markets. These means, which are often complementary, include reviewing and improving upon some of the institutional and regulatory processes by which wholesale prices are passed along to customers and the load-serving entities who serve them, considering broader implementation of more sophisticated metering and communications technology, and using the existing metering technology to send more accurate price signals.

NEDRI recognized that one of the means for effecting closer linkages between the wholesale and retail markets – between supply and demand – is pricing. In September 2002, NEDRI formed the Pricing, Metering, and Default Service Reform Working Group. Over the course of several months, through correspondence, conference calls, and two meetings, the group presented to NEDRI an integrated package of actions and policies to support demand response among end-users. Detailed review and revision of the proposed package resulted in the adoption by NEDRI of a recommendation that state utility commissions consider taking several actions, including, but not limited to: (1) implementing a real-time price component in the generation costs assessed to large-volume default (or standard offer) customers (see Table 3-1); (2) expanding the deployment of sophisticated metering to default service business customers whose demand is 100 kW or greater (see Table 3-1); (3) implementing less dynamic, yet time-sensitive pricing structures for medium- and low-volume (*i.e.*, mass market) default service customers (see Table 3-1); (4) initiating a process to consider more fully the costs and benefits of deploying advanced metering, and of the pricing options such metering will make possible, to mass market customers (see Table 3-2); and (5) taking related actions to reform default service and load profiling so as to improve both the incentives and means (among customers and suppliers) for acquiring demand response (see Table 3-3). Tables 3-1, 3-2, and 3-3 list the strategy sets and briefly describe their key features:

57 Faruqui, Ahmad, and Stephen S. George, *The Value of Dynamic Pricing in Mass Markets*, The Electricity Journal, Elsevier Science, Inc., July 2002. Weston, Frederick, and Jim Lazar, *Framing Paper #3: Metering and Retail Pricing*, NEDRI, May 1, 2002.

Table 3.1. Strategy Set One: Improving Pricing for Retail Customers to Allow Price-Induced Demand Response		
	Program/Policy	***Description***
Strategy 1	State Commissions consider and determine rate designs that improve price signals for all customers	PUCs investigate and evaluate alternative time-sensitive rate designs for different customer classes
Strategy 1A	Real-time pricing for large-volume default service customers	PUCs should consider several approaches, based in part on the NiMo and Georgia Power programs
Strategy 1B	Critical peak pricing for medium-volume default service customers	Approaches modeled on the Gulf States Power pilot program
Strategy 1C	Inverted block rates for residential and small general service customers	Increasing tail-block rates to capture usages with a high degree of peak coincidence

Table 3.2. Strategy Set Two: Strategies to Support Demand Response in the Mass Market		
	Program/Policy	***Description***
Strategy 2A	Protocols to assist PUCs in evaluating mass market rate designs and the deployment of advanced metering (AM)	Guidelines for investigating whether there are net benefits to AM
Strategy 2B	Load-profiling to support	To enable aggregation, etc.

	mass-market demand response	
Strategy 2C	Energy efficiency for low-volume customers	Targeting efficiency for low elasticity, low-usage consumers

Table 3.3. Strategy Set Three: Cross-Cutting Efforts		
	Program/Policy	***Description***
Strategy 3A	Default service reforms	Reforms to encourage demand response; methods of allocating customers among default service suppliers; supporting competitive provision of demand response
Strategy 3B	Curtailable load programs	The retail analogue of the ISO PRL programs: how they are delivered
Strategy 3C	Improving distribution company participation in demand response programs	PUC to consider alternative methods of regulating utilities; breaking the link between sales (throughput) and profits

The implementation of these recommendations is within the domain of state policymakers, primarily state public utility commissioners.

Background

New England has moved toward creating more a competitive wholesale electricity market.[58] Hourly wholesale energy prices are now market-based, determined primarily by the interaction

[58] There is not unanimous agreement on the extent to which New England has actually achieved a workably competitive wholesale market. That question, however, is outside the scope of this paper.

of supply and demand in real-time and not, in the vast majority of circumstances, on those costs of generators that have been deemed acceptable by regulators. One of the principal consequences of this restructuring has been far greater volatility in hourly energy costs than was experienced under the preceding regulated regime. Insofar as the wholesale market reveals more realistic costs of electricity during critical times, it has been regarded by many as a benefit. This is because it is believed to promote more economically efficient behavior by allowing customers to decide whether they would prefer to pay the justifiably high costs of on-peak consumption or alternatively to reduce or defer consumption when the value of electricity to the customer is less than the capital and operating costs of additional electricity production. Retail pricing that better reflects the wholesale market price of power seeks to allow price-induced customer demand response to compete with new and existing generation.

Price-induced demand response can also provide at least some protection against market power abuse. Competitive day-ahead and real-time electricity markets are characterized by the “last person bidding” phenomenon. If a generating firm knows that the system requires its generation to maintain reliability, there is no limit, other than embarrassment or price caps, on the price the firm could charge. There are at least two possible solutions to this problem in the short term. One is aggressive market monitoring and mitigation. The other is price-induced demand response where the ability to exert market power is tempered, though not necessarily eliminated, by customers reducing their demand so that the “last person’s” generation is less critical to reliable operation. These solutions are not mutually exclusive and both are desirable.

The difficulty policymakers and others face, however, is that retail markets, not wholesale markets, determine the price that end-use customers actually pay for a kilowatt-hour of energy consumed at a given time and place. If retail market prices closely track wholesale prices, then individual customers will see, and presumably have the incentive to respond to, hourly variations in the wholesale market price. For various reasons, however, few retail customers in New England are exposed to, or given the opportunity to respond to, hourly variations in the wholesale price.

The retail market in New England can be characterized as a mix of regulated, deregulated, and hybrid markets, depending on the specific state and on the size and type of customer under consideration. In those states served by deregulated load-serving entities (LSEs), suppliers compete for customers, and prices are negotiated between suppliers and customers. State public utility commissions (PUCs) have no direct role in how these deregulated prices are set. In other cases, such as Vermont, retail sales of electric generation are still regulated and the Public Service Board sets the electric generation price (bundled with the transmission, distribution, and other components of the electric service). Finally, there are a wide variety of hybrid cases, under the headings of default and standard offer service, where regulators exercise varying degrees of influence over the retail price of supply.

The details of default and standard offer service vary by state, but, generally speaking, it is the service that provides electric generation to customers who, for whatever reason, have not explicitly chosen a competitive LSE.[59] The structure of default service is important for two reasons. First, in some cases, particularly for residential and smaller non-residential customers, most customers are served under the default service and the specific design of the service will directly affect them. Second, among those customer classes whose members typically do not take default service, *i.e.*, large-volume users, many LSEs market their product as being similar or identical to the default service but less expensive than it. Thus, default service design can directly affect the offers made by deregulated LSEs to retail customers.

The large customer retail market in Maine presents an interesting illustration of the interaction between the default service and the deregulated retail markets. The vast majority (80% to 90%) of large customer load[60] is served by deregulated LSEs, not under the standard offer. Many of these customers are sophisticated industrial concerns whose electric purchases are large enough to justify in-house electricity expertise and elaborate monitoring and control systems. Furthermore, these customers historically have contracted for around 200 MW of interruptible load, which indicates a willingness and ability to manage hourly energy purchases. All of these customers already have sophisticated metering in place that can accommodate real time pricing and hourly load response when it is economic for the customer. These are the customers who would most likely benefit from real-time load response. Despite this, however, the major LSEs in Maine report that virtually all of these customers are served under firm price contracts. To illustrate: if the customer has contracted for summer on peak energy at, say, five cents per kilowatt-hour, and the market price during an hour is, say, 25 cents, any demand reductions that the customers initiates on its own will produce only a five-cent/kWh savings only, not a 25-cent savings.[61] Thus, the customer would continue to make marginal purchase decisions based on the five-cent price.

There appear to be two explanations for this. First, the standard offer contract for large customers in Maine contains seasonal and peak/off-peak charges that remain fixed in place for a year. Apparently, LSEs find it easier to market a similar product distinguished only by lower cost than to market a real-time product that differs substantially from the standard offer alternative.[62] Second, the fixed-price standard offer or LSE contract actually provides two different and distinct products: electric generation and a price hedge against possible price changes due to any number of factors, such as fuel cost increases, unusually high load levels, short-term supply outages or other disruptions, and so on. It is perfectly natural for customers to value such a hedge, and for competitive suppliers to offer a hedge that mimics the one provided

[59] For simplicity's sake, we use term "default service" to refer to all forms of generation service provided to customers that have not chosen a competitive supplier. It includes the services that the various states call "Standard Offer Service," "Default Service," "Transition Service," etc.

[60] Maine defines large customers as those with a demand greater than 400 kW.

[61] In principle, the LSE and the customer could negotiate an agreement where the customer actually saved approximately 25 cents, rather than five, in effect "passing through" to the customer some or all of the savings, but few if any such contracts have been negotiated.

[62] Such a product may also be easier for the customer to justify within the firm since the in-house proponent can fairly describe it as a "can't lose" proposition.

in fixed-price standard offer service. But similar price protection could also be provided in ways that do not entirely mitigate the customer's incentive or ability to respond to prices.[63]

The challenges in eliciting demand response from large-volume customers have analogues among the medium- and lower-volume customers. Customers of all sizes and classes are demand responsive, to greater or lesser degrees, but their willingness to adjust their consumption in response to price changes and the amount of consumption that they can shift or forego are critical factors in determining what kinds of rate designs and metering technologies can be cost-effectively employed to deliver the required price signals to them.[64] In light of the different usage characteristics of different customer groups, different approaches to eliciting demand response from them must be developed (at least until the costs of technology decrease enough to make such differences unnecessary). Recognizing this led the NEDRI to develop the multi-track strategies recommended here. Briefly, several assumptions and hypotheses underlie this proposed approach:

- The cost of advanced metering is now significantly lower than it was in the past, due to technological evolution.[65]
- Advanced metering is certainly cost-effective for the largest customers (over 300 kW demand) and almost certainly cost-effective for medium-sized customers (100 kW to 300 kW demand).
- Determination of the cost-effectiveness of advanced metering will require an investigative process of some kind, particularly in the case of lower-volume customers. Determining the acceptability to customers of time-based rate designs will also require an investigative process, although it may make sense to combine this effort with the metering investigation. The public utility state commissions are best suited to these tasks.
- For those customer classes for which the state commissions determine that advanced metering and/or time-based rate designs are not appropriate, sufficient load research needs to be secured in order to support load profiling of different classes and subclasses of customers for both pricing and settlement purposes. Distribution utilities are best suited to conduct this research – in many cases, already do so – and PUCs will need to address ratemaking treatment of such research costs.
- Assuming that load research supports the hypothesis that smaller residential consumers have less expensive load shapes than larger residential consumers (*i.e.*, air conditioning is

[63] Financial hedges such as price caps, price collars, and contracts for differences (purchased from one's supplier or a third party) all offer degrees of price risk protection, and can be fashioned in ways that do not totally obscure the market price signals. Agreements to interrupt load at times of high prices are also a form of hedge, as well as a form of demand response.

[64] Another factor is the number of customers to whom the metering technology will be deployed. There tend to be large economies of scale associated with metering, which can significantly affect the design and cost-effectiveness of a dynamic rate design program.

[65] By "advanced metering" we are using the term as it was defined in NEDRI's *Framing Paper #3*, that is to mean electricity meters and associated equipment "that can, to varying degrees, record, process, and transmit time-specific information about a customer's electricity usage. Interval metering, recording at least hourly usage data, is the basic and most common form of advanced metering." *Framing Paper #3*, May 2002, at 12.

a higher-cost end-use) and assuming that advanced metering is not available, an appropriate response may be the implementation of either:
  - inverted power supply rates of general applicability to the residential class or
  - higher residential power supply rates applicable to larger residential customers.
- There is a constructive tension between time-based rate design (encouraging customers to shift load) and direct load control (offering a discount of some sort for utility control of end-uses). If the state commissions find that advanced metering is not cost-effective for smaller customers, they should examine direct load control programs as an alternative. Similarly, if the state commissions find that direct load control programs offer a greater potential demand response benefit than pricing options, appropriate consideration should be given to the certainty provided by direct load control and to the relative customer acceptance of both direct load control and time-based pricing alternatives.
- Some residential consumers may best be able to contribute to peak demand reduction through energy efficiency programs, rather than through pricing or metering incentives.

The following sections of this chapter describe in greater detail the policies and strategies that NEDRI believes state PUCs should adopt. NEDRI fully understands that these recommendations deal with complex multi-dimensional issues and that state regulators need to consider the wide range of impacts, beyond merely the effects on demand response that their decisions can have. We also recognize that some of these recommendations embody policies that are under consideration or have already been adopted in one or more of the New England states. In those cases, the recommendations represent our view of current "best practice."

Summary of Recommendations

NEDRI recommends that policymakers adopt the following policies or take the following actions to support and promote demand response among retail customers:

Strategy Set One: Improving Pricing for Retail Customers to Allow Price-Induced Demand Response[66]

Recommendation PM-1: Investigate Time-Sensitive Pricing for Default Service Customers

State regulatory commissions should initiate dockets to consider and determine whether default service should be provided using more time-sensitive rate designs that encourage greater economic demand response. Commissions should consider cost-based rate designs with greater time differentiation, greater emphasis on critical peaks, and greater recognition of uses that are highly peak coincident. Specifically, NEDRI recommends that commissions evaluate the applicability of the following more time-sensitive rate designs to different customer classes. NEDRI notes that this evaluation must necessarily take into account the availability and cost-effectiveness of advanced metering and other factors.[67]

[66] See Appendix 3-A for more detailed description and discussion of Strategy Set One.

[67] NEDRI also recommends evaluating the cost-effectiveness of interval metering for mass-market customers (Recommendation 2A, below).

Recommendation PM-1A: Real-Time Pricing
PUCs should consider implementing some form of real-time pricing for large customers on default service (*e.g.*, those with demands greater than 200-400 kW). NEDRI is not recommending any particular real-time pricing design, but instead describes in this report several that the commissions should consider.

Recommendation PM-1B: Critical Peak Pricing
PUCs should consider rate designs for medium-size default general service customers (*e.g.*, over 100 kW initially, but less than "large" as described above) that contain a critical-peak pricing element. Depending on the outcome of the recommended metering study (Strategy 2A), the program could be extended to other customers.

Recommendation PM-1C: Inverted Block Rates
PUCs should consider replacing existing flat rates for residential and small general service default service customers with rate structures that would price levels of usage typically reached by customers with peak-coincident end-uses (*e.g.*, air conditioning) at a higher level than that for basic usage. (Examples of such rate structures include inverted-block rates, but could also include time-of-use rates, critical peak pricing, and separation of rate classes.)

Strategy Set Two: Strategies to Support Demand Response in the Mass Market[68]

Recommendation PM-2A: Protocols to Assist Regulators in Evaluating Mass Market Rate Designs and the Deployment of Advanced Metering
State regulators should conduct an investigation to explore the costs, benefits, and options for providing advanced metering to mass-market customers. Within that proceeding, PUCs should also consider associated rate designs (*e.g.*, time-of-use and critical peak prices as discussed in Strategy 1C) for mass-market customers. It is through individual state examinations that the important issues of cost, technology choice, and benefits can be explored with the appropriate rigor. PUCs should not implement a rate design for low-income customers without considering its potential effects on those customers.

Recommendation PM-2B: Load Profiling
The distribution companies should continue to do load research to develop load profiles to support alternative rate design research, settlement, and demand response for mass-market customers. In addition, research on the load shapes of specific end-uses should be performed, in order to support quantification of the value of curtailable load programs such as interruptible water heating, air conditioning, or swimming pool pumping. The state PUCs should consider directing their distribution companies to establish and maintain load research programs that are adequate to support these activities. The group data and evaluation of load research programs should be available to the public.

[68] See Appendix 3-B for a more detailed description and discussion of Strategy Set Two

Recommendation PM-2C: Energy Efficiency
For small residential customers, such as those with usage only in the initial block of the advanced rate designs (*e.g.*, inverted rate design) proposed above, an effective demand-response program may be energy efficiency assistance targeted to those end-uses with comparatively high peak coincidence.

Strategy Set Three: Cross-Cutting Efforts[69]

Recommendation PM- 3A: Default Service Reform
Default service should be priced at a level that recovers all relevant costs. In addition, default service suppliers have a greater incentive and better means to acquire demand response if they are responsible for serving specific customers rather than merely a share of the default service load at wholesale.

Recommendation PM-3B: Curtailable Load Programs
ISO curtailable load programs should be implemented by curtailment service providers. In the case of regulated CSPs, 70% of the funding provided by the ISO for curtailment should flow to the customer, and 30% should be retained by the CSP to cover its costs of the program.

Recommendation PM-3C: Improving Distribution Company Participation in Demand Response Programs
Where distribution utilities deliver demand response programs, state public utility commissions should evaluate and consider implementing policies that remove financial disincentives to distribution utility support for those programs.

[69] See Appendix 3-C for more detailed description and discussion of Strategy Set Three.

Appendix 3-A. Strategy Set One: Improving Pricing for Retail Customers to Allow Price-Induced Demand Response

Strategy PM 1: PUCs Should Consider and Determine Whether to Implement Default Service Rate Designs that Improve Time-Sensitive Price Signals for All Customers

Recommendation PM-1:

State regulatory commissions should initiate dockets to consider and determine whether default service should be provided using more time-sensitive rate designs that encourage greater economic demand response. Commissions should consider cost-based rate designs with greater time differentiation, greater emphasis on critical peaks, and greater recognition of uses that are highly peak coincident. Specifically, NEDRI recommends that commissions evaluate the applicability of the following more time-sensitive rate designs to different customer classes. NEDRI notes that this evaluation must necessarily take into account the availability and cost-effectiveness of advanced metering and other factors.[70]

Options:

At a minimum, rate designs that encourage demand response should be considered for the following customer groups:

- Large-Volume Customers (above 300 – 400 kW): Real-time pricing, with or without hedging mechanisms.
- Medium-Volume Customers (100 – 300 kW): Critical Peak Pricing and/or Time-of-Use Pricing.
- Medium-Volume Customers (20 – 100 kW): Critical Peak Pricing and/or Time-of-Use Pricing, depending on the results of the recommended metering studies and associated decisions on the deployment of advanced meters.
- Residential Customers: Inverted block pricing or separate (higher) rates to customers with central air conditioning.[71]

Discussion:

NEDRI believes that more time-sensitive rate designs would produce a beneficial demand response effect. There is not, however, a consensus on the "best" rate design for any particular customer class, nor on whether such rate designs are desirable after consideration of customer acceptance, cost-effectiveness, and other criteria that are important to the design of electric rates.

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[70] NEDRI also recommends evaluating the cost-effectiveness of interval-metering for mass market customers below.
[71] The question of whether such rates should be implemented for small, non-residential customers remains open.

Each of the states has unique characteristics, and each comes to these issues from a slightly different "starting point." For this reason, we offer a series of rate design options for large-volume customers, medium-volume general service customers, and residential customers. It will fall to the state commissions to determine which, if any, of these approaches should be implemented locally.

Many of the proposed improvements in rate design can be implemented very quickly. Others will require the use of advanced metering for consumers not currently fitted with such metering, and therefore will likely await the results of the metering studies that we separately recommend in Strategy Set Two.

Strategy **PM-1A: For the Largest-Volume Customers, PUCs Should Consider Rate Designs that Provide Hourly Price Indicators to Customers**

Recommendation PM-1A:

PUCs should consider implementing some form of real-time pricing for large customers on default service (*e.g.*, those with demands greater than 200-400 kW). NEDRI is not recommending any particular real-time pricing design, but instead describes in this report several that the commissions should consider.

Options:

NEDRI has considered three options with respect to large customer rate design. Others may be presented as the commissions conduct their investigations.

- Real time pricing for electricity commodity costs based on day-ahead market prices, and recovery of transmission and distribution charges through alternative rate design. A program offered by Niagara Mohawk has served as a model.
- Real time pricing for bundled electricity service with a customer-specific baseline, subscription quantity, or partial hedge. A program offered by Georgia Power has served as a model.
- Monthly time-of-use prices for default and/or standard service.

Discussion:

The simplest approach to encourage real-time pricing for default service customers would simply be to use hourly market prices plus or minus an adder for administering the service. Delivery costs would be recovered separately. This tariff structure is similar to the method used by Niagara Mohawk in New York.

This approach suffers from a problem that could make it unacceptable to regulators and the public at large. Customers whose purchases are all at hourly prices are exposed to substantial risks of price swings. For example, if the market generally trades at $0.05/kWh but there is a chance that it could spike to $0.50/kWh for twenty hours in a given month, then the spike could increase customers' monthly bills by as much as 25%. Many, probably most, customers would find such exposure unacceptable. Thus, Niagara Mohawk offered large customers the option of specifying and purchasing some or all of their electricity at a fixed price (which included the estimated "risk premium") during a five-year transition period.

Another approach, loosely modeled on a plan used in Georgia, would be to allow customers to lock in a fixed price for a defined quantity of electricity.[72] For example, at the beginning of each month, a customer could choose to purchase a fixed amount of energy for the upcoming month, for example 1,000 kilowatt-hours per hour, at a price tied to the market price for futures contracts for that month.[73] (Conceptually, this is very similar to a heating oil dealer allowing a customer to commit in August to purchase, say, 1,000 gallons of oil for use in the following winter.) Any deviations from the preset amount would be charged or credited to customers at the hourly energy price. The overall effect would be to allow the customer to substantially fix her monthly energy bill while still being exposed to the hourly market for all changes in consumption.

The following table gives illustrative examples of these real-time pricing programs:

Rate Element	***Traditional Rate (for comparison)***	***Market RTP Rate***	***Baseline-Referenced or Subscription-based RTP Rate***
Customer Charge	$500.00	$500.00 (not affected)	$500.00 (not affected)
Delivery Service Charge(s)	$/kVa and / or $/kWh	$/kVa and / or $/kWh (not affected)	$/kVa and / or $/kWh (not affected)
Energy Charge for Power Supply (Competitive Service Is Alternative)	$.05/kWh	Market Price + margin	$.05/kWh * CBL or subscription amount
Usage In Excess of CBL or subscription amount	$.05/kWh	N/A	Market Price + margin
Savings Below CBL or subscription amount	$.05/kWh	N/A	Market Price + margin
Customer demand < Threshold (300 – 1000 kVa, determined by state commissions)		Not eligible; see TOU / Critical Peak Pricing	Not eligible see TOU / Critical Peak Pricing

[72] This fixed amount of consumption is often referred to as the customer baseline or CBL.
[73] A similar program might also allow customers to lock in a price for longer terms, such as a quarter or a year.

Some might argue that there is no need to include such a hedging mechanism in a standard offer product. Instead, they expect that competitive firms could step in to offer the same hedge outside the default service framework. While such arguments may ultimately prove correct, NEDRI recommends that PUCs carefully consider including a hedge in the default RTP product. First, it is not certain that such retail hedging products will, in fact, be available. (Currently, many of the traders who would be an integral part of such a hedging market may not be in a financial position to significantly expand their operations in the near term.) It would be risky for regulators to require real-time pricing for all purchases without a functional hedging market. Second, even if the hedging market flourishes, there may be some large customers (and large employers) who lack the creditworthiness or financial resources that would allow them to purchase hedges in the competitive market.

Indeed, there is a plausible argument that over time, a disproportionate number of the business customers on default or standard offer service may be there because of their own credit problems. Customers with strong credit could migrate to LSEs providing competitive service, but the financially weaker customers might not be able to find suppliers. It may not be good policy to have large credit impaired customers taking service under real-time rates without the ability to protect themselves against fluctuations in the hourly market. Without a viable hedging mechanism, there would be a significant risk of exacerbating the financial difficulties of weaker firms unnecessarily.

Another approach would be to have the market prices for standard offer or default service set more frequently – monthly instead of on a multi-month basis, and to have a time-of-use component to it. The incentives for hourly demand response would be lost, but the incentive for diurnal and seasonal demand response would remain.

The amount of demand response that a PUC can expect from a particular rate design will be a function of the degree of the time-sensitivity of the prices (*i.e.*, how dynamic or "real" they are) and of the extent to which customers can hedge that risk. These same questions, however, affect the degree to which such rate designs will be acceptable to consumers. Greater demand response will be elicited if the rate design is mandatory for all and lacking in hedging mechanisms, but other potential difficulties – customer acceptability and degree of exposure to price and financial risks, as described above – arise. PUCs will need to design a real-time rate program that, in their view, strikes the appropriate balance among these competing concerns and objectives.[74]

Strategy PM-1B: PUCs Should Consider Critical Peak Pricing and/or Time-of-Use Pricing for Medium General Service Customers

Recommendation PM-1B:

PUCs should consider rate designs for medium-size default general service customers (*e.g.*, over 100 kW initially, but less than "large" as described above) that contain a critical-peak

[74] It goes without saying that the costs of administering a real-time rate program must be taken into account when evaluating the overall costs and benefits of the program.

pricing element. Depending on the outcome of the recommended metering study (Strategy 2A), the program could be extended to other customers.

Options:

Among the spectrum of options NEDRI recommends be considered are the following:

- Time-of-use pricing with a real-time critical peak price
- Time-of-use pricing with a fixed critical peak price
- Time-of-use pricing without a critical peak price
- Non-TOU pricing with a fixed critical peak price

The first option, TOU pricing with a real-time critical peak price, would provide customers with a TOU rate (two- or three-period) that would be fixed except during critical peak periods. The benefit of this is that it provides the greatest certainty of cost recovery during the critical peak hours for the power supplier, leading to expected lower bid prices for all other hours. The disadvantage is that customers have more difficulty planning their responses in advance, insofar as they do not know what the critical peak price will be.[75] This option requires advanced metering, and should be initially implemented only for the larger customers in this category, pending the outcome of the metering studies called for in Strategy Set Two.

The second option, TOU pricing with fixed critical peak price, would provide customers with a fixed TOU rate (two or three period), and a fixed critical peak period price, set at a level that is three to five times the "normal" on-peak price. The advantage of this is that customers know what the price of electricity will be well in advance and can plan a response so that when a critical peak is called, they can implement a planned response. The disadvantage is that the fixed price may be above or below the market price at the time it is invoked. This option requires advanced metering, and should be initially implemented only for the larger customers in this category, pending the outcome of the metering studies called for in Strategy Set Two.

The third option, TOU pricing without a critical peak price, would simply give customers a two- or three-period TOU price. This would be a simple, but improved (insofar as it increases demand response) rate form for these customers. It would give the customers substantial predictability in energy costs, but would be expected to produce a much more modest demand-response than a rate structure with a critical peak feature.

The fourth option, non-TOU pricing with a fixed critical peak price, would give customers a flat rate during all hours, except for the critical peak period, and a fixed rate during the Critical Peak hours that is three to five times higher than the "normal" rate. The advantage of this is that it allows customers to focus their efforts exclusively on the critical peak periods, when demand-

[75] They can, however, program certain end-uses to cease drawing power when the price exceeds a specified threshold. This requires additional micro-processing functionality on premises. The Gulf Power program offers this feature.

response is most valuable. The disadvantage is that it "loses" some of the off-peak load-shifting incentive that TOU rates create.

Discussion:

Critical peak pricing (CPP) is a real-time rate that is effective during periods of significant system stress, when short-run market prices significantly exceed average retail rates.[76] Such a rate would give customers a predictable price (flat or TOU) during all but a limited number of hours per year, when (much higher) rates would be charged. These rates could be set in advance or be based on short-run market conditions. Customers would receive notice of higher prices by e-mail or direct notification.

The real-time pricing proposal, above, can only be implemented for customers who have meters[77] capable of recording hourly use during each hour in the billing period. Some customers may use too little electricity to justify such meters. NEDRI recommends that PUCs consider installing interval meters for customers with peak usage of 100 kilowatts or more. For customers with peak usage less than that, NEDRI recommends that PUCs consider a critical peak pricing program in conjunction with the metering studies called for in Strategy Set Two.

All but the TOU-only option require both interval metering and some mechanism to signal the meter when a critical period begins and ends. This proposal is limited to customers with a minimum demand of 100 kilowatts (initially), as advanced metering for this subgroup we believe is not problematic. The critical peak period should be determined on the basis of day-ahead prices, allowing notification to customers by email, media, and/or on-premises indicators.[78]

NEDRI believes that critical peak pricing should apply only during the summer months, should only take effect when the ISO declares an event that calls for demand-response, and should be limited to a maximum of a few hours per day and a few days per month.[79] The declaration should be based on day-ahead market expectations, since most customers require advance notification in order to allow them to adjust consumption levels. The idea is to have a sharply higher price for a few hours, hopefully achieving a high level of demand-response during those hours. The Critical Peak prices would be invoked only at these times, and the declaration of events leading to these prices being invoked would not be under the control of the default service power supplier.

[76] See Weston, Frederick, and Jim Lazar, *Framing Paper #3: Metering and Retail Pricing*, NEDRI, May 1, 2002 for a detailed description of the Gulf Power critical peak program.
[77] Strictly speaking meter and telecommunication combinations be used in place of true real time recording meters.
[78] Electricite de France uses an in-premises indicator for customers on this type of rate, with color-coded lights in a mandatory rate program. Gulf States Power uses a similar approach, but with automatic shedding of non-essential loads when higher prices are invoked in an optional critical peak pricing program.
[79] We note, however, that the summer-only limitation is based on the assumption that it is primarily during these months that the system events that would lead to the invocation of a critical peak occur. Regulators may wish to consider whether there are potential benefits to be captured by increasing the number of months during which a critical peak may be called.

The table below gives illustrative examples of several critical peak pricing alternatives. State commissions should consider these and other options.

