Commonwealth of Massachusetts

Electricity
Price, Reliability, and Markets Report
2005

A Report to the Great and General Court on the
Status of Restructured Electricity Markets in Massachusetts

December 2006

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This report is also posted on DOER's website at http://www.mass.gov/doer/.

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Executive Summary

Prices

Massachusetts remains a high-price region for electricity. Even though the nation as a whole experienced higher prices in 2005, the state and New England region suffered higher percentage increases in electricity prices, mostly due to the greater dependence on natural gas for power generation. ISO-NE continues to undertake efforts to improve the operations of wholesale electricity markets, but they have little or no control over the delivery of natural gas to the region.

There were several enhancements in the wholesale markets design to encourage price transparency and allocate costs to load zones on a demand/supply basis. Despite these improvements, wholesale electricity costs, especially the cost spikes due to the tight natural gas conditions, were not immediately passed on in retail prices. Most consumers therefore are not challenged to change their consumption behavior during high cost electricity times. As a result, ISO-NE significantly expanded its demand response program in the winter to provide incentives for conservation during peak periods.

There is a need for more demand response awareness and incentives to conserve energy at certain times and how those actions translate into consumer savings. Also, there must be a better connection between wholesale costs and retail prices for consumers to push for more efficient markets.

On the other hand, due the fact that these large price increases were not passed on to consumers in 2005, there continue to be significant savings to consumers due to the Restructuring Act. When adjusted for inflation, consumers have saved over $5 billion since the passage of the Act in 1997. That is, while other goods' prices have increased, electricity prices have increased at a much lower rate.

Reliability

The reliability of the wholesale electric grid remains strong despite record peak demands in the Summer of 2005. However, a more long term view shows that there may be reliability problems as soon as 2010, if additional generation is not built in certain regions of New England and peak load growth continues to grow at historical levels. Reliability concerns were largely responsible for support of additional market mechanisms, such as the forward capacity market, that would provide incentives for development of new generation resources. As an alternative, expanded use of demand response may lessen the need for reliance on additional generation as a small percentage of hours feature extremely high peak levels.

Fuel diversity showed little change with continuing reliance on natural gas and a slow rate of penetration of renewable technologies. Use of other fossil fuels and nuclear remained at similar levels to 2002-2004.

Reliability at local levels was not as strong as found at the wholesale level. Distribution system reliability featured outage levels higher than the 1 day in 10 years reliability standard that is routinely at the wholesale level.

Markets

During 2005, the progress of the competitive retail market was very different in each of the three market segments. The market for large commercial and industrial customers was very competitive with three or more competitive offerings available a majority of the time. These customers displayed considerable market savvy by returning to regulated service in November when confronted with uncertainty or risk associated with the aftermath of Hurricane Katrina. Residential and small commercial and industrial customers did not often have competitive service available to them and showed limited progress in market development. The one exception was the CLC aggregation, which enrolled a large number of residential customers. Perhaps the most difficult to gauge market segment remains the medium commercial and industrial customers for whom some progress was made, but no clear pattern has emerged.

A disconnect between wholesale market prices and the basic service rates obtained through period and layered procurements undermines the operation of a retail market where price directly influences customer behavior. This disconnect became pronounced during the second half of 2005. As a results, switching is spasmodic and occurs more pronounced in brief periods in which the gap between market price and the price of utility-procured power is the widest.

The interest of competitive suppliers entering the Massachusetts retail electricity market remains almost exclusively limited to large commercial and industrial customers with little interest in the mass market or residential and small commercial and industrial customers. The DOER survey of the retail competitive suppliers to monitor the market and identify issues or barriers to market development revealed a host of barriers still inhibit the development of a competitive market for smaller customers.

Finally, though there was entry of potential providers of competitive supply in 2005, market share data show a reduced concentration among three major suppliers and several new entrants, implying that there is interest in the MA market.

Chapter 1—Introduction

In order to monitor the progress of electric industry restructuring and customer movement to competitive suppliers, the Electric Restructuring Act (Chapter 164 of the Acts and Resolves of 1997) ("the Act") required the Division of Energy Resources (DOER) to make periodic reports to the Legislature (M.G.L. c. 25A §§ 7, 11D, 11E). This report analyzes data and reports on relevant events from 2005.

Purpose of Report

This report examines electricity markets and prices and assesses electricity system reliability at both the distribution and wholesale as experienced by the Commonwealth's residents and businesses during 2005. Events in 2006 that occurred prior to the release of this report are discussed sparsely and only if they represent a culmination of important proceedings that commenced in 2005. As such, it represents a historical examination of a particular year. We only include prior years in order to place the 2005 events in context. This report, when examined with prior years' reports, allows a thorough examination of important electricity-related issues in the Commonwealth.

Report Outline

The Restructuring Act tasks DOER with reporting on two major issues related to electricity. The first consists of an analysis of prices and price disparity, and the second concentrates on reliability. The Act also has a number of additional reporting requirements related to market development and how restructured markets have impacted both prices and reliability. Hence, the next three chapters discuss price, reliability, and market issues, respectively.

Chapter 2 contains an analysis of electricity price changes during 2005 as compared to 2004 prices. First provided is an overview of Massachusetts' retail prices compared to regional and national prices. These prices are then investigated in more detail with an analysis of prices at both wholesale and retail levels. The main concentration is on retail prices because the independent system operator of New England's bulk power system, ISO-NE, already produces extensive analyses of wholesale prices[1]. This report's analysis, however, does highlight wholesale prices because they are passed through to retail customers and represent a large percentage of monthly bills. Furthermore, this chapter includes the price disparity discussion that is required by the Act. The chapter concludes with an update of monetary savings for customers due to the provisions of the Act and resulting events.

Chapter 3 contains an analysis of reliability issues at both the wholesale and retail levels. We discuss how reliability standards at each of these levels are determined and monitored/regulated. We also report on the extent to which reliability has been provided by the electricity delivery system at both the wholesale and local-distribution-company levels compared to set standards.

[1] For example, see the 2004, Q3 Quarterly Report, ISO-NE. http://www.iso-ne.com/smd/market_analysis_and_reports/quarterly_reports/

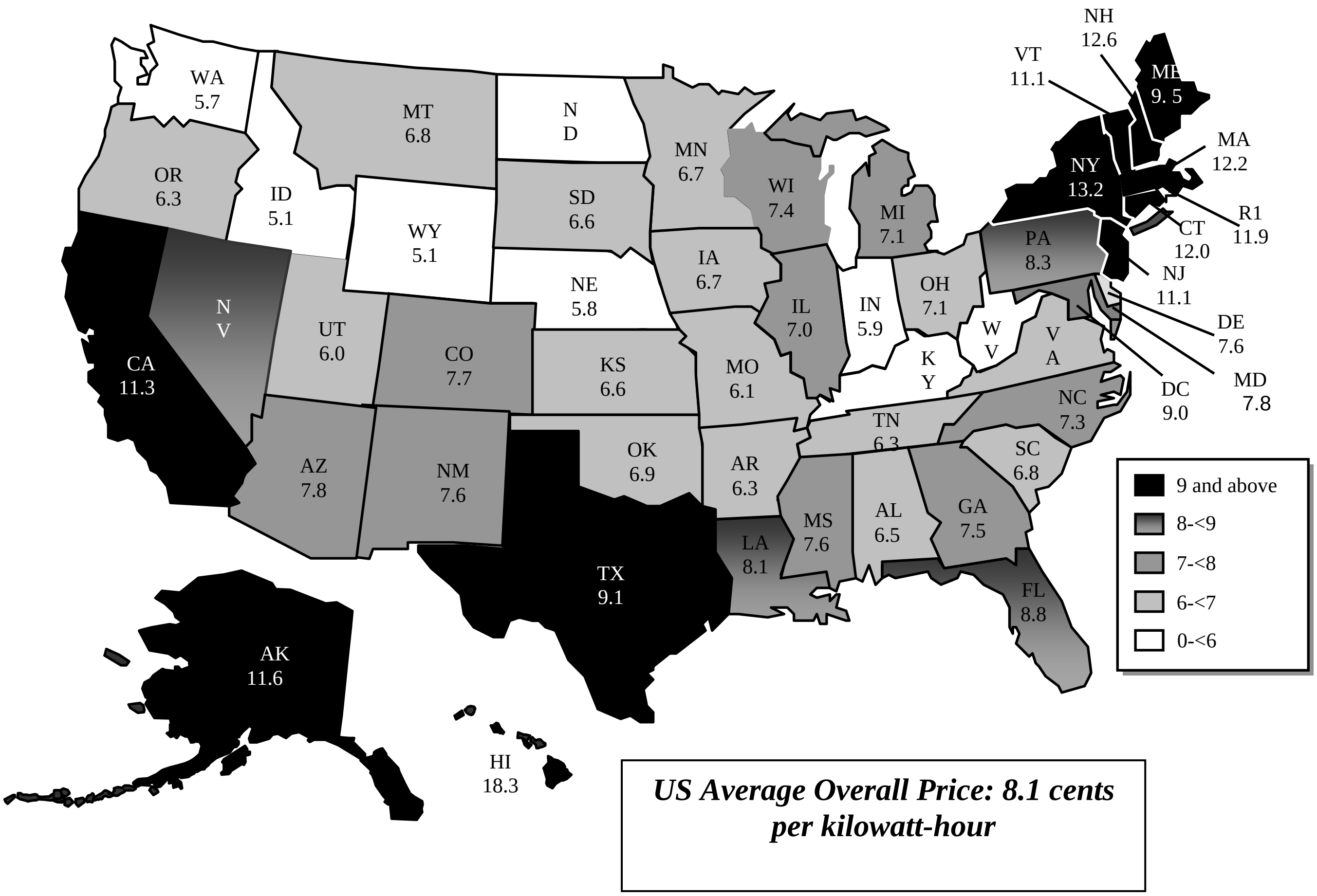
Chapter 4 provides a review of the development of the retail market during 2005. As with last year's report, wholesale market developments are only sparsely discussed (compared to the 1998-2000 Market Monitors). Rather, most of the chapter discusses changes in the retail markets and the success with retail access, a major creation of the Act.

Chapter 2—Prices

Electricity Price Overview

In 2005, Massachusetts was the 4th highest priced state in the nation. Massachusetts continues to be included in a group of high-cost states, composed of New England, New York, New Jersey, California, and the two non-contiguous states of Alaska and Hawaii. Texas prices increased dramatically in 2005, but Texas has traditionally had prices at about the national average. The figures show the great disparity in prices across the nation.

Figure 2-1
Retail Prices for 2005



Source: EIA

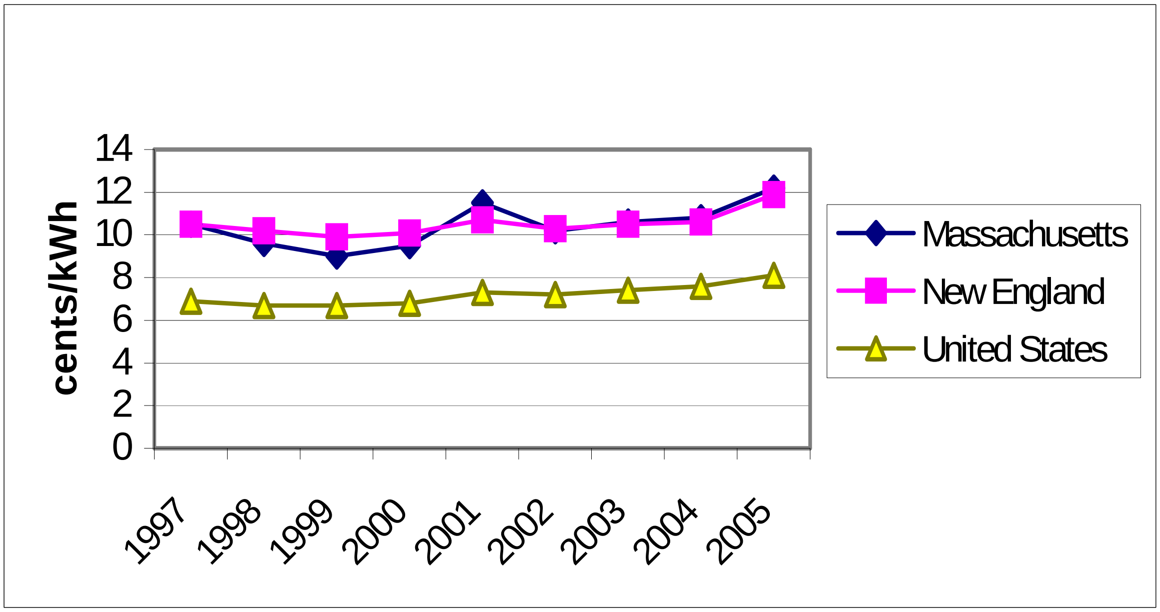
Massachusetts Retail Electricity Prices Increased Significantly in 2005

In both Massachusetts and the country, 2005 was a high-price year for electricity. Prices, however, in this state and New England increased at a much faster rate than for the nation. We provide some explanation for these high prices throughout this chapter. Table 2-1 shows the historical prices. Figure 2-2 depicts the information in graphical format.

Table 2-1
Historial Electricity Prices for all Consumers
MA, New England, and the Nation
(cents per kilowatt-hour)

	1997	1998	1999	2000	2001	2002	2003	2004	2005
Massachusetts	10.5	9.6	9.0	9.5	11.5	10.2	10.6	10.8	12.2
New England	10.5	10.2	9.9	10.1	10.7	10.3	10.5	10.6	11.9
United States	6.9	6.7	6.7	6.8	7.3	7.2	7.4	7.6	8.1

Figure 2-2
Historical Retail Electrical Prices for all Customers (1997-2005)



Source: EIA Electric Power Annuals, Electric Power Monthly

Given this overview, we describe, in the next two sections, events and changes in wholesale and retail markets, respectively. As will be obvious, occurrences in both these markets and the interactions between them are critical determinants of the prices consumers actually pay.

Wholesale Electricity Price Analysis

In 1999, New England's wholesale electricity market was restructured wherein buyers and sellers now trade electricity at market based prices rather than at traditional cost-of-service rates. The Independent System Operator of New England (ISO-NE), the entity overseeing the wholesale market, is responsible for three functions:

- The day-to-day reliable operation of New England's bulk power generation and the transmission system;
- Oversight and fair administration of the region's wholesale electricity markets; and
- Management of a comprehensive regional bulk power system planning process.

Since its inception, the reformed wholesale market had some flaws and unintended consequences. The ISO-NE, market participants, state regulators and the Federal Energy Regulatory Commission (FERC) addressed many of the problems through new or changed market rules. During 2005, ISO-NE continued to discuss market design changes with stakeholders, and implement several changes to enhance the functioning of wholesale markets, most notably the capacity market.

This section examines wholesale electricity prices and their components. It concentrates mainly on the generation or energy cost, since that is the largest cost component of wholesale electricity.

<u>On-Peak Energy Prices</u>

Average "On-Peak" Energy Prices Increased, Mostly Due to Hurricane-induced Natural Gas Price spikes

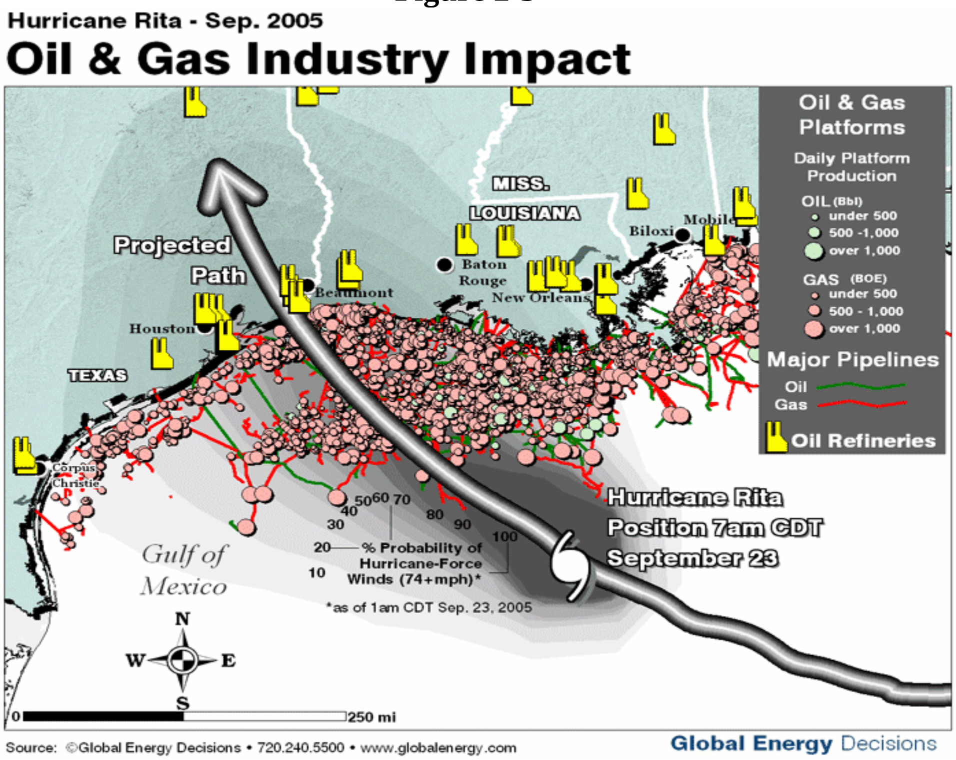
Wholesale electricity prices hit their highest levels since the ISO-NE began administering the competitive market in the late 1990s. One of the hottest summers in recent history throughout the U.S. resulted in record energy and capacity demand levels in almost all markets throughout the country. The record demands, relatively low levels of natural gas in storage, and increased speculation by investment outfits resulted in record prices in fuel and electricity.

Since natural gas-fired generation is mainly the marginal capacity setting electricity prices, we start with a discussion of what happened to the price of gas. In summer 2005, natural gas prices were the highest in history for any mid-summer timeframe. Prices were over $9/MMbtu in the beginning of August, and then the U.S. gas infrastructure in the Gulf of Mexico (GOM) was extensively damaged by massive hurricanes which resulted in loss of gas supplies, exacerbating the already tight gas market and droving natural gas prices to record highs.

