New England Demand Response Initiative

To: NEDRI Stakeholders and participants
From: Richard Cowart, RAP, Project Director
Date: February 19, 2002

Re: Enclosed Outlines for the 4 Framing Papers

First, on behalf of RAP, Raab Associates, and our technical team, welcome to the New England Demand Response Initiative! Response to this project has been very positive, and we are looking forward to our take-off meeting on February 26. As we launch, I'd like to acknowledge the support and sponsorship of the New England ISO, NECPUC, EPA and state environmental agencies, and the U.S. DOE. The NEDRI project was the subject of positive discussion at the FERC-DOE Demand Response Conference last week, including the announcement by DOE Assistant Secretary David Garman of DOE's support for the project. There is a growing awareness at FERC and in many other circles that wholesale, transmission, and retail policies must all be dealt with to realize the value of demand-side resources in today's energy markets.

A few days ago, Jonathan Raab sent you a set of draft ground rules for the NEDRI stakeholder process, an agenda for the February 26th meeting, and a nearly complete list of Stakeholders. Please take a few minutes before the meeting to review these materials. They will be discussed at the outset.

Enclosed today are outlines for the Framing Papers for the four main topics that NEDRI will address. The papers and their principal authors are:

(1) Demand-Side Resources and Reliability (Richard Cowart and Eric Hirst)
(2) Price-Responsive Load (Chuck Goldman)
(3) Retail Pricing and Metering (Frederick Weston and Jim Lazar)
(4) Energy Efficiency (Jeff Schlegel)

Please review these outlines before next week's meeting. Discussing the outlines will provide our first opportunity as a group to review the entire policy scope of this project. Please keep in mind that the Framing Papers are intended only to set the stage for our work together, not to provide the ultimate answers or final policy recommendations for the Initiative. As you review the outlines, please consider:

- Are the important issues covered? Are key issues or sub-issues left out?
- What important documents, case examples, or references should we look at?
- Can you recommend names of program managers, technical or policy experts to whom we should be speaking as we develop the Framing Papers?

We look forward to seeing you next week.

New England Demand Response Initiative

Framing Paper #1: Demand-side Resources and Reliability

Outline: February 16, 2002

I. Introduction

(A) Overview: This paper focuses on the role of demand-side programs in providing reliability services rather than purely economic gains to participating end-users. Of course, purely economic programs (e.g., demand-sale backs in response to price, and real-time pricing at retail) also have reliability impacts, and reliability programs also have price impacts, but these two types of programs can be distinguished in two ways: (1) They differ in their **principal purposes** (reliability/contingency/system benefit vs. market-clearing/normal operations/private benefit) and (2) The **decision-makers and decision-making processes** are different in that reliability decisions and costs are largely regional and socialized, and they are administrative in nature, not pure market plays.

(B) Reliability Fundamentals:

(1) Elements of bulk-power reliability and unique features of electricity
(2) NERC requirements; their impact on demand-side resources
(3) FERC definitions of ancillary services and RTO responsibilities
(4) Maintaining reliability in competitive markets is very different than with regulated, vertically integrated utilities
(5) Reliability functions and their relevance to customer loads
(6) Transmission and generation adequacy

(C) Three types of reliability interventions:

(1) Operations: bidding of demand-side services as ancillary services;
(2) Operations: Emergency demand-response programs (purchases for reliability by the system operator or ISO);
(3) Investment: Demand response (including embedded efficiency) as an alternative to transmission upgrades

II. Demand-Side Resources in Wholesale Reliability Markets

A. Overview: What markets exist, which ones should exist, how do they relate to reliability, what would it take for customer loads to participate in these markets

(1) Day-ahead energy
(2) Day-ahead ancillary services, including spinning, non-spinning, and replacement reserves
(3) Real-time (intrahour) energy balancing and congestion management

(4) Involuntary load reductions
(5) Installed capability requirements and markets

(B) Experience with Demand-Side Reliability Programs in Wholesale Markets

(1) ISO-NE Programs to date – reasons these markets have problems
(2) PJM's current system – does not include markets for contingency reserves
(3) NY-ISO experience

(C) How Current Reliability Rules May Limit Demand-Side Participation

(Explain why there is a problem and begin to suggest solutions)

