Commonwealth of Massachusetts

Electricity
Price, Reliability, and Markets Report
2002-2004

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

Spring 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

A new era for energy policy in the Commonwealth commenced with the passage of the Electric Utility Restructuring Act (Chapter 164 of the Acts and Resolves of 1997) ("the Act"). The Act had a number of laudable goals: reduce electricity prices, provide retail customers with a choice of power suppliers, maintain the reliability of the electric system, and improve distribution performance, among others.

This report examines the final years—2002, 2003, and 2004—in the Standard Offer period in terms of progress made to meet the price, reliability, and market-development goals set out in the Act. In addition, it revisits past market monitoring efforts and recasts them in terms of a more streamlined, directed analysis of important events and data.

Prices

Wholesale electricity markets underwent significant changes during the 2002 to 2004 timeframe. The energy marketplace was restructured from a single zone, single settlement system to a multi-zone, multi-settlement system similar to New York and the Mid-Atlantic markets. Electricity prices increased drastically due to fuel price increases from 2002 to 2004, not market restructuring, particularly increases in natural gas prices which fires a large percentage of new power plants in New England and other parts of the country.

Market participants encountered limited opportunities to employ demand response resources due to low peak-to-off-peak energy price ratios during 2002-2004, but efforts continue to increase demand response penetration at the wholesale level. The energy component continued to account for the vast majority of the all-in wholesale costs and is expected to continue that way in the near future. Capacity market costs dropped over the three years due to the capacity over-supply in the region: however, they should pick up as reserve margins begin to decrease due to little capacity addition, load growth and regulatory commitments to implement pricing structures to maintain resource adequacy.

Transmission costs remained relatively stable, increasing only slightly, over the study period, while transition costs will continue for several more years until the utility "stranded cost" balance is eliminated.

Despite the public claims and perceptions that restructuring efforts have not resulted in savings, a comparison of retail electric prices and expenditures in the periods immediately prior to and after the start of retail access do show savings. This conclusion holds even if potential inflation in prices since 1997 are not accounted for, a scenario that is highly unlikely given historical trends and the lack of indigenous energy resources in or close to the Massachusetts and New England markets.

Restructuring, however, remains a work in progress. Trends in the post-restructuring period clearly show an upward trend in prices. If this trend continues, savings that have been earned to date may begin to erode dependent on the rate of growth in electricity prices. However, it is important to note that while prices increased by about 18% for all consumer goods during the

1998-2004 period according to the CPI,[1] the increase in electricity prices during that time was about 13%. If such a trend is sustained, consumers will continue to enjoy savings in real dollars.

Reliability

ISO-NE has maintained short term system reliability adequately over the 2002-2004 period. Installed capacity reserve margins are acceptable but have dropped from highs in 2002 due to little new capacity development and load growth exceeding ISO-NE projections. The region's reliance on natural gas continues to be a concern and potentially jeopardizes the reliability of the electricity system. Increasing or maintaining the region's use of nuclear, coal and renewable-fueled power plants should be a priority for the regional authorities. Until a greater share of more stable fuels can penetrate the New England market, ISO-NE operating procedures and market rules have been established to minimize risk of over-reliance on gas-fired power plants during peak winter heating season when the gas pipeline delivery system in the Northeast is heavily used to deliver gas for space heating.

The region's long term supply of electricity generation appears adequate to meet even peak demands through 2010, but at this time the "loss of load" (LOLE) expectation begins to creep higher and risks increase of violating the acceptable LOLE reliability standard. Supply adequacy could, however, become compromised much sooner in the event of earlier-than-expected plant retirements, unexpected long-term plant outages (e.g. of nuclear plants) or significant delays in the construction of anticipated transmission lines.

In terms of the electric distribution system, reliability data showed successive performance improvements in the service territories from year 2002 to year 2004. These performance improvements could be attributable to better weather conditions (i.e. the demand for heating and cooling energy was normal or below normal), application of better technology, and/or increased financial incentives to avoid possible financial penalties for poor performance). It is also possible that more transparent performance data produced more attention to the quality of service to consumers on the part of distribution company management.