Hurricane Katrina made landfall on August 29th and promptly shut in delivery capacity of 8.5 billion cubic feet per day (bcf/d) or 85% of the natural gas production in the GOM and 1.5 million barrels per day or close to 100% of crude oil production in the GOM (see Figure 2-3 below). The GOM shut-in production amounts to almost 20% of the U.S. daily gas production and 28% of the U.S. daily oil production. The refining capacity lost to the storm reached approximately 15% of the U.S. capacity or 2.5 million barrels per day.

After a significant amount of natural gas production was restored, Hurricane Rita hit the Gulf Coast on September 20th and again shut-in gas supplies. See figure 2-3 for the path of Hurricane Rita. The shut-in spiked back to 8.0 bcf/d immediately following Rita. It took months of repairs before shut-in gas production reached less than 1.0 bcf/d as some infrastructure was damaged beyond repair. As a result of these storms, the Henry Hub natural gas prices increased nearly 50% in 2005 from prior year levels.

Figure 2-3



During 2005, New England's on-peak[2] electric energy prices trended significantly upwards and spiked dramatically in September and October and again during a cold spell in December. These spikes and runups were largely due to an increase in the price of fuel, most notably natural gas, used to generate electricity as discussed above.[3]

Locational Marginal Prices Tracked Increased Natural Gas Prices

The wholesale electricity market in Massachusetts is divided into three zones: Boston/Northeastern Massachusetts (NEMA), Southeastern Massachusetts (SEMA) and Western/Central Massachusetts (WCMA) regions. Figure 2-4 shows the average annual on-peak, real time locational marginal prices (LMPs) for Massachusetts' customers in 2005 according to these zones. It also shows the price for the New England hub which is designed to

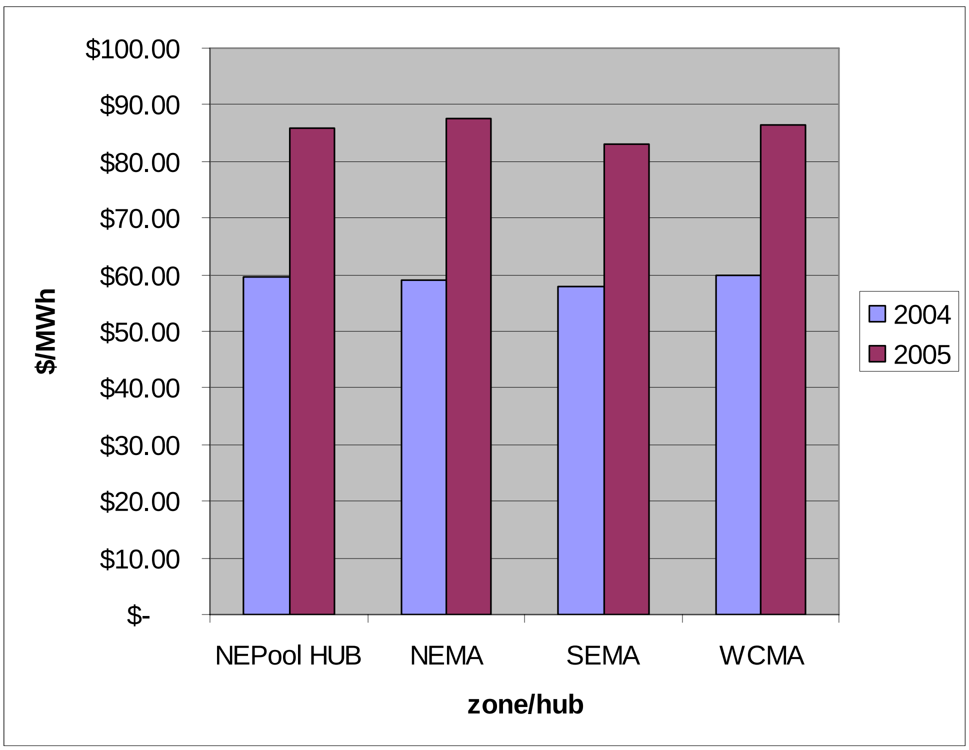
[2] On-Peak vs. Off-Peak definition: On peak hours are defined as hours between 7:00 a.m. and 11:00 p.m. on non-holiday weekdays in the New England Control Area. The off-peak period is from 11:00 p.m. to 7:00 a.m. on weekdays, all day on Saturdays, Sundays, and holidays. Demand for electricity is generally higher during the on-peak periods and lower in the off-peak periods, driven primarily by commercial and industrial sector use.

[3] Natural Gas prices for New England consumers who procure gas off the El Paso Tennessee interstate pipeline, Algonquin Gas Pipeline or at the Dracut citygate rose about 43% in 2005. Natural gas prices at the Algonquin citygate averaged $9.73/MMbtu in 2005 compared to $6.85/MMbtu in 2004, a 42% increase.

represent a non-locational reference point.[4] As shown, the wholesale Massachusetts zonal prices hovered between $83/MWh and $87/MWh in 2005, which is a 45% increase over 2004 prices. In addition, due to heavier demand in 2005, zonal prices in Massachusetts exceed the hub price. These prices are for the real time market and are different than the ISO-NE-administered day-ahead market prices and bilateral contract prices that account for the majority of load obligations.

This distinction is important because retail prices that consumers pay are loosely related to wholesale real-time and day-ahead prices. Transactions in these two markets only account for about 25% of all wholesale electricity transactions. The bulk of transactions is done through bilateral deals, which may have prices significantly different from these two markets, especially under extreme price conditions.

Figure 2-4
New England Hub and MA Zonal LMPs (On Peak Real-Time), 2004-2005



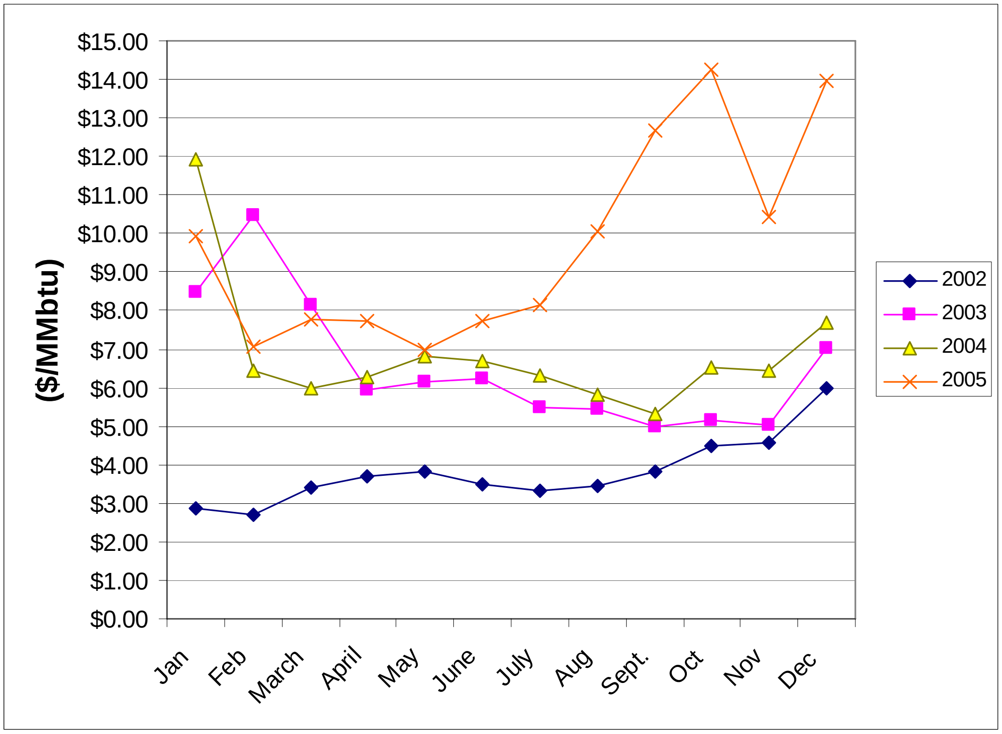
Source: ISO-NE, DOER

During this study's time period, natural gas-fired plants operated "on the margin" (the marginal unit generally sets the locational energy clearing price levels or LMPs) over 50%[5] of all hours,

[4] These prices are simple averages of monthly prices, as opposed to a load-weighted average price. The New England average real-time, load weighted energy price in 2005 was $79.96/MWh. (State of The Market Report 2005, ISO-NE)
[5] ISO- NE Annual Markets Reports.

while the natural gas capable (gas/oil) plants set prices over 30% of the hours.[6] One can see the dramatic increase in monthly gas prices in 2005 relative to the previous years in Figure 2-5 below.

Figure 2-5
Monthly Midpoint Average Gas Prices
Algonquin City Gate
2002-2005

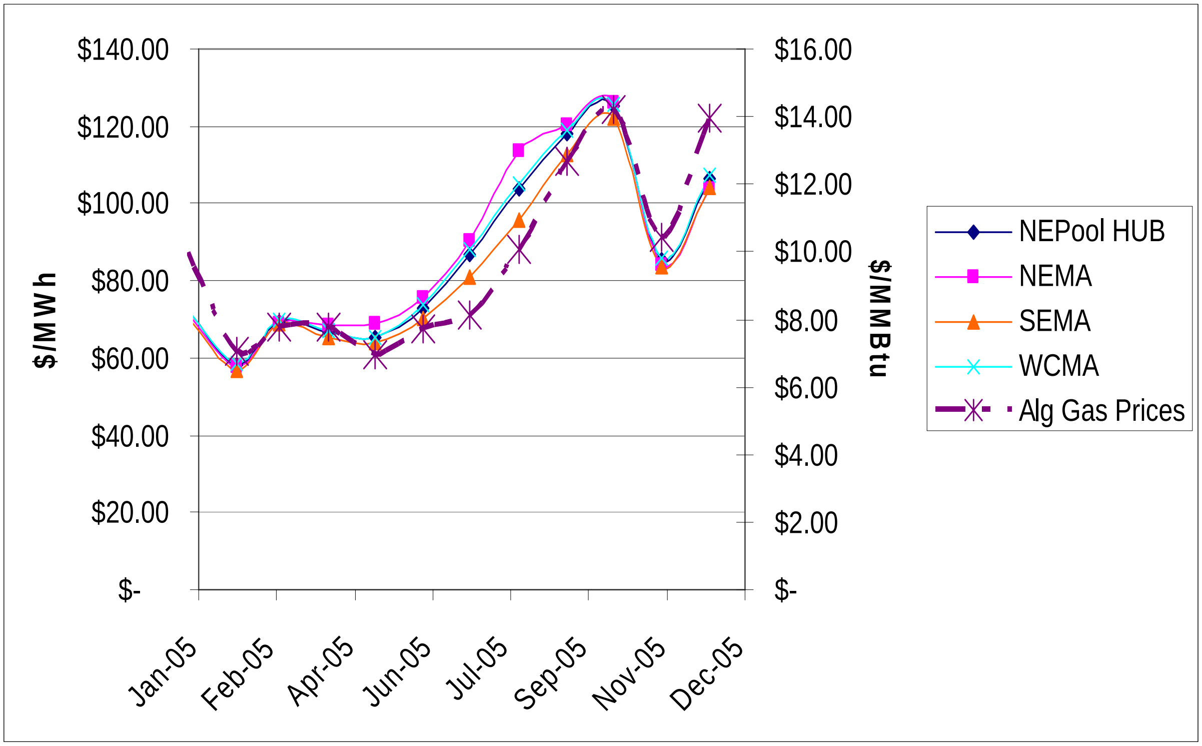


Source: Gas Daily

Historically, the peak load summer or winter months are the highest price months as they are the highest demand months, which constrains delivery infrastructure.[7] However, due to the devastation in the GOM and curtailment of fuel supply, the fall months of September and October realized the highest prices. Figure 2-6 shows Massachusetts monthly on-peak energy prices for 2005.

[6] Oil fired plants set prices in close to 20% of marginal hours in 2005, while the coal and pumped storage hydro set real time prices close to 10% each. Note the marginal prices are set by different plants in the eight New England LMP zones, thus the percentage sums to greater than 100%.
[7] The peak demand of 26,885 MW on July 27, 2005 broke the record of 25,348 MW by 6.1%.

Figure 2-6
Wholesale Electricity Prices –
Average Monthly On-Peak Real-Time LMPs
January – December 2005



Source: ISO-NE, DOER

The figure illustrates how closely the electric prices track natural gas price trends as discussed previously. The double axis shows electricity prices ($/MWh) on the left hand side and the natural gas prices ($/MMBtu) on the right hand side. Note that while gas prices are very close to one another no matter which pipeline into New England a generator takes gas deliveries from, we only show the monthly Algonquin pipeline gas price in the graph as the majority of gas power plants receive supplies from that pipeline.[8]

One noticeable separation in the price data in the figure above is between the NEMA price in August 2005 from the other zonal prices and the hub price for New England (see data in Table 2.2). Congestion costs were once included in transmission expenses; however, since the implementation of Standard Market Design (SMD) on March 1, 2003, congestion costs are now a component of the energy commodity price. Zonal pricing differences are typically due to constrained import capabilities and/or lack of installed or operable load-pocket generation in the import-constrained zone. The congestion component can be hedged by market participants using Financial Transmission Rights (FTRs) which are auctioned by the ISO-NE. The data below

[8] According to the company, Algonquin delivers gas to 11,390 MW of generating capacity including 4,756 MW directly connected to the pipeline while 6,634 MW are connected behind LDC city gates. Only about 3,750 MW have firm contracts which has become an increasing reliability concern for regulators and policy makers.

shows the premium price for NEMA power relative to the other Massachusetts zonal prices and the trading hub. One can see that SEMA's LMPs are lower than other zones. That is because the congestion cost in an export-constrained zone manifests in a negative congestion value (due to oversupply of generation in region compared to demand), which reduces LMP in the area.

Table 2-2
On-Peak Real Time Locational Marginal Price by Zone

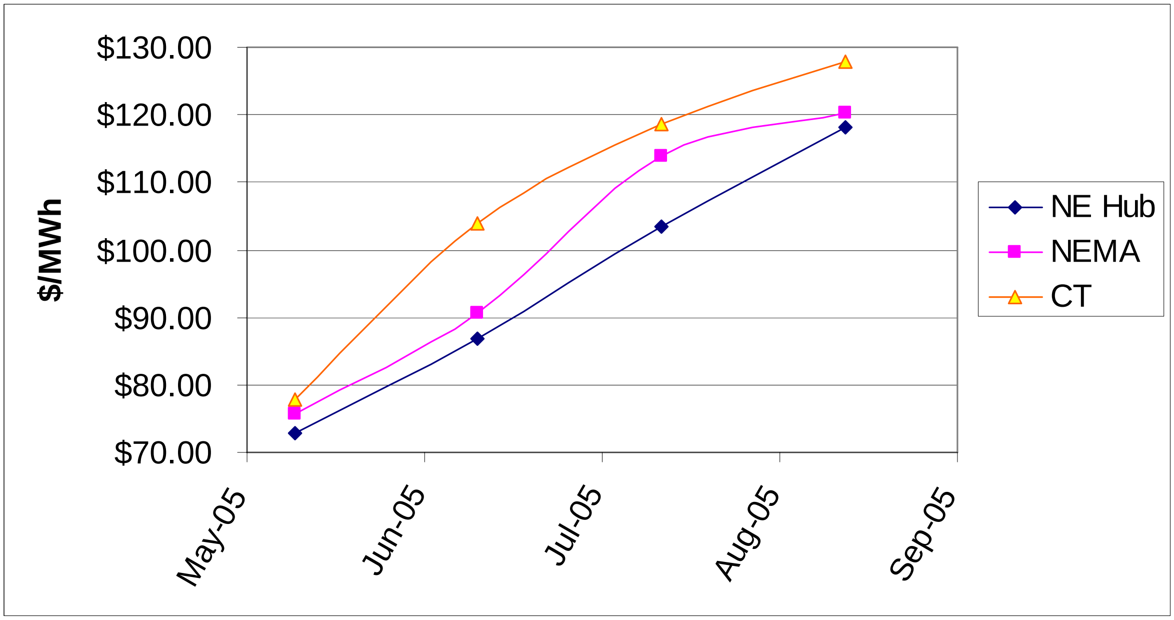
	NEPool HUB	NEMA	SEMA	WCMA
Jul-05	$86.92	$ 90.56	$ 80.77	$ 88.16
Aug-05	$103.55	$ 113.76	$ 95.90	$ 105.01

Source: ISO-NE

NEMA experienced significant congestion prices in August 2005 due to record breaking demand in 2005, binding import limits, and unavailable generation in the Boston area. Peak weekday demand and a record breaking demand on a weekend day pushed the average congestion component price to close to $10.00/MWh for the month. However, with the construction of a NStar 345 kilovolt (kV) underground transmission line close to completion, the Boston area should have adequate import capability to serve peak summer days several years in the future.

Massachusetts zones are not the most congested in New England. The Connecticut (CT) zone consists of the entire state, but most of the congestion is found in the southwest part of the state. The July 2005 congestion for the CT zone averaged close to $17/MWh and has become more severe in summer 2006. Anticipated network upgrades will not be completed until 2008. Figure 2-7 illustrates how much the Connecticut electricity supply tended to be higher cost than Massachusetts supply in 2005. This divergence is due to the constrained transmission infrastructure and high-priced generation located in southwest Connecticut.

Figure 2-7
On-Peak Real-Time LMPs
CT, NEMA, and New England Hub
Summer 2005



Source: ISO-NE

<u>On-Peak/Off-Peak Energy Price Ratios</u>

Higher On-Peak vs Off-Peak Prices Provide Opportunities for Demand Response During On-Peak Periods.

A high on-peak/off-peak energy ratio suggests that there are times when market participants, and ultimately consumers, would want to respond to high energy prices through demand curtailment to save on electricity costs or smooth price volatility. In fact, the ability of customers to respond to price signals is an important component of a workably competitive marketplace.

For several reasons, though, predicting the amount of demand response is a difficult figure to estimate. A key inducement metric, however, for customer demand response is sustained and transparent high on-peak to off-peak price ratios. Without both sustained and transparent high price ratios, customers will not be motivated to substitute for their electric consumption behavior. If on-peak to off-peak ratios do not reach a significant level, customers will not bother with peak shaving investments and will turn to energy efficiency measure investments that can be effective regardless of changing daily or monthly prices.

At the wholesale market level, ISO-NE administers both reliability and price-based Load (demand) Response programs to provide opportunity and flexibility to end use customers to react to volatile real time generation prices[9]. The inducement of large C&I end users to reduce demand via the ISO administered Load Response programs ultimately produces a more efficient energy market and price benefits for the region as a whole. The following table shows as of January 2006 the Demand Response (DR) assets ready to respond in each of the three MA LMP zones.