Review NERC and NPCC rules concerning contingency reserves
Review ISO New England practices
Review ISO New England plans for contingency-reserve markets
Review ISO New England plans for installed capability and its alternatives
Possible alternatives to ensure that customer loads can and do participate in reliability markets on a level playing field

(D) Barriers to Participation by Customer Loads in Reliability Markets

(Address the question: If demand response is such a good idea, why is so little occurring?)
Principal barriers include:

Lack of metering and communications infrastructure
Should such infrastructure costs be socialized?
Limited customer understanding of profit opportunities
Limited customer knowledge of how their operations can participate
Limited ISO experience with demand-side resources
Jurisdictional problems (FERC vs state PUCs)
Tradition: loads are to be met, not managed; and price elasticity is assumed to be zero
Ambiguity over whether ISO or LSEs should design, market, and run programs and be responsible for their profitability

III. Emergency Demand-Response Programs

(A) Status/Experience of programs in New England

(1) Summer 2000, 2001 -- explaining the weak response
(2) Problem of reconciling local utility and ISO programs and payments
(3) Program designs for 2002

(B) Lessons from programs developed elsewhere:

CA, PJM, Pacific NW, Key Midwest examples

(C) Role of involuntary load reductions

(1) When all else fails, system operators disconnect loads. Should those that involuntarily provide reliability services be compensated for doing so? Are there practical problems with paying them for this service?)
(2) Why this occurs
(3) Reasons to pay loads when they are involuntarily interrupted
(4) Potential problems with implementing such a scheme

(D) Emergency Reliability Programs – Options and Topics for review

(1) Reconciling ISO emergency actions and utility/LSE actions
Who decides? Who has access to the customer? Who pays for the action?
(2) Lessons learned and suggestions for the future -- including, will we need these at all? As economic programs (Load-side bidding and price-responsive load) and routine demand-side ancillary services expand, will ISO-level *emergency* programs be unnecessary?

IV. Transmission Planning and Expansion: Demand Options

(A) Introduction

(1) New England transmission situation
(2) Likely future demands on the transmission system
(3) Why transmission policies are crucial for competitive markets, costs and environmental consequences
(4) What is congestion? Distinguish commercial from reliability problems
(5) Jurisdictional challenges - FERC authority over transmission tariffs vs state jurisdiction over bundled transmission (at least so far) and over siting
(6) Transmission pricing options: access (fixed costs), congestion, and losses
How do these options affect participant investment decisions?
Problems if transmission costs are socialized
(7) Transmission planning: reconcile markets for generation and load vs regulated, centralized network for transmission

(B) Integrating demand-side options into transmission expansion

(1) In the planning process -- what are the options for considering demand-side and distributed options in the transmission planning process cost- effectively and without undue delay to the process?
–Experience with RTEP thus far
–Examples to consider: Long Island Sound, NW Mass, SW Conn
(2) In a bidding process or open season:

-- Can transmission options be exposed to an “open season” bidding process in which alternative solutions to congestion or other transmission needs can compete on an equal basis?

-- Can winning bids in such a process be given the same assurance of recovering their costs (i.e., their bid price) as transmission options would receive?

(3) In the siting process:

–What is the role for regional needs determinations in state-level transmission siting decisions?

–How can demand-side options be included in constructing those need determinations?

(4) Challenges

(a) Planning vs. markets

(b) Will demand resource be reliable over the long-term

(c) Citizen opposition to new transmission facilities

(d) System operator concern about the reliability of demand options

(e) Incentives to transmission owners -- are they properly aligned?

V. Conclusions and Options

(A) Conclusions

(1)A 1-MW load reduction is exactly equivalent, from a reliability perspective to a 1-MW generation increase

(2) A suitably located load reduction can substitute for transmission capacity

(3) To date, retail-load participation in wholesale energy, reliability, and transmission markets has been very limited

(4) Program designs and policy changes are needed at both the state/retail, and ISO/wholesale levels to improve the contribution of demand-response programs to system reliability

(B) Options to Consider

(1) Options at the ISO/regional level

>Conduct research on customers to learn what program features would encourage participation in reliability-focused load response programs, and how they can best and most easily modify their loads

> Require the ISO to ensure that demand can participate fully and comparably in all markets for energy, ancillary services, and congestion management

>Can ISO rules recognize the unique characteristics of loads, just as they now do for generators (energy-limited hydro, ramprate constraints, minimum runtimes, etc.)?