Finally, data show that despite the statistical improvement in reliability , there is still incidence of higher—and unacceptable levels based on wholesale-system criteria—loss of load expectation in the reliability of the retail-level distribution system compared to the wholesale electric grid. This difference in reliability levels may require a shift in policy emphasis or attention to reliability problems at local, rather than region-wide, levels.

Markets

During the period 2002-2004 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 the institution of Standard Market Design in April 2003. Residential and small commercial and industrial customers did not often have

[1] The index in 2004 was 200.2 compared to the 1998 value of 170.0.

competitive service available to them and showed limited progress in market development. The one exception was the Cape Light Compact aggregation, which enrolled a large number of residential customers with a single competitive supplier. Perhaps the most difficult to gauge market segment was the medium commercial and industrial customers who demonstrated some movement to the use of competitive suppliers but for whom no clear pattern has emerged.

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. DOER will conduct periodic survey of the retail competitive suppliers to monitor the market and identify issues or barriers to market development.

Finally, though there was significant entry of potential providers of competitive supply in 2005, market share data show high concentration among 3 major suppliers, implying an interest in providing competitive supplies to Massachusetts consumers on the part of more companies than are actually able or willing to do so.

Chapter 1—Introduction

A new era for energy policy in the Commonwealth commenced with the passage of the Electric Utility Restructuring Act (Chapter 164 of the Acts and Resolves of 1997) ("the Act").[2] The Act had a number of laudable goals: reduce electricity prices, provide retail customers with a choice of power suppliers, maintain the reliability of the electric system, and improve distribution performance, among others. A key provision of the Act was to provide an orderly transition for customers. Distribution companies were required to provide Standard Offer generation service to all customers who were receiving service as of March 1, 1998 and who had not chosen a competitive power supplier. This service was provided at a fixed price that increased annually until March 2005 when the Standard Offer ended.

In order to monitor the progress of electric industry restructuring and customer movement to competitive suppliers, the Act required the Division of Energy Resources (DOER) to make periodic reports to the Legislature (M.G.L. c. 25A §§ 7, 11D, 11E). Since inception of electric restructuring, DOER has written comprehensive reports ("Market Monitors") in which DOER presented major findings on electricity prices and price disparities, competitive market developments, and electric system reliability. DOER also made recommendations for policy, legislative, and regulatory changes.[3]

In addition to these reports, in November of 2003, DOER sponsored an assessment[4] of the restructuring experience in Massachusetts compared to other jurisdictions to help inform the development of policies and actions for the post-Standard Offer period.

Purpose of Report

This report examines the final years—2002, 2003, and 2004—in the Standard Offer period in terms of progress made to meet the price, reliability, and market-development goals set out in the Act. In addition, it revisits past market monitoring efforts and recasts them in terms of a more streamlined, directed analysis of important events and data.

Report Outline

The Restructuring Act actually 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 the 2002-2004 period. First provided is an overview of Massachusetts' retail prices compared to regional and national prices.

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[2] Signed into law on November 25, 1997.
[3] These documents can be found at the following address: http://www.mass.gov/doer/pub_info/pub_info.htm#ed for the years 1998, 1999, 2000 and a summary pamphlet for 2001.
[4] "Massachusetts Electric Restructuring: Beyond the Standard Offer," November 14, 2003.

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[5]. 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 a discussion 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.

Chapter 4 provides a review of the development of the retail market during this time period. Wholesale market developments are only sparsely discussed (compared to the 1998-2000 Market Monitors) because (a) as with wholesale prices, the regional grid operator, ISO-NE, provides extensive analyses and discussions of wholesale market events and (b) state policy and intervention has limited impact on regional, wholesale electricity market development. Rather, most of the chapter discusses changes in the retail markets and the success with retail access, a major creation of the Act.

As discussed above, this report is intended to provide in-depth analyses of the period 2002-2004. Where possible, the report offers a comparison of the data during this period to data for 1997, the year prior to passage of the Act, thereby enabling conclusions regarding progress towards achieving the goals set out in the Act.