Table 2-3 shows 370 Massachusetts DR assets representing 130 MW of resource capacity. Of that, 73 MW or 56% of all MA DR assets were involved in the Real Time 30 minute reliability program.. There were 4 reliability program event days in NEMA in 2005, one in SEMA and two in WCMA, but there were an enormous increase of real time price program opportunities as there were 209 price event days and 1,188 price event hours in NEMA and 175 and 179 event days in SEMA and WCMA. In 2004, there were only 47 real time price event days in NEMA and 37 and 44 in SEMA and WCMA.

Table 2-3
Demand Response Assets in New England as of January 2006

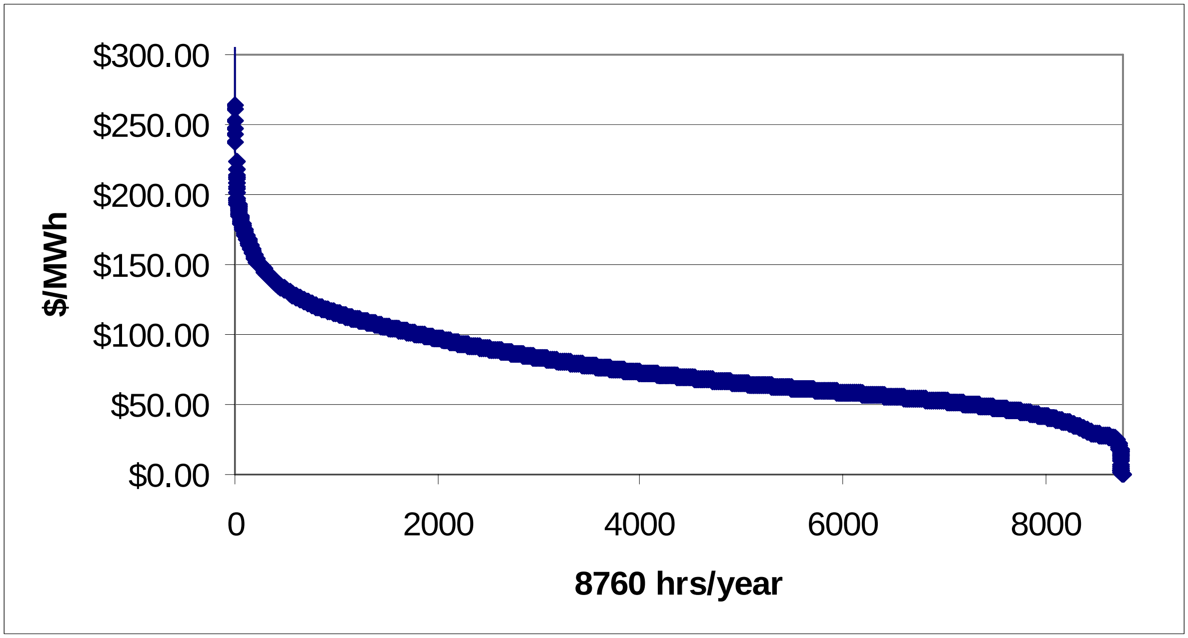
Zone	Number of Assets	MW
NEMA	138	81.0
SEMA	101	12.0
WCMA	131	37.9
MA Total	370	130.9
New England Total	923	529.9

Source: ISO-NE

Figure 2-8 is the 2005 price duration curve, which shows the distribution of real time prices at the NEPOOL Hub. Over 1,800 hours realized $100/MWh prices in 2005 of a possible 8,760 hours in the year with a price of $856/MWh in one hour in the summer. This provided a great opportunity of DR to participate in the ISO-NE price program, unlike any year in the past.

[9] The Reliability DR programs require qualified customer response to the ISO control room via IBCS within 30 minutes or 2 hours and receive a monthly capacity payment as well as an energy payment of $500/MWh for 30 minute response or $350/MWh for 2 hour response. The minimum reduction requirement for a facility or aggregation is 100 kw and each event lasts a minimum of 2 hours. The Price-based DR program participants can voluntarily respond to real time price events when ISO-NE forecasts prices to exceed $100/MWh or are obligated to respond if they clear in the Day Ahead market. The Price DR programs receive the prevailing energy clearing price when they reduced their load or a minimum of $100/MWh, but receive no capacity payment.

Figure 2-8
NEPOOL RT LMP Duration Curve 2005



Source: ISO-NE

The success of the customer response with advanced metering capabilities is also influenced by the ratio of on-peak to off-peak prices. Focusing on summer months, the NEMA on-peak/off-peak energy price difference was 42% during the high demand summer months in 2005. The NEMA on-peak prices were 49% and 44% higher than off-peak prices in July and August, respectively. (The comparison of prices in the winter months, January through March, when electricity demand is not as high and does not spike as much as in summer, showed only about a 19% difference.) Several DR providers have been providing metering installations as advanced metering technology prices continue to drop, and energy management services as the DR initiatives have grown over the past few years in response to prodding by FERC to incorporate demand side resource participation into markets.

Table 2-4 below enumerates the summer season on-peak/off-peak ratios for 2004-05. Note the larger ratios in the slightly congested NEMA relative to the SEMA and WCMA. The ratio in NEMA increased as congestion spiked in several peak demand hours of summer 2005.

Table 2-4
Summer Season (June – September)
On-Peak/Off-Peak Ratios

	NEMA	**SEMA**	**WCMA**
2004	1.30	1.28	1.31
2005	1.42	1.30	1.35

Source: ISO-NE

In the fall 2005, in response to potential winter reliability problems due to a potential lack of natural gas supplies, ISO-NE also revised its Cold Weather Event Procedures. This procedure was initially implemented in January 2005. The revision included a supplemental winter demand response program. The addition of several DR assets in MA and other New England states can be attributed to reliability based program included in the 2005-06 Winter Package filing with FERC which included capacity payments for qualified assets of $14/kw-month in December 2005 and stepped down to $8/kw-month in March 2006. These values compare favorably to the low values (less than $1.00/kw-month) that was usually offered in the regular DR program. The following table shows the active or approved DR assets as the end of each Calendar year the past 2 years.[10]

Table 2-5
Comparison of Demand Response Assets
Winter 2004 and 2005, MW

	Active or Approved MA Assets	MA DR Capacity	New England DR Capacity
2004	288	99	379
2005	350	137	519

Source: ISO-NE

Wholesale Price Components

Bulk power suppliers (competitive suppliers and default distribution utilities) must procure, in addition to energy, other services from ISO-NE administered markets. The energy price is the dominant component in the wholesale power costs, but other components are necessary to maintain system integrity and resource adequacy. These components include Reliability or "Uplift", Capacity and Ancillary Services. The data in Table 2-6 represents the components of the bulk power price in a price per unit format.

The energy component of the total price or "All-In" cost decreased slightly from 96% to 95% from 2004 to 2005 due to relatively large increases in reliability costs and capacity costs. Reliability costs or uplift refers to the costs borne from dispatching a plant out-of-economic

[10] These data refer to assets in existence as of December 2005 and thus differ slightly from data in Table 2-3.

merit order or for special local reliability purposes. In 2005, the uplift in the Boston area increased dramatically because a large pivotal supplier was dispatched out-of economic merit for a significant number of hours thus reducing the competitiveness of pricing. Capacity increases can be traced to greater use of deficiency auctions (rather than bilateral deals) to meet capacity requirements. During early 2005, prices were relatively high in these auctions compared to 2004. Ancillary services remained at 1.7% of the All-In cost as the forward reserve market prices retreated slightly. (In October 2006, a new locational reserve market became effective with intentions to attract a more flexible resource fleet in load pockets.) Notice that the annual all-in price increased 51% over 2004 as all components increased over 50%.

A new capacity market referred to as the Forward Capacity Market (FCM) is scheduled for implementation in a transitional form in December 2006 per a June 15, 2006 FERC order[11]. The FCM construct is the result of legal proceedings which began in early 2003 in response to several generators' requests for reliability (must-run) contracts (which essentially suppress market prices), and because the new wholesale market design which lacked reserve markets. The FCM attempts to ensure that power resources are purchased to meet forecasted demand and reserve requirements to maintain regional electricity reliability for a power year three years in the future. There is evidence that the market design changes are seen as effective investment incentives as 21 new power plants have been proposed since February 2006.[12]

Table 2-6
2005 Annual All-In Prices ($/Mwh)

	2004	**2005**
Energy	$ 54.77	$ 82.05
Uplift	$ 1.26	$ 2.11
Capacity	$ 0.06	$ 0.51
Ancillary Services	$ 0.97	$ 1.46
Total Price	$ 57.05	$ 86.13

Source: ISO-NE 2005 Annual Markets Report

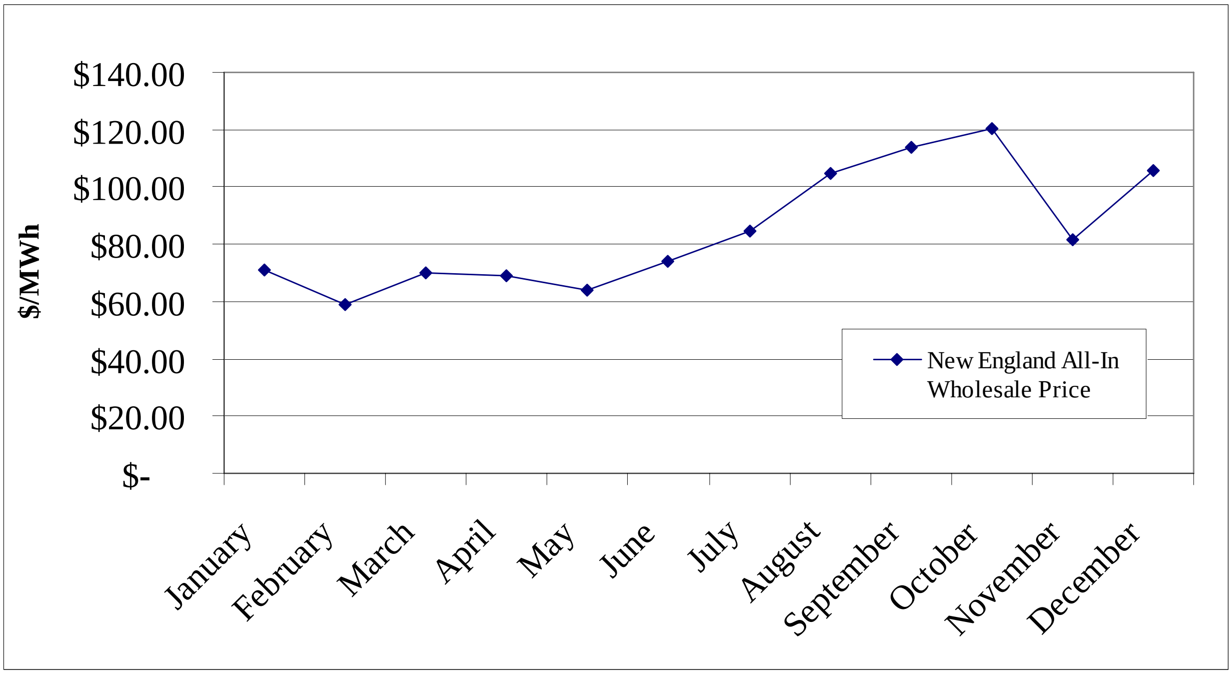
All-In Wholesale Price and Costs

Figure 2-9 illustrates the monthly average All-In wholesale power prices for the New England region over the study period. These prices include all of the components listed in Table 2-4. The

[11] The first official Forward Capacity Auction takes place in February 2008 for the Power Year 2010-11 which begins June 2010. The transitional forward capacity payments will begin in December 2006 at $3.05/kw-month increasing to $4.15/kw-month through the 3rd transition year. The descending clock auction start-of-auction price begins at twice the Cost of New Entry ($7.50/kw-month.) or $15/kw-month. There is a collar of $4.50 to $10.50/kw-month for the first 3 successful auctions and there is a peak energy rent adjustment applied to prevent double payments and exercise of market power.
[12] Boston Globe, September 25, 2006, "Flurry of Power Plant Proposals Offers Hope."

average monthly All-In prices are for around-the-clock (ATC) hours, as opposed to prices in Figure 2-6, which shows only average monthly on-peak hours. Similar to the on-peak hour graphics, the same peaks are evident in Figure 2-9. The All-In price, a defined FERC metric, provides for regional market monitors to compare different bid based markets around the country. Each regional market has other unique costs that are not captured in the FERC All-In cost, but such costs typically are very small and do not skew the comparison.

Figure 2-9
2005 New England All-In Prices



Source: ISO-NE

Uplift Costs in MA

There are several forms of uplift which target payments for specific reliability services not captured through the ISO-NE administered energy markets. Uplift or reliability costs are borne from ISO-NE supplemental commitments to the Resource Adequacy Analysis (RAA) dispatch protocol[13]. Reliability cost categories include first-contingency, second-contingency, voltage reliability and distribution reliability which provide transmission system support. Table 2-7 illustrates the Massachusetts reliability costs by category and the change over 2004.

[13] The ISO uses a seven-step procedure to commit resources to meet the NERC, NPCC standards. Details can be found in the 2005 Annual Markets Report, section 4.

Table 2-7
Uplift Costs for Out of Market Energy and Reserve, 2004 and 2005, Millions $

Category	2004	2005	% Change
Local Second Contingency - Boston	15	91	507%
Local Second Contingency - Other MA zones	1	0	-50%
First Contingency	21	32	53%
Voltage Support	31	35	10%
SCR/Distribution Support	6	5	-17%
MA Total	74	163	121%

Source: DOER and ISO-NE IMMU, July 2006

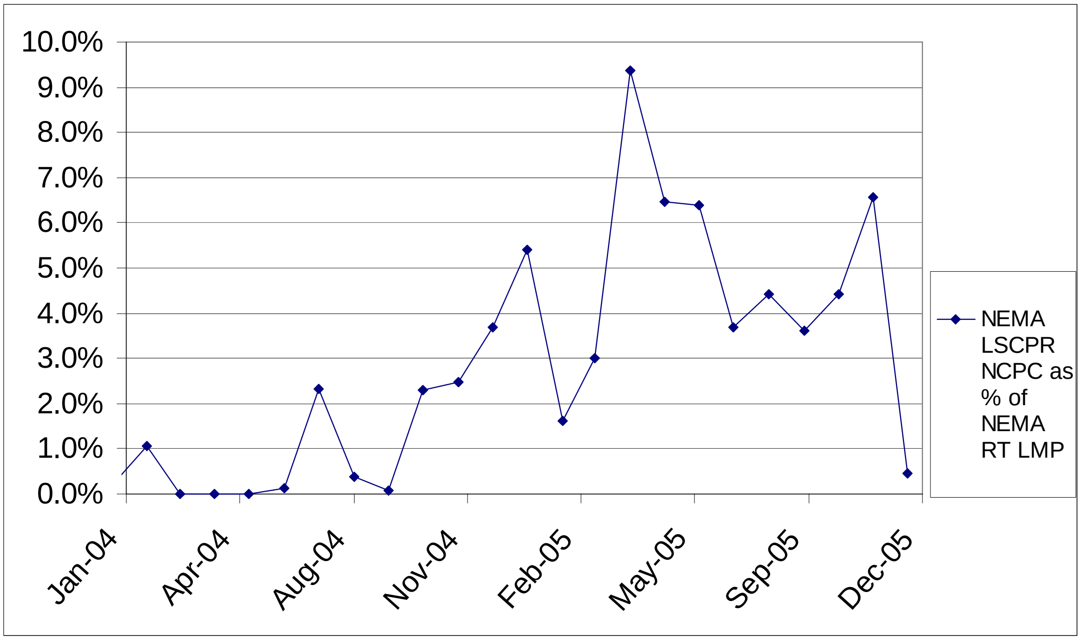
Second contingency costs are not socialized among all regional customers, but are allocated to the zone where resources are dispatched to maintain reliable service. Typically, less flexible resources are dispatched several hours in advance of need because the import constrained region lacks flexible, quick-start units to produce a more optimal, least cost dispatch. In 2005, NEMA was charged in excess of $91 million in 2nd contingency payments alone, up from $15 Million in 2004. Most of the increase had to do with one generator in the Boston area which did not correctly indicate availability for pool scheduling and misrepresented start up times when submitting generating offers to the ISO-NE[14]. An increase in self committed resources after the RAA also increased the uplift costs in NEMA as ISO-NE would have lowered the number of units needed for 2nd contingency coverage. The Massachusetts Attorney General's Office demanded a probe of potential market manipulation in December 2005 claiming that Sempra Energy manipulated the system and cost Boston area ratepayers $70 Million[15]. Reliability costs in NEMA have declined since the Attorney General demanded the manipulation probe of the Boston Generating plant's power marketer.

Figure 2-10 illustrates the monthly unit uplift cost in NEMA as a percentage of the monthly NEMA Real Time LMP from January to December 2005. One can see the spike to over 9% in Spring 2005 and over 4% throughout the entire calendar year. One should expect a small amount of uplift as a normal part of a functioning market, but an amount greater than 4% is an area of concern that should be addressed.

The second contingency unit cost average reached close to $5.00/MWh in 2005, which is an out of market cost which suppliers must account for when bidding for supply contracts in the region. The effects from increased out of market commitments are depressed Real Time LMPs as there is reduced liquidity and additional unhedgeable costs. The cost allocation methodology used by ISO-NE changed effective March 1, 2005. Rather than allocating the second contingency costs only to Real Time load deviations, the FERC approved ISO-NE's petition to charge the entire real time load in the zone.

[14] NPC Meeting, COO report, January 2006, page 18.
[15] Megawatt Daily, December 21, 2005, "AG demands probe of Sempra 'manipulation', page 1.

Figure 2-10
NEMA Local Second Contingency Uplift as % of RT LMP



Source: ISO-NE, DOER

<u>Ancillary Services</u>

The Ancillary Services market has changed considerably since the ISO-NE began administering the competitive market in 1999. Prior to SMD implementation in March 2003, ancillary services included payments for Automatic Generation Control (AGC), spinning, and operating reserve markets. In SMD 2003, only regulation market payments[16] were distributed to generators, while in 2004-05, the ancillary services included regulation market and forward reserve market payments.