>Could NE-ISO fully consider demand-side options (as well as suitably located generation) in transmission planning and expansion?

>What are the procedural and design features needed to provide a realistic opportunity for transmission and non-transmission alternatives to compete evenly in an "open season" addressing transmission congestion problems?

>Options for socializing reliability resources: consider the options from broad support, to support only for the, to virtually no support (all solutions market-based, or internalized to particular cost-causers)

(2) Options for state regulators, utilities, and load-serving entities:

>Possible use of a Distributed Utility Planning process by utilities to identify locations on the distribution grid where reliability enhancements through active load management are most valuable at the *local* level

>Should interval meters be mandated, at least for larger customers?

>Should PUCs redefine default service as service with interval metering and real-time pricing, especially for larger customers?

>Should PUCs adopt policies requiring payments to customers for involuntary load interruptions?

>Should customers be permitted to contract directly with the ISO for reliability load management programs, or must those arrangements be made through LSEs?

>Promote technologies (e.g., automation) that make it simpler for customers to participate in such programs.

VI. Interactions with the topics in the other Framing Papers

New England Demand Response Initiative

Framing Paper #2: Price-Responsive Load (PRL) Programs
Outline #3 2/18/02

I. Introduction

(A) Overview – Paper focuses on role of demand side resources in providing load curtailments or decrements in response to market (price) signals.

(1) Price-responsive Load Programs typically offer/buy load reductions in a day-ahead energy market (or short-term forward market – e.g. several days to one week)
(2) New England is developing a day-ahead power market as part of Standard Market Design
(3) Even with introduction of day-ahead market, trading of load reductions would be limited without mechanisms to determine and agree on load reduction quantities
(4) Price responsive Load (or economic load response programs) should be strongly considered in order to increase demand elasticity
(5) NE ISO is considering several wholesale market DR program options
(6) This framing paper discusses PRL programs in wholesale markets, summarizes experiences in other states, explores type of program offerings that retail load serving entities (either electric distribution companies (EDC), or competitive retail suppliers) or other curtailment service providers might develop that can participate in ISO PRL program, and identifies key policy and program design issues.

(B) Conceptually, various types of demand-side programs offered by EDC or competitive retail energy suppliers could be eligible to participate in an ISO PRL-type program, depending on its design (e.g., ranging from real-time pricing program, load reduction bidding program into day-ahead market, TOU rate program with a super-peak period, and a direct load control program)

II. Price-Responsive Load (PRL) Programs in Wholesale Markets

(A) Overview:

(1) What markets exist, what does it take for customer loads to participate in these markets
(2) Brief conceptual description of these programs
(3) Summarize Existing demand response assets in New England: existing dispatchable load control programs, special contracts (if applicable), time-varying rates (focusing on real-time pricing tariffs)

(B) Status/Experience with PRL Programs offered by ISOs

(1) Summary of NY DADRP Experience
(2) Summary of PJM Experience

- Describe relationships between ISO and eligible Load Serving Entities
- Market Response
- Technical, Institutional, and Other Barriers
- Process and Impact Evaluation Results (if available)

(C) Status/Experience with PRL Programs offered by Utilities (or Federal Power Marketing Authorities)

(1) Focus on PRL programs that are not interfacing/coordinating with ISO program offering
(2) Discuss examples and results from Pacific Northwest (e.g., PGE, BPA), Midwest (e.g., Cinergy, Commonwealth Edison,)

(D) Summary of Current Experience/Lessons Learned

(1) Current Level of Market Activity is relatively low; most programs are relatively new (compared to DR programs triggered by system contingency
  – Example: Actual load curtailed in “Market” DR is typically <50 MW;
  – Programs are typically1/5 to 1/10 of actual demand reductions obtained in “Emergency Demand Response Programs” (e.g., in NY, 420 MW in EDRP vs. 25 MW in DADRP)
(2) In Pac NW, programs were very active in Winter and Spring 2001 (e.g. BPA, Pacificorp), until prices in wholesale markets dropped significantly, FERC rate mitigation measures were enacted, and longer-term demand buy-back contracts were put in place by utilities/customers
(3) Describe types of customers and market segments likely to participate in such programs
(4) Range in financial incentives required in order to obtain significant customer response (e.g., $150-200/MWh)
(5) Most successful retail programs offered by LSEs feature broad array of DR programs – including both emergency and PRL-type programs (e.g., Cinergy)
(6) Emergency-backup generation is an important resource in some PRL programs; in other cases, use of “dirty” generating resources is prohibited or strictly limited (e.g., NY, CA)