Element	***Example 1: Flat Rate With Defined CPP***	***Example 2: TOU Critical Peak Rate with Defined CPP (preferred)***	***Example 3: TOU Critical Peak Rate With Market CPP***
Sum of Delivery and Power Supply Rate Design Elements	All kWh @ \$.09 except Critical Peak kWh @ \$.60/kWh	7 A.M. to 7 P.M. @ \$.117 7 P.M. to 7 A.M. @ \$.05 except Critical Peak kWh @ \$.60/kWh	7 A.M. to 7 P.M. @ \$.117 7 P.M. to 7 A.M. @ \$.05 except Critical Peak kWh @ Market + margin (~2 mills/kWh)
Maximum Number of Critical Peak Hours	40 - 100 per year 10 – 25 per month June – Sept. Only	40 – 100 per year 10 – 25 per month June – Sept. Only	40 - 100 per year 10 – 25 per month June – Sept. Only
Trigger Event for Critical Peak Price	ISO Calls on Day-Ahead Demand Response Resources	ISO Calls on Day-Ahead Demand Response Resources	ISO Calls on Day-Ahead Demand Response Resources
Advance Notice of Critical Peak Hours	Day Ahead (24 hours)	Day Ahead (24 hours)	Day Ahead (24 hours)

Like the real-time program, the critical peak rate program would constitute the basic service provided by the default supplier. The PUC would design a specific product type, specifying items such as:

- The maximum number and length of critical peak pricing events;
- The mechanism for determining the critical peak charge (*e.g.*, the hourly market price or a preset prices such as $0.25/kWh);
- The circumstances under which the a critical period would be invoked, *e.g.*, only when the day-ahead price exceeded some a specified level or when the ISO anticipated it would need to invoke specific emergency actions;[80]

[80] This condition is intended to address in some measure the default supplier's incentive to call critical peaks as a part of a revenue-enhancing strategy, as distinct from its efforts to manage its system loads and costs. Both affect its profitability, of course, but there may be a potential for gaming. We should point out that this condition does not

- The structure of prices during non-critical periods, *e.g.*, seasonal and/or time-of-use variations; and
- Any additional hedging mechanisms that might enable customers to better manage their electricity demand and costs.[81]

Given these specifications, an RFP would seek firms willing to provide the services. Like the real-time program above, the prices to default customers would be the market prices bid in by the successful bidder.

Strategy PM-1C: Inverted Block Rates

Recommendation PM-1C:

PUCs should consider replacing existing flat rates for residential default service customers with rate structures that would price levels of usage typically reached by customers with peak-coincident end-uses (*e.g.*, air conditioning) at a higher level than that for basic residential usage. (Examples of such rate structures include inverted-block rates, but could also include time-of-use rates, critical peak pricing, and separation of rate classes.)

Options:

NEDRI has considered the following options for residential rate design:

- Flat rates (typical currently)
- Multiple flat-rate scheduled, based on end-uses present
- Inverted block rates, with an initial block based on non-air-conditioning usage

Of these options, it appears that inverted block rates are most consistent with cost-causation principles, by pricing the level of usage most likely to be concentrated during the system peak demand period at a rate that reflects on-peak costs.

Discussion:

Low-usage residential customers are the group for whom sophisticated metering appears least likely to be cost-effective. As discussed section VI.A below, NEDRI recommends that state regulators conduct an investigation to explore various options for providing advanced metering

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prohibit the default supplier from not calling a critical peak, even though the criteria for calling one have been met. In any event, PUCs will want to carefully consider how these rate program affect supplier behavior.

[81] As in the case of the RTP program for large customers, the issue here is whether the critical peak rate is mandatory and, if so, if there are additions options available to customers to manage the price risk. For instance, does it make sense to design a premium product (in effect, a kind of insurance) that covers the incremental costs incurred by a customer when a critical peak is called?

to mass-market customers, and the costs and benefits of those options. For the interim, NEDRI recommends that PUCs consider an inverted block rate structure or, equivalently, separate determination of load profiles, and thus of rates, for low-use customers. Depending on the outcome of the investigation, this could be supplanted with a different rate design in the future.

Generally speaking, the highest cost times for a summer peaking system, such as New England and most other areas of the United States, occur during periods of extremely hot (and often humid) weather when air conditioning demands are highest. There is a strong correlation between a customer's usage level and the specific electric end-uses that the customer employs. The lower-usage customers typically use electricity for lighting, refrigeration, and miscellaneous appliances. There is empirical evidence that customers who use less than 300-400 kWh per month in the summer typically have little or no air conditioning use and tend to have their usage more concentrated in the lower cost hours of summer. Higher-volume users, on the other hand, are more likely to use a significant amount of electricity for air conditioning during the highest-cost on-peak hours. (Just where the break between the initial and tail blocks should be set is a matter for policymakers to decide; other considerations, such as equity and revenue stability, will be factors in these decisions.)

Thus an inverted rate design is time-sensitive in a fairly crude manner. A larger proportion of the tail-block usage occurs during the peak period than is the case for initial block usage, simply because of the expected higher peak-coincidence of the end-uses characteristic of large residential usage. This will definitely not be the case for every consumer, but is a generally predictable pattern.

The intent of this recommendation is not to arbitrarily label low-use residential customers as "good" or to penalize air conditioning use as "bad." Rather the object is to align customers' electricity bills with the costs they impose on the system and, perhaps more importantly, to send price signals that will encourage economic decision-making. For example, if we under-price electricity at times of summer peaks, we are, by definition, encouraging rational consumers to over-consume. This mis-pricing of the electricity might lead a consumer to purchase a lower initial-cost, lower-efficiency air conditioner even though a higher-efficiency unit would produce the same level of comfort at a lower overall cost.

Of course, inverted block and time-of-use rates are, at best, blunt instruments, when compared with real-time pricing. They send price signals that encourage customers to use less electricity either above a given usage level or during broadly defined time periods; but they do not focus on the limited number of hours when demand response is particularly important. In this regard, inverted block rates and time-of-use prices are less effective at encouraging demand response than other rate structures, such as real-time and critical peak pricing. Inverted-block rates have the advantage, however, of being compatible with the existing metering and billing infrastructure.[82]

[82] One alternative suggested was that larger residential consumers be placed on time-of-use rates or critical peak pricing rates, with smaller consumers left on flat or inverted rates. This would permit capture of demand-response benefits from the customers with the largest usage. This class bifurcation is an appropriate consideration for the Commissions in comparing the potential benefits of mass deployment of advanced metering.

Whether low-use customers do, in fact, consume primarily during low-cost times is an empirical question. In a number of western states – Arizona, California, Idaho, and Washington – statistically valid load research has confirmed that there is a clear correlation between high usage levels and consumption during peak periods. As a result, these states use inverted block rates extensively. Vermont has also used an inverted block rate approach based on a similar analysis of usage during high- and low-cost periods. NEDRI recommends that PUCs direct utilities under their jurisdiction to perform, or have performed on their behalf, similar studies into the relationship between overall monthly usage and usage at peak (high cost) times.

Perhaps the simplest way to implement an inverted block structure would be to disaggregate the load profiles assigned to residential customers. Load profiles are currently used to determine the hourly loads of LSEs when they serve customers who do not have hourly meters. Conceptually, they operate by taking the monthly metered monthly load of each customer and allocating it to each hour in the month according to the statistically derived load patterns. For example, one would use a statistical sample of all residential customers to determine an average load shape and then use this average load shape to assign hourly loads, and costs, to customers.[83]

What we are suggesting is that PUCs should review, or have utilities review, whether there are significant differences in the load shapes of low- and high-use customers. If, as we believe, there are differences, then each group should be assigned its own load profile and billed accordingly. If this is done, the market would presumably recognize it and begin to differentiate between the prices charged to low- and high-use residential customers. If the market were set up so that the initial usage level of all customers were based on one load profile, and the incremental usage beyond that threshold were based on a second load profile, and the expected relationship prevails, the result would be an inverted block power supply rate.

A separate issue is whether an inverted block delivery rate is appropriate. To the extent that the load factor of upper block usage is lower than that of lower block usage, a justification exists for inverted block delivery charges. If these were implemented, however, some means to address the increased revenue volatility of the distribution company for distribution service may need to be addressed.

[83] For more detail on load profiling, refer to the discussion on it in the following section describing Strategy Set Two. See also Weston, Frederick, and Jim Lazar, *Framing Paper #3: Metering and Retail Pricing*, NEDRI, May 1, 2002, at 16-18.

Appendix 3-B. Strategy Set Two: Strategies to Support Demand Response in the Mass Market

Strategy PM-2A: Protocols to Assist Regulators in Evaluating Mass Market Rate Designs and the Deployment of Advanced Metering

Recommendation PM-2A :

State regulators should conduct an investigation to explore the costs, benefits, and options for providing advanced metering to mass-market customers. Within that proceeding, PUCs should also consider associated rate designs (*e.g.*, time-of-use and critical peak prices as discussed in Strategy 1C) for mass-market customers. It is through individual state examinations that the important issues of cost, technology choice, and benefits can be explored with the appropriate rigor. PUCs should not implement a rate design for low-income customers without considering its potential effects on those customers.

Discussion:

Advanced metering has the potential to create many opportunities for demand response by customers, large and small. The information provided through advanced meters may also create opportunities for more efficient operation of the electric system from generators to customer transformers. NEDRI recommends that every customer should have advanced metering capabilities when it is shown to be cost-effective.

Advanced metering can generally be defined as a package of metering and communications equipment that is, at a minimum, capable of (1) recording data hourly; (2) communicating data to the utility daily; and (3) providing customer access to the data daily.[84] There are many different types of metering and communication systems that provide this level of functionality.[85] In practice, the appropriate level of functionality will likely vary by customer class. For example, some of the largest customers may require 15-minute data, rather than hourly data. Small customers may only require time-of-use data (*e.g.*, 3 reads per day), rather than hourly data (24 reads per day). There are, of course, cost implications associated with going to higher or lower levels of functionality.[86]

[84] NEDRI recommends, however, that the level of functionality to be deployed be among the issues to be considered in the state PUC proceedings recommended below.
[85] The providers of several different types of metering systems presented at a Metering Technologies Workshop on July 11, 2002 co-sponsored by NEDRI, the New Hampshire PUC, and the New England Conference of Public Utility Commissioners. Copies of those presentations are available at www.puc.state.nh.us/metering.htm.
[86] We note also that advanced metering must be distinguished from automated meter reading ("AMR"). AMR systems replace manual, monthly meter reads with an automated system that collects the **same** information. They typically use one-way communication to a mobile receiver, *e.g.*, a van. AMR systems do not necessarily support demand response because they may not provide sufficient frequency of either data recording or communication.

NEDRI recommends that each state conduct an investigation to explore the costs, benefits, and options for providing advanced metering to small customers.[87] It is through individual state examinations that the important issues of cost, technology choice, and benefits can be explored with the appropriate rigor. At the same time, NEDRI recognizes that many of the benefits and costs of advanced metering go beyond the scope of demand response and NEDRI urges that any state action view metering as a cross-cutting technology, such that the total benefits are compared to total costs.[88]

State proceedings regarding advanced metering should examine issues including the following.

Technology
Commissions should not attempt to pick a particular technology, but instead should determine the level of functionality – of performance – that is required. Key issues include:

- Communications – one-way or two-way
- Frequency of recording, *e.g.*, at least hourly
- Frequency of data retrieval, *e.g.*, at least daily
- Type of information to be recorded
- Frequency and method of customer access to usage data, e.g., at least a daily via a website.
- "Upgradability" to provide enhanced functionality or to take advantage of technological improvements, *e.g.*, the potential use of "smart" technology – technology that could automatically adjust customer energy usage.
- Different levels of functionality for different customer classes

[87] The California Commission has opened just such a proceeding. See Order Instituting Rulemaking on policies and practices for advanced metering, demand response, and dynamic pricing, CA PUC R.02-06-001, (June 10, 2002).
[88] Numerous analyses have concluded that, advanced metering systems are cost-effective under a wide range of assumptions regarding costs and benefits. See, *e.g.*, A. Faruqui and S. George, "The Value of Dynamic Pricing in Mass Markets," *The Electricity Journal* (July 2002); R Levy, *Meter Scoping Report*, California Energy Commission Report for the PIER Program (February 2002); Cambridge Energy Research Associates, *Capturing Value: The Future of Advanced Metering and Energy Information* (1999); and C. King, *The Economics of Real-Time and Time of Use Pricing for Residential Consumers*, American Energy Institute (June 2001). *See also* S. Borenstein, M. Jaske, A. Rosenfeld, *Dynamic Pricing, Advanced Metering and Demand Response in Electricity Markets*, University of California Energy Institute, Center for the Study of Energy Markets, (October 2002).

Deployment Options

Deployment choices are a key factor in both the cost and benefits of advanced metering. The key choice is between a "saturation" deployment, which covers most or all customers in a territory, and a scattered deployment. On a per meter basis, the cost of a saturation deployment is substantially less than the cost of a scattered deployment.[89] Saturation deployments also create greater benefits because they reduce utility costs such as meter reading. However, since many more meters are typically installed in a saturation deployment than a scattered deployment, the total cost (including potential participant costs) is higher. The deployment options to consider include:

- coordinated, wide-scale saturation deployment
- location-specific mass deployment (e.g. city-wide, district wide)
- gradual introduction via new construction, meter replacement, etc.
- by customer characteristics, e.g., size or end uses
- upon customer request
- exemption of certain customer categories

Costs

The core cost categories to identify and examine are:

Potential System Costs

The costs of installing and operating the meters, including:

- New or replacement meter capable of communications, or
- Communications module for retrofit of existing meter, and
- Cost of fixed communications network, total and also on a per meter basis
- Installation Costs
- Operation and maintenance (as compared to the equivalent costs for the existing meters)
- Integration with utility back office systems
- Software
- Programming
- Data retrieval and management
- Risk of stranded costs

Potential Participant Costs

Direct and indirect costs including:

- Health costs, *e.g.*, if as a result of metering enabled dynamic pricing customers choose to use less electricity on peak.[90]
- Loss of comfort
- Loss of convenience

[89] Demand Response and Advanced Metering Coalition, *Costs of Advanced Metering and Communication Technologies* (2002). For example, for mass-market customers the per-meter installation costs in a saturation deployment may be as little as one-tenth of what they are in a scattered deployment.

[90] Any such costs would need to be netted against benefits resulting from customers' ability to use more electricity off-peak.

- Customer costs of demand response related hardware and software
- Foregone safety inspections by meter readers
- Potential loss of control over private customer information
- Loss of productivity, including such losses due to impaired health
- Loss of education
- Lost jobs

Benefits

The areas that a Commission should explore include:

Potential Individual Customer Benefits

- New information about electricity usage
- Additional rate opportunities
- Enhanced ability to manage and control electricity costs
- Potential for participants to lower bills through direct savings at retail
- Potential for non-participants and participants to lower bills through indirect savings due to lower system wholesale costs.
- Improved customer service
- Allows participation in ISO demand response programs

Potential System Benefits

- Lower wholesale electric prices
- Improved reliability
- Reduced generator market power[91]
- Insurance benefits[92]
- Reduced lag time between trading date and wholesale settlements, reducing working capital requirements, financial risks, and bonding requirements for wholesale market participants[93]
- Improved data
- Improved forecasting
- System operations optimization
- Optimize system planning and expansion

Potential Distribution Company Benefits

- Outage Management/Response
    - Trip avoidance
    - Crew Optimization
- Customer Care

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[91] Eric Hirst, Retail Load Participation in Competitive Wholesale Electricity Markets (January 2001)
[92] Eric Hirst, The Financial and Physical Insurance Benefits of Price-Responsive Demand, (February 2002)
[93] Cambridge Energy Research Associates, Capturing Value: The Future of Advanced Metering and Energy Information, pp. VI-14 to VI-16 (1999).

    - More efficient customer response
- New Customer Choices
    - Customers can be presented with new service and rate options.

- Reduced Meter Reading Costs
    - Reduced labor costs
    - Avoided vehicle and equipment costs
- Improved Meter Reading Accuracy and Efficiency
- Reduction in estimated bills
- Two-way communications ability and interactive messaging ability
- Load control and management
- Improved data
- Improved forecasting
- Substation monitoring and management
- Distribution system optimization
- Distribution system planning and expansion

Other issues
Other questions that the Commission should consider include the following:

- Who should pay for the metering technology?
    - Participants
    - All Customers
        - Utility
        - State
        - Regional
    - System benefits funding[94]
    - Combination of above
- Should customers have options regarding levels of service and costs? For example, should the costs of the basic technology be recovered from all customers through distribution rates (as is traditionally the case with metering costs)? Should all of the costs, or only the incremental costs associated with an advanced service (e.g., TOU or hourly meter reads) be borne only by customers choosing such service as an option?
- Are rate caps/freezes and stranded investment concerns acting as a barrier to utility deployment of advanced metering?
- Should utilities have PBR rate incentives for deployment of advanced metering?
- What rate options are appropriate to be put in place so as to capture the value of the advanced metering?
- How can advanced metering affect or support net metering programs for on-site generation?

[94] While NEDRI recognizes that it may be reasonable to consider whether it is appropriate to use system benefits funds in support of advanced metering and other demand response infrastructure, a number of participants in fact are reluctant to use funds in this way. In particular, there was opposition to allocating to advanced metering efforts any monies dedicated to low-income efficiency programs.

- What other technology options are complementary for demand response and should also be considered for deployment?
- Risks of technological obsolescence vs. opportunity costs of waiting.
- Who should deploy the metering technology? Utilities? Competitive firms?
- Who owns the information? Customer specific information? Aggregated information?

Strategy PM-2B: Load Profiling to Support Mass Market Demand Response

Recommendation PM-2B:

The distribution companies should continue to do load research to develop load profiles to support alternative rate design research, settlement, and demand response for mass-market customers. In addition, research on the load shapes of specific end-uses should be performed, in order to support quantification of the value of curtailable load programs such as interruptible water heating, air conditioning, or swimming pool pumping. The state PUCs should consider directing their distribution companies to establish and maintain load research programs that are adequate to support these activities. The group data and evaluation of load research programs should be available to the public.

Discussion:

In states where the electric industry has been restructured to allow for a competitive generation market, it is important to establish "special" load profiles for non-interval metered customers that want to participate in one of the ISO's load response program.[95] Without special load profiles, non-interval metered customers will not receive the full financial benefits available through the load response programs.

The need for load profiling is a consequence of the manner in which the ISO financial settlements work, for both the load response programs and the energy spot market. A customer that participates in a demand response program should see two streams of benefits. First, the customer receives a direct payment from the load response program for reducing its load,[96] based on information provided by the customer's curtailment service provider ("CSP") that verifies that the customer reduced its consumption, during the applicable time period, below its baseline consumption.[97] We assume that special rules will be developed regarding verification of

[95] This memo assumes that customers without interval meters can participate in one of the ISO's load response programs.
[96] The payment actually is made to the customer's "curtailment service provider," the entity that signed the customer up to participate in the programs. For the sake of simplicity, this memo assumes that the provider passes 100 percent of the payment to the customer.
[97] The customer's CSP may or may not be its load serving entity.

customer load reduction to allow non-interval metered customers to participate in the load response program.[98]

The second stream of benefits results from the customer's load reduction being taken into account in the ISO's spot market settlement system. The market settlement system establishes the load obligation for each load serving entity ("LSE")[99] based on hourly consumption information for the LSE's retail customers. This information is provided by each distribution company ("disco"). For example, if an LSE is serving a customer in a disco's service territory, the disco will determine the hourly consumption for the customer, and report the hourly consumption to the ISO for use in the LSE's market settlement account. If the customer has an interval meter with telecommunications capability, its hourly consumption, as reported by the disco, would be based on actual metered data. Thus, any reductions in the customer's consumption would be taken into account in the hourly consumption reported by the disco for the customer's LSE. Therefore, the load obligation of the LSE would be lower, and the LSE would benefit from having a lower load obligation during hours when spot market prices would be high.

However, if the customer does not have an interval meter, its hourly consumption is based on load profiles that break out the customer's monthly metered consumption into hourly components. Load profiles are not able to assign load reductions achieved by individual customers to the particular hour(s) in which they occur. Thus, if the customer were to reduce its consumption in a particular hour, the decrease in its monthly metered consumption would be spread evenly over all hours of the month – *i.e.*, the load reduction would not be credited to the appropriate hour (in which, as stated above, spot market prices would be expected to be high). Thus, the load obligation of the customer's LSE would not decrease during the high-price hour, depriving the customer and the LSE of reaping the full financial benefit from the load reduction.

The problem goes beyond merely the question of settling loads for the purposes of the ISO's load response programs. Since savings cannot be properly attributed to an LSE or its customers at the times when they occur, the LSE has little incentive to acquire demand response savings from its customers for the purposes of reselling the saved energy back into the market, in an effort to make a profit through arbitrage.[100]

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[98] For example, settlement of the ISO's Real-Time Profile Response Program makes use of statistically reliable data. Billing-quality interval meters have been installed on a representative sample of participants, and the load response from the sample is attribute to the entire population of participants. Measuring load response in real-time on a sample of participants has the advantage of picking up the average load response of customers to real-time variations in weather and other factors.

[99] We use the term "load-serving entity" to refer to the NEPOOL Participant that takes responsibility for a customer's load obligation in the ISO's market settlement system. For the sake of simplicity, we assume that a customer's load serving entity is the customer's retail supplier.

[100] Weston, Frederick, and Jim Lazar, *Framing Paper #3: Metering and Retail Pricing*, NEDRI, May 1, 2002, at 16-18. This disincentive is further exacerbated in Massachusetts, where some default service providers are responsible for only a share of a customer class's default service load at wholesale. In those cases, any demand response savings among default service customers is necessarily spread among all DSPs. Refer to the discussion on default service reform in Section V, below.

There are a couple of ways in which this dilemma could be resolved. First, load response customers could purchase interval meters,[101] which would obviate the need to use a load profile to determine the customers' hourly consumption. The problem with this solution is that, for small customers, the cost of having an interval meter installed is large in comparison to these customers' monthly electric bills (this is particularly true for residential customers). A requirement that small customers have interval meters installed could present a significant barrier to participation by these customers in the ISO load response programs (this question would be addressed in the recommended PUC investigation into advanced metering). As discussed in section VI.A above, NEDRI recommends that state regulators conduct an investigation to explore a range of other options, and the associated costs and benefits, for providing advanced metering to mass-market customers.

For the interim, separate load profiles could be created for small customer participants in load response programs. State regulators could direct discos to continue to conduct load research on their customers, determine load profiles, and to make that information available to LSEs and other demand response providers. Additional load profiles, describing different usages, may need to be created, but the expertise for doing so already resides, for the most part, in the distribution companies. Implementation details may need to be worked out. Insofar as additional analytical efforts might be required, state commissions may want to consider their potential costs and benefits (*i.e.*, do smaller customers have the potential to reduce their load to a degree great enough to warrant the effort that would be required to establish the new load profiles) before going down this road. This question could be taken up as part of the investigation into advanced metering.[102]

NEDRI recommends that the state PUCs consider directing the distribution companies to establish and maintain load research programs that are adequate to support rate design, class and subclass settlement, and other purposes (such as interruptible programs). The group data and evaluation of load research programs should be available to the public.

Strategy PM-2C: Energy Efficiency Programs for Low-Volume Customers

Recommendation PM-2C:

For small residential customers, those with usage only in the initial block of the advanced rate designs (*e.g.*, inverted rate design) proposed above, an effective demand-response program may be energy efficiency assistance targeted to those end-uses with comparatively high peak coincidence.

[101] In Massachusetts, each distribution company has a PUC-approved tariff governing the terms and conditions by which customers may purchase advanced metering technology.

[102] The Working Group considered whether a third approach – ISO-sponsored load research – would also be appropriate. For several reasons, the Group concluded it would not be: (1) financing such research could be deemed as taking a market position with respect to a particular resource, which the ISO is prohibited from doing; (2) such research may not add much value, insofar as distribution companies, already do it; and (3) being related to retail activities (in particular, billing and metering, responsibility for which the discos currently retain), it is within the authority of PUCs to direct the distribution companies to conduct it.

Discussion:

For some small residential customers, the only cost-effective demand response program may be energy efficiency. Many small customers, by virtue of their small bills, cannot cost-justify an investment required for demand response; indeed, almost by definition they lack the type of usage (such as central air conditioning) on which direct load control or price-driven demand response programs are based. A large fraction of small residential consumers are low-income households, who are not able to make a demand response investment even if it were cost-effective.

Almost any reduction in demand includes a reduction in peak demand; thus efficiency programs are, in effect, also demand response programs, reducing peak and energy usage in addition to all their other benefits. Efficiency programs are generally long-term investments, which thus produce long-lasting responses on which generation planning can be based. By focusing some energy efficiency program funding on measures with relatively high peak coincidence factors, it may be possible to elicit peak load reductions from small residential consumers that could not be achieved through other forms of demand response programs.

The principal end-uses of this group of customers are lighting, refrigeration, cooking, and television. Of these, lighting and refrigeration are promising avenues for efficiency investments and incentive programs.

Appendix 3-C. Strategy Set Three: Cross-Cutting Efforts

Strategy PM-3A: Default Service Reform

Recommendation PM-3A:

Default service should be priced at a level that recovers all relevant costs. In addition, default service suppliers have a greater incentive and better means to acquire demand response if they are responsible for serving specific customers rather than merely a share of the default service load at wholesale.

Discussion:

For large customers, demand response would be fostered by reforming default service[103] to facilitate customer migration to the competitive market. This is because competitive retail suppliers are better suited to promoting demand response than are default service suppliers, for several reasons:

- Competitive suppliers are able to design price and service offerings to meet the needs of, and promote demand response by, individual customers. Indeed, they have the incentive to do so in order to attract and retain customers. By contrast, default service prices are set by regulators, and are set on a class-wide basis, not an individual customer basis.

- Competitive suppliers have retail relationships with individual customers, and so are in a position to provide services. By contrast, default services suppliers typically do not have a retail relationship with customers. Instead, default service is typically provided on a wholesale basis to the utility.

- Competitive suppliers typically serve customers under contracts for terms of years, and so have the opportunity to recoup the cost of marketing and providing demand response services. By contrast, default service customers are not bound by a contract; they are free to leave whenever they wish. As a result, default service providers cannot count on being able to recoup any costs associated with marketing and providing services.

For small customers, there are different views among NEDRI members regarding whether the competitive market will promote demand response. Some believe that it will, for the reasons articulated above. Others point out that a competitive retail market for residential customer has not yet developed in any New England state. Thus, there is no evidence that competition will in fact foster demand response for these customers.

[103] The term "default service" is used here to refer to all forms of generation service provided to customers that have not chosen a competitive supplier. It includes the services that the various states call "Standard Offer Service," "Default Service," "Transition Service," etc.

Accordingly, NEDRI recommends the following reforms to default service:[104]

All Customers

- Default service supply should be procured using a competitive procurement process, in which competitive suppliers submit bids to provide the service. The service should be re-bid periodically and the prices re-set no less frequently than once per year.

- The default service price to customers should reflect all of the costs of providing the service. The price should include the wholesale supplier's bid price. Wholesale suppliers should be responsible for energy, ancillary services, load shaping, losses, price and volume risk, and other supply-related costs, and presumably will include those costs in their bid prices. The default service price to customers should also include certain costs incurred by the utility, including: (i) the administrative costs incurred by the utility in procuring and managing default service supply; and (ii) the credit, collections, and bad debt costs associated with generation charges to default service customers.[105]

- For large customers, where more than one wholesale default service supplier is selected to serve a customer class, the suppliers should be responsible for serving the loads of specific customers, as opposed to a percentage of the class's overall default service load.

Large Customers

- For large customers, the default service should be priced in relation to the local hourly market price This pricing structure would place the full risk for daily and long term price fluctuations on the customer. Default service pricing for large customers is discussed in greater detail in Section V, above.

Small Customers

- For small customers, default service resources should be obtained and prices should be fixed in ways that achieve the goal of price stability, with provision for time-sensitive pricing and critical peak pricing elements.

- Some NEDRI members recommend that consideration should be given to including demand response measures in the bidding process by which default service supplies are obtained. Others recommend that default service be reformed to enable competitive suppliers to acquire large numbers of small customers at once, and thus foster the development of the competitive market for those customers.

Default service should be provided at rates that reflect the overall cost of power in the market over time. The best way to do this appears to be to periodically issue an RFP for default

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[104] Many of these proposed reforms are based on the default service mechanisms that are in place in Maine and Massachusetts.

[105] Some NEDRI members believe that the default service price should also include additional costs, such as an allocation of utility customer service, billing, and administrative and general costs. Other NEDRI members disagree with this position.

providers specifying the precise product being sought. The bid prices to provide those services then represent the market's assessment of the market price for those services. For example, if an RFP requests full requirements service with two price options, one to provide service at the hourly energy cost plus an adder and the second for a one year fixed price contract, then one can conclude that the price difference between the two alternatives is a fair representation of the true cost of hedging the product and accepting any attendant risks.[106]

The reason to prefer market-based approaches here is simple. In the end, competitive LSEs, not default providers are more likely to have a relationship to the customer and the ability to tailor products, such as taking advantage of hourly market swings, to customers needs. Setting market-based default rates allows LSEs to fairly compete, which is a necessary step toward achieving price-based load response.

In those states where the T&D utility is responsible for providing default service, the utility could follow a similar approach, issuing an RFP with PUC guidance and then setting the rates charged to customers at the amounts bid by the provider(s).

State PUCs should determine the desirable price structure for default service and then design the RFP seek bids to supply according to that structure. Moreover, for large customers where real-time metering capability is in place, this price structure set the prices for marginal electricity purchases based on the real time market costs of electric generation. Such a structure would mean that all default customers would see proper price signals when they make purchase decisions and would also encourage competitive LSEs to develop similar product offerings.[107]

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[106] A significant risk of fixed-price all-requirements service is the risk of load migration. In particular, if market prices drop after the default contract is executed, standard offer customers could switch to competitive LSEs, potentially leaving the default provider with substantial amounts of fixed-price power that it purchased to serve the customers. On the other hand, if it avoids this risk by not pre-buying at a fixed price, it is now exposed to the risk of market price increases and it would be contractually bound to sell at loss.

[107] Jerrold Oppenheim of the Low-Income Network does not support the recommendations regarding methods of allocating customers among default service suppliers, supporting competitive provision of demand response, or market-based approaches on the grounds that when the benefits to small residential customers of competitive markets remain unproven.

Strategy PM-3B: Curtailable Load Programs

Recommendation PM-3B:

ISO curtailable load programs should be implemented by curtailment service providers. In the case of regulated CSPs, 70% of the funding provided by the ISO for curtailment should flow to the customer, and 30% should be retained by the CSP to cover its costs of the program.

Discussion:

This strategy consists of the actions and policies necessary at retail to enable promotion and use of the ISO's Day-Ahead and Emergency Demand Response Programs. Refer to the Price-Responsive Load strategies for specifics on program duration, customer eligibility, end-user requirements, baselines, etc.