The Ancillary Services market continues to evolve, including Phase I and II design enhancements. Phase I was filed with FERC in April 2005 and became effective October 1, 2005. The Phase I key components include regulation market enhancements, an enhanced re-offer period, and allowing for external transactions to set price. The ASM phase II design filed in February 2006 includes a provision for an enhanced forward reserve market to add a locational component, real time reserve pricing, and demand side participation in the reserve markets. Details of the 2004 and 2005 forward reserve market results are in Table 2-8 below. The forward reserves market provides the system with non-spinning reserve generation capacity to protect against 50% of the system first contingency (~1,500 MW) and 50% of the second

[16] Regulation is generation under automatic control (AGC) which is independent of economic cost signals and receives signals to adjust output at four-second periodicity

contingency (~1,400 MW). The total requirement varies by procurement period based on most recent system data, but as seen below, clears at close to 2,000 MW which takes into account unit forced outage and failure to start rates.

Table 2-8
Forward Reserve Market Cost Component of Ancillary Services

	Total Cleared (MW)	Clearing Price ($/MW-month)
Winter-Spring 2004	1,876	4,495
Summer 2004	1,963	4,075
Winter 2004-05	1,863	3,690
Summer 2005	1,972	2,400
Winter 2005-06	2,185	2,000

Source: ISO-NE

The amounts shown in Table 2-8 represent a significant revenue stream to participating generators. The market has become increasingly competitive resulting in the lower prices. The supply offers have increased from 3,500 MW to over 4,500 MW while total reserve has increased by only about 350 MW. Asset managers have retrofitted facilities, contracts and storage tanks to provide for this premium reliability service.

<u>RMR Cost Analysis</u>

Reliability Must Run (RMR) costs refer to payments made for reliability purposes to generators which otherwise might not run because they are uneconomic. Utilities allocate RMR contract costs to the Network Load of a reliability region where ISO-NE has identified a specific generation need for reliability. As legal proceedings dragged on at FERC regarding the capacity market, several generators requested Determination of Reliability from the ISO-NE and filed RMR agreements at FERC in consultation with ISO-NE for generation units throughout the New England region. Connecticut had 3,082 MW and Massachusetts had 2,367 MW of generating capacity with effective or pending RMR agreements at FERC.

In 2005 and early 2006, an additional 1,950 MW (5 plants) filed for RMR status. Only the 350 MW South Boston station and 72 MW of Cambridge's Kendall station had RMR agreements prior to 2005[17]. Two stations (Fore River and Potter) in the SEMA zone had RMR agreements rejected by the FERC. Dominion's Salem Harbor plant also entered into a special contract which provides for payments of $0.38/kw-month or $6.75 M through September 2008. Found in Table 2-9 is a summary of the Massachusetts RMR contracts which are effective or pending in Massachusetts as of November 28, 2006. Note that the Mystic 8&9 agreement is in the midst of

[17] The 350 MW Exelon Station in South Boston has operated under a RMR agreement to maintain downtown Boston reliability for several years, while Mirant Kendall units have been under a RMR since October 2004. The New Boston Station was to be retired in November 2006 upon commercial operation of an NStar transmission line, however, that did not occur due to delays in reliable commercial operation in the line.

a FERC settlement hearing, while Berkshire Power is the only plant in the Western Central Mass zone with a final FERC approved agreement. Further details on RMR agreements can be found on the ISO-NE website[18].

Table 2-9
Reliability Agreements - Annual Fixed Costs Summary as of November, 2006*

	Owner/Unit	Effective Date (Granted or Requested)	SSCC (MW)	AFRR $
NEMA/Boston	ExelonNew Boston 1	01/01/02	350.00	$30,000,000
	Mirant Kendall, Steam 1-3, Jet 1	10/08/04	72.11	7,920,000
	Boston Gen -- Mystic 8 & 9	01/01/06	1,398.26	238,253,200
		NEMA/Boston Subtotal	**1,820.37**	**$276,173,200**
Western Central Mass	ConEd -- W.Springfield 3	05/01/05	101.19	8,292,690
	Berkshire Power	07/01/05	229.54	26,000,000
	Pittsfield Gen. "Altresco"	12/01/05	141.00	36,529,015
	ConEd -- W.Springfield GT-1 GT-2	03/31/06	75.52	11,957,605
		WCMA Subtotal	**547.24**	**$ 82,779,310**
		Total Massachusetts	**2,367.61**	**$ 358,952,510**

Source: ISO-NE

Of the 3,595 MW in the NEMA load pocket, only 487 MW or 13% were not under a special contract, RMR, or awaiting a pending agreement at FERC in 2005. This lack of competition depresses real time LMPs, reduces liquidity, and increases unhedgeable costs to suppliers. In contrast, the SEMA zone has close to 6,000 MW in supply and not a single unit a traditional RMR or special contract. The WCMA zone has close to 3,900 MW of supply of which 2,900 MW takes part in the wholesale competitive market as about 1,000 MW is under RMR agreements or have been determined to not be needed for reliability.

Retail Electricity Price Analysis

Retail electricity prices are composed of wholesale power costs, adjusted for losses during transmission to the local distribution companies, and wholesale and retail delivery costs. Since the energy supply cost is a predominant component of retail prices, it gets a lot of attention in analyzing the overall retail electric service costs. However, many other services must be procured and provided to deliver safe, reliable electricity. The 2002-2004 version of this report featured a detailed discussion of the different cost components of retail prices. This section furnishes an analysis of Massachusetts' retail electricity prices in 2005.

[18] http://www.iso-ne.com/genrtion_resrcs/reports/rmr/index.html

Overview of Default Service Prices by Load Zone

The local distribution companies (LDCs) procure energy in any one or more of the three Massachusetts' load zones, depending on each LDCs service territory. After SMD took effect in March 2003, the Massachusetts LDCs for the first time procured energy in all the different load zones, namely NEMA, SEMA and WCMASS. Initially, the NEMA zone was expected to command a higher price due to high demand and congestion problems.

Table 2-10 supplies data on the weighted, average industrial service prices in Massachusetts classified by Massachusetts' load zones. Note that supplies procured by the different local distribution companies on behalf of the Industrial sector and are known as Default Service prices. NEMA continues to be the highest-priced zone, but WCMASS is also experiencing increases. Price differentials continue lower than when the zonal markets started. In addition, there are some differences in the prices among LDCs, even though customers were located in the same load zone. Most of these differences were due to the timing and size of the particular procurement. For example, Fitchburg Gas & Electric had the highest December prices, much higher than even the NEMA prices in the other LDCs due to the fact that this power was procured right after the effects of the Hurricanes on wholesale gas and electric markets.

Table 2-10
Average Industrial Default Service Prices by Load Zone

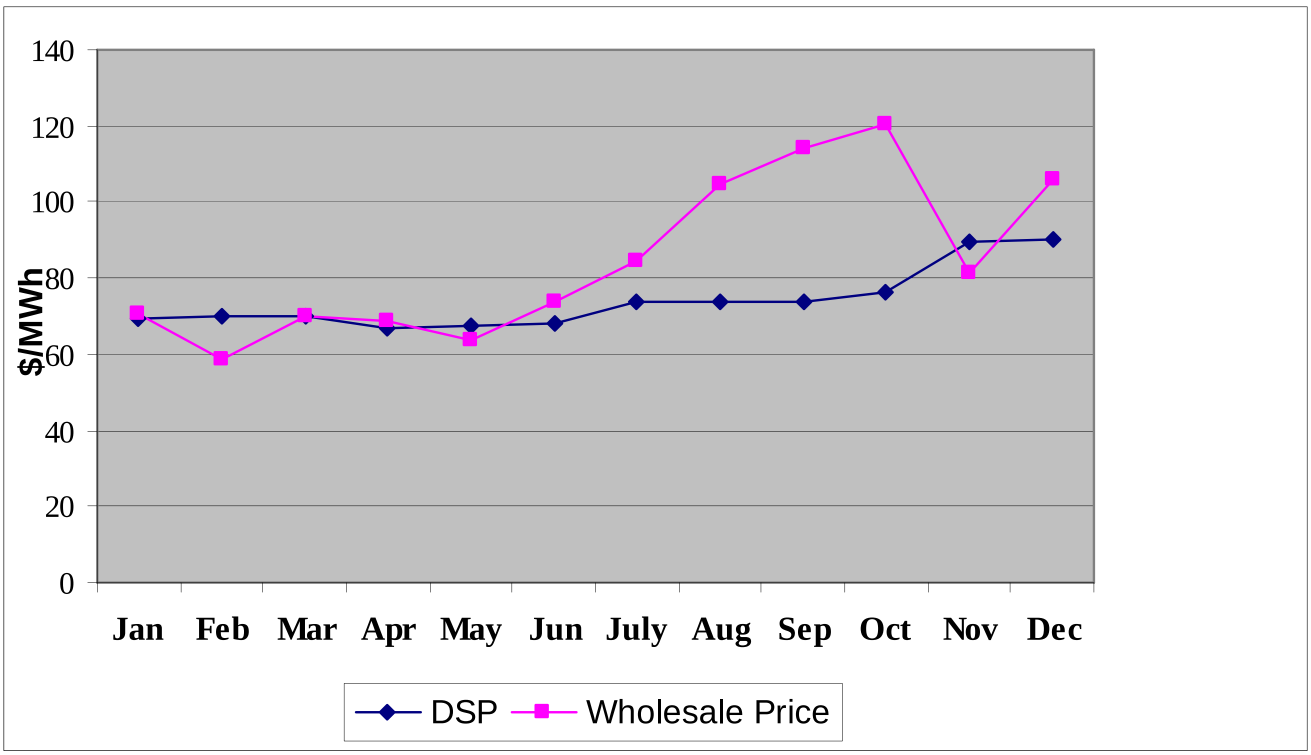
	NStar		Fitchburg Gas & Electric	Massachusetts Electric			WMECO
	NEMA	SEMA	WCMASS	NEMA	SEMA	WCMASS	WCMASS
Jan-05	9.407	9.009	9.528	7.920	7.732	7.791	9.046
Feb-05	9.409	9.014	9.133	8.683	7.732	7.791	9.102
Mar-05	8.461	8.009	6.684	7.330	7.910	7.500	7.244
Apr-05	7.186	6.603	6.605	6.756	6.346	6.957	6.636
May-05	7.172	6.566	6.422	7.382	7.245	7.308	6.584
Jun-05	7.371	6.706	7.617	7.680	7.474	7.622	6.810
Jul-05	8.434	7.663	8.151	8.266	8.133	8.229	7.794
Aug-05	8.688	7.831	8.141	8.524	8.122	8.657	7.930
Sep-05	7.842	7.088	7.903	7.498	7.271	7.634	7.195
Oct-05	9.256	8.544	7.838	7.502	7.187	7.551	9.289
Nov-05	9.497	8.794	8.060	12.413	11.170	11.492	9.514
Dec-05	10.129	9.270	15.641	12.876	12.175	12.475	10.344
Average	8.571	7.925	8.477	8.569	8.208	8.417	8.124

Source: DOER, LDCs

Retail Default Service Lags All-In Wholesale Costs

According to Figure 2-11, the retail default service prices lag the All-In wholesale prices and are not as volatile, largely due to the longer-term procurements found in default and standard offer service. Such a disconnect between wholesale and retail prices provides challenges to customers when evaluating competitive market alternatives to utility provided generation service. The retail market conditions shown in the figure prove difficult to retail suppliers as wholesale costs were much higher than prices offered by the utility company to customers. Retail suppliers can sign contracts to avoid such price swings, but their ability to attract customers is still limited. We comment on the impacts of the relationship between wholesale and retail prices on migration to the competitive market in Chapter 4.

Figure 2-11
Weighted Average Monthly Default Service Prices vs. Wholesale Prices
2005



Source: MA LDCs, ISO-NE, DOER

<u>Retail Prices by Massachusetts Electric Companies</u>

Table 2-11 shows total retail prices for all customers for each of the LDCs and the municipal companies as a whole. The retail prices shown in the table (and in this section) result from the addition of wholesale power costs and the various components discussed above and retail price components, including distribution, transmission, and stranded charges paid to the utility companies, and system-benefit charges that are used to promote expansion of energy efficiency and renewable energy measures. The figures represent the actual prices paid, on average, by all consumers and businesses of the Commonwealth for their electricity purchases.

Table 2-11
Revenue per kWh for Massachusetts Electric Companies
2004-2005
(average price in cents/kwh)

	2004 Average Price	2005 Average Price	Change (2004-2005)
Boston Edison	10.5	11.6	10.0%
Cambridge Electric	8.9	8.6	-2.7%
Commonwealth Electric	11.6	10.8	-7.6%
Fitchburg Gas & Electric	10.1	11.5	13.8%
Massachusetts Electric	8.7	9.2	5.0%
Nantucket Electric	11.8	12.1	1.9%
Western Massachusetts Electric	8.9	9.4	5.5%
Total: Distribution Company	9.6	10.1	5.1%
Total: Municipal Company	9.6	10.4	8.6%
Total of Entire State	9.6	10.1	5.6%

Source: FERC Form 1, Massachusetts Electric, EIA (for Massachusetts Electric & 2005 overall price), DOER

The data show that overall prices paid by all customers classes showed a rather large increase in 2005, especially for municipal light district customers, which as a group suffered higher rates than LDCs in 2005[19] compared to 2004. As shown in Table 2-12, however, municipal companies continue to provide electric service at cheaper rates for their residential customers.

[19] The 2005 overall price shown in Table 2-9 differs from the overall price shown in Figure 2-1 due to different data sources. The analysis of Figure 2-1 is a comparison of MA average prices to other states' and national prices. The analysis shown in Table 2-9 is a temporal analysis and utility specific.

Table 2-12
Comparison of Distribution Company and Municipal Company Prices
(2004-2005)

	2004	2005
Residential		
Average LDC Company Price	11.9	11.8
Average Municipal Utility Price	9.96	10.9
Difference	-19.7%	-8.3%
Small Commercial or Industrial		
Average LDC Company Price	8.8	9.3
Average Municipal Utility Price	10.6	14.9
Difference	16.5%	37.6%
Large Commercial or Industrial		
Average LDC Company Price	6.3	6.0
Average Municipal Utility Price	8.5	8.0
Difference	25.6%	25.0%
Overall		
Average LDC Company Price	9.6	10.1
Average Municipal Utility Price	9.6	10.4
Difference	-0.3%	2.9%

Source**:** FERC, Massachusetts Electric, Municipal Electric Companies

Retail Price Disparity

Retail price disparity refers to the difference in prices among the LDCs and customer classes. A higher value for price disparity for a customer class indicates that there are greater differences among customers in a particular customer group. As part of its annual market monitor reports, DOER has reported on *changes* in price disparity from year to year. Table 2-13 shows this analysis for 2005. As in prior years, price disparity increases with the range of sizes within the customer class—that is, it is more likely one will find greater price disparity among commercial and industrial (C&I) customers than among residential customers; hence prices paid by customers in the C&I group should differ by a greater amount. Overall, price disparity likely did not change as the F-Test is 94%[20]. However, it is likely that price disparity changed (and fell) for residential and industrial customers, especially, given the low F-Test values for those two customer groups.

[20] The F-Test is a statistical test that measures the probability that the variance among two datasets are not statistically significant and thus measures the probability that price disparity did not change from year to year. A higher value implies that disparity among two datasets is less likely.

Table 2-13
2004-2005 Price Disparity Among Distribution Companies

	Residential		Commercial		Industrial		Overall	
	2004	**2005**	**2004**	**2005**	**2004**	**2005**	**2004**	**2005**
Price Disparity	1.4	2.8	3.8	5.6	17.1	4.2	1.7	1.9
F-TEST		0.41	0.65		0.11		0.94	

Source: FERC, National Grid, DOER

Restructuring Savings Analysis

This final section updates the comprehensive savings analysis that was included in the 2002-2004 Price, Reliability, and Markets Report. As specified in the prior PRM, increasing prices was a major policy concern and prices increased steadily from 1990 to 1997. The Act mandated rate reductions in 1998 and 1999 and prices have steadily risen since those years, mostly due to fuel-related, in the form of natural gas used to power electricity plants, increases. As with last year's report, we include a couple of different scenarios for analysis purposes.

Scenario 1: Restructuring vs. prices growing at historical rates - consumers saved about $4.5 billion.

This scenario assumes that prices after 1997 grow at historical rates. This assumption is analogous to examining what would have happened without restructuring, assuming that recent history is a good indicator of future events. Historical data is used for the time period 1990-1997 and a linear trend is used for the assumption for the 1998-2004 period. Table 2-14 summarizes the results of these assumptions.

Table 2-14
Savings from Restructuring, Scenario 1
1998-2005
(millions $)

	Residential	Commercial	Industrial	Total
1998-2004	-2,131	-2,098	-774	-4,390
2005	-109	71	-103	-37
Total	-2,240	-2,027	-877	-4,427

Source: DOER, EIA, MA LDCs

Scenario 2: Restructuring vs. prices growing at rates of consumer goods inflation – consumers saved $5.4 billion through restructuring.

In the other scenario, the price of electricity increases at the same level of other consumer goods such as furniture, autos, and household expenditures. This scenario compares the impacts of restructuring to price growth in other industries. The consumer price index (CPI) for northeast urban customers, published by the Bureau of Labor Statistics, is the inflation source. Table 2-15 shows the impact on total bills.

Table 2-15
Savings from Restructuring, Scenario 2
1998-2005
(millions $)

	Residential	Commercial	Industrial	Total
1998-2004	-1,677	-1,745	-565	-4,897
2005	-187	-84	-152	-432
Total	-1,864	-1,829	-717	-5,329

Source: DOER, EIA, MA LDCs

Using the CPI as the inflation measure yields even higher savings calculations than the ones calculated in Scenario 2 that used the historical growth in electricity prices. Hence, if electricity prices had grown at the same rate as a basket of consumer goods during the post-1997 period, rather than growing at the actual rates during that period, consumers would have paid an additional $5.4 billion for the same electricity product. Thus, using this assumption for growth in prices, consumers saved about $5.4 billion during the post-1997 period.

Conclusion

Massachusetts remains a high-price region. Even though the nation as a whole experienced much higher prices in 2005, the state and New England region suffered higher percentage increases in prices, mostly due to the greater dependence on natural gas for power generation. ISO-NE continues to undertake efforts to improve the operations of wholesale markets but they have little or no control over the delivered of natural gas to the region.