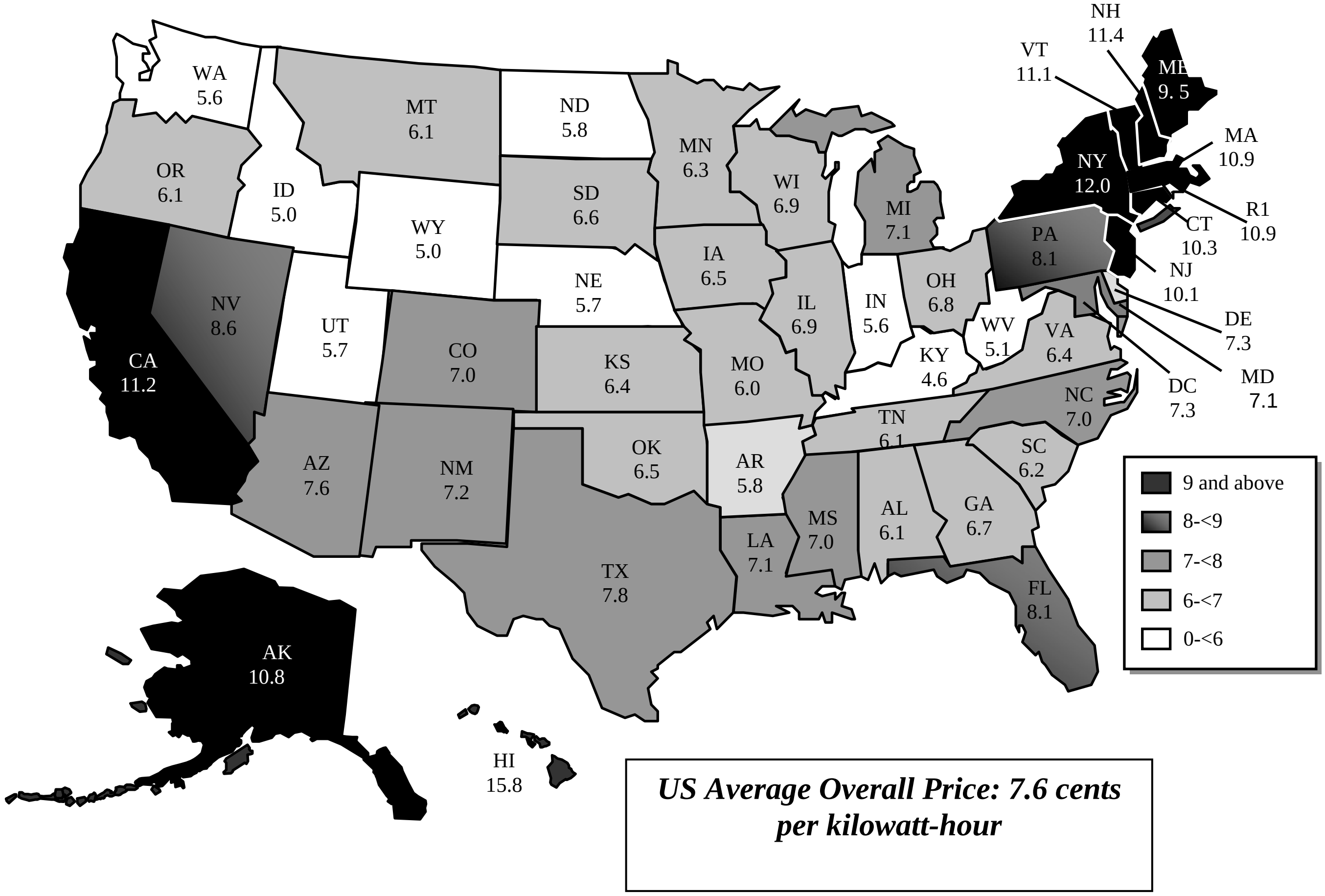
[5] For example, see the 2004, Q3 Quarterly Report, ISO-NE. http://www.iso-ne.com/smd/market_analysis_and_reports/quarterly_reports/

