December 30, 2004

Via Hand Delivery

Honorable Magalie R. Salas, Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, D.C. 20246

Re: Independent Assessment of Demand Response Programs of ISO New England Inc., FERC Docket No. ER02-2330-

Dear Ms. Salas,

On June 6, 2003, the Federal Energy Regulatory Commission ("Commission") issued an order in the above-referenced docket which, among other things, directed ISO New England Inc. (the "ISO") to "prepare and submit an 'independent' in-depth process and impact evaluation and market assessment of its 2003 demand response programs by December 31, 2003, and to provide a similar evaluation by the end of each calendar year until and including December 31, 2005."[1] The ISO retained RLW Analytics, LLC and Neenan Associates, LLC to prepare the attached assessment, entitled *An Evaluation of the Performance of the Demand Response Programs Implemented by ISO-NE in 2004*. The report contains descriptions of each of the demand response programs, descriptions of program participation and performance, an analysis of the market impacts of the programs, a comprehensive process evaluation, an assessment of customer satisfaction and preferences, and a market assessment.

Pursuant to Rule 1907 of the Commission's Rules of Practice and Procedure,[2] the ISO hereby submits an original and 5 copies of this report in accordance with the June 6 Order. Copies of this report are being served on all persons on the Commission's official service list in the captioned proceeding, as well as on the governors and electric utility regulatory agencies for the six New England states that comprise the NEPOOL Control Area. All NEPOOL Participants Committee members are being furnished with an electronic copy of this report. In accordance with the Commission's rules and practice,

[1] Order on Rehearing and Accepting in Part and Rejecting in Part Compliance Filings, 103 FERC ¶ 61,304 at P 69 (June 6, 2003) ("June 6 Order").

[2] *See* 18 C.F.R. § 385.1907 (2004).

there is no need for these entities to be included on the Commission's official service list in this proceeding unless such entities already are or become intervenors in this proceeding. A draft form of notice that is suitable for publication in the Federal Register is included in this filing, and a diskette containing this form of notice in electronic format is also enclosed.

Respectfully submitted,

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Attachments

cc: All parties to FERC Docket No. ER02-2330-004 et al.

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in these proceedings.

Dated at Washington, D.C. this 30th day of December, 2004.

Lyndsey K.Sites
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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

New England Power Pool	)	Docket No. ER02-2330-___

NOTICE OF FILING
(_____)

Take notice that on December 30, 2004, ISO New England Inc. (ISO) submitted an Independent Assessment of Demand Response Programs as directed by the Commission in its June 6, 2003 Order on Rehearing and Accepting in Part and Rejecting in Part Compliance Filings, 103 FERC ¶ 61,304. The ISO states that copies of the filing have been served on all parties to the above-captioned proceeding.

Any person desiring to intervene or to protest this filing should file with the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211 and 385.214). Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a motion to intervene. All such motions or protests should be filed on or before the comment date, and, to the extent applicable, must be served on the applicant and on any other person designated on the official service list. This filing is available for review at the Commission or may be viewed on the Commission's web site at http://www.ferc.gov, using the "eLibrary" link. Enter the docket number excluding the last three digits in the docket number field to access the document. For assistance, contact FERC Online Support at FERCOnlineSupport@ferc.gov or toll-free at (866)208-3676, or for TTY, contact (202)502-8659. Protests and interventions may be filed electronically via the Internet in lieu of paper; see 18 CFR 385.2001(a)(1)(iii) and the instructions on the Commission's web site under the "e-Filing" link. The Commission strongly encourages electronic filings.

Comment date:_____

Magalie R. Salas
Secretary

An Evaluation of the Performance of the Demand Response Programs Implemented by ISO-NE in 2004

Prepared for:

ISO New England Inc.
One Sullivan Road
Holyoke, Massachusetts 01040-2841

Prepared by:

RLW Analytics, LLC
Neenan Associates, LLC

December 29, 2004

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ISO-NE 2004 Demand Response Program Evaluation

1 Introduction

1.1 Overview

ISO New England Inc. (ISO-NE) commissioned the team of RLW Analytics and Neenan Associates to conduct a comprehensive evaluation of its portfolio of demand response programs. This evaluation was conducted to comply with a June 6, 2003 Order issued by the Federal Energy Regulatory Commission, which directed ISO-NE to prepare and submit an annual independent evaluation of its demand response programs at the end of each calendar year until December 31, 2005. This evaluation was performed during the period mid-August through December 2004. The evaluation was comprised of four main elements:

- A market impacts evaluation,
- A process evaluation study,
- An assessment of customer satisfaction and a product and feature preference study, and
- A market potential study.

The market impact evaluation quantified the benefits from curtailments undertaken during Real-Time Price Response Program events. To measure market price impacts, a supply model of the NEPOOL market was constructed. The model provides the means for estimating how prices are impacted during curtailment events, and projecting the impacts of those price changes into bill savings realized by buyers of electricity. Another model produces the reliability benefits associated with load curtailed by participants in the Real-Time Demand and Profiled Response Programs. Since there were no reliability events during 2004, no reliability benefits were calculated.

The process evaluation study identified the procedures and processes involved in implementing the program and evaluated how well ISO-NE performed its function. The primary sources of data were surveys/interviews with ISO-NE staff and stakeholders, as well as reviews of program manuals and records.

Customer satisfaction and preferences were evaluated by analyzing the results of a survey that was administered to both participating and non-participating retail customers. All current program participants received the survey. In addition, customer contact lists were developed to provide a frame for surveying customers that previously participated, but retired from the program, as well as customers that had shown interest and had been exposed to the program particulars, but chose not to participate. The survey responses provided data for the variety of analyses undertaken to characterize and compare the perceptions of the customer groups.

This document is organized in the following manner:

- Section 1 provides an overview of this evaluation report and a description of the various demand response programs implemented by ISO-NE in 2004.
- Section 2 discusses the market impacts of the Real-Time Price Response program.
- Section 3 presents the results of the process evaluation.
- Section 4 shows the findings of the survey on customer satisfaction and preferences with regard to product types and features.
- Section 5 discusses the market potential of demand response programs in the New England region.

1.2 Program Descriptions

ISO-NE introduced several demand response programs in March 2003, concurrent with the introduction of Standard Market Design (SMD). The new programs, which replaced the existing ISO-NE offerings that had been available since 2001, are organized into two categories, as follows:

- Programs that provide reliability ("reliability programs"), which includes the Real-Time Demand Response Program (including programs with 30-minute and 2-hour notice provisions) and the Real-Time Profiled Response Program.

- Programs designed to encourage load reduction in response to high real-time wholesale energy prices, which currently includes the Real-Time Price Response Program ("price program").

Customers are enrolled in a program through an Enrolling Participant, which is a local distribution company (LDC), competitive energy service provider, or independent Demand Response Provider.[3] The program provisions are described further below. Complete details of the ISO-NE demand response programs can be found in the program manuals available at the ISO-NE web site (www.ISO-NE.com).

1.3 Real-Time Demand Response Program

The Real-Time Demand Response Program was designed for customers that can reduce their electricity usage within either 30 minutes or two hours of notice from ISO-NE. Compliance with curtailment events, which are coincident with New England Power Pool (NEPOOL) Operating Procedure No. 4 (OP-4) conditions that are characterized by expected reserve shortfalls, is mandatory.[4] Participants that curtail load are paid the greater of the Real-Time Locational Marginal Price (LMP) applicable to their Load Zone or the floor price, which is $0.50/kWh in the 30-minute program and $0.35/kWh in the two-hour program. ISO-NE guarantees a minimum of two hours of curtailment for each event. Participants are also eligible to receive ICAP payments. Failure to comply with a curtailment event results in the forfeiture of ICAP payment accumulated for the month, and the customer's curtailment capability going forward is de-rated accordingly.

[3] Demand Response Providers are non-NEPOOL entities that aggregate and enroll curtailable loads into the demand response programs.

[4] OP-4 defines the actions taken during a capacity deficiency. The first ten actions of OP-4 are implemented to maintain operating reserves. Later actions of OP-4, Actions 11 through 16, represent more extreme dispatch actions and may result in degraded system reliability since full operating reserve required for normal operation is not maintained. For example, at Action 11 of OP-4, ISO-NE will allow the 30-minute operating reserve to reduce to zero.

The Real-Time Demand Response Program is activated at various Action Steps of OP-4 depending on the program's notification time and the technology used by the participating customer to accomplish the load reduction, as described in the table below.

Allowed Notification Time	Technology	OP-4 Action Step
30-Minutes	Load Reduction with or without Emergency Generation[5]	Actions 9 and 12
2-Hours	Load Reduction with or without Emergency Generation	Actions 3, 4, 5, 7, and 8

Participation in the Real-Time Demand Response Program requires metering capable of recording the participant's usage in five-minute intervals, as well as Internet-based communication capability. These metering and communication systems are referred to as Internet Based Communication Systems (IBCS). NEPOOL provides financial support to demand response program participants to purchase and maintain metering systems that meet the IBCS requirements. The equipment incentive is either $2,200 or $2,800, depending upon installation requirements, provided that the facility enrolls a load reduction of at least 100 kW. Participants that commit to a load reduction of 300 kW or greater also receive up to $100 per month towards the cost of maintaining the IBCS. The IBCS system set up by ISO-NE is an open-architecture system – called the IBCS Open Solution or IBCS OS – which allows for a variety of vendors to provide participating customers with IBCS services.

[5] While each state in New England has slightly different environmental rules, typical emergency generator operating permits will only allow such generators to operate following ISO-NE declaration of OP-4 Action 12 or following loss of external power to the facility. Therefore, such emergency generators must be in the Action 12 portion of the 30-Minute Notice program to avoid violating their operating permit.

No demand response program curtailment events were called during 2004. In accordance with the program rules, ISO-NE conducted a test of the reliability programs on August 20, 2004 by activating an Audit Event. Audit Events are conducted in a manner similar to real demand response events – no prior warning is given and Enrolling Participants are not informed of whether the Event is an Audit or a real OP-4 event. The Audit Event started at 11:00 a.m. and ended at 1:30 p.m. and 3:00 p.m. for customers that elected 30-minutes and 2-hours notice, respectively. At approximately 10:45 a.m. on the Audit Event day, notification indicating that the event would start at 11:00 a.m. was sent to participating customers using the IBCS. The results of the Audit Event are described in Section 2.3.1.

1.4 Real-Time Price Response Program

In the Real-Time Price Response Program, voluntary reductions in load by participants are eligible for payment when the ISO forecasts hourly Zonal Prices to be greater than or equal to $0.10/kWh during any of the hours of 7 a.m. to 6 p.m. on non-holiday weekdays and the ISO transmits instructions that the eligibility period is open.[6] ISO-NE typically makes the determination to open the eligibility period late in the day for the next day. Once the eligibility period is opened, ISO-NE usually authorizes payments for any load that is curtailed during the entire 11-hour period. However, program rules also permit ISO-NE to declare an event on the same day, or for a shorter period.

During 2004, most events started at 7:00 a.m. and extended to 6:00 p.m. Enrolling Participants and their participating customers are notified of price response events by several means, including e-mail, and by a posting on the ISO-NE web site. Some Enrolling Participants notify their program participants of price response events using pagers, automated phone calls, and other means. Meter readings for this program are submitted daily or monthly by the Enrolling Participant to the ISO-NE on the same schedule as other hourly meter data.

[6] ISO-NE opens the eligibility period in one or more Load Zones when actual Day-Ahead Locational Marginal Prices (LMP) or Real-Time LMP as forecasted by a Resource Adequacy Analysis in a given Load Zone equals or exceeds $100/MWh during the eligible hours (7:00 a.m. to 6:00 p.m.).

The Real-Time Price Response Program allows for an alternative data reporting option. The Super Low Tech option allows price program customers that do not have daily meter reading capabilities to participate in the program as long as their Enrolling Participant supplies hourly data to ISO-NE prior to the 90-day resettlement period.[7] When the ISO performs the 90-day resettlement of the Real-Time Energy Market, the Enrolling Participants for these resources are paid for verified load curtailments that occurred during event hours.

1.5 Real-Time Profiled Response Program

The Real-Time Profiled Response Program is for Enrolling Participants with loads that are capable of being interrupted within 2-hours after receiving instructions to interrupt load from ISO-NE. The Real-Time Profiled Response Program is activated at Action Step 3 of OP-4. Individual customers participating in the Real-Time Profiled Response Program are not required to have an interval meter. The Enrolling Participant is required to develop a monitoring and verification plan (M&V) plan under the guidelines specified in Appendix E of the Load Response manual and submit the plan to ISO-NE for approval.

The Enrolling Participant is paid the higher of the Real-Time Locational Marginal Price in their Load Zone or a minimum payment of $0.10/kWh for the actual load reduction as specified in its approved M&V plan. Demand resources that participate in the Real-Time Profiled Response Program are eligible to qualify as ICAP resources.

1.6 2004 Program Changes

No fundamental changes were made to any of the demand response programs in 2004. However, some administrative changes were made, as follows:

[7] Only data sent to the ISO within 36 hours of an event, or true-up data sent before the 20th of the month, are included in the initial settlement. Beginning in June 2004, the time period within which ISO-NE would accept meter data was changed to 60 hours. The Enrolling Participants typically send the Super Low Technology customers load data once a month after the deadline for inclusion in initial settlement.

- The baseline computation was changed to allow demand response assets to become "Ready to Respond" faster. Previously, ISO-NE required that 10 days of data be used to set the initial baseline. Now, only 5 days of data are required, thereby speeding up the process of making participants eligible to respond to events.
- The IBCS cost reimbursement policy was modified to allow for reimbursement in cases in which smaller, individual assets are aggregated together to meet program size requirements.
- Requirements for the IBCS Open Solution and IBCS Providers were developed in order to clarify the roles, responsibilities, and relationship of those entities providing telemetering services that enable customers to participate in ISO-NE's load response programs.
- A Web Notification Page was developed to enable program participants to obtain definitive information from the web regarding load event start and restoration times.
- The meter data submission deadline was increased from 36 hours to 60 hours after the operating day. This provides Enrolling Participants a wider window within which to submit initial meter data, which expedites settlement.
- Policies regarding when to activate assets in the Real-Time Price Response program using the Super Low Tech metering option were clarified.
- Data validation procedures were implemented and policies regarding the submission of meter data with missing or zero values were clarified.

Many of these changes were in response to needs expressed by program participants and Enrolling Participants as part of the 2003 program evaluation.

1.7 Southwest Connecticut "Gap" RFP

On December 1, 2003, ISO-NE issued a Request for Proposals (RFP) soliciting up to 300 MW of temporary supply and demand resources for Southwest Connecticut (SWCT) for the period 2004 to 2008. The stated goal was to improve electric system reliability in SWCT through the summer of 2007, at which time a 345 kV transmission loop expansion is expected to come into service.

In response to this RFP, ISO-NE received 34 proposal packages from 25 different companies. The proposals totaled 1,081 MW encompassing demand response, on-peak conservation and load management (C&LM), and peaking generation resources.

ISO-NE has contracted with seven companies for ten projects. Most of the projects involve multiple resources at various locations. Some of the resources selected were in service by June 1, 2004, with others to be ramped up later, to approximately 260 MW by the summer of 2007.

Several types of resources were eligible to respond to the RFP: quick-start generation, either new or incremental from existing generation, demand reduction, emergency generation, and C&LM projects. Demand reduction resources are required to participate in the 30-Minute Real-Time Demand Response Program. The RFP did not state a preference for any one of these resource types. The evaluation criteria in the RFP stated that the objective was minimizing the expected cost of achieving the reliability objective. The RFP listed other evaluation factors such as location, permitting, and proposed in-service date.

The types of resources selected under the procurement and their in-service dates are summarized in Table 1.1 below:

Resource Type	*Customer Type*	*2004*	*2005*	*2006*	*2007*
C&LM	Commercial	0.7	4.3	5.0	5.3
C&LM Total		**0.7**	**4.3**	**5.0**	**5.3**
Emergency Generation	Commercial	13.9	43.7	49.3	51.8
	Education	2.0	2.8	2.8	2.8
	Healthcare	0.0	9.7	9.7	9.7
	Municipal	10.2	33.5	33.5	33.5
	Other	69.3	69.3	69.3	69.3
Emergency Generation Total		**95.4**	**158.9**	**164.5**	**167.0**
Load Reduction	Commercial	16.6	26.1	31.1	33.6
	Healthcare	0.0	0.3	0.3	0.3
	Municipal	3.1	3.4	3.4	3.4
	Residential	0.9	19.1	39.7	40.2
	Small Commercial	2.5	10.0	10.0	10.0
Load Reduction Total		**23.1**	**58.9**	**84.5**	**87.4**
Grand Total		**119.2**	**222.1**	**254.0**	**259.8**

Table 1.1: Resources Selected in ISO-NE SWCT RFP for 2004-2007

ISO-NE selected the total resource MW to meet the reliability need based on the 2004 NEPOOL Load Forecast. The resources selected will provide 119 MW in 2004 and increase to 260 MW by 2007. The expected total cost is $128 million.

The selected resources in combination represent the lowest cost, most viable, and best-located resources. They will provide SWCT with additional emergency resources to reduce the risk of load shedding under high peak loads and high system outage conditions.

The demand reduction resources, selected under the SWCT RFP and available on or before August 20, 2004, are included in the participation and performance information presented later in this report.

2 Program Participation and Performance

The program year 2004 is comprised of the period September 1, 2003 through midnight, August 31, 2004.[8] Program enrollment is measured by number of assets, which are individual customers or aggregations of customers, and by enrolled MW, which is the amount of load those assets committed to the program for curtailment.

2.1 Participation

As of September 1, 2004 there were 486 assets enrolled in ISO-NE's demand response programs, comprised of 367 assets in the price program (76%) and 119 assets enrolled in the reliability programs (24%), as shown in Figure 2.1.[9] Figure 2.2 illustrates the curtailable load (MW) enrolled in the price and reliability programs. While the majority of the assets are enrolled in the price program, they represent only 30% of the curtailable load.

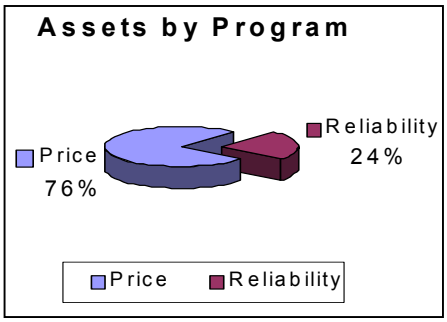


Figure 2.1 2004 Demand Response Assets by Program

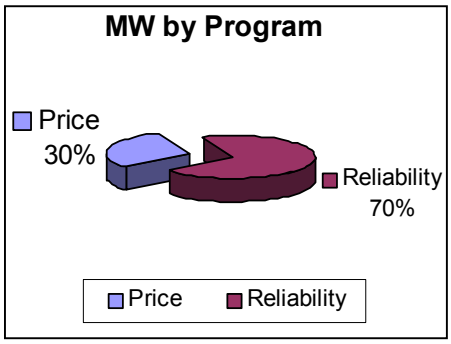


Figure 2.2 2004 Demand Response Assets by Program

Enrolled MW by load zone and by program is shown in Table 2.1. Participation in the reliability programs was highest in Connecticut (147 MW), which comprised about 59% of the total reliability program MWs, followed by Maine (77 MW) with 31%. In 2004, no other zone had more than 8% of the total reliability program

[8] This period was selected because of the time needed to survey program participants and to process and analyze data in time to meet a Federal Energy Regulatory Commission directive that this report be filed with the Commission by December 31 of each calendar year. Sufficient time was not available to collect and analyze data from later months in the current year.

[9] Throughout this and subsequent sections, the programs offered by ISO-NE are referred to as the reliability programs and the price program. In this context, the reliability programs include three distinct programs: 30-Minute Real-Time Demand Response Program, 2-Hour Real-Time Demand Response Program and Real-Time Profiled Response Program. The reliability programs differ with regard to program features, but all are treated as dispatchable resources for the purpose of maintaining system reliability. The price program refers only to the Real-Time Price Response program.

MWs. The NEMA zone provided the largest amount of load (40 MW) in the price response program, which comprised 37% of total price program MWs. Connecticut was the only other zone providing more than 9% of the total enrolled price program load; its 32 MW represented 29% of total price program MWs.

	Price		Reliability - Profiled		Reliability - Action 9		Reliability - Action 12		Reliability 2-HR	
Zone	Asset	MW	Asset	MW	Asset	MW	Asset	MW	Asset	MW
VT	15	7.5	1	5.9	0	0	1	0.1	0	0
NH	2	1.2	0	0	0	0	1	0.4	0	0
ME	1	1.5	3	76	0	0	0	0	1	1
WCMA	100	13.7	0	0	2	0.7	1	1.5	3	9.3
NEMA	105	39.5	1	1.4	6	3	2	0.4	4	1.5
SEMA	92	9.5	0	0	0	0	1	0.5	0	0
CT	37	31.7	0	0	44	46.4	45	100	3	0.4
RI	15	3.3	0	0	0	0	0	0	0	0
Totals	**367**	**107.9**	**5**	**83.3**	**52**	**50.1**	**51**	**102.9**	**11**	**12.2**

Table 2.1 Demand Response Program Participation by Program and Zone[10]

Figures 2.3 and 2.4 further illustrate the concentration of program assets. The highest concentration of assets for the reliability programs is in Connecticut with 92 participants,

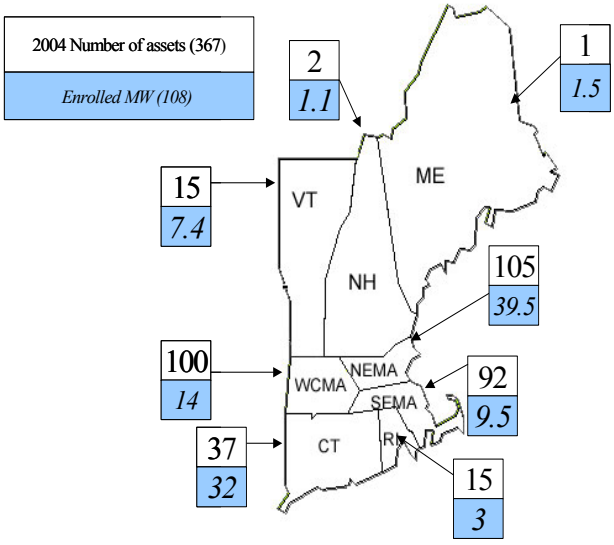


Figure 2.3 Price Program by Zone

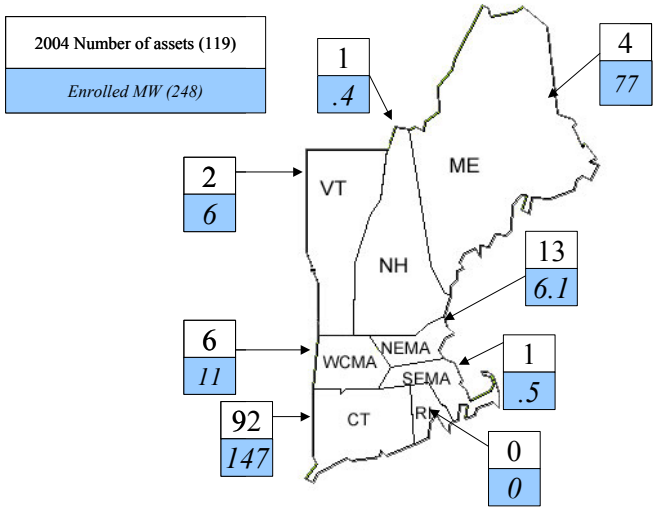


Figure 2.4 Reliability Programs by Zone

[10] Both Action 9 and Action 12 reliability programs are part of the 30-Minute Real-Time Demand Response Program.

which accounts for 77% of total reliability program assets. NEMA, WCMA and SEMA make up the majority of assets in the price program with 105, 100 and 92 assets, respectively in 2004.

Enrolling Participants register assets into ISO-NE's demand response programs and payments to assets are distributed through the Enrolling Participants. An Enrolling Participant can be a local distribution company (LDC), demand response provider (DR Provider) or a competitive supplier. Figure 2.5 shows the assets and MW in the reliability programs by Enrolling Participant type. LDCs enrolled 60% of the programs' assets, representing only 30% of the curtailable load. DR Providers have a more balanced ratio of percent of assets (35.3%) to enrolled MW (40%). Conversely, competitive suppliers provided only 4.2% of the enrolled assets, which comprised 30% of the curtailable load in the reliability programs.

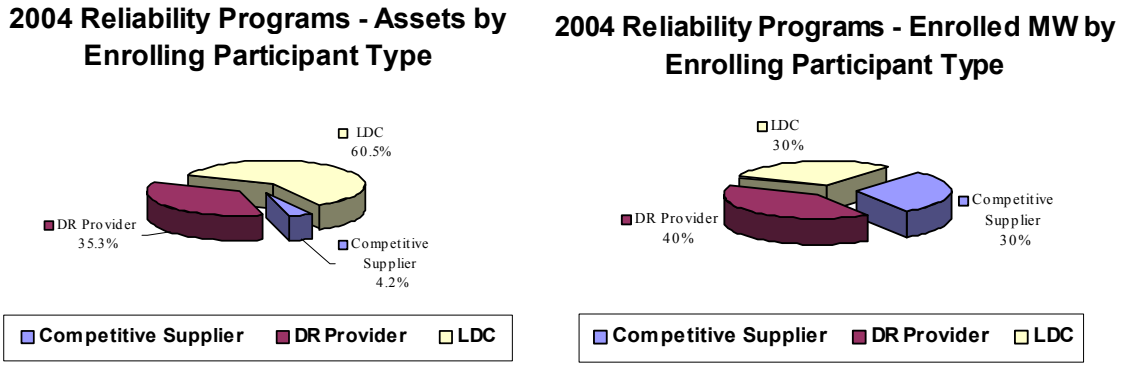


Figure 2.5 Reliability Program Assets and MW by Enrolling Participant Type

LDCs enrolled almost all (over 98%) of the assets enrolled in the price program (Figure 2.6), which accounted for only 68% of the curtailable load in the price program. Competitive suppliers registered only 2% of the customers, but supplied 21% of the curtailable load in the price program. Demand Response Providers enrolled few assets in the price program (less than 1%), but they provided 12% of the program's curtailable load.

