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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

July 23, 2003

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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
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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.

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

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.

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).

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.

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.

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

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]

[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

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

[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).

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).

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.

[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).

- *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:

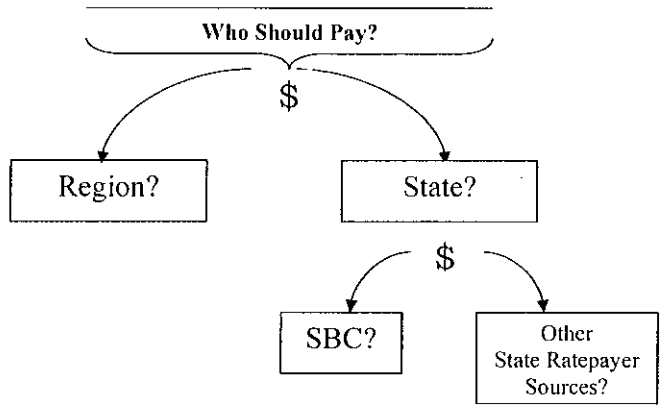
In its Order of December 20, 2002 on Standard Market Design issues in New England, FERC granted a request for rehearing on the topic of metering requirements for participation in demand response programs and directed "NEPOOL and ISO-NE to work with interested parties and experts at the Department of 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.)

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.

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

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.

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.

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.

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.

NEW ENGLAND DEMAND RESPONSE INITIATIVE

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.

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.

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

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.

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

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.

[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.

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.

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.

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

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.

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]

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[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.

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

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[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.

    - 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.

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.

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.

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

[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.

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.

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.

NEW ENGLAND DEMAND RESPONSE INITIATIVE

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

[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.

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]

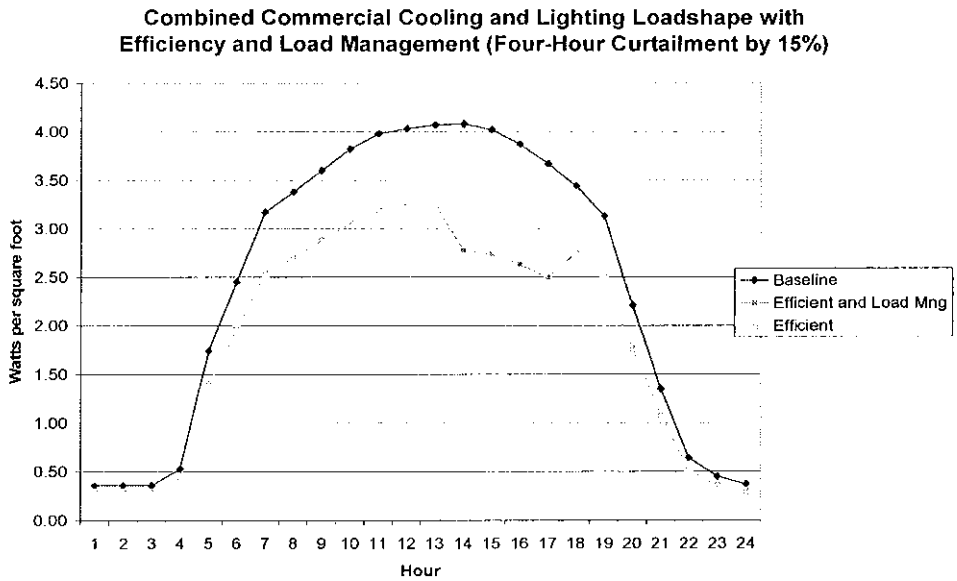

Figure 4-1: Combined effects of efficiency and load management in a typical commercial space. Energy efficiency reduces load in many hours, including peak loads. Load management can add to the peak load savings.