Program Marketers and Offerings. The retail offering of ISO demand-response programs will be effected by Curtailable Service Providers (CSPs). A CSP could be a traditional vertically integrated monopoly utility, a regulated electric delivery utility in a competitive market, a default service provider (DSP), competitive electricity supplier, or a stand-alone CSP. For a non-regulated CSP, *i.e.*, the stand-alone CSP or competitive electric supplier, the terms of the agreement could be negotiated or be part of a standard product or products. In the case of regulated CSPs (regulated utilities and DSPs), the terms of agreement would be subject to approval by the PUC and embodied in tariffs or special contracts. CSPs are notified by the ISO when interruptions are needed, and it in turn notifies the customer. The ISO makes payments directly to CSPs, who in turn pay consumers for load reductions provided when called upon.[108]

Compensation. The amount of the payment to the consumer will typically represent a share of the payment made by the ISO for the reduction. The sharing between the CSP and the customer must be sufficient to induce the desired behavior by the customer and cover the costs (including profit) incurred by the CSP to provide the service. The product will not be offered if not enough money will be available to encourage participation and recover costs of the CSP.

There are policy and market implications to the question of how the ISO payments are shared between customers and providers. In the case of non-regulated CSPs, sharing will be determined by the price negotiated or offered through a standard product (*i.e.*, the provider's share is the margin between the price paid to the customer and the price paid by the ISO). In the case of regulated CSPs, the sharing will be determined by the PUC,

[108] Precisely how payments are made may, in fact, be nuanced. The reserve margin (ICAP) credit is given to the entity that brings the resource to the ISO – *i.e.*, the CSP. The CSP can either use the credit to reduce its ICAP responsibility (if it is an LSE) or sell the credit on the market. The reduced cost from the reduced ICAP responsibility, or the revenue from the ICAP sale, could be shared with the customer in some proportion.

taking into account traditional regulatory concerns – equity, efficiency, cost-allocation, and revenue collection. The regulated CSP share should be set to cover at least the costs of marketing and providing the service. We recommend the following split:

Customer	***Provider***
70%	30%

The ratio effectively determines the margins available to CSPs and others who wish to market the ISO programs.

Other Regulatory Requirements. Regulatory oversight is minimal or not required at all for transactions between customers and *competitive (non-regulated) CSPs*. This is because the transactions are between parties who are not subject to the jurisdiction of state utility regulators. Moreover, the activity should not affect the relationship between the customer and the regulated distribution company, except insofar as the CSP requires access to customer billing and related information. Protocols for providing that information – with the express permission of the customer – can be easily developed, while preserving the full range of consumer protections. However, insofar as the programs are marketed by regulated CSPs, it is important that the programs be developed at the wholesale level, and approved by FERC, to allow time to receive regulatory approval at the retail level in time for the next peak season. Lastly, the wholesale programs must be designed and approved by regulators in time for all potential CSPs to build the administrative infrastructure for the programs in time for the next peak season.

Eligibility. Customer eligibility for interval-metered programs is defined in the strategy options for the emergency and day-ahead demand response programs. In addition, aggregation of non-interval metered customers could be permitted. The amount of the curtailments through aggregation could be determined by alternative approaches to the ISO's basic metering and measurement requirements.[109] Such approaches, typically relying on statistical methods, would be proposed by aggregators and approved by the ISO. The aggregations must be at least 0.1 MW for the emergency program and 1.0 MW for the day ahead. For settlement purposes, the load reductions will be treated as if they were interval metered, that is, reductions will be assigned to the hours in which they were expected to occur (or, insofar as they are based on statistical sampling in real-time,[110] in the hours which they did occur).

Strategy PM-3C: Improving Distribution Company Participation in Demand Response Programs

Recommendation PM-3C:

[109] Currently, NYISO and PJM allow up to 25 MW of aggregated load to participate, but there is no reason why the program should be capped in this way. What is critical is that any savings resulting from aggregation be real and measurable with a high degree of confidence.
[110] As in the case of ISO-NE's Real-Time Profile Response Program.

Where distribution utilities deliver demand response programs, state public utility commissions should evaluate and consider implementing policies that remove financial disincentives to distribution utility support for those programs.

Discussion:

Demand response can have a variety of financial impacts, both positive and negative, on distribution utilities. To the extent that short-term demand response (*e.g.*, load management and on-site customer generation) avoids energy deliveries at times when incremental costs exceed incremental revenues, utilities will benefit. Shifting loads from high-cost periods to low-cost ones will have the same effect, with the added benefit of additional net revenues during the low-cost times. However, to the extent that some demand response (*e.g.*, end-use efficiency and other conservation measures) yields long-term benefits but may result in short-term net revenue losses, the utility faces a disincentive to participate in or deliver those programs.[111]

There are a variety of approaches for addressing this potential barrier to demand response. Some utilities, for example, have successfully run demand-side programs for many years under an incentive scheme that rewards superior performance in delivering demand side programs. Alternatively, some utilities have operated under rate-setting mechanisms that provide earnings stability while breaking the financial link between energy throughput and profits. They include, for example, lost-revenue adjustments and revenue-capped performance-based regulation (PBR). Since demand response improves the efficiency of both the production and consumption of electricity, it can in many cases result in reduced throughput. Lost-revenue adjustments allow recovery of net revenues foregone as a consequence of demand response programs and keep the distribution utility "whole" in the short run. Revenue-capped PBRs work in much the same way.

NEDRI recommends that state public utility commissions evaluate and consider implementing rate-setting or other mechanisms that will encourage distribution utilities and default service providers to support both energy efficiency and shorter-term demand response.

[111] That is, at times when incremental revenue would have exceeded incremental cost and thus there is a reduction in earnings.

CHAPTER 4: ENERGY EFFICIENCY AS A DEMAND RESPONSE RESOURCE

Introduction and Overview

Electric utilities and governmental decision-makers in New England have long understood that improvements in energy efficiency can provide multiple benefits to electricity customers, to the economy, the electric grid, and the region's environment.[112] Those benefits remain vital today, following restructuring, divestiture, and the evolution of regional wholesale markets. There is substantial evidence that significant market barriers to cost-effective energy efficiency investments remain, even in conditions of active wholesale competition, and that those investments could lower market clearing prices, improve reliability, and lower the region's total cost of electric service. For these reasons, NEDRI has examined a number of policies and strategies that would support longer-term, cost-effective, shifts in consumption patterns in addition to the shorter term regional demand response strategies discussed in Chapter 2.

Following a discussion of energy efficiency as a valuable, longer-term form of customer demand response, this Chapter presents the following strategies and recommendations[113]:

- System Benefit Charge (SBC) Funds and Ratepayer Support for Energy Efficiency
- Principles for Effective Energy Efficiency Programs and Portfolios
- Minimum Energy Efficiency Standards for Appliances and Equipment
- Building Energy Codes
- Enhanced Regional Coordination for Demand-Side Resources
- Complementary and Integrated Options for Energy Efficiency and Shorter-Term Demand Response

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[112] As the U.S. EPA noted in its summary of the environmental review of the NEDRI proposals, “Energy efficiency improvements consistent with NEDRI’s recommendations have quite positive environmental effects, since efficiency reduces generation needed across many hours and displaces high-cost, high-emitting units at peak times as well.” See Letter from EPA to NEDRI, Appendix E.

[113] Energy efficiency can also play a role in moderating loads on transmission and distribution power delivery systems. The treatment of energy efficiency as a demand resource in power delivery is addressed in Chapter 6 of this Report.

Energy Efficiency as Longer-Term Demand Response

Cost-effective energy efficiency resources make electricity markets more competitive and more efficient, significantly improve the reliability of the electric system in New England, diversify the resource portfolio, and reduce the costs and environmental impacts of electric service. Energy efficiency load reductions result in lower costs of electric service for consumers who install energy efficiency measures, and lower total costs for all consumers on the grid. Energy efficiency is often less costly and more cost effective compared to central generation, transmission, and distribution. Compared to supply options, energy efficiency is more distributed with no need for transmission or distribution, more diverse, less risky in terms of market and fuel price volatility, less subject to security risks and interruptions, and much less harmful to the environment. Energy efficiency provides financial and other benefits to consumers and businesses, and creates jobs and improves the economy.

Energy efficiency is a valuable longer-term demand response strategy, in addition to pricing and metering, and shorter-term demand response strategies such as emergency and price-responsive load programs. Therefore, the states and region should adopt regulatory, institutional, and market reforms that would increase the region's reliance on energy efficiency as a resource, together with other beneficial demand-side and distributed energy resources.

The New England states and region should offer and pursue a full continuum of market opportunities and programs so that all options are considered and all customers have an opportunity to participate. Energy efficiency provides what may be the most effective option for reducing the cost of energy service for many small, medium, and even large customers – by focusing on efficient energy use and reducing load, thereby reducing the size of the bill, not just focusing on the rate or price of generation service.

When assessing the value and effectiveness of various resource options, the integrated value of energy efficiency should be considered and accounted for. The integrated benefits of energy efficiency should be maintained, represented, assessed, and fully valued, rather than being de-integrated.

Energy Efficiency Reduces Load

Energy efficiency can reduce load significantly, and the load reductions occur over many hours of the load shape and for many days of the year (see Fig. 4-1).[114] These systematic load

[114] We developed an illustrative example for an existing large commercial office building located in Albany, NY – the closest location to New England for which we had 8760 hour load shape data – and examined the impacts on peak load and load shape on a summer day (July 9). We analyzed two primary scenarios: (1) energy efficiency measures for lighting and cooling that reduced load by 20%; and (2) shorter-term demand response (load management) defined as a four-hour curtailment from 1:00 pm to 5:00 pm, with a curtailment load reduction of 15%

reductions save energy as well as reduce peak demand. Energy efficiency reduces load over the life of the energy efficient measure, typically for many years.

The comparison in Fig. 4-1 is illustrative, using one example of a large commercial office building, and it does not necessarily represent all energy efficiency or all shorter-term demand response. The point is that energy efficiency is *different* than shorter-term demand response (load management) – and both are valuable demand response resources in their own ways.[115]

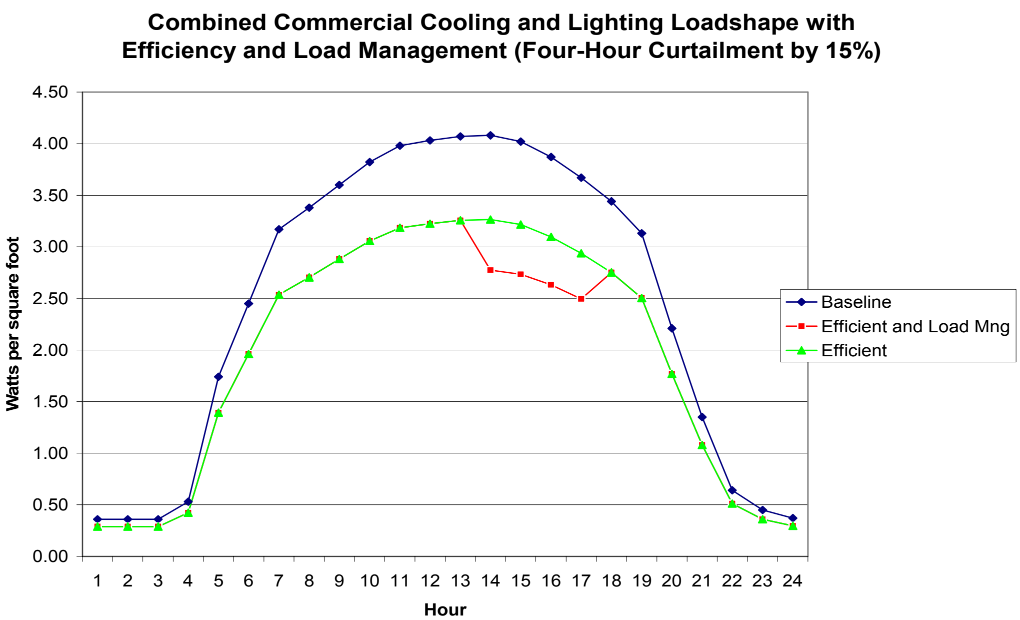

Figure 4-1: Combined effects of efficiency and load management in a typical commercial space. Energy efficiency reduces load in many hours, including peak loads. Load management can add to the peak load savings.

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achieved by reducing lighting and HVAC load. We used a conservative estimate of 20% load reduction from the HVAC and lighting energy efficiency measures. For existing, previously-untreated large commercial office buildings in New England, savings of 25% or more from comprehensive measures are common, and savings of 20% are near universal. The load management load reduction is 15% from a four-hour load curtailment based on facilities that used lighting and HVAC strategies to reduce load. See Goldman et al, *Do "Enabling Technologies" Affect Customer Performance in Price-Responsive Load Programs?*

[115] Their combined environmental effects can also be positive. The US EPA's review of NEDRI's recommendations on efficiency and short-term load response concluded: "Finally, the study finds that implementing both NEDRI's short-term load response programs and its longer-term efficiency recommendations would yield greater environmental improvements than pursuing either type of resource by itself.." See Letter from U.S. EPA to NEDRI, Appendix E.

Energy Efficiency Experience in New England

New England has been investing in energy efficiency as a cost-effective and valuable resource for more than a decade.[116] States and utilities in New England have achieved net benefits (i.e., benefits exceeding costs) of about $3 billion dollars and peak load reductions of over 1,200 MW.[117]

For example, one estimate, from a 1999 report that reviewed commercial and industrial programs administered by three utilities serving portions of New England, concluded that the three utilities spent approximately $1 billion promoting energy efficiency within the business community to leverage almost $3 billion in energy savings through avoided electricity purchases over the lifetimes of the installed measures, resulting in net benefits (benefits minus costs) of $2 billion.[118] New capacity needs were reduced by almost 1,000 MW. The resulting $2 billion in net benefits were achieved in the business (C&I) sector alone – savings and net benefits in the residential and low income sectors, and savings since 1999, would be on top of that amount.

In Massachusetts alone, in-state annual peak load reductions from both energy efficiency and SBC-funded load management programs have ranged from 98 to 135 MW for 1998, 1999, and 2000. Total cumulative peak load reductions in Massachusetts from energy efficiency and load management were approximately 700 MW as of 2000, with energy efficiency accounting for over 90% of the reductions.[119] For energy efficiency alone, annual incremental peak load reductions have been about 50 to 60 MW for each of 1998, 1999, and 2000.
Fig. 4-2 shows that without the 51 MW of energy efficiency summer peak load reductions in 2000, the summer peak would have been 0.6% higher in Massachusetts. The summer peak would have been 7.2% higher without the 648 MW of cumulative energy efficiency summer peak load reductions. The comparison is to the 1999 system peak, which was higher than the 2000 summer peak.

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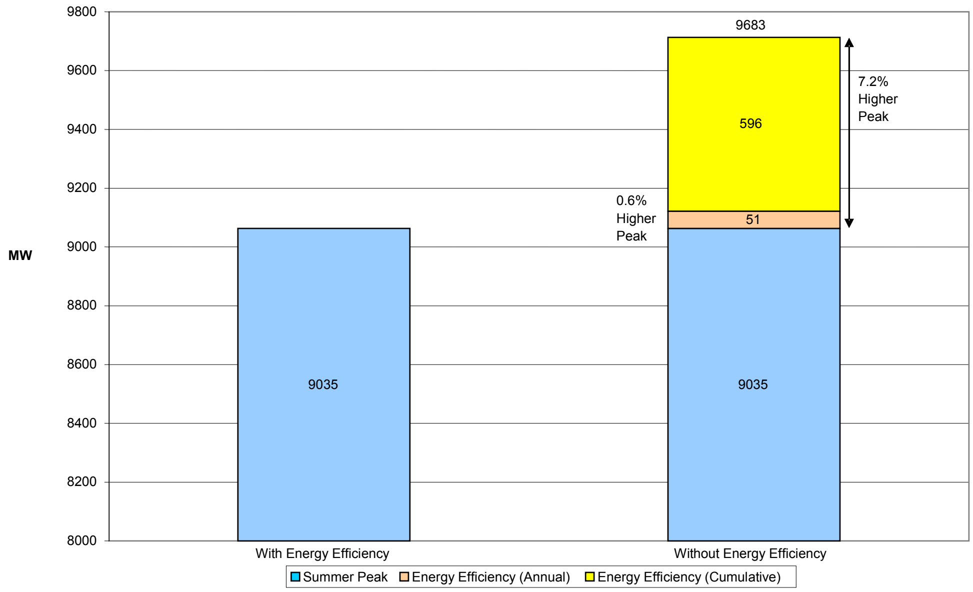
[116] SBC funding levels in recent years total about $250 million annually.
[117] Estimate by Jeff Schlegel, based on compilation of cumulative results from individual states.
[118] See *A Decade of Progress with Business Energy Efficiency in New England*, prepared by Boston Edison, the NEES Companies, and Northeast Utilities, July 1999.
[119] These peak demand savings are stated as currently-available, meaning that they account for retirement of energy efficiency measures whose useful lives have ended.

Fig. 4-2. Massachusetts 2000 Energy Efficiency Impact on Summer Peak



These Massachusetts peak demand savings are from broad-based energy efficiency programs. The programs were not targeted specifically or primarily to provide summer kW savings. Increasing focus on a summer peak savings objective would likely increase the annual summer peak load reductions going forward. This consideration should be made in a process that considers all of the goals and objectives of SBC-funded energy efficiency programs.

Energy efficiency reduces peak demand, and therefore it can and has reduced market prices for everyone purchasing electricity in the power market. For example, the Massachusetts DOER 1999 annual report found:

> "The situation that occurred in the New England power pool on June 7th, 1999 illustrates this phenomena of market-price reduction as a result of energy efficiency activities. June 7th was an unusually hot day for that time of year, and the electricity system in New England was not fully prepared to meet the unexpected high demand for electricity during the peak hours of the day (9am to 10pm), given the number of plants that were off-line for maintenance, etc. During this 13-hour period, New England's electricity demand reached an average peak of 21,394 MW, where during those hours market prices reached an average of $392 per MW (where the highest hourly price was $680 per MW). Had there not been 115 MW in energy efficiency related demand reductions during each

of these 13 hours[120], the average peak demand could have been 21,518 MW, and the additional demand being bid in each hour, at higher bid prices, could have resulted in roughly $6.7 million in *additional* costs to the system (i.e., all customers). This estimate is based on the difference in what the market clearing price *could have been in each of the 13 hours absent the 115 MW of demand savings*, and the actual market clearing price in each of those hours, times the demand in the spot market.[121] DOER estimates that absent the demand savings from the energy efficiency programs, the average market clearing price over the 13 hour period could have been $554 per MW (the highest hourly price being $999 per MW), or 40% higher than the average market clearing price absent the impact of the 115 MW demand savings." (MA DOER, 2000)

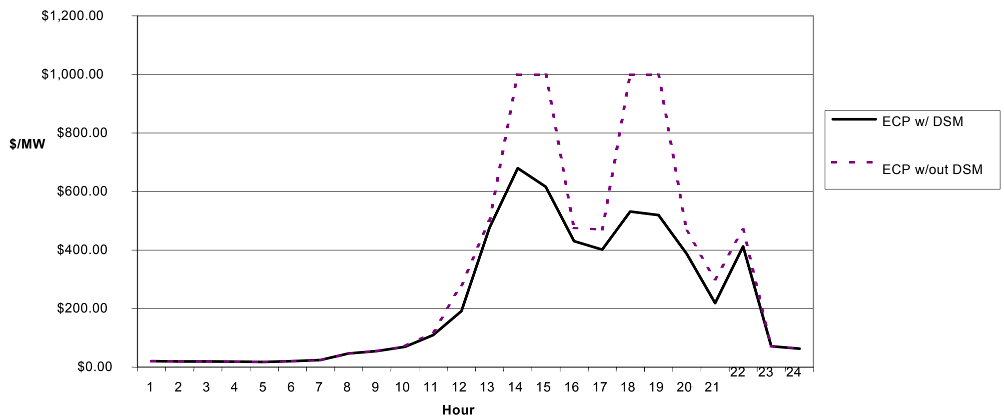


Figure 4.3: Impact of Massachusetts DSM on Spot Market Clearing Price, June 7, 1999

Fig. 4-3 illustrates the impact of Massachusetts energy efficiency and DSM load reductions on market clearing prices during a 13-hour period on June 7, 1999. In addition to lowering the program participants' energy costs by $20 million in 1999, DOER concluded that the energy efficiency programs provided reliability benefits and power cost savings to all customers – and the value of the market price benefit on one high-cost day was over $6 million.

[120] For simplicity, the DOER analysis assumes that the distribution companies' combined coincident peak demand reductions of 115 MW occurred in these hours on June 7th, 1999.

[121] Massachusetts DOER's 1999 analysis (including load data, bid schedules, and market clearing prices) was based upon data reported by ISO-NE. Note that the $6.7 million in savings reflects savings to the spot market load (i.e., what was traded in the spot market in each hour), as opposed to total load (most of which is traded through bilateral contracts). The average spot market load over the 13-hour period was 3,159 MW. See Massachusetts DOER annual report for details.

When the margin between available generation and load is thin, and the ability of generators to charge high prices for supply-side resources is high, load reductions from energy efficiency and other demand-response resources can moderate the market power of generators, and reduce their ability to raise market prices well above the marginal cost of production.[122] The result is increased competitiveness in the market, with benefits provided to all consumers.

Recommendations

Recommendation EE-1. System Benefit Charge (SBC) Funds and Ratepayer Support for Energy Efficiency

NEDRI stakeholders recommend:

- The goal of publicly-funded energy efficiency efforts in each state is to capture all cost-effective energy efficiency that is not being achieved in the market without intervention. The System Benefits Charge (SBC) funds and other ratepayer support[123] in each state should be set at levels at least equal to current funding for energy efficiency.[124] Over time, states and stakeholders should consider increasing SBC and other ratepayer funding to levels sufficient to capture all cost-effective energy efficiency.

- Within the context of multiple objectives and considering various statutes and other explicit rules in each state, states and program administrators should consider targeting energy efficiency programs funded through SBC and/or other funding sources to geographical locations with reliability needs or constraints, energy efficiency measures that reduce peak load, and savings opportunities in high-value time periods, to the extent that these are not already being addressed by the market.

Discussion

Energy Efficiency Policy and Funding Levels

Some state policy makers and regulators are perplexed that they still need to be involved in energy efficiency policy and programs. Wasn't the market supposed to have taken hold by now, and replaced bureaucratic planning with competition that serves customer needs?

One problem is that the competitive energy market envisioned has not come to pass, and many customers do not appear to be interested in such a competitive market. The large majority of

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[122] See Richard Cowart, *Efficient Reliability: The Critical Role of Demand-Side Resources in Power Systems and Markets* (NARUC 2001) for a more complete discussion.
[123] "Ratepayer funding" is stated broadly and includes Pay as You Save (PAYS) approaches, though PAYS approaches are largely participant funded.
[124] SBC funding levels in recent years total about $250 million annually in the six New England states.

customers continue to buy energy from their distribution utilities, which are supposed to have already exited the retail energy business to concentrate on the "pipes and wires" business. This situation does not appear likely to change anytime soon. Competitive retail suppliers are struggling to field profitable offers that can compete with utility standard offer or default service. States are studying ways to gently force customers into the competitive marketplace, but no acceptable political model has yet emerged.

In the absence of a robust competitive retail electricity market, which may be some years in the future, the time-differentiated component of electricity cost is communicated to customers qualitatively rather than quantitatively. That is, customers are told that electricity used at system peak times is more expensive than electricity used at off-peak times, but most customers do not see a seasonal or time-of-day price differential on their bills.

Another problem is that cost-effective energy efficiency resources in New England are often untapped in the private competitive market due to significant market barriers faced by customers and other market participants (e.g., retailers, distributors, manufacturers, builders, contractors, and property managers). These market barriers include information or search costs, hassle and transaction costs, performance uncertainties, market response uncertainties, asymmetric information and opportunism, product or service unavailability, infrastructure limitations, uneven product quality, limited access to financing, bounded rationality (behavior during the decision making process that appears to be inconsistent with stated goals), organizational practices or customs, split incentives, inseparability of product features, irreversibility, the failure of prices to reflect the time-differentiated nature of demand and energy use, and the failure of market electricity prices to reflect the full cost of energy to society including environmental and social externalities.[125]

Some large customers see electricity as a commodity, and they may be willing to shop for better prices or for other alternatives. But most small customers (and even many large customers) see energy as a service, and generally they do not shop for or consider other choices. Also, energy efficiency is more of a product or service attribute, rather than a distinct product or service with its own market. Even when customers are interested in exploring alternatives, the market barriers listed above limit their ability to consider and adopt energy efficiency products and services. These market barriers also limit the perceived viability of and market size for energy efficiency products and services in the minds of manufacturers and suppliers.

Even in competitive retail electric market systems proposed by restructuring advocates, most of these market barriers to energy efficiency will remain. The failure of prices to reflect the time-differentiated nature of demand and energy use appears to be the only market barrier in the above list that may be substantially reduced. Therefore, most of the cost-effective energy efficiency resources that could provide net benefits to New England and its customers will not be acquired

[125] In addition to these market barriers, there are institutional barriers, including the disincentive for distribution companies to reduce energy use because their revenues are based on energy throughput. See Chapter 3, Pricing and Metering, for more discussion.

in the competitive market, absent intervention – at best, we are looking at a long transition period. The end result of a competitive-market-only approach would be an electricity market with higher societal costs for electric energy services, higher customer bills, less efficiency, fewer jobs, and more environmental damage.

A study published in 2001 by Martin Kushler and Patti Witte for the American Council for an Energy Efficiency Economy (ACEEE) entitled "An Examination of the Role of Private Market Actors in an Era of Electric Market Restructuring" (see www.aceee.org, Report U011), casts doubt on the notion that a competitive market will optimize energy efficiency. Citing experience in nine states, Kushler and Witte conclude that "this study has found little evidence to support the premise that relying on private market actors to provide energy efficiency would be a superior approach and that government/regulatory policies and funding for energy efficiency can be phased out or eliminated."

Therefore, for the foreseeable future, a well-designed and implemented public policy is necessary to harvest the full potential of energy efficiency and provide the benefits to consumers and the electrical system.

NEDRI stakeholders noted that the level of existing state distribution ratepayer funding, including SBC funding, is not large enough to adequately support cost-effective energy efficiency and shorter-term demand response.[126] Over time, states and stakeholders should consider increasing SBC and other ratepayer funding to levels sufficient to capture all cost-effective energy efficiency.

How Much Potential Remains?

The cost-effective energy efficiency potential in New England is several times the level of resources being captured with the current program funding levels. Several studies, including the Five-Lab study, have documented potential savings of 15% to 18% by 2010, and about 30% by 2020. A Massachusetts Department of Energy Resources study found significant cost-effective potential savings of 16% to 25% remaining, despite more than a decade of investment in energy efficiency in the state. See Appendix 4-A for a summary of some recent studies on the remaining and achievable potential of energy efficiency.

Targeting of SBC and Ratepayer-Funded Programs

SBC and ratepayer-funded energy efficiency programs are administered to serve multiple objectives and purposes. Within this context of balancing multiple objectives, NEDRI believes there is great value in targeting energy efficiency resources to geographical locations with

[126] Funding for shorter-term regional demand response programs is discussed in Chapter 2.

reliability needs or constraints, energy efficiency measures that reduce peak load, and savings opportunities in high-value time periods, to the extent that these are not already being addressed by the market. States and program administrators should consider such targeting, within the context of multiple objectives and considering the statutes and explicit rules for SBC funding in their state. For example, many states require SBC programs to provide opportunities for all customers, and states consider parity among contributions to the funds and benefits from it (parity among rate classes) when allocating funds.

Recommendation EE-2: Principles for Effective Energy Efficiency Programs and Portfolios

NEDRI recommends that New England states balance several principles in achieving effective energy efficiency programs and portfolios. Specifically, NEDRI recommends that energy efficiency programs and portfolios:

- Focus on reducing or overcoming market barriers.
- Provide opportunities for a large number and broad mix of customers to benefit from the energy efficiency programs.
- Maximize long-term savings and net benefits.
- Encourage comprehensive and whole building approaches to capture all cost-effective energy efficiency.
- Use performance-based benchmarking to document program impacts, inform customers of the performance of their buildings, and give customers the tools to be aware of and manage their energy use.
- Capture potential lost opportunities.
- Work with product and service markets and promote market transformation.
- Increase market influence and leverage by participating in regional and national initiatives.

Recommendation EE-3. Minimum Energy Efficiency Standards for Appliances and Equipment

By reducing peak energy demand across New England, new minimum energy efficiency product standards could serve as one very low-cost and effective way to cope with projected growth in overall peak demand and address the related reliability, economic and environmental issues. A recent study estimates that New England could achieve by 2020 peak demand savings of 2,163 MW through reduced growth in electric demand, equivalent to 25 percent of projected load growth.[127] To achieve these savings, NEDRI participants recommend that New England States:

[127] *Energy Efficiency Standards: A Low-Cost, High-Leverage Policy for Northeast States*, Summer 2002, by Ned Raynolds, Northeast Energy Efficiency Partnerships, Inc. (NEEP) and Andrew deLaski, Appliance Standards Awareness Project (ASAP); Updated estimates based on more recent cost and savings information provided by NEEP and ASAP, December 2002.

- Establish state minimum appliance and equipment energy efficiency standards.
- Adopt state standards in 2003 for ten specific products in model legislation. Standards for these ten products would provide 820 MW of load reduction by 2020.
- Coordinate efforts regionally to research, adopt, and enforce energy efficiency standards.
- Continue to participate in federal energy efficiency standards rulemakings.

Appliance and Equipment Purchases Contribute to Growth in Peak Demand: Business and consumer purchase and use of new and replacement appliances and equipment are important components of forecasted peak demand and energy growth for the region. Each year, New England businesses and consumers purchase hundreds of thousands of appliances and electricity-using equipment. *Each unit purchased represents a commitment to future energy use and related power system capacity in the region.* In many cases, high efficiency product options exist. However, a number of market barriers often prevent selection of higher efficiency options. Minimum energy efficiency standards overcome the barriers and provide cost-effective energy savings that benefit consumers directly, while reducing the growth in regional energy use and peak demand that would otherwise increase costs for everyone.

Efficiency Standards Lock In Savings from Energy Efficiency Programs: Product standards are a valuable complement to broad-based energy efficiency programs funded by ratepayers through system benefits charges. Many ratepayer-funded energy efficiency programs in New England states are designed to increase the availability of high efficiency products, broaden product options and foster product competition. When consumers and the marketplace have responded with increased purchases and sales of high efficiency products, minimum energy efficiency standards for these products lock in the efficiency gains by eliminating from the marketplace what is least energy efficient. The recent establishment of new federal minimum efficiency standards for residential clothes washers, following very successful programs that increased the availability, options and sale of high efficiency clothes washers, illustrates how standards can complement ratepayer-funded energy efficiency programs.