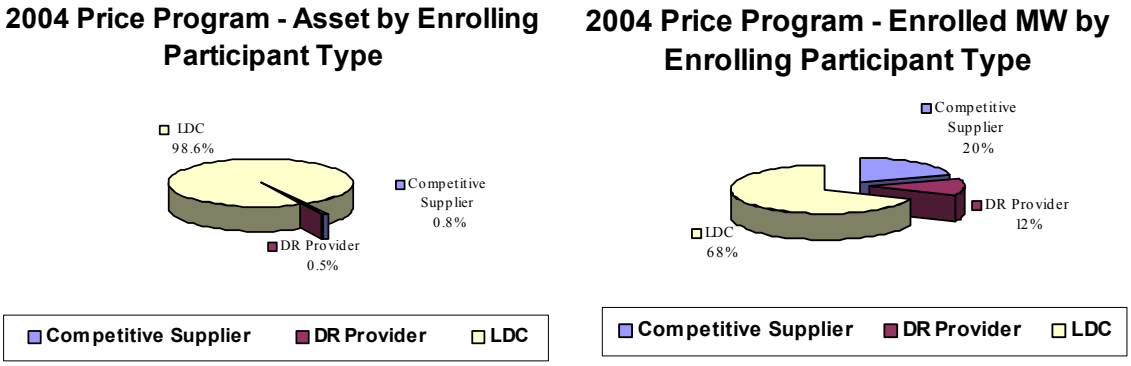


Figure 2.6 Price Program Assets and MW by Enrolling Participant Type

2.2 Program Retention and Migration

Program year 2004 was the second year of operation for ISO-NE's revised demand response programs. An analysis of participant retention and migration was undertaken to track trends in program enrollment. Retention refers to assets that re-enroll in the same program in 2004. Migration refers to assets that moved to a different program in 2004. Such studies help program managers measure trends and changes in program participation.

Overall, the number of participants in ISO-NE's demand response programs increased in 2004 by 11%. The details of changes in participation are illustrated in Table 2.2. The largest increase in participation was in the reliability 2-hour program, with an 83% increase in assets and a 216% increase in curtailable MW. This program had the lowest number of assets and enrolled MW in 2003 and the second-lowest number of assets in 2004. The largest decrease in both assets (-67%) and curtailable MW (-39%) occurred in the reliability-profiled program. Even with the dramatic reduction in enrollment and curtailable load in the reliability-profiled program, the enrolled MW accounted for approximately one-third of the all reliability program curtailable load in 2004.

	2003		2004		Percent Change From 2003 to 2004		Enrolled MW per Asset		
	Assets	MW	Assets	MW	Assets	MW	2003	2004	Percent Change
Price	332	129.67	367	107.77	11%	-17%	0.39	0.29	-25%
Reliability-Profiled	15	136.9	5	83.24	-67%	-39%	9.13	16.65	82%
Reliability - Action 9	51	50.74	52	50.01	2%	-1%	0.99	0.96	-3%
Reliability - Action 12	34	57.67	51	102.9	50%	78%	1.7	2.02	19%
Reliability 2-HR	6	3.88	11	12.26	83%	216%	0.65	1.11	72%

Table 2.2 Program Statistics 2003 to 2004

The reduction in the reliability-profiled program's enrollment is a direct result of the expiration of one LDC's interruptible rate tariff. In prior program years, many customers on the LDC's interruptible rate tariff had been simultaneously enrolled in the Real-Time Profiled Response Program. With the expiration of the interruptible rate tariff, the LDC chose to retire these assets from the demand response program.

Table 2.3 provides a detailed accounting of how the number of assets (the top section of the table) and enrolled MW (the bottom section of the table) changed from 2003 to 2004 in each of the four demand response programs. The first column of the top section includes the retention and migration accounting categories: the Previous Year's enrolled assets, Drops (the number of assets that left the program altogether), New (assets that enrolled for the first time), Net Migration In (assets that switched from another program) and Net Migration Out (assets that switched to another program).

For example, consider the price program asset accounting presented in the second column of the top section of Table 2.3. The first row shows the Previous Year's assets (332), the starting point for identifying changes in enrollment between 2003 and 2004. The second row (Drop) shows the number of assets (46) that were enrolled in 2003, but withdrew from the price program and did not enroll in another ISO-NE program in 2004. The third row (New) shows that 81 assets enrolled for the first time in the Price program. The fourth and fifth rows show Net Migration In (2) and Net Migration Out (2) respectively, representing the net change in the number of assets who were enrolled in a reliability program and switched to the price program (+Net Migration In), or who left the price program for a reliability program (-Net Migration Out). For 2004, the Net Migration

numbers also include assets where a change of program was required to correct a registration error (e.g., an Enrolling Participant registering an asset into the wrong program) as well as assets that chose to move to another program for some other reason. The final row in the upper section, Current Year, shows the current number of assets (367) in the price program in 2004.

Assets	Price *2003 to 2004*	Reliability - Profiled *2003 to 2004*	Reliability 30-Min *2003 to 2004*	Reliability 2-HR *2003 to 2004*
Previous Year	332	15	85	6
- Drop	46	11	27	1
+ New	81	1	45	6
+ Net Migration In	2	0	7	1
- Net Migration Out	2	0	7	1
= Current Year	367	5	103	11

MWs	Price *2003 to 2004*	Reliability - Profiled *2003 to 2004*	Reliability 30-Min *2003 to 2004*	Reliability 2-HR *2003 to 2004*
Previous Year	129.7	136.9	108.41	3.9
- Drop	52.0	64.7	16.19	0.1
+ New	37.0	11.0	36.89	8.8
+ Net Migration In	2.6	0	4.65	0.3
- Net Migration Out	6.8	0.0	4.95	0.6
+ Changes to Sub. MW [4]	-2.7	0.0	24.1	0.0
= Current Year	107.8	83.2	152.9	12.3

Table 2.3 Program Changes 2003 - 2004

The bottom section of table 2.3 provides a similar accounting of retention and migration in terms of the level of enrolled MW in each of the four programs. It contains an additional category, "Changes to Sub. MW," to account for changes to the level of enrolled MW resulting from assets that re-enrolled in the same program in 2004, but changed the level of MW offered.

This comparison of ISO-NE's demand response program enrollment from August 2003 to August 2004 shows two programs where new assets replaced retiring assets (-Drop) at a rate of almost 2:1 (i.e., the price program and reliability 30-min program). However, the enrolled MW lost and gained in these two programs are very different. The price program lost 52 MW and gained back about 71% of it with the new assets, while the

reliability 30-min program gained four times more load than it lost. The reliability 30-min program also had the largest increase in enrolled MW for assets that continued participation from 2003 (24 MW). As indicated earlier, the largest decrease in assets occurred in the reliability-profiled program.

The increased participation in the reliability 30-min program can be attributed to ISO-NE's December 2003 (which is included in the 2004 program year) solicitation of emergency resources in Southwest Connecticut (SWCT Gap RFP). The majority of the new assets in the 30-Minute Real-Time Demand Response Program are also attributable to Enrolling Participants that were awarded Supplemental Capacity Agreements under the SWCT Gap RFP.

2.3 Performance

Performance, measured by individual participant and collective program curtailments and payments during events, reflects the initial settlement data. Subsequent reports of program performance may vary from those reported herein due to revisions that were undertaken during the 90-day settlement period.

2.3.1 Reliability Programs

During the summer of 2004, ISO-NE did not activate the reliability programs in response to a system emergency. However, a test applicable to the reliability 30-min program assets was conducted on August 20, 2004 from 11:00 a.m. to 1:30 p.m. The 2-Hour Demand Response and Profiled Response program assets were tested concurrently, but the test extended through 3:00 p.m. Payment pursuant to each program's rules was made to all assets that performed.

Table 2.4 details, by program, the results of the test conducted. Overall, a 45.8% response rate was achieved for a total of 349.42 MW of load curtailed during the test, resulting in total payments of $168,927. The assets in the 30-min Demand Response with Generation (also known as Reliability-Action 12) provided 61% of the overall curtailed

MW during the test. The assets in the 30-min Demand Response without Generation (also known as Reliability-Action 9) provided 33% of the overall curtailed MW.

August 20, 2004 Settlement Data - All Zones

Program	Hour Ending	Enrolled MW	Interruption MW	Payment	Performance Factor
2-Hour Demand Response	12	12.26	1.03	$360	8.4%
11 a.m. to 3 p.m.	13	12.26	2.71	$950	22.1%
	14	12.26	2.31	$810	18.9%
	15	12.26	2.58	$903	21.1%
Sub-Total		**49.04**	**8.64**	**$3,023**	**17.6%**
30-Minute Demand Response	12	102.56	63.11	$31,556	61.5%
with Emergency Generation	13	102.56	99.91	$49,956	97.4%
11 a.m. to 1:30 p.m.	14 *	51.28	49.73	$24,863	97.0%
Sub-Total		**256.40**	**212.75**	**$106,375**	**83.0%**
30-Minute Demand Response	12	50.01	42.09	$21,044	84.2%
without Emergency Generation	13	50.01	49.28	$24,638	98.5%
11 a.m. to 1:30 p.m.	14 *	25.01	25.45	$12,726	101.8%
Sub-Total		**125.03**	**116.82**	**$58,408**	**93.4%**
Profiled Response Program	12	83.24	0.00	$0	0.0%
11 a.m. to 3 p.m.	13	83.24	0.00	$0	0.0%
	14	83.24	0.18	$18	0.2%
	15	83.24	11.04	$1,104	13.3%
Sub-Total		**332.94**	**11.21**	**$1,121**	**3.4%**
Grand Total		**763.41**	**349.42**	**$168,927**	**45.8%**

* Represents equivalent capacity for 1/2 of Hour 14

Table 2.4 Settlement Data by Program for August 20, 2004 Reliability Program Test

Table 2.5 provides details of the test results by program and by zone for the hour ending 1300 of the test day. The section of columns labeled No Participation (columns 3 – 5) provides information about assets that were enrolled in the program at the time of the test, but did not respond. Approximately 33% of the MW enrolled in the reliability programs overall did not respond during this hour of the test event – the majority of the unresponsive MWs were enrolled in the Profiled Response program.

Participation by Program and Load Zone

		No Participation			Participated			
Program	Load Zone	Enrolled MW	Interruption MW	Number of Assets	Enrolled MW	Interruption MW	Performance Factor	Number of Assets
2-Hour Demand Response	CT	0.20	0.00	2	0.23	0.15	66.2%	1
	ME				1.00	0.88	87.9%	1
	NEMA	1.23	0.00	3	0.30	0.19	64.3%	1
	WCMA	2.00	0.00	1	7.30	1.49	20.5%	2
Sub-Total		**3.43**	**0.00**	**6**	**8.83**	**2.71**	**30.8%**	**5**
30-Minute Demand Response with Emergency Generation	CT	0.60	0.00	1	99.05	99.19	100.1%	43
	NEMA				0.38	0.07	17.6%	2
	WCMA	1.50	0.00	1				
	NH				0.40	0.27	66.8%	1
	SEMA				0.50	0.31	62.2%	1
	VT				0.14	0.08	56.5%	1
Sub-Total		**2.10**	**0.00**	**2**	**100.46**	**99.91**	**99.5%**	**48**
30-Minute Demand Response without Emergency Generation	CT	1.95	0.00	5	44.41	47.35	106.6%	39
	NEMA	0.95	0.00	3	2.00	1.93	96.6%	3
	WCMA	0.70	0.00	2				
Sub-Total		**3.60**	**0.00**	**10**	**46.41**	**49.28**	**106.2%**	**42**
Profiled Response Program	ME	65.00	0.00	2	11.00	11.04	100.3%	1
	NEMA	1.35	0.00	1				
	VT	5.89	0.00	1				
Sub-Total		**72.24**	**0.00**	**4**	**11.00**	**11.04**	**100.3%**	**1**
Grand Total		**81.37**	**0.00**	**22**	**166.69**	**162.94**	**97.7%**	**96**

Table 2.5 Participation by Program and Load Zone – Hour Ending 13

Columns 6 through 9 of Table 2.5 show the performance of those assets that curtailed load during the test. A total of 96 assets participated in the test, curtailing 166.69 MW in test hour 1300. The overall performance factor, which compares Interruption MW to Enrolled MW, was 97.7% during that hour, with the assets in reliability 30-min programs in CT curtailing more load than they had enrolled. One asset in the Profiled Response program in Maine also over-performed slightly during hour ending 1300. Assets enrolled in the reliability 30-min programs provided 88% of the load reduction in the hour, 100.46 MW from the 30-min with emergency generation (i.e., Action 12 of OP-4) and 46.41 MW from the 30-min without emergency generation (i.e., Action 9 of OP-4).

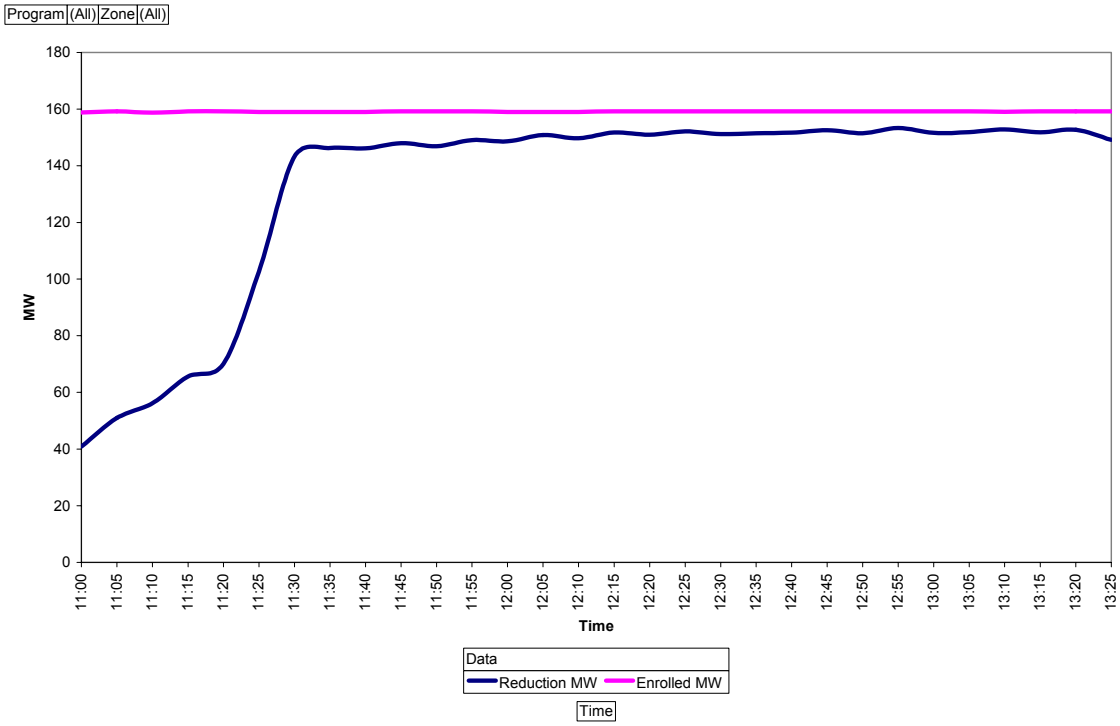


Figure 2.7 Reliability Program Response to Test Event – 5-Minute Data

Figure 2.7 plots the response of assets to the Audit Event (where 5-minute interval data was available) beginning at 11:00 a.m. through 1:25 p.m. (13:25). The dark line shows the level of curtailments (Reduction MW) and the straight, light-colored line shows the amount of load enrolled in the reliability programs (Enrolled MW). Curtailments reached almost 90% of the enrolled level within 30 minutes of the beginning of the test.

2.3.2 Price Program

Table 2.6 lists price response program events and response by month for the 2004 program year. ISO-NE paid for load curtailments on 56 distinct days for a total of 2,132 event hours and resulting in 9,216 MWh of load curtailments. By comparison, last year, during the period January 2003 – August 2003, there was only 1,950 total MWh of load curtailment. The number of participants curtailing during event hours ranged from a minimum of 44 (November 2003) to a maximum of 337 (January 2004).

Price Response Program Monthly Event Performance Summary					
Month	Distinct Event Days	Event Hours	Responding Asset Count	Total MWh Curtailed	Total Payment
Sep. '03	1	67	333	340	$34,982
Oct. '03	6	66	54	392	$40,569
Nov. '03	14	144	44	1,028	$102,956
Dec. '03	3	132	245	1,007	$100,740
Jan. '04	16	1137	337	4,841	$597,385
Feb '04	5	266	334	1,031	$103,143
Mar '04	0	0	N/A	N/A	N/A
Apr. '04	1	33	93	26	$2,571
May '04	2	23	215	125	$15,258
Jun. '04	6	220	317	311	$31,215
Jul. '04	0	0	N/A	N/A	N/A
Aug. '04	2	44	148	113	$11,387
Total	56	2,132		9,216	$1,040,206

Table 2.6 Price Program Event Summary by Month

In August 2004, 367 assets were enrolled in the program, but only about 40% of those assets actually curtailed during an event in the 2004 program year. The average asset curtailment was 0.19 MWh per hour.

During the study period, events were called in all but two months, March and July 2004. January 2004 had the most event days (16) followed by November 2003 (14), October 2003 and June 2004 (6), February 2004 (5), December 2003 (3), May and August 2004 (2), and finally April 2004 with only one event. The total event respondent count was highest in January 2004 (332 assets curtailed), closely followed by September 2003 (333) and February 2004 (334). The events declared in the middle of January 2004, were in large part due to a severe cold snap that resulted in the interruption of natural gas supplies to some generators, which caused prices to rise, reaching $900 or more in some hours.

The peak participation day was in late January 2004 while the highest load curtailment day was in middle of that month. The highest payout day coincides more with the peak participation day than the highest curtailment day – mid-January 2004 saw the day with

the largest payout ($89,000). In total, price program participants were paid $1,040,206, or about $21/participant-hour. The average price paid for curtailments was $113/MWh ($0.113/kWh).

Three measures of performance were calculated to quantify the relative degree of asset performance, as follows:

1. The Subscribed Performance Index (SPI) is defined as the actual load curtailed (MWh) during events divided by the amount of load (MWh) that participating customers indicated when they enrolled that they would curtail during event hours. For example, if a participating customer reduced 1 MW in each hour of a price event that lasted 10 hours, their actual load curtailed would equal 10 MWh. If that same customer had enrolled 2 MW of load, then its expected load reduction for the same 10-hour event would be 20 MWh. Consequently, the customer's SPI would be 10 MWh divided by 20 MWh or 0.50

   SPI = Performance / Subscription
2. The CBL Performance Index (CPI) is defined as the actual event load curtailed (MWh) divided by the participant's baseline consumption (MWh) during the price event. For example, if a customer's baseline consumption (CBL) were 10 MW in each hour of a 10-hour price event, their baseline consumption would be 100 MWh. If the customer reduced 1 MW in each hour of the 10-hour event their actual load curtailed would equal 10 MWh. Therefore, the customer's CPI would be 10 MWh divided by 100 MWh or 0.10.

   CPI = Performance / Customer Baseline (CBL)
3. The Subscribed CBL Index (SCI) is defined as the amount of load the participating customer indicated that it would curtail during events divided by the participant's base consumption. The CBL is the level of usage the customers is deemed to have otherwise used had it not responded to the event by curtailing load. Using the same examples described above, the customer's SCI would be 20 MWh divided by 100 MWh or 0.20.

   SCI = Subscription / Customer Baseline (CBL)

Average performance index values were estimated for the price program by zone. Because the curtailment under the price program is voluntary in nature, the indices were calculated using only the records for those customers that actually curtailed during events. Table 2.7 illustrates the results. Overall assets provided curtailments of about one-third of the level they enrolled, as indicated by the SPI index of 0.36. However, the amount of load reduction that assets provided, relative to their total energy consumption during event days (CBL) is relatively low, as indicated by the overall low CPI index value (0.09). SEMA had both the highest CPI and SPI index values, but one of the lowest SCI values. Both NEMA and CT had a high SCI, indicating customers in these areas subscribed a larger portion of their CBL than did participants from other zones. However, NEMA customers performed the best relative to what they enrolled (SPI=0.66).

Zone	Performance (MWH	CBL (MWH)	Subscription (MWH)	CPI	SPI	SCI
VT	393	7,722	1,009	0.05	0.39	0.13
NH	2	36	11	0.06	0.18	0.31
WCMA	853	9,614	1,244	0.09	0.69	0.13
RI	119	1,801	227	0.07	0.53	0.13
SEMA	708	6,096	842	0.12	0.84	0.14
Maine	0	N/A	0	N/A	N/A	N/A
NEMA*	1,114	10,250	-	0.11	-	-
NEMA	4,207	-	6,417	-	0.66	-
NEMA**	-	10,250	2,817	-	-	0.27
CT	3,196	35,212	8,115	0.09	0.39	0.23
ISO-NE				**0.09**	**0.36**	**0.20**

* CBL for customers with a generator are zero. This metric excludes their performance information.
** CBL for customers with a generator are zero. This metric excludes their subscription information.

Table 2.7 Price Program Performance Indices by Zone

2.4 Conclusions

The Real-Time Price Response program pays customers to curtail when real-time market prices are forecast to be at least $100/MWh. Over the past year, this has come about on 56 days, for a total of 2,132 hours. The number of assets that curtailed and the total load curtailed varied widely from event to event. The highest level of participation was in the winter months, especially December 2003 and January 2004.

3 Market Impacts of the Price Response Program

The goal of ISO-NE's price response program is to abate the most serious consequences of real-time market price volatility. Methods that have been developed specifically to measure the value of demand response were adapted to reflect ISO-NE market circumstances, and then applied to the 2004 program year events. The approach is to simulate what the real-time market price would have been if the pricing program curtailments had not been undertaken. Estimates of the program's benefits were produced by calculating the difference between the simulated and actual real-time market prices multiplied by the loads that would have paid that price premium. Program benefits are then compared to payments made to participants to provide an index of program performance.

A reduction in load to be served in real-time, all else constant, results in a generating unit (or several units) being backed down from the point at which it otherwise would have operated. Because ISO-NE dispatches units according to an ascending bid supply curve, the market-clearing LMP drops as load drops, all other things equal, and as a consequence buyers in the real-time market realize price reductions at that time. The direct benefits, defined as the bill savings realized by purchasers of energy in the real-time market, are the product of the reduction in LMP that results from the curtailments and the load purchased in the real-time market during the event. For this study, 11% of the ISO-NE market volume is assumed to be transacted through the real-time market.

There is an important secondary (indirect) impact of the program on electricity prices in the market. Lower price volatility acts to reduce the premiums that purchasers of bilateral contracts pay. So, they too benefit from the program. These benefits are defined by the product of the reduction in the month's average price resulting from the program times the load transacted through bilateral agreements. The study assumes that 60% of market transactions are bilateral agreements between generation owners and entities that serve retail customers.

The impact of program curtailments on market prices was estimated by first developing a statistical representation of the relationship between load and LMP in ISO-NE's real-time energy market.[11] This supply relationship, which reflects the bid curve that is used to set LMP, was then used to simulate the impact of curtailments on LMP. Event-specific price impacts were developed by adding the curtailed load back into the load actually served in each event hour. The intersection of this higher load with the simulated supply curve produces an estimate of the real-time price (LMP) that otherwise would have prevailed.[12] The difference between the actual and simulated LMP defines the price change that is used to quantify the direct price effect of load curtailments.

An approximation of the indirect market impact is accomplished by calculating the effect of the real-time price changes on the monthly average price, which is lower due to the lower prices during event hours. If the market were perfectly fluid and adjusted instantaneously, then the market would reflect those lower risks through a reduction in the prices that retailer suppliers pay for hedge contracts. The product of the reduction in the average price times the amount of load purchased through bilateral contracts provides an estimate of those savings. In reality, markets react with a lag, so while some impacts are realized soon after events, others are felt over subsequent months, or in some cases years.[13]

The degree to which curtailments impact real-time LMPs depends on the slope, or steepness, of the supply curve at that time the curtailments are undertaken. The steeper the curve, the more pronounced the reduction in LMP. The supply flexibility, which is defined

[11] Details on how the market supply relationship is estimated are available in: Neenan, B., D. Pratt, P. Cappers, J. Doane, J. Anderson, L. Scholle-Cotton, K. Butkins, R. Boisvert (2004) "A Study of NYISO 2003 PRL Program Performance " Final report prepared for the New York Independent System Operator, January 2004.

[12] More detailed simulations utilizing ISO-NE's system modeling capabilities were used to verify the statistical characterization of the ISO-NE supply characteristics, and were used in some cases to produce more refined estimates of the slope of the supply curve.

[13] If the program is successful in reducing price volatility, then retailers will be more inclined to split their purchases between the spot and bilateral market, and to decrease reliance on bilateral market purchases in order to enjoy the benefits of reduced hedging costs.

as the percentage change in LMP resulting from a one percent change in the load served, is a convenient measure of the impact of load curtailments on the real-time market price. The higher the supply flexibility, the greater the impact curtailments exert on LMP.

Supply curves were estimated for the ISO-NE market for three distinct periods to account for seasonal differences in market fundamentals. The first period is comprised of the fall and spring months of the program year, the months of September, October, November 2003 and March, April, and May 2004. The second, winter period includes the months December 2003 and January and February 2004. The last is the summer period consisting of the months June, July and August 2004. Figures 3.1 – 3.3 illustrate ISO-NE real-time market prices for these three periods.