(E) Barriers to End User Participation

(1) Economic incentives required for customers to curtail loads
(2) Lack of metering and communications infrastructure
(3) Customer education/information needed given historic lack of ability/tools to respond to price signals
(4) Environmental and building permitting issues, particularly related to onsite, or emergency generation

(5) Other market barriers encountered in getting customers to participate in energy efficiency/demand-side programs (e.g., uncertainty surrounding performance, hassle costs, misplaced or split incentives)

III. Wholesale Market Program Options[1]

(1) Day Ahead Price-Capped Load Bidding

- Load Serving Entity bids quantity of lead expected to serve and price bids at which it will reduce loads to specified MW levels
- Can be viewed as the "basecase" option as part of a Standard Market Design (SMD)
- Revenues and penalties are based on total metered load
- Must be implemented through the Load Serving Entity that supplies each participating customer's generation

(2) Load Reduction Bidding as Generation

- Option establishes an unbundled "Load Reduction" product; quantities of this new "Load reduction" product can be bid into market and incorporated into day-ahead scheduling process, potentially displacing other resources
- Quantity of Load Reduction "Product" is based on difference between customer's total metered load and a specified baseline;
- Provides incentive payments to providers and/or end users
- Option based on New York Day-Ahead Demand Response Program (DADRP)

(3) Transitional Load Reduction Pricing

- In this option, customers would be allowed to bid a load reduction price in advance, which would then serve as a guaranteed price floor for duration of load reduction request by ISO (rather than seeing the estimated ECP at 6 pm the day before and getting paid at the ECP wherever it clears)
- Based on premise that objectives of load response programs are best served by variety of pricing arrangements, including those that are customized to be as simple and predictable for load response customers as possible; pricing terms would be less tightly tied to actual ISO market prices, whether real-time or day-ahead, than other options
- Can be introduced prior to SMD; transition step toward a day-ahead market
- In this option, ISO dispatchable load programs (type 3 and 4) could also be adapted to work (e.g., bid in large amounts of direct load control at price floor)

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[1] This section is based on forthcoming KEMA Consulting report, "Load Response Program Design Issues," December 7, 2001, which explores several wholesale market program options.

(4) Voluntary Response to Market Price

- Option corresponds most closely to ISO-NE 2001 economic program; allows customers to implement additional reductions beyond those reflected in the day-ahead schedule
- Voluntary transactions that are not an integral part of scheduling and dispatch, do not set a Marginal Clearing Price

(For each option, describe it, summarize strengths and weaknesses relative to key criteria)

IV. Key Policy & Program Design Issues

(A) Policy Issues[2]

(1) Are PRL-type programs efforts that should be undertaken/supported by ISOs or should they be considered solely at the state/retail jurisdictional level?

Potentially large economic benefits of increased demand elasticity in wholesale markets vs. primary mission/responsibilities of ISO (e.g., reliability, competitive wholesale electricity markets)

(2) Relationship between PRL programs and real-time pricing - Are economic demand-bidding programs necessary if RTP was widespread?

- Regulators are reluctant to expose customers to volatile wholesale prices (e.g., RTP programs)
- Discuss relationship between retail, time-varying rates and wholesale market PRL programs

(3) To what extent, should Price-Responsive Load services be unbundled from the services provided by the Electric Distribution Company (e.g., should this only be a "competitive" service provided by retailers, or, given, level of development of retail market, should there be a strong explicit role for EDC)

(4) What types of demand-side "resources" should be eligible to participate in "economic" load response programs – specifically role of and/or limits on use of diesel-fired back-up generators?

(B) Program Design Issues

[2] The forthcoming KEMA Consulting report, "Load Response Program Design Issues," December 7, 2001 also explores many of these program design issues in more technical detail and depth.