Federal Efficiency Standards Are Limited: The federal laws[128] that establish pre-emptive federal authority to set minimum efficiency standards addressed a limited range of appliance and equipment types. Many of these standards were set through rulemakings at the U.S. Department of Energy (U.S. DOE). Several of these proceedings are overdue or have been delayed. Further, no new products have been slated for minimum efficiency standards since 1992. States can address this gap in federal policy by establishing minimum energy efficiency standards for products not covered by federal law. Other states and regions, most notably California, are doing so by developing and adopting standards for products not covered by federal law.

[128] National Appliance Energy Conservation Act of 1987 (NAECA) and the Energy Policy Act of 1992 (EPACT).

Cost-Effective Opportunities for New Efficiency Standards Identified for New England: Recent research performed for the Northeast States Energy Efficiency Standards Project[129] identified and recommended for state adoption additional minimum efficiency product standards as a cost-effective energy, economic and environmental policy. The analysis found that new or updated efficiency standards for the 15 listed products could reduce the projected growth in annual electricity consumption for New England through 2020 by more than 17.5 percent, or over 7,145 annual gigawatt-hours (GWh), roughly equivalent to 13 percent of the total electricity consumption of Massachusetts in 1999 (see Table 4-1).[130] Minimum efficiency standards for these products could also reduce peak demand in 2020 by about 2,163 MW in the NEPOOL region alone, equivalent to 25 percent of projected load growth (see Fig. 4-4). The standards would save business and residential energy consumers nearly $6 billion by 2020. *Many have a payback period of less than one year based on current product costs (see Table 4-1).* All of the higher efficiency products are available in New England. Some are already required in state building energy codes for new construction or renovation.

Table 4-1. New England Energy and Demand Impacts in Year 2020 of New Minimum Efficiency Standards in 2005

Product	Cumulative Annual Energy Savings (GWh)	Demand Impacts (MW)	Simple Payback (Years)**	Recommended Action
Furnace fans	2,732	198	1.5	Update federal furnace standard
Consumer electronics (standby power) *	1,041	137	.4	Establish state standard for set top boxes, federal for all
Ceiling fans *	528	199	2.4	Establish state standard
Torchiere lamps *	1,295	409	1.4	Establish state standard
Central air conditioners and heat pumps	463	752	2.8	Update federal standard
Commercial package air conditioners and heat pumps	474	332	1.7	Update federal standard; update state building code
Refrigerated beverage vending machines	130	29	.8	Establish federal standards
Dry-type building	135	20	1.8	Establish state standard;

[129] See Raynolds and deLaski, *Energy Efficiency Standards: A Low-Cost, High-Leverage Policy for Northeast States*, , December 2002.
[130] The report estimated that minimum efficiency standards for these products would provide cumulative electricity savings of 71,200 GWh by 2020.

Product	**Cumulative Annual Energy Savings (GWh)**	**Demand Impacts (MW)**	**Simple Payback (Years)****	**Recommended Action**
transformers *				update state building code
Commercial refrigerators and freezers *	64	14	.7	Establish state standard
Traffic signals *	79	10	2	Establish state standard
Exit Signs *	66	8	.9	Establish state standard
Commercial (coin operated) clothes washers *	18	6	3.5	Establish state standard
Beverage merchandisers	49	18	.5	Establish federal standard
Ice makers	38	8	.7	Establish federal standard
Large packaged air conditioners (>20 tons) *	33	23	4.7	Establish state standard

*Products included in proposed 2003 legislation in three New England States.

**Payback period based on electricity costs of 10 cents/kWh and 60 cents per therm for commercial clothes washers

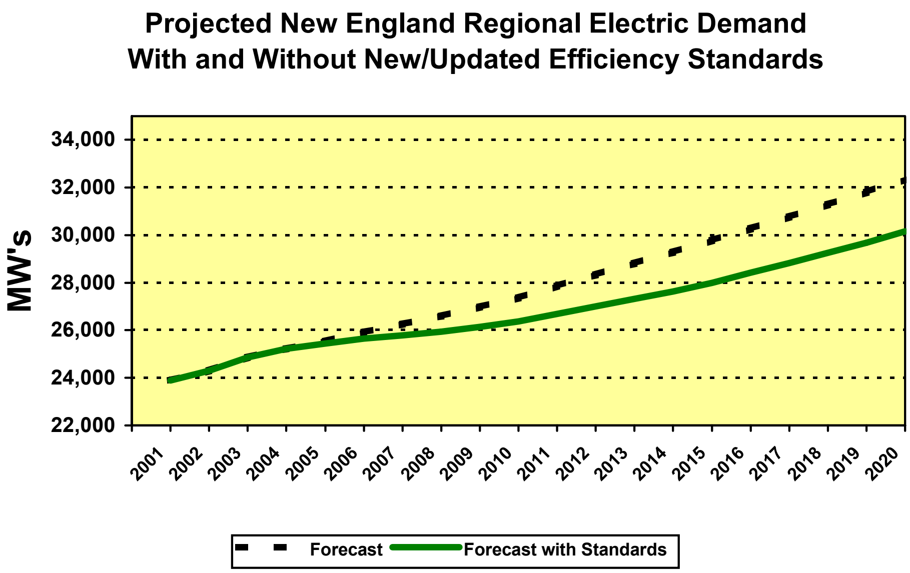

Figure 4-4: Improved efficiency standards could lower regional electrical demand growth by 25% (from 8000 to 6000 MW) between 2001 and 2020.

Suggested Actions for New England States

Establish State Minimum Energy Efficiency Standards: In most New England states, legislation is needed to establish state authority to set standards for products not preempted by federal law. It should be encouraged in each New England state. Where this is cost-effective and products are widely available, the legislation should include minimum efficiency standards for products (e.g., such as those products identified in Table 1).

Lawmakers in Massachusetts, Maine and New Hampshire have proposed 2003 legislation to both establish that authority and set standards for ten of the listed products. Similar legislative bills are expected in 2003 in Connecticut and Rhode Island. The Rhode Island climate change action plan embraces such standards, and explicitly expresses hope that neighboring states will also choose the course. If adopted by all New England states, efficiency standards for these ten products by 2005 could provide up to 820 MW and 3,260 cumulative annual GWh savings by 2020.

Coordinate Efforts Regionally to Research, Adopt and Enforce Efficiency Standards: Given the overlap of product markets and distribution in New England, the states should establish common standards to maximize their effectiveness and minimize costs and requirements for affected product manufacturers as well as for state agencies responsible for oversight of reporting requirements and enforcement. Specifically, states should work together to adopt identical technical specifications for product standards, coordinate retailer education, manufacturer reporting and enforcement programs, and conduct research regarding new opportunities for minimum efficiency standards. A regional coordinating council (e.g., Regional State Committee) could be a valuable vehicle for assessments and coordination.

Participate in Federal Efficiency Standards Rulemakings: New England states could increase savings from new minimum energy efficiency standards by actively participating in federal rulemakings scheduled by the U.S. DOE to establish or update standards for products covered by NAECA or EPACT. This participation is particularly important for New England states, where energy costs are among the highest in the country. U.S. DOE's rulemaking schedule for federal efficiency standards includes: furnace fans and commercial and residential air conditioning and heating equipment.

Recommendation EE-4. Effective Building Energy Codes

Commercial, industrial, and residential construction activity, including remodeling and renovations, are significant drivers of load growth. A key policy to minimize the negative impacts of this growth on the regional power system is to reduce the increase in energy consumption and demand driven by new and expanded buildings by:

- Regularly updating building energy code requirements to reflect advances in design and construction practices, and equipment choices that affect building energy use, and
- Effectively implementing current building energy codes by:
  - Providing ongoing training and technical support for inspectors and builders
  - Linking ratepayer-funded energy efficiency programs with building energy code training and development

These efforts could achieve summer peak demand savings of 1,115 MW by 2020 compared to forecasted growth in peak demand use.[131]

Effective Implementation of Building Energy Codes is the Key to Large Savings:

Effective building energy code implementation (i.e., 75% or better) can be achieved with:

- Development of energy code requirements that are readily understood and enforceable,

[131] See Pacific Northwest National Laboratory study of Building Energy Code Implementation in Northeast states, 1999; updated by the Northeast Energy Efficiency Partnerships, Inc. (NEEP), 2001. The study assumed 100% code compliance is achieved.

- Ongoing training and technical support for building energy code inspectors regarding energy code requirements and technical interpretations.
- Ongoing training and technical support for architects, designers, developers, and contractors regarding energy code requirements and how to meet them.
- Increased use of energy code compliance tools for architects, engineers and designers to more accurately document compliance.
- Linking ratepayer-funded energy efficiency programs with building energy codes development and market place training.

Adoption of National Model Energy Codes Is the First Step to Energy and Demand Savings. The International Energy Conservation Code (IECC), recognized as the most current code for residential and commercial buildings, reflects recent developments in construction practices and materials, and offers New England states a model energy code that is straightforward to implement. By adopting the IECC standards as statewide requirements for all new construction, New England states can improve the effectiveness of building energy code implementation and increase energy and demand savings. As indicated in Tables 4-2 and 4-3, some states have already adopted the most recent IECC standards; other states have not.

Table 4-2: Status of Commercial Building Energy Codes in New England

Meets or exceeds IECC 2001 or ASHRAE 1999	Maine, Massachusetts, Rhode Island
Updating to IECC 2001 or ASHRAE 1999	Vermont
Meets IECC 2000 or ASHRAE 1989	New Hampshire, Connecticut

Table 4-3: Status of Residential Building Energy Codes in New England

Meets or exceeds IECC 2000	None yet
Updating to IECC 2000	Massachusetts, New Hampshire, Rhode Island, Vermont
Meets or exceeds MEC 1995/1993	Connecticut
Voluntary – Meets MEC 1992	Maine

Continuously Update Building Energy Code Requirements: The IECC is a continuously updated model building energy code. A major update of the IECC will be released in early 2003 with a supplement planned for 2004. New England states should participate in this building energy code development process so that the result reflects the issues, needs and current status of construction practices of New England states. In addition, New England states should commit to a continuous process to review and adopt state building energy codes to consider the latest, cost-effective developments in national model energy codes as well as state-specific factors.

Provide Ongoing Training and Technical Support for Inspectors and Builders: Beyond adoption of up-to-date and user-friendly codes, most states implement programs to train building inspectors in the energy code requirements including checklists and software tools to assess building compliance. Depending on the resources available, training reaches 30% to 90% of the building inspectors. Energy code compliance can be further improved by training the large majority of building inspectors, and by extending energy code training and technical support to the regulated community (i.e., builders, developers, designers, architects and engineers). Unfortunately, states have very limited, if any, resources for such training. Funding for building energy code training and technical support should be given priority by states as part of strategy to provide power system *reliability* cost-effectively and equitably.

Link Ratepayer-Funded Energy Efficiency Programs with Building Energy Code Training and Development: Significant ratepayer funding for energy efficiency programs in New England States is devoted to promoting best practices for energy efficiency in new residential and commercial construction (e.g., ENERGY STAR Homes, Design 2000+ and Energy Conscious Construction). Program administrators in Massachusetts, Rhode Island, New Hampshire and Vermont currently link builder training and technical support for these above code programs with information about minimum energy code requirements and compliance tools. This practice should be encouraged and resources leveraged through regional training resources such as those developed through the Northeast Regional Building Energy Code Project hosted by NEEP.

Recommendation EE-5. Enhanced Regional Coordination for Demand-Side Resources

Enhanced regional coordination could increase the effectiveness and cost-efficiency of energy efficiency efforts as a key element of demand-response policies and programs in New England. Three aspects of enhanced regional coordination should be considered – regional planning and resource assessment; regional programs; and regional research and evaluation. More specifically, NEDRI recommends that New England states consider:

- Regionally planning for and assessing the potential for demand-side resources.
- Where valuable, regionally coordinating the development and implementation of demand-side programs and policies (e.g., regional market transformation, products with regional markets or avenues of commerce, regional appliance and equipment standards).
- Evaluating the effectiveness of existing regional energy efficiency programs.

- Conducting regional research to identify new opportunities for as well as evaluating the impact of implemented demand-side resources.

- Establishing a regional coordinating council[132] for demand-side resources.[133]

These activities would complement, not replace, current state-based efforts to develop, approve, establish and implement demand-side programs and policies, and would work with existing regional planning efforts. Concerning demand-response, enhanced regional coordination would provide information and forums to inform and address opportunities to use state and regional demand-side policies and programs to meet regional energy and environmental policy goals needs. For example, enhanced regional coordination would make it possible to integrate demand-side options into regional system expansion and reliability planning.

Regionally Plan for and Assess the Potential for Demand-Side Resources to Address Regional Energy and Environmental Needs and Goals: The aggregate impacts of energy efficiency, load management and curtailment, and distributed generation can provide a significant resource to help meet system reliability needs as well as address transmission and distribution capacity needs within the NEPOOL system[134]. These same regional demand-side resources can help New England Governors also meet environmental[135] and economic goals including energy security. However, New England is not now served by an ongoing regional planning effort[136] to characterize and target cost-effective policies and programs for demand-side resources.[137] Lacking such information to inform annual transmission and reliability planning, many cost-effective demand-side resources are not addressed. Indeed, lacking this information, regional transmission system planning favors supply-side resource options over demand-side options. Furthermore, regional planning will facilitate regional coordination of demand-side programs and policies, where this would be of value to leverage the greatest market response to provide economic peak load reductions in the long-term as well as the short-term.

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[132] The word "council" is used here to mean a body that would address demand-side issues.
[133] Specific institutional arrangements to achieve this are not considered in this paper. Participants in the New England Governors Council have stated a preference to allow the six New England governors the opportunity to address this in comments before FERC in 2003 concerning the Regional State Committee proposed in FERC's Standard Market Design.
[134] For example, NEEP's regional assessment of the potential impacts of building energy codes and minimum energy efficiency standards demonstrated large potential energy and demand impacts, and economic savings.
[135] In 2002, the Conference of New England Governors and Eastern Canadian Premiers passed the "Resolution 27-7 Concerning Climate Change" which directs the Committee on the Environment and the Northeast International Committee on Energy to evaluate and recommend options for reducing greenhouse emissions from the electricity sector and increase the amount of energy saved through conservation programs in a cost-effective manner.
[136] In the Pacific Northwest, the Northwest Power Planning Council and the Northwest Energy Efficiency Alliance (a non-profit organization with a board comprised of utility, government, and stakeholder representatives) plan and implement regional demand-side programs.
[137] A recent study by Xenergy, Inc. assessed the achievable energy efficiency potential over the next ten years across California for all electricity customers using hundreds of commercially available measures. The study calculates that California can save up to 3,500 megawatts of peak demand and net over $8 billion in savings over the next decade by restoring public efficiency funding to nearly 1994 levels (adjusted for inflation).

To provide regular information to integrate, coordinate and the leverage the role of demand-side resources to meet state and regional energy, economic and environmental policies, New England states should establish an ongoing planning and assessment capacity regarding energy efficiency and other demand-side resources. This capacity should be organized to provide information in a form and schedule that will enable it to be used in the context of regional planning for transmission and system reliability planning (e.g., include as a task for the Regional State Committee).

Coordinate the Development and Implementation of Demand-Side Programs and Policies Regionally to Maximize Market Impacts and Savings: In some cases, regionally developed demand-side programs and policies, and coordinated, consistent implementation, may be more effective because of the nature of the technology, the avenue of commerce, the market opportunity, or the program strategy.[138] Three examples of high priorities for regional efforts are market transformation programs that focus on regional or national markets (e.g., to introduce high efficiency new equipment), minimum energy efficiency standards for appliance and equipment, and high efficiency new construction programs. Several programs are currently coordinated regionally in New England. NEEP facilitates many regional programs implemented through joint and coordinated activities of program administrators in each state through ratepayer-funded programs. The Consortium for Energy Efficiency (CEE) provides technical and program assistance on regional and national opportunities. Utilities and program administrators participate in several national and regional consortia (e.g., ENERGY STAR Homes, Compressed Air Challenge). These efforts reduce costs and increase market participation.

New England states should continue to support and encourage such efforts where they can leverage national and regional resources, increase program effectiveness, and reduce program costs. Further, New England states should seek to reduce institutional barriers to such efforts (e.g., adopt common regulatory requirements for regional initiative planning, evaluation and implementation; support regional as well as state-focused data collection; approve programs on a multi-year basis where cost-justified).

Conduct Regional Research and Evaluation of Demand-Side Resource Impacts: A key to successful planning for and coordination of regional demand-side resources is having consistent data to assess market opportunities and evaluate the impact and progress of regional policies and programs. Energy efficiency program administrators in New England states do conduct some studies and evaluations on a regional basis (e.g., baseline research regarding the status of specific equipment or appliance types, or construction practices). But these efforts are occasional and rarely include all New England states. This lack of consistency in data and information can impede regional assessments or coordination of programs and policies to address reliability and transmissions system needs. Furthermore, separate research and evaluation efforts can miss opportunities to reduce study costs or to leverage data. To support regional planning and

[138] Regional approaches to program development and implementation are not necessary in all cases. Many programs can be effectively implemented without such a regional interface.

coordination of demand-side resources regionally, New England states should support regional research and evaluation efforts, and require the regional planning council, in whatever form it takes, to produce a regional plan for demand-side research and evaluation.

Establish a Regional Coordinating Council for Demand-Side Resources: To support regional planning, development, implementation and evaluation of demand-side resources, New England policy makers and other stakeholders should establish a regional coordinating council for energy efficiency programs and policies, including for some SBC-funded programs and appliance and equipment standards. The coordinating council could assess regional opportunities to achieve cost-effective peak demand reductions through energy efficiency and load management, prepare regional plans for energy efficiency and other demand-side resources, coordinate regional implementation, and conduct regional evaluations. This information could be used to assist system expansion planning including all cost-effective demand-side resources. In the Pacific Northwest, the Northwest Power Planning Council and the Northwest Energy Efficiency Alliance (a non-profit organization with a board comprised of utility, government, and stakeholder representatives) plan and implement regional programs. Such a coordinating council could be established in New England through existing forums (e.g., New England Governor's Council, Conference of Northeast Governors, Northeast Energy Efficiency Partnerships, Inc.) or a new forum or capacity could be established (e.g., a Regional State Committee).

Recommendation EE-6. Complementary and Integrated Options for Energy Efficiency and Shorter-Term Demand Response

Some energy efficiency and shorter-term demand response activities could be designed and implemented to complement or be integrated with each other, to achieve synergies and increase value for customers and the electric system. New England states should pursue demand response strategies that recognize the multiple attributes and uses of demand response technologies and integrate shorter-term demand response and energy efficiency programs into complementary program offerings by:

- Making full use of demand response technologies for both energy efficiency and shorter-term demand response,
- Promoting effective and efficient facility operations and maintenance (O&M),
- Implementing comprehensive, coherent marketing programs, and
- Coordinating the administration and delivery of EE and shorter-term DR.

Background

Almost all customers can participate in demand response, even though the response capability of customers differs significantly. Some customers can curtail electricity use on short notice (e.g., 30-120 minutes), and so are able to participate in emergency or real-time DR programs. A second set of customers is able to curtail usage with day-ahead notice, and so can participate in economic, day-ahead market DR programs.

A much larger number of customers can participate in longer-term demand response (energy efficiency) programs. Virtually all energy efficiency programs, from market transformation programs (appliances and building codes) to immediate resource acquisition programs (rebates and performance contracting) help to lower system peaks, even if peak reduction is not the primary program goal. Customers often do not connect their participation in energy efficiency programs with demand response, because they do not understand that reducing their peak usage changes the system load profile and makes the electricity system more efficient.

Strategies

New England can pursue the following three major strategies to get the full benefit of the multiple attributes and uses of integrated energy efficiency and demand response programs.

Make Full Use of Demand Response Technologies

One of the key characteristics of energy efficiency programs of the last decade is their ability to quickly move specialized technologies into mass distribution. New refrigerators today use a fraction of the energy of the units they are replacing. T-8 lighting technology is now available in every home improvement store. We can expect that several cutting edge demand response technologies will make a similar quick penetration of the mass market.

Today, utilities and ISO-NE are promoting the use of advanced metering, communications and control systems in commercial buildings. One of the uses of this technology is dimming lighting systems in short-term demand response programs. Anecdotal evidence suggests, however, that after building owners dim their lights a few times in response to requests by an ISO to curtail load, they will learn that they save some money and cause no hardship to their tenants or employees. They will then begin to dim their lights on all sunny afternoons, not just those hot summer days when the system is nearing its peak. The technology will thus lose its value as shorter-term demand response but will have significant long-term value as an energy efficiency measure.

The flip side of this example is a high-end office building owner, who wants to optimize tenant comfort with the best possible HVAC and lighting controls, and so installs an advanced metering, communications and control system in a new or renovated building. Some time later, the tenants learn that they have the ability to dim lights in short-term demand response programs.

Thus, the same technology can deliver either short-term or longer-term demand response in different buildings, or even in the same building with different tenants. Other technologies, in addition to dimmable lighting systems, which can have multiple program applications include HVAC system controls, industrial process controls and building infrastructure (piping and wiring) re-design. The proliferation of these technologies can have significant impacts on both utility revenues (by lowering usage) and the need for peak generating units (by reducing system peaks), which should be understood by both market participants and policy makers.

Promote Effective and Efficient Facility Operations and Maintenance (O&M)

Many large commercial and industrial (C/I) facilities today are not operated and maintained to optimize energy use. Industrial customers tend to focus on production concerns. Institutional customers are often starved for maintenance resources. Commercial tenants and building owners are not equally motivated to save energy. This lack of focus on energy use means that the vast majority of large customers are not ready to participate in either short or long-term demand response programs.

A common condition among large and medium-sized C/I customers is that they either do not know their load profile or cannot quantify the major components of that profile. They make very modest use of the capabilities of their installed metering, control and EMS systems; have limited knowledge of their short or long-term demand response options; and, lack the tools required to quantify the value of these options. If they have a systematic preventive maintenance program, they typically cannot determine if that program is optimizing their energy use.

There is a growing body of evidence, accumulated both in the US and Europe, that rigorous O&M programs that feature regular energy use feedback to building operators and managers can reduce energy use, without significant capital investment, by 5-15% for industrial facilities and up to 25% for commercial and institutional facilities. It is becoming increasingly clear that the detailed facility knowledge inculcated by a rigorous O&M program also enables building operators and managers to identify and implement short-term demand response measures.

Facility O&M is thus a very cost effective short and long-term demand response option, but it is also very difficult to implement on a mass scale because it involves a major change in the mind set of most customers. The US did not embrace total quality in manufacturing for more than a decade after it had become the mantra of Japanese manufacturers, even though TQM was invented in the U.S. Likewise, it will take some time for the majority of large facility owners and operators to embrace the kind of continuous improvement process that motivates rigorous O&M programs. It is therefore important that demand response programs identify and publicize useful examples of successful, energy-oriented O&M programs.

Implement Comprehensive, Coherent Marketing Programs

The relative success of Demand Response programs in New York during summer 2001 and 2002 is due, in no small part, to the comprehensive and coherent marketing message that was delivered in New York. Unlike PJM or ISO-NE, which are multi-state entities, New York delivers a coherent, clear message to consumers: the state is short of capacity; new generation resources are not going to solve the problem in the short term; large-scale demand response is necessary to keep the electricity system running. This message is repeated by all of the players in New York: the Governor; Legislative leaders; executives of NYSERDA, LIPA and NYPA; and the investor-owned utility companies. As a consequence, New York's Emergency Demand Response program is significantly larger than similar programs offered by other ISOs.

New York has also done a good job of targeting some of its energy efficiency programs, such as the room air conditioner bounty program, or the C/I performance program, at peak reduction goals. This targeting is beginning to build in the minds of customers the notion that demand response consists of a full spectrum of activities, and that many customers can participate in demand response. Not every customer can participate in short-term demand response, but almost every customer can lower his or her peak demand with affordable activities that do not require sacrifice or hardship.

Unfortunately, in New England the message is not nearly so coherent or clear. Customers hear pleas from utilities to sign up for emergency demand response programs with one ear, and contradictory assurances from public officials that electricity supply is ample with the other ear. Customers across New England hear a veritable Babel of messages and slogans, which typically mix corporate identification with program promotion objectives, from utility companies and competitive market suppliers. As a consequence, it is not clear to most customers that energy efficiency and short term demand response programs are part of the same continuum. Nor is it clear to most individual customers where they have a likely fit on that continuum.

The utilities see themselves in the business of administering energy efficiency programs for the long term, but are only in the short-term demand response marketplace because the competitive retail market, which was supposed to handle these programs, faltered in the starting gate. Because of this disconnect, utilities often don't market a full continuum of demand response options, but rather a set of seemingly disconnected programs. Furthermore, utilities are only beginning to come to grips with the technical potential and economic ramifications of the new metering, communications and control technologies or of the rigorous large facility O&M programs.

It is therefore important that New England regulators take an active role in shaping the content of demand response marketing programs, to assure that the full continuum of demand response programs is communicated to customers clearly and coherently. This job falls to regulators because the source of the marketing funds is regulated activities, either from dedicated DSM or System Benefit Charge funds, or from a portion of the rates collected by the ISO from customers who overwhelmingly remain in regulated retail service.

Appendix 4-A: Energy Efficiency Potential

Summary of Electricity (or All Fuels) Savings Potential Studies

Technical potential is defined as the complete penetration of all measures analyzed in applications where they were deemed to be technically feasible from an engineering perspective.

Economic potential refers to the technical potential of those energy conservation measures that are cost-effective when compared to supply-side alternatives.
Achievable potential is defined as the amount of technical or economic potential that could be achieved over time under the most aggressive program scenario possible.
Program funding constrained potential refers to the amount of savings that would occur in response to specific program funding and measure incentive levels.

Area(s) Covered	Type of Savings Potential	Year Completed	Author	Estimated Consumption Savings as % of Sales				Estimated Summer Peak Demand Savings as % of Total Capacity	Years to Achieve Estimated Savings Potential	Comments
				Res.	Com.	Ind.	Total			
US	Technical	2000	Interlab Wkg. Grp.				25-35%		20	High estimate removes barriers to DG
California	Tech./Econ./Ach. of Econ./ Prog. Fund. Constrained	2002	Xenergy	N.A.			18% / 13% / 10% / 5%	22% / 15% / 9% / 6%	10	Integrated measures not addressed
Massachusetts	Program Funding Constrained	2001	RLW Analytics	25%	16% - C&I		N.A.	N.A.	5	Savings adjusted to compare to sales in same yr
New York	Technical	2002	OEI/VEIC/ACEEE	37%	41%	22%	37%	N.A.	10	Also 5- and 20-year scenarios, econ potential not public yet
New Jersey, New York, Pennsylvania	Achievable of Economic	1997	ACEEE	35%	35%	41%	N.A.	N.A.	14	Res. savings for all fuels, not available for just electric
New Jersey	Technical/Economic	1999	Xenergy/Utilities	32%	27%	31%	N.A.		N.A.	Submitted by utilities to NJ BPU in CRA Case
SW Region (AZ,CO NV, NM,UT,WY)	Achievable of Economic	2002	SWEEP	14%	20%	19%	18%	N.A.	8	Also 18-year scenario
Vermont	Achievable of Technical	2002	OEI/VEIC	30%	32% - C&I		31%	38%	10	Includes fuel switching; also 5-year scenario
Illinois	Technical	1998	ACEEE				44%		17	
National	Program Funding Constrained	1997	U.S. DOE	9%	8%	11%	10%	14%	13	Addresses all fuel; also 23-year scenario

Source: Chris Neme Vermont Energy Investment Corporation

CHAPTER 5: OPPORTUNITIES FOR LOAD PARTICIPATION IN CONTINGENCY RESERVE MARKETS

Summary

This chapter focuses on policies and strategies that are required to encourage customer loads to participate in providing reliability services in contingency reserve markets.[139] Potential benefits include increased reliability because generation can be freed up to provide energy and reduced costs to power system customers because the pool of contingency resources is increased and there will be increased price competition.[140] However, encouraging demand-side participation requires a careful review of existing reliability rules and market designs to ensure they do not unfairly exclude resources that can provide valuable services to the grid. To further that objective, NEDRI offers the following recommendations:

- Recommendation CR-1: ISO New England (ISO-NE) should continue efforts to design and implement markets for contingency reserve services as soon as possible after thorough consideration and review.

- Recommendation CR-2: There should be a market potential study and pilot demonstrations that assess the benefits and costs of using large and small loads to provide contingency reserves. The pilot demonstrations should be reflective of the actual system logistics involved in aggregating and incorporating numerous small load resources. As part of the pilot, load research protocols for aggregations of small loads should be developed and evaluated, which may serve as a functionally equivalent alternative to traditional performance measurements used for generators. These studies and pilot demonstrations should be coordinated and led by ISO-NE. Potential support could come from US DOE, states, market participants, and others.

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[139] Customer loads can provide contingency reserve services either through load curtailments or on-site generation.

[140] In New England, there may also be meaningful environmental gains. As the U.S. EPA noted, "Regional Demand Response programs could provide significant environmental benefits in circumstances where DR resources are eligible for treatment as contingency reserves as recommended by NEDRI. This is due to the DR resources backing down generator-based spinning reserves, which in New England are often provided by units that are relatively highly-polluting. To ensure that these benefits are realized, mechanisms would need to be established to prevent the loss of these emission reductions through emissions trading" See Letter from EPA to NEDRI, Appendix E.

- Recommendation CR-3: The Northeast Power Coordinating Council (NPCC), working with ISO-NE, should ensure that the reliability rules and requirements related to Disturbance Control Standard (DCS) and contingency reserves are technology-neutral, performance-based, and applied consistently to all contingency resources. NPCC should publish engineering/economic analyses used to justify reliability rules. If demand response resources are able to provide contingency reserves in the manner that provides equal or better performance to conventional generation, then such resources should be allowed to provide contingency reserves and the rules should be changed to allow for this. These rules should recognize technical and operational differences between central station generators and small demand response resources.

- Recommendation CR-4: The New England region's stakeholders and ISO-NE should systematically review the current contingency reserve metering and communications requirements and consider appropriate data recording and reporting requirements for small demand response resources; any revision of these requirements must be contingent on the continued maintenance of reliability requirements.

Introduction and Background

Direct participation of retail loads in wholesale power markets is likely to improve reliability, expand the scope of these markets, lower prices, and reduce the opportunities for the exercise of market power. Encouraging such demand participation requires a careful review of existing reliability rules and market designs to ensure they do not unfairly exclude resources that can provide valuable services to the grid. This chapter, complements the chapter on Regional Demand Response programs to facilitate short-term demand response, and focuses on issues and opportunities facing New England if retail loads are to participate effectively in certain ancillary services markets: 10-minute spinning reserve, 10-minute non-spinning (supplemental) reserve, and 30-minute (replacement) reserve.[141] The chapter describes specific ancillary services, summarizes the design and results for contingency reserves markets in the Northeast, the technical and performance reliability requirements imposed on resources that provide these services, the characteristics and challenges facing retail loads that might provide these reserves, and several recommendations for ISO-NE, reliability organizations, and New England policymakers.