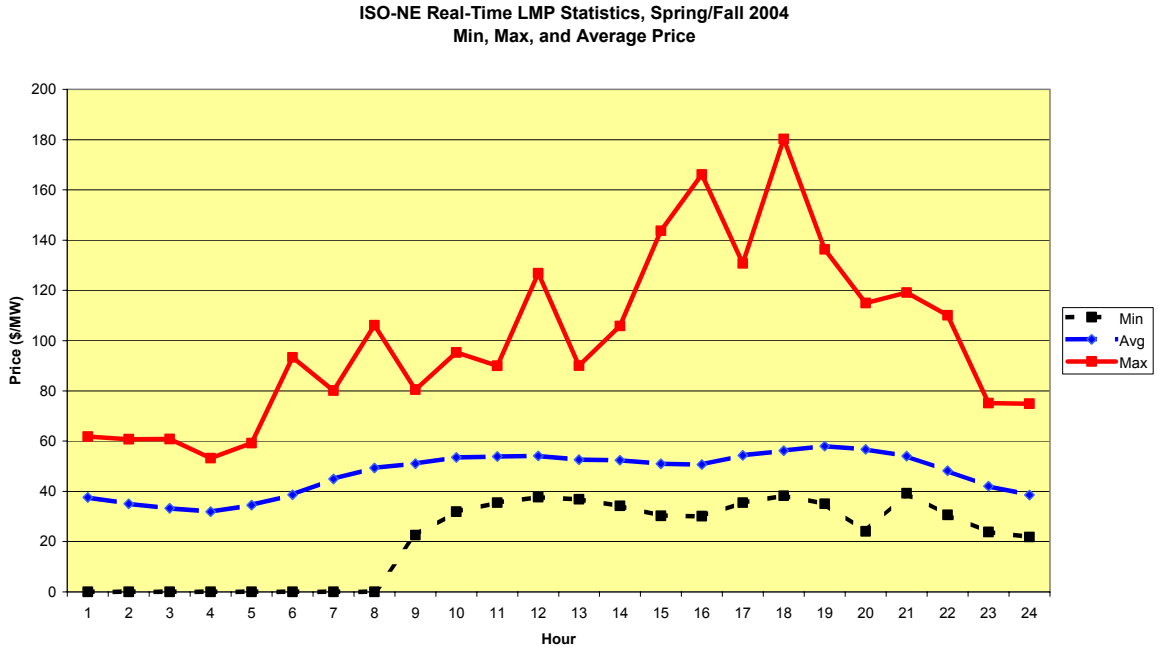


Figure 3.1 ISO-NE Real-Time LMP Statistics, Spring 2004 & Fall 2003

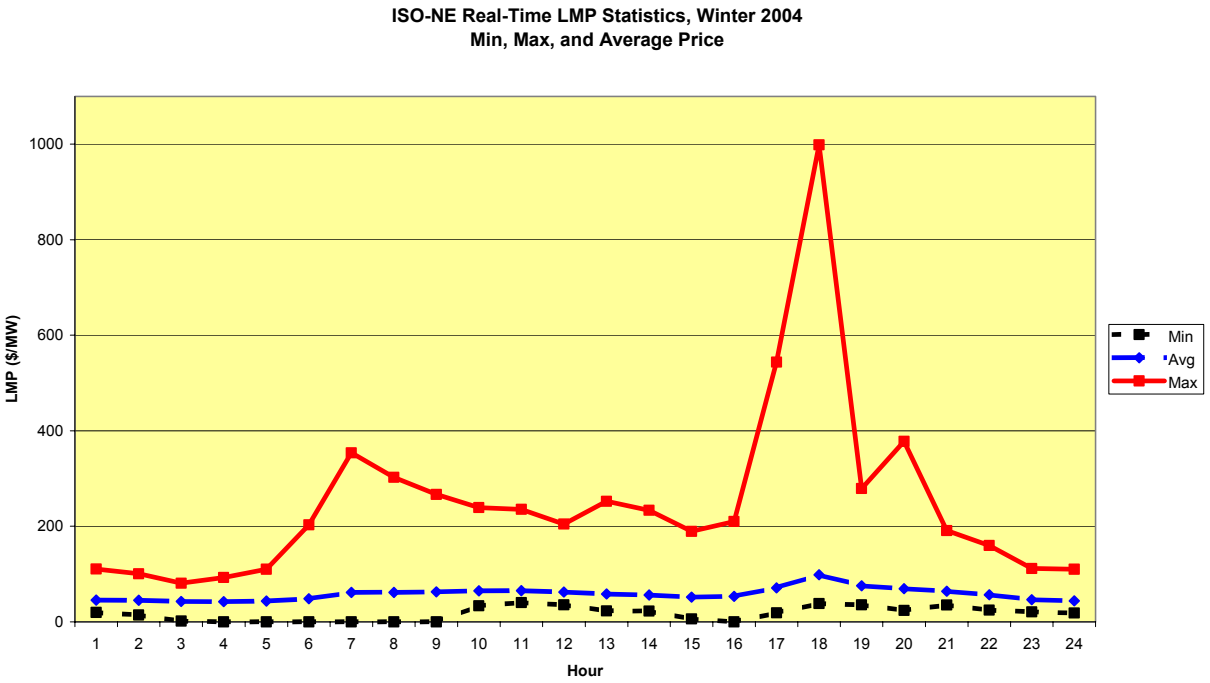


Figure 3.2 ISO-NE Real-Time LMP Statistics, Winter 2004

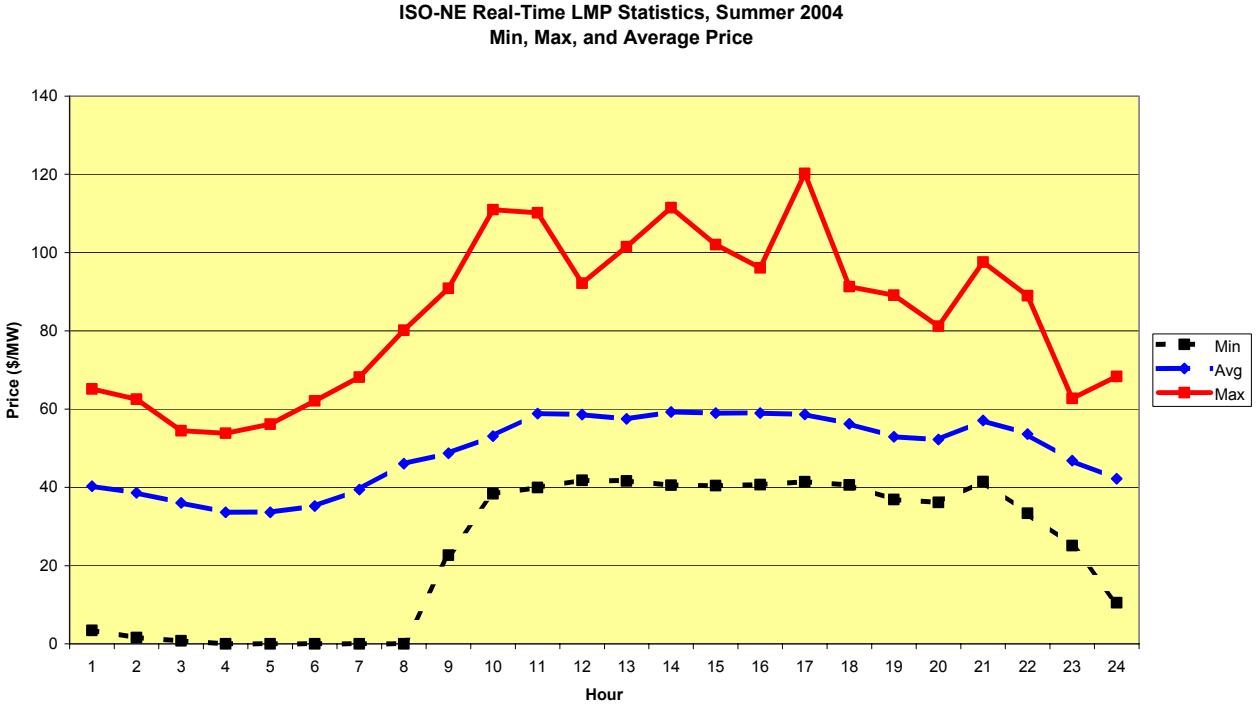


Figure 3.3 ISO-NE Real-Time LMP Statistics, Summer 2004

The three periods have distinctive daily average supply curves. The winter period (Figure 3.2) shows a pronounced spike in the maximum price ($1,000/MWh in one hour) in the later afternoon hours, in contrast to otherwise relatively stable average daily prices. During the summer months, average hourly prices were same most of the daylight hours, and modestly lower overnight. The maximum prices are more dramatic in the difference between day and night levels, but they never exceed $120/MWh. The fall/spring period exhibits higher maximum prices than the summer, exceeding $140/MWh in four hours, but average prices vary little across the day, reflecting the fact that high prices were infrequent.

As described earlier, the supply flexibility measures the slope of the real-time supply (generator bid) curve. Table 3.1 provides the supply flexibilities estimated for the three periods during declared events. The maximum supply flexibility in the 2004 program year winter period (5.1) is substantially higher than the maximum in the other two periods, consistent with the common portrayal of the supply curve as a hockey stick. During the fall/spring and summer periods, the market supply curve is much flatter, as indicated by the supply flexibilities that are below 2.5, and at times under 1.0, indicating that the supply curve was almost flat during most of the time, including some event periods, which has important consequences of the level of benefits realized.

Price Response Program 2004 Summary of Market Price Impacts							
	Load (MWh)			Price ($/MW)			Supply
Season	Actual	Simulated	Change	Actual	Simulated	Change	Flexibility
Fall/Spring	1,228,004	1,229,915	-1,911	$58.64	$58.76	(0.12)	0.4 - 1.5
Winter	4,118,925	4,125,804	-6,879	$88.97	$89.92	(0.95)	2.6 - 5.1
Summer	860,107	860,532	-425	$74.07	$74.13	(0.06)	0.8 - 2.4

Values are the average impact for all Zones

Table 3.1 2004 Market Impacts - Price Response Program Summary

Table 3.1 also provides both the actual and simulated average load and price data for the price response events for each of the three seasons. Because of the relatively low price flexibilities in the fall/spring and summer periods, price response program curtailments during those periods resulted in very small (under two-tenths of a percent) changes to LMP, $0.12 and $0.06/MWh respectively. The higher supply flexibility during the winter

period produced a simulated price change of almost $1.00/MWh, which equates to an average reduction in real-time LMP during event hours of over 1%.

The benefits associated with the price program curtailments estimated for each of the three periods are summarized in Table 3.2. Bill Savings are the direct result of load reductions – the product of the price reduction times the load transacted in the real-time market. The program produced a total of $222,745 in savings to those purchasing energy in the real-time market coincident with program curtailments, most of which were realized in the Winter months. The same is true for the hedge savings, which are calculated as the product of the change in the average monthly LMP times the load served through bilateral contracts. Almost three-quarters to the total hedge savings of $4,653,603 were the result of winter curtailments.

ISO-NE Price Response Program Impacts					
Season	Bill Savings	Hedge Savings	Total Savings	Program Payments	Market Impact Ratio
Fall/Spring	$7,313	$900,375	$907,687	$196,336	462%
Winter	$212,674	$3,405,415	$3,618,089	$801,269	452%
Summer	$2,759	$347,814	$350,573	$42,601	823%
Total	$222,745	$4,653,603	$4,876,349	$1,040,206	469%

Bill savings are the price change in the real-time market times the load that cleared in real-time

Hedge savings are the corresponding reduced change in the monthly average real-time prices times the bilaterally contracted load

Table 3.2 ISO-NE Price Response Program Benefits

The Program Payments listed in Table 3.2, which totaled $1,040,206 in 2004, are the payments that assets received for curtailing load. The Market Impact Ratio is the ratio of the total savings to total program payments, which is provided as a percentage in Table 3.2 for each individual period and for the year overall. The overall value of 469% indicates that benefits exceeded payments by more than a factor of four.

The Bill and Hedge savings represent transfers from suppliers to retailers, and ultimately to consumers. The savings go to retailers in the form of higher operating margins if they are selling electricity to consumers under fixed priced agreements, or under fixed tariffs in the case of utilities offering standard offer/default service. However, the combination of

regulation and competition eventually will result in these benefits being passed on to retail consumers in the form of lower retail prices or tariff rates.

Some may question the legitimacy of this measure of program benefits.[14] Economists prefer to use the change in social welfare as the measure of the value of programs of this type because it considers the net impact on both consumers and producers.[15] Transfers represent gains by one sector (e.g., retail electricity consumers) at the expense of another (e.g., wholesale generators). Assessing the merit of such redistributions invariably requires making a subjective judgment about the relative utility or value of the parties involved, since one gains while the other loses. Economists contend that monetary value is not a sufficient measure of the marginal value of utility.

How then are the benefits (transfers) estimated for ISO-NE's price program to be interpreted? In this case, ISO-NE has promulgated market rules that result in consumers receiving payments to reduce their usage at times when such reductions are expected to produce savings to all consumers.[16] This program is part of the overall market design which anticipates the possibility that spot market prices can become very volatile, due to episodic situations where supply and demand are mismatched, or supplier market power is exercised, or both. Absent retail rates implemented by retail market participants and policymakers to induce customers to respond to contemporaneous price changes, to abate price volatility, the Federal Energy Regulatory Commission (FERC) has required ISO-NE

[14] See S. Braithwait, "Demand Response is Important – But Let's Not Oversell (Or Over-Price) It"' Electricity Journal, June 2003.

[15] The social welfare framework was developed to guide the promulgation of programs financed by public funding. ISO-NE is a private corporation that operates under a public charter, which leads some to apply social welfare tests to some, but not all, programs it implements to fulfill its obligation for market operation.

[16] In addition to six New England states, each with differing market philosophies, there are a myriad of market participants (e.g., generators, alternative energy producers, retail suppliers, transmission and distribution companies, public power, end-use customers) each with a financial stake in the wholesale market. In developing its market protocols and rules, ISO-NE attempts to strike a balance among the various interests that make up New England's electricity industry. Accordingly, the market rules implemented by ISO-NE might diverge from theoretically ideal market structures in order to balance the interests among opposing market stakeholders.

to implement market protocols and rules to accomplish that end, one of which is the Real-Time Price Response program.

Retail markets are developing more slowly than their wholesale counterpart. Most consumers pay usage rates that do follow daily or hourly changes in supply costs, as measured by ISO-NE administered spot market prices. Standard offer and default service rates provided by utilities still rely on traditional, average cost rate making principles. Competitive retailers largely have focused on acquiring customers under hedge agreements, both because that appears to be what customers want, and such arrangements are more profitable.

Consequently, very few New England electricity consumers are exposed to real-time changes in supply costs that characterize ISO-NE administered spot markets. Lacking the discipline of a downward sloping demand curve, these markets are prone to large and erratic price swings, a consequence that benefits neither consumers nor suppliers. But, the current market structure is not conducive to resolving this dilemma at the present time.[17] Given the absence of retail policies in the region to encourage price responsive demand, ISO-NE, with FERC guidance, has acted to implement price programs as a means of abating extreme price swings. The performance of the price program is correctly measured in terms of what it pays to program participants relative to the value they deliver. The bill savings and hedge benefits derived herein provide a compelling measure of benefits that consumers realize.[18]

[17] The current market structure does not permit ISO-NE to implement retail market policies or to set retail prices. The individual states have exclusive jurisdiction over the retail electricity markets within their state, which includes the ability to establish rules for retail competition and/or to set retail tariffs for regulated services. To date, the individual New England states have not established retail rates or policies that encourage price responsiveness. Retail customers are the ultimate consumers of electricity and thus are the ultimate providers of price responsive demand. Therefore, ISO-NE needs to implement programs like the Real-Time Price Response Program to achieve the FERC's objective of encouraging price responsive demand.

[18] When retailers are routinely offering real-time and other innovative rate structures that encourage customers to respond to wholesale prices, a computation of the social welfare implications of the program would be relevant to fully characterize the stream of gains associated with the program.

Overall, the benefits realized by buyers of electricity (and eventually by consumers) were over four times the payments made by ISO-NE to participants, on behalf of all consumers, for curtailing load. The relatively high Market Impact Ratio in all three periods (Table 3.2 reflects the fact that prices were volatile at times, especially in January due to natural gas shortages, producing sizable market benefits. However, prices were relatively low during many events; only about a quarter of event hours were above $100/MWh (see Table 3.3 and Figures 3.4 – 3.7, which appear at the end of this section).

The reason why prices were relatively low during most price events is due to program provisions that govern how events are declared. Events in 2004 generally extended from 7:00 a.m. until 6:00 p.m., when ISO-NE foresaw at least one hourly price above the $100/MWh threshold in that period. However, the real-time zonal LMP exceeded the threshold price in only a few hours of each of the 56 declared event days, and sometimes did not reach this level at all. Consequently, customers were paid to curtail in many hours when prices in all likelihood would have been low, even without the price program curtailments. Consequently, the market price impacts were small. Improving the coincidence of program events with conditions conducive to higher wholesale electricity prices, above the floor price of $100/MWh, would improve the program's overall performance.

2004 Price Response Program LMP Statistics				
Zone	Total Event Hours	Number of Hours with LMP>$100	% Hours with LMP>$100	Avg Event LMP
VT	266	56	21%	$90
NH	202	50	25%	$95
W. Mass	294	60	20%	$88
RI	224	51	23%	$91
SE Mass	191	49	26%	$97
Maine	127	34	27%	$102
NEMA	262	55	21%	$89
CT	566	65	11%	$73

Table 3.3 ISO-NE Price Response Program Impacts

3.1 Recommendations

The goal of the price program is to abate price volatility. If curtailments are called for when the supply curve is very steep, then the impact on LMP can be pronounced. This was the case in many hours of 2004, and overall the program delivered benefits that exceeded payments to those that curtailed. But, the performance might be improved if some revisions were made to the program dispatch protocols.

As illustrated in Table 3.2, over the past year the market LMP exceeded the floor price only about one quarter of the hours for which curtailments were being paid. Average event prices were below $100/MWh in all but one zone, and probably would have been so in many cases had the curtailments not been undertaken. Under the current design, the program reduces LMP when it would otherwise be very high, but not as effectively as it might. The overall program performance would improve if calls for curtailments better coincided with those hours when the supply conditions are conducive to moderately to very high real-time market prices.

Some program modifications that might improve the program performance include:

1. Improving the accuracy of the price event triggering methodology to reduce incidence of payments when real-time market prices are already low. An improved methodology would better characterize the next day's market conditions and reduce the number to false calls, instances where the pricing program curtailment window is opened for the next day but conditions are such that high prices are not realized for reasons other than curtailments by program participants.
2. A complementary protocol would require that more than two or more hours of forecasted prices be above the threshold prices of $100/MWh before the curtailment window is opened. Alternatively, or additionally, the threshold prices could be raised, thereby ensuring an even greater coincidence of curtailments with conditions that would produce high prices, if unabated by participant curtailments.
3. Reducing the window during which curtailments are called for would also improve program efficiency. Currently, payments are typically made for the entire period

7:00 a.m. to 6:00 p.m. if a price event is declared. A shorter window, perhaps including only the afternoon hours, will likely result in a closer correspondence between payments and market conditions that warrant those payments.

These improvements will result in lower payments to customers, but the associated bill and hedge savings overall will remain high. As a result, the overall market impact ratio would improve considerably. The challenge facing ISO-NE is to retain price-responsive customers during the low-priced periods so that when prices do spike, a ready supply of demand response resources are available to deliver price abatement. Consequently, ISO-NE must take into consideration the impact of changes program provisions on program participation – overly stringent criteria could result in reduced program participation, which would defeat the program's objective of having available stand-by resources to abate price spikes

Encouraging customers in import-constrained load zones to migrate from the pricing program to one of the ISO-NE's reliability-based programs might improve the performance of both programs. However, this may be a hard sell until full implementation of location-based installed capacity markets is accomplished, and demand response is integrated into location-based reserve markets. A more immediate means of improving the overall program performance may be to encourage price program customers to migrate to a day-ahead program, when it becomes available, wherein payments are more closely associated with actual market conditions.

Improving and maintaining the Real-Time Price Response program is vital given that ISO-NE is currently the only entity in New England, with authority to implement electric industry policy, attempting to encourage price responsive demand in the region. The voluntary nature of the Real-Time Price Response Program allows customers to gain experience with demand response and becomes an excellent entry point for customers who may later migrate to the more cost-effective Day-Ahead and reliability programs. Furthermore, until such time as real-time and other innovative retail pricing that

communicates wholesale price signals to customers becomes pervasive, the New England market needs the Real-Time Price Response Program. The program enables (1) participating customers to continue responding to varying wholesale power costs, (2) encourages additional customers to become price responsive, and (3) provides economic incentives for technology and service companies to develop demand response products and services.