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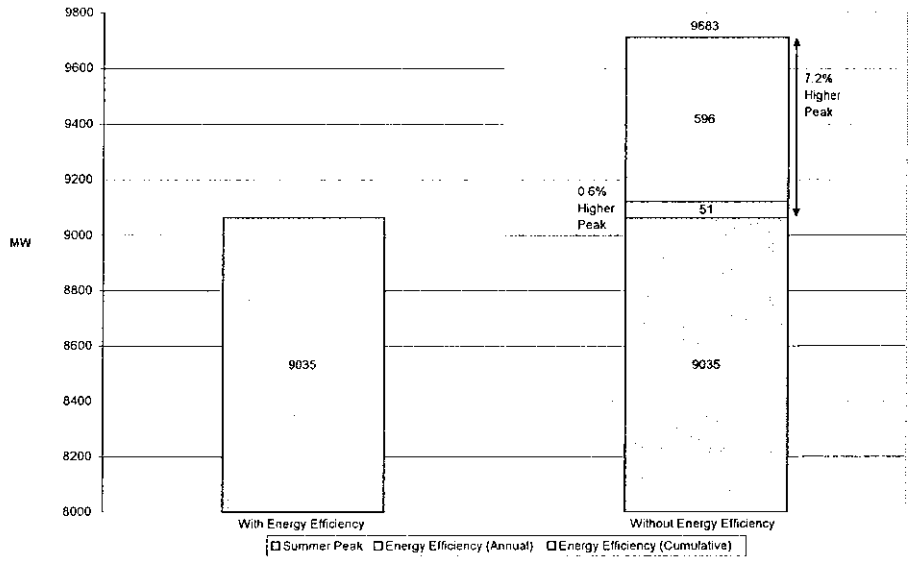
achieved by reducing lighting and HVAC load. We used a conservative estimate of 20% load reduction from the HVAC and lighting energy efficiency measures. For existing, previously-untreated large commercial office buildings in New England, savings of 25% or more from comprehensive measures are common, 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.

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

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.

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.

- 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).

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

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.

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.

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.

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.

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.

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.

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.

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

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).

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.

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).

B. Kirby and E. Hirst 2003, *Technical Issues Related to Retail-Load Provision of Ancillary Services*, draft, New England Demand Response Initiative, February 10.

B. Kranz, R. Pike, and E. Hirst 2002, *Integrated Electricity Markets in New York: Day-Ahead and Real-Time Markets for Energy, Ancillary Services, and Transmission*, New York Independent System Operator, Schenectady, NY, November.

North American Electric Reliability Council 2001, "Frequency Response Standard, Version 5, proposed revision to Policy 1 of *NERC Operating Manual*," Princeton, NJ, March 7.

North American Electric Reliability Council 2002, "Policy 1 Generation Control and Performance," *NERC Operating Manual*, Princeton, NJ, November 21.

Northeast Power Coordinating Council (NPCC) 2002, *Operating Reserve Criteria*, Document A-06, New York, NY, November 14.

Northeast Power Coordinating Council (NPCC) 2003, "Comments on NEDRI Documents", J. Mosier, Jr., Director of Operations, May 6.

D. B. Patton 2002, *Review of Peak Energy Pricing in New England During Summer 2002*, Potomac Economics, Washington, DC, December.

PJM Interconnection 2002, "Spinning Reserve Market," Docket No. ER02-2519-000, submitted to the Federal Energy Regulatory Commission, Norristown, PA, August 29.

U.S. Federal Energy Regulatory Commission 1999, *ISO New England, Inc., Order Accepting for Filing Revisions to Operable Capability Market Rules*, Docket No. ER99-4002-000, Washington, DC, September 30.

U.S. Federal Energy Regulatory Commission 2002a, *Notice of Proposed Rulemaking: Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design*, Docket No. RM01-12-000, Washington, DC, July 31.

U.S. Federal Energy Regulatory Commission 2002b, *Order Accepting Spinning Reserve Market*, Docket No. ER02-2519-000, Washington, DC, October 31.

U.S. Federal Energy Regulatory Commission 2002c, *Order on Rehearing and Accepting Compliance Filing*, Docket Nos. ER02-2330-001, Washington, DC, December 20.

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.

[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.

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.

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).

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.

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[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.

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.

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 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.

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

[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.

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.

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;

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]

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[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.

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.

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.

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												

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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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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:

[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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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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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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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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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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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 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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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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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.

APPENDIX F: LETTERS OF SUPPORT FROM GOVERNMENTAL AGENCIES

NEW ENGLAND CONFERENCE OF PUBLIC UTILITIES COMMISSIONERS, INC.

One Eagle Square, Suite 514
Concord, NH 03301
(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 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