NEW ENGLAND DEMAND RESPONSE INITIATIVE

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

Report and Recommendations of the New England Demand Response Initiative

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

NEDRI would not have been possible without two other critical ingredients – generous financial support by our sponsors and active participation by stakeholders. Funding for the initiative came from ISO New England; U.S. Environmental Protection Agency, Office of Atmospheric Programs, Climate Protection Partnerships Division (Rick Morgan, Tom Kerr), and US Environmental Protection Agency Region 1 (Bill White); U.S. Department of Energy, Office of Electricity Transmission and Distribution (Larry Mansueti, Phil Overholt); the New York Independent System Operator (NYISO); and the Energy Foundation. The NEDRI members, representing a comprehensive cross-section of stakeholders including state and federal regulatory agencies, market participants, customers, and public interest organizations are listed on the following page.

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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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.

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

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

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

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

Related Actions Needed to Support Regional Demand Response Programs

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

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

One potential problem with more robust demand-response programs is the possibility that they will lead to the more frequent use of relatively highly polluting, back-up generation by

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

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

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).

[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).

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

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

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

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

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

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

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

Discussion:

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

[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).

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.

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

Recommendation RDR-7: Evaluate and Improve Demand Response Programs33

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

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

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

[33] NEDRI Participants unanimously approved the recommendations in this section.

- Discuss their impacts on the environment, including timing and location of emissions, and

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

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

- *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]

[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

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

- *There is a need to overcome significant market barriers to increase customer participation in shorter-term demand response (both emergency and price-responsive programs) during the transition to effective competitive markets. NEDRI recommends that additional funds be made available to support enabling infrastructure, technical assistance, and customer education and information. Funding for these activities could come from regional and/or state sources should be relatively small in amount, and should preferably be incremental to existing state System Benefit Charge funding targeted at energy efficiency.*

Discussion

Funding Need: Why and For What

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

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

Funding Source

The source of funds for these supporting activities could come from regional sources or state sources (including SBC or ratepayer funding), as shown in Fig. 2-1. The funding source may vary by state and needs further careful analysis and discussion. However, in most, if not all cases state SBC funds are not adequate to fully fund cost effective energy efficiency. Thus,

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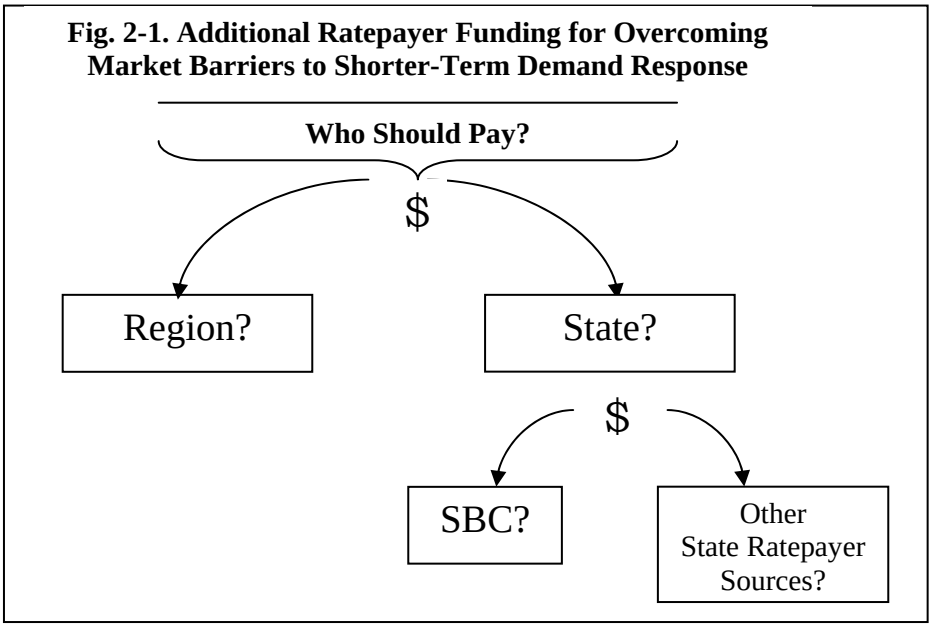
facilitate a robust demand response are essential to the success of competitive wholesale markets. As markets mature in other regions, the Commission will insist on similar measures in all regional markets." (ISO-NE filed this report with FERC on June 18, 2003.)

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

many NEDRI participants prefer that public funding of shorter term demand response infrastructure be incremental to existing state system benefit charges, while others believe that limited use of existing state system benefit charges for shorter term demand response is appropriate.[38]

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.

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

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

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

Discussion:

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

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

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

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

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

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

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

Appendix 2-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

[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.

and the price paid by the ISO). In the case of regulated monopolies and DSPs, the sharing will be determined by the PUC, taking into account traditional regulatory concerns – equity, efficiency, cost-allocation, and revenue collection.

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

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

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

We recommend that state PUCs permit regulated DSPs and monopolies to retain up to 30% of the ISO payments. This should, in most cases, provide enough cash to cover DSP costs and yield a profit. This sharing will act as a *de facto* maximum for the market. If Demand Response Providers can do better, they will capture more of the market and force DSPs to either reduce their share of the payments or cease providing the service. To the extent that the ISO payments include ICAP credits or reservation payments (which extend over a period of time), the revenue stability problem can be mitigated to some degree.

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

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

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

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

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

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

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

Recommendation PM-3C:

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 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.