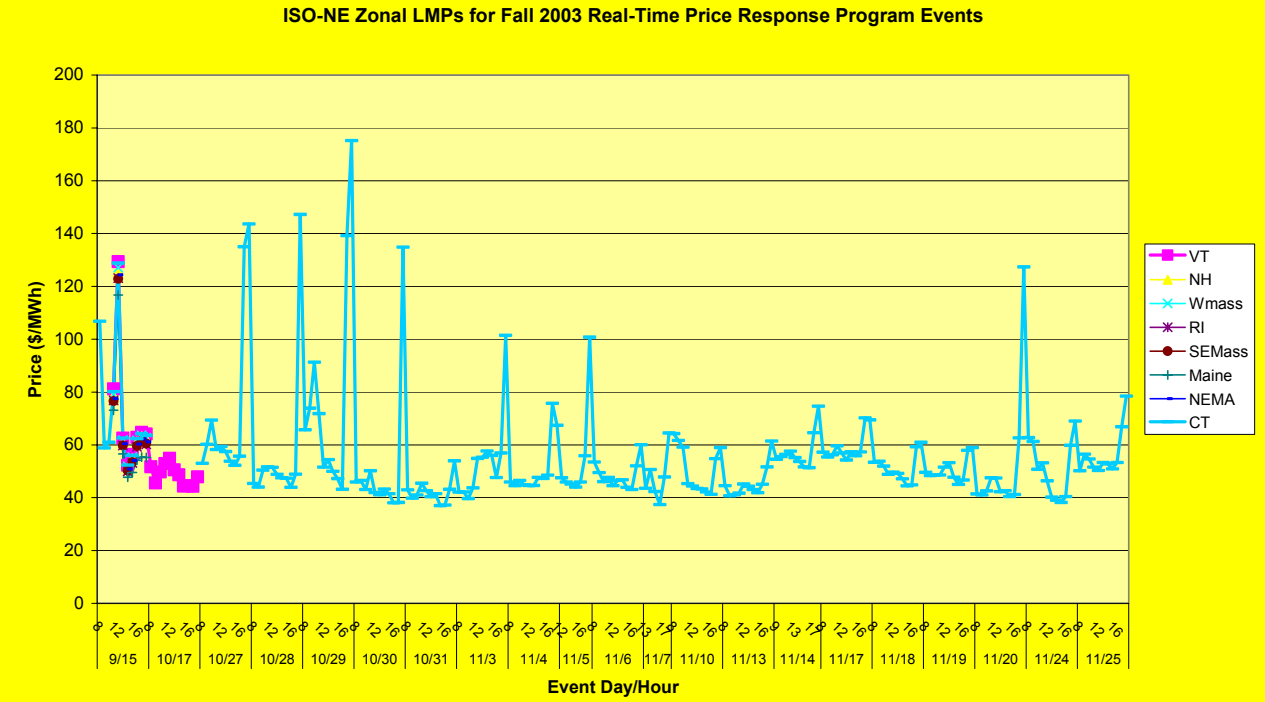


Figure 3.4 ISO-NE Zonal LMPs – Fall 2003 – Price Response Events

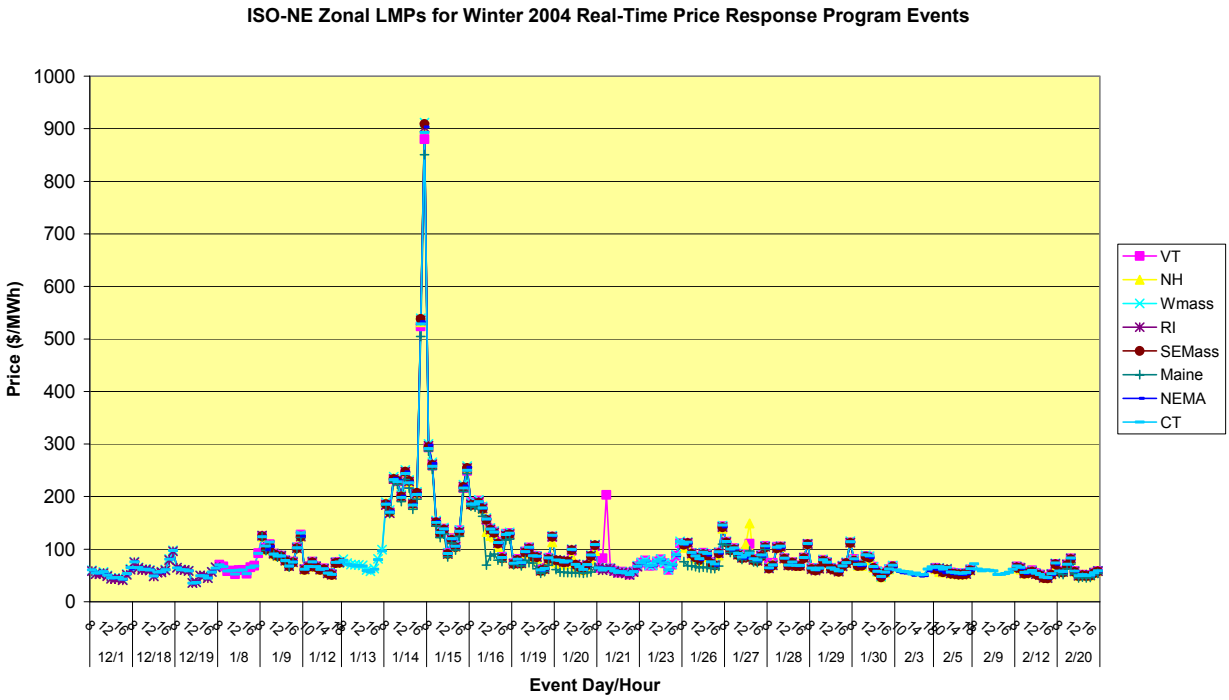


Figure 3.5 ISO-NE Zonal LMPs – Winter 2004 – Price Response Events

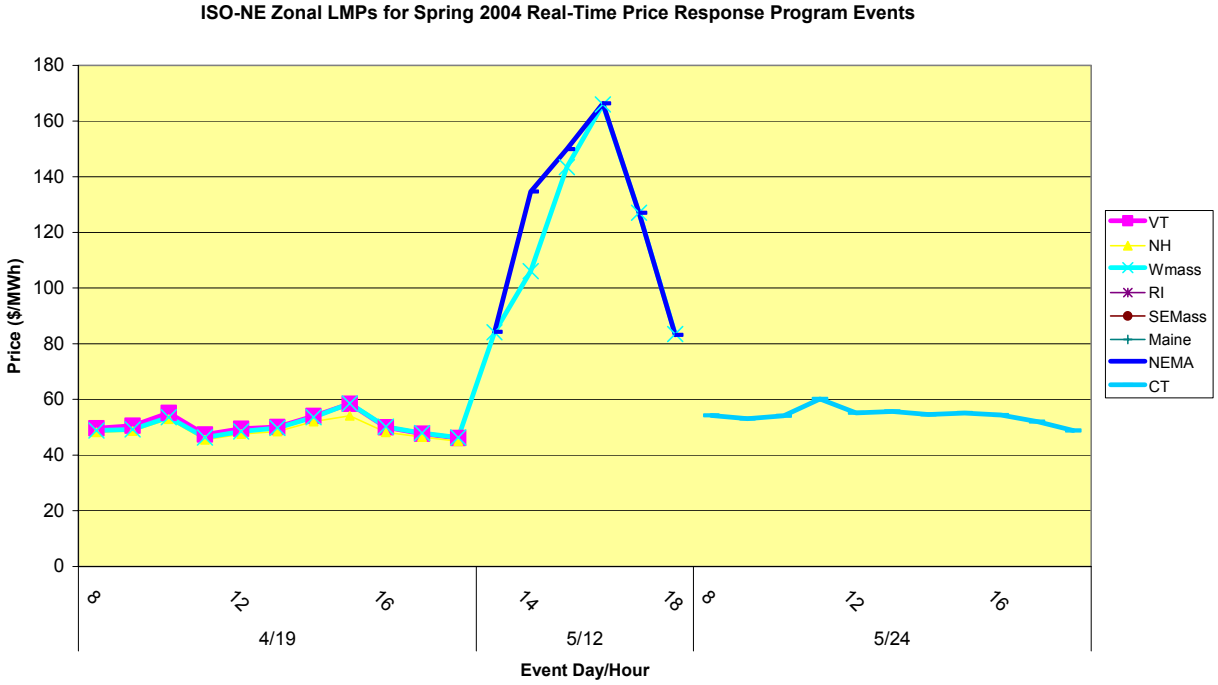


Figure 3.6 ISO-NE Zonal LMPs – Spring 2004 – Price Response Events

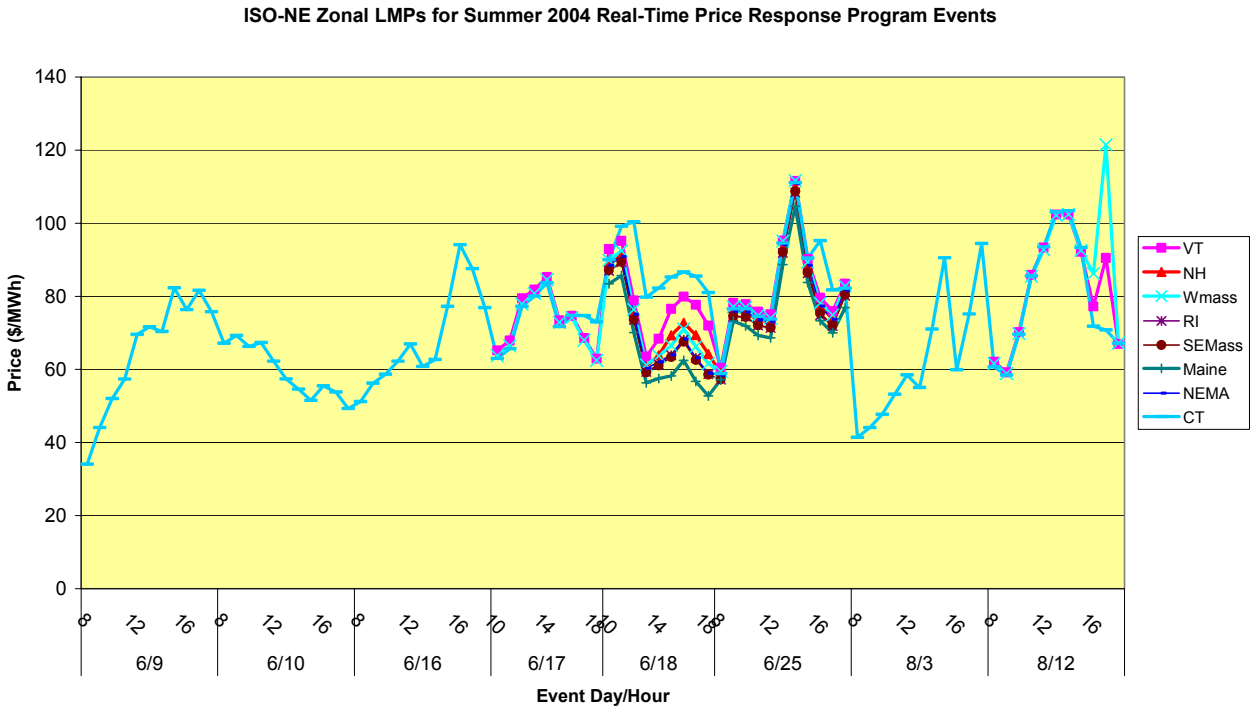


Figure 3.7 ISO-NE Zonal LMPs – Summer 2004 – Price Response Events

4 Process Evaluation

4.1 Introduction

An in-depth process review was conducted as part of the 2003 program evaluation, and a list of problems/issues was generated. As part of the 2004 process evaluation, the primary goal was to find out from stakeholders how they felt about the steps taken by ISO-NE to address these problems/issues. There are two primary objectives of the Process Evaluation Report:

1. Provide a general understanding of how the various business processes function and interface with each other, and
2. Evaluate the effectiveness of the steps implemented by ISO-NE staff to address problems/issues identified by stakeholders during last year's process evaluation.

Three primary activities contributed information to the process evaluation: (1) phone surveys with program stakeholders, (2) customer surveys, and (3) a program documentation review.

4.1.1 Evaluation Overview

A key aspect of this study was to utilize existing data resources at ISO-NE to gain an understanding of the operations of the demand response programs. ISO-NE program documentation was gathered and reviewed in the early stages of the study. This information was then used to frame the stakeholder interview scripts and customer surveys.

Stakeholder surveys/interviews were performed with a total of 29 individuals from various stakeholder groups. The interviewee groups represent six distinct stakeholder groups, as follows:

- Local distribution companies,

- Demand response providers,
- Competitive retail electricity providers,
- Metering and internet-based communication system providers,
- State regulators, and
- ISO-NE staff.

Structured surveys were used to direct these interviews, which ran about 45 minutes each. The information gathered from the surveys was categorized and used to formulate observations about how well key processes are being performed. In addition, information about program satisfaction, gathered from a survey administered to customers, which is discussed in Section 4.3 below, was also used to formulate recommendations for process improvements.

4.1.2 Program Design

Stakeholder interviews examined interviewees' perceptions about the program design process, along with queries to draw out responses on what they perceive to be the current program design successes and constraints. In this section, the discussion is organized around the primary observations, accompanied by suggestions for improving future program efforts that were listed in the 2003 Demand Response Evaluation Report. A new section has been added that provides a description of the actions implemented by ISO-NE staff to address the problem/issue.

- ***Observation****:* The monthly Demand Response Working Group meetings improve the opportunity for stakeholders to provide input directly to ISO-NE program staff.
  - *Suggestion:* Monthly meetings should continue to be held with sufficient time provided for stakeholders' issues to foster an environment that promotes widespread ownership of the program and dedication to its success.

➢ **ISO-NE Actions Taken:** The ISO-NE staff has continued to conduct the monthly demand response working group meetings and have used it as a forum for developing

program concepts that will allow demand response assets to be more fully integrated into the energy, capacity, and reserves markets.

- ***Observation**:* Customer participation in demand response is too reliant on manual implementation.
    - *Suggestion:* ISO-NE should look for ways to utilize the existing DSM delivery infrastructure among local distribution companies to promote investments in building automation and control systems.

➢ **ISO-NE Actions Taken:** ISO-NE continued to work with Massachusetts and Connecticut LDCs, energy conservation boards that make recommendations on the disbursement of social benefits charge proceeds, and Public Utility Commissions (PUCs) to encourage funding that supports participation in demand response programs. Additionally, ISO-NE is working with the region's PUCs (through the New England Conference of Public Utility Commissioners) to encourage the implementation of dynamic retail pricing in the region. The customized monitoring and verification option, available under all the programs, can accommodate direct load control and other automation projects.[19]

- ***Observation**:* Some LDCs do not receive value from ICAP credits**.**
    - *Suggestion:* It appears that some LDCs staff is not fully cognizant of the procedures required to receive value for ICAP credits resulting from demand response program participation by bidding curtailment resources into the ICAP supply auction. ISO-NE should provide training specifically aimed at instructing LDC program managers on how to submit their ICAP credits into the monthly ICAP supply auction.

[19] It is important to note that in other jurisdictions like zone J and zone K in New York, the state PSC has allowed the utilities implementing the thermostat load control projects to have full rate recovery. There are no direct load control projects in ISO-NE control area because none of the state regulatory agencies have provided any subsidies for direct load control projects. As part of the SWCT Gap RFP there will be one vendor using DLC with residential and small commercial customers, but this effort will not be funded through the Connecticut system benefit charge.

- **ISO-NE Actions Taken:** The ISO-NE staff has not conducted formal training for all Enrolling Participants. However, the majority of the Enrolling Participants with ICAP eligible resources have Supplemental Capacity Agreements with ISO-NE as part of the SWCT "Gap" RFP. Consequently, these Enrolling Participants have been consistently submitting their resources into the monthly ICAP supply auction. ISO-NE plans to conduct formal training prior to the implementation of the Locational ICAP (LICAP) market.

- ***Observation**:* The current ICAP payments for the demand response program are insufficient to attract additional participation.
    - *Suggestion:* Demand response assets should be fully integrated into any future ICAP market so that they receive payment commensurate with that of generators.
- **ISO-NE Actions Taken:** On March 1, 2004, ISO-NE issued its Locational ICAP (LICAP) compliance filing, which included the provision for demand response resources that had been eligible for ICAP to receive LICAP. The Federal Energy Regulatory Commission subsequently delayed the implementation of LICAP pending the outcome of litigation before the Commission. The above-mentioned provision will be effective upon implementation of LICAP, which is currently scheduled for January 1, 2006.

- ***Observation**:* As discussed more below, survey respondents rated the program as quite friendly, with a mean rating of 2.3, where a score of 1 indicated *very friendly* and a score of 5 *not friendly at all*.
    - *Suggestion:* As the program continues to evolve, customer rated friendliness will be an important metric that should be monitored regularly.
- **ISO-NE Actions Taken:** The mean customer friendliness rating from the 2004 customer survey was 2.48, on the same scale described above.

4.1.3 Program Delivery Mechanism

The following two sections present the major findings and suggested recommendations regarding Marketing and Enrollment, and Notification and Settlement that were noted as part of the 2003 evaluation. A new section has been added that provides a description of the actions implemented by ISO-NE staff during 2004 to address each problem/issue.

Marketing and Enrollment

- ***Observation****:* ISO-NE performed a broad and improved set of marketing activities in 2003, including technical forums, web casts, group and individual presentations, seminars and workshops.
    - *Suggestion:* ISO-NE should continue to expand the marketing vehicles used to promote its demand response offerings, including cooperative program marketing with LDC conservation and other program initiatives.

➢ **ISO-NE Actions Taken:** ISO-NE continued to work with LDCs to promote the integration of marketing efforts for demand response offerings with other LDC conservation and metering initiatives.

- ***Observation****:* The continuous changes experienced by the program have acted as a deterrent to soliciting participation. Program changes require redundant marketing and education by program implementers and make it difficult for participants to forecast program benefits.
    - *Suggestion:* ISO-NE should strive to provide a stable environment for demand response and arrangements should be made to provide an estimate of program benefits for potential program participants.

➢ **ISO-NE Actions Taken:** ISO-NE did not implement the types changes to the DR programs during 2004 that would make it necessary for an Enrolling Participant to have to modify their marketing materials or contracts with enrolled assets. ISO-NE also provides a spreadsheet tool, which is available on their website, that Enrolling

Participants and customers can use to estimate program benefits at various participation levels.

- ***Observation**:* Demand response programs are not currently coordinated with other LDC program offerings. Opportunities for better coordination identified by stakeholders include better integration with energy efficiency programs and with LDC meter upgrade services.
    - *Suggestion:* Integration of ISO-NE demand response programs with LDC demand-side management and other initiatives should be rationalized and coordinated to the extent practical.

➢ **ISO-NE Actions Taken:** ISO-NE is continuing to work with state regulators and LDCs to promote the idea of integrating demand response with energy conservation and advanced metering programs. The challenge is that funding for most energy conservation programs is based on cost effectiveness tests that evaluate annual kWh savings relative to implementation costs. Energy conservation measures that effect end-uses with significant annual operating hours save more kWh than those effecting end-uses with small or intermittent operating hours. Since demand response programs operate infrequently, reducing relatively few kWh, they are evaluated under the energy conservation funding guidelines as less cost effective relative to energy conservation.[20]

- ***Observation**:* ISO-NE may be better positioned to coordinate marketing with regional and national chains than individual Enrolling Participants.
    - *Suggestion:* ISO-NE should consider coordinating marketing activities with LDCs and others to promote participation by regional and national chains.

[20] Although most of the LDCs actively recruit customers into the ISO DR programs, only a couple tried to include demand response with energy conservation measures utilizing EMS controls. These offerings were restricted to large customers with new construction projects and most regulators require that demand response activities be accounted for separately from energy conservation activities.

- **ISO-NE Actions Taken:** ISO-NE staff have made presentations and attended meetings of national chains energy managers. The staff is available to Enrolling Participants to help market the DR programs as the need arises.

- ***Observation****:* The low technology and super low technology options for providing consumption data promote greater participation among customers in the price program.
    - *Suggestion:* ISO-NE should continue to offer customers both the low and the high technology metering option where appropriate.
- **ISO-NE Actions Taken:** ISO-NE continues to offer the low technology and super low technology metering options in addition to the high technology IBCS option.

- ***Observation:*** Competitive energy suppliers are not aggressively marketing the program due to low profit margins.
    - *Suggestion:* ISO-NE should continue to work with competitive energy suppliers to assess opportunities to improve the marketability and profitability of the demand response programs.
- **ISO-NE Actions Taken:** ISO-NE is working to implement LICAP, which should increase the capacity payments for the reliability programs, and is working on market designs for a day-ahead and an ancillary service market that should create greater incentives for competitive energy suppliers to offer ISO-NE's demand response programs to their retail customers.

- ***Observation****:* The asset activation notice sends a confusing message to the end-use customer.
    - *Suggestion:* ISO-NE should only send the "Ready to Respond" notice to the end-use customer.
- **ISO-NE Actions Taken:** ISO-NE has modified its enrollment notification process and messaging in an effort to reduce customer confusion. The "asset activation"

notice that was the primary source of confusion is no longer being sent to end-use customers.

Notification and Settlement

- ***Observation****:* The contact information for participants can become unreliable over time due to staff turnover and domain name changes, among other things.
    - *Suggestion:* ISO-NE should send test notification messages at the point of enrollment and at the beginning of each summer season. Lists of invalid contact information should be passed to the Enrolling Participants so they can be reconciled.

➢ **ISO-NE Actions Taken:** ISO-NE implemented an e-mail test of all the enrolled assets during the late spring of 2004. The test e-mail asked the recipient to reply in order to confirm receipt. The results of the e-mail test were shared with the Demand Response Working Group (DRWG). As a result, many of the Enrolling Participants are developing their own procedures to maintain up-to-date customer contact information.

- ***Observation****:* The process for terminating demand response events needs to be reevaluated to prevent misunderstandings about event stop times.
    - *Suggestion:* ISO-NE should consider implementing a web-based demand response event page that clearly indicates event start and stop times for end-use customers and other stakeholders.

➢ **ISO-NE Actions Taken:** In the late fall of 2003, ISO-NE developed a web-page with input of the DRWG that lists the start time, estimated stop time, and actual stop time of events for all of the demand response programs and all of the load zones. The Load Response Event Summary web-page can be accessed at http://www.iso-ne.com/Load_Response/event_summary/index.php.

- ***Observation**:* Demand response assets need to be tested on a regular basis to establish capacity in the absence of called events.
    - *Suggestion:* ISO-NE should conduct regular audits of enrolled demand response assets.

➢ **ISO-NE Actions Taken:** In the spring of 2004, ISO-NE staff amended the rules of the reliability programs so that assets could be paid for their performance during Audit Events. On August 20, 2004, ISO-NE implemented an Audit Event for all of the reliability program assets in all of the load zones.

4.1.4 2004 Stakeholder Survey

At the January 2004 Demand Response Working Group meeting, ISO-NE staff presented the fourteen observations and suggestions listed above and asked the stakeholders in attendance to rate each one in order of importance, with 1 being very important and 14 being not important at all. The Market Design issue of low capacity payments for reliability assets was the number one concern of all in attendance receiving an average score of 2.9 compared to the second lowest score of 5.9 for providing a stable environment of the DR programs. There were only two other issues that scored below 7.0, an indication that the stakeholders did not place a lot of importance in them. As part of the process survey, stakeholders were asked to rate how well ISO-NE pursued these suggestions on a scale from 1 to 5, with 1 being very good and 5 being poor. The respondents gave the ISO-NE staff an average rating of 2.2 as further indication and acknowledgement of their effort to improve the DR programs.

4.2 Customer Satisfaction and Characterization

A survey was designed and administered in late September and early October 2004 to measure program participants' satisfaction with the program and its key features, to characterize the population of program participants and contrast them to non-participants, and to identify customers' load management capabilities. Two customer categories were constructed to guide the survey design and its administration, as follows:

1. Participants – customers who were enrolled in any of the ISO-NE demand response programs during the period January to August 2004; and
2. Non-Participants (NPs) – customers that were enrolled in a ISO-NE demand response program before 2004 (but not in 2004) and customers that had participated in a workshop or seminar during 2003 or 2004 that described the program offerings but that chose not to participate in the program.

The Participant survey category was further divided into customers that participated in either the price or reliability programs. A total of 460 surveys were administered using a web-based survey tool. A total of 42 surveys were undeliverable due to incorrect e-mail addresses, and 88 customers completed the survey using the web-based tool.

	Surveys Sent	Bounces	Corrected	Net Sent	Complete	Complete Ratio
Reliability Programs	75	14	6	67	28	42%
Price Programs	322	49	26	299	48	16%
Non-participants	63	22	5	46	12	26%
Totals	460	85	37	412	88	21%

Table 4-1 Survey Frame and Response Rates

Table 4-1 provides a breakdown of the number of surveys that were sent to each of the groups, the net number of surveys and the response rate for each.[21] The reliability program participants' response was the highest (42%), followed by that for Non-participants (27%) and the price program participants had the lowest response rate (16%). The overall average response rate of 21% is comparable with that of similar survey of demand response customers endeavors in New York.

4.2.1 Survey Frame and Response

Contact information (i.e., name, e-mail address, phone number) for program participants was taken from information provided by Enrolling Participants when customers were

[21] The survey was distributed by e-mail and follow-up phone calls and other e-mail reminders were sent out during the administration period. Customers were provided a link to the survey, which was completed on-line. The customers had the ability to leave the survey at any point and come back in where they left off.

enrolled in their respective program. Consequently, in many cases the survey instrument may have been sent to an individual that did not see the value of completing and returning the survey. Moreover, many customers may not have recognized the connection between the survey and the ISO-NE program they joined, especially when their primary contact was with their Enrolling Participant (i.e., their Local Distribution Company or competitive supplier).

The sample frame for non-participants was limited to the contact information provided by those customers that attended a conference or workshop sponsored by ISO-NE and also included customers who had retired from the programs.

To improve the response in future survey initiatives, Enrolling Participants should be encouraged to acquire and supply to ISO-NE the primary contact information of the person best able to respond to surveys and other inquiries regarding their company's reasons for and opinions about participation in the programs. Additionally, they should be encouraged to track their program marketing activities and provide ISO-NE with contact information for use in program evaluations. Involving Enrolling Participants directly in the survey administration process would increase customer awareness of the value of responding to the survey, and response rates would benefit substantially from such a representation.

The distribution of responses by load zone are displayed in Figure 4-1, which shows that the CT zone had the highest number of survey respondents with a total of 39 survey respondents or 44% of the total. In general, the responses across programs and zones were fairly representative of the number of surveys that were sent out with the exception of the Rhode Island zone, which had no completed surveys.

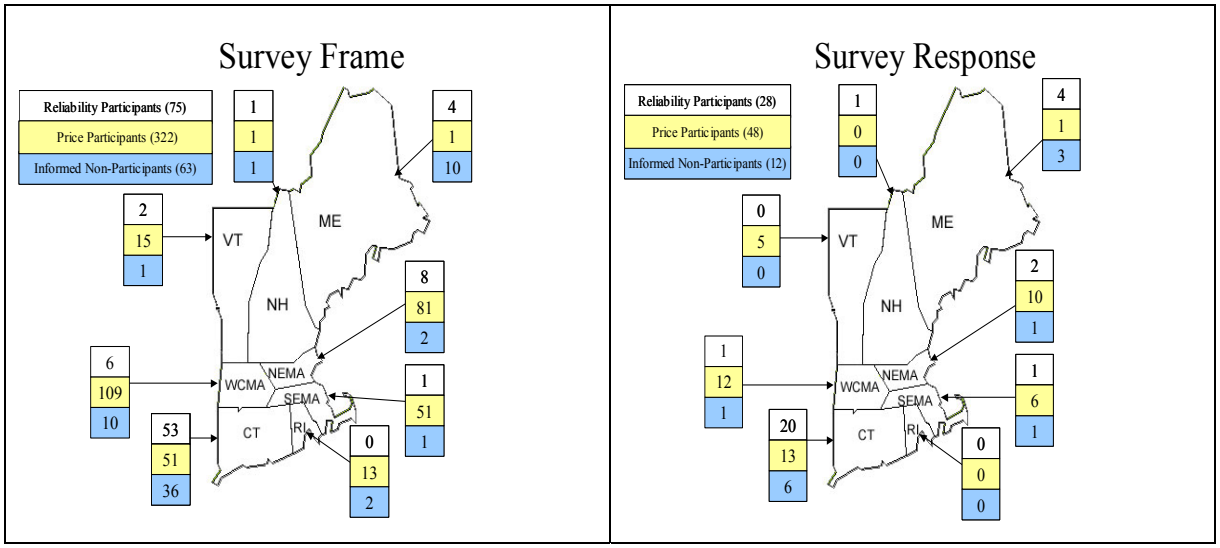


Figure 4-1 Survey Sample Frame and Responses by Zone

The survey responses provide a rich source of insight into how customers value demand response program participation that is useful for improving program marketing and administration, and for evaluating program modifications and refinements to make participation more attractive and effective.

4.2.2 Overall Program Satisfaction

Participants in the reliability and price response programs reported that overall they were quite satisfied as illustrated in Figure 4-2, providing ratings of 2.68 and 2.70 for the reliability and price programs respectively.

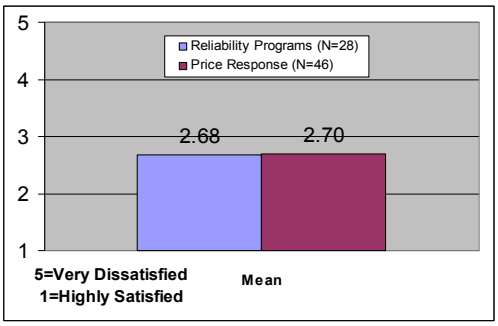


Figure 4-2 Overall Program Satisfaction

Satisfaction scores (where 1 indicates *very satisfied* and 5 *very dissatisfied*) were provided for the program metering requirements, speed of payments, notification process, ease of understanding of marketing materials and the overall customer friendliness of the program. For the most part, the scores were very good with customers rating their level of satisfaction between 2.23 and 2.91 for all of the categories, with the exception of the speed of payment. The speed of payment rating was still fairly good, with reliability customers rating a 3.08 and price customers rating a 3.02. Survey results indicate that event notification was sufficient (almost 80% responded yes, it was) and the notification process was given the highest satisfaction rating of all of the parameters with a rating of 2.48 and 2.23 from the reliability and price participants, respectively.

All survey respondents were asked to indicate scores for the usefulness of the program marketing materials that ISO-NE provided at informational presentations and seminars. The results illustrated in Figure 4.3 compare the responses of non-participants to those of reliability and price program participants along with customer friendliness ratings provided by the program participants.