The NEDRI Process

The NEDRI stakeholders discussed load participation in Contingency Reserve Markets over a twelve month period, beginning with Framing Paper on Demand Side Resources

[141] The Regional Demand Response Program chapter includes ISO markets for day-ahead and real-time energy, capacity, and "emergency resources", while this chapter focuses on contingency reserves. Key differences include level of market development and technical and performance requirements that effectively exclude load participation, which caused us to treat these regional, wholesale markets in separate chapters.

and Reliability (April 2002),[142] technical papers on retail load provision of ancillary services (Feb. 2003), and recommendations on policies and strategies to facilitate participation by customer loads (Feb. 2003).[143]

What are Ancillary Services?

Ancillary services are those functions performed by the equipment and people that generate, control, and transmit electricity in support of the basic services of generating capacity, energy supply, and power delivery. These services are required to respond to the two unique characteristics of bulk-power systems: the need to maintain a balance between generation and load in near real-time and the need to re-dispatch generation (or load) to manage power flows through individual transmission facilities. Table 5-1 lists the key real-power ancillary services that ISOs generally buy in competitive markets.

Table 5-1. Definitions of Real-Power Ancillary Services

Market	Description
Regulation	Generators online, on automatic generation control, that can respond rapidly to system-operator requests for up and down movements; used to track the minute-to-minute fluctuations in system load and to correct for unintended fluctuations in generator output to comply with NERC CPS
Spinning Reserve	Generators online, synchronized to the grid, that can increase output immediately in response to a major generator or transmission outage and can reach full output within 10 minutes to comply with NERC DCS
Supplemental reserve	Same as spinning reserve, but need not respond *immediately;* therefore units can be offline but still must be capable of reaching full output within the required 10 minutes
Replacement reserve	Same as supplemental reserve, but with a 30-minute response time, used to restore spinning and supplemental reserves to their pre-contingency status

The North American Electric Reliability Council's (NERC 2002) Policy 1 on "Generation Control and Performance" specifies two standards that control areas must meet to maintain reliability in real time. The Control Performance Standard (CPS) covers normal operations and the Disturbance Control Standard (DCS) deals with recovery from major generator or transmission outages. System operators rely mainly on regulation resources to meet CPS. Because provision of regulation service requires a change in output (or consumption) on a minute-to-minute basis and, therefore, requires special automatic-control equipment at the generator (or customer facility), it seems unlikely that many retail loads will be able to or want to provide this service.

[142] E. Hirst and R. Cowart, "Demand-Side Resources and Reliability," NEDRI Framing Paper #2, March 2002

[143] B. Kirby and E. Hirst, "Technical Issues related to Retail Load Provision of Ancillary Services", NEDRI technical paper, Feb 2003 and "Opportunities for Demand Participation in New England Contingency Reserve Markets," Feb. 2003.

The three contingency-reserve services (spinning, supplemental and replacement reserves) are primarily used to help control-area operators meet the DCS requirement.[144] The DCS is a performance measure and specifies what must be accomplished without specifying how that goal must be reached.[145] DCS requires that the electric system recover from a major outage within 15 minutes; a major outage is defined as an event between 80 and 100% of the largest single contingency.[146] Spinning reserve is the most valuable service, and therefore generally the most expensive, because it requires the generator to be on line and synchronized to the grid.[147] Supplemental reserve is less valuable because it does not necessarily provide an *immediate* response to an outage. Both spinning and supplemental reserves must reach their committed output within 10 minutes of being called by the system operator. Replacement reserves are less valuable because it need not respond fully until 30 minutes after being deployed.

The *Operating Reserve Criteria* of the Northeast Power Coordinating Council (NPCC 2002) tends to be more prescriptive in its requirements for each type of reserve (Table 5-2). NPCC requires that the resources providing reserves be able to sustain full output for at least 60 minutes.[148] The system operator uses this time to acquire and deploy replacement reserves. NPCC also requires the system operator to restore the 10-minute reserves within 105 minutes of when the DCS event occurred, to be ready to respond to another major outage.

ISO-NE typically acquires about 600 to 700 MW each of spinning reserve, supplemental reserve, and replacement reserve.[149] The largest contingency in New England is generally a nuclear unit or the power flowing from Hydro Quebec into New England over a DC transmission line. The amounts vary from hour to hour and from month to month; the total amount of reserves acquired during January 2002 ranged from 1270 to 2000 MW, with an average of 1730 MW.

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[144] Contingency reserves may be called on occasions other than a DCS event, for amounts less than stipulated for a DCS event.

[145] Policy 1 requires that: "Each Control Area or Reserve Sharing Group shall activate sufficient Contingency Reserve to comply with the NERC Disturbance Control Standard. As a minimum, the Control Area or Reserve Sharing Group shall carry at least enough Contingency Reserves to cover the Most Severe Single Contingency."

[146] Although NERC requires recovery from a major disturbance within 15 minutes, the control-area operators require the resources providing contingency reserves to respond fully within 10 minutes. The extra five minute is often needed by the operators to decide whether a major contingency has occurred and, if so, how best to respond.

[147] Because such generators are online, they can begin responding to a contingency immediately; that is, their governors sense the drop in Interconnection frequency associated with the outage and begin to increase output within seconds.

[148] The primary reason for 60 minute sustainability is the typical market need to perform a day ahead Unit Commitment with an hourly resolution; Hourly markets reinforce the need for this requirement (NPCC 2003).

[149] In May 2002, ISO-NE increased its purchase of replacement reserves from about 600 to 1200 MW to make explicit the ISO's former implicit commitment of resources day ahead to meet its second-contingency requirement. New England needs these extra reserves because the region has little quick-start (e.g., combustion turbine) capacity.

Table 5-2. NPCC Contingency-Reserve Requirements

	10-minute reserve	30-minute reserve
Amount required	100% of first contingency	50% of second contingency
Maximum response time	10 minutes	30 minutes
% of reserve that must be spinning[a]	25 to 100	0
Minimum sustainable time	1 hour	1 hour
Maximum restoration time	90 to 105 minutes[b]	4 hours

Notes:
[a] The percentage of 10-minute reserve that must be spinning (synchronized) depends on the performance of the control area in recovering from DCS-reportable events within the required 15 minutes.
[b] The maximum time to restore reserves (from the start of the event) is 105 minutes for a DCS event (a loss greater than 500 MW) and 90 minutes for a smaller deficiency.

Markets for Contingency Reserves

In its Standard Market Design proposal, FERC (2002a) would require day-ahead markets for spinning and supplemental reserves, but not for the 30-minute replacement reserve; these markets would be open to demand-side resources as well as generators. FERC proposes that these markets be integrated with the energy market; this implies that the market-clearing price will reflect both the availability bids of the resource plus the location-specific opportunity cost of the resource. FERC also proposes operation of real-time markets for ancillary services. These real-time markets would differ from the day-ahead markets in that potential suppliers would not be permitted to submit availability bids. In other words, the prices for each reserve service in real time would be a function only of the real-time energy-related opportunity costs. Current market design for ancillary services varies by ISO.

New England

ISO-NE has experienced problems with its markets for reserve services, particularly during the initial months of operation (May-August 1999). Complications in the design of ISO-NE's day-ahead unit-commitment and its 5-minute security-constrained dispatch prevented it from notifying beforehand the winning bidders in its ancillary-services markets. As a consequence, generators did not know whether they were "selected" to provide operating reserves until after the fact. In addition, during a major outage, the ISO might have called upon units that were not selected to provide reserves, and therefore they did not get paid for providing the service. In August 1999, ISO New England filed emergency market revisions with FERC to address problems during the first three months of operation.[150]

[150] ISO-NE (1999) concluded that "four of the [ISO] markets, ten-minute non-spinning reserve, 30-minute operating reserve, operable capability, and installed capability are fundamentally flawed They do not

In 2002, the annual cost to New England of the three reserve services was about $30 million. Between January 2000 through December 2002, reserve market prices in New England have been consistently below $2/MW-hr, averaging $1.15 for spinning reserve, $2.08 for supplemental reserves, and $0.81/MW-hr for replacement reserve. (During 2002, the prices averaged $1.68, $1.67, and $1.10/MW-hr, respectively). However, historic prices paid for reserves by ISO-NE may not be a good proxy for the actual value of reserves because of design problems in the reserve markets.

New England implemented a new, improved market design in March 2003, based on the design now operating in PJM. However, this new market system will not include PJM's two-part market for spinning reserve (see discussion below) (Patton 2002). ISO New England has not yet decided on the structure of its markets for contingency reserves and, therefore, may have no operating markets for any of the contingency reserves until mid- or late-2003.

New York

The New York ISO (NYISO) acquires roughly 600 MW per hour of each of the three reserve services and spent about $29 million on contingency reserves during 2002, an amount comparable to New England. NYISO operates an integrated set of markets for energy, real-power ancillary services, and congestion management (Kranz, Pike, and Hirst 2002). Because of the severity of transmission constraints in New York, especially in New York City and Long Island, New York's reserve markets have three zones. Between January 2001 through December 2002, the prices of spinning, supplemental, and replacement reserve in New York averaged 2.74, 1.69, and $1.16/MW-hr, respectively.[151] This ordering of prices is consistent with the value of each service and might be a more reasonable indicator of relative pricing of various ancillary services in a well-functioning market.

PJM

Until December 2002, PJM had no markets for contingency reserves. Any generator committed for service by PJM is guaranteed recovery of the costs associated with unit startup and no-load costs. To the extent these costs are not recovered from energy markets during each day, PJM pays these units the difference between their operating costs and revenues for the day. These uplift costs were collected from PJM customers through an operating-reserve payment, although the nexus between these costs and reserves is ambiguous.

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require delivery of any physical product, and there is no difference in the costs or risks incurred by those participants who receive payments in and those who do not. As a result the only economically rational bid in the market is a bid of zero (to ensure selection in the hope there is any positive price) or a bid that is an attempt to set the clearing price."

[151] The price of spinning reserve in New York may be slightly higher because this number does not include the opportunity-cost payments the ISO makes to generators that are dispatched below their economic point to provide spinning reserve

Since December 1, 2002, PJM (2002) has operated a two-tier market for spinning reserve; PJM does not yet operate markets for supplemental or replacement reserves. FERC (2002b) approved the PJM market, noting, however, that it "does not contain all the attributes contemplated by the Commission in the SMD NOPR, and the PJM proposal is different from the spinning reserve markets in New York and New England."

Tier 1 of the spinning reserve market consists of units that are online, following economic dispatch, and able to ramp up in response to a contingency. These units do not receive an upfront reservation payment, although they do receive an extra $50-100/MWh for energy produced during a DCS event. Tier 2 consists of additional capacity synchronized to the grid, including condensing units, which can provide spinning reserve.[152] These units are paid a reservation charge, based on a real-time market-clearing price but receive no extra energy payment during a reserve pickup.

The PJM markets for spinning reserve appear to be aimed at particular kinds of generating units, perhaps in recognition of the fleet of generators within its control area. As a consequence, the market design is not well-suited for demand resources because there is no way for retail loads to participate in these markets.

Technical Requirements to Provide Contingency Reserves

ISOs impose various performance, metering, and communication requirements on resources that provide contingency reserves. These technical requirements were typically developed with large generators in mind, in part because historically generators have provided ancillary services. Thus, a fundamental challenge is to encourage regional reliability councils and ISOs/RTOs to think more broadly about the resources that can provide reliability services to accommodate participation by customer loads, how to value and pay for the reliability services these resources provide, and how to cost-effectively deploy such resources.

For example, in terms of performance, contingency reserve resources must demonstrate the claimed ramping capability (in MW/minutes) so the ISO can be confident that, during an emergency, the resource will be able to respond as rapidly as required so the ISO can meet DCS. The resource must also sustain the committed output for a minimum amount of time, typically an hour or more, and must then be able to ramp down within a specified time to its pre-contingency level so that it is positioned to respond to another outage (see Table 2).

Because the time between a major outage and full recovery is so short (15 minutes), the system operator requires close communications and frequent updates on the status of the resources providing contingency reserves. During an emergency, the ISO must be able to send its request for increased output (or reduced load) to participating resources quickly, and the system operator requires the resources to confirm receipt of the dispatch order rapidly. Traditionally, generators that provide contingency reserves measure and report

[152] A combustion turbine capable of connecting to the grid and spinning the generator without burning fuel is one type of synchronous condenser (PJM 2002).

their output to the system operator once every several seconds. For generators, real-time telemetry is a key to successfully achieving compliance with the NERC DCS, because additional resources can be called if initial generators that were called fail to respond or under-perform. Thus, these units have sophisticated and expensive metering and telecommunications systems. In addition, the system operator requires the units to have telephone (or other voice) communication links with the control center.

Customer Load as Reliability Resource: Characteristics and Challenges

At present, no retail loads provide reserve services in any of the three Northeastern ISOs (PJM, NYISO, or ISO-NE), perhaps because of these extensive and expensive technical requirements.[153] A few large customer loads (large water-pumping loads) provide reserves in the California ISO's (CAISO) Participating Load program. The CAISO adopted the concept of an Aggregating Load Meter Data Server, a data-acquisition and processing system that collects data from individual loads and passes the aggregate data to the ISO's computer system. Although the data server is required to send data to the ISO every four seconds for supplemental reserve and once a minute for replacement reserve, the individual loads report data to the data server at one-minute intervals for supplemental reserve and once every five minutes for replacement

However, many different types of loads can potentially supply contingency reserves to the power system. Loads that are potentially good candidates to provide these services would share common characteristics. These characteristics include:

- loads that have storage involved in its process or processes that can add storage (e.g., thermal storage such as water heating and heating/cooling, process inventory, compressed air, and water pumping),
- control capability,
- loads that require little or no advanced notification, rapid response to curtail (including communications time),
- ability to quickly restore load,
- sufficient aggregate size, and
- loads with acceptable standby and deployment costs.

For example, households with electric water heaters are unlikely to notice any performance degradation (e.g., lukewarm water) if the duration of the interruption is short (e.g., less than an hour). Water heaters can also be turned back on again very quickly, and be ready, once again, to provide contingency reserves. Based on characteristics of individual loads that could potentially supply contingency reserves services, it is probable that many loads would prefer a faster and shorter response and may have more difficulty sustaining long periods of interruption.

[153] In the initial ISO New England ancillary services markets, four pumping loads and one industrial load actively participated.

Typically, DCS events occur rarely, roughly once a month.[154] Thus, a retail load selling reserves could expect an occasional interruption and can count on a modest reservation (capacity) payment hour after hour. Viewed in this light, the desirable demand characteristics might be driven as much by financial and convenience considerations as by physical characteristics of the load, i.e., the willingness to adjust to an occasional curtailment in exchange for a steady revenue stream.

However, the existing technical and performance requirements create a significant challenge for loads to participate. An alternative way to view demand-side provision of contingency reserves is to ask what the system operator really needs to maintain reliability rather than just accept the current rules. Conceivably, a more flexible set of performance-based requirements would likely encourage demand participation and potentially improve reliability. For example, to what extent do these requirements make sense for individual and aggregated resources provided by customer loads? There is no reason why an *individual* resource must maintain its emergency output or load reduction for the 60 minutes specified by NPCC. DCS performance could be just as good if aggregators were allowed to package individual loads as part of a contingency reserve product that could be sustained for an hour if necessary. With this simple modification to the NPCC requirements, individual loads that can interrupt for 30 minutes, but not for 60 minutes, would be able to provide contingency reserves as part of a broader product offering of a load aggregator.[155] Similarly, while large generators require real-time monitoring, these requirements may not apply to a fleet of small load resources with statistically independent failures.

Table 5-3 provides an overview of the characteristics of loads and some key program design feature that should be considered if loads are to provide contingency reserves.

Table 5-3. Characteristics and proposed Requirements for Load Participation in Contingency-Reserve Markets

	Spinning reserve	Supplemental reserve	Replacement reserve
Aggregation	Specify minimum resource size (e.g., 1 MW); allow aggregation and sampling of small loads to infer performance for total population		
Metering	Sufficient data to measure performance of individual resources; interval meters capable of recording consumption at 1-, 5-, and 10-minute levels for large loads		
Communication	Daily submission (or standing offers) of hourly capacity and energy bids to RTO; RTO calls winning bids to curtail loads within required times		

[154] New England has averaged 14 DCS events a year during the past five years (12 in 1998, 10 in 1999, 15 in 2000, 19 in 2001, and 10 during the first three quarters of 2002). This is about the same rate experienced in New York and PJM. Note that contingency reserves may be called on occasions other than a DCS event and for amounts less than that stipulated for a DCS event.

[155] However, the 60-minute requirement would reduce by 50% the amount of contingency reserves provided by loads relative to a 30-minute requirement for sustained output.

Response time	10 minutes	30 minutes
Frequency	Voluntary customer participation; customer load commits to provide contingency reserve service if ISO selects and schedules their day-ahead bid to sell reserves during certain hours	
Duration	30 to 60 minutes	
Penalties	Penalties applied because load committed to make reductions upon RTO call for reliability service (quid pro quo for reservation payment)	
Payments	Day-ahead hourly market clearing prices for capacity and energy bid	
Baseline	Baseline consumption based on one or a few intervals before the ISO call because of short advance notice	

Recommendations

Retail loads have the potential to make a substantial contribution to contingency reserves. Modifying the reliability requirements to accommodate demand response resources and including demand resources in revised markets will improve the efficiency of wholesale energy, ancillary-service, and congestion-management markets. NEDRI participants offer the following recommendations to facilitate customer load participation in contingency reserve markets.

Recommendation CR-1:

ISO New England (ISO-NE) should continue efforts to design and implement markets for contingency reserve services as soon as possible after thorough consideration and review.

We recommend that ISO-NE continue efforts to develop and implement contingency reserve markets that follow closely FERC's SMD proposal. Over the long term, NEDRI participants believe that customers would benefit if the three Northeastern ISOs adopted more consistent and uniform approaches for customer loads to participate in contingency reserve markets. ISO-NE should continue its efforts to develop a day-ahead market design that integrates availability bids for the reserve services with energy bids and integrates reserves and energy in real time. Such an integrated system will ensure that reserve prices fully reflect their value, especially during periods of scarcity (Patton 2002). Loads would participate in the day-ahead reserve markets by submitting availability bids (in $/MW-hr) and the energy strike price (in $/MWh) above which they would be willing to interrupt some load. Accepted load and generator bids would be treated the same way; in the event of a major outage, the ISO would dispatch generators and loads in economic merit order. Loads and generators that failed to respond to the ISO's dispatch signal during a DCS event would face the same nonperformance penalties.

Recommendation CR-2:

There should be a market potential study and pilot demonstrations that assess the benefits and costs of using large and small loads to provide contingency reserves.

The pilot demonstrations should be reflective of the actual system logistics involved in aggregating and incorporating numerous small load resources. As part of the pilot, load research protocols for aggregations of small loads should be developed and evaluated, which may serve a functionally equivalent alternative to traditional performance measurements used for generators. Candidate sponsors to conduct these studies and pilot demonstrations include US DOE, ISO New England, and New England utilities.

Given limited participation by loads in contingency reserves markets, demonstration pilots are needed to assess benefits and costs under varying metering and communications requirements, assess and overcome technical and market barriers, and work with ISO system operators to accommodate customer load participation while meeting ISO system reliability needs. Such pilot demonstrations could involve a few large industrial loads and an aggregation of residential loads (perhaps through a utility's existing direct-load-control program). A market potential study would examine opportunities in the residential, commercial, and industrial sectors to see which customers and which end uses are most suitable for the provision of contingency reserves. The study would characterize customer loads based on their seasonal characteristics, storage capabilities, the speed with which they can be interrupted and rearmed (restored), and the costs of the necessary metering and communications equipment. The resultant estimates of resource potential will be a function of reliability and market rules as well as the payments to retail loads for provision of reserve services.

Recommendation CR-3:

The Northeast Power Coordinating Council (NPCC), working with ISO-NE, should ensure that the reliability rules and requirements related to Disturbance Control Standard (DCS) and contingency reserves are technology-neutral, performance-based, and applied consistently to all contingency resources. NPCC should publish engineering/economic analyses used to justify reliability rules. If demand response resources are able to provide contingency reserves in the manner that provides equal or better performance to conventional generation, then such resources should be allowed to provide contingency reserves and the rules should be changed to allow for this. These rules should recognize technical and operational differences between central station generators and small demand response resources.

The NPCC contingency reserve requirements were initially designed to accommodate typical generating units and were not necessarily well-suited for demand resources that might fully satisfy appropriate reliability requirements. NEDRI supports the NPCC and ISO New England's current efforts to update and revise reliability rules and requirements. Reliability rules should also recognize the technical differences between reserves provided by large resources (whose expected performance is generally deterministic) and small resources (whose expected performance can be derived from statistical approaches).

The rules should also accommodate resources whose availability and size varies, especially for those resources where the variability is positively correlated with system load (in particular, weather-sensitive loads). These rules should address the reliability requirements associated with speed of response, duration of response, and speed of restoration. For example, some retail loads with modest amounts of storage (e.g., residential electric water heaters) can be interrupted very quickly (within seconds of notification) but can conveniently sustain the interruption for only short periods (e.g., less than one hour). Options that should be considered included allowing resources with shorter minimum sustainable time to provide contingency reserves using more sophisticated resource deployment strategies (e.g., dispatch one set of electric water heaters when the outage occurs and a second set 30 minutes later when the first set is restored to normal operation).

Recommendation CR-4:

The New England region's stakeholders and ISO-NE should systematically review the current contingency reserve metering and communications requirements and consider appropriate data recording and reporting requirements for small demand response resources; any revision of these requirements must be contingent on the continued maintenance of reliability requirements.

As part of a broad-based stakeholder process, ISO-NE should review the requirements it imposes on resources that provide contingency reserves with respect to the frequency of metering output (or consumption) and the frequency with which these MW values are communicated to the ISO's control center. The 4-second recording and reporting requirement imposed on generators is probably not needed for retail loads that provide contingency reserves, primarily because of the much smaller size of these demand resources. It may be sufficient for large loads to record load data at the 1- or 5-minute level for 10-minute reserves and the 5- or 10-minute level for 30-minute reserve. For small load resources (e.g., residential water heaters), sampling approaches should be considered, where a representative sample of loads are metered and results are then scaled up to the population of participating loads.[156] In both cases, there may be no reliability reason to report performance results to the ISO in near real-time; it may be sufficient to provide such data at the end of each month for billing and settlement purposes. Changes in data recording and reporting requirements must ensure that the service provided by loads is functionally equivalent compared to that provided by generation. Revised data recording and reporting protocols would necessarily have to be integrated within ISO-NE's Energy Management System.

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(Note: these references will be converted to footnotes where applicable, for consistency with other chapters in this report)

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[156] The use of statistical approaches is not foreign to ISO New England; internal operating procedures already call for the activation of 125% of the magnitude of contingency losses in order to cover most occurrences of under-delivery by individual resources (NPCC 2003).

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NEW ENGLAND DEMAND RESPONSE INITIATIVE

CHAPTER 6: DEMAND RESPONSE RESOURCES AND POWER DELIVERY SYSTEMS

Summary

This chapter focuses on the role that Demand Response resources can play in addressing reliability and congestion problems across the transmission and distribution networks[157] serving New England at both the regional and local levels. Restructuring, divestiture, and competition have changed the historic relationships among those who own and manage the regional power grid, those who manage local distribution networks, and those who supply electric power to customers. New system planning and investment strategies are under development in this new environment, and those strategies should be designed to take into consideration all resources (including generation, wires, short-term demand response and efficiency resources) to address reliability and congestion problems. In this chapter[158]:

(A) NEDRI recommends a regional **resource development policy** that relies principally on competitive markets and market signals to the extent practicable, including:

- Competitive energy and capacity markets with locational marginal prices, real-time and day-ahead energy markets, financial transmission rights, and cost-based delivery tariffs;
- Incentive regulations for wires companies that will encourage efficient management of power delivery services, including the opportunity to reduce costs through investments in customer-based demand response; and
- A planning process that identifies grid problems and seeks market-based responses to resolve them to the extent practicable.

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[157] This chapter addresses the potential of demand resources to relieve loads and improve reliability on the power delivery systems serving customers in New England, at both the transmission and distribution levels. Text and recommendations refer to "transmission" or "distribution" where appropriate, and to "the wires" and "wires companies" when referring to both transmission and distribution together.

[158] ISO-NE is presently engaged in discussions with the New England Public Utility Commissioners and with a diverse, comprehensive group of industry stakeholders in order to improve the Regional Planning Process. These discussions are being held within the context of meetings that focus on the steps to transform ISO-NE into an RTO. At this time, ISO-NE needs to remain neutral on issues concerning the Regional System Planning Process as the discussions unfold. Accordingly, ISO New England must recuse itself from endorsing or opposing any recommendations made by NEDRI on Power System Planning and Investment. For similar reasons, NYISO also abstains from participating in the recommendations in this chapter.

(B) NEDRI recommends a **regional planning and assessment** process that:

- Is conducted by an entity such as an ISO/RTO, that is financially independent of the solutions recommended by the process;
- Actively engages New England's state governments as well as other interested stakeholders and the broader public;
- Is transparent; and
- Evaluates on an even-handed basis all feasible, comparable solutions to emerging problems including generation, transmission, and demand-response resources.

(C) NEDRI also recommends a **regional power system investment policy** that builds on this planning process and that:

- Encourages the emergence of market-based responses to regional power system needs, wherever possible
- Explores ways in which siting of major energy facilities or deployment of alternatives can be coordinated on a regional basis;

Continues the regional dialogue to explore the process and policies by which to allocate and recover costs of projects to address reliability and persistent economic congestion.

(D) Finally, NEDRI addresses the question of **distribution-level grid enhancement**. Wires companies in New England routinely invest more on *distribution* system expansion and upgrades than they do on expanding the *transmission* system. NEDRI participants conclude that distribution utilities and regulators should seek out opportunities to assess the potential for demand response in order to expand available resources to meet distribution needs on a cost effective basis, If successful, regulators should require broad scale applications of such approaches and provide appropriate funding or cost recovery. NEDRI participants conclude that distribution utility companies should be given the incentive and the opportunity to deploy a variety of resources – distribution upgrades, strategic generation, energy efficiency and other demand-management resources – to resolve reliability and congestion problems on the distribution networks.
NEDRI concludes that these planning and investment policies would support both reliability and economic objectives for New England, and would allow demand-side solutions, including energy efficiency and price-responsive load, to deliver greater value to the region's power system.

NEDRI recognizes that regional planning and investment policies are complex, and raise many issues and choices for decision-makers. The NEDRI process has not attempted to address all of those issues, but has focused on those most directly connected to the potential role of demand-side resources. Those recommendations are set out in this Chapter.

A Separate Statement from
National Grid, Northeast Utilities and United Illuminating:

In order to preserve independence, National Grid, Northeast Utilities and United Illuminating cannot agree with any suggestion, implied or otherwise, that advocates the operation of demand response programs by transmission businesses in competitive markets or the inclusion of market-based costs in regulated rates. The issue of independence was addressed by member utilities during the NEDRI meetings. FERC has required utilities to separate market-based and transmission functions in order to provide fair, non-discriminatory, open access to the transmission system, i.e., the Transmission Owner cannot be a market participant. Any suggestion that transmission companies should be directly involved in the procurement of demand response would violate this separation. Demand response is a market product that competes directly with generators for energy. Transmission, on the other hand, is a regulated product that enables competitive markets through efficient delivery of energy. Suggestions to allow market-based solutions to receive subsidies through regulated transmission rates only serve to undermine the future of energy markets.

With the exception of short-term stop-gap resource acquisitions, National Grid, Northeast Utilities, and United Illuminating disagree with any inference in the language of this chapter that could be taken to mean that, when competitive solutions fail to present themselves, the ISO ought to select for regulatory cost treatment resources that should otherwise compete in the market. The regional planning and assessment recommendation was discussed by NEDRI members in response to ISO-NE's concern that evaluating and selecting between market-based solutions is not part of its responsibility or authority.* The current regional planning process is one that was carefully crafted by the stakeholders in New England after thorough evaluation of many alternative planning processes. Assessments by ISO-NE focus on whether market proposals brought forward by market participants adequately solve reliability needs and/or reduce congestion costs thereby improving market efficiency. Thus, these utilities believe that ISO-NE does not select between proposed market-based outcomes, rather, it determines whether the proposed solutions are feasible and accounts for the solutions' impacts in its planning process. The utilities do not support Alternative B of Recommendation PD-6 and that is the only place in this chapter that should be read to support active selection by the ISO-NE of specific projects offered by market participants.

*Note: The other NEDRI members listed in footnote #182 also believe that the ISO should not select among resource options unless the market has failed to provide adequate reliability or remove persistent congestion. However, rather than pursuing only a regulated transmission option, these NEDRI members conclude that at this point of market failure the ISO should pursue an efficient reliability solution that seeks the most cost-effective solution among transmission, generation, and demand-side options. See Alternative B on page 123.

Introduction: The Role of Demand Response in Power Delivery Systems

Since the passage of the EPACT in 1992, the FERC has been engaged in a series of complex open-access and regional market initiatives that greatly change the role of transmission in the electric system. Transmission decisions are now critically related to the nature of regional electricity markets, the environmental footprint of the electric industry, and to the future of distributed resources, including demand-side resources. Transmission is no longer just an implementation tool for utilities to deliver power within integrated franchises, but is an avenue of commerce that facilitates trade among multiple generators and multiple load centers, often at great geographic distance.

The New England electric system functions as a regional machine. The power sources and load centers, and the power lines that connect them, operate without regard for state boundaries. A fundamental question (and challenge) for the electric industry and its regulators is: How can we maintain a reliable electric system across this region at least cost over the long term? Demand-response resources are but one component of the answer to this question, but they have a potentially important role to play in maintaining a reliable grid at reasonable cost.