Chapter 2—Prices

Electricity Price Overview

Prior to implementation of the Electric Restructuring Act in 1998, Massachusetts historically had some of the highest electricity prices in the nation. In 1997, Massachusetts had the fifth highest average retail electricity price,[6] in the country at 10.5 cents per kilowatt-hour. The national average was 6.85 cents per kilowatt-hour.[7] Indeed a major impetus behind passage of the Act was the high electricity price paid by consumers and businesses in the Commonwealth. Figure 2-1 below shows the 2004 retail prices by state compared to the national average.

Figure 2-1
Retail Prices for 2004



Source: EIA

[6] Unless otherwise noted electricity prices are defined as the average price paid per kWh of electricity. It is determined by dividing the total revenue received by the total amount of electricity sold and reported in cents/kWh. Individual customer's prices may differ substantially from the average.
[7] U.S. Department of Energy (DOE), Energy Information Administration (EIA), "Electric Power Monthly March 1999," Table 55, p.67.

Massachusetts Retail Electricity Prices About the Same As Those in 1997.

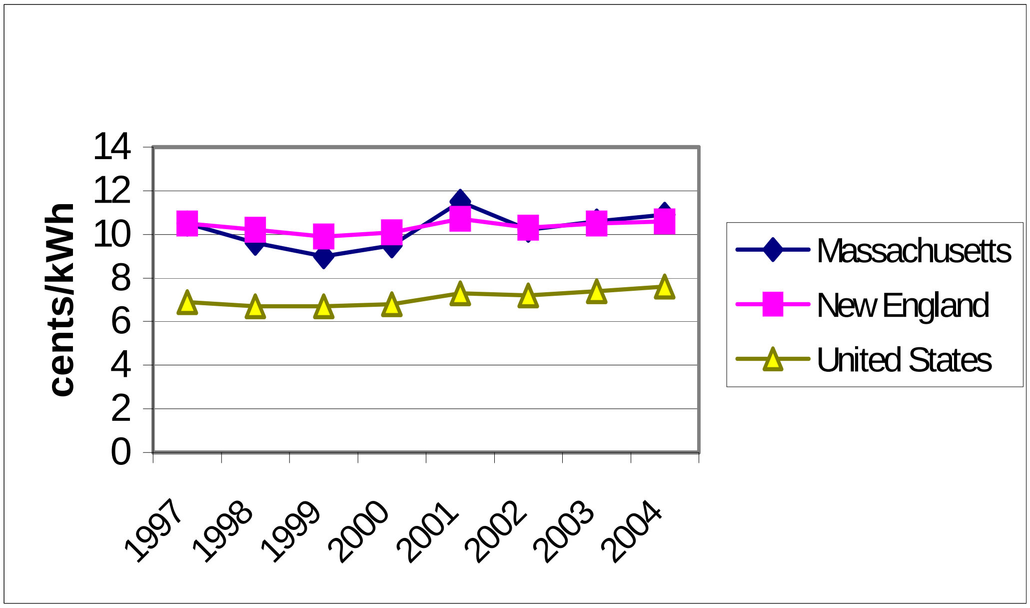
In 1998 and 1999, the first and second year of the implementation of the Act, Massachusetts' retail electricity prices fell from 10.5 cents per kilowatt-hour to 9.6 and 9.0 cents per kilowatt-hour, respectively, largely due to legislatively-mandated rate reductions. Prices started to climb again in 2000, but remained relatively steady, with only a 7% increase, in the period 2002-2004. In 2004, prices were almost the same level (in nominal dollars) as those prior to electric restructuring, 7 years ago. On the other hand, average retail prices in the U.S, although lower than those in Massachusetts, have increased 10% in the last several years. 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

	1997	1998	1999	2000	2001	2002	2003	2004
Massachusetts	10.5	9.6	9.0	9.5	11.5	10.2	10.6	10.9
New England	10.5	10.2	9.9	10.1	10.7	10.3	10.5	10.6
United States	6.9	6.7	6.7	6.8	7.3	7.2	7.4	7.6

Source: EIA Electric Power Annuals

Figure 2-2
Historical Retail Electrical Prices for all Customers (1997-2004)



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 2002-2004, FERC ordered ISO-NE to implement major structural changes, commonly referred to Standard Market Design (SMD), to the wholesale market design.[8] An interim market, commonly referred to as pre-Standard Market Design (SMD), with some rule changes existed from 1999 to February 2003.