There are myriad program design issues – this section focuses on major design issues assumed to be important to stakeholders and which involve coordination/institutional issues between ISO/state entities or energy/environment regulators

(1) ISO/End User relationship and eligible entities
- In implementing a PRL-Program, does the ISO deal only with Load Serving Entities (LSE), or with LSEs and other entities that can deliver Load Reductions (e.g., competitive retail energy suppliers, Curtailment Service Providers), or with LSE, CSP, and end users directly?

(2) Financial incentives for PRL programs --

- Payments from ISO to LR provider that provides proxy for market value of the PRL program
- Source of funds for ISP payments – uplift charges?
- Determining incentive payment levels?

(3) What types of end user resources should be eligible to participate in PRL Program?
- Load reductions only
- Load reductions + Onsite Generation (e.g., Emergency, Back-up generation)
- On-site Generation

(4) Baseline methods used to compute quantity of load reductions that customers get paid for
- Baseline consumption minus actual demand consumption: (i.e. what would have happened in absence of load reduction)
- Issues related to equivalent comparability and certainty with generation resources

(5) Relationship between "emergency" demand response and "economic" demand response programs

- Should Customers be allowed to participate in both types of programs?
- Emergency DR programs increasingly involve "calls" during system contingency events
- Issues involved in working out inter-relationships between "emergency" and "economic" DR prograsm

NEW ENGLAND DEMAND RESPONSE INITIATIVE

FRAMING PAPER #3: METERING AND RETAIL PRICING
Outline and Issues, Draft: 19 February 2002

I. INTRODUCTION

A. Purpose and Challenges

Objective: Maximize the capability of demand-response to compete in the wholesale market and to improve the overall efficiency and environmental profile of the electric sector.

Challenge: At the retail level, what policies need to be implemented and what metering and communications technologies deployed to support demand-response programs? In other words, what can be done to reveal to customers and load-serving entities (LSEs) the value (cost) of energy savings (consumption) during times of high loads, or system constraints? Specific questions to addressed include:

- Should large C&I customers be put on interval metering?
- Should advanced metering be broadly implemented?
- What modifications to the system of load profiling are needed?
- How should tariffed franchise service and default service be modified to support customer demand response?

B. Summary of Major Conclusions and Policy Options

II. BACKGROUND

A. Retail Pricing, Metering, and Communications

Electric service is priced in a variety of ways. Pricing policy, whether set by firms or regulators, is influenced by a number of factors and objectives, such as economic efficiency, fairness, revenue stability, etc., as well as by certain practical considerations, among them the availability and costs of metering and communications technologies to support those policies. When viewed in this light, price structures run along a continuum that marks the trade-offs between innovative and more complex pricing on the one hand and information needs and administrability on the other. That continuum can be roughly divided into three broad segments:

- Rate designs that do not require special metering capability beyond that of the traditional revenue meter, which measures energy consumption only and is read typically once a month: flat, seasonal, block, etc.
- Rate designs that depend upon more sophisticated metering: multi-part (energy and demand) and time of use.

- Rate designs that send customers different prices for different hours of the day and for different days, to in some way reflect the changing conditions in the short-term market.

Default service issues: Even in competitive retail markets, most small commercial and residential customers purchase electricity under default, or standard offer, service. For the most part, this has meant that these customers have continued to receive electricity at fixed two-part (energy and customer) or three-part (demand, energy, and customer) rates. How can the structure of a state's transition to competition and the nature of default service support or impede demand-responsiveness by customers and LSEs?

B. Energy-Only Rates and Revenue Meters

Flat energy-only rates and periodic customer charges. Seasonal differentiation in some jurisdictions. Block rate structures (inclining and declining).

1. Information Requirements

Energy only. Monthly information collection

C. Time-of-Use Rates, Demand Charges, and Metering

Time-of-day (TOD or time-of-use, TOU) and rates broken down between demand and energy.

Given the higher costs of metering and administration for TOU rate structures, they have been limited primarily to the higher usage consumers. Many experiments with residential TOU rates were conducted in the post-PURPA era of the early 1980s; many were abandoned as consumer response was slight, costs high, and savings small.

1. Information Requirements

TOU meters, demand meters, monthly data collection.