A regional power system planning process is both necessary and desirable in order to better ensure system reliability over time. A well-designed planning process can identify system needs, balance competing public interests (e.g., cost, reliability, environmental impact), and help to allocate scarce resources among potential investment choices.[159]

ISO-NE currently administers a process called the Regional Transmission Expansion Plan (RTEP).[160] The RTEP process is intended to provide a "request for solutions" that serves as the market signals appropriate for the planning of generation, merchant transmission facilities, elective upgrades, demand side management and demand response programs. To the extent that the market signals provided by the RTEP process fail to result in the market responding with adequate solutions for system problems or needs, the RTEP summarizes a coordinated transmission plan that identifies appropriate projects for ensuring a reliable electric system and for reducing congestion in an economic manner. The timeframe for system reliability analysis conducted within the RTEP process is generally 10 years. The RTEP process thus ensures consistency with planning criteria by integrating market responses with needed Reliability Upgrades and Economic Upgrades. The RTEP goal is the achievement of a reliable transmission system that facilitates the development of a robust market with due consideration to environmental issues. In preparing the plan, ISO-NE gets input from the work of the Transmission Expansion

[159] The sums involved can be quite substantial, and unlike the costs of competitive generation, are proposed for collection in non-bypassable tariffs. NEDRI participants are aware of the significant transmission investment proposals now pending in the region, totaling nearly one billion dollars. If these transmission investments are made, the costs will ultimately be borne by electric ratepayers, however they are assigned throughout the region.

[160] In parallel with its petition to FERC to become an RTO, ISO-NE is considering changing the name of this process to Regional System Planning. A critical feature of the planning process recommended by NEDRI is that it will openly consider non-traditional transmission actions, and supply-side and customer-located resources as potential lower-cost solutions to power system problems.

Advisory Committee, a group with open membership that meets regularly to discuss system solutions, as well as the transmission studies done by ISO-NE and others. ISO-NE has taken significant steps to make this process accessible and has begun to include customer-based resources in its planning analyses. ISO-NE is currently engaged with the New England Conference of Public Utility Commissioners and with the region's stakeholders to improve the regional planning process.

Demand Response resources can potentially strengthen power delivery systems and improve economic performance at both the distribution and transmission levels. At the distribution level, targeted DR investments, including load management, energy efficiency, and distributed generation, can relieve loads on stressed substations and feeders, improving reliability and extending the useful life of existing facilities. In New England, the Mad River Valley project (Green Mountain Power), and the Brockton Pilot (National Grid) are examples of this potential.[161] In the right circumstances, similar potential exists at the wholesale level as well: targeted investments in load reduction may be able to relieve reliability and congestion challenges on the transmission grid more economically than the available generation and delivery alternatives.

In its National Transmission Grid Study (NTGS), the U.S. DOE concludes that transmission constraints increase electricity costs and decrease electric system reliability to consumers in many regions of the country. The study identifies a number of policies that could promote investments in new transmission facilities, and emphasizes that transmission upgrades are likely to be needed in many locations across the nation. The NTGS also notes that demand-side options can play an important role in delaying or avoiding the need for those investments:

> *Enabling customers to reduce load on the transmission system through voluntary load reduction or through targeted energy efficiency and reliance on distributed generation are important but currently underutilized approaches that could do much to address transmission bottlenecks today and delay the need for new transmission facilities.*[162]

Since transmission operations and planning are done on a regional basis, the Study points out that "opportunities for customers to reduce their electrical demand voluntarily, and targeted energy-efficiency and distributed generation, should be coordinated within regional markets," and concludes that regional planning processes "must consider ***transmission and non-transmission alternatives*** when trying to eliminate bottlenecks."[163]

These aspects of the NTGS echo and expand upon the positions announced by FERC in recent RTO orders and reviews. FERC has made clear its view that transmission planning, transmission adequacy, and transmission pricing should be the responsibility of the nation's Regional Transmission Organizations. Thus, regional transmission providers

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[161] See text at note 182, below.
[162] U.S. Department of Energy, National Transmission Grid Study (May 2002) at p.41 (hereinafter NTGS).
[163] NTGS p. xiii (emphasis added).

must conduct system planning and expansion activities that historically have been conducted chiefly within state-regulated franchise utilities.

Market Foundations for Delivery System Planning and Investment

Recommendation PD-1:

NEDRI recommends a regional resource development policy that relies chiefly on competitive markets and market signals that reveal, to the extent practicable, the temporal and locational value of energy services. NEDRI participants support the ongoing development of the region's power markets and trading rules so as to reveal those values .

The essential foundations for a sound resource planning and investment policy for New England lie in sound market structures in the markets for power supply. Although the power delivery infrastructure remains a natural monopoly, subject to regulation under tariffed rates, demands upon that infrastructure will be inefficient unless the underlying energy service markets are themselves efficient and competitive. For example, a power market lacking active demand response may seem to require additional transmission and distribution capacity that might not be required if demand response resources were engaged. Implementation of locational pricing will also affect demand patterns, and thus demands on the power delivery systems. With respect to wires systems in particular, the underlying power markets should:

- Include provisions for meaningful and active demand response by loads (e.g., multi-settlements, demand-response resales, regional DR programs);
- Incorporate locational marginal prices and other mechanisms to reveal the locational value of capacity, energy, demand response, and reserves; and
- Provide tradeable financial rights to transmission capability (e.g., FTRs) to reveal the value of congestion relief to those who provide and benefit from transmission capacity additions.

Competitive markets that reveal both the temporal and locational value of energy services will provide efficient signals as to the region's power delivery infrastructure needs as well. NEDRI participants support the ongoing development of the region's power markets and trading rules so as to reveal those values. Note, however, that the conditions for efficient markets in electric services must be carefully considered. Where market structures and market barriers impair the contribution of demand response resources, investment policies that rely on private markets alone may not be successful.[164] Moreover, we recognize that even where competitive wholesale markets operate well, the provision of default service and regulated retail service and renewable portfolio standards will be subject to public policy decisions at the state level.

[164] There are a number of key market and policy conditions that would provide a foundation for solutions to emerge without regional intervention. Some, like region-wide locational marginal pricing, are outside the scope of NEDRI's work. Others, such as creating markets for price-responsive load, and ensuring resource adequacy eligibility for demand-side resources, are taken up in other sections of the NEDRI report.

Recommendation PD-2:

Transmission and distribution providers, ISO-NE, State utility commissions, and FERC should carefully consider the value of incentive regulation plans for regulated transmission and distribution companies that would encourage those firms to lower the overall costs of power delivery for their customers.

The regulation of wires companies has historically provided only modest incentives to institute management practices that would lower the overall cost of the delivery function. Due to the fixed cost nature of the wires infrastructure in the short run, in the period between rate cases, wires companies generally profit from increased throughput, even where increased load will drive up costs in the long run. Wires company incentives to lower system costs are typically even lower in a restructured environment, where power supply costs are not part of the utility's equation.

This problem also arises at the wholesale level. On the one hand, transmission owners tend to benefit from increased throughput on the wires between rate cases. Thus, they have little or no direct financial incentive to support energy efficiency and other demand-reducing efforts that could be cost-effective for their customers.[165] At the same time, they do not benefit from any decrease in congestion costs that they may provide to ultimate customers. Since total congestion costs are often quite large in relation to the costs of congestion-relief opportunities, this mismatch can result in an under-investment in congestion relief and unnecessarily high power costs for consumers.[166]

New England has recently adopted a system of Financial Transmission Rights (FTRs), and Auction Revenue Rights (ARRs), which provides mechanisms to mitigate congestion costs, and provides incentives to transmission companies who do so. Wires companies and regulators should consider, in addition, at least two important options to provide wires companies with the financial incentives to invest in grid improvements and demand-response options that would lower congestion costs and power bills.

At the distribution level, regulators should consider the merits of incentive regulation plans that would reward utilities for improvements in service quality, reliability, and energy efficiency, rather than for increases in electricity use.[167] Such plans could provide valuable incentives to wires companies to improve reliability, lower system costs, and where cost-effective, to deploy Demand Response resources to defer costly upgrades.

[165] A wires company paid entirely on a throughput basis would not even have a direct financial incentive to reduce line losses across its own system, and is actually harmed by decreased sales. The fact that distribution companies often address these issues is a testament to their public service traditions, but regulators will want to consider whether improved financial incentives would be a better basis for future performance.

[166] Congestion-relief opportunities may arise from a variety of technological options: enhanced transmission performance, new investments in transmission capacity, deployment of generation, or deployment of demand-response resources.

[167] See also, Recommendation PD-7 and associated discussion, below.

At the wholesale level, regulators should consider the merits of incentive regulation plans that would reward transmission owners for reducing both transmission costs and congestion charges paid by their customers, and would remove their financial incentive to promote increased sales[168] rather than energy efficiency improvements, through a performance-based mechanism.[169]

Recommendations for Regional System Planning

Overview: NEDRI recommends that the ISO,[170] regional market participants and states seek ways to enhance the ability of the regional planning process to identify the best solutions to grid problems from all types of resources – traditional grid upgrades, operational improvements, strategically-located generation, and targeted investments in demand response resources (DRR).[171] NEDRI recognizes that the structure, authority, and governing rules for a regional planning entity will be critical to its success, but concludes that decisions on those topics will be taken in other forums.[172] However, whatever structure is adopted for regional system planning, it must be one that accommodates a long-term view of the system, and can openly consider the potential for DRR to resolve grid problems. Thus, the recommendations below focus not on the structure or governance details of a regional planning entity, but on the basic principles to support an appropriate balancing of resources, including DRR, in resolving power system challenges.

Recommendation PD-3:

Conduct a continuing, regional power system planning process, involving the ISO, appropriate state agencies, and other stakeholders to identify system needs and consider alternative strategies to meet them.

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[168] While National Grid, Northeast Utilities and United Illuminating acknowledge that ratemaking policies may inhibit the development of demand resources, they respectfully disagree with the claim that utilities are incited to increase throughput. This claim is premised on a specific rate design that is not uniformly adopted for every utility, especially transmission utilities. Also, specific circumstances may not make this theory prove true. Inflation, investment for growth, greater demands on older equipment and many other issues contribute to a marginal cost curve for distribution that is upward sloping and eliminate any opportunity for increasing profits as described above. Finally, customers receive benefits from pricing on deliveries because customers who use more electricity pay more and have a greater incentive to conserve and, if added growth can fund additional investments and expenses, average rates to customers can be kept lower over time by limiting the number of rate cases.

[169] Transmission incentive plans incorporating congestion costs have been instituted in other countries (notably the UK and New Zealand) but have not been attempted in the US.

[170] ISO-NE has announced that it will take steps to transform itself into an RTO. The recommendations in this paper apply to whatever organization becomes the duly constituted system operator for the New England region. For purposes of consistency, this chapter will refer to that organization as "the ISO."

[171] What problems should the planning process address? Clearly, it should address emerging reliability challenges. Whether it should also seek to mitigate persistent "unhedgable" congestion is a matter of further discussion.

[172] We note that a discussion addressing this topic is underway among the six New England states.

Regardless of the structure that New England ultimately chooses to employ for regional system planning, the region should employ a continuing power system planning process that takes a long-term view of system needs, identifies reliability issues, and identifies both traditional and non-transmission alternatives to resolve them, within the context of a competitive wholesale electricity market.

As a starting point, NEDRI recommends increased cooperation on regional power system issues among the six states and the ISO. At present, there is no entity that is structured and empowered to adequately reflect public policy in resource deployment on a regional scale. A robust planning capacity, reflecting the interests of all of the states and the region as a whole, is needed to address regional needs for transmission, for congestion relief, and for long-term resource adequacy.[173]

While state governments should actively participate in the regional planning process, states must also retain their ability to rule on issues subject to their jurisdiction and responsibility. Thus, any regional effort must be designed so that state decision-makers can conduct reviews as required by their governing statutes, often on an independent, quasi-judicial basis. For a regional effort to be valuable, it is also important that states apply significant weight to its findings. Thus, the process should be designed so that states can rely both upon the data and the assessments developed in the regional plans. This should in turn help to streamline state review and approval processes.

The focus of the regional power system planning process should be to identify emerging system deficiencies, and attract resources to address them. The planning process should be cyclical; a periodic assessment of the electric system would be produced, identifying deficiencies of varying types and urgencies Market participants, including regulated companies, could use this information to develop projects that address these identified deficiencies. A sufficient planning horizon (7-10 years) would be necessary to enable the aggregation of small-scale resources to have a meaningful effect on a significant system need.

Recommendation PD-4:

The regional power system planning process should evaluate on an even-handed basis all feasible, comparable solutions to emerging problems including generation, transmission, and demand-response resources.

To anticipate and resolve system challenges and bottlenecks requires analysis of a range of potential solutions including transmission investments, transmission operations, strategic generation, and demand-side programs and investments. As the National Transmission Grid Study concluded,

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[173] NEDRI is not alone in raising the need for greater coordination among states in regional power system planning. FERC has focused on the need for regional coordination in planning, specifically noting that regional entities could establish resource adequacy standards. See, e.g., Order 2000, pgs 71-72. The National Governors' Association and the New England Governors' Conference Task Force on Electricity Infrastructure are also working on this issue.

> Expansion of the transmission system must be viewed as one strategy in a portfolio to address transmission bottlenecks; this portfolio also includes locating generation closer to loads, relying on voluntary customer load reductions, and targeting energy efficiency and distributed generation.[174]

NEDRI recommends that the regional planning process employed in New England be organized and conducted with a clear capability to assess all technically feasible, reasonably-priced solutions that could meet reliability objectives. The region's planning process should review a complete array of potential solutions to system deficiencies, and consider their costs and benefits, and their ability to address reliability needs.[175] Prospective solutions may be offered by private sector competitors (e.g., merchant generation, merchant transmission, demand response service providers), monopoly providers (e.g., transmission utilities), state energy efficiency initiatives[176]) or other state policy initiatives. The planning process should consider them on an equivalent basis based on how well each solution would address an identified deficiency.[177]

Recommendations -- Regional Power System Investment Policy

The regional system planning process outlined above provides the critical foundation for major power system enhancements. Most significantly, it will identify emerging reliability and persistent congestion problems, and consider potential solutions that could mitigate or resolve them. System operators have traditionally focused on supply-side resources in meeting reliability requirements for electric networks, especially in periods of stress. However, in appropriate instances, DRR may offer substantial value as part of a mix of resources to meet system needs. In this section, NEDRI recommends: (a) that the region rely first upon market forces and participants to fill any pending resource "gaps" identified in the planning process; and (b) that New England stakeholders continue current regional dialogues about the means by which costs for reliability-enhancing investments should be recovered.

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[174] NTGS at p.51. For the range of options considered, see NTGS at pp33-38 (operations), pp41-45 (demand-side and distributed generation), pp61-67 (advanced technologies), pp. 50-60 (transmission investment and siting).

[175] This approach is consistent with the view recently expressed by NECPUC, which urges the ISO to "develop a resource planning protocol that is based on resource parity and involves a full and complete analysis that will identify the project which will be the least cost solution to the problem." Letter from NECPUC to ISO-NE ("Re: Regional System Planning") dated February 4, 2003. While subsequent correspondence reveals that the states do not presently agree on the question of *investments* in non-transmission assets, all of the region's PUCs have stated that the *planning process* should assess both transmission and non-transmission alternatives to reliability problems on an even-handed basis.

[176] State energy efficiency initiatives include both state regulated SBC programs and intensive geographically targeted energy efficiency. Intensive targeted energy efficiency means programs justified by higher avoided costs, with geographical targeting, expanded eligible services or populations, and/or greater focus on near-term load reductions.

[177] System operators have legitimate questions about the reliability of some resources to produce load reductions at specific times when they are needed. The limitations and beneficial characteristics of these resources can be better understood with experience.

Recommendation PD-5:

Market-based responses to regional power system needs should be encouraged to emerge, wherever possible.

After grid problems and potential solutions are identified in the system planning process, these results should be posted publicly so that market participants can consider what actions they might take within the existing market structure to meet emerging needs. Wherever possible, market-based responses to system needs should be encouraged to emerge, consistent with the other recommendations in this report. Interventions to promote or pay for grid solutions through regulated rates should be taken only where it is evident that adequate resolution is not forthcoming in the market.

Recommendation PD-6:

Continue the regional dialogue to explore the process and policies by which to allocate and recover costs of projects to address reliability and persistent economic congestion.

Since the creation of the New England Power Pool, utilities, regulators, and other stakeholders in the region have engaged in extended discussions concerning needed improvements to the region's power infrastructure and the means by which those improvements would be paid for. Costs and responsibilities have been shared in many ways and for a variety of purposes.[178] New England stakeholders are today engaged in an ongoing discussion in multiple forums of the principles and rules that should govern investments for reliability, including the questions of who ought to pay for such investments and whether broad-based funding mechanisms, such as transmission tariffs or uplift charges, should be used to support either transmission investments or non-transmission alternatives to them. NEDRI recommends the continuation of an effective dialogue on these topics.

NEDRI participants conclude that efficiently constructed wholesale electricity markets, including adequate demand response programs and policies, will moderate both the volatility of markets and the degree to which reliability managers must intervene in the market to ensure reliable service. As noted above (Recommendations PD-4 and PD-5) we support a planning process that identifies emerging reliability problems and notifies market participants and public decision-makers about them, giving market responses adequate time to develop. Identifying resource needs and giving all resources a reasonable opportunity to respond to market signals serves as a strong signal for the planning of unregulated generation, merchant transmission facilities, elective upgrades, demand-side management, and load response programs.

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[178] For example, support for Reliability Must-Run units, Pool Transmission Facilities, generating units deemed needed for reliability purposes (e.g., Seabrook), uplift for congestion, the HVDC line to Quebec, and regional demand response programs, among others.

When reliability "gaps" or significant, persistent congestion remain, however, regulatory or investment interventions will be needed. NEDRI participants have developed and discussed a variety of approaches to the investment question, with particular attention to the issue of support for reliability-enhancing DRR, in addition to the policies adopted to date by NEPOOL and the ISO. While NEDRI participants have not reached a consensus on the best path to pursue on this particular issue, its discussions have helped to better articulate several alternative approaches. These approaches are presented below, and NEDRI members recommend continued regional dialogue to weigh their relative merits:

Alternative Approach A: Proponents of this alternative[179] advocate the use of market driven approaches to meet regional needs, while avoiding subsidies to market-based solutions if at all possible. Should market signals not produce sufficient market response to fully address the needs of the system, the planning process should provide a coordinated, regulated transmission plan that identifies appropriate transmission upgrades to ensure reliability of New England's bulk power system. The costs associated with such cost based transmission assets would then be recovered through regulated transmission rates.

Providing the market with the ongoing opportunity to respond to identified regional needs supports and encourages the development of a competitive wholesale energy market. This approach reflects resource parity for needs assessment purposes only. With this alternative, the regional resource planning model takes into account responses and projects of all resources when planning for future needs, yet does not give preference to any particular solution.

If market solutions do not fully resolve an identified reliability concern, a regulated transmission solution may be required to resolve the problem. In this instance, the planning process would identify appropriate transmission projects necessary to ensure reliability. As is required currently, regulated transmission companies would continue to be obligated to implement the lowest cost, reasonably available transmission solution to address the reliability need. Cost recovery for regulated, regional transmission solutions would be through the regional open access transmission tariff (OATT) under FERC jurisdiction.

Proponents of this approach have advanced several reasons to support it, including:

- The need for additional transmission infrastructure may not constitute a failure of the market but rather may indicate that the most appropriate market based resource is remote to the load and regulated transmission infrastructure is necessary to bring that resource to the load.[180]

[179] Proponents supporting Approach A include: Massachusetts Division of Energy Resources, Northeast Utilities, National Grid, PowerOptions/Massachusetts Health and Education Facilities Authority, and United Illuminating.

[180] See, Letter from Massachusetts Department of Telecommunications and Energy and Connecticut Department of Public Utility Control to Board of Directors, ISO New England (May 8, 2003) at 2. The Commissions recognize that there may also be a need for short-term, "stop-gap" resource solicitations,

- When the market fails to provide generation or demand response solutions, it may reflect a judgment by the market that those resources will not be appropriate for cost or other reasons.
- Competitive energy wholesale markets can be distorted when regulatory incentives are provided to stimulate competitive, market-based resources. Such subsidies should be avoided if at all possible and, if necessary to meet regional reliability needs, should be minimized. (One example of such a subsidy would be to provide avenues for market project developers to shift market risks to load.) It is inefficient to create subsidies that provide artificial incentives to competitive market based solutions. Such subsidies have the potential to significantly distort the competitive energy wholesale market.
- The benefits of transmission investments facilitate interstate commerce and are inherently regional in scope while the benefits of non-transmission resources are generally local in nature and therefore should be funded locally. The regional benefits of regulated transmission investments are more certain than the regional benefits of non-transmission solutions.
- To the extent there are concerns with market barriers, *market incentives* targeted to overcome those barriers are a more appropriate remedial mechanism than subsidies.

Through utilization of this approach, market-based investments would be encouraged by effective market signals, with cost recovery and market related risks borne by the market based providers. If the market does not fully satisfy the system needs and state agencies elect to implement public policy corrections to the market, cost recovery for such initiatives should be through state and local non-transmission tariff charges. Federally regulated transmission rates would be used to reflect collection of costs for regulated transmission assets.

Alternative Approach B: Permit cost recovery for both transmission and non-transmission investments: Like proponents of alternative A, supporters of this alternative advocate the use of market driven approaches to meet regional needs. However, when the market fails to respond, FERC and state utility regulators should apply an "efficient reliability" test, based on principles of cost minimization and resource neutrality when considering proposals to recover the costs of system improvements through wholesale rules and tariffs.

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involving non-transmission assets, in order to prevent a reliability criteria violation while a more long-term backstop solution is pursued. However, such solicitations should be made only in limited circumstances and for a limited duration. Beyond these limited circumstances, if a state chooses to recover from its own customers the costs of market-based resources in local regulated rates, that state should be free to do so. Although the letter does not explicitly state how the costs of "stop-gap" emergency generation or demand-management initiatives would be recovered, it does clearly state that the Commissions *"oppose using regulated transmission rates to regionally pay for the costs of other [non-transmission] resources."* The advocates of Alternative Approach A support the Commissions' position.

Some NEDRI participants[181] believe that public intervention to resolve reliability problems should consider both transmission and non-transmission options on an even-handed basis. They hold that when the cost of those interventions is proposed to be recovered through regulated rates or uplift charges, investment decisions should be governed by two important principles:

- *Minimizing costs and maximizing value:* A principal criterion for selecting a solution that is qualified to receive socialized support should be whether it is the lowest-cost, reasonably available solution to an unmet system need, considered on a total cost basis.[182]
- *Resource neutrality*: Demand Response resources– in addition to traditional generation and transmission resources -- are all potentially cost-effective means of meeting reliability needs identified by system operators and power pool managers. When cost recovery is sought through regulated rate or uplift tariffs, that all available resources – transmission, strategic generation, or demand-response resources -- should be treated comparably both in analysis and in access to funding.

Under this approach, the burden of demonstrating compliance with these standards would lie with the entity that is proposing an investment, or seeking cost recovery for it. Thus, before authorizing rate recovery for a proposed reliability-enhancing investment through tariff, uplift, or other cost-sharing requirement, FERC and any relevant state PUC would require the applicant to demonstrate:

(1) That careful consideration was given to all resources – generation, transmission, and demand-response resources – capable of addressing an emerging reliability problem identified in the planning process;
(2) That the proposed investment provides the greatest value /lowest cost solution that is reasonably available to correct a reliability challenge that is not being addressed by market participants; and
(3) That benefits from the investment will be widespread, and thus appropriate for support through broad-based funding.

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[181] Proponents supporting Approach B include Connecticut Office of Consumer Counsel, Connecticut Department of Environmental Protection, Demand Response and Advanced Metering Coalition, Environment Northeast, US Environmental Protection Agency, Joint Demand Response Resource Supporters, Maine Public Advocate, Massachusetts Department of Environmentl Protection, National Association of Energy Service Companies, Northeast Energy Efficiency Partnerships Northeast States for Coordinated Air Use Management, PACE University Energy Project, Price Responsive Load Coalition, Union of Concerned Scientists, Vermont Department of Public Service and Vermont Energy Investment Corporation.

[182] It is important to recognize that different solutions will bring different values to this analysis. Demand-side solutions may be less certain than investments in "hard" assets, but they can lower line losses and distribution costs, and will likely deliver power cost and environmental savings, as well as the grid enhancements being sought. Policy discussion should consider all of these costs and savings when considering the net project costs of demand-side option. A further question is whether non-electric societal values (air quality, water quality and supply, for example) would factor in.

A key element of this "all resources" approach is that the opportunity for cost recovery should be comparable among competing resource solutions. Comparability between transmission and non-transmission investments can be achieved in a variety of ways. One option is to authorize wires companies to assemble an array of resources to resolve grid problems on a least-cost basis. (This approach is discussed in the following section). Another option is to issue a Request for Solutions, in which the responsible decision-maker solicits proposals from suppliers of competing resources (supply, DRR, and/or wires) who must offer realistic solutions to meet defined reliability standards.[183] In either case, under this approach, cost recovery would be available for both transmission and non-transmission components of the winning solution on a comparable basis.

Proponents of this approach have advanced several reasons to support it. They assert:

- It will lower the costs of addressing transmission constraints. This is accomplished by expanding the range of options that can be used to meet service delivery needs and ensuring that the option providing the best combination of reliability and cost is selected.
- It can provide additional economic benefits that exclusive reliance on investments in wires would forgo. For example, if energy efficiency investments are used to address transmission constraints, the system will also realize savings in distribution system investments, capacity and energy savings, lower consumer exposure to fuel price fluctuations and environmental compliance costs, reductions in market clearing prices at times of system peak, etc.
- It can provide environmental benefits that exclusive reliance on investments in wires would forgo. Where energy efficiency investments are used to address transmission constraints, air emissions of numerous pollutants will be lower than they would under a wires-only investment policy because less energy would be needed to meet customer demand.
- It can reduce the financial cost and risk of inaccurate demand forecasts. Conclusions regarding future transmission constraints are based on assumptions about future demand growth. Such forecasts are necessarily uncertain. Efficiency investments can reduce the uncertainty associated with those forecasts because efficiency opportunities are associated with load growth. Moreover, major transmission lines or expansions tend to be very "lumpy," while distributed options are more modular and may be more easily adjusted to changing circumstances.
- It would improve the likelihood of sound market solutions. Regulatory interventions to pay for transmission are not market-neutral; they *lower the value* of merchant transmission options, and of load center resources of all kinds, and

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183 This potential approach was addressed in the National Transmission Grid Study, which recommends that "(w)here possible, solutions to bottlenecks should be solicited through open, competitive processes that allow private developers to offer proposals that might encompass new transmission facilities, non-transmission alternatives, or both." A major challenge in attempts to expose transmission to "all-source" bids is the asymmetry in risks to investors. Transmission costs can usually be recovered in non-bypassable, tariffed rates. Absent a comparability rule, providers of non-transmission alternatives have no such option, and thus must assume a much higher set of market and investment risks.

add value to remote resources. Even the potential that such actions may occur will influence investment and locational decisions by generators, demand-side providers, and transmission companies.

- Investments in efficiency and some other non-wires solutions can have significant regional benefits. In addition to addressing congestion and reliability problems, reductions in load and/or increased generation within load pockets can release transmission capacity for use by others, improve reserve margins, lower regional market-clearing prices, reduce regional fuel price volatility risk, and reduce regional environmental problems.
- Finally, a process that examines and deploys all resources will make transmission siting efforts more successful, because the public will have confidence in the conclusion that the facilities are needed.[184]

In making this recommendation, proponents note that they are not recommending a comprehensive least-cost planning procedure for the New England Power Pool or the region. Comprehensive utility planning has been put aside in most New England states in favor of increased market competition, or (in Vermont) is still practiced by local utilities under state authority. The efficient reliability test would be triggered only in those instances where governmental decision-makers are intervening in the market to acquire resources, such as transmission upgrades, that will be paid for through utility tariffs, and not through voluntary market prices.

Alternative Approach C: Permit cost recovery for reliability solutions, including non-transmission components, implemented by transmission providers: Regulators should permit recovery of both transmission and non-transmission costs when they are incurred by transmission providers to resolve grid problems through planned actions that are consistent with the principles of cost minimization and resource neutrality.

Some NEDRI participants[185] support an approach that recognizes the potential value of non-transmission investments to resolve grid problems, but which focuses responsibility on transmission providers to develop them. This approach is consistent with the general goals of cost minimization and resource neutrality, discussed above, but differs in placing the responsibility and cost recovery roles for all aspects of a reliability solution with the transmission provider.

While recognizing that competition between transmission and non-transmission investments could be achieved in a variety of ways, proponents of this approach conclude that cost recovery for non-transmission solutions should be limited to circumstances in which they are acquired *by a transmission provider* as part of that provider's solution mix

[184] This applies in all states, but is even more needed in states with a least-cost mandate in their siting processes.
[185] Proponents supporting Approach C include: Joint Demand Response Resource Supporters, Northeast Energy Efficiency Partnerships, and PACE University Energy Project. While preferring Option B, these NEDRI members also believe Option C has some merit.

to a set of reliability or congestion problems.[186] Two assertions govern this conclusion. First, the principles of resource neutrality and cost minimization help to ensure that high-value and low-cost solutions to grid problems can be funded, and therefore made available to resolve grid problems and serve customer needs. But at the same time, there is little experience in the industry with deploying non-transmission resources to meet reliability goals. Transmission providers and reliability managers are concerned that such resources must be reliably provided, monitored over time, and properly accounted for.

By placing responsibility to acquire demand response and other non-transmission resources with transmission providers, this approach would seek to ensure their delivery when they offer superior opportunities to the grid and to customers. And by providing cost recovery opportunities to transmission providers for those investments, it would seek to ensure that transmission providers can invest in them and/or require their delivery and maintenance by others over time. For these reasons, in the case of mixed or non-transmission solutions by wires companies, all elements of the least-cost solution would be eligible for cost recovery in regulated rates on comparable terms.

Recommendations -- Distribution Power System Planning

Throughout New England, electric distribution is a fully-regulated monopoly function, and the total costs of distribution comprise a substantial portion of the overall cost of electric service, significantly exceeding the cost of transmission.[187] Rapid and/or concentrated load growth on portions of the distribution system can impose reliability problems and expensive upgrades on local networks. Demand response resources that are targeted to those hot spots can quickly moderate local reliability problems, and can defer costly upgrades, lowering the cost of distribution services.