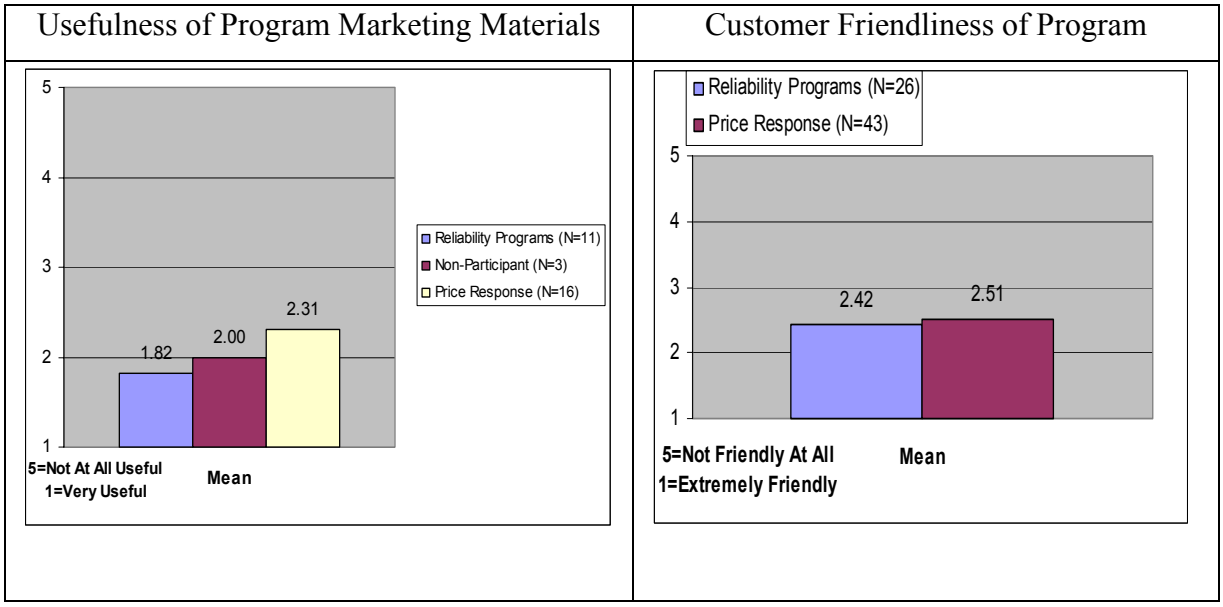


Figure 4-3 Measurements of DR Program Accessibility

All found the program and marketing materials to be reasonably accessible and understandable, which suggests that the technical information customers need to

understand regarding program terms and conditions are being conveyed quite successfully. Survey respondents report that they found the process of finding out about participation to be friendly and pleasant. Overall, it appears that customers who were involved in ISO-NE's marketing efforts are satisfied with how ISO-NE has implemented its demand response programs.

4.2.3 Participant Characterization

The survey asked respondents to describe their business and to characterize their business premises. The results provide a basis for identifying factors that help explain whether or not customers participate at all, and for those that do, why they chose either the reliability or the price response program. Throughout the discussion below, comparisons are made between participants in the price response program and those that were in any of the reliability programs.

Figure 4.4 compares the business activity of the survey respondents to that of the population of all program participants separately for both reliability (left side panel) and price (right side panel) response programs. Overall, survey respondents appear to be quite representative of the overall participant population based on business activity.

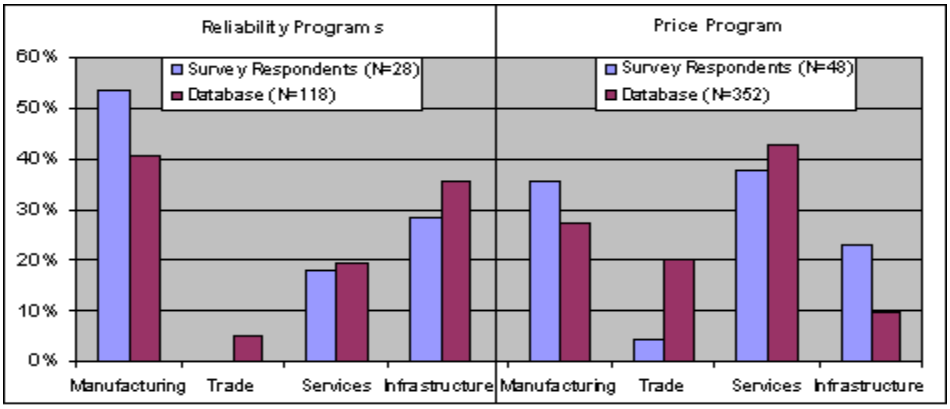


Figure 4-4 Major Business Activities of Program Participants

A greater proportion of reliability program participants are involved in manufacturing (41%) and a higher percentage of price program participants (43%) are in a service

business. Both programs show participation in excess of 10% by all of the business categories portrayed with the exception of the trade sector in the reliability programs.

Figure 4-5 depicts the distribution of responses regarding facility size (square feet). There seems to be no important distinction that would serve as an indicator of an inclination to participate. Price program participants tend be larger than reliability program participants and non-participants, with about 76% of the facilities 100,000 ft^2 or larger and almost 30% of the facilities over 1 million ft^2. In contrast to this, about 40% of the reliability program participant's facilities are under 100,000 ft^2 and only about 11% are over 1 million ft^2. The prevalence of smaller facilities is indicative of more energy intensive customers typically related to manufacturing and infrastructure facilities, which is consistent with the customer business type distributions discussed previously. The non-participant facilities are also of a similar size to the reliability program participants.

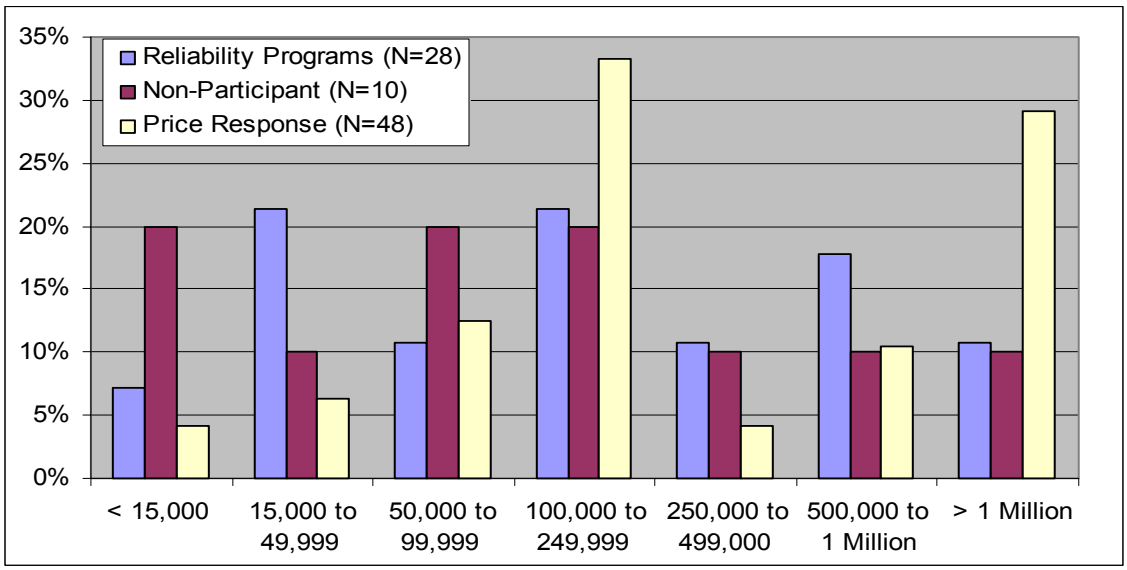


Figure 4-5 Facility Size

Responses to how many buildings comprise the customer's facility (not illustrated) provide only one useful distinction: almost twice as many price program participants reported two to ten buildings as reliability program participants, which is perhaps indicative that service facilities are more inclined to participate in the price program,

especially campus-type facilities and facilities with several premises, such as college and medical facility campuses and office parks.

Reliability program participants indicted a slightly higher capability to displace electrical loads with either alternative equipment or on-site generation than price program participants (Figure 4-6). But, non-participants indicated that they had a higher frequency of alternative fuel equipment and almost the same percentage of on-site generation as the reliability program participants.

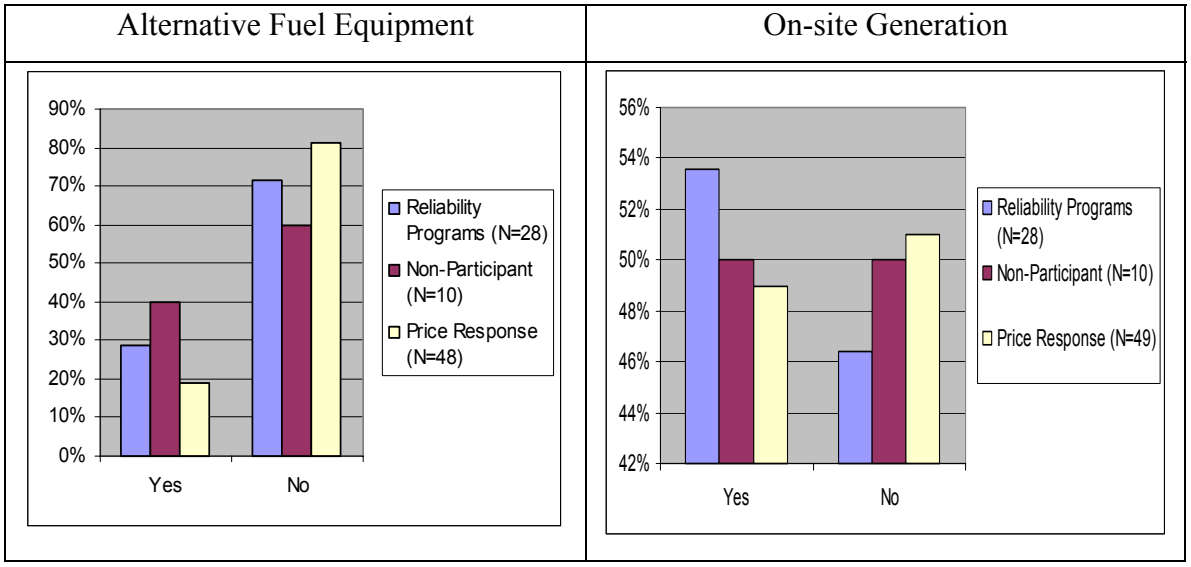


Figure 4-6 Ability to Displace Electrical Consumption

In general, easily verifiable facility characteristics are not very useful in predicting participation in an ISO-NE demand response program. Facilities with apparently similar circumstances came to different conclusions about the value of participation. Accordingly, estimating market potential or qualifying facilities as to their inclination to participate requires a more in-depth understanding of the facility and how it operates, and by whom.

Comparison of participation according to the level of energy usage suggests that these measures are not very good predictors of participation in ISO-NE programs. Figure 4-7

shows the results for August peak demand, which, like reported summer or winter maximum demand, provides ambiguous results regarding its use as a marker for likelihood of participation. The greatest number of customers is in the 1 MW to 10 MW category, while the greatest number of non-participants is in the 500 kW to less than 1 MW category. However, low response rates to this question particularly among non-participants (6) make conclusions drawn from these data dubious at best.[22]

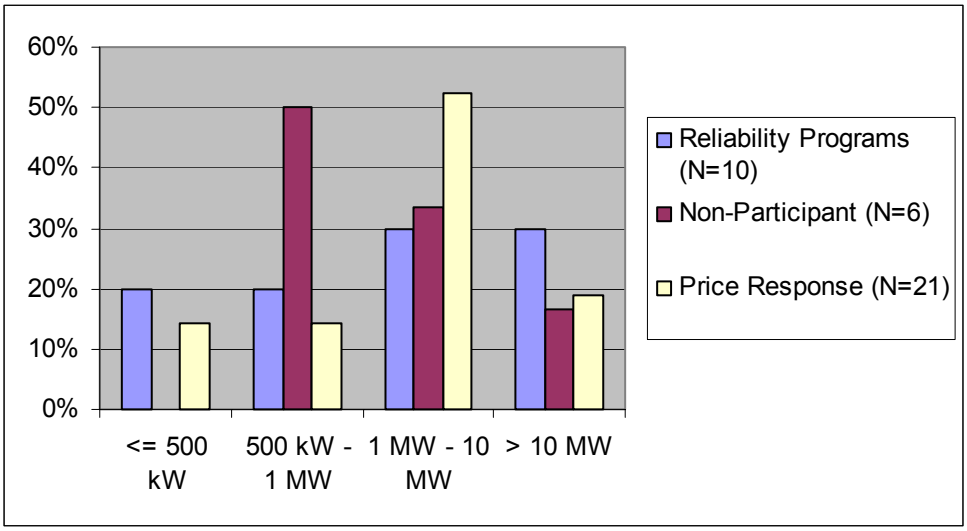


Figure 4-7 August Peak Demand

In the under 500 kW category, there is a smaller percentage of price response participants compared to reliability participants, while the opposite is true in the 1–10 MW category. Knowing the program in which a customer participates does not help to predict its size, nor can size be used to predict participation in any program, or a specific program, with any degree of comfort. This result challenges the credibility of the conventional wisdom that large customers are the best candidates for demand response program participation. Larger customers may be desirable in that they are easier to locate and contact, and if they enroll they may provide a larger curtailment asset. But, based on the results of the survey, smaller customers appear to be likely to participate in both reliability and price programs.

[22] Many of the survey respondents either did not answer this question or provided answers that were not reasonable based upon their reported energy consumption and LDC load data.

The amount of time respondents spend buying and managing energy would seem to be a good indicator of participation in a program. The maintained hypothesis was that those companies that spend more time managing energy are more likely to participate. Because they better understand the facility's load management capability, they should be more attuned to opportunities to save money by participating in demand response programs. As Figure 4-8 illustrates, each of the three groups report very similar results. However, more reliability and price participants report spending a higher amount of time managing energy than non-participants, but not by a wide margin. Moreover, the percentage of program participants reporting that they spend a low amount of time managing energy (0-10%) is slightly lower than for the non-participants. However, there does not appear to be a significant difference in the amount of time spent managing energy by program participants and non-participants.

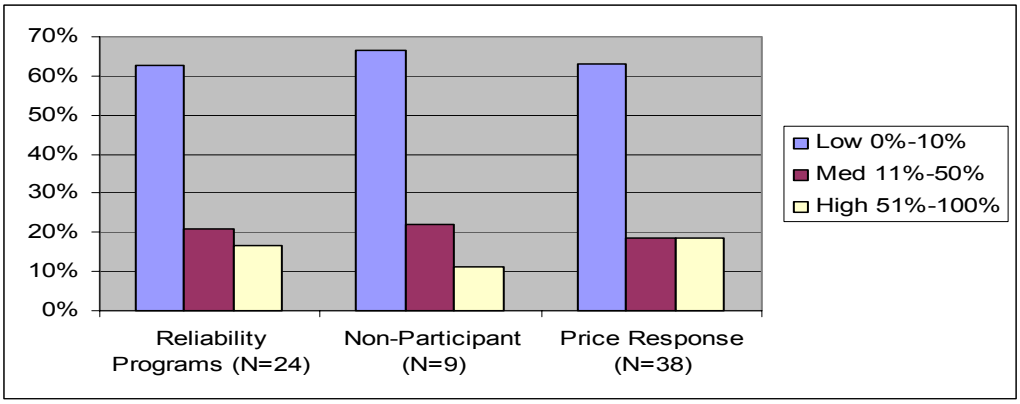


Figure 4-8 Time Spent Managing Energy

To summarize, it is difficult to draw a clear distinction between reliability and price program participants based on the characteristics of the facility. Thus, basing participation estimates only on the more easily obtained facility characteristics is fraught with inconsistencies. Ruling out customers based on conventional rules of thumb that historically have been used to recruit customers to interruptible programs will bypass many good candidates. Anticipating that this might be the outcome, the survey involved additional lines of inquiry to establish linkages between customers' perceptions of their

ability to manage their loads and barriers to doing so, which are discussed in the next section.

4.2.4 Load Management Capability

Survey respondents were asked to specify what improvements they had made in demand or load management capability since 2001. Their responses paint a picture of the current state of load management capability in the market. Figure 4-9 illustrates the response percentage by respondent type, organized by technology groupings. In general, the reliability program participants had the highest installation rates of load management equipment for all of the individual technologies listed, and the price program participants had the second highest for all except for whole premise interval meters.

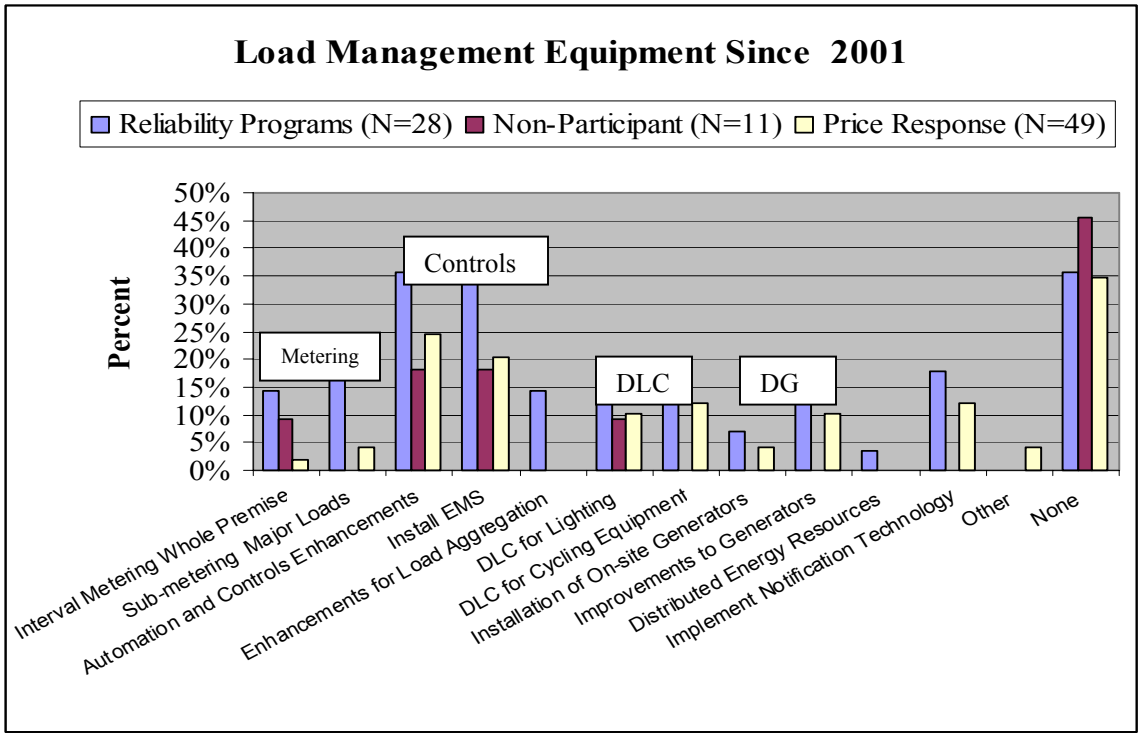


Figure 4-9 Load Management Improvements Since 2001

The relatively higher reported improvements in metering and energy information systems may reflect the requirement that most of the reliability program participants meter loads at 5-minute intervals and provide that data to ISO-NE every 5-minutes. However, many said they had made no improvements at all. Since many reliability program participants

previously participated in a load management program, they already had such equipment.

Automation and control improvements were the most common type of improvements reported with reliability program participants reporting over 35% frequencies and price program participants and non-participants reporting frequencies of up to 25% and 18%, respectively. Reliability program participants also report relatively high adoption of lighting controls and direct load control (DLC) devices compared to non-participants. Finally, the incidence of the installation of an on-site generator or improvement to existing generation equipment was reported at zero by non-participants, along with the acquisition of notification technologies.

Respondents were asked to describe actions they would undertake if asked to curtail. Figure 4.10 displays the results. The responses of program participants may reflect actions they actually undertook, either during the current year or previously, while those of non-participants are responses to an unspecified hypothetical situation.

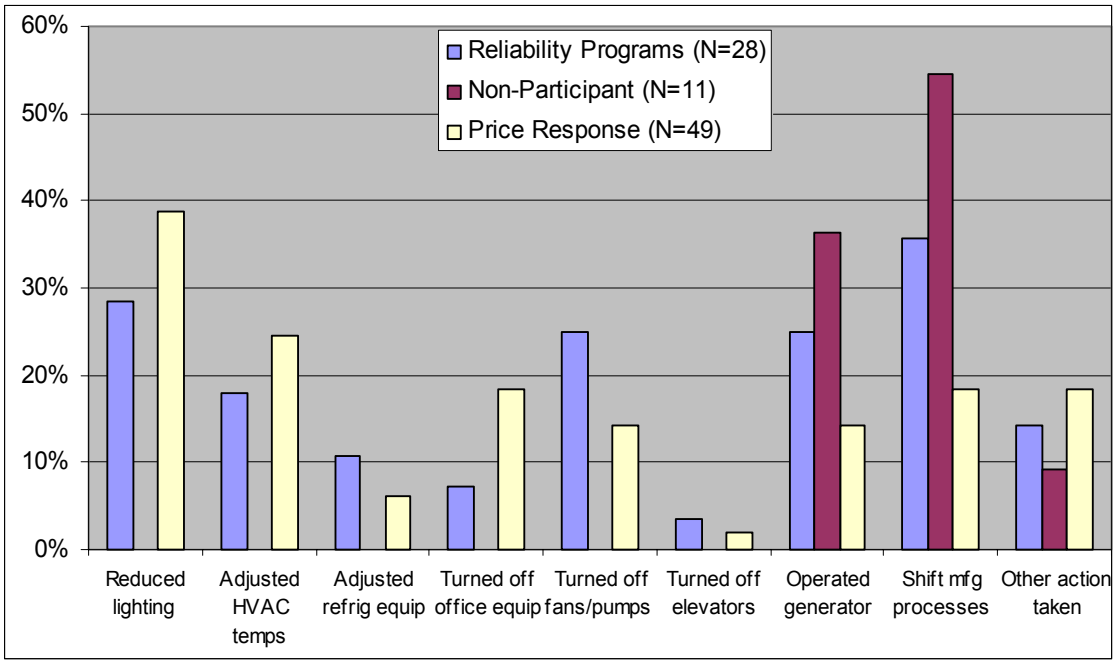


Figure 4-10 Actions Undertaken if Asked to Curtail

In general, no single action was undertaken by a majority of the survey respondents, with the exception of shifting manufacturing processes, which 55% of the non-participants reported that they would do. Also, a large percentage (36%) of the non-participants reported that they would operate generators. Both of these activities are usually conducive to large reductions in load and are indicative of good program candidates. The most employed action untaken by the price program participants was to reduce lighting (39%), followed by adjusting HVAC temperatures (24%), and turning off office equipment (18%). In contrast to this, the most employed procedure by reliability program participants was to shift manufacturing (36%), operate generators (25%), and turn off pumps and fans (25%), although 29% also reported that they reduced lighting. Price program participants report higher instances of employing behaviors available to commercial facility operators such as reducing lighting, plug loads and HVAC loads. Reliability program participants, conversely, are more likely to employ strategies available to industrial and infrastructure facility operators such as shifting manufacturing processes, turning off fans and pumps, or operating generators. Given the relative percentage of survey response rates between the two types of program participants, reliability program participants (54% manufacturing and 29% infrastructure) and price program participants (43% services and 23% trade), the dichotomy of load curtailment strategies employed makes perfect sense.

To summarize, more reliability program participants appear to implement major load reduction steps than those in the price program, while price participants turn off smaller discretionary loads than their reliability program counterparts. Non-participant responses are closer to those of reliability program participants, yet another indication that they constitute a population of potential participants.

When asked to indicate the single largest impediment to reducing load during the period 8:00 a.m. to 6:00 p.m., about 61% of reliability participants said meeting production schedules was the largest barrier, compared to 39% for price participants Figure 4-11.

Comfort was chosen by about 41% of price program participants, many of which are involved in a service industry. However, only 18% of reliability participants reported that comfort was their primary concern. As was often the case, the responses of non-participants closely resembled those of reliability program participants.

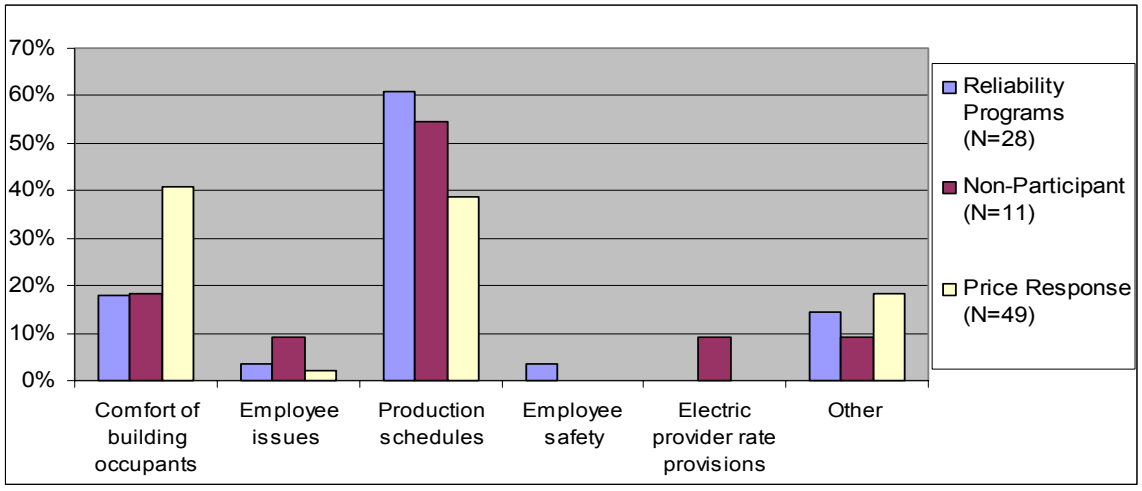


Figure 4-11 Single Largest Impediment to Load Reduction

Over half of reliability program participants (54%) said that they had electrical process equipment. Additionally, over half (53%) of them reported that they could shift their process load by 26% or more (Figure 4-12). Almost two thirds (64%) of non-participants reported that they had electrical process equipment and over 70% reported that they could shift 26% or more of their process load. The price program participants also reported that 54% of respondents had electrical processes, but were much more conservative in terms of the amount of process load they could shift.