D. Real-Time Pricing

Real-time pricing (RTP) is any system that charges different retail electricity prices for different hours of the day and for different days. RTP does not necessarily mean that the retail price in any given hour would be equal to the wholesale price for that hour (although that's one way to do it). There are a wide range of RTP programs around the country, and most of them combine wholesale and regulated pricing mechanisms, with trade-offs in risk and price levels.

1. Information Requirements

- Types, capabilities of advanced metering systems
    - Uses: to support real-time pricing, load response programs, or demand-bidding

- Automated Meter Reading (AMR)
    - Frequency of data collection
    - Network requirements
- Smart meters that manage load or energy management systems that also report usage to the utility.
- Metering that enables mass marketing of electricity services

E. Determining Loads and Settling LSE Obligations:

1. Load Profiling

In the absence of individual customer information that describes the customer's hourly usage, an estimate of the customer's load profile must be made in order to determine the contribution of the customer's demand to the LSE's overall load. Customers are grouped according to the general characteristics of their usage (for example, low-use residential, high-use residential, small commercial, large industrial, etc.), and a load profile for each customer class is determined (typically through a "load study" using statistical methods). All customers within a class are deemed to have the same load profile; they differ only in the amount of energy they use during a billing period. The LSE's class load profiles are then summed to establish the LSE's overall load profile. Each month, the system operator uses the LSE's composite load profile to allocate the total amount of energy purchased by the LSE (adjusted for losses and "unaccounted for" energy) across the period's hours in order to establish the LSE's responsibility, hour by hour, for the system dispatch.

This process is called "settlement." It establishes what LSEs must pay to wholesale providers, reconciling the costs and volumes of contractual obligations with actual deliveries and allocating unaccounted for energy among the market participants.

Since the load profiles determine what an LSE pays for power, what an individual customer's demand actually looks like is not relevant. To the extent that a customer's actual load profile differs from the class average, the LSE sees neither the savings (if, for instance, the customer has less-than-average on-peak demand) nor the costs (if the converse were the case). Without some kind of mechanism in the settlement process that recognizes changes in demand, the LSE or the customer has little incentive to go after cost-effective savings through demand-response programs, energy efficiency, or innovative rate structures.

2. Settlement of Interval-Metered Load

How load is settled for end-uses with interval metering.

III. EXPERIENCE IN NEW ENGLAND AND ELSEWHERE

A. Time, Demand, and Usage Differentiated Rate Structures in Practice

Experience with TOU rates, seasonally-differentiated rates, block rates, demand charges, etc.

1. Puget

Description of Puget's Edison Personal Energy Management System.

2. New England

a) Vermont

Time-of-Day: effect of putting high-use residential and commercial customers on TOU rates, and of putting all customers on seasonally differentiated rates.

b) Maine

Absence of TOU rates for high-volume residential and commercial customers.

3. Lessons Learned

Significant long-term savings through changes in usage patterns and building stock. Cost-effectiveness is a function of energy demand. No short-term "dispatchability." In this way, the effect of more economically efficient rate designs on customer class load profiles is similar to that of improved end-use efficiency.

B. Real Time Pricing in Practice

1. Georgia Power

2. Duke

3. TVA

4. PG&E

5. SDG &E

6. Ontario Hydro

7. California Energy Commission Proposal

8. Pacific Northwest

Washington/Oregon drought buy-back arrangements. Puget, Pacific, Avista, and Bonneville paid up to $100/MWh to get customers to reduce load (this was in addition to bill savings).

9. Lessons Learned

Significant load shifting benefits, but most of the short-term load response comes from relatively few customers. With two-part RTP rates (regulated rates for usage up to a base amount, and RTP rates for incremental prices and decremental credits), utilities limit the risk of revenue loss and customers limit the risk of price/cost volatility. In such cases, utilities and customers often prefer simpler "customer baseline" (CBL) computations. RTP programs have been successfully combined with interruptible programs.

10. Barriers to RTP

Default service (if provided at a discount below average market prices or if provided at a flat-rate which would under other circumstances command a price premium). Customer concerns about price volatility. Utility revenue loss (overcome by making the RTP rates mandatory, thus avoiding customer self-selection). Gaming of two-part RTP rates. Availability of needed metering and communications systems, and the costs of those systems. Regulatory concerns: fairness, distribution equity, consumer protection, wholesale price caps.

11. Metering in New England

What percentage of customers currently has interval metering? What kinds of communications networks support them?