There were several enhancements in the wholesale markets design to encourage price transparency and allocate costs to load zones on a demand/supply basis. Despite these wholesale market improvements, wholesale electricity costs, especially the cost spikes due to the tight natural gas conditions, were not immediately passed on in retail prices. Most consumers therefore are not challenged to change their consumption behavior during high cost electricity times. As a result, ISO-NE significantly expanded its demand response program in the winter to provide incentives for conservation during peak periods.

There is a need for more demand response awareness and incentives to conserve energy at certain times and how those actions translate into consumer savings. Also, there must be a better connection between wholesale costs and retail prices for consumers to push for more efficient markets.

On the other hand, due the fact that these large price increases were not passed on to consumers in 2005, there continue to be significant savings to consumers due to the Restructuring Act. When adjusted for inflation, consumers have saved over $5 billion since the passage of the Act in 1998. That is, while other goods' prices have increased, electricity prices have increased at a much lower rate.

Chapter 3 -- Reliability

A broad definition of reliability of the electric system is the degree of performance of the system that results in electricity being delivered to customers within accepted standards and in the amount desired. As in prior PRM reports, we examine reliability at both wholesale and distribution-system levels. Wholesale reliability relates to the reliability of generating plants and the transmission grid. Distribution-system reliability refers to the ability of the local electricity network and feeder system to homes and businesses to maintain service. This chapter reviews some metrics for measuring the reliability of the New England bulk power system and reliability at the Massachusetts local distribution level.

Wholesale Reliability

In the U.S., the National Energy Reliability Council (NERC) sets reliability resource adequacy standards, which are then administered by regional NERC entities, such as the Northeast Power Coordinating Council (NPCC) in Northeastern U.S. and Canada. Although there is no strict NPCC criteria for reserve margins in power pools, reliability criteria in New England is currently based on loss of load probabilities. The NPCC defines its Loss of Load Expectation (LOLE) criteria as the loss of firm or non-interruptible customers, on average, no more than one day in 10 years or one tenth of one day per year[21].

<u>Reserve Margins and Loss of Load Expectation</u>

Since electricity cannot be stored, the dynamics of power supply and demand require a sufficient generating capacity reserve margin to maintain a safe and reliable power supply system. Reserve margin is generally considered to be the amount of electric generating capacity that exceeds demand. In other words, it represents the extra supply capacity available to respond to unexpected events and should be adequate to cover a reasonable amount of extreme weather and/or unplanned generation plant shutdowns.

The reserve margin discussed in this report represents the percent of New England's installed capacity above the adjusted peak load forecast. For example, the reference load forecast for 2006 of 28,638 MW is adjusted down per demand side management activities accounting for slightly over 1,600 MW. Figure 3-1 depicts ISO-NE's ten-year projections of percent of summer reserve margins which are listed in ISO-NE's annual Capacity, Energy, Load and Transmission Forecast (CELT) reports.

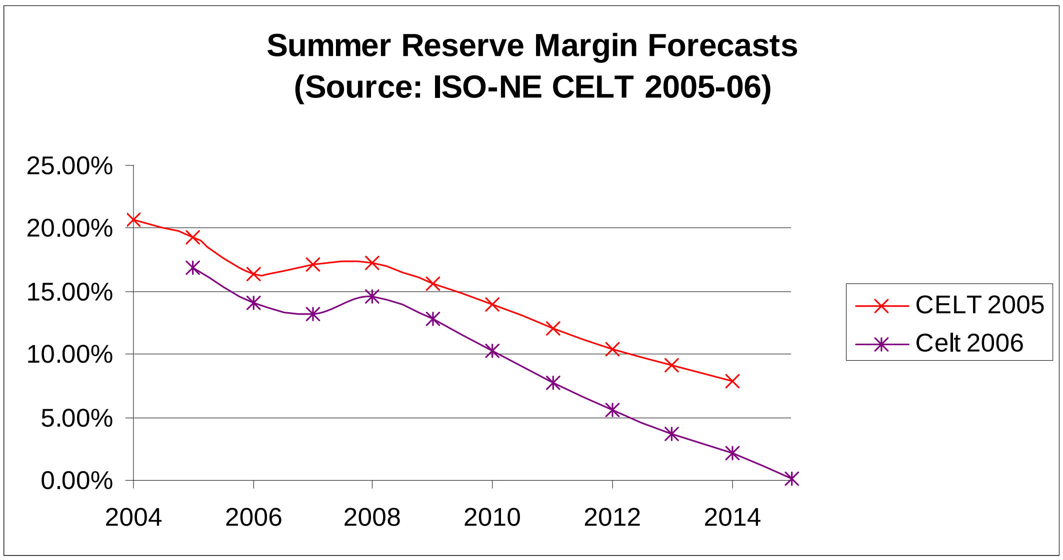
As shown, the ISO-NE has forecasted that reserve margins will diminish over time. According to the CELT06 data, the reserve margin dips below 15% in 2006. The data from the CELT 2006 Report, shown in Figure 3-1, indicate that by 2010 the reserve margin forecasted by ISO-NE will be at an unacceptable 10% level. As such, the situation for maintaining reliability (in terms of the 1-day-in-10-year standard) may become dangerously inadequate. In fact, decisions about

[21] One day in ten years equals twenty four hours divided by ten years which is 2.4 hours in a year. The 2.4 hours times sixty minutes equals one hundred forty-four minutes a year. Therefore, one day in ten years equals one hundred forty-four minutes loss of load expectation in a year

corrective actions are needed sooner than 2010 due to the lead time needed to construct a central station power plant. Depending on the type of plant built, the construction lead time varies, but can take up to seven years. Demand response and energy efficiency have shorter lead times and thus may be better options.

The ISO-NE Regional System Plan's (RSP) deterministic system-wide Operable Capacity (OC) analysis indicates the region will be deficient by 157 MW in 2008 under normal load conditions where the load has a 50% chance of exceedance [22]. Where Figure 3-1 does not include the reserve requirement in the peak load forecast, nor the peak outage capacity in the supply projection, the RSP OC analysis does include the 1,700 MW reserve requirement and an anticipated capacity outage of 2,100 MW.

Figure 3-1
NEPOOL Summer Reserve Margins Forecasts, 2005-2015



Source: ISO-NE, Celt Reports for years 2005-06

It is important to note that the role of transmission resources is not accounted for in evaluating the deterministic reserve margin levels. ISO-NE performs bulk power system reliability assessments or resource adequacy assessments (RAA) on an annual basis and publishes these results in their Regional System Plan (RSP)[23]. The probabilistic analysis measures the impact of subarea loan and/or resource changes on NEPOOL's Loss of Load Expectation (LOLE). This

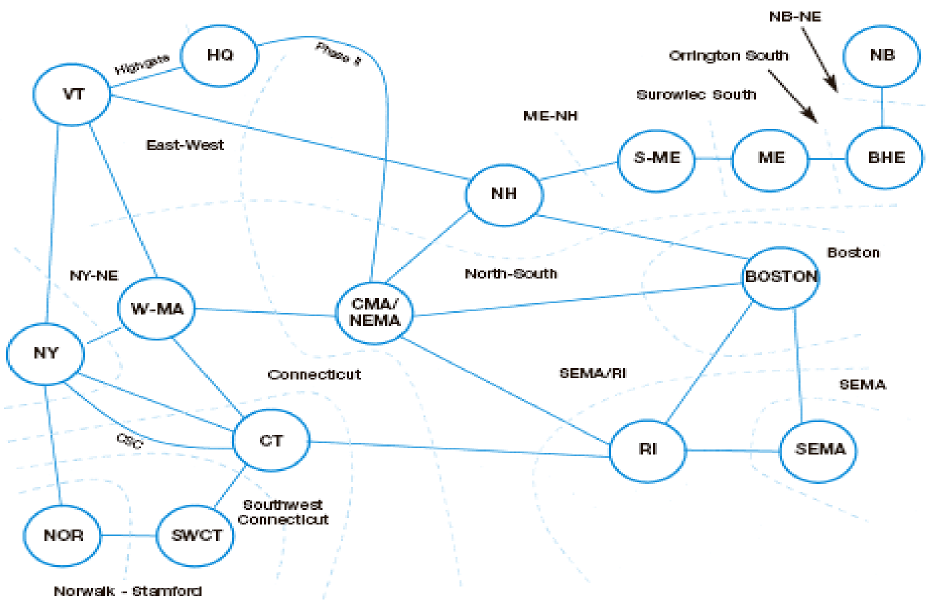
[22] The Regional System Plan also performs probabilistic system-wide Installed Capacity (IC) analyses of resource adequacy which models the system as a single bus, ie without consideration for transmission interfaces and other operational constraints. The Installed Capacity analysis indicates a need for 172 MW (assuming 10% EFORd and five weeks of O&M) in 2010 assuming a 2,000 of Tie Reliability Benefit (TRB) in order to keep LOLE at or better than the 1 day in 10 years system criterion of not disconnecting . The supply need would be 690 MW by 2009 assuming a 1,000 TRB from adjacent power markets including NY and Canadian markets.

[23] Since 2001, ISO New England has also conducted annual resource adequacy assessments for the ISO New England Regional System Plan. Prior to being designated as an RTO, ISO-NE published the RSP equivalent referred to as a Regional Transmission Expansion Plan (RTEP).

measure accounts for the transmission interfaces throughout the region which allow control areas to rely upon one another for resources. Deterministic generating capacity reserve margin analysis as shown in Figure 3-1 simply shows the wholesale reserve capacity margin, but does not account for dynamics of random plant outages, load asset changes, and interactions with transmission resources.

In its assessment, ISO-NE divides the New England system into thirteen sub-areas (see Figure 3-4) to reflect the expected transmission constraints. The RAA results identify zones or sub areas that are in jeopardy of reliability problems. Massachusetts is broken into four RSP sub areas: Boston, CMA/NEMA, WMA, and SEMA. Boston is the only zone in Massachusetts which is import constrained and is thus more vulnerable to reliability problems.

Figure 3-2
New England RSP Subareas



Source: ISO-NE RSP05

The incremental LOLE assessment of generation resource adequacy represents a somewhat limited assessment of system reliability as the method does not address operational and local transmission problems internal to the Sub-areas which could result in other reliability problems. Even if this type of analysis indicates that the system is meeting LOLE criteria, there may still be any number of reliability concerns that deterministic and more detailed system assessment methods are designed to identify.

According to the 2005 RSP Incremental LOLE analysis, the entire region and Boston sub area are projected to be sufficiently reliable in 2006 as the LOLE is no more than 0.1 days per year.

The modeling of the Boston import limit reflected the addition of two new cable circuits by Summer 2006 and the third cable by Summer 2008. The analysis shows that the system is most sensitive to load or resource changes in the Norwalk, Southwest Connecticut, and Connecicut subareas. The incremental LOLE analysis indicates the system will meet the required 0.1 day per year criterion in 2009, but will be 270 MW short in 2010. Resources or conservation measures would have to be implemented in Norwalk or SWCT to comply with NERC standards. The region as a whole will need 1,900 MW of new resources by 2014.

Generation projects in the development/interconnection queue at ISO-NE are not taken into account in the above analysis as ultimate development remains uncertain. A list of the 15 projects totaling 1,028 MW, of which 756 MW is active as of Fall 2006, in which sponsors requested interconnection agreements per FERC guidelines in 2005 is found in Table 3.1 below.[24] Note that only 3 of the 15 projects were proposed to be built in the Commonwealth, one project in ME is already commercial, and three projects of the 15 have been withdrawn.

Table 3-1
New England Project Queue as of Fall 2006

Queue Position	Request Status	Request Date	State	Project Name	Summer Net MW
128	W 4/15/2005	2/11/2005	CT	Biomass	39
129	C	2/28/2005	ME	Georgia Pacific	16
130	W	5/24/2005	VT	Wind Project	53
131	A	6/21/2005	ME	Wind Project	90
132	A	7/21/2005	VT	Wind Project	9
133	W 9/29/2005	8/1/2005	VT	Combined Cycle	115
134	A	8/3/2005	VT	Wind Project	45
135	A	8/19/2005	MA	Biomass	55
136	A	8/19/2005	ME	Biomass	39
137	A	9/23/2005	ME	Hydro	TBD
138	A	9/26/2005	ME	Wind Project	131
139	A	10/14/2005	MA	Lowell Power Generators	99
140	A	12/13/2005	CT	Gas Turbine	89
141	A	12/14/2005	MA	Gas Turbine	200
142	W 4/13/2006	12/21/2005	VT	Wind Project	48

Source: ISO-NE; Note: W=Withdrawn, A=Active, C=Commercial

[24] ISO-NE manages the interconnection queue and posts a public version on its website with various details for each sponsored project. ISO-NE also posts the projects which have been withdrawn from the process for a variety of permitting or financing reasons over the past several years.

In addition to the larger facilities requesting interconnection on the New England transmission system, there are also smaller on-site generation facilities which must interconnect with the local distribution system per state interconnection procedures. About 328 new on-site generation projects applied for interconnection with MA utilities between spring 2004 and early 2006. Over 275 projects or 20 MW have been approved for installation, but the larger on site facilities accounting for 38 MW had not been approved by February 2006.[25] The utilities have agreed to resume interconnection reporting on an annual basis beginning in 2007.

System Reliability

Despite some extreme demand conditions during the study period, New England's grid system reliability has been strong. For example, on July 27, 2005, New England hit a record peak demand of 26,885 MW, but ISO-NE was able to maintain system reliability. ISO-NE implemented emergency operating procedures on July 27 for the Connecticut region only.

New England's emergency Operating Procedure #4 (OP4)[26] was activated three times in 2005, but only twice in Massachusetts. The third OP4 activation occurred only in Connecticut. The emergency OP4 implemented various actions of the procedure on August 13 and October 25.

Table 3-2 illustrates the annual summer peak loads from 2000- 2005. Note that the regional peak load compounded annual growth rate (CAGR) over the past 5 years has been 4.17%, while the year over year growth from 2004 to 2005 was 11.5%. Massachusetts peak load growth over the same 5 year timeframe was 4.42% and 12.6% from 2004 to 2005. These 5-year growth figures are significantly larger than the prior five-year period. Also, peak load growth has been much higher than overall load growth of 1.69% in New England and 1.89% in Massachusetts over this same time period.

Table 3-2 New England and MA Summer Peak Loads, 2000-2005

	ISO -NE		MA	
	MW	% Growth from prior year	MW	% Growth from prior year
2000	21,919	-	10,154	-
2001	24,967	13.9%	11,416	12.4%
2002	25,348	1.5%	11,710	2.6%
2003	24,685	-2.6%	11,403	-2.6%
2004	24,116	-2.3%	11,189	-1.9%
2005	26,885	11.5%	12,604	12.6%
2000-05		**4.17%**		**4.42%**

Source: ISO-NE

[25] MA Distributed Generation Collaborative, 2006 Report, June 30, 2006.

[26] OP4 Procedure establishes criteria and guides for actions during capacity deficiencies, as directed by the ISO and as implemented by the ISO and the Local Control Center Control Centers. This Procedure may be implemented any time one or more of qualified events are expected to occur, as detailed in the operating procedure 4.

Table 3-3 illustrates the annual summer peak record loads from 2005 compared to the previous record high set in 2002. The 2005 peak capacity of 26,885 MW broke the August 2002 record by 6.1%. Note that the region also realized a massive increase in all-time peak demand for a weekend day in 2005. On August 13, 2005, a Saturday, the peak demand hit 24,065 MW which is 12.3% greater than the previous weekend peak demand achieved in August 2004 and ISO-NE was forced to implement a rare weekend OP4 event.

Table 3-3 New England All-time Peak Loads Records

	Peak Demand	Peak Demand Growth	
Date	(MW)	(MW)	(%)
27-Jul-05	26,885	1,537	6.1%
19-Jul-05	26,736	1,388	5.5%
5-Aug-05	25,983	635	2.5%
26-Jul-05	25,555	207	0.8%
14-Aug-02	25,348	-	-

Source: ISO-NE

Winter peak load growth has not been as dramatic but has still increased. Following the January 2004 cold snap, ISO-NE and stakeholders developed a final report which identified actions of generators used to maximize profit during the cold weather event and how the ISO-NE should attempt to prevent reliability issues in the future. On January 28, 2005, the ISO-NE introduced "Cold Weather Event Procedures"[27] as Appendix H of Market Rule 1 with a sunset date of April 15, 2006. The filing proposed to change the Market Rule 1 by implementing procedures designed to avoid OP4. The proposals included a set of criteria to identify qualified cold weather events, specific communication protocols, switching dual fuel generators from gas to liquids fuel, and notifying demand response participants to prepare for interruption. On October 28, the 2005-06 Winter Package included revisions to the Event Procedures, Appendix F related to generator posturing payments, and a new OP21 to provide periodic surveys of generator fuel availability to address emergency energy situations.

Table 3-4 illustrates the annual winter peak loads from 2000-2005. Note that the regional peak load compounded annual growth rate (CAGR) over the past 5 years has been 1.34%, while the year over year growth from 2004 to 2005 was -0.8%. Massachusetts peak load growth over the same 5 year timeframe was 1.22% and -2.88% from 2004 to 2005.

[27] A "Cold Weather Event" is defined in Market Rule 1 as days when cold weather conditions are forecasted and the capacity margin is forecasted at less than or equal to 0 MW for an operating day.