Starting on March 1, 2003, ISO-NE began to administer a revised market with substantial changes known as SMD. One reason for the changes was that many of New England's market modifications were already being executed in other wholesale control areas like the PJM market. The basic difference with prior market structures was that the pre-SMD market consisted of one zone (New England) with a single settlement clearing price market. The SMD market consists of eight zones throughout New England and a new Locational Marginal Pricing (LMP) based market that clears twice, in the day-ahead and real-time markets. The bid price of the marginal unit in New England basically determined the pre-SMD Energy Clearing Price (ECP) and the marginal unit in the zones sets the post-SMD Locational Marginal Prices (LMPs).

Given the market changes and other market influences during 2000-2004, 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 Natural Gas Price Increases.

During 2002-2004, New England's on-peak[9] electric energy prices have trended upwards and spiked three times in - August 2002, February 2003, and January 2004. This upward price trend

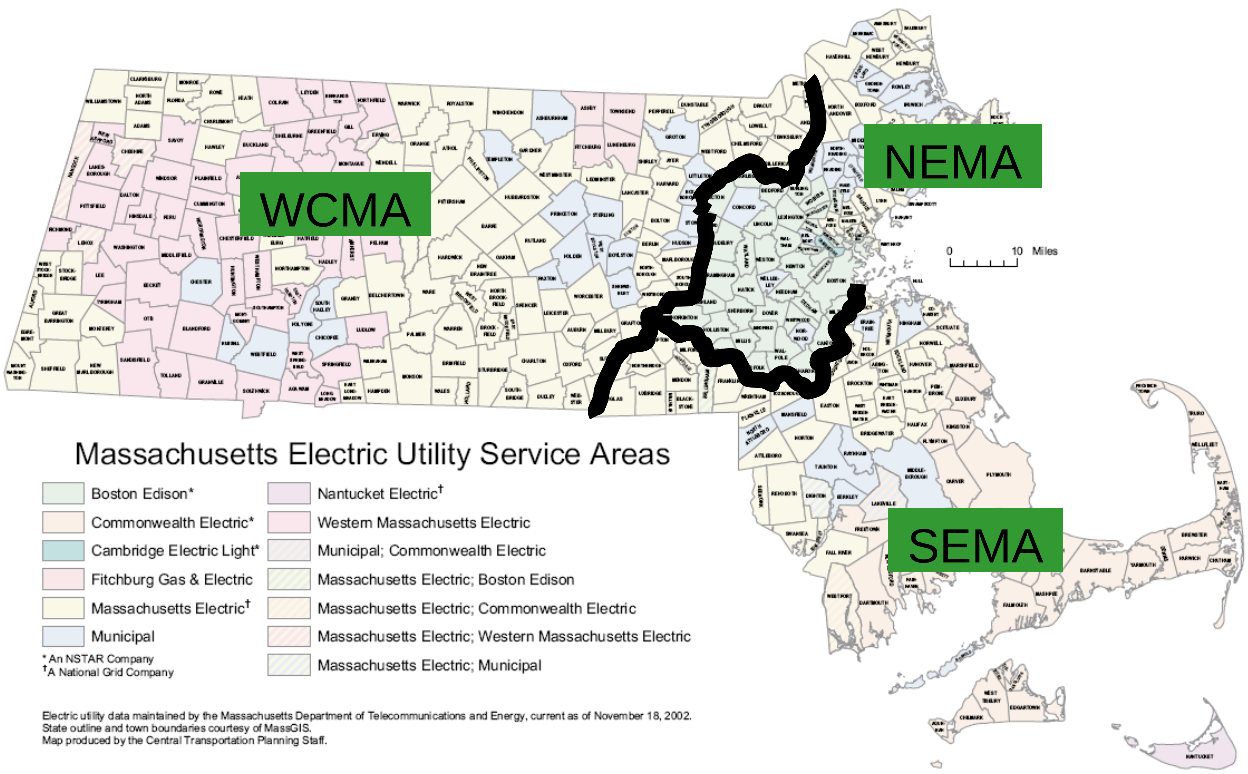
[8] See ISO-NE website for the history of SMD Orders.