IV. Pricing Strategies: Considerations and Options

A. Principles and Issues

- Economic efficiency: markets and rules that produce least-cost outcomes. Improved economic efficiency flowing from prices more closely approximating marginal cost. Tensions between long-run investment efficiency and demand response in short-run wholesale markets.
- Overcoming the barriers to efficient choices.
- Simplicity.
- Roles of the ISO, utilities, load-serving entities, and customers. To whom is the price signal most efficiently sent, the LSE or the end-user? Who has the comparative advantage in bearing the risks? Where should the policy effort be focused, and what can be done to assist LSEs and customers to extract the highest potential value from demand-response?
- Integration of retail pricing with ISO load response (*e.g.*, interruptible) programs and needs
- Improved system dispatch.
- Environmental impacts. Avoided emissions and avoided new construction. Internalization of external costs into planning, dispatch, pricing?

B. A Menu of Pricing Options

1. Pricing for Lower-Volume Customers and Default Service

- TOU
- Seasonally differentiated
- Interruptible
- Demand and energy
- Block rates
- Rate design for distribution-only service

2. Real-Time Pricing

a) RTP Options

- Spot pricing
  - Unlimited; caps and floors; options for locked prices for limited periods; triggers (where the spot price is paid only when it exceeds a specified minimum for a specified period).
- "Two-part" pricing, where there is an access charge for using a pre-determined baseline quantity that is often specified on a customer-specific basis (*e.g.*, baseline kWhs * embedded rate/kWh), and spot prices (or credits) for variations from the baseline.

3. Considerations

- Mandatory or voluntary; utility net lost revenues; low-volume v. high-volume customers; cross-subsidies in rate design

C. Policies and Technologies to Support Innovative Rate Designs

1. Flexibility in Load Profiling

What can be done to enable the settlements process to flexibly and swiftly reflect changes in customer class usage? How can demand savings be reliably demonstrated? This is critical not only for the purposes of retail rate design but also for capturing the value, at wholesale, of increases in end-use efficiency and interruptible programs (demand sale-backs) for consumers whose overall usage levels do not justify the costs of advanced metering for RTP.

2. Metering and Data Management for RTP

Categories of technologies necessary to, or affected by, TOU, RTP, and other innovative rate structures:

- Metering and Measurement of Customer Energy and Power
- Internet access to these data in real time (or near real time) by consumers.
- Wide Area Access Networking Technology

a) Issues in Deployment

Challenges associated with large-scale deployment of RTP. Scale and scope, integration of systems (utilities', ISO's, vendors', customers', etc.). Vertically-integrated utility systems v. competitive systems. Ownership of the meters and communications systems.

3. Integration with Policies in Other Issue Areas

E.g., price-responsive load programs.

NEW ENGLAND DEMAND RESPONSE INITIATIVE

FRAMING PAPER # 4: ENERGY EFFICIENCY
Outline #3, 2/19/02

I. Executive Summary

II. Introduction and Overview

A. Purpose and objectives

1. Summarize the impact of energy efficiency programs on load (document as % of load growth in the region).

2. Consider energy efficiency efforts and programs that could be more effective in providing region-wide benefits to the region if coordinated or implemented regionally (existing or new programs).

3. Consider energy efficiency efforts concentrated in local geographic areas to relieve constraints or defer investments.

4. Consider explicit ISO/RTO support for regional, statewide, or local area energy efficiency programs that provide documented value to the regional pool (e.g., funding or co-funding using an uplift charge, planning and consideration of alternatives within a least-cost framework, bidding into the pool of resources).

B. Summary of options (planning, accounting and valuation, program, and funding options), with discussion in section VI

C. Summary of issues and challenges, with discussion in section V

III. Energy Efficiency Experience in New England

A. Energy efficiency reduces average consumption, peak consumption, and peak prices for everyone purchasing in the power market (e.g., MA DOER study, California studies)

B. Energy efficiency can help defer or avoid transmission and distribution investments (examples and documentation)

C. Summary of funding, energy savings, and peak demand savings, across the region and by state (will require some surveying or review of reports)

D. Summary of environmental benefits due to energy efficiency programs (e.g., MA DOER report, RI impacts)

E. Summary of some key relevant programs [C&I HVAC, residential HVAC, new construction (add only efficient load), lighting, etc.]