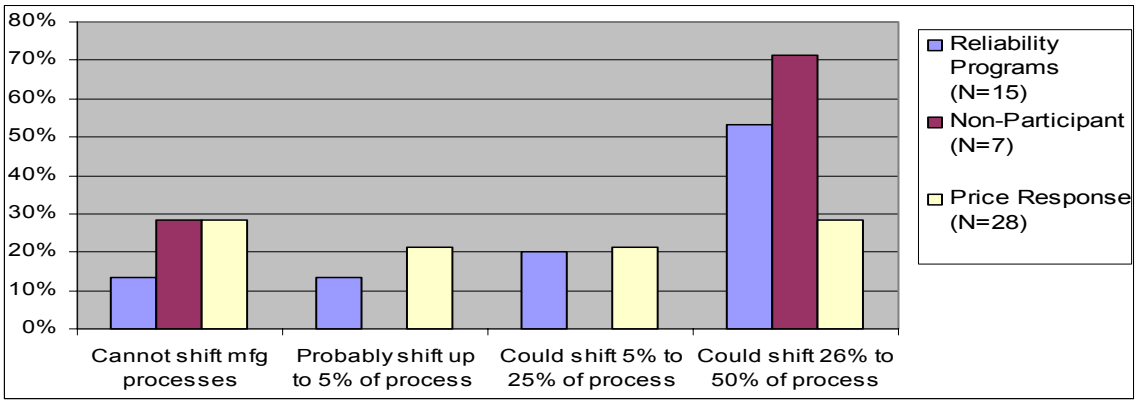


Figure 4-12 Ability to Shift a Manufacturing Process

Two thirds of reliability program participants indicated that they had some level of computer automated process control. In contrast, 60% of the price program participants utilized manual or rudimentary process controls (Figure 4-13).

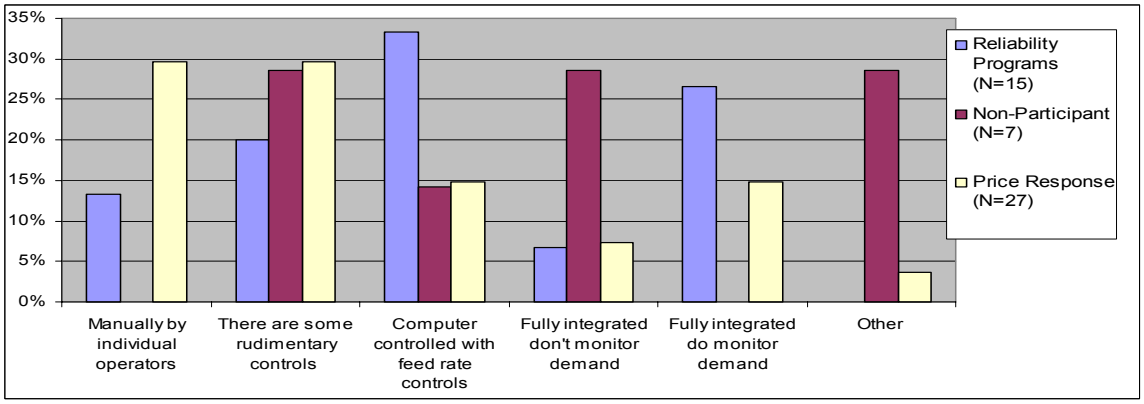


Figure 4-13 Control Methods for Process Equipment

The process control question was cross-tabulated with the amount of process load that the respondents indicated they could shift to see if there was any correlation. Figure 4-14 presents the results of this cross tabulation, which indicates that at the high end of ability to shift process load (26% to 50%) the presence of computer controls increases the self-reported ability to shift load by about 20%.

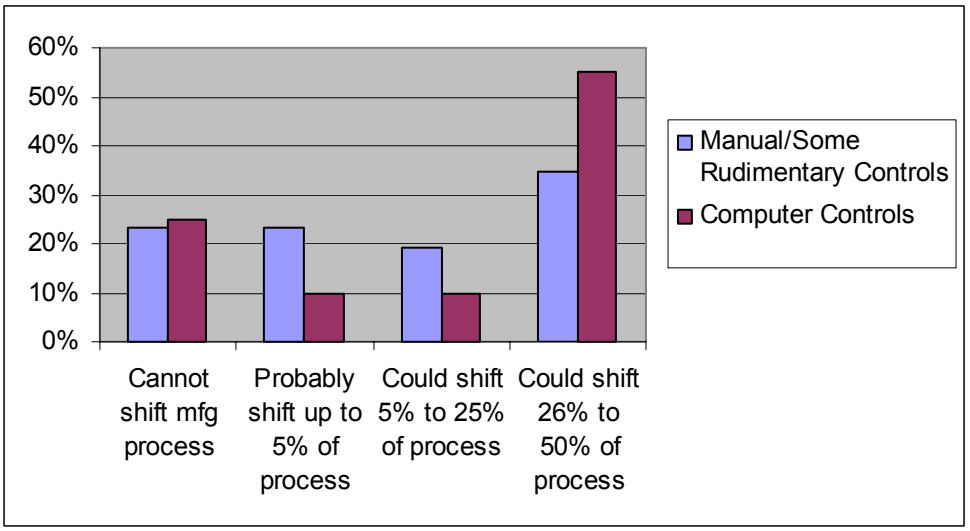


Figure 4-14 Cross Tabulation of Process Controls versus Ability to Shift Process

The customer survey also explored the linkage between lighting and HVAC Controls and the self-reported ability to curtail those loads.

Lighting

Wall switches were the most prominent type of lighting control among all survey respondents as illustrated in Figure 4-15, with 72% of price program participants, 79% of reliability program participants, and 90% of non-participants reporting wall switches as their primary form of lighting control device. Additionally, the survey respondents reported their ability to curtail lighting on a scale ranging from none (0%), a little (5% - 10%), and some (10% - 20%) and all (over 20% using dimmable or dual ballasts). The price program participants had the most ability, with over 90% reporting some ability to reduce lighting and about 4% indicating that all lighting could be curtailed. The reliability program participants and non-participants reported lower rates of the ability to reduce lighting in general (5% -over 20%); however both had higher reported rates of being able to reduce between 10% and 20% of lighting load.

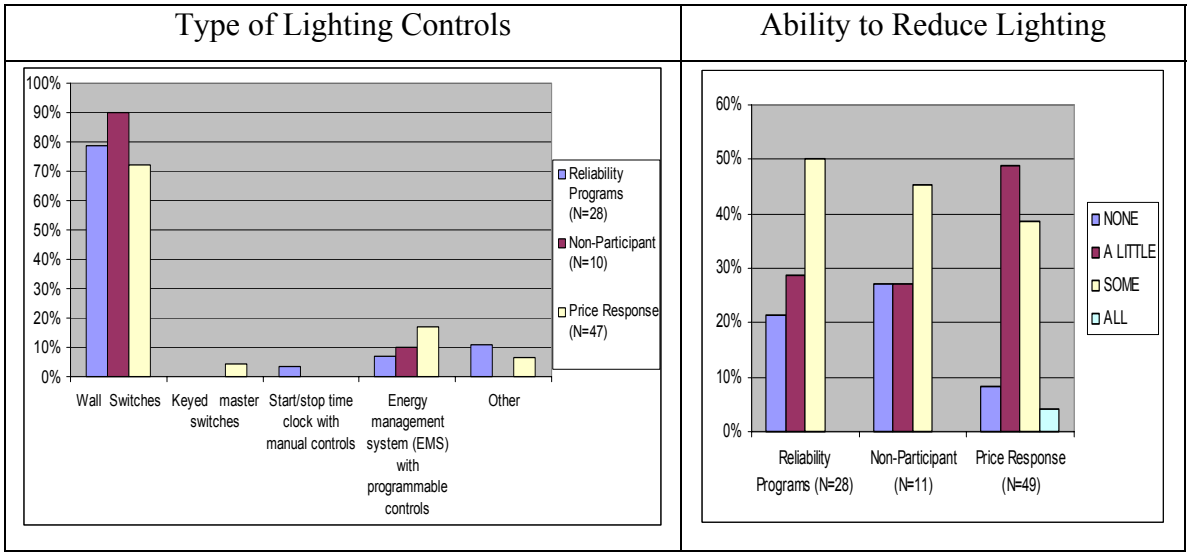


Figure 4-15 Type of Lighting Controls and Ability to Reduce Lighting

The linkage between the ability to reduce lighting and lighting control types was also investigated by cross tabulating the ability to reduce lighting for customers with wall switches and programmable EMS controls. Figure 4-16 provides the result of the cross tabulation, which are somewhat inconclusive since the customers with EMS lighting controls reported a higher incidence of not being able to reduce load, but also reported a higher percentage (9% vs. 2%) of being able to reduce a large amount (>20%) of lighting load. Additionally, the EMS customers reported less ability to reduce lighting in the range of 5% to 20% of lighting load.

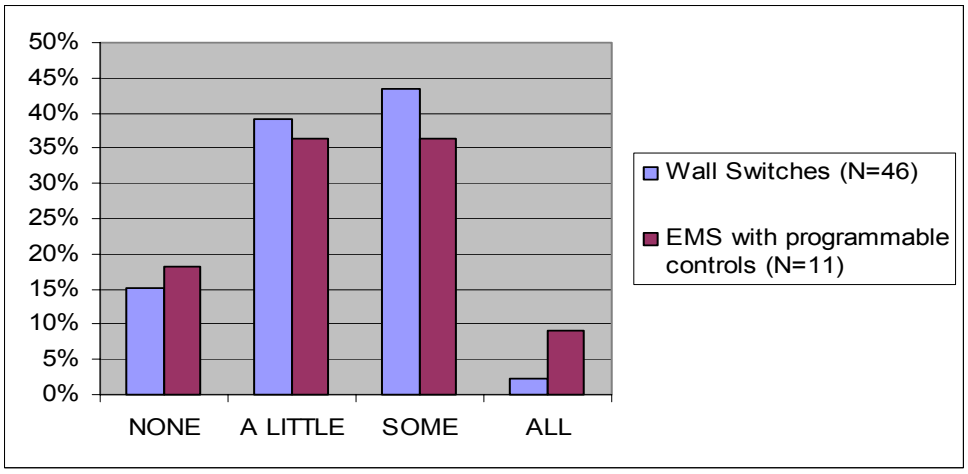


Figure 4-16 Lighting Controls versus the Ability to Reduce Lighting

HVAC Equipment

The customers were questioned about the primary type of HVAC equipment that they had, the primary type of HVAC controls, and their ability to change either temperature or airflow settings. Package or split air conditioning units were the most prevalent type of systems among all three types of survey respondents, particularly among non-participants (81%) as illustrated in Figure 4-17.

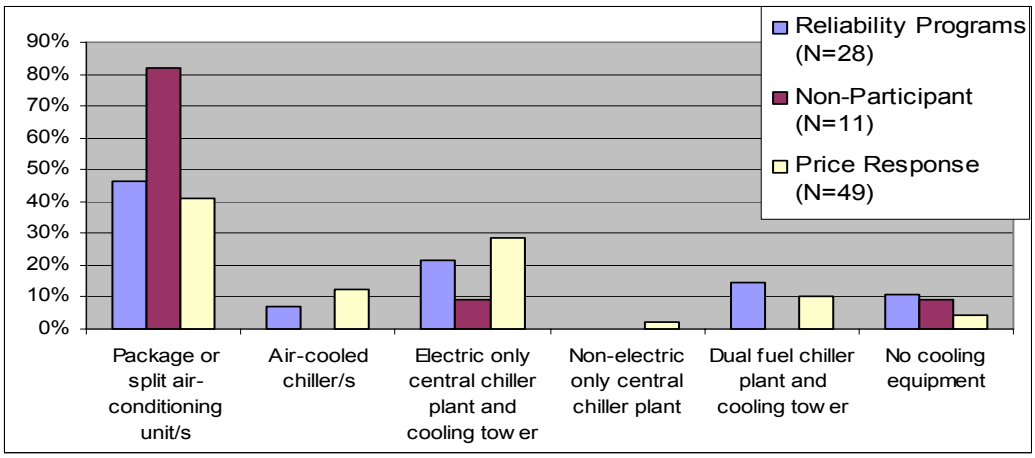


Figure 4-17 Primary Type of Cooling Equipment

Although the type of cooling equipment is sometimes indicative of the ability to curtail cooling load, the type of air distribution system usually is a more meaningful indicator of ability to curtail load particularly with respect to airflow adjustments. The least flexible system (Constant Volume) was the most prevalent system particularly among non-participants (70%) as illustrated in Figure 4-18. Note that the price program participants had the highest percentage (35%) of Variable Air Volume (VAV) systems with Variable Frequency Drives (VFDs) controlling the fan motors, which is the most controllable type of system.

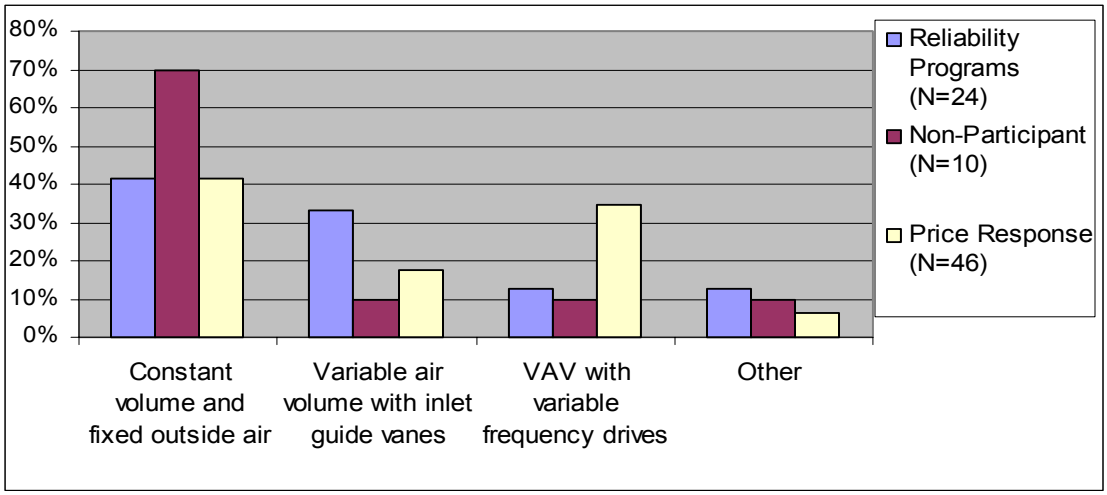


Figure 4-18 Primary Type of Ventilation and Air Distribution System

The type of air systems and the types of controls were cross tabulated against the reported ability to either raise cooling set point temperatures or adjust the airflow settings to determine the correlation between the equipment and controls and the reported ability to reduce load (Figure 4-19). The type of controls had a strong influence on the ability to adjust airflow parameters with over two thirds of the Customers with EMS controls reporting that they could adjust airflow. The linkage between controls and the ability to adjust space temperatures was not very conclusive, with about 13% of the EMS customers reporting that they could not adjust temperature settings, while 25% reported that they could easily raise temperatures 2ºF to 4ºF or more.

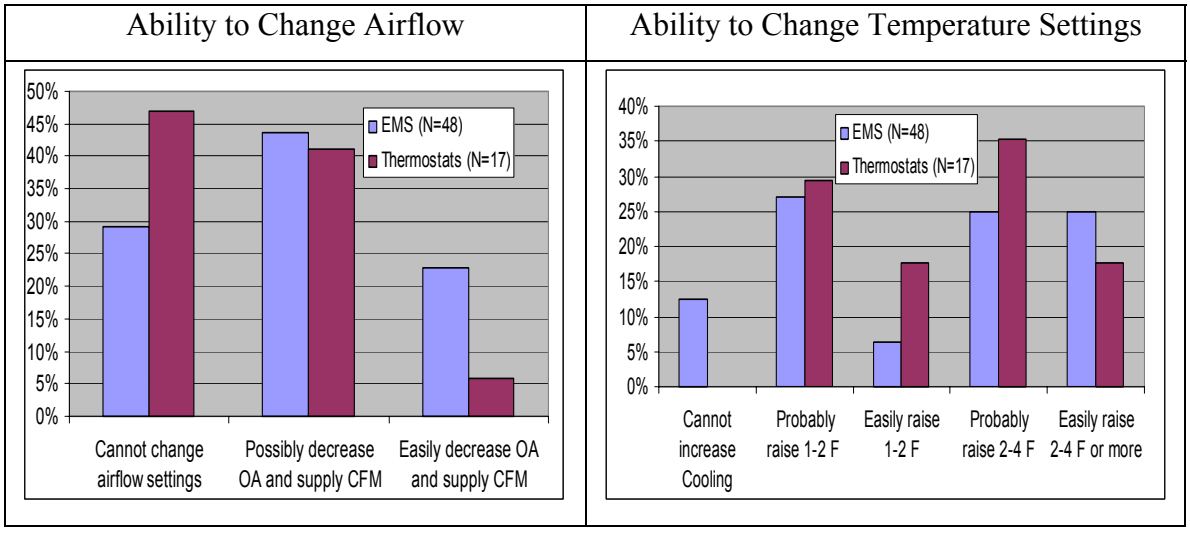


Figure 4-19 Type of Controls vs. the Ability to Adjust Airflow and Temperature

The pattern of response follows the previous example where the EMS customers report a higher rate of not being able to do anything and then also report a higher rate of being able to perform at the maximum level, but reported lower rates at the intermediate performance levels.

The type of air distribution system did show a strong correlation with the reported ability to adjust airflow parameters. About 78% of customers with VAV systems indicated they could adjust their airflow as opposed to 46% of customers with constant volume systems.

To summarize, the link between the type of controls and the customer's reported ability to reduce load are more a function of the customer's attitudes than they are of the level of sophistication of the controls. In some cases, sophisticated control systems are installed because the system being controlled is so critical that it needs to be operated within a very narrow range. This is not to say that improved controls do not contribute to a greater ability to curtail load, but that controls alone are not an indicator of load curtailment capacity. The human factor cannot be ignored when attempting to identify load curtailment potential. As these customers become more experienced with program participation, and if the benefits increase, or expectations of benefits rise, then the

existing base of participants may be able to substantially increase the amount of load available for curtailment by adopting control technologies. Such intrinsic program growth would offset the need to attract new participants to achieve program goals for demand response, therefore justifying funding for providing technical assistance to end-use customers.

4.3 Program Choice

To ascertain barriers to program participation imposed by the design of the reliability and price programs, the survey included questions to solicit the reasons why customers chose the program they did, or chose to not participate. In addition, respondents were asked to react to changes in program features, and to a new program design, i.e., a day-ahead price response program.

4.3.1 Barriers to Participation in Current Program Offerings

Both the price program participants and the non-participants were asked to indicate why they did not participate in the reliability programs (Figure 4-20). The responses of the non-participants indicate that, by and large, the benefits were insufficient. Specifically, survey responses indicate that the monthly capacity payments were too low (30%), or that the payment for load curtailments was too low (30%). Three other non-participants (30%) cited program rules as the reason and only one non-participant (10%) indicated that they were unable to shift usage. The results are that 90% of non-participants cited benefits or program rules not lack of ability to curtail, as the primary barrier to participation. On the other hand, 45% of the price participants indicated that they were unable to shift usage and another 25% indicated that inadequate program knowledge or permitting issues were the primary barriers to participation.

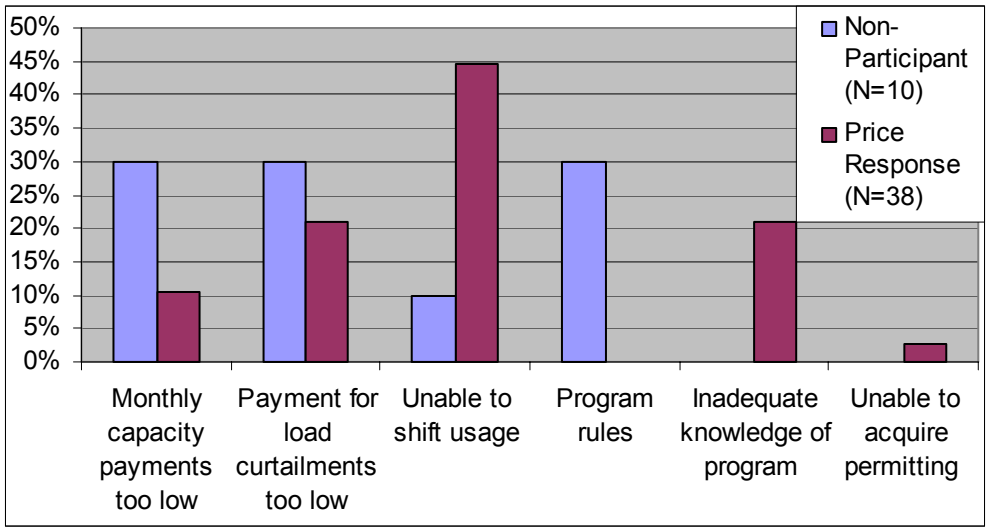


Figure 4-20 Reasons for not Participating in the Reliability Programs

Given the current ICAP market in New England, characterized by low monthly spot market prices, it is not surprising that many customers find participation not to be economically attractive. ICAP payments to demand participants were relatively low throughout 2003, averaging about $.23/kW-month.[23] Consequently, curtailment events are the primary source of payments, and to many customers, the expected payouts do not justify undertaking the transactions required to successfully participate.

To see if specific program provisions were the reason why customers eschewed participation, non-participants were asked if they would be more likely to enroll in a reliability program if some of the compliance risks were reduced. Almost half (45%) of the non-participants said they would be likely to participate in a reliability program if curtailments were limited to a total of 20 summer hours, and 36% indicated they would participate if curtailments were limited to three consecutive days. Additionally, the non-participants were asked to identify the amount of event notification lead time they would

[23] All reliability program participants receive ICAP credits that can be monetized through ISO-NE's monthly ICAP supply auction.

need and 45% responded that they would need 30 minutes and another 27% indicated that they could respond within two-hours.[24]

Participants were asked to indicate what feature change would most influence them to increase the level of curtailment during events in the program in which they participated. As Figure 4-21 illustrates, most indicate that it would take higher financial benefits to induce more participation, although a small number indicated longer event notice. This finding suggests that modifications to the program provisions to limit exposure of customers to load curtailment events are unlikely to have much effect on participation until curtailments become more frequent.

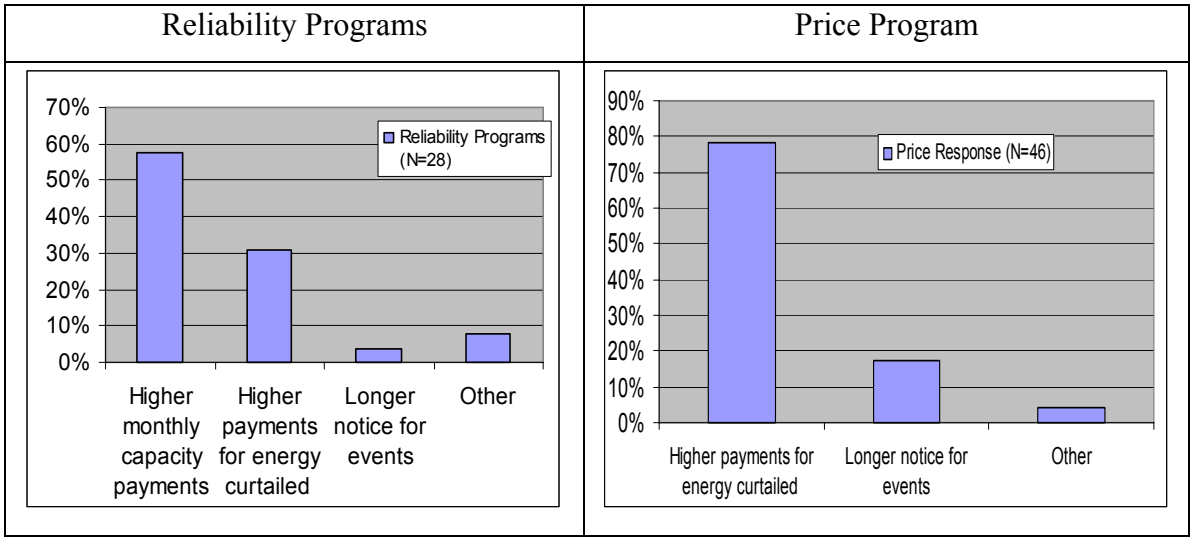


Figure 4-21 Feature Change Most likely to Increase Level of Participation

What was the most important factor in the decision to participate? Figure 4-22 displays the responses to this survey question. As was the case in other similar situations, most of the respondents in both the reliability and price programs indicated that the decision turns

[24] Two hours is the maximum response time available under the current reliability programs.

on the perceived benefits (either utility bill savings or financial incentives). In both cases, the third highest rated motivating factor was a sense of duty to help protect against widespread blackouts. The fact that some customers see this as being important suggests that marketing and promotion programs should emphasize the contribution to system reliability in marketing participation, especially in the price program.