Table 3-4 New England and MA Winter Peak Loads, 2000-2005

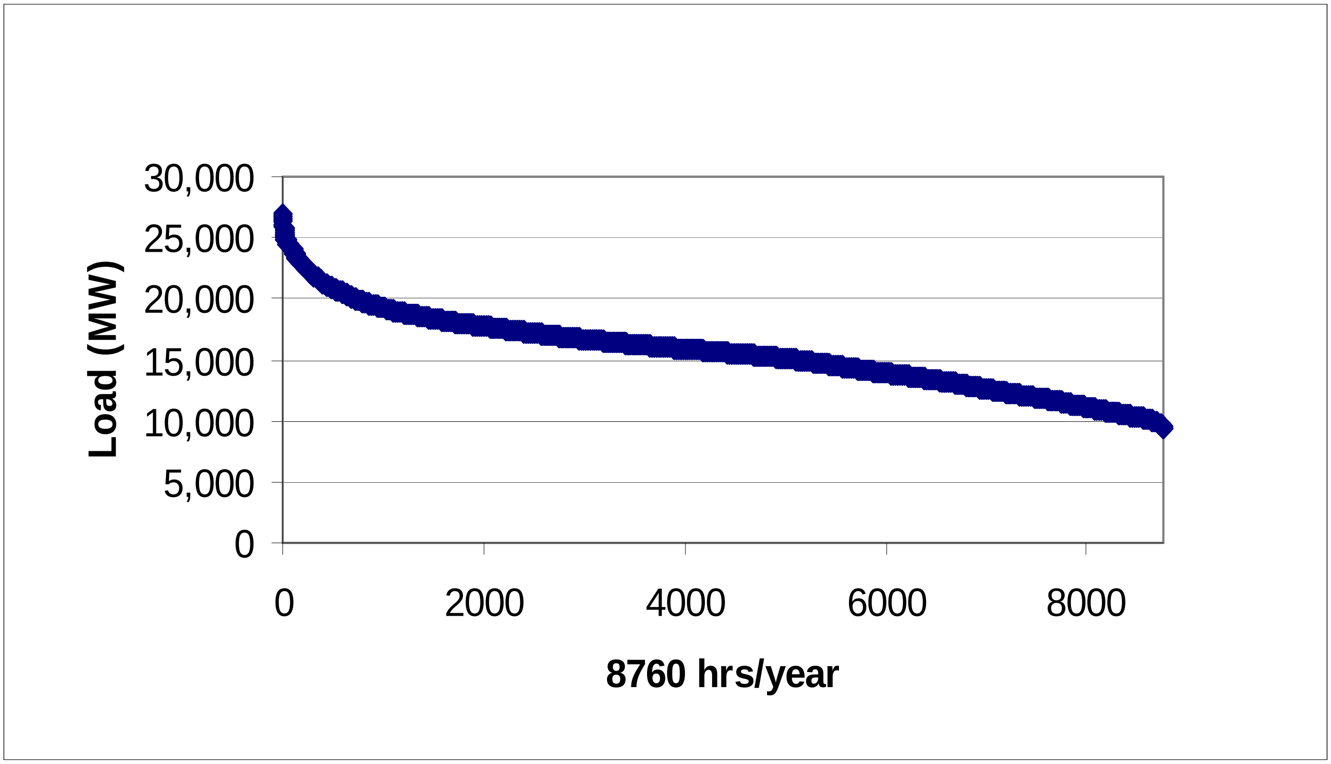
	ISO -NE		MA	
	MW	% Growth from prior year	MW	% Growth from prior year
2000	21,176	-	9,548	-
2001	20,088	-5.14%	9,035	-5.37%
2002	19,872	-1.08%	8,923	-1.24%
2003	21,533	8.36%	9,759	9.37%
2004	22,818	5.97%	10,444	7.02%
2005	22,635	-0.80%	10,143	-2.88%
2000-05		**1.34%**		**1.22%**

Source: ISO-NE

Figure 3-3 below show the NEPOOL load duration curve which illustrates the distribution of hourly regional load for all 2005 hours. The average hourly load in 2005 was 15,565 MW which represents a 58% system load factor as the peak hit 26,885 MW on July 27th. The minimum system hourly load was 9,310 MW. The regional system load factor continues to decrease as the air conditioning penetration increases. The system load factor was close to 68% in the early 1980s and has gradually fallen to the current level. A lower system load factor should and has induced more investment in demand response investment and peak shaving pricing discussions.

The system load duration curve illustrates the frequency of hours above a certain load threshold. Only 28 hours or less than 0.3% of all hours in 2005 exceeded 25,000 MW load and 100 hours or 1.1% of hours exceeded 24,000 MW. This provides the empirical data necessary to invest in researching and developing peak shaving pricing approaches and demand response technology efforts.

Figure 3-3
NEPOOL System Load Duration Curve 2005



Source: ISO-NE

Fuel Diversity

Table 3-5 uses ISO-NE data to examine the New England fuel mix[28] in terms of percentage of total load for 2005 relative to 2004. The data show that fuel diversity was essentially unchanged from 2004 levels. Gas continues to be the dominant generation fuel, but nuclear plays an important role in fuel diversity. Renewable power, mostly from large hydro and biomass facilities, continues to play a minor role, indicating that a large expansion in that sector is needed to supplant generation from fossil fuel and nuclear plants.

[28] ISO-NE does not break down generation fuels usage from dual fuel generating units.

Table 3-5
New England Generation Fuel Mix
2004-2005

	2004	**2005**
Gas	29%	28%
Nuclear	28%	25%
Oil/Gas	12%	12%
Coal	11%	12%
Oil	4%	4%
Wood/Refuse	4%	4%
Hydro	5%	6%
Coal/Oil	3%	3%
Refuse	1%	2%
Small Generation	1%	1%

Source: ISO-NE

Due to New England's relatively high-cost fuel mix, its energy prices are higher than other organized power markets in the U.S. which utilize vastly different fuels for their generating portfolio. For example, the largest power market in the U.S., PJM Interconnection, serves the middle Atlantic States and a growing portion of the Midwestern U.S. The majority of PJM's generation resource base is powered mainly by stable-priced fuels (i.e. low fuel price risk) including 56% of generation fuel mix by coal, 34% by nuclear power and less than 6% by gas.[29] As a result, the energy prices in PJM are markedly lower and less volatile than those in New England and New York.

Import/Export Capabilities

On a daily basis, neighboring power markets support New England's system reliability by sharing resources for reserve needs. The three main power markets physically tied to New England are New York ISO, Hydro Quebec and New Brunswick. The interface transmission line resources (ties), which can transmit power from outside pools, are also considered as reliability assets in meeting New England's electricity demands. These resources are included in New England's annual Installed Capability (IC) requirements. This accounting helps to ultimately reduce the cost for resources in the region. The Tie Reliability Benefits (TRBs) assumed in the IC calculations are as follows: 1,200 MWs for Hydro-Quebec, 200 MWs for New Brunswick and 600 MWs from New York, however, these values are subject to change in upcoming Power Year requirements.

In 2005, New England used more supply from neighbors than in 2004, as shown in Table 3-6. Total net imports from neighboring regions in 2005 amounted to 6,318 GWh or 4.6% of the annual New England load. This represents an increase over 2004 when neighbors supplied 3.7% of the New England demand. The 2005 net power import value represents an average power import of 721 MW, up from 560 MW per hour in 2004.

[29] 2005 State of the Market Report, PJM Market Monitoring Unit, March 8. 2006, page 29.

Table 3-6
2005 New England
Generation Import/Exports

	MW	GWh	% of Net Flow
New Brunswick	185	1,620	26%
New York	(11)	(94)	-1%
Hydro Quebec	547	4,792	76%
Total Net Flow	721	6,318	

Source: ISO-NE

Distribution System Reliability

The above section discussed reliability at the wholesale level, which has been excellent with no loss of load due to events at the level of the wholesale electric grid. In this section, we examine distribution system reliability, which is maintained and operated by the LDCs. Recently, the DTE required the MA investor-owned LDCs to file certain data in order to determine the quality of their service. A set of reliability attributes are measured and weighted for their importance in the overall calculation of satisfaction with LDC service. This is known as the Service Quality Index (SQI). Individual LDC's information is then monitored and benchmarked against certain historical standards.

Two measurements used in MA are the System Average Interruption Duration Index (SAIDI) and the System Average Interruption Frequency Index (SAIFI).

<u>SAIDI</u>

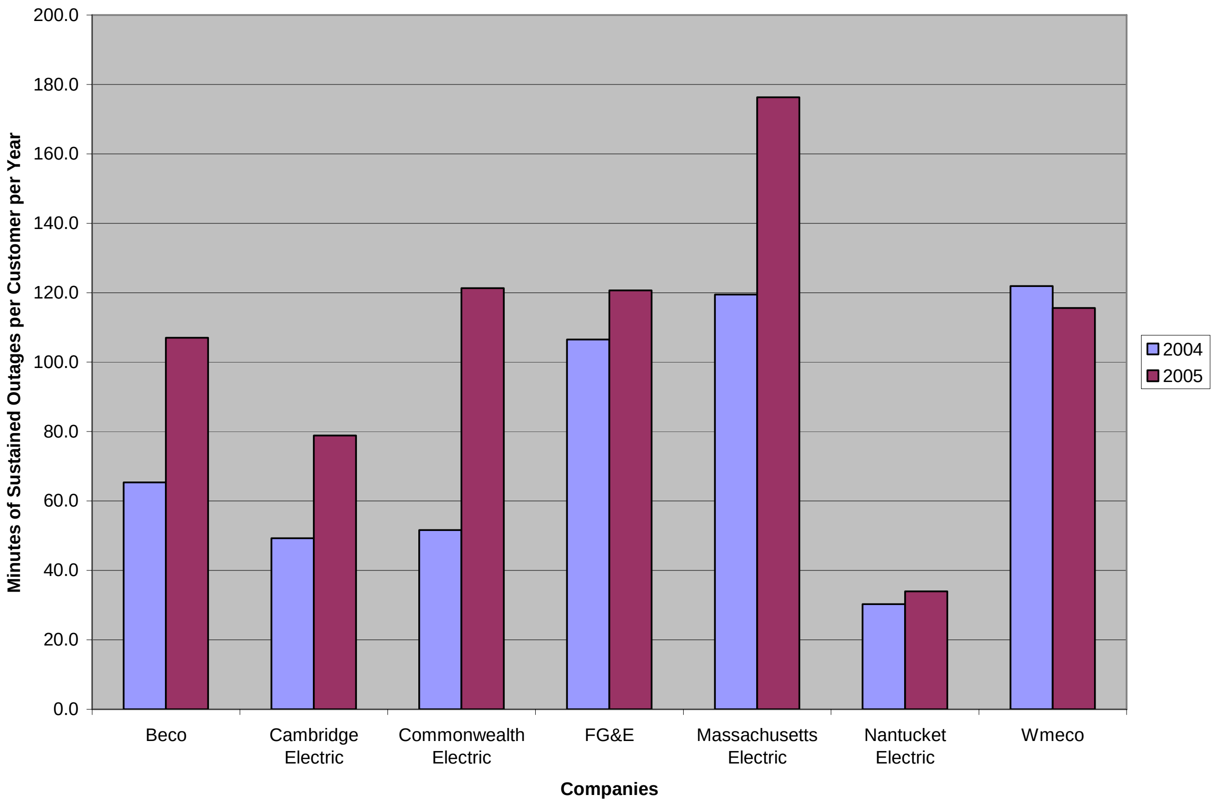
The System Average Interruption Duration Index (SAIDI) is a measure that determines the length of time the average customer is without electric service during a prescribed period of time. The measurement used is the total minutes of sustained customer interruption durations divided by the total number of customers, and is expressed in minutes per year. The SAIDI figures reported by LDCS do not include Excludable Major Events[30].

Figure 3-4 shows the SAIDI measurements by LDC for 2005. In 2005, Commonwealth Electric Company, Boston Edison Company, and Massachusetts Electric Company had the most increases in sustained outages per customer than 2004 among LDCs, respectively. Massachusetts Electric Company had the most sustained outages per customer and Western Massachusetts Electric Company had the least sustained outages per customer in 2005. The data show that the year 2005 had more minutes of sustained outages per customer per year across most LDCs with the exception of Western Massachusetts Electric Company compared to same data of year 2004.

[30] Excludable Major Events include: 1) natural disaster such as earthquake, fire or storm resulting in state of emergency declaration by the Governor, 2) unplanned interruption to more than 15% customers of the electric LDC's operating area, and 3) events from other system failures not owned or operated by the electric LDC, such as disturbance of a transmission line and power supply.

SAIDI is a system-wide reporting mechanism and does not accurately account for customers in a subarea of an LDC's service territory who have endured more minutes of sustained outages than the reported average minutes of sustained outages. Unfortunately, such data are not publicly available.

Figure 3-4
Electric System Average Interruption Duration Index, SAIDI (Exclude Major Events) 2005



Source: Massachusetts Department of Telecommunications and Energy

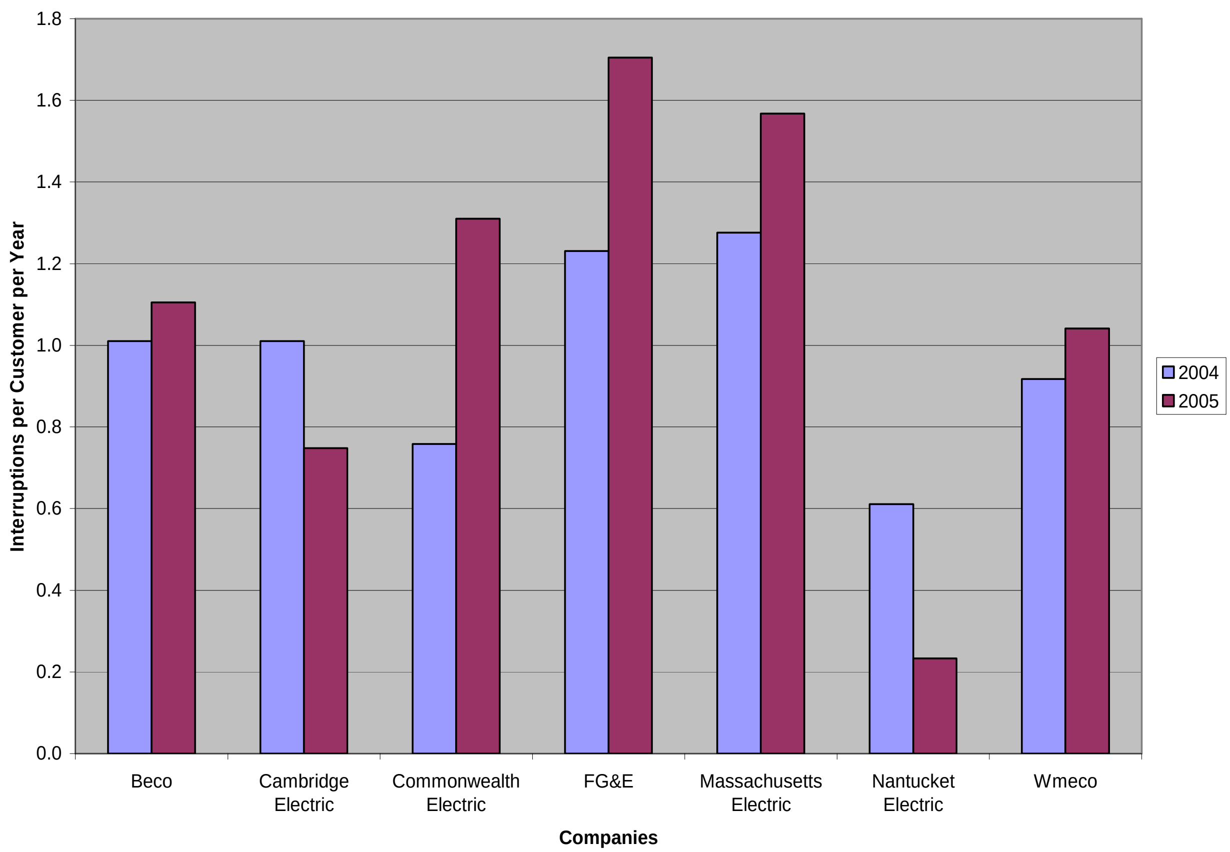
<u>SAIFI</u>

The System Average Interruption Frequency Index (SAIFI) is a measure that determines the number of times (frequency) the average customer experiences a loss of electric service that lasts at least five minutes (sustained outage) and is not classified as a momentary outage. It is measured by the total number of sustained customer interruptions divided by the total number of customers and is expressed in interruptions per customer per year.

Figure 3-5 shows that 2005 SAIFI data having more frequent interruptions than 2004. In 2005, Commonwealth Electric Company, Fitchburg Electric Company and Massachusetts Electric Company had the most increase in frequent interruptions than 2004, respectively. Boston Edison Company and Western Mass Electric Company had modest increases in frequent interruptions while Cambridge Electric Company, and Nantucket Electric Company had shown decreased

frequent interruptions than 2004. Fitchburg Electric Company and Massachusetts Electric Company continue to maintain higher frequent interruptions than 2004.
As previously mentioned, the SAIFI is system-wide reporting in the frequency of interruptions and does not account for specific customers who may have suffered more frequent interruptions than the average frequency of interruptions shown in the figure.

Figure 3-5
Electric System Interruption Frequency Index, SAIFI (Exclude Major Events)
2005



Source: Mass Department of Telecommunications & Energy

One Day In Ten Years Loss of Load Expectation

In the prior section, an LOLE of one day in ten years was examined as a wholesale reliability threshold. We apply this level to reliability levels at the distribution-system level. Table 3-7 shows the multiplication of SAIDI and SAIFI, which corresponds to the average total loss of load in one year. The data show that in 2005, Commonwealth Electric Company, Fitchburg Electric Company, and Massachusetts Electric Company did not meet the one day in ten years reliability standard criterion (more than 144 minutes of interruptions a year) at the distribution level. In the 2005 service period, the LDCs, did not meet, as a group, the one in ten years reliability standard 43% (3/7) of the time, which is much worse than the performance of the wholesale electricity network, as measured by LOLE over the past 3 years. This deterioration in performance may have been due to the extreme peaks that were experienced in 2005.

Table 3-7
One Day In Ten Years Loss of Load Expectation (LOLE)

	SAIFI * SAIDI (minutes per year)		1 in 10 Standard	
	2004	2005	2004	2005
Beco	66	118	Under	Under
Cambridge Electric	50	60	Under	Under
Commonwealth Electric	39	159	Under	Over
FG&E	131	206	Under	Over
Massachusetts Electric	152	276	Over	Over
Nantucket Electric	19	8	Under	Under
Wmeco	112	120	Under	Under

Source: Figures 3-5 and 3-6, DOER

Conclusion

The reliability of the wholesale electric grid remains strong despite record peak demands in the Summer of 2005. However, a more long term view shows that there may be reliability problems as soon as 2010 if additional generation is not built in certain regions of New England and peak load growth continues to grow at historical levels. Reliability concerns were largely responsible for support of additional market mechanisms (described in Chapter 2) that would provide incentives for development of new generation resources. As an alternative, expanded use of demand response may lessen the need for reliance on additional generation as a small percentage of hours feature extremely high peak levels.

Fuel diversity showed little change with continuing reliance on natural gas and a slow rate of penetration of renewable technologies. Use of other fossil fuels and nuclear remained at similar levels to 2002-2004.