[9] On-Peak vs. Off-Peak definition: Bilateral contracts cover the hours between 7:00 a.m. and 11:00 p.m. on non-holiday weekdays as on-peak hours 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.

is largely attributed to an increase in the price of fuel, most notably natural gas, used to generate electricity.[10] During this study's time period, natural gas-fired or natural gas-capable plants operated "on the margin" (the marginal unit generally set the energy clearing price levels or LMPs) during 81%[11] of all hours.

The new SMD structure, implemented in March 2003 is depicted below in Figure 2-3. The new regime divided the Massachusetts' electric market into three zones: Boston/Northeastern MA region (NEMA), Southeastern MA (SEMA) and Western/Central MA (WCMA).

Figure 2-3
Massachusetts Wholesale Electricity Pricing Zones
(effective March 2003)



Source: MA DG Collaborative Discussion Document, Sept. 9th, 2005, Eight Opportunities Analysis Approach_090205.ppt

[10] Henry Hub natural gas prices rose 75% from 2002 to 2004. 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 80% over the study period. See Appendix table A-1 for further price details for the three major New England pipeline supplies.
[11] ISO- NE Annual Markets Reports (2002-2004).

Table 2-2 lists the average annual on-peak energy prices for Massachusetts' customers from 2002 to 2004. In 2002, that price was $41.35/MWh. The 2002 data is the average on-peak price paid by all customers in New England. The data is depicted in this manner because prices for MA in 2002 and January and February 2003 are the same as those throughout New England. Under the new zonal pricing structure, the different New England zones experienced different clearing prices, now known as locational marginal prices (LMPs). As shown, the MA zonal prices hovered around $56-57/MWh in 2003 and $58-59/MWh in 2004.

Table 2-2
Massachusetts' Average Annual On Peak Prices, 2002-2004
($/MWh)