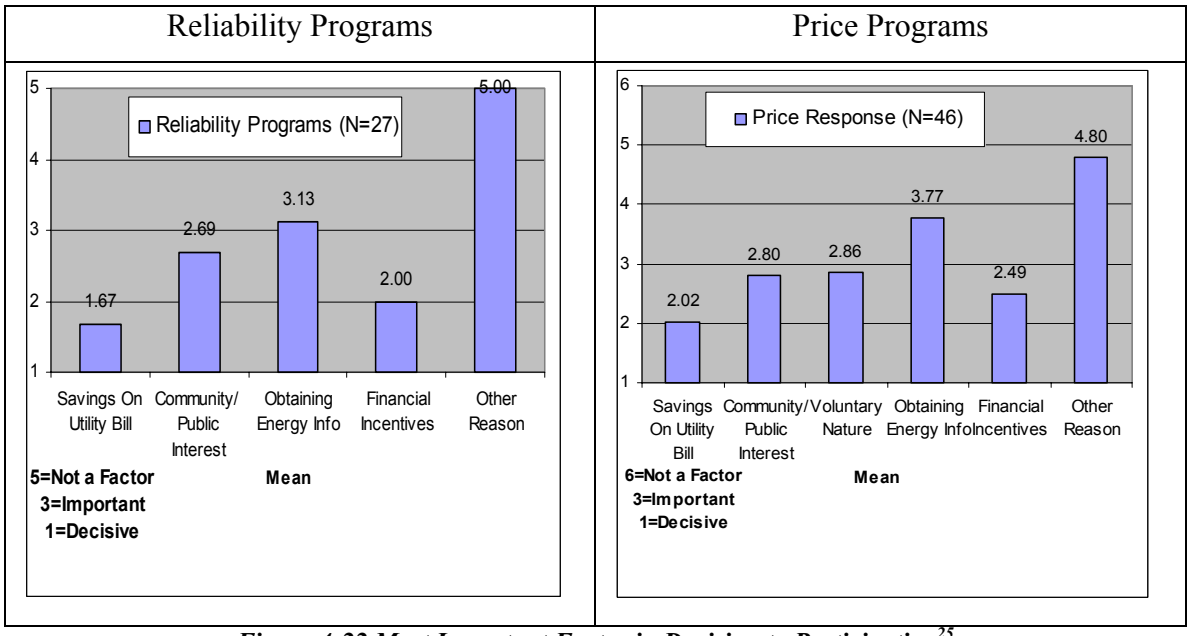


Figure 4-22 Most Important Factor in Decision to Participation[25]

The inability to clearly distinguish between a typical reliability and price program participant, as well as the inconsistencies in both customer behavior and opinions revealed by the survey, is reflective of the relative immaturity of the demand response market. This observation is not unusual for customers who are the early adopters of new products and services. In the case of demand response, participating customers are still learning what they can and cannot accomplish in terms of the amount and frequency of load reductions. In other words, many are experimenting in real-time to extract value out of the product. However, since the economic benefits of demand response are relatively small when compared with traditional energy efficiency projects, most customers cannot

[25] The scales in the graphs are different because the reliability programs are not voluntary and therefore, "the voluntary nature of the program" was not an option.

justify devoting a significant amount of time and resources to master the programs. This contributes to the inconsistency in customer behavior and, if unchanged, may stall further participation in the programs.

The challenge facing ISO-NE is to successfully bridge the gap between the early adopters of demand response and the more mainstream customers who will need clear examples and value propositions to entice their participation. Providing technical assistance and developing case studies can help bridge this gap.

Customers would likely take advantage of technical assistance to help quantify the amount and methods of load reduction, if their Enrolling Participant, Demand Response Providers, or Local Distribution Company offered it. One Massachusetts based local distribution company is currently offering technical assistance (funded through the States' energy efficiency funds) to its customers in the form of a Load Reduction Audit. The Load Reduction Audit provides customers with reasonable expectations on what they can accomplish through the program, as well as a plan for achieving their goals. In addition to helping the individual customer, the results of the Load Reduction Audits can be used to develop case studies to help other customers evaluate whether to participate and then choose the program best suited for them.

4.3.2 Alternative Design and Product Preferences

Over 300 customers chose to participate in the ISO-NE Real-Time Price Response Program in 2004. That choice reflects customer preferences for a program that pays only for performance, and lets customers decide when and how to curtail. The tradeoff relative to the reliability programs is that the price program offers no monthly capacity payment through the ICAP market. Moreover, price response program participants have no assurance that opportunities will arise to curtail and get paid, since payment is limited to when ISO-NE forecasts real-time LMPs in excess of $0.10/kWh, and opens up the curtailment window of opportunity. This strong interest in responding to prices as the

market reveals them (as opposed to committing to curtailments) suggests that there might be a substantial interest in participating in a Day-Ahead Price Response Program.[26]

The survey posed a hypothetical Day-Ahead Price Response Program for respondents to consider, with the following characteristics:[27]

1. Participants would enter bids to curtail, during specified hours of the next day, to ISO-NE the day before;
2. Bidders would be informed by 4:00 p.m. whether or not their bid was accepted;
3. Curtailment bids that are accepted would be paid the higher of their bid price or their zonal Day-Ahead LMP; and
4. Deviations from the scheduled performance would be charged at their zonal Real-Time LMP for energy.

Respondents were then asked to indicate the likelihood that they would participate in such a program if it were offered. The responses are illustrated in Figure 4-23. About 50% of reliability program participants and 41% of price program participants indicated that they *definitely would* or *probably would* participate. Non-participants were even more inclined to participate (55%) using the same measure, but they all indicated that they *probably would* participate as opposed to *definitely would.* In fact, the non-participants were non-committal in general, because they did not make the definitive choice to participate or not to participate. This could be an indication as to why they are non-participants to begin with, but still exhibit a lot of the characteristics of participants.

[26] ISO-NE has proposed to implement a Day-Ahead Load Response Program (DALRP) in 2005. ISO-NE's DALRP design gives all Real-Time program participants an option to submit Day-Ahead load curtailment offers, including Real-Time Price Response Program participants. The Day-Ahead option in the Real-Time Price Response Program is equivalent to a stand-alone Day-Ahead Price Response Program.

[27] These characteristics are consistent with ISO-NE's proposed DALRP.

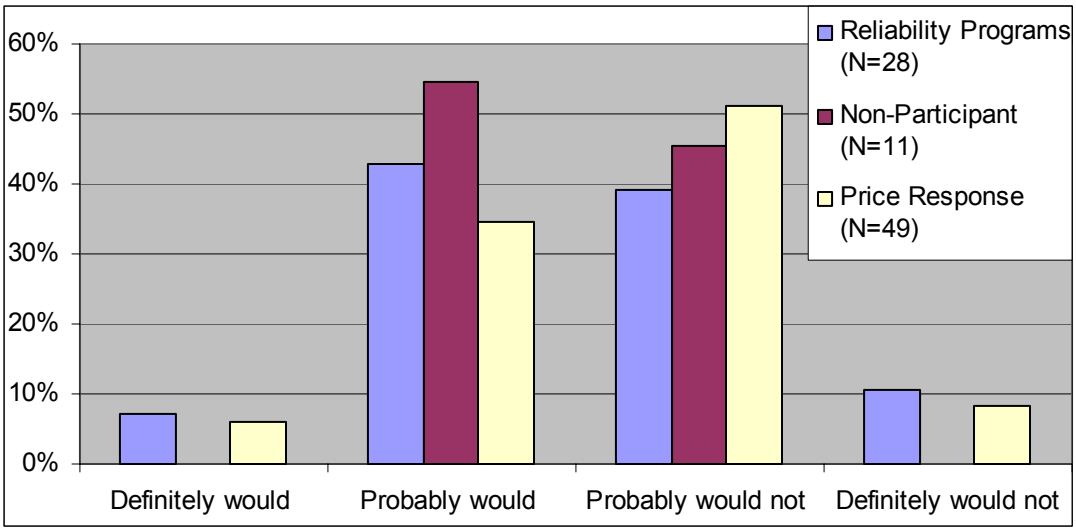


Figure 4-23 Likelihood of participating in a Day-Ahead DR Program

The strong interest by price participants is expected, as the day-ahead notice improves on a design they already have a preference for; they get longer notice of events and they control when they enter the market by the price they bid. The fact that they are willing to become exposed to the non-compliance penalty suggests that more market access and control are worth the risks.

The high interest on the part of reliability participants may reflect the current market situation characterized by low ICAP payments and few curtailment events to earn performance payments. Some customers appear to be willing to switch to a program where all the benefits are derived directly from day-ahead energy market prices. However, customers do not necessarily have to choose between the two programs. ISO-NE plans to offer participants in both the reliability and price programs the option of participating in the Day-Ahead Load Response Program.

To explore the potential participation in the Day-Ahead Program and examine minimum bid requirements, survey respondents that indicated they *would probably* or *definitely would* participate were asked to indicate the average amount of load and minimum bid

price they would offer into the Day-Ahead Program.[28] The responses to the amount of load question are illustrated in Figure 4-24, which clearly shows that, for a majority of all respondent types, a minimum bid limit of 100 kW would allow the vast majority of customers to participate. In fact 35% of reliability participants and 23% of price participants indicated that they would be submitting average minimum bids of 1 MW or greater.

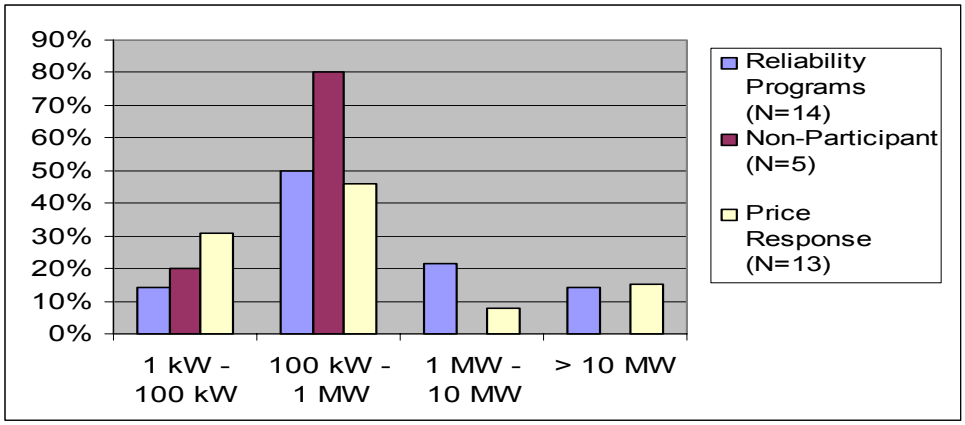


Figure 4-24 Average Amount of Load that would be Bid into Day-Ahead Program

The customer reported minimum bid prices are illustrated in Figure 4-25, which shows that the reliability program participants had a fairly bell-shaped distribution centered on the $0.20/kWh to $0.25/kWh pricing bin. This type of standard distribution with 53% reporting bids of $0.25/kWh or under is what might be expected with fairly savvy customers providing honest answers about their intentions. Over 20% of price program participants indicated that they would bid at the minimum of $0.05/kWh, which may be an attempt at arbitrage or an indication that they can self-generate power for less than $0.05 kWh.

[28] It is typically difficult to get an accurate response from customers about their minimum bid either because of lack of knowledge or opportunity bias.

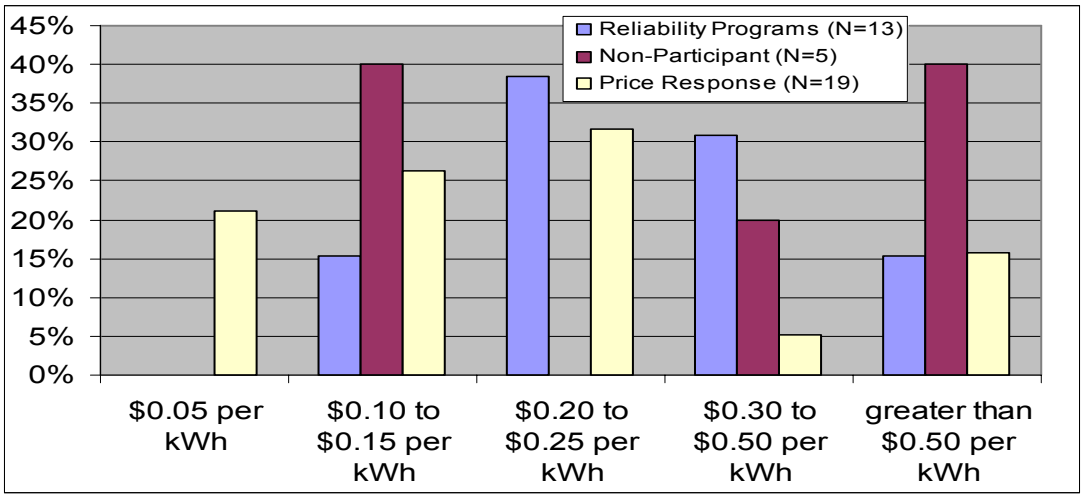


Figure 4-25 Minimum Bid Price for Energy in the Day-Ahead Program

In general, the price participants indicated that they were more likely to bid at the lower price bins ($0.10/kWh - $0.15/kWh and $0.20kWh - $0.25/kWh) and consequently would play a more active role in the Day-Ahead Program. The non-participants exhibited bimodal behavior with 40% of respondents indicating a minimum bid of $0.15/kWh (a fairly likely event) and the remaining 60% indicating a minimum bid preference of $0.30/kWh or greater (it is highly unlikely that such bids would clear under the current market conditions).

4.3.3 Event Level Survey Results Price Response Program

As part of the 2004 program evaluation, ISO-NE issued internet-based event level surveys to Real-Time Price Response Program participants, which were issued to customers immediately after a price event in their load zone. The surveys were extremely short and were designed to determine whether or not a customer tried to participate in an event, determine why certain customers decided not to participate, and determine the type of strategies employed to curtail load. Additionally, customers were asked if they checked the Real-Time LMP before deciding to curtail.

Table 4-2 provides a summary the total number of event level survey responses and the number of customers that indicated that they participated in each event along with the

percentage of survey respondents that participated in the event. There were a total of seven event level surveys administered and the response rate was highest for the first survey (27). The response rate then began to drop after the first three surveys when the survey length was doubled from three questions to six questions. The percentage of respondents that indicated that they participated in the event fluctuated between 25% and 56% with a total of 45 customers out of the 104 survey respondents indicating that they participated in an event.

Event Date	Total Survey Responses	Total Event Responses	Event Response Rate
14-Jan-04	27	15	56%
12-May-04	19	8	42%
24-May-04	16	4	25%
9-Jun-04	8	3	38%
10-Jun-04	8	3	38%
3-Aug-04	10	5	50%
12-Aug-04	16	7	44%
Totals	**104**	**45**	**43%**

Table 4-2 Event Level Survey Responses

Figure 4-26 provides the responses for both the larger main survey described in previous sections above and the event level survey regarding the types of curtailment strategies employed during a price event. Reducing lighting was the top strategy reported in both surveys and adjusting HVAC temperatures and turning off office equipment was the second and third most employed strategies in both surveys as well. In general, the responses in both surveys are relatively consistent with exception of *operating the EMS,* which was reportedly employed by 20% of the event level respondents, but only by 2% of the main survey respondents.

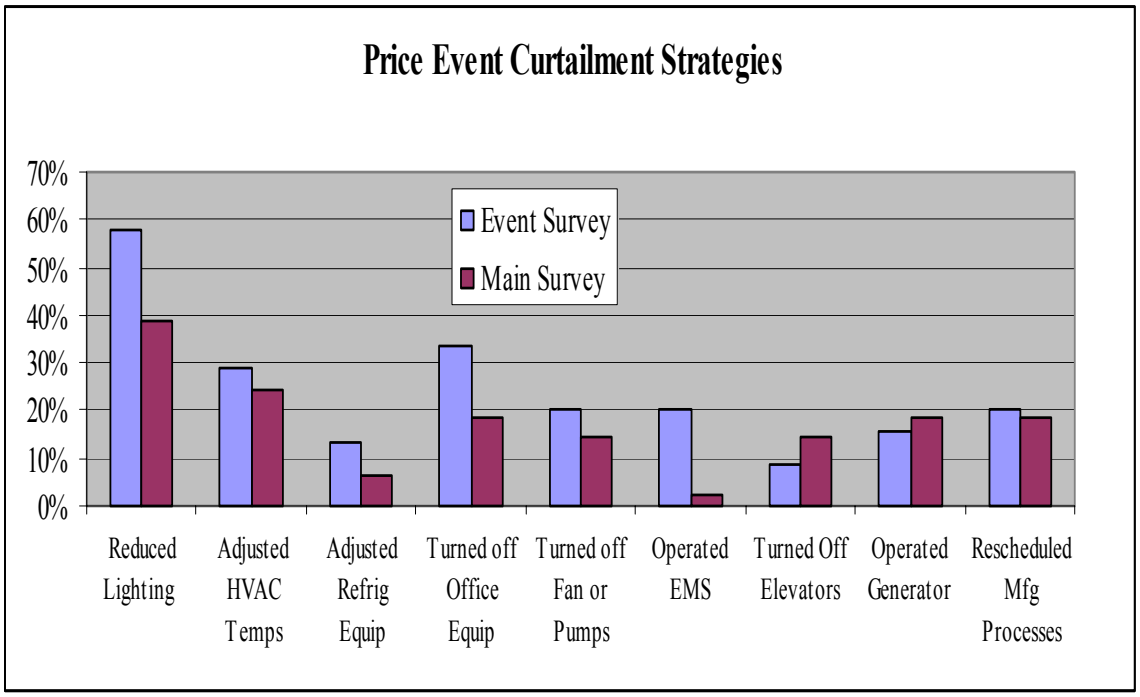


Figure 4-26 Comparison of Price Event Curtailment Strategies

The price program participants were also asked program-specific questions about the frequency of price events, the amount of events they participated in and whether or not they look at the LMP before deciding to participate in an event.

Figure 4-27 illustrate the responses of the price program participants to the question about why they did not participate in either a particular event (event level survey) or in any price events (main customer survey). Essentially, the *Resources not available* and the *Interruptible Processes not operating* could be combined with the more general *Business conditions* reason, which was the top reason cited for not participating by 52% of respondents in the event level survey and 39% in the main survey. The second most cited reason was that the event notice was either not received at all or was not received in a timely manner (26% Event Level Survey, 17% Main Survey). A low wholesale price for energy was cited as a reason for not participating by 8% of the customers in the event level survey, while none of the customers in the main survey gave this reason. Finally,

about 8% of the customers in both surveys indicted that they did not know how to curtail their load.

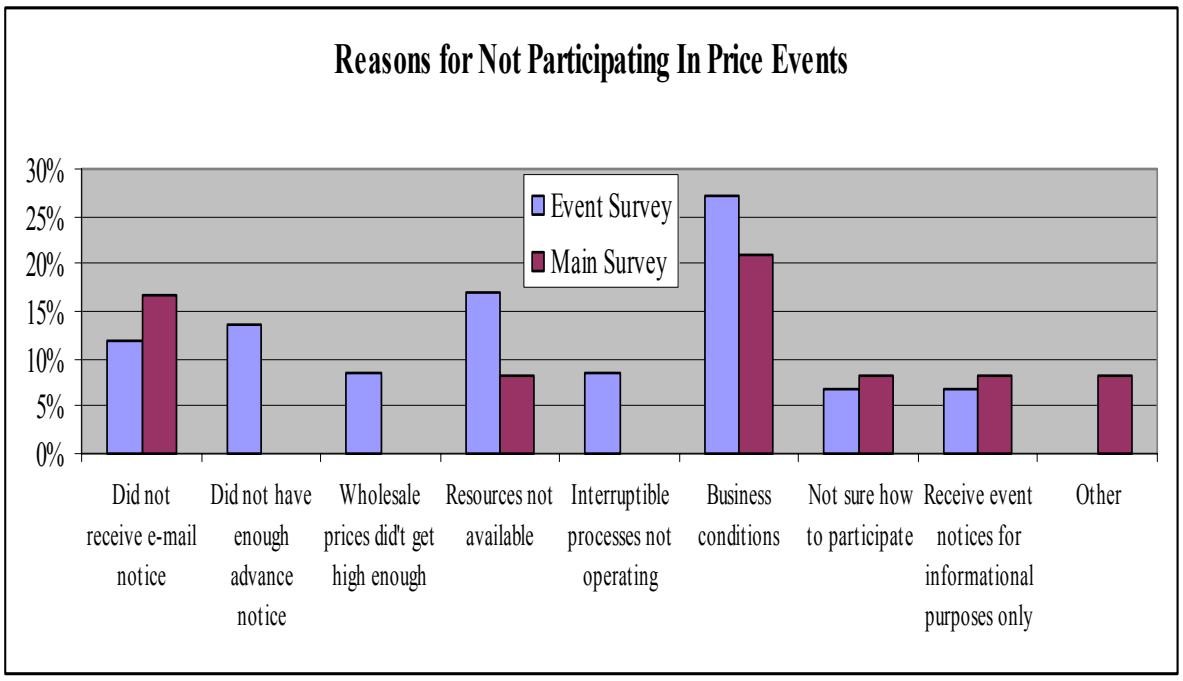


Figure 4-27 Reasons for not Participating in Price Events

The price program participants were also asked how they felt about the frequency of price events and to estimate the percentage of events that they participated in as part of the main customer evaluation survey. As illustrated in Figure 4-28, over 80% of the price participants felt that the number of events was the right amount, however 40% of customers indicated that they only participated in about 25% of the events and 32% did not participate in any events.

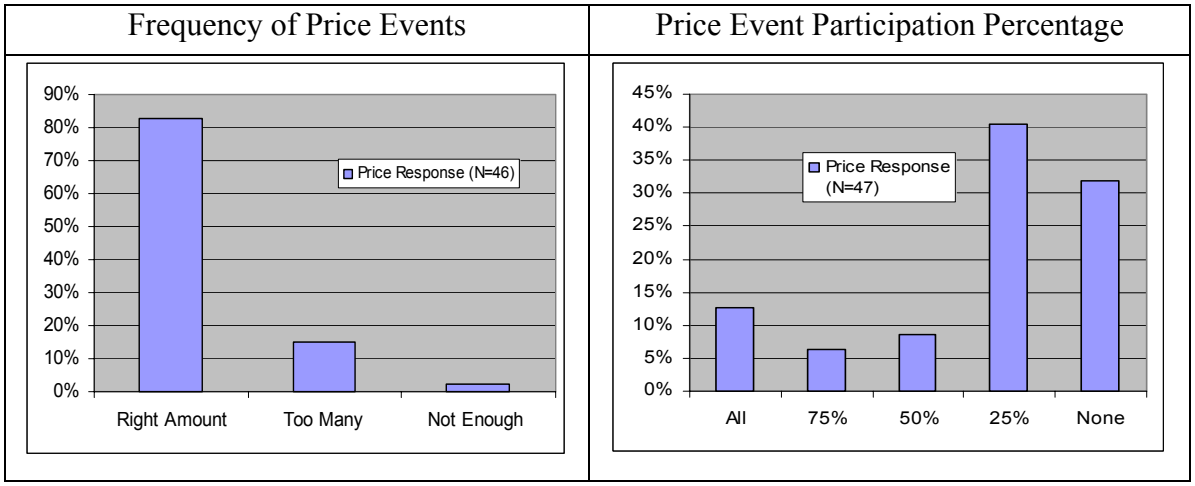


Figure 4-28 Frequency of Price Event and Customer Participation Percentage

Finally the price program participants were asked whether they actually checked the LMP while making the decision to curtail and the minimum price at which they would curtail load. Figure 4-29 shows that almost 70% of the price program participants make a decision on whether to participate in a price event without even considering the LMP. This is probably due, in part, to the guaranteed minimum floor payment of $0.10/kWh for all event hours. However, the more likely scenario is that customers base their decision to participate on the existing business conditions at the facility at the time of the event, as previously reported above. The minimum price at which price customers would curtail load is very similar to numbers they reported for the Day-Ahead Program - about 18% of customers reported that they would curtail for $0.05/kWh and another 36% were willing to curtail for between $0.10/kWh and $0.15/kWh.

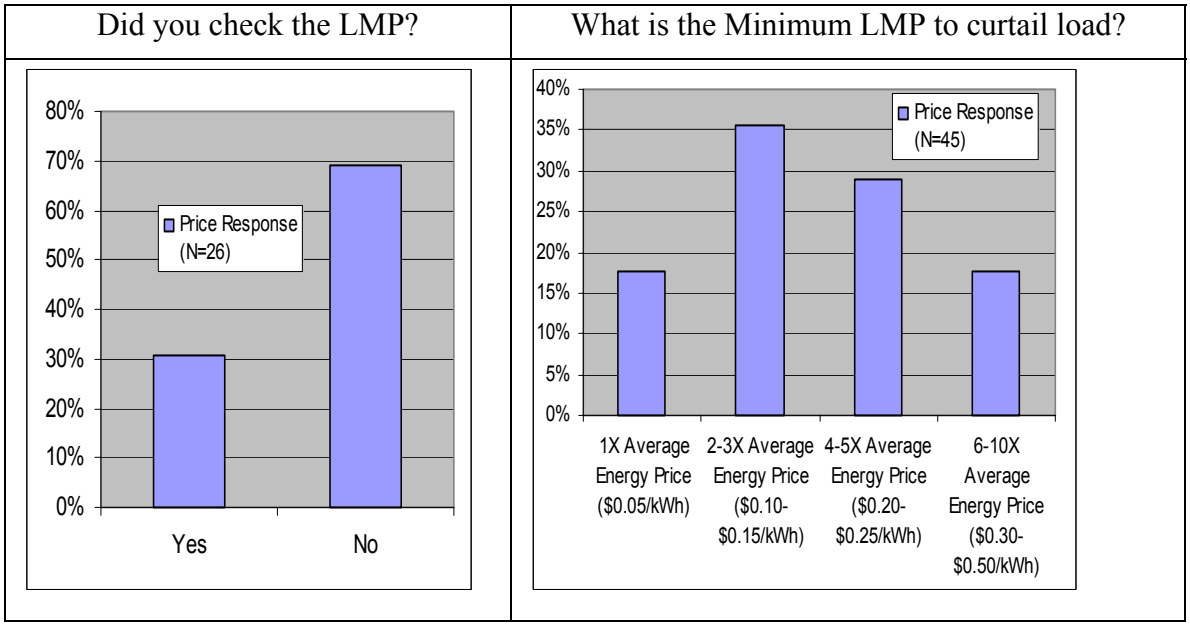


Figure 4-29 Did you Check the LMP/ and What is the Minimum Price to Curtail?

To summarize, it appears that for a majority of the price program participants the decision to participate in a price event is not driven by the hourly LMP during the event period, but by facility specific conditions when an event is called and the guaranteed minimum payment of $0.10/kWh. The reason for this behavior is most likely due to the fact that there is no economic disincentive for participating in price events. Virtually all participating customers are not exposed to paying the real-time price of electricity. Therefore, these customers behave in a manner that does not correlate well to economic models driven by the LMP. Unfortunately, the primary behavioral driver, facility specific conditions, cannot be incorporated into a predictive model. It is difficult to say with certainty that higher prices would spark a greater level of participation in the price events, especially since prices have been relatively low over the last several of years.