Distribution utility companies should organize a planning process for the distribution system that identifies the locations on the local grid that could benefit most from targeted addition of energy efficiency and other demand response resources. They should seek to deploy those resources through their own actions, by targeting state and regional DR efforts, and by offering distribution credits to those deploying especially valuable demand resources on the local grid.[188]

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[186] This approach is also consistent with Recommendation 2, above, on incentive regulation for wires companies. Encouraging the use of performance-based ratemaking that would give transmission providers a clear financial incentive to pursue high-quality grid solutions at lower costs. It is also responsive to a question posed by FERC in its recent policy proposal on transmission investments, which states: "We realize that the most timely and cost-effective ways to meet demand for additional grid capacity will not always be additional transmission facilities; rather, they may be innovative operating practices, …distributed generation, demand response or demand-side management. We invite comments on what actions other than investments in new facilities should receive incentives, what form those incentives should take, and how we can encourage them."

[187] Distribution rates are often seven or eight times higher than transmission rates per kWh delivered.

[188] Many distribution systems also operate a transmission system to interconnect its local feeders. Upgrades to this system may be entirely in responsibility of the distribution company. This section focuses on distribution company level issues, so the discussion in this section applies to this category of transmission facilities.

Recommendation PD-7:

New England's electric distribution companies should seek out and acquire cost-effective demand side resources that would improve the reliability, operation and economics of the local distribution system.

In particular,

- Distribution utilities should identify promising opportunities for effective demand response resources (DRR) on the distribution grid, and implement pilot projects in which DRR are deployed to reliably defer distribution investments;
- Where pilot programs demonstrate that DRR can cost-effectively meet reliability objectives, distribution utilities should expand their planning processes in order to consider all available resources to meet distribution needs on a cost-effective basis, and should seek to acquire DRR in similar high-value situations across their service territories;
- Investments or expenditures in DRR approved by state regulators should be afforded cost recovery, including a return on investment or other performance incentives, on a comparable basis with investments in traditional distribution facilities; and
- Regulators should examine regulatory policies for distribution to see how they might be improved to support deployment of DRR to improve local distribution services.

Discussion

Regional and distribution needs differ. Compared to transmission-level challenges, distribution-level problems are much more localized, both in space and time. Distribution managers are concerned with peak loads on individual transformers, feeders, and lines. These peaks may be driven by very specific customers or events and may, and often do, occur at different times of the day or year than do system peaks and may grow even when the total system peak declines. The planning horizon for the distribution system also differs from that of the transmission and generation sectors and is often shorter (e.g., sometimes as little as weeks or months out to three to five years).

For these reasons, distributed resources policies and programs that address regional peak load challenges and large-scale transmission needs, will not necessarily provide the most economic or reliable solutions to local distribution concerns. Those concerns should be addressed through a distribution planning and investment process that identifies reliability needs on a localized basis, and is open to the most cost-effective solutions, including various distributed resources, to address them.

Implementing distributed utility planning – the need for pilot programs.
Growing experience with distributed resources, strongly suggests that some distribution expansion and reliability needs can be met with distributed resources, including dispatchable demand response, distributed generation, and long-term energy efficiency,

The distribution company may enjoy avoided or delayed investment costs[189], reduced energy cost volatility, more economical provision of ancillary services and other benefits by deploying these resources.

However, experience with distributed utility planning in New England is still rather limited.[190] Modifying the distribution system planning process to seek out and acquire customer resources will require careful attention, both by utilities and by regulatory agencies. NEDRI recommends that distribution utilities and state regulators seek out high-value locations to conduct pilot programs for the use of DRR to meet local reliability goals. In particular, they should focus on those local areas and facilities that are challenged by historic or pending growth, and where a concentration of DRR could provide immediate value.[191] The utility could demonstrate the concept with attention to details of process and staffing requirements, and then scale it up to the rest of the service area.

Distribution planning traditions and opportunities. Distribution engineers have, for decades, largely considered similar approaches to plan and expand the system and to solve specific problems. Because of safety and reliability concerns, distribution utilities have not typically embraced solutions that lie on the customer's side of the meter. Fairly rigorous and prescriptive engineering criteria have driven the decision-making process. Engineering solutions usually include higher capacity wires and transformers or other system add-ons, such as capacitors that are wholly in control of the utility.[192] The overriding need for adequate and reliable power delivery can inhibit the consideration and adoption of alternative and potentially less costly means of serving customers.

DRR have rarely been identified or pursued based upon their particular value to the distribution system, as opposed to their more general value in deferring overall load growth or overall system peaks.[193] However, the distribution utility is in a strong position

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[189] Even where demand-side alternatives do not permanently avoid distribution investments, they can still provide meaningful value by delaying more expensive investments and deferring their capital costs.

[190] A particularly instructive exception is Green Mountain Power's Mad River Valley project, in which an expensive feeder and substation upgrade was consciously deferred through targeted energy efficiency and load management in the service area surrounding a substation in one of Vermont's rapidly-growing ski area communities. *See* Cowart, et al., "Distributed Resources and Electric System Reliability," (RAP 2001) at pp16-18. (posted at www.raponline.org) This report also describes (at pp. 15-16) an extensive program by Commonwealth Edison (now Exelon) to target distributed resources to stressed local circuits as part of a major distribution system upgrade in Chicago.

[191] National Grid is testing this concept in Brockton, MA, and in several other locations. *See*, Massachusetts Electric Report on the Load Curtailment Pilot Program in Brockton, October 31, 2002,. In Vermont, utilities are working with regulators on how to implement distributed utility planning. *See* Vermont PSB docket 6290.

[192] Distribution system costs can generally be divided into two groups: transformers and substations, and lines and feeders. Transformers and substations are both the first and intermediate interfaces between transmission and customer-level service. Feeders generally connect the highest voltage transformers to intermediate level transformers. Lines carry the lowest distribution voltage power to individual customer transformers and drop lines.

[193] Interruptible contracts, in which the customer receives a discount in return for accepting the chance of some interruptions, are a partial exception. They are sometimes used to defer local system upgrades. In most cases, however, there has been an expectation that the utility would not use these interruption options;

to call forth DRR to strengthen the local grid. The distribution company occupies a pivotal place with respect to the delivery of demand response resources. It has a mandate to operate its system efficiently, and to achieve reliability objectives. It has a deep connection to customers, and it has the opportunity to deploy cost-effective resources and to include DRR costs in rates when they will lower the cost of distribution service.

All-resources distribution planning process. What would an enhanced distribution planning enterprise look like? First, the planning horizon would be as long as demand forecasts allow. Distribution companies would enhance their effort to project increased electricity use of their customers by getting a discrete understanding of each distribution system planning area or circuit. In the hub and spoke design of most distribution systems, the company would approach each planning area or circuit as a system.

With each area or circuit characterized by expected customer needs, the distribution planner determines if there is a potential need for investment within the planning horizon. If so, there is now an avoidable cost specific to the circuit. Alternatives on both sides of the meter can be considered to address the need.[194]

The cost of customer-based alternatives would include the cost of any incentives needed to enroll customers. These costs could include more intensive efforts or higher cost-shares for energy efficiency than are typical elsewhere in the service territory, incentives to customers to install distributed generation, and payments under demand response tariffs.[195]

As part of the analysis of trade-offs, each utility or regulatory body would have to choose a methodology to consider alternative resources and resource combinations. Most NEDRI members support states considering the adoption of a broad-based societal or total resource cost methodology that reflects all values, including risk and environmental factors.[196]

Implementing distributed utility planning – three policy changes should be considered.

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moreover, since customers could opt out of the relationship on relatively short notice, distribution planners have not wanted to rely on them to protect distribution-level reliability.

[194] If not, utility-wide or region-wide needs may still call forth customer resources from the circuit.

[195] For distributed generation, there are three important points to keep in mind. First, there should be an interconnection standard available to accommodate those combined energy and power installations where economics are served by a grid connection. Second, there should be a cost-based tariff for back-up power. Third, distributed generation should not create or exacerbate air quality problems. *See, e.g.,* "Model Regulations for the Output of Specified Air Emissions from Smaller-Scale Electric Generation Resources," Regulatory Assistance Project, October 31, 2002.

[196] Some jurisdictions prefer to focus only on market-oriented values. If so, the "ratepayer-impact test," which seeks to assure that no customer's rates are raised due to the investment in question, would be particularly inappropriate. It would make no sense to apply the test to DR investments that defer distribution upgrades if it were not also applied to the upgrade itself. NEDRI is unaware of a utility or commission that has ever applied the RIM test to proposed distribution upgrades needed for local reliability.

State regulatory commissions should consider and examine three types of policy changes that support cost-effective distribution investment practices:

- First, distribution company regulators should consider adopting rules that would require the distribution planning process to consider DRR when resolving growth and reliability problems on local distribution systems.
- Second, they should consider examining tariffs and policies for special contracts that would accommodate the incentives or credits necessary to enroll customer resources in distribution support programs. States may wish to adopt new tariffs to reflect these new financial relationships, which differ from the averaged distribution rates and bases for interruptible contracts now in effect.[197]

Third, states should also consider examining whether current ratemaking policies linking the distribution company's corporate net income to the quantity of energy delivered[198] create a barrier to acquiring valuable customer resources. Because distribution tariffs are heavily weighted to volumetric sales, customer energy efficiency tends to reduce net margins, at least in the periods between rate cases.[199] Performance-based ratemaking plans for distribution utilities, and policies that provide stable revenues regardless of sales volume are options that regulators could examine to remove this barrier and reward utilities for lowering overall distribution costs.[200]

[197] These contracts could include localized distribution credits to customers that provide valuable deferral or reliability services to the local grid. The use of special distributed resource credits can encourage customers to install needed resources in the high-cost parts of the system or as part of a customer-specific development, thereby avoiding more costly investments in distribution. This helps overcome customer barriers to investment in distributed resources and secures the investment value for the utility and its customers. *See* Moskovitz, et al, "Distributed Resource Distribution Credit Pilot Programs: Revealing the Value to Consumers and Vendors" (RAP 2001) posted at www.raponline.org.

[198] See footnote #168 on throughput.

[199] The reality is that there is significant electricity sales growth on most distribution systems. Even if this growth in electricity service demand is offset 100% by DR resources, utility net income from sales will not suffer based on costs from the most recent rate case, though it may not match historic expectations.

[200] These policies are described more fully in Moskovitz, et al. "Profits and Progress Through Distributed Resources," (RAP February 2000) posted at www.raponline.org.

GLOSSARY

Advanced Metering (AM): Electricity meters and associated equipment that can, to varying degrees, record, process, and transmit time specific information about a customer's electricity usage. Interval metering, recording at least hourly usage data, is the basic and most common form of advanced metering.

Ancillary Services: Those services necessary to support the transmission of electric power from seller to purchaser, given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system. Ancillary services include contingency reserves, regulation, voltage control, system black-start capability, and various other services.

Contingency Reserve: The set of ancillary services that consist of providing reserve capacity to respond to sudden failures of generation or transmission facilities. Three types of contingency reserves are typically provided: spinning reserves, supplemental reserves, and replacement reserves.

Control Performance Standard: Standards established by the North American Electric Reliability Council relating to how closely a control area operator must maintain the instantaneous balance between supply and demand, in order to ensure sufficient reliability.

Critical Peak Pricing(CPP): A retail electricity pricing rate on which customers are charged a high price during a limited number of critical peak periods initiated in response to electricity market or system conditions such as wholesale price spikes or supply shortages. Depending on the particular tariff, the critical peak price may either be fixed at a pre-determined level or varied to reflect short-term market or system conditions. Critical peak pricing may be combined either with a standard Time-of-Use rate or a flat rate.

Curtailment Service Provider: See "Demand Response Provider".

Customer Baseline Load: In a demand response program, the estimated load that a customer would have consumed in the absence of the demand response event. The customer is paid for their load reduction based upon the difference between their customer baseline load and their actual load during the event. In a two-part real time pricing tariff, the customer baseline load refers to the load that is purchased at a pre-determined fixed price.

Default Service: The retail electricity service in a competitive market that is automatically provided to those customers who have not elected to switch to a competitive supplier; often also referred to as "standard offer service." Default service is regulated by the state public utilities commission and may be provided by the incumbent regulated utility or by third parties selected through a competitive solicitation. (Note: Some states distinguish between "standard offer" and "default" service, reserving the term "default service" for situations in which customers have chosen a competitive supplier, but have lost that service due to nonpayment, the provider's withdrawal from the market, etc.)

Demand Response: Demand Response includes all intentional modifications to the electric consumption patterns of end-use customers that are intended to modify the timing or quantity (including both the level of instantaneous demand (capacity), and total consumption (in kWh or MWh) of customer demand on the power system.

Demand Response Resource: DR resources include load curtailments, customer response to price, customer-based generation and longer-term investments in the energy efficiency of end uses.

Demand Response Provider: An entity in a demand response program that serves as an intermediary between individual customers and the ISO/RTO. A demand response provider aggregates individual customers, coordinating the demand response event notification, measurement and verification, and billing and settlement for those customers. Any number of possible entities may potentially serve as a demand response provider, including regulated utilities, competitive electricity service providers, and energy service companies or other third parties.

Disturbance Control Standard: A set of performance measures established by the North American Electric Reliability Council that pertain to the recovery from major generator or transmission outages. Among other things, the disturbance control standard specifies the amount of contingency reserves that must be maintained and the speed with which the control-area operator must recover from a major disturbance.

Electricity Service Provider: A competitive provider of retail electricity service.

Energy Efficiency: Reducing the energy used by end-use devices and systems while maintaining comparable service, generally achieved by substituting technically more advanced equipment and practices to produce the same level of end-use service with less electricity.

Energy Service Company: A company that provides design, installation, project management, and/or financing for energy efficiency retrofits, distributed generation projects, and/or building commissioning.

Financial Transmission Rights: A financial instrument for which the holder is paid or pays based on the difference in the locational marginal prices between two points in an electricity network.

Installed Capacity: The dependable generation and demand response capacity that each load serving entity must own or procure a commitment of availability from; also called "Installed Capability".

Inverted Block Rate: A retail electricity rate on which customers are charged progressively higher flat rates for successive increments of electricity usage in each billing cycle.

Load Serving Entity (LSE): The generic term for a retail provider of electricity service, either a competitive supplier or a regulated utility.

Locational Marginal Prices(LMP): Wholesale spot market electricity prices defined for individual zones within the control area of an independent or regional transmission operator.

Operating Reserve: See "Contingency Reserve".

Price Capped Load Bidding: One mechanism for incorporating demand response into wholesale energy markets, whereby load serving entities are able to bid different levels of load at different prices

Real Time Pricing (RTP) Rate: A retail electricity rate on which customers are charged prices that vary by hour and reflect hourly variations in wholesale electricity prices. Real time pricing tariffs may vary with respect to a number of other options, such as the availability of price hedging options (e.g., price collars) and the components of the electricity service (generation, transmission, and distribution) billed at the hourly rates.

Regional Demand Response (RDR) Programs: The generic term for wholesale (i.e., RTO or ISO-sponsored) programs that provide payments for load reductions in response to system emergencies or spot-market energy prices, including those programs that allow demand response providers to bid load reductions into energy markets.

Regional Transmission Expansion Plan (RTEP): A process administered by ISO-NE to identify regional transmission constraints and recommend potential transmission projects needed to ensure system reliability and efficiency.

Replacement Reserve: The type of contingency reserves requiring the least rapid response, used to replace spinning and supplemental reserves to their pre-contingency status. Units providing replacement reserves are not required to respond immediately and must reach full output within 30 minutes.

Spinning Reserve: The type of contingency reserves requiring the most rapid response. Providers of spinning reserve must be able to immediately respond to a major outage and reach full output within 10 minutes.

Standard Market Design (SMD): A set of proposals by the Federal Energy Regulatory Commission to establish standardized wholesale electricity market rules and practices.

Standard Offer Service: See “Default Service”.

Supplemental Reserve: A type of contingency reserves similar to spinning reserves, except that the unit is not required to respond immediately, although it still must reach full output within 10 minutes.

System Benefits Charge (SBC): A non-bypassable per kWh charge, established by state legislatures and/or regulators, that is assessed on all or most customers of the state’s regulated distribution utilities and is used to fund energy efficiency and other public benefits programs, such as low income assistance, renewable energy, and research and development.

Time of Use Rate (TOU): A retail electricity rate on which customers are charged according fixed price tiers that apply to specified times of the day and days of the week.

APPENDIX A: NEDRI PARTICIPATION (MEMBERS AND GUESTS)

Attendance by Organization

Organization	26-Feb	2-Apr	2-May	4-Jun	25-Jun	16-Jul	10-Sep	8-Oct	19-Nov	10-Dec	15-Jan	11-Feb	10-Feb	25-Mar	26-Mar	8-May	18-Jun	19-Jun	23-July
AES New Energy		x	x				x		x	x									
AIM		x				x	x	x	x	x									
CT Consumer Counsel						x		x	x	x	x	x	x	x	x	x	x	x	
CT DEP	x	x	x		x		x	x	x	x	x			x	x		x	x	
CT PUC	x	x	x	x	x	x	x	x	x		x			x	x	x	x	x	x
DRAM	x	x	x	x	x	x	x	x	x		x		x				x	x	
EPA	x	x	x	x	x	x	x	x	x	x	x		x	x	x	x	x	x	x
Environment Northeast				x			x	x									x	X	X
FERC							x	x	x	x		x							
HEFA	x	x	x	x	x	x	x	x	x	x	x	x	x			x			x
ISO-NE	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
Joint DRR Supporters	x	x		x	x	x	x	x	x	x				x		x	x	x	x
Low Income Network	x			x		x	x	x	x		x	x	x						
MA DEP	x	x	x		x	x	x		x	x									
MA DOER	x	x		x	x	x	x	x	x	x		x	x	x	x	x	x		x
MA DTE	x	x	x	x		x	x	x		x	x			x		x			
Maine PUC	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	
ME Public Advocate	x		x	x		x		x	x	x	x		x	x	x	x			x
Mirant	x	x	x		x			x	x	x									
MTC	x	2	x	x	x	x	x	x	x				x	x					
NAESCo	x	x	x	x	x		x	x	x	x	x	x	x	x	x	x	x	x	
National Grid	x	x	x	x	x		x	x	x	x		x	x		x	x	x		x
NECPUC	x				x			x	x		x	x	x			x			

Organization	26-Feb	2-Apr	2-May	4-Jun	25-Jun	16-Jul	10-Sep	8-Oct	19-Nov	10-Dec	15-Jan	11-Feb	10-Feb	25-Mar	26-Mar	8-May	18-Jun	19-Jun	23-July
NEEP	x	x		x	x		x	x	x	x	x	x	x	x					
NESCAUM		x	x	x	x	x	x	x	x	x	x	x	x						
NH PUC	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x				
Northeast Utilities		x	x	x	x	x	x		x	x	x		x			x	x	x	x
NY ISO	x	x	x	x			x										x	x	
PACE	x	x	x			x	x	x	x	x				x	x	x	x		x
PG&E	x	x	x		x	x		x	x	x		x							
PJM				x					x	x	x	x	x		x	x	x	x	x
PRL Coalition								x	x	x	x			x	x		x	x	x
RETX/PLMA		x	x	x	x	x	x		x	x	x		x	x					
RI PUC		x	x	x	x	x	x		x										
Sithe	x		x					x											
Union Concerned Scientists	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	
United Illuminating			X2	x	x	x	x	x	x								x		x
US DOE							x	x	x										
US EPA							x	x									x		
VEIC		x		x	x	x	x	x	x	x	x	x	x	x	x	X*	x		
VT DPS		x	x	x	x	x	x	x											
VT PSB	x		x	x	x	x	x	x	x			x	x	x	x	x	x	x	x
Guests																			
PJA Energy Systems Design		x	x	x	x	x	x	x	x	x	x	x	x				x	x	
Northeast Energy Efficiency Council		x				x													
Praxair			x																
PSE&G						x	x	x	x	x	x	x	x				x	x	
Xenergy / KEMA	x						x												

Organization	**26-Feb**	**2-Apr**	**2-May**	**4-Jun**	**25-Jun**	**16-Jul**	**10-Sep**	**8-Oct**	**19-Nov**	**10-Dec**	**15-Jan**	**11-Feb**	**10-Feb**	**25-Mar**	**26-Mar**	**8-May**	**18-Jun**	**19-Jun**	**23-July**
Consulting/Facilitation Team																			
Raab Associates	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	
RAP	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	
Lawrence Berkeley Labs	x	x	x		x	x	x	x	x			x	x			x	x	x	
Consultant		x					x		x					x	x				
Oak Ridge Nat'l Labs										x						x			
Consultant				x		x	x	x	x	x	x	x	x	x	x		x		

* Numerous organizations often sent multiple people.

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PLMA	Leo Desjardins
PRL Coalition	Aaron Breidenbaugh
RI PUC	Doug Hartley
Sithe	John O'Brien
Union of Concerned Scientists	Lucy Johnston
United Illuminating	Pat McDonnell
	Roger Parisi
US DOE	Larry Mansueti
US EPA	Bill White
	Rick Morgan
	Tom Kerr
VEIC	Chris Neme
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Vt. PSB	Michael Dworkin
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	Ann Bishop

APPENDIX B: SUMMARY OF RECOMMENDATIONS

NEW ENGLAND DEMAND RESPONSE INITIATIVE

NEDRI Recommendations

June 25, 2003

NEDRI participants have developed policy and program recommendations to support Demand Response Resources in New England across a broad range of relevant issue areas. The recommendations in each issue area are set out below. For background material and discussion of each recommendation, please see the full NEDRI Report.

CHAPTER 2: REGIONAL DEMAND RESPONSE PROGRAMS[201]

A. Recommendations on ISO-NE's Demand Response Program Designs

Recommendation RDR-1: Strengthen the Real-Time Demand Response Program (RT-EDRP)

We recommend that ISO-NE file a revised real-time, "emergency" demand response program with FERC for adoption in 2003. That program should incorporate the four specific features set out below:

- *Higher minimum floor payments for called resources.*
- *Lower entry barriers for Demand Response Providers*.
- *A longer-term commitment to DR programs*.
- *ICAP treatment that incorporates credit for reduced reserve requirements*

Recommendation RDR-2: Strengthen the Day-Ahead Demand Response Program (DADRP):

ISO-NE's proposed DADRP is a reliability-focused program, in contrast to the more price-driven day-ahead market programs in other regions. While we recommend that the ISO investigate development of a basic, economic, day-ahead market DR program (see Recommendation #4 below), we also recommend improvements to the

[201] Recommendations RDR 1-8 were formally adopted by NEDRI in January 2003, were filed at FERC shortly thereafter, and in large measure were accepted by FERC in orders dated February 25, 2003 (Docket no. ER01-3086-001) and June 6, 2003 (Docket no. ER02-2330-004). No additional action on these recommendations is being taken by NEDRI at this time. Recommendations #9-11 were approved in the June 18-19, 2003 NEDRI meeting.

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reliability-oriented day-ahead market program planned for 2003. ISO-NE should file a revised "reliability-oriented" day-ahead demand response program (DADRP-R) for adoption in 2003. The DADRP program should incorporate the following five features,

- *Greater flexibility in bidding increments*.
- *Greater flexibility in bidding process*.

In addition to the two revisions above, NEDRI recommends three changes to the ISO-NE's Day-Ahead DR Program that are also recommended for the Emergency Program above. Those recommendations are:

- *Lower entry barriers for Demand Response Providers.*
- *A longer-term commitment to DR programs, and*
- *ICAP treatment that incorporates credit for reduced reserve requirements* (See discussion at recommendation #5 below).

Finally, after discussion of the FERC's Order of December 20, 2002 on New England market design issues, NEDRI recommends two additional changes for this program. Those recommendations are:

- *Permit demand resources to enroll in both the Day-Ahead and Real-Time programs.*
- *Equal bid ceilings for demand and supply resources*

Recommendation RDR-3: Develop an Economic, Price-Driven Day Ahead Market DR Program by 2004

Although ISO-NE has proposed an "emergency" and a "day-ahead" DR program for 2003, a close look at the way they would operate reveals that both are essentially reliability-focused programs. In contrast to NYISO and PJM, NE-ISO does not presently plan to offer a day-ahead, economic DR program in which DR resources would be called solely on an economic, bid-based basis. We recommend that ISO-NE commit to developing an "economic, price-driven" day-ahead market demand response program by summer 2004. In designing this program, the ISO should use the NEDRI program design as a starting place (See attached Program Strategy RDR #2 - Day-Ahead DR – Economic) and should draw upon best practices and recent experience in other regions of the country.

B. Related Actions Needed to Support Regional Demand Response Programs

Recommendation RDR-4: Monitor and Limit Environmental Impacts of Demand Response Programs

- Adopt output-based, technology-neutral standards for new on-site generators.
- Update state regulations for existing generators.
- Provide an information base for environmental analysis of DR program impacts.

With respect to ISO New England's Summer 2003 Day-Ahead Demand Response and Real-Time Price Response Programs, NEDRI recommends the following:

- ISO New England should require Demand Response Providers to provide information on any on-site generators their customers plan to use in conjunction with load response events in the above-mentioned programs.
- Air regulators will work collaboratively with Demand Response Providers and others to develop a user-friendly interface and process for customers owning on-site generation to expedite processing of requests for permits and waivers (for those without permits).
- ISO New England will make information on actual load response events available to air regulators for purposes of evaluating the potential environmental impacts of load response programs.

Recommendation RDR-5: Provide Location-Based Capacity Credits to DR Resources

- NEDRI recommends that ISO-NE implement an effective, location-based ICAP resource credit for demand response resources as soon as possible.[202]
- Until ISO-NE implements locational ICAP, we recommend that the ISO continue to develop interim solutions to encourage demand response and supply resources in congested, constrained regions. These interim solutions may include additional financial support from utility ratepayers or states, such as capacity reservation payments ($/kW), in order to address local reliability problems in constrained areas during the transition to effective location-based wholesale electricity markets (e.g., ICAP).

Recommendation RDR-6: Provide Adequate Resources and Cost Recovery for DR Programs[203]

If Regional Demand Response programs are to succeed, they must be adequately funded, and those incurring costs must have a fair prospect of recovering them in rates. In addition, regulatory policy at the retail level should give potential competitive demand response providers a viable commercial opportunity to enroll customers in competition with default service providers and distribution wires companies. For these reasons, we recommend:

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[202] National Grid and United Illuminating do not support the implementation of location-based ICAP in New England. Northeast Utilities believes that alternative solutions to location-based ICAP need to be explored.

[203] To the extent the language in this recommendation expresses a preference for regulatory intervention in demand response, National Grid and United Illuminating do not support this recommendation and specifically do not support the allocation of these costs to network load. The other NEDRI members do not believe that this recommendation expresses such a preference.

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- *Allocate 2003 ISO RDR program costs to network load.*
- *Review cost allocation alternatives for 2004 and beyond.*
- *New England State regulators should adopt retail tariffs and policies that support delivery of the ISO's Day-Ahead and Real-Time (Emergency) Demand Response Programs.*

Recommendation RDR-7: Evaluate and Improve Demand Response Programs

- *Conduct an Independent Assessment and Impact Evaluation.*
- *Enhance Effectiveness of the Regional Demand Response Working Group.*
  We recommend that ISO-NE seek more input from customers and DR market participants on DR policy and program designs using a Regional Demand Response Working Group.

Recommendation RDR-8: Adopt Performance-Based Metering and Telemetry Standards to Reduce Unnecessary Costs for Demand Response Resources

Metering and telemetry requirements for participating in demand-response programs should be designed to provide an appropriate level of accuracy, with a goal to minimize unnecessary costs for DR services. ISO-NE, in consultation with market participants and technology experts, should develop and implement such standards.

Recommendation RDR-9: Ratepayer Funding to Overcome Market Barriers to and Increase Participation in Shorter-Term Demand Response

There is a need to overcome significant market barriers to increase customer participation in shorter-term demand response (both emergency and price-responsive programs) during the transition to effective competitive markets. NEDRI recommends that additional funds be made available to support enabling infrastructure, technical assistance, and customer education and information. Funding for these activities could come from regional and/or state sources and should be relatively small in amount and should preferably be incremental to existing state System Benefit Charge funding targeted at energy efficiency.

Recommendation RDR-10: Distributed Generation: Clean and Behind the Meter

DG that is "clean," "behind the meter," is sized at, below, or modestly above the host load, and does not export power to the grid (i.e., is on the customer's side of the meter) should be able to participate in wholesale markets (e.g., day-ahead, real-time and ancillary services markets, and capacity markets) on a comparable basis to other forms of demand response.

Recommendation RDR-11: Support Participation by "Clean" DG in Real-Time Markets

NEDRI recommends that ISO-NE allow customer-located clean DG units to sell energy in excess of customer or contract load without requiring such units to bid in the ISO markets. The metered output of such DG units registered with the ISO as Settlement Only Generators receive compensatory real-time prices (note that all generators, including Settlement Only Generators, settle at the nodal level). They also receive an ICAP credit.

CHAPTER 3: PRICING, METERING, AND DEFAULT SERVICE REFORM

Strategy Set One: Improving Pricing for Retail Customers to Allow Price-Induced Demand Response

Recommendation PM-1: Investigate Time-Sensitive Pricing for Default Service Customers

State regulatory commissions should initiate dockets to consider and determine whether default service should be provided using more time-sensitive rate designs that encourage greater economic demand response. Commissions should consider cost-based rate designs with greater time differentiation, greater emphasis on critical peaks, and greater recognition of uses that are highly peak coincident. Specifically, NEDRI recommends that commissions evaluate the applicability of the following more time-sensitive rate designs to different customer classes. NEDRI notes that this evaluation must necessarily take into account the availability and cost-effectiveness of advanced metering and other factors.

Recommendation PM-1A: Real-Time Pricing

PUCs should consider implementing some form of real-time pricing for large customers on default service (*e.g.*, those with demands greater than 200-400 kW). NEDRI is not recommending any particular real-time pricing design, but instead describes in this report several that the commissions should consider.

Recommendation PM-1B: Critical Peak Pricing

PUCs should consider rate designs for medium-size default general service customers (*e.g.*, over 100 kW initially, but less than "large" as described above) that contain a critical-peak pricing element. Depending on the outcome of the recommended metering study (Strategy 2A), the program could be extended to other customers.

Recommendation PM-1C: Inverted Block Rates

PUCs should consider replacing existing flat rates for residential and small general service default service customers with rate structures that would price levels of usage typically reached by customers with peak-coincident end-uses (*e.g.*, air conditioning) at a higher level than that for basic usage. (Examples of

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such rate structures include inverted-block rates, but could also include time-of-use rates, critical peak pricing, and separation of rate classes.)