Reliability at local levels was not as strong as found at the wholesale level. Distribution system reliability featured outage levels higher than the 1 day in 10 years reliability standard that is routinely at the wholesale level.

Chapter 4 – Markets

Market Overview

Table 4-1 provides an overview of the Massachusetts retail electricity market. We include data from both the local distribution companies (LDCs) and the municipal utility companies, though it is should be noted that customers in municipal service territories are not permitted to shop for electricity and should not be considered as part of the competitive retail electricity market. The data show that there was little change in the number of customers (less than a 1% increase), which is not surprising given the lack of growth in population and week growth in gross state product from 2004 to 2005.[31] Revenues increased significantly, mostly due to increase in prices; warmer weather in 2005 also contributed to higher sales, and thus revenues. Assuming that generation-related revenues are approximately 60% of total revenues, total sales available to retail competitive suppliers were over $3 billion in 2005.

Table 4-1
Composition of Massachusetts Demand, 2005

Distribution Company	Number of Customers (Yearly Average)	Electric Revenue ($ Millions)	Customer Sales (MWh)
Boston Edison	702,551	1,803,001,310	15,598,553
Cambridge Electric	47,327	147,721,667	1,715,388
Commonwealth Electric	364,081	469,573,918	4,367,433
Fitchburg Gas & Electric	27,713	55,633,126	549,168
Massachusetts Electric	1,230,699	2,152,995,659	23,440,210
Nantucket Electric	11,864	17,328,851	143,645
Western Massachusetts Electric	204,134	388,346,562	4,146,863
Total: Distribution Companies	2,588,629	5,038,211,221	49,925,958
Total: Municipal Companies	388,651	827,187,365	7,943,407
TOTAL OF ENTIRE STATE	2,977,280	5,865,398,586	57,869,365

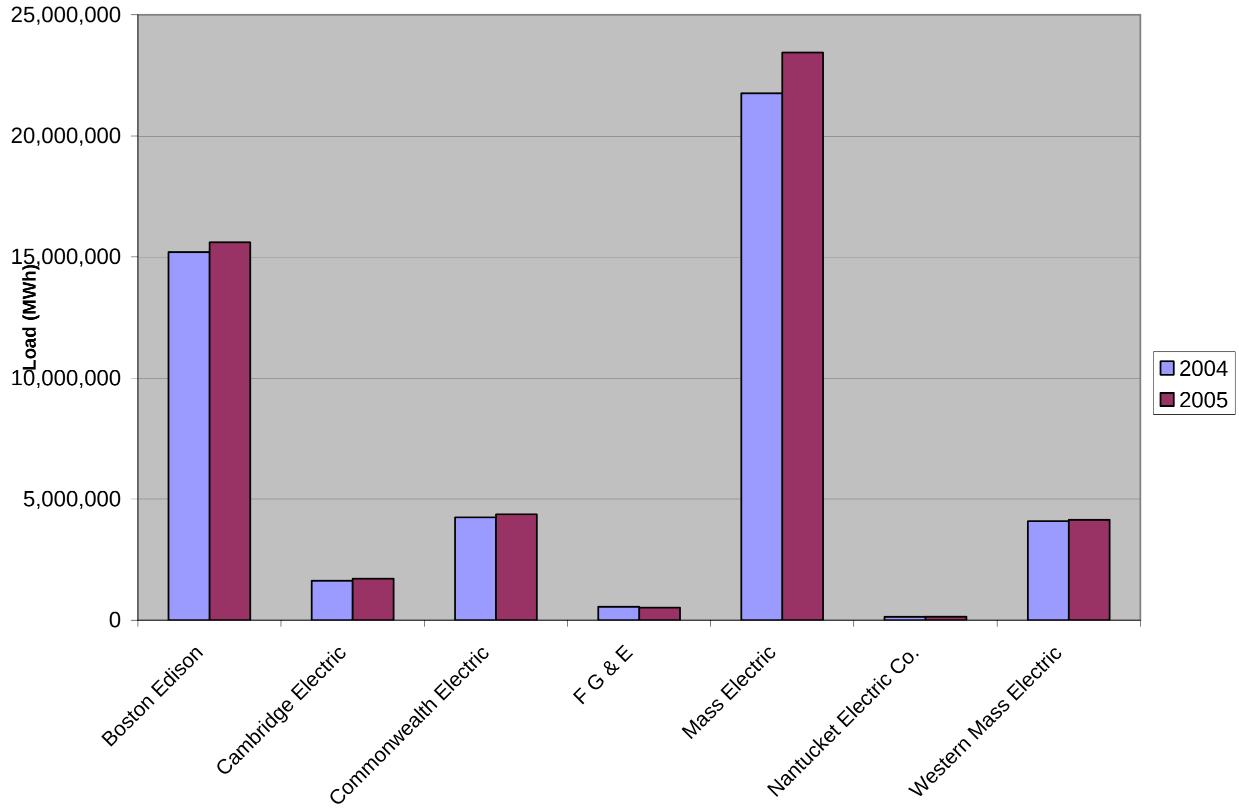
Sources: FERC Form 1, Municipal Reports to DTE, Massachusetts Electric

Electricity Demand Has Increased

As mentioned above, electricity demand, as measured by MWh sales, increased by about 5% in 2005, compared to 2004. Figure 4-1 contains data for the LDCs. Though large swings in demand is weather-dependent, electricity usage, especially during peak periods (see Chapter 3), have increased over time due to growth in the economy and changes in end-uses that use electricity during peak times.

[31] Gross state product increase 1.7% from 2004 to 2005, compared to growth in gross national product of 3.6% (Bureau of Economic Analysis). Population actually decreased during the same time period, according to the Census Bureau.

Figure 4-1
Load (MWh) by Distribution Company, 2004-2005

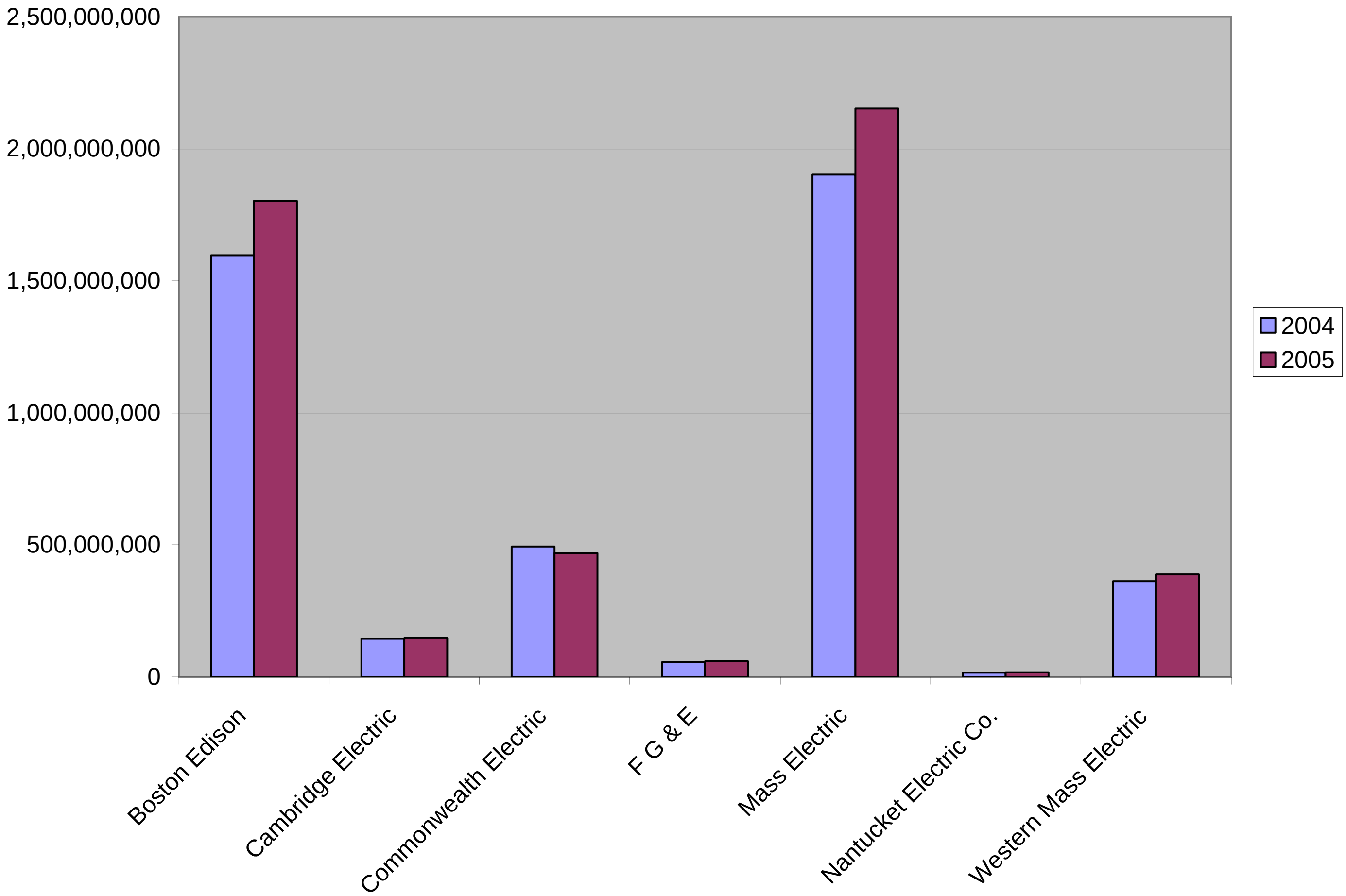


Sources: FERC Form 1, Massachusetts Electric

Revenues Are More Volatile Than Sales

During 2005, the LDCs' revenues were more volatile than sales, but revenues are a function not only of load but of prices--distribution-service prices, which usually consistently grow at about the inflation rate and generation-service prices, which are dependent on fuel prices and are thus more volatile. Given that this volatility is associated with the generation portion of the bill, one would expect competitive suppliers' purchased-energy costs and revenues in MA also to be somewhat volatile. Figure 4-2 shows data from 2005 and 2004.

Figure 4-2
Revenues by Distribution Company, 2004-2005



Sources: FERC Form 1, Massachusetts Electric

End of the Transition Period

The year 2005 was a significant milestone in the transition from a regulated to a competitive electricity market in the Commonwealth. The restructuring Act of 1997 (Chapter 164 of the Acts of 1997) set March 1, 2005 as the end of transition period from a regulated to a competitive electric market. On March 1, Standard Offer Service, an administrative rate designed to ease customers toward competitive service, would no longer be available. All customers not having chosen competitive service would receive Default Service (later renamed Basic Service), a market-based rate procured by the distribution companies through a competitive bid process for customers at market prices at the time of the procurement. Default Service varies by customer class and is procured at different times of the year, depending on the distribution company.

As a result, there was widespread speculation in the period leading up to this date about the likelihood of customers to enroll with competitive suppliers in order to avoid paying the new market-based prices. A large number of customers did not choose to switch to competitive service in April 2005. This may in part be due to differences in default-service rates relative to the market prices as shown by wholesale market indicators (see discussion later on in this chapter). Other possible explanations include (a) most standard offer customers consist of smaller customers that traditionally have not had a lot of offers, and (b) standard offer customers have been less aggressive in their pursuit of offers and are probably most tentative in pursuing competitive supply even after the standard offer period ended, and (c) standard offer prices have been close to default service prices due to fuel-price adjustments, thus there may not have been enough differences in the change from standard offer to a market-based default rate. However, the market did see a major number of customers switch to Competitive Service because of their participation in a public aggregation which picked up all standard offer customers in the service area.

In 2005 Competitive generation service captured more of the total MWh or load and more customers than in 2004. Competitive generation load as a percentage of the total was 32% in 2005 compared to 25% in 2004. The increase in 2005 can be ostensibly attributed to an increase in the number of residential and small commercial customers in the Cape Light Compact public aggregation and a significant number of large customers choosing competitive service. Table 4-2 enumerates in MWH the size of the Utility vs. Competitive Service during 2004-2005. In this section we will look at the MA market in three segments; Residential and Small Commercial and Industrial, Medium Commercial and Industrial, and Large Commercial and Industrial.[32] Each segment had very different activity in 2005 and looking at each separately will allow a better understanding of market activity in 2005. In addition, we will look at some other indicators of market development, and results from a DOER Survey of competitive suppliers and the number of competitive supplier Licenses issued in 2005.

Table 4-2
Utility vs. Competitive Service, MWh
2004-2005

	2004	2005
Utility Service	35,256,628	33,230.919
Competitive Service	11,978,495	15,319,409
Total	47,235,123	48,550,409

Source: DOER Migration Data

[32] DOER designates customer groups by aggregating rate class data as follows: small commercial and industrial (C&I) includes rate classes with average monthly usage levels below or equal to 3,000 kWh/month; medium C&I includes rate classes with average monthly levels greater than 3,000 kWh/month but less than or equal to 120,000 kWh/month; large C&I includes rate classes with average monthly usage levels greater than 120,000 kWh/month. Data in Table 4-2 differs with table 4-1 due to disparate data sources and reporting frequencies.

Competitive Market Migration Analysis

Figures 4-3 and 4-4 contain monthly migration data by load and number of customers, respectively. Load percentages are higher than customer percentages for each group because customers who elect competitive options are, in general, much larger, on average, than those customers that stay on default (or basic) service. We refer to these figures in the text below.

<u>Residential and Small Commercial and Industrial Customers</u>

April 2005 Rise in Competitive Customers and Load – Cape Light Compact

Residential and Small Commercial and Industrial customers are often considered together and viewed as a distinct market. This is because customers in these sectors have relatively low consumption and competitive suppliers need to have sophisticated information systems to enroll and service large numbers of these customers.

The percentage of customers and load in the residential and small commercial and industrial sectors on competitive service increased in 2005. In the 2004 report we highlighted as the major event in residential and small commercial segment when in May 2002 Cape Light Compact (CLC), a regional aggregation of 21 towns in Barnstable County, initiated a pilot program to provide competitive generation service to all the customers in the area. Cape Light Compact arranged supply for all 41,000 default service customers, with a substantial majority of which were residential and small commercial customers. In addition, the number of Cape Light Compact customers increased throughout the remainder of 2003 and 2004, to approximately 53,000 customers in December 2004.

In 2005, Cape Light Compact was again responsible for the larges increase in the number of competitive service customers. On March 1, 2005 at the end of standard offer service, all customers living in the CLC region who had not selected a competitive supplier became CLC customers. This was approximately 140,000 customers, mainly residential and small commercial and industrial. Figures 4-3 and 4-4 show the change occurring in April 2005 when the bulk of the customers, approximately 120,000, were transferred to CLC service, and then again in May when another 20,000 other customers were transferred. Competitive generation load in the Commonwealth Electric Company service territory increased from 77 million kWh in January to over 181 million kWh in April. This is by far the single largest event in customer movement to the competitive market in 2005 and during deregulation (in terms of load).

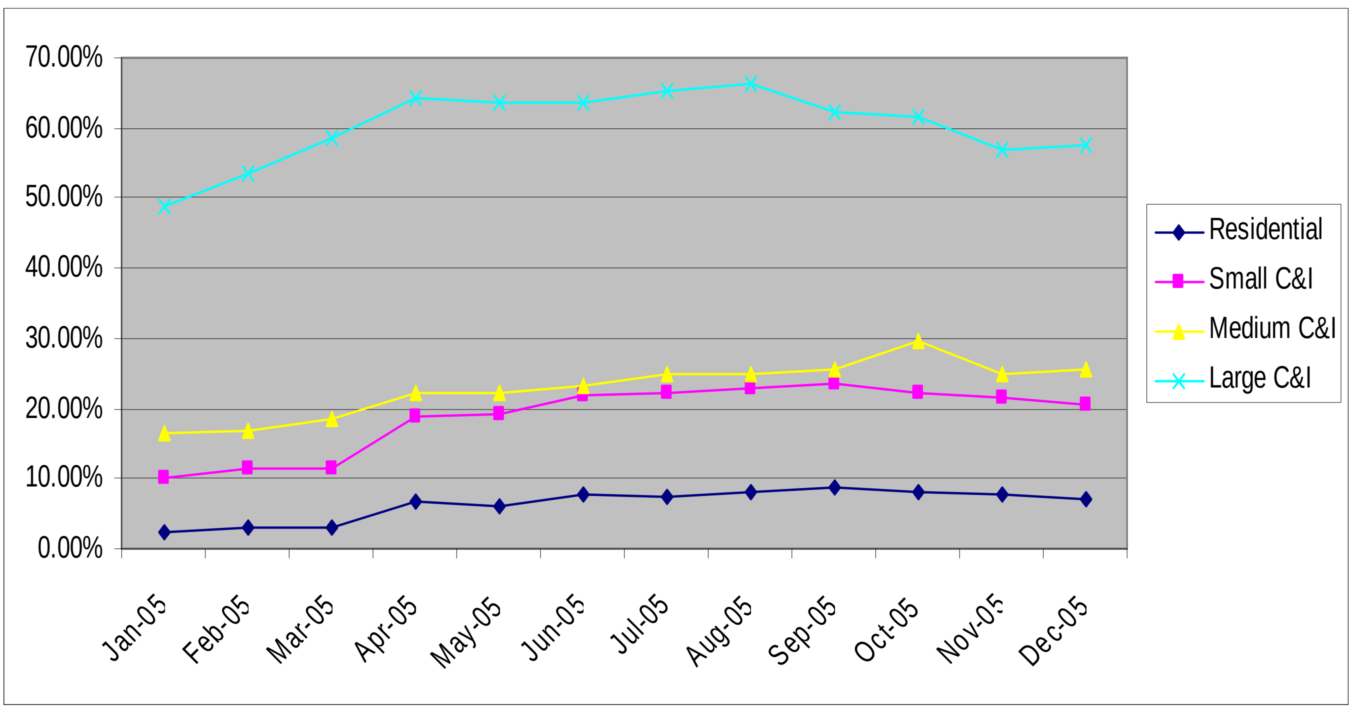
Statewide competitive service for the residential market opened the year at 2.88%, rose to 6.77% in March, peaked in April at 8.90 % in September and closed the year at 7.18%. This is an annual increase of 150%. Small commercial and industrial customers also followed this trajectory in competitive service load, staring the year at 10.17% in January, climbing to 18.82% in April, and peaking at 23.64% in September. Small C&I competitive service closed the year at 13.31% of the customers 20.51% of the load, a doubling of the competitive load in 2005.