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

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

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

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

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

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

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

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

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

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

*Note: The other NEDRI members listed in footnote #182 also believe that the ISO should not select among resource options unless the market has failed to provide adequate reliability or remove persistent congestion. However, rather than pursuing only a regulated transmission option, these NEDRI members conclude that at this point of market failure the ISO should pursue an efficient reliability solution that seeks the most cost-effective solution among transmission, generation, and demand-side options. See Alternative B on page 133.

Introduction: The Role of Demand Response in Power Delivery Systems

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

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

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

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

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

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

The RTEP goal is the achievement of a reliable transmission system that facilitates the development of a robust market with due consideration to environmental issues. In preparing the plan, ISO-NE gets input from the work of the Transmission Expansion 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]

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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).

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

Market Foundations for Delivery System Planning and Investment

Recommendation PD-1:

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

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

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

Competitive markets that reveal both the temporal and locational value of energy services will provide efficient signals as to the region's power delivery infrastructure needs as well. NEDRI participants support the ongoing development of the region's power markets and trading rules so as to reveal those values. Note, however, that the conditions for efficient markets in electric services must be carefully considered. Where market structures and market barriers impair the contribution of demand response resources,

investment policies that rely on private markets alone may not be successful.[164] Moreover, we recognize that even where competitive wholesale markets operate well, the provision of default service and regulated retail service and renewable portfolio standards will be subject to public policy decisions at the state level.

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

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

[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.

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.

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

Recommendations for Regional System Planning

Overview: NEDRI recommends that the ISO,[170] regional market participants and states seek ways to enhance the ability of the regional planning process to identify the best solutions to grid problems from all types of resources – traditional grid upgrades, operational improvements, strategically-located generation, and targeted investments in demand response resources (DRR).[171] NEDRI recognizes that the structure, authority, and governing rules for a regional planning entity will be critical to its success, but concludes that decisions on those topics will be taken in other forums.[172] However, whatever structure is adopted for regional system planning, it must be one that accommodates a long-term view of the system, and can openly consider the potential for

[167] See also, Recommendation PD-7 and associated discussion, below.
[168] While National Grid, Northeast Utilities and United Illuminating acknowledge that ratemaking policies may inhibit the development of demand resources, they respectfully disagree with the claim that utilities are incited to increase throughput. This claim is premised on a specific rate design that is not uniformly adopted for every utility, especially transmission utilities. Also, specific circumstances may not make this theory prove true. Inflation, investment for growth, greater demands on older equipment and many other issues contribute to a marginal cost curve for distribution that is upward sloping and eliminate any opportunity for increasing profits as described above. Finally, customers receive benefits from pricing on deliveries because customers who use more electricity pay more and have a greater incentive to conserve and, if added growth can fund additional investments and expenses, average rates to customers can be kept lower over time by limiting the number of rate cases.
[169] Transmission incentive plans incorporating congestion costs have been instituted in other countries (notably the UK and New Zealand) but have not been attempted in the US.
[170] ISO-NE has announced that it will take steps to transform itself into an RTO. The recommendations in this paper apply to whatever organization becomes the duly constituted system operator for the New England region. For purposes of consistency, this chapter will refer to that organization as "the ISO."
[171] What problems should the planning process address? Clearly, it should address emerging reliability challenges. Whether it should also seek to mitigate persistent "unhedgable" congestion is a matter of further discussion.
[172] We note that a discussion addressing this topic is underway among the six New England states.

DRR to resolve grid problems. Thus, the recommendations below focus not on the structure or governance details of a regional planning entity, but on the basic principles to support an appropriate balancing of resources, including DRR, in resolving power system challenges.

Recommendation PD-3:

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

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.

[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-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,

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

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

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

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

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

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

Recommendations -- Regional Power System Investment Policy

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

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-

[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.

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.

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

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

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

If market solutions do not fully resolve an identified reliability concern, a regulated transmission solution may be required to resolve the problem. In this instance, the

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

planning process would identify appropriate transmission projects necessary to ensure reliability. As is required currently, regulated transmission companies would continue to be obligated to implement the lowest cost, reasonably available transmission solution to address the reliability need. Cost recovery for regulated, regional transmission solutions would be through the regional open access transmission tariff (OATT) under FERC jurisdiction.

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

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

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

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.

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

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

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

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

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

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

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.

[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.

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

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

Alternative Approach C: Permit cost recovery for reliability solutions, including non-transmission components, implemented by transmission providers: Regulators should permit recovery of both transmission and non-transmission costs when they are incurred by transmission providers to resolve grid problems through planned

[184] This applies in all states, but is even more needed in states with a least-cost mandate in their siting processes.

actions that are consistent with the principles of cost minimization and resource neutrality.

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

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

[185] Proponents supporting Approach C include: Joint Demand Response Resource Supporters, Northeast Energy Efficiency Partnerships, and PACE University Energy Project. While preferring Option B, these NEDRI members also believe Option C has some merit.

[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."

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]

Recommendation PD-7:

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

In particular,

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

[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.

Discussion

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

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

Implementing distributed utility planning – the need for pilot programs. Growing experience with distributed resources, strongly suggests that some distribution expansion and reliability needs can be met with distributed resources, including dispatchable demand response, distributed generation, and long-term energy efficiency, The distribution company may enjoy avoided or delayed investment costs[189], reduced energy cost volatility, more economical provision of ancillary services and other benefits by deploying these resources.

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

[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.

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

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

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

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

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

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

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

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

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]

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

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

[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.

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]

[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.