4.3.4 Event Level Survey Results Reliability Programs

During 2004, there were no events called for the reliability programs. However, as previously stated, an Audit Event of all reliability programs in all load zones was called on August 20, 2004. After the event, a short internet-based survey was sent out to the

customers that consisted of twelve questions. The questions were designed primarily to determine whether the customer participated in the event, what types of strategies they used, and if they did not participate, why not? Additionally, there were questions about whether the customers used their IBCS to monitor the amount of their curtailment, the method of notification that they received and whether they used equipment to automate the load curtailment process.

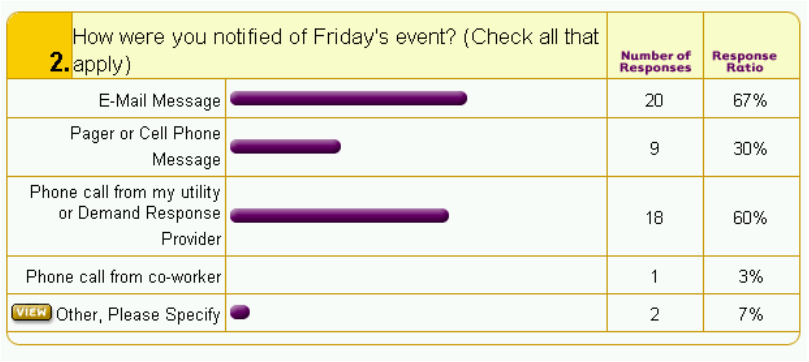
A total of 77 e-mail surveys were sent out and 34 were completed (44% completion ratio). The results are presented Figure 4-30, which shows that 88% of respondents did participate.

1. Did your company or organization participate in the Demand Response Program event on Friday, August 20, 2004?	Number of Responses	Response Ratio
Yes	30	88%
No	4	12%
Total	34	100%

Figure 4-30 Did You Participate in the August 20, 2004 Event?

Three of the four customers that did not participate indicated that there were problems with the notification process and the fourth customer indicated "that the incentive to participate was not clear."

Figure 4-31 provides the method of event notification that was used by the survey respondents who could choose all of the methods that apply. As expected, notification by e-mail was the most prevalent (67%), although, a large proportion of customers (60%) were called by their utility or demand response provider. Text messages to pagers and cell phones were also employed by 30% of respondents.



2. How were you notified of Friday's event? (Check all that apply)	Number of Responses	Response Ratio
E-Mail Message	20	67%
Pager or Cell Phone Message	9	30%
Phone call from my utility or Demand Response Provider	18	60%
Phone call from co-worker	1	3%
VIEW Other, Please Specify	2	7%

Figure 4-31 Method of Event Notification

The customers were asked to indicate the types of strategies they employed to curtail load during the event and the results from this survey are presented in Figure 4-32 along with the answer to the same question that was asked as part of the main evaluation customer survey. One of the interesting things to note is that the frequency of virtually every strategy was higher for the event survey than for the main survey, which is probably due to the timing of the survey.[29] The most employed strategy according to respondents of the event survey was to *turn off pumps and fans* (59%); in contrast, that was the third most popular strategy reported in the main survey by only a quarter of the respondents. Rounding out the top three strategies reported in the event level survey were operating generators (52%) and adjusting HVAC Temperatures (45%). The top strategy reported by reliability program participants in the main survey was to *shift manufacturing processes* (36%), followed by *reduced lighting* (29%).

[29] The event level survey was issued less than a week after the event while the event was still fresh in the respondents mind. The main survey was issued at least a month or more after the event and therefore the respondent may have forgotten some of the specific details about the event.

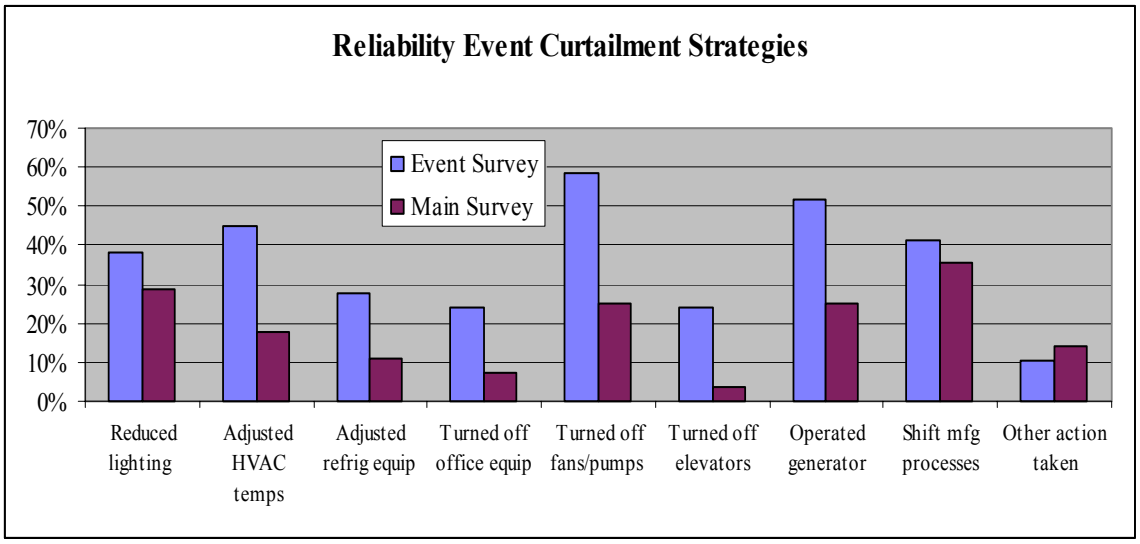


Figure 4-32 Comparison of Reliability Event Curtailment Strategies

The reliability program customers were also asked if they utilized the near real-time feature of their IBCS to monitor the amount of their load reduction during the event and whether it was necessary to increase the amount of the load reduction. Figure 4-33 provides the results to these two questions, which shows that two thirds of the respondents did monitor their load using the IBCS and that a quarter of those customers did have to increase their load reduction to meet their commitment level. Additionally, 80% of the customers that needed to shed more load, reported that they were able to do so. This discussion illustrates the added value that the IBCS brings to reliability customers by providing them near real-time feedback on their performance.

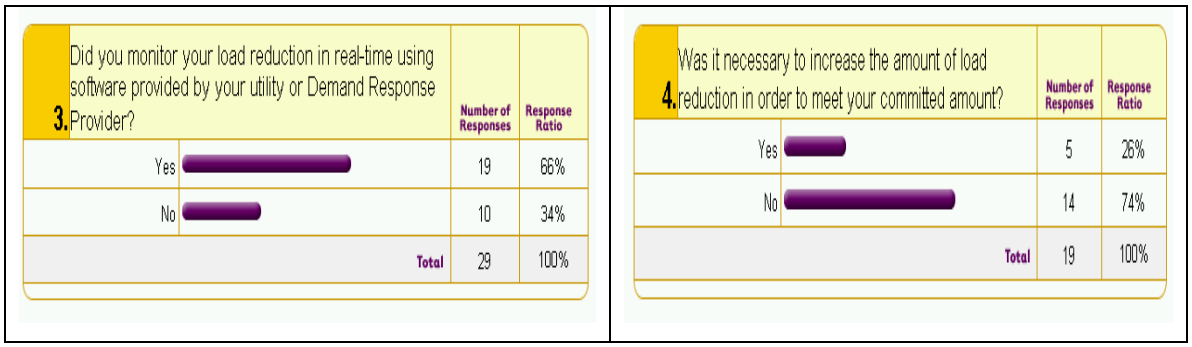


Figure 4-33 Did you Monitor Load? And was it Necessary to Increase the Amount of Load Reduction?

Finally, reliability program customers were queried about the level of automation employed to implement load curtailment and about their ability to respond within ten-minutes or less. Only 17% of the survey respondents indicated that they used automated controls to implement load reductions. The automation equipment that was used consisted of either remote start capabilities for generators or the use of Direct Digital Controllers (DDC) as part of an Energy Management System (EMS) that controlled lighting, HVAC equipment, refrigeration equipment, and fans & pumps.

In summary, reliability program customers who responded to the survey reported a fairly high performance rate of 88%. The customers that did not perform generally cited communication problems for non-performance. A large portion of the customers used their IBCS to monitor their performance, and 80% of the customers that were not meeting their required performance level were actually able to shed more load.

5 Market Assessment

The task of assessing the market for relatively new program offerings like the ISO-NE demand response programs is a complex and challenging exercise. Electricity markets in the Northeast have undergone a radical change in the past five years. The impacts on customer participation in load management have been no less extraordinary. Programs that were in place for over 20 years have been replaced with new ones based on a totally different valuation premise. As a result, even customers with years of experience responding to curtailment calls have to become acquainted with new program provisions and requirements, and understand how market circumstances affect reliability and prices. In this context, estimating market potential requires being circumspect, focusing on setting boundaries and guidelines, and avoiding hard and fast rules.

Defining the market participants and then establishing reasonable bounds regarding the size of the market are the foundation of establishing market potential. Developing finer market segments and estimating market penetration within the segments to a higher resolution allows for further refinements of the market assessment. However, since the ISO-NE demand response programs are in their infancy, there is limited market intelligence available to support a very fine degree of granularity. Therefore, to establish the market size and develop market penetration estimates and potential, rate-base information on customer usage and business activity provided by the local distribution utilities (LDCs) was combined with a variety of secondary sources of information on customer size and business activity. The results provide the basis for developing a first approximation market assessment, but tempered by factors such as imprecise data, limitations on available data sources, and self-selection biases in program participation, which contribute to the ambiguity of the analysis.

5.1 Defining the Market

LDC and supplementary secondary data sources were used to define the annual electrical consumption and contribution to peak demand of residences and businesses in New England. The following supplemental data sources were used in this analysis: the Residential Electric Consumption Survey (RECS), Commercial Building Energy Consumption Survey (CBECS), and

Manufacturing Energy Consumption Survey (MECS).[30] Table 5-1 provides an estimate of the annual energy consumption and peak demand across four market sectors derived from these data sources. The total energy consumption and peak demand were calibrated to 2002 ISO-NE data. It should be noted that the "Other" sector consists of transportation, public utilities, governmental agencies, as well as non-classifiable accounts.[31]

Sector	Total Energy (MWh)	Number of Buildings	Demand (MW)
Residential	46,302,398	5,822,935	12,005
Commercial	55,244,046	142,810	10,146
Industrial	24,268,503	24,104	2,971
Other	1,640,286	38,573	226
Total	**127,455,232**	**6,028,422**	**25,348**

Table 5-1: Annual Electric Consumption Data for New England 2002

5.2 Market Penetration of Current Programs

ISO-NE has offered demand response programs since the spring of 2001. In 2003, the programs were revised to comport with how they deliver value and include reliability-based programs and price programs. Table 5-2 provides a summary of the program participation rates in these program categories as of August 31, 2004. A total 356 MW of load reduction capacity has been enrolled in these programs. This is equal to about 1.4% of the 2002 system peak of 25,348 MW. Note that in general the average amount of enrolled MW per asset was over seven times higher for the reliability programs – 2.09 MW/asset for reliability and 0.29 MW/asset for price. The total average asset size was 0.73 MW/asset.

Program Type	Total # of Assets	Total Capacity (MW)	Avg Red. (MW/Asset)
Price Program	367	108	0.29
Reliability Programs	119	248	2.09
Total	**486**	**356**	**0.73**

Table 5-2: Demand Response Program Participation

The ISO-NE program registry database (the NX11C Customer database) was categorized by program and sector type to identify program preferences. Table 5-3 provides program

[30] The secondary data sources are survey data results based on a national sample and the results were then allocated to the New England region.

[31] Variations in how facilities are classified between data sources can be problematic even at the most fundamental level of classification. In this case, the survey data appears to have grossly under estimated the Other sector load.

participation by customer sector, indicating that Commercial customers are seven times more likely to enroll in the price program as opposed to the reliability program. Treating the participation frequencies as representative of the probability of participation, Industrial customers are about 2 times more likely to enroll in the price program.[32] Interestingly, the Other customers are more likely to participate in the reliability programs based on both a frequency and capacity. Note, that all customers enroll a higher amount of demand reduction capacity in a Reliability program than in the Price program.[33]

	Price Program			Reliability Programs		
Sector	**Count**	**Capacity (MW)**	**MW/Asset**	**Count**	**Capacity (MW)**	**MW/Asset**
Commercial	232	48	0.21	32	28	0.87
Industrial	106	38	0.36	47	134	2.85
Other	29	22	0.75	40	87	2.17
Total	**367**	**108**	**0.29**	**119**	**248**	**2.09**

Table 5-3: DR Program Participation by Customer Sector

5.3 Preliminary Market Segmentation Analysis

The potential for program participation was estimated for the four primary electric end-use sectors defined previously, i.e., Residential, Commercial, Industrial, and Other. For each, a single, primary driver for participation is identified and used to project participation over the sector population. In the case of the non-residential sectors, LDC load data were used to develop a population dataset that divided the customers into the three sectors (Commercial, Industrial, and Other). Additionally, the three customer sectors were stratified based upon the peak demand of the customers into three tiers consisting of:

- **Tier 1** (1MW and greater),
- **Tier 2** (350 kW to 999 kW), and

[32] A more comprehensive analysis would treat the frequency of participation as the dependent variable in a choice model that seeks to identify drivers to participation. Such an exercise requires extensive customer characteristic data and may not provide definitive results. The lack of a clear pattern indicates that customers are attempting to feel out this new market and are trying different things to see what might help. However, given the complexity of the market, the constant changes to market design and underlying cost drivers (e.g., fuel availability and costs), and the given that the secondary market of service providers to help customers figure these things out is nascent, the pattern of customer behavior appears somewhat random.

[33] 69.2 MW of the Other reliability-based capacity is from a quick-start generator selected under the SWCT Gap RFP.

- **Tier 3** (100 kW to 349 kW).[34]

The market potentials for each sector are based on a range of enrollment or participation rates (high, medium, and low). The estimated enrollment rates vary by market sector and are based on existing program enrollment rates within each sector and tier.[35] There are two key variables that were used to develop the estimates of Enrolled Assets (MW); they are defined as follows:

The Enrollment Rate = ***Enrolled NCPD*** / ***Total NCPD***

Where,

Total NCPD = the total Non-coincident Peak Demand of the customer by Sector and Tier

Enrolled NCPD = the total Non-coincident Peak Demand of the customers enrolled in the demand response program from that Sector and Tier

The Subscription Ratio = ***Subscribed Load*** / ***NCPD***

Where,

Subscribed Load = the average amount of load subscribed into the program by customer Sector and Tier

NCPD = the average Non-coincident Peak Demand of the customer by Sector and Tier

5.3.1 Residential Sector

The residential sector is characterized by a large quantity of small customers. For this analysis, the primary driver to participation in a demand response program is assumed to be the presence

[34] Load data was not obtained from all of the LDCs operating in the ISO-NE control area, but data was available for virtually all of CT, MA, RI and large portion of NH. This analysis did not include any data from ME or VT.

[35] The enrollment data from the NX11C customer database as of August 31, 2004 were used to develop the lower limit estimates of enrollment for each customer sector and tier.

of central air conditioning or electric heat pump units at the residence (CAC).[36] There is currently one Demand Response Provider installing direct load control devices on residential and small commercial customers in Southwest Connecticut under the SWCT Gap RFP. These resources will participate in the 30-Minute Real-Time Demand Response Program. As of August 2004, the Demand Response Provider had only recently started installations and, therefore, no resources were available to participate in the August 20, 2004 Audit Event.

Table 5-4 provides an estimate of the potential average total load reduction for a residential CAC load reduction program using a range of participation rates and load reduction amounts. Obviously the incentive levels, program longevity and intensity of marketing efforts would influence participation rates, but these factors are taken into account in this analysis. The high participation rate of 30% of homes with CAC units reflects participation rates for a mature program.[37]

	Total Residences		5,642,424
	Market Saturation of CAC units		24.2%
	Homes w/ CAC		1,365,466
	Total Average Reduction (MW)		
Participation Rate	**High (1.30 kW/Unit)**	**Medium (1.15 kW/Unit)**	**Low (1.0 kW/Unit)**
High 30%	533	471	410
Medium 20%	355	314	273
Low 10%	178	157	137

Table 5-4: Estimates of Potential Residential CAC Load Reductions [38]

The average reduction per household represents an estimate of the average performance across a portfolio of residences throughout an event, estimated to be approximately 1.15 kW at the time of summer peak.[39] A large-scale residential direct load control program will cost about $500 to

[36] Of course, there are other opportunities for residential customers to curtail load, e.g., electric water heating, swimming pool pumps, etc., so this should be considered a lower boundary.

[37] EXCEL energy in Minnesota reports participation rates of about 30% for their "Saver's Switch " air conditioning load reduction program which has been in existence for more than 10 years.

[38] The CAC market saturation of 24.2% and the total number of residences comes from 2001 Department of Energy census data for the New England region.

[39] These results are based on a study by Applied Energy Group of the LIPA Edge and Con Edison direct load control programs that showed an average net reduction of 1.15 kW per home across a four-hour event period during the hottest summer hours in July and August. The amount of load reduction achieved in residential load control programs is highly dependent on the outdoor temperature, the duration of the event, and the average amount of cooling load that is being controlled. In this study, the highest average net reduction was 1.29 kW/unit observed during the first hour of control.

$600 per kW, which requires that sufficient revenue (i.e., energy payment, ICAP, etc.) must exist to justify the significant investment. The resulting estimates of demand reduction potential ranged from a low of about 137 MW to a high of 553 MW. This represents a range from 0.5% to 2.1% of system peak. For the New England area, the 30% enrollment rate represents approximately 410,000 homes.

5.3.2 Commercial Sector

Since ISO-NE market-based demand response programs are relatively new, there are no examples of mature programs that can be utilized to establish an upper limit for expected program participation rates. In an effort to refine the analysis, load data was requested from LDCs throughout New England. Not every LDC was able to provide load data; therefore this analysis reflects the load data available at the time the analysis was conducted. The load data were used to further segment the commercial customers into three tiers based upon their peak demand. Table 5-5 presents the Commercial Customer sector with demand above 100 kW by tier.[40]

	Commercial	
	Demand (MW)	**Count**
Tier 1 (over 1 MW)	1,772	750
Tier 2 (350 kW -999 kW)	1,729	3,133
Tier 3 (100 kW - 349 kW)	1,987	11,389
Total	**5,488**	**15,272**

Table 5-5: Commercial Market Sector by Tier

The total peak demand of 5,488 MW is significantly lower than the survey data estimate of 10,146 MW, primarily because of the limited LDC data available, and because there are many small commercial accounts (under 100 kW) that are represented in the CBECS data and not in the LDC data. Note that the demand is fairly evenly distributed among the three tiers although, obviously the number of customers differ dramatically.

The Commercial sector has substantial representation in the NX11C Customer database with over 243 commercial customers. The available data were used to perform a multi-tiered analysis

[40] Once these again, these data do not include load from VT, ME, or a portion of NH.

of the peak reduction ratio for the sector, which was then used to develop the average subscription ratio for each tier of commercial customers. The current participation ratios of the tiers were developed using the NX11C enrollment rates and the LDC load data. Finally, estimates of enrolled MW were developed based upon the average subscription ratio for each tier and a high, medium, and low enrollment rate.

Table 5-6 provides estimates of potential commercial customer enrolled capacity across a range of enrollment rates and tier specific subscription ratios.[41] These estimates range from a low of 65 MW to a high of 120 MW.

				Subscription Ratio			
				Tier 1	Tier 2	Tier 3	
				12.9%	22.3%	62.0%	
Enrollment Rate				Enrolled Commercial Assets (MW)			
	Tier 1	Tier 2	Tier 3	Tier 1	Tier 2	Tier 3	Total
High	30.0%	10.0%	1.0%	69	39	12	120
Medium	20.0%	8.0%	0.8%	46	31	10	87
Low	15.0%	6.0%	0.6%	34	23	7	65

Table 5-6 Estimates of Potential Commercial Participation

As a sanity check on the estimates, the NX11C database through August 31, 2004 was augmented to include a 2-digit SIC code designation and analyzed for current commercial sector participation rates. The database shows that the Commercial sector has a total enrolled capacity of 76 MW and 264 assets[42] in the demand response programs. The current level of enrolled capacity is consistent with the lower level estimates of market participation for the Commercial sector. This suggests that there is opportunity for expansion of participation in this sector.

5.3.3 Industrial Sector

The Industrial sector was also analyzed using the tiered LDC data to establish reasonable upper limits on this sector's market potential. Table 5-7 provides a breakdown of the Industrial customer sector by tier as provided by the LDC load data. Note that in this case, Tier 1 Industrial customers actually make up about 57 % of the total peak demand of customers over

[41] The subscription ratio is the enrolled DR capacity divided by the customer's non-coincident peak demand, and were developed using the average peak demand per customer within each of the tiers and the enrolled capacity for each tier.

[42] The commercial customer status was taken from the NX11C database as of August 31, 2004.

100 kW and that the relative percentage of peak load gets lower with each tier. The total peak demand for the Industrial sector is 3,309 MW, which is actually higher than the MECS data (2,971 MW) and is most likely due to statistical error and/or errors in customer classification.

	Industrial	
	Demand (MW)	**Count**
Tier 1 (over 1 MW)	1,889	722
Tier 2 (350 kW -999 kW)	819	1,442
Tier 3 (100 kW - 349 kW)	601	3,166
Total	**3,309**	**5,330**

Table 5-7 Industrial Sector by Tier

Table 5-8 provides a range of potential demand response capacity for the Industrial sector using various enrollment rates and subscription ratios.[43] The estimates of enrolled capacity for the Industrial sector ranged from a low of 164 MW to a high of 330. The NX11C database contained a total of 153 Industrial assets with an enrolled capacity of 172 MW enrolled in the demand response programs as of August 31, 2004. The actual enrolled capacity is very close to the low estimate of enrolled capacity of 164 MW.

				Subscription Ratio			
				Tier 1	**Tier 2**	**Tier 3**	
				82.6%	21.2%	61.1%	
Enrollment Rate				**Enrolled Industrial Assets (MW)**			
	Tier 1	**Tier 2**	**Tier 3**	**Tier 1**	**Tier 2**	**Tier 3**	**Total**
High	20.0%	8.0%	1.0%	312	14	4	330
Medium	15.0%	6.0%	0.8%	234	10	3	248
Low	10.0%	3.0%	0.6%	156	5	2	164

Table 5-8 Estimates of Potential Industrial Participation

5.3.4 Other Sector

The Other Sector consists of transportation, public utilities, governmental agencies as well as non-classifiable accounts. These customers were also analyzed using the tiered LDC data and the results are illustrated in Table 5-9, which shows a similar load distribution to the Industrial

[43] A few extremely large assets that enrolled their entire load into the program caused the extremely high subscription ratio of 82.6% for the tier 1 customers. Fortunately the effects of these assets are mitigated by the use of the average tier 1 peak demand of about 2.62 MW.

sector with Tier 1 accounting for about 58% of the total load. There is also a large discrepancy in the total load for the sector with the survey data indicating that the Other sector consists of 229 MW as opposed to 1,235 MW from the LDC data. Once again, these discrepancies are most likely due to statistical errors and/or classification errors.

	Other	
	Demand (MW)	**Count**
Tier 1 (over 1 MW)	714	176
Tier 2 (350 kW -999 kW)	227	416
Tier 3 (100 kW - 349 kW)	294	1,661
Total	**1,235**	**2,253**

Table 5-9 Other Sector by Tier

Table 5-10 provides an estimate of the potential for demand response capacity in the Other sector across various enrollment rates and subscription ratios. These range from a low of 49 MW to a high of 98 MW. The NX11C had a total of 68 assets defined as "Other" assets; the total enrolled capacity for this group was 40 MW.[44] The current level of enrolled capacity is less than the lower level estimates of market participation for the Other sector. This suggests that there is opportunity for expansion of participation in this sector.

				Subscription Ratio			
				Tier 1	**Tier 2**	**Tier 3**	
				60.7%	42.6%	60.8%	
Enrollment Rate				**Enrolled Other Assets (MW)**			
	Tier 1	**Tier 2**	**Tier 3**	**Tier 1**	**Tier 2**	**Tier 3**	**Total**
High	20.0%	10.0%	1.2%	87	10	2	98
Medium	15.0%	8.0%	1.0%	65	8	2	74
Low	10.0%	4.0%	0.8%	43	4	1	49

Table 5-10: Estimates of Potential Other Participation

5.4 Conclusions

The projections of available demand response potential indicate ample opportunity for increasing customer enrollment in demand response initiatives. Table 5-11 summarizes the estimates by customer sector, providing the estimated MW associated with the low, medium, and high market penetration assumptions. The resulting low-end market potential is about 280 MW and the upper

[44] This total excludes the large 69.2 MW quick start generator selected under the SWCT Gap RFP.

end is about 550 MW.[45] The Residential sector is also presented in the table, and has a market potential ranging from 137 MW to about 533 MW. However, tapping into the Residential sector will require a large expenditure in control equipment. These are first approximations constructed from basic and transparent assumptions. As more experience is acquired with program participation and response, more sophisticated methods can be employed to refine these estimates and provide greater granularity.

		Range Estimate for Enrolled Capacity		
	Actual Enrolled	Estimate Range Category		
Sector	Capacity (8/31/04)	Low	Medium	High
Commercial	76	65	87	120
Industrial	172	164	248	330
Other	40	49	74	98
Total C/I	**287**	**277**	**409**	**548**
Residential	NA	137	314	533
Total Residential & C/I	**287**	**414**	**723**	**1080**

Table 5-11: Estimates of Potential Participation

[45] These estimates do not include large, stand-alone generators (i.e., generators that are not directly linked to a specific end-use customer load) like the 69 MW asset that was excluded from this analysis.