Strategy Set Two: Strategies to Support Demand Response in the Mass Market

Recommendation PM-2A: Protocols to Assist Regulators in Evaluating Mass Market Rate Designs and the Deployment of Advanced Metering
State regulators should conduct an investigation to explore the costs, benefits, and options for providing advanced metering to mass-market customers. Within that proceeding, PUCs should also consider associated rate designs (*e.g.*, time-of-use and critical peak prices as discussed in Strategy 1C) for mass-market customers. It is through individual state examinations that the important issues of cost, technology choice, and benefits can be explored with the appropriate rigor. PUCs should not implement a rate design for low-income customers without considering its potential effects on those customers.

Recommendation PM-2B: Load Profiling
The distribution companies should continue to do load research to develop load profiles to support alternative rate design research, settlement, and demand response for mass-market customers. In addition, research on the load shapes of specific end-uses should be performed, in order to support quantification of the value of curtailable load programs such as interruptible water heating, air conditioning, or swimming pool pumping. The state PUCs should consider directing their distribution companies to establish and maintain load research programs that are adequate to support these activities. The group data and evaluation of load research programs should be available to the public.

Recommendation PM-2C: Energy Efficiency
For small residential customers, such as those with usage only in the initial block of the advanced rate designs (*e.g.*, inverted rate design) proposed above, an effective demand-response program may be energy efficiency assistance targeted to those end-uses with comparatively high peak coincidence.

Strategy Set Three: Cross-Cutting Efforts

Recommendation PM-3A: Default Service Reform
Default service should be priced at a level that recovers all relevant costs. In addition, default service suppliers have a greater incentive and better means to acquire demand response if they are responsible for serving specific customers rather than merely a share of the default service load at wholesale.

Recommendation PM-3B: Curtailable Load Programs
ISO curtailable load programs should be implemented by curtailment service providers. In the case of regulated CSPs, 70% of the funding provided by the ISO

for curtailment should flow to the customer, and 30% should be retained by the CSP to cover its costs of the program.

Recommendation PM-3C: Improving Distribution Company Participation in Demand Response Programs
Where distribution utilities deliver demand response programs, state public utility commissions should evaluate and consider implementing policies that remove financial disincentives to distribution utility support for those programs.

CHAPTER 4: ENERGY EFFICIENCY AS A DEMAND RESPONSE RESOURCE

Recommendation EE-1. System Benefit Charge (SBC) Funds and Ratepayer Support for Energy Efficiency

NEDRI stakeholders recommend:

- The goal of publicly-funded energy efficiency efforts in each state is to capture all cost-effective energy efficiency that is not being achieved in the market without intervention. The System Benefits Charge (SBC) funds and other ratepayer support in each state should be set at levels at least equal to current funding for energy efficiency. Over time, states and stakeholders should consider increasing SBC and other ratepayer funding to levels sufficient to capture all cost-effective energy efficiency.

- Within the context of multiple objectives and considering various statutes and other explicit rules in each state, states and program administrators should consider targeting energy efficiency programs funded through SBC and/or other funding sources to geographical locations with reliability needs or constraints, energy efficiency measures that reduce peak load, and savings opportunities in high-value time periods, to the extent that these are not already being addressed by the market.

Recommendation EE-2: Principles for Effective Energy Efficiency Programs and Portfolios

NEDRI recommends that New England states balance several principles in achieving effective energy efficiency programs and portfolios. Specifically, NEDRI recommends that energy efficiency programs and portfolios:

- Focus on reducing or overcoming market barriers.
- Provide opportunities for a large number and broad mix of customers to benefit from the energy efficiency programs.
- Maximize long-term savings and net benefits.
- Encourage comprehensive and whole building approaches to capture all cost-effective energy efficiency.

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- Use performance-based benchmarking to document program impacts, inform customers of the performance of their buildings, and give customers the tools to be aware of and manage their energy use.
- Capture potential lost opportunities.
- Work with product and service markets and promote market transformation.
- Increase market influence and leverage by participating in regional and national initiatives.

Recommendation EE-3. Minimum Energy Efficiency Standards for Appliances and Equipment

By reducing peak energy demand across New England, new minimum energy efficiency product standards could serve as one very low-cost and effective way to cope with projected growth in overall peak demand and address the related reliability, economic and environmental issues. A recent study estimates that New England could achieve by 2020 peak demand savings of 2,163 MW through reduced growth in electric demand, equivalent to 25 percent of projected load growth. To accomplish this, the NEDRI stakeholders recommend that New England States:

- Establish state minimum appliance and equipment energy efficiency standards.
- Adopt state standards in 2003 for ten specific products in model legislation. Standards for these ten products would provide 820 MW of load reduction by 2020.
- Coordinate efforts regionally to research, adopt, and enforce energy efficiency standards.
- Continue to participate in federal energy efficiency standards rulemakings.

Recommendation EE-4. Effective Building Energy Codes

Commercial, industrial, and residential construction activity, including remodeling and renovations, are significant drivers of load growth. A key policy to minimize the negative impacts of this growth on the regional power system is to reduce the increase in energy consumption and demand driven by new and expanded buildings by:

- Regularly updating building energy code requirements to reflect advances in design and construction practices, and equipment choices that affect building energy use, and
- Effectively implementing current building energy codes by:
    - Providing ongoing training and technical support for inspectors and builders
    - Linking ratepayer-funded energy efficiency programs with building energy code training and development

These efforts could achieve demand savings of 1,115 MW (summer peak) by 2020 compared to forecasted growth in peak demand use.

Recommendation EE-5. Enhanced Regional Coordination for Demand-Side Resources

Enhanced regional coordination could increase the effectiveness and cost-efficiency of energy efficiency efforts as a key element of demand-response policies and programs in New England. Three aspects of enhanced regional coordination should be considered – regional planning and resource assessment; regional programs; and regional research and evaluation. More specifically, NEDRI recommends that New England states consider:

- Regionally planning for and assessing the potential for demand-side resources.
- Where valuable, regionally coordinating the development and implementation of demand-side programs and policies (e.g., regional market transformation, products with regional markets or avenues of commerce, regional appliance and equipment standards).
- Evaluating the effectiveness of existing regional energy efficiency programs.
- Conducting regional research to identify new opportunities for as well as evaluating the impact of implemented demand-side resources.
- Establishing a regional coordinating council[204] for demand-side resources.

Recommendation EE-6. Complementary and Integrated Options for Energy Efficiency and Shorter-Term Demand Response

Some energy efficiency and shorter-term demand response activities could be designed and implemented to complement or be integrated with each other, to achieve synergies and increase value for customers and the electric system. New England states should pursue demand response strategies that recognize the multiple attributes and uses of demand response technologies and integrate shorter-term demand response and energy efficiency programs into complementary program offerings by:

- Making full use of demand response technologies for both energy efficiency and shorter-term demand response,
- Promoting effective and efficient facility operations and maintenance (O&M),
- Implementing comprehensive, coherent marketing programs, and
- Coordinating the administration and delivery of EE and shorter-term DR.

[204] The word “council” is used here to mean a body that would address demand-side issues.

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CHAPTER 5: OPPORTUNITIES FOR LOAD PARTICIPATION IN CONTINGENCY RESERVE MARKETS

Recommendation CR-1: ISO New England (ISO-NE) should continue efforts to design and implement markets for contingency reserve services as soon as possible after thorough consideration and review.

Recommendation CR-2: There should be a market potential study and pilot demonstrations that assess the benefits and costs of using large and small loads to provide contingency reserves. The pilot demonstrations should be reflective of the actual system logistics involved in aggregating and incorporating numerous small load resources. As part of the pilot, load research protocols for aggregations of small loads should be developed and evaluated, which may serve as a functionally equivalent alternative to traditional performance measurements used for generators. These studies and pilot demonstrations should be coordinated and led by ISO-New England. Potential support could come from US DOE, states, market participants, and others.

Recommendation CR-3: NPCC, working with ISO-NE, should ensure that the reliability rules and requirements related to Disturbance Control Standard (DCS) and contingency reserves are technology-neutral, performance-based, and applied consistently to all contingency resources. NPCC should publish engineering/economic analyses used to justify reliability rules. If demand response resources are able to provide contingency reserves in the manner that provides equal or better performance to conventional generation, then such resources should be allowed to provide contingency reserves and the rules should be changed to allow for this. These rules should recognize technical and operational differences between central station generators and small demand response resources.

Recommendation CR-4: The New England region's stakeholders and ISO New England should systematically review the current contingency reserve metering and communications requirements and consider appropriate data recording and reporting requirements for small demand response resources; any revision of these requirements must be contingent on the continued maintenance of reliability requirements.

CHAPTER 6: DEMAND RESPONSE RESOURCES AND POWER DELIVERY SYSTEMS

(*Note:* National Grid, Northeast Utilities and United Illuminating have submitted a separate statement regarding key issues in the recommendations in this chapter. See NEDRI Final Report, page 115.)

A. Market Foundations for Delivery System Planning and Investment

Recommendation PD-1: NEDRI recommends a regional resource development policy that relies chiefly on competitive markets and market signals that reveal, to the extent practicable, the temporal and locational value of energy services. NEDRI participants support the ongoing development of the region's power markets and trading rules so as to reveal those values**.**

Recommendation PD-2: Transmission and distribution providers, ISO-New England, State utility commissions, and FERC should carefully consider the value of incentive regulation plans for regulated transmission and distribution companies that would encourage those firms to lower the overall costs of power delivery for their customers.

B. Recommendations for Regional System Planning

NEDRI recommends that the ISO, regional market participants and states seek ways to enhance the ability of the regional planning process to identify the best solutions to grid problems from all types of resources – traditional grid upgrades, operational improvements, strategically-located generation, and targeted investments in demand response resources. NEDRI recognizes that the structure, authority, and governing rules for a regional planning entity will be critical to its success, but concludes that decisions on those topics will be taken in other forums. However, whatever structure is adopted for regional system planning, it must be one that accommodates a long-term view of the system, and can openly consider the potential for demand response resources to resolve grid problems. Thus, the recommendations below focus not on the structure or governance details of a regional planning entity, but on the basic principles to support an appropriate balancing of resources, including demand response resources, in resolving power system challenges.

Recommendation PD-3: Conduct a continuing, regional power system planning process, involving the ISO, appropriate state agencies, and other stakeholders to identify system needs and consider alternative strategies to meet them**.**

Recommendation PD-4: The regional power system planning process should evaluate on an even-handed basis all feasible, comparable solutions to emerging problems including generation, transmission, and demand-response resources.

C. Recommendations -- Regional Power System Investment Policy

The regional system planning process outlined above provides the critical foundation for major power system enhancements. Most significantly, it will identify emerging reliability and persistent congestion problems, and consider potential solutions that could mitigate or resolve them. System operators have traditionally focused on supply-side resources in meeting reliability requirements for electric networks, especially in periods

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of stress. However, in appropriate instances, demand response resources may offer substantial value as part of a mix of resources to meet system needs. In this section, NEDRI recommends: (a) that the region rely first upon market forces and participants to fill any pending resource "gaps" identified in the planning process; and (b) that New England stakeholders continue current regional dialogues about the means by which costs for reliability-enhancing investments should be recovered.

Recommendation PD-5: Market-based responses to regional power system needs should be encouraged to emerge, wherever possible**.**

Recommendation PD-6: Continue the regional dialogue to explore the process and policies by which to allocate and recover costs of projects to address reliability and persistent economic congestion**.**

> Alternative Approach A: Proponents of this alternative[205] advocate the use of market driven approaches to meet regional needs, while avoiding subsidies to market-based solutions if at all possible. Should market signals not produce sufficient market response to fully address the needs of the system, the planning process should provide a coordinated, regulated transmission plan that identifies appropriate transmission upgrades to ensure reliability of New England's bulk power system. The costs associated with such cost based transmission assets would then be recovered through regulated transmission rates.
>
> Alternate Approach B: Permit cost recovery for both transmission and non-transmission investments: Like proponents of alternative A, supporters of this alternative[206] advocate the use of market driven approaches to meet regional needs. However, when the market fails to respond, FERC and state utility regulators should apply an "efficient reliability" test, based on principles of cost minimization and resource neutrality when considering proposals to recover the costs of system improvements through wholesale rules and tariffs.
>
> Alternative Approach C: [207] Permit cost recovery for reliability solutions, including non-transmission components, implemented by transmission providers: Regulators should permit recovery of both transmission and non-transmission

[205] Proponents supporting Approach A include: Massachusetts Division of Energy Resources, Northeast Utilities, National Grid, PowerOptions/Massachusetts Health and Education Facilities Authority, and United Illuminating.

[206] Proponents supporting Approach B include Connecticut Consumers Counsel, Connecticut Department of Environmental Protection, Demand Response Advanced Metering Coalition, Environment Northeast, US Environmental Protection Agency, Joint Demand Response Resource Supporters, Maine Public Advocate, Massachusetts Department of Environmental Protection, National Association of Energy Service Companies, Northeast Energy Efficiency Partnership, Northeast States for Coordinated Air Use Management, PACE University Energy Project, Price Responsive Load Coalition, Union of Concerned Scientists, Vermont Department of Public Service and Vermont Energy Investment Corporation.

[207] Proponents supporting Approach C include: Joint Demand Response Resource Supporters, Northeast Energy Efficiency Partnership, and PACE University. While preferring Option B, these NEDRI members also believe Option C has some merit.

costs when they are incurred by transmission providers to resolve grid problems through planned actions that are consistent with the principles of cost minimization and resource neutrality.

D. Recommendations -- Distribution Power System Planning

Throughout New England, electric distribution is a fully-regulated monopoly function, and the total costs of distribution comprise a substantial portion of the overall cost of electric service, significantly exceeding the cost of transmission. Rapid and/or concentrated load growth on portions of the distribution system can impose reliability problems and expensive upgrades on local networks. Demand response resources that are targeted to those hot spots can quickly moderate local reliability problems, and can defer costly upgrades, lowering the cost of distribution services.

Distribution utility companies should organize a planning process for the distribution system that identifies the locations on the local grid that could benefit most from targeted addition of energy efficiency and other demand response resources. They should seek to deploy those resources through their own actions, by targeting state and regional DR efforts, and by offering distribution credits to those deploying especially valuable demand resources on the local grid.

Recommendation PD-7: New England's electric distribution companies should seek out and acquire cost-effective demand side resources that would improve the reliability, operation and economics of the local distribution system. In particular,

- Distribution utilities should identify promising opportunities for effective demand response resources on the distribution grid, and implement pilot projects in which DR resources are deployed to reliably defer distribution investments;
- Where pilot programs demonstrate that demand resources can cost-effectively meet reliability objectives, distribution utilities should expand their planning processes in order to consider all available resources to meet distribution needs on a cost-effective basis, and should seek to acquire demand resources in similar high-value situations across their service territories;
- Investments or expenditures in demand resources approved by state regulators should be afforded cost recovery, including a return on investment or other performance incentives, on a comparable basis with investments in traditional distribution facilities; and
- Regulators should examine regulatory policies for distribution to see how they might be improved to support deployment of demand-response resources to improve local distribution services.

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APPENDIX C: NEDRI SUPPORTING DOCUMENTS

Set out below is a list of key Framing Papers and other scoping documents that were produced during the NEDRI process by the consulting team to commence discussions on the Chapters in this Report. While providing important background material for NEDRI's deliberations, please note that these working papers were not adopted or endorsed by NEDRI, other than what appears in this Final Report.

NEDRI Background Materials and Discussion Papers:

"Framing Paper #1: Price-Responsive Load (PRL) Programs" (Chuck Goldman) (March 2002)

"Framing Paper #2: Demand Side Resources and Reliability" (Eric Hirst and Richard Cowart) (March 2002)

"Framing Paper #3: Metering and Retail Pricing" (Frederick Weston and Jim Lazar) (April 2002)

"Framing Paper #4: Energy Efficiency" (Jeff Schlegel) (May 2002)

"Principles and Goals for Demand Response Resources in New England"
(NEDRI Consulting Team, June 2002)

"Barriers to Demand Response" (Richard Cowart, July 2002)

"Draft Model Regulation for the Output of Specified Air Emissions From Smaller-Scale Electric Generation Resources: Model Rule and Supporting Documentation" (Regulatory Assistance Project October 31, 2002).

"Long-Term Resource Adequacy: The Role of Demand Resources" (Eric Hirst) (January 2003)

"Opportunities for Demand Participation in New England Contingency-Reserve Markets" (Eric Hirst and Brendan Kirby) (January 2003).

"Technical Issues Related to Retail-Load Provision of Ancillary Services" (Brendan Kirby and Eric Hirst) (February 2003).

"Power System Planning and Investment" (Richard Sedano and Richard Cowart) (March 2003).

"Results of Demand Response Emissions Modeling" (Geoff Keith and Bruce Biewald) (June 2003).

These and other NEDRI documents are posted at the project's website: http://nedri.raabassociates.org/ and at the website of the Regulatory Assistance Project, www.raponline.org.

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APPENDIX D: NEDRI PROCESS GROUND RULES

New England Demand Response Initiative
Draft Ground Rules

Revised Based on 2/26/02 Meeting

Member Group:

Membership

1. Each member organization will designate a lead representative, and, at their discretion, an alternate or alternates.

2. Only the lead representative, or the alternate in the case of the representative's absence, will participate in formal decision-making.

3. Group members can participate in all discussions and deliberations.

4. New members can only be added by consensus of the Group.

Members' Roles and Responsibilities

5. Group members will make every attempt to attend all Group meetings, to be on time, and to review all documents disseminated prior to the meeting. Members who can not make a meeting should let the Facilitator know prior to the meeting (by voice or e-mail), and can provide the Facilitator with comments on the materials scheduled for discussion at the meeting to relay to the Group.

6. Group members will be expected to participate in good faith negotiations, to be truthful and communicative, and to act respectfully toward each other.

7. It is the responsibility of Group members to keep their organizations and constituencies "up to speed" on developments in the NEDRI process.

8. Group members will not speak on behalf of the NEDRI Group or its members without the Group's permission. Furthermore, it is understood that members are operating in a mode of inquiry, and that members' position statements may not be attributed to them outside of the group without their permission.

9. Group members may confer with each other and with the Facilitator (Raab) and the Technical Consultants (RAP et al.) in between meetings.

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Decision Making

10. The goal of the process will be to make recommendations by consensus of the NEDRI Group (excluding ex officio representation), where consensus shall mean that everyone is at least willing to live with a decision and chooses not to dissent. If unable to consent, a member will be expected to explain why and, if possible, offer a positive alternative. Members are responsible for voicing their objections and concerns. Silence or absence will not be allowed to delay the group's development of recommendations.

11. The Final Report at the end of the NEDRI process will describe all areas of consensus and, where consensus was not reached, any alternative approaches preferred by Group members. Group members' names will be listed next to their preferred alternatives for issues that lack a consensus resolution.

12. Meeting summaries covering all decisions reached will be circulated to the group, and all attending members will be given an opportunity to make additions, clarifications, or request changes.

13. The NEDRI Group recognizes that the governmental members of this process do not have the right to commit their respective organizations to any specific recommendations and, in addition, may need to recuse themselves personally from reaching conclusions on specific recommendations, in order to preserve their ability to fairly consider similar questions elsewhere as parts of their professional responsibilities.

Working Groups:

If the Group determines that using Working Groups in one or more area would be advantageous to the process, and if there is sufficient funding and other resources to support Working Groups, then each Working Group will be bound by the following ground rules:

Membership

14. Working Group representatives can be members of the NEDRI Group or their designees. Working Group membership is subject to approval by the NEDRI Group.

Members' Roles and Responsibilities

15. Working Group members will make every attempt to attend all workgroup meetings, to be on time, and to review all documents disseminated prior to the meeting. Members who cannot make a meeting should let the Facilitator know

prior to the meeting (by voice or e-mail).

16. Working Group members will be expected to participate in good faith negotiations, to be truthful and communicative, and to act respectfully toward each other.

17. It is the responsibility of the Working Group members to keep their organizations and constituencies "up to speed" on developments in the Working Group process.

18. Working Group members will not speak on behalf of the Working Group or its members without the Working Group's permission. Furthermore, it is understood that members are operating in a mode of inquiry, and that members' position statements may not be attributed to them outside of the group without their permission.

19. Working Group members may confer with each other and with the Facilitator and Technical Consultants (RAP et al.) in between meetings.

Decision Making

20. The goal of the Working Groups is to analyze options in a collaborative fashion, assisted by the Technical Consultants and Facilitator, and to prepare recommendations for the NEDRI Group's consideration.

21. Each Working Group's recommendations to the NEDRI Group will describe all areas of consensus and, where consensus was not reached, any alternative approaches preferred by Group members. Group members' names will be listed next to their preferred alternatives for issues that lack a consensus resolution. Consensus shall mean that everyone is at least willing to live with a decision and chooses not to dissent. Representatives are responsible for voicing their objections and concerns. Silence or absence will be considered consent.

Facilitator's and Consultants' Roles and Responsibilities:

22. Facilitator will facilitate all meetings of the NEDRI Group and the Working Groups.

23. The Facilitator will draft all agendas and meeting summaries and distribute to Members in a timely fashion. Facilitator will also distribute documents prepared by Consultants. All documents will be distributed once via email, and will then be available on a web site maintained by the Facilitator for the duration of the process.

24. Consultants will prepare all memos, documents, modeling runs, and reports in a

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timely manner and for distribution by the Facilitator prior to meetings.

Facilitator will act in a non-partisan manner, and will treat confidential discussions with parties confidentially.

APPENDIX E: LETTER FROM US EPA ON ENVIRONMENTAL ANALYSIS OF DR OPTIONS*

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

OFFICE OF AIR AND RADIATION

Climate Protection Partnerships Division
U.S. EPA 6202J
Washington, DC 20460

June 13, 2003

Dear NEDRI Participant,

In preparation for the next week's meeting, we are pleased to provide you with a summary of the results of the demand response modeling performed by Synapse Energy Economics. A discussion of the work is scheduled on Wednesday, June 18 in Holyoke, Massachusetts. A final report will be available shortly after the meeting.

A principal goal of this study is to examine the potential environmental impacts of NEDRI's load response and energy efficiency recommendations. As a general matter, the study's findings suggest that adoption of NEDRI's recommendations would be likely to improve the environmental profile of the New England electric system, assuming that environmental concerns receive appropriate attention. Here are a few highlights gleaned from the findings of Synapse study that have implications for the larger NEDRI effort:

- Regional Demand Response programs could provide significant environmental benefits in circumstances where DR resources are eligible for treatment as contingency reserves as recommended by NEDRI. This is due to the DR resources backing down generator-based spinning reserves, which in New England are often provided by units that are relatively highly-polluting. To ensure that these benefits are realized, mechanisms would need to be established to prevent the loss of these emission reductions through emissions trading.

- If demand response resources were not used to meet reserve requirements, emissions impacts would be much smaller, and emissions could increase or decrease depending on the amount of demand response generation and the fuel mix of that generation.

- More work is needed to assess the health risks posed by emissions from the on-site generators likely to participate in demand response programs.

- Energy efficiency improvements consistent with NEDRI's recommendations have quite positive environmental effects, since efficiency reduces generation needed across many hours and displaces high-cost, high-emitting units at peak times as well. Significantly, modeled levels of energy efficiency approximate the levels achieved by current programs, whereas modeled levels of DR are several times the levels actually achieved thus far.

- Finally, the study finds that implementing both NEDRI's short-term load response programs and its longer-term efficiency recommendations would yield greater environmental improvements than pursuing either type of resource by itself.

As New England's policymakers move forward with implementation of NEDRI-recommended DR measures, we hope that this study will provide useful guidance regarding environmental matters that need attention, as well as guidance for monitoring environmental impacts over time.

This analysis by Synapse was conducted for the U.S. Environmental Protection Agency under a contract with ERG, Inc. EPA and the authors are grateful to the members of our environmental analysis group as well as NEDRI consultants, whose input facilitated improvements to both the analysis and the paper.

We look forward to discussing the paper at the NEDRI meeting next week.

Sincerely,

Rick Morgan
Senior Energy Analyst
Climate Protection Partnerships Div. (6202J)
Office of Atmospheric Programs
(202) 564-9143

Bill White
Senior Analyst
EPA Region 1
Boston, MA
(617) 918-1333

* Inclusion of this letter in the Report is for informational purposes only and is not an endorsement of the Letter by the NEDRI Group. The NEDRI participants did not have the opportunity to fully consider the statements made by EPA or the Study upon which the Letter is based. Only a preliminary draft of the study was available at the time of NEDRI's final meeting.

APPENDIX F: LETTERS OF SUPPORT FROM GOVERNMENTAL AGENCIES

NEW ENGLAND CONFERENCE OF PUBLIC UTILITIES COMMISSIONERS, INC.

One Eagle Square, Suite 514
Concord, NH O3301
(603) 229-0308

Elia Germani
President

Amy Ignatius
Executive Director

July 1, 2003

Richard Cowart
Jonathan Raab
New England Demand Response Initiative
50 State Street
Montpelier, VT
05602

Re: NEDRI Report and Recommendations

Dear Mr. Cowart and Mr. Raab:

The New England Conference of Public Utilities Commissioners (NECPUC)[208] expresses its appreciation to the New England Demand Response Initiative (NEDRI) technical and facilitation team for their hard work and successful efforts. NECPUC also appreciates the support of the Federal Energy Regulatory Commission, the U.S. Department of Energy, and the U.S. Environmental Protection Agency in the NEDRI process. The final NEDRI Report and Recommendations represent their efforts as well as those of a broad array of stakeholders throughout New England.

NECPUC believes that the development of markets for demand response resources is an integral component of the long-term success of restructured New England electric markets and that public policy efforts are necessary to fully and evenhandedly integrate demand side resources into electric power markets. The NEDRI Report provides an important foundation for understanding the contribution of demand side resources to electric reliability, price stability, and environmental improvement.

[208] NECPUC comprises the public utility regulatory agencies for the six New England States. They are the Connecticut Department of Public Utility Control, the Maine Public Utilities Commission, the Massachusetts Department of Telecommunications and Energy; the New Hampshire Public Utilities Commission, the Rhode Island Public Utilities Commission, the Vermont Department of Public Service and the Vermont Public Service Board.

The NEDRI Report offers a technical and empirical analysis of demand resources and their potential in electric power markets. It also indicates a consensus on many policy recommendations, some of which are general, while others are more specific and technical. Some of the recommendations have not yet been fully considered by state public utility commissions, and an endorsement by a utility commission before full consideration could be interpreted as prejudging an issue. Other recommendations may exceed the legal authority of state utility commissions.

Therefore, consistent with NEDRI Revised Ground Rule No. 13, NECPUC abstains from approving the specific policy recommendations put forward in the NEDRI Report.[209] In a memorandum of August 2, 2002 on this topic, we stated that New England public utility commissions will give "(S)erious and expeditious consideration of suggestions made through this process for actions that could be taken in individual states."[210] The States will now consider the NEDRI Report. Ultimately, the six states comprising NECPUC have a variety of electric supply resources and may employ the NEDRI policy recommendations in various ways to suit states' individual policy preferences and the unique characteristics of each state's power markets and power delivery systems.

NECPUC thanks the NEDRI participants for their important contribution in formulating policy options for successfully integrating demand side resources into power markets. The Report provides a valuable resource guide and policy tool for New England public utility commissions as they consider the legal, technical, and economic intricacies of integrating demand side resources into electric power markets.

Sincerely,

Elia Germani

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209 Revised Ground Rules No. 13 states, "The NEDRI Group recognizes that the governmental members of this process do not have the right to commit their respective organizations to any specific recommendations and, in addition, may need to recuse themselves personally from reaching conclusions on specific recommendations, in order to preserve their ability to fairly consider similar questions elsewhere as part of their professional responsibilities."

210 NECPUC Memorandum to FERC Commissioner Nora Brownell, et al dated August 2, 2002 (Appendix A, *Outline of Contributions and Commitments by Key Institutions*).

The Secretary of Energy
Washington, DC 20585

June 18, 2003

Dear NEDRI Participants:

As you meet for the last time and with your final report about to be issued, I am pleased to offer this letter of commendation and thanks from the U.S. Department of Energy to all the participants of the groundbreaking New England Demand Response Initiative (NEDRI).

Thanks to you for your hard work during 15 stakeholder meetings over the last 16 months, New England's citizens this summer will be able to get the benefit of better and improved demand response programs through ISO-New England. I expect even more benefits in future years.

I am heartened to see such a broad range of groups --ISO-New England, state utility and environmental regulators, power generators and marketers, utilities, consumer and environmental advocates, and other stakeholder groups --all working together to propose a comprehensive set of demand response programs for the region's wholesale and retail electric markets.

Details matter in demand response, and so I want to recognize all the help you have gotten from the technical experts that helped with those details: Chuck Goldman of LBNL, Brendan Kirby of ORNL, Rick Weston and Rich Sedano from Regulatory Assistance Project, Jim Lazar, Jeff Schlegel, and Eric Hirst --but particularly the professional work of your lead facilitator Jonathan Raab and lead consultant Rich Cowart.

I want to also acknowledge and thank ISO-New England, NYISO, U.S. EPA and the Energy Foundation for their funding and help. I especially want to thank DOE's sister agency FERC for its strong interest in NEDRI as shown by their expedited review of this summer's New England demand response programs.

I expect NEDRI's accomplishments will serve as a model for other regions to follow. Getting the customer to participate in wholesale markets through demand response is crucial to improving our country's electric markets.

Congratulations!

Sincerely,

Jimmy Glotfelty

Senior Policy Advisor to the Secretary

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

OFFICE OF AIR AND RADIATION

Climate Protection Partnerships Division
U.S. EPA 6202
Washington, DC 20460

July 8, 2003

Mr. Richard Cowart
Regulatory Assistance Project
50 State Street
Montpelier, VT 05602

Mr. Jonathan Raab
Raab Associates, Ltd.
280 Summer Street
Boston, MA 02210

Dear Rich and Jonathan:
On behalf of EPA ' s Office of Atmospheric Programs, I want to express appreciation for all that you have accomplished through the New England Demand Response Initiative over the past year and a half. Your inspiration and leadership has produced a roadmap for identifying ways to improve electricity markets in New England -and hopefully clean the air at the same time.

By pulling together dozens of diverse parties, you have tackled the toughest issues in the electric power business today. In this way, NEDRI has set an example for the entire country.

EPA is proud to have played a role in helping get the NEDRI process off the ground. Indeed, as NEDRI's recommendations begin to bear fruit, it promises a substantial payback on the initial seed money that EPA invested two years ago.

Thank you again for your inspirational leadership in helping to develop the promise of demand response in New England.

Since I will soon be leaving EPA, I recommend that you stay in touch with Tom Kerr (202- 564-0047; kerr.tom@epa.gov) regarding further developments related to NEDRI.

Sincerely,

Rick Morgan
Senior Energy Analyst
Energy Supply and Industry Branch