Other notable events in this segment were offers in June and July from Dominion Retail Marketing at a price of 7.9 cents until December 31, 2005 and in October an offer from Mx

Energy to “set your own price.” This was a system where a customer would contact the supplier and name a price they would switch at and then if and when the supply could be delivered at that price, service would begin. Though not at the scale of the CLC market event, these events are important because of the scant offerings that have been available to this customer over the past few years.

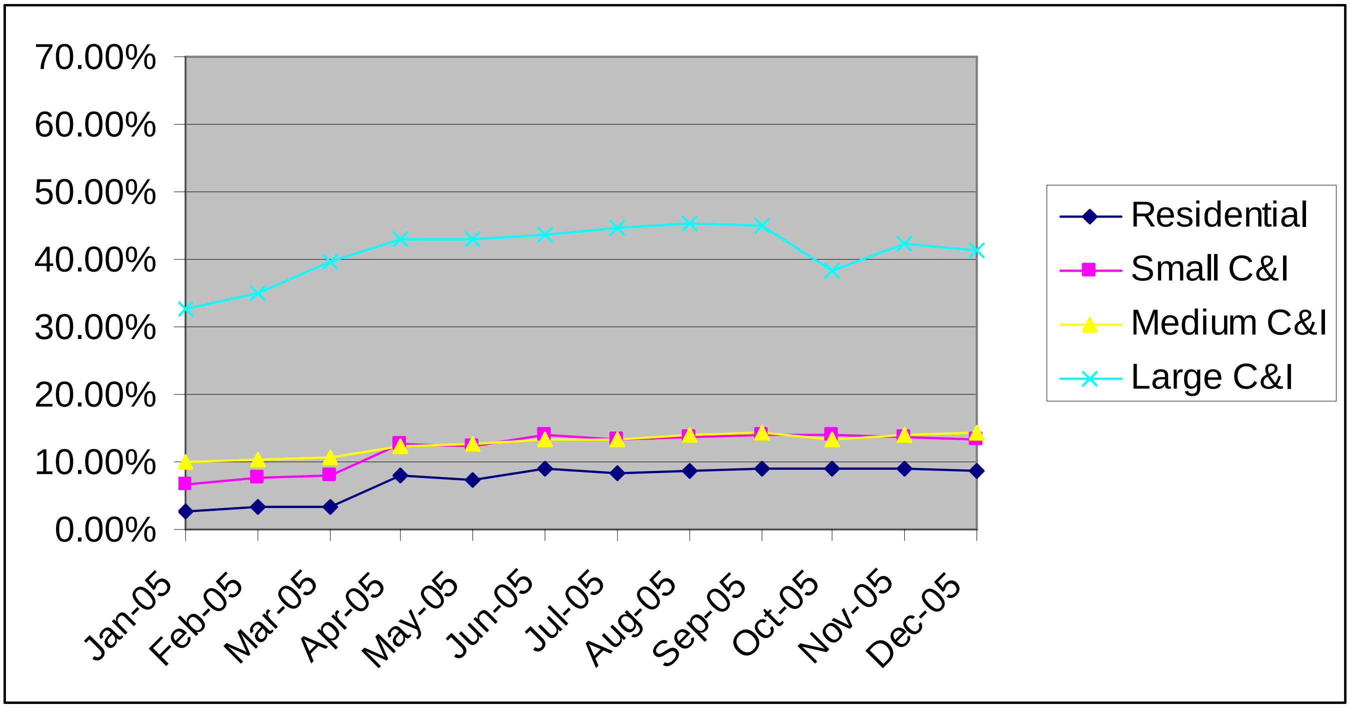
In 2005 suppliers offered a few products to the mass market of residential and small commercial and industrial customers, however there was one marketing campaign aimed at acquiring 500 or more customers. In June, Dominion Retail offered a fixed price product extending to December 2007 at 7.9 cents per kWh to a select customer set of 340,000 in the Massachusetts Electric Company service area. Customers served by Massachusetts Electric Basic Service were at that time paying 7.213 cents/kWh through November 1, 2005. The offer would provide price stability and not savings when compared to the current Basic Service rate. Customers weighed the certainty of a fixed 30 month fixed price, at rates higher than they were currently paying, versus the prospect they could be unprotected if prices climb higher this year and next. Dominion closed the offer at the end of July. MX Energy offered a 12 –month rate of 7.1 cents/kWh to 500 customers in the Attleboro area. MX cited the desire of customers to be protected from high prices as the value of the offer.

Figure 4-3
Competitive Market Load (% of Total Load in each Customer Group), 2005



Source: LDCs, DOER

Figure 4-4
Competitive Market Customers (% of Total Customers in Each Customer Group), 2005



Source: LDCs, DOER

<u>Medium Commercial and Industrial Customers</u>

The Medium Commercial and Industrial customers can be characterized as having attractive-to-adequate load size to support one-at-a- time customer acquisition by suppliers, but, as a group, have less accurate load information than larger customers. This lack of interval data makes it more difficult for suppliers to accurately price supply to meet customer load and also lowers a supplier's margins. Medium sized customers are generally seen as a group suppliers target after large commercial and industrial.

The competitive market for medium commercial and industrial customers enjoyed a degree of success in 2005. In January 16% of load was on competitive service, rising to 22% in April, peaking at 29% in October, and closing the year at 25%. The January-to-December 2005 rise from 16% to 25%, or plus 9% is an over 50% increase. The October peak is particular to this market segment and may be attributed to a difference between the price obtained in the distribution company procurement method and the all in market price at a specific time.

Competitive Service Medium C&I customers rose from 10% in January to 14.5 % in December, a 40% increase. The higher percentage of load 25% than customers 14% is also an indication that customers with larger than the average load for the group are migrating to competitive service..

Large Commercial and Industrial Customers

These Customers Had Most Success in Migration

The Large Commercial and Industrial Customers are viewed as the ideal customers for competitive suppliers. These customers purchase large amounts of electricity and have sophisticated metering information that allows suppliers to more accurately match electric supply to a customer's needs. Understandably, this customer class showed the most success in migration of customers and load to competitive service.

In 2005 the Large Commercial and Industrial customers continued to lead all other customer segments in the percentage of customers and load on competitive service. In January the percentage of large C&I customers on competitive service was 32.6% and closed the year in December at 41.4%, a gain of almost 9% or an increase of 27%. Large C&I load was 48.8% of this customer group in January and closed the year at 57.5%, a plus of 9% or an 18% increase.

Customers in this segment had offers from many suppliers. By far the largest number of licensed suppliers and brokers are active in the large commercial and industrial segment.

DOER Supplier Survey

In 2005 DOER conducted a semi-annual survey of competitive suppliers to learn about the products and service offered to customers and to identify issues suppliers see as barriers to market development. Participation was voluntary and results are seen as providing anecdotal information on market activity in the period.

In the residential and small commercial and industrial segment there were few products available. When products were offered they were available a period and then closed. Often times there were no products being actively marketed to customers. Only Dominion and MX Energy were notable in this segment.

In the medium and large commercial and industrial customer segment suppliers estimated savings to customers at 5% or less. Suppliers offered somewhat longer term product later in the year, product terms ranged between 12 and 48 months in the first half of the year, and extended to 12 to 120 months in the second half of the year. Several suppliers also chose not to be active in the Western Massachusetts Electric Company and Fitchburg Gas & Electric service areas.

When asked to comment on barriers to market participation, suppliers offered a variety of issues that they see as inhibiting the development of the competitive market. Suppliers cited the uncertainty about wholesale market rules and uplift costs as a barrier to product development. Utility procurements and the application of the Default Service Adjustment mechanism[33], which posed a problem for suppliers seeking to compete against an all in cost service at the utility. The purchase of supplier receivables by the distribution companies, as is the practice in other states was cited as a necessary change for mass market development. Finally, many suppliers sited the

[33] This mechanism allocates some default-serve related costs to all customers, instead of only default-service customers, thereby potentially lowering the utility default-service price relative to competitive offers.

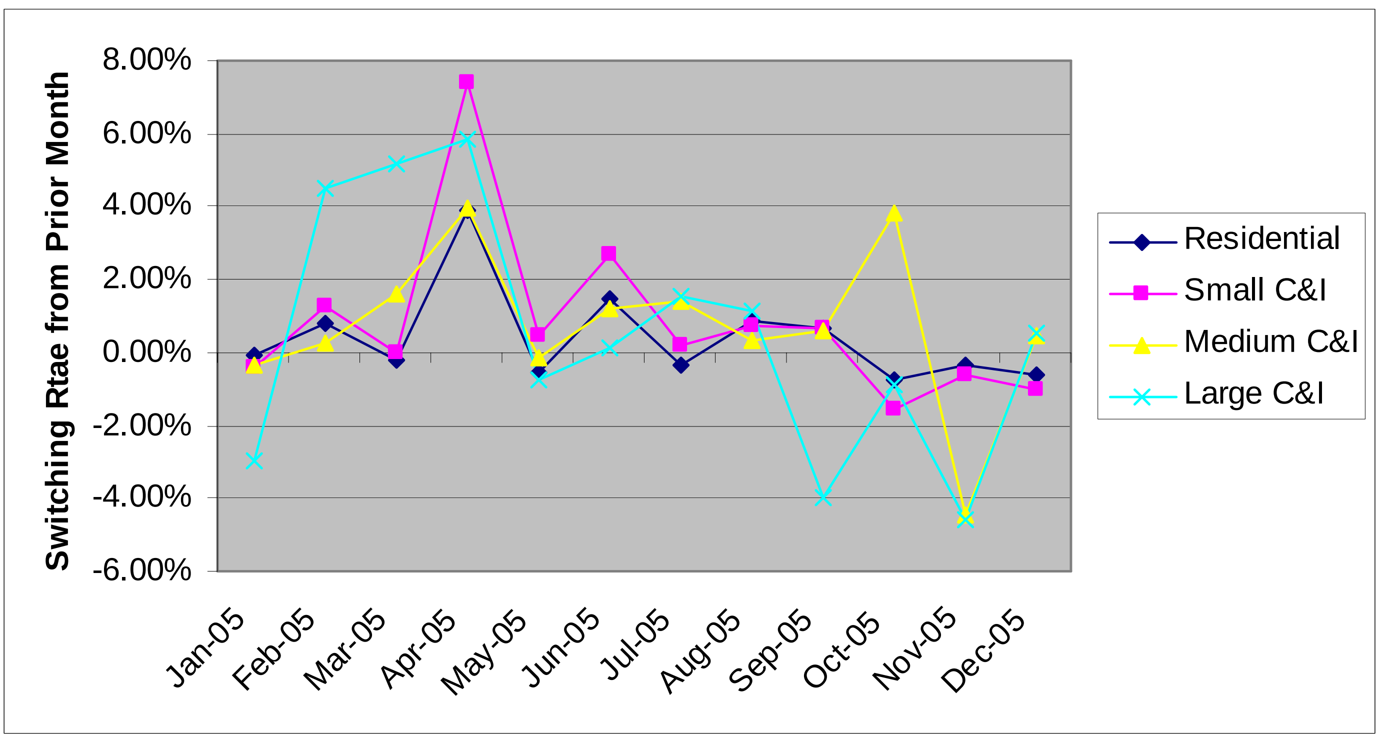
difficulty in obtaining interval data both for pricing product offers and billing as an impediment to customer acquisition and service.

Monthly Switching and Return Rates

The activity in a competitive market can be tracked through looking at Figure 4-5 which illustrates the rate of change in the customer load on a monthly basis in 2005 for all customer classes. Positive numbers indicate an increase in the percent of load on competitive service from the previous month and negative numbers indicate a drop in the percent of load on competitive service from the previous month. The April transfer of the 140,000 Cape Light Compact customers is responsible for the April spike. April showed a plus 4% climb in residential and medium segments and a 7.4% jump in small commercial and industrial. Large customers registered high positive switching rates in February, March and April and negative switching rates in September though November.

Medium customers switching rates generally track the large customers throughout the period, exhibiting less dramatic swings in the rate but simultaneous increases and decreases. All customer groups show a negative switching rate from October through December 2005. This may be attributed to regulatory uncertainty surrounding the spread between the basic service rate and the market price for the three month period and end of the year contracting.

Figure 4-5
Monthly Switching Rates, 2005



Source: LDCs, DOER

Disconnect Between Basic Service Procurements and Market Prices

The fact that there is little relationship between the market price at a particular time and the basic service rates is not helpful for stability and in competitive markets. This is almost entirely a function of the utility procurement method. For example, when NStar Electric buys power for Boston Edison Company, Commonwealth Electric Company, and Cambridge Electric Company they do so by means of an April Request for Proposals, seeking power to serve (1) 50 percent of the Default Service load for residential and small commercial customer groups of each company for the period July1, 2005 through June 30, 2005; and (2) 100 percent of the Default Service load for customers in the industrial customer groups of each distribution company for the period July1, 2005 through September 30, 2005. At the end of April bids are evaluated and prices approved by DTE and go into effect from July 1, 2005 to December 30, 2005. Should a major market event, such as a hurricane or other supply disruption occur and market prices increase dramatically, these new prices will create a gap between the default service price and the market. Default Service rates will be "out of market".

Out of market default service prices cause informed customers to reevaluate their positions and to maximize their savings by either opting to stay with or renew a competitive supply agreement, or revert to Default Service where they can get the July price through December 2005 which is not sensitive to market events.

As a result, the residential and small commercial segment is disconnected from the actual market price at a particular time. This is clear because the switch rate for these customers does not go up or down in periods of high or low prices. In addition, there are almost no products available for these customers.

In the Medium and Large C&I segment this is also true. Looking at the switching rate for these customers it is primarily the periods of major disconnect, when the two options, either competitive service at the market price, or default service at the price obtained in a months prior procurement are most likely to be disconnected that influences the switching rate.

In December 2005 this feature of the relationship between the three month procurement and the market price in the service period is acknowledged by the NStar DTE filing regarding gaming in this customer class. The assumption in the petition is that there are periods when the default service rate will be so independent of the current market that customers will elect to switch back and forth to maximize savings.

Finally, customer migration at the end of 2005 exhibited this disconnect after the impacts of Hurricanes Katrina and Rita on gas infrastructure caused natural gas prices, a prime driver of electricity prices, to rise sharply. During late fall of 2005, electricity prices in wholesale markets rose by almost 35% ($80/MWh in July to $120/MWh in October). At that time, the weighted average Default Service Price was $76.46/MWh. A customer with the opportunity to return to default service in October could save a third of their bill. In November the Weighted Average Default Service Price was $89.62/MWh and the All In Price was $81.58/MWh. The Large C&I customer switching rate reflects this "out of market" then "in market pricing. Large C&I default service prices are closes to market prices, on average, because they change every 3 months. We will return to this topic in the 2006 PRM report, as default service prices finally caught up with market prices in early 2006.

Licensed Competitive Brokers and Suppliers

The Massachusetts Department of Telecommunications and Energy issues licenses to Competitive Suppliers and Electricity Brokers. Licensed Competitive Suppliers take title to electric power and are a required intermediary in a retail power transaction. Brokers are also licensed by the Commonwealth but do not take title to power. Brokers often work with one or more suppliers to offer customer service to customers prior to contracting with a supplier for competitive service. In addition, the MA DTE licensing procedure requires suppliers to state the customer group(s) to whom they plan to offer power. As a result, it is possible to infer from the entrance of suppliers seeking to offer power to a specific customer group(s) the vitality of specific markets. The number of retail suppliers and brokers is an indication of a vibrant or competitive market. Many entrants into a market are an indication that opportunity exists to make money and future prospects look good. The exit or loss of suppliers and brokers would indicate a still or receding market.

Table 4-3 looks at the entrance of licensed suppliers into the Massachusetts market by customer group. It presents the change in supplier licenses issued by DTE in 2005. In 2005, of the 14 electricity brokers licensed, 1 indicated the intention to work in the residential market, 11 brokers chose the commercial market, and 10 the industrial market.

Six competitive suppliers entered the Massachusetts market in 2005. Three were interested in the residential market, while 6 stated a preference for commercial and 5 for industrial. It is interesting to note that the number of suppliers stating a preference for the residential market is much smaller than the other sectors.

Table 4-3
Issued Licenses by Type Broker and Supplier and by Sector Served
2005

	Total Licenses Issued	For Residential	For Commercial	For Industrial
Broker	14	1	11	10
Supplier Licenses	6	3	6	5
Total	20	4	17	15

Source: MA DTE

Competitive Suppliers' Market Share

The top 3 competitive market suppliers held 84.1% market share in 2004. This market share declined to 64.6% in 2005. In addition, 15 suppliers recorded activity in wholesale market accounts. Table 4-4 shows 2005 market share data illustrating the concentration of the largest players in the market. The data show decreased concentration of market share among the 3 largest suppliers and active participation by a greater number of suppliers. DOER will continue to track market share in future PRM reports.

Table 4-4
Market Share of Suppliers

	2004	2005
Top 3 Suppliers	84.1%	64.6%
Remaining Suppliers	15.9%	35.4%
Total # of Suppliers	9	15

Source: NEPOOL GIS, DOER

Conclusion

During 2005 the progress of the competitive retail market was very different in each of the three market segments. The market for large commercial and industrial customers was very competitive with three or more competitive offerings available a majority of the time, These customers displayed considerable market savvy by returning to regulated service when confronted with uncertainty or risk associated with Hurricane Katrina in November. Residential and small commercial and industrial customers did not often have competitive service available to them and showed limited progress in market development. The one exception was the CLC aggregation, which enrolled a large number of residential customers. Perhaps the most difficult to gauge market segment remains the medium commercial and industrial customers for whom some progress was made but no clear pattern has emerged.

A disconnect between wholesale market prices and the basic service rates obtained through period and layered procurements undermines the operation of a retail market where price directly influences customer behavior. This disconnect became pronounced during the second half of 2005. As a results, switching is spasmodic and occurs more pronounced in brief periods in which the gap between market price and the price of utility-procured power is the widest.

The interest of competitive suppliers entering the MA market remains almost exclusively limited to large commercial and industrial customers with little interest in the mass market or residential and small commercial and industrial customers. The DOER survey of the retail competitive suppliers to monitor the market and identify issues or barriers to market development revealed a host of barriers still inhibit the development of a competitive market for smaller customers..

Finally, though there was entry of potential providers of competitive supply in 2005, market share data show a reduced concentration among 3 major suppliers and several new entrants, implying that there is interest in the MA market.