IV. Efforts and Experiences in Other Regions

A. Summary of key efforts and experiences in other regions. Focus on the handful of the most relevant projects (e.g., benefits for regional pools, targeted T&D programs, etc.). Pacific NW, NEEA regional programs. BPA decided to meet a certain amount of load growth through energy efficiency (250 aMW of total load growth). States have decided to grow efficiently, not inefficiently, through codes and standards (California). Texas, ERCOT are addressing reliability and transmission, and PUC set standard to achieve efficiency savings equivalent to 10% of load growth. Examples of targeted T&D efforts, where imports were constrained or limited.

V. Issues and Challenges

A. Accounting for and valuation of energy efficiency benefits to the region. Note that the framework for evaluating demand response programs is developing further and sharpening in approach (NY work). Encourage adequate time horizons in planning so that energy efficiency can be implemented in an integrated manner (e.g., can some demand response initiatives be longer term so that energy efficiency can bid into the pool, or could a statewide system benefits program bid into the pool of regional resources?). Planning and investment for longer-term versus short-term (day ahead) needs. Regional benefits from reduced consumption (all consumers benefit when some consumers reduce their load; multiplier for avoided cost in CA; cite Marcus study and PG&E follow up study).

B. Assessing, valuing, and selecting energy efficiency programs based on the load shape in addition to the contribution to peak demand, energy savings, and environmental benefits.

C. Funding and fiscal administration issues. Are the existing system benefits charge programs expected to fund energy efficiency and demand response programs (emergency and price-responsive), or is the ISO/RTO providing funding for coordinated, supplemental, and/or targeted energy efficiency efforts, as well as for emergency and price-responsive programs? For energy efficiency efforts, use ISO/RTO supplemental funding for supplemental programs? Three main funding options for energy efficiency efforts: (1) existing system benefits funding, possibly reallocated to focus more on regional needs; (2) complete a regional analysis of the benefits and value of energy efficiency, and increase the level of system benefits funding in each state to achieve even more value across the region; (3) regional funding and support from regional entities (ISO/RTO) for supplemental or targeted programs.

D. Regional program administration and management. Who can or should administer the region-wide programs?

E. Coordination across jurisdictions (regional vs. state vs. local) and purposes/focus (regional-wide vs. state vs. local area purposes). Include states encouraging each other to fund system benefits programs at adequate levels.

F. Who pays and who benefits (e.g., summer initiatives in recent years supported by state system benefits energy efficiency funding, or by conservation and load management funding in some states).

G. What are the risks of undoing some of the positive aspects of current statewide planning and support (e.g., does current planning already value regional benefits to some degree, including regional transmission benefits? Impact on MDC values in current cost-effectiveness tests?)

VI. Energy Efficiency Options

A. Set up options for discussion by stakeholders and decision makers. How to merge existing framework for planning and analysis of energy efficiency programs with developing framework for valuing and evaluating demand response programs?

B. Coordination and valuation of state system benefits programs (in terms of regional and pool benefits, including reliability and price). Potential reallocation or refocusing of system benefits programs to focus more on regional needs.

C. Regional programs funded, supported, and/or administered by ISO/RTO (including energy efficiency bids for longer-term demand response initiatives).

D. Technology options that have energy efficiency and demand response attributes (e.g., smart chips in energy efficient appliances)

E. Coordination and valuation (regional and pool benefits) of codes and standards

F. Programs targeted to local geographic areas (programs targeted to relieve constraints, or programs targeted to avoid/defer transmission or distribution investments)

G. Least-cost planning framework for regional transmission and power investments, or alternate approach of bidding against price of transmission and power options (these could be planning frameworks for several or all of the above options)

VII. Integration and Cross-Cutting Issues

A. Coordination and overlap with other NEDRI papers, and examples of applications

B. Congestion that can be relieved using a combination of approaches, including targeted energy efficiency to reduce load, pricing and metering options implemented locally to encourage price response, demand response programs or contracts, etc.

C. Planned transmission or distribution investment that can be eliminated or deferred, through aggressive energy efficiency together with longer term demand response contracts, and possibly CHP and distributed generation.

D. Interaction between real time pricing (paper 3) and energy efficiency (paper 4) in terms of reducing overall load (and therefore prices for everyone).