	NE	NEMA	SEMA	WCMA
2002	$41.35			
2003		$56.83	$56.26	$57.46
2004		$58.91	$57.88	$59.95

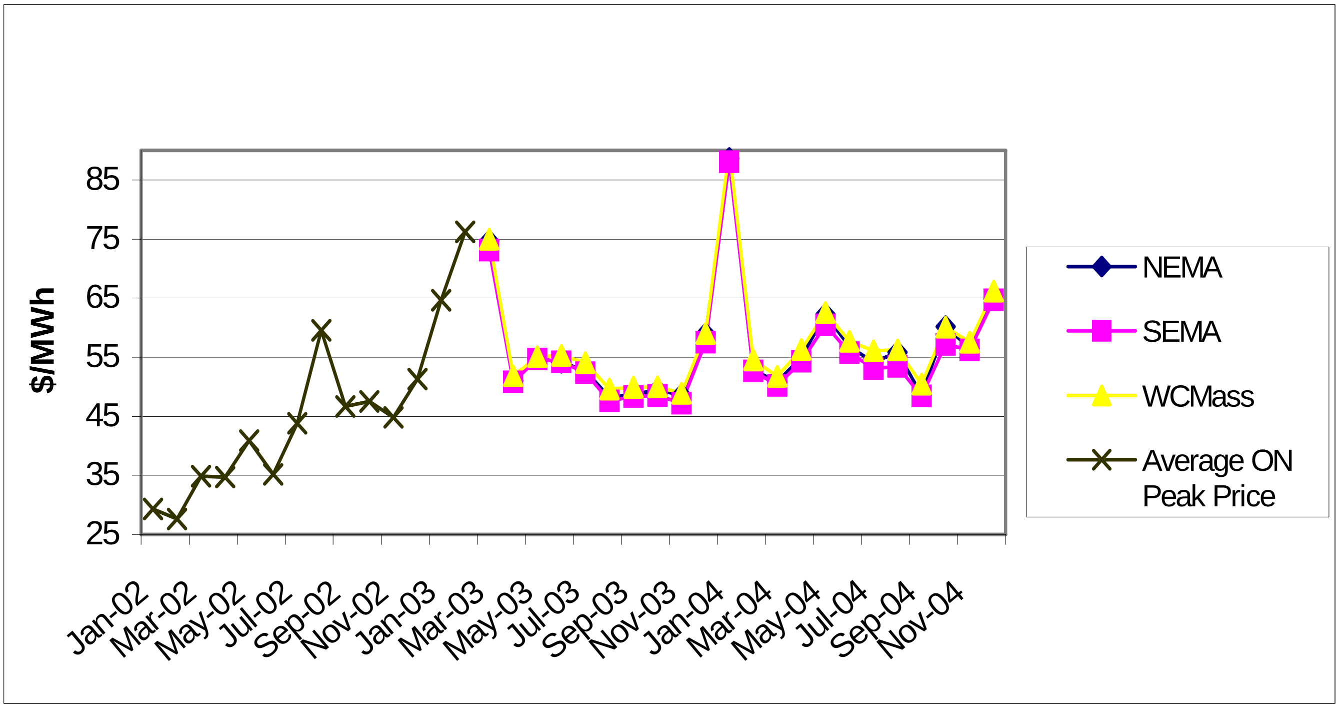
Source: ISO-NE, DOER

Historically, the peak load summer months were the highest price months. That has not been the trend over the period studied. Interestingly, during this time, fuel (oil and natural gas) prices increased, in general, but especially in the winter when the delivery infrastructures for those fuels experienced extreme strain due to high demand.[12]

Figure 2-4 shows New England's average monthly on-peak energy prices from January 2002 to March 2003. It also incorporates the Massachusetts zonal prices for NEMA, SEMA and WCMA from 2003 (post-SMD) through December 2004. Although there was a rise in energy prices, the data show that the Massachusetts' zonal energy prices consistently converged during 2003-2004. This means that there was relatively little congestion in transmitting power in Massachusetts among the zones. Prior to SMD implementation, more significant congestion impacts were expected in the NEMA/Boston electrical area zone relative to other New England zones than was realized during the study period.[13]

[12] Appendix Table A-2 illustrates the New England summer and winter peak load hours experienced in 2002-2004.
[13] 'New England Brings Power Market In Line With Federal Plan', DJ Newswire, Feb 28, 2003, Wholesale power prices are projected to rise most significantly in greater Boston and SW CT due to transmission import constraints. ISO-NE simulated a 14% increase in power prices from current levels.

Figure 2-4
Wholesale Electricity Prices – Average Monthly On-Peak ECPs and Real-Time LMPs (2002-2004)



Source: ISO-NE

MA On-Peak Zonal Energy Prices Diverge from Connecticut Zonal Prices.

In the SMD market, Connecticut (CT) is considered one load zone for purposes of locational pricing. The CT load zone includes the southwestern part of the state, a severely import constrained area. Figure 2-5 compares the locational energy prices in Massachusetts' zones with the CT zone. The graph illustrates the relatively considerable divergence in prices and how Connecticut supply tended to be higher cost than Massachusetts electricity supply. This divergence is due to the constrained transmission infrastructure and high-priced generation located in southwest CT.

The New England electric market also uses a common commercial hub to support trading and hedging activities for market participants. A major reason for the hub is to help participants hedge their exposure to risk in the real-time market, when electricity is delivered. The three Massachusetts' zones to which power must be physically delivered are typically priced very close to the hub price. The Western MA premium during the SMD era was less than 1%, while the NEMA and SEMA prices were 1 to 2% less than the hub price.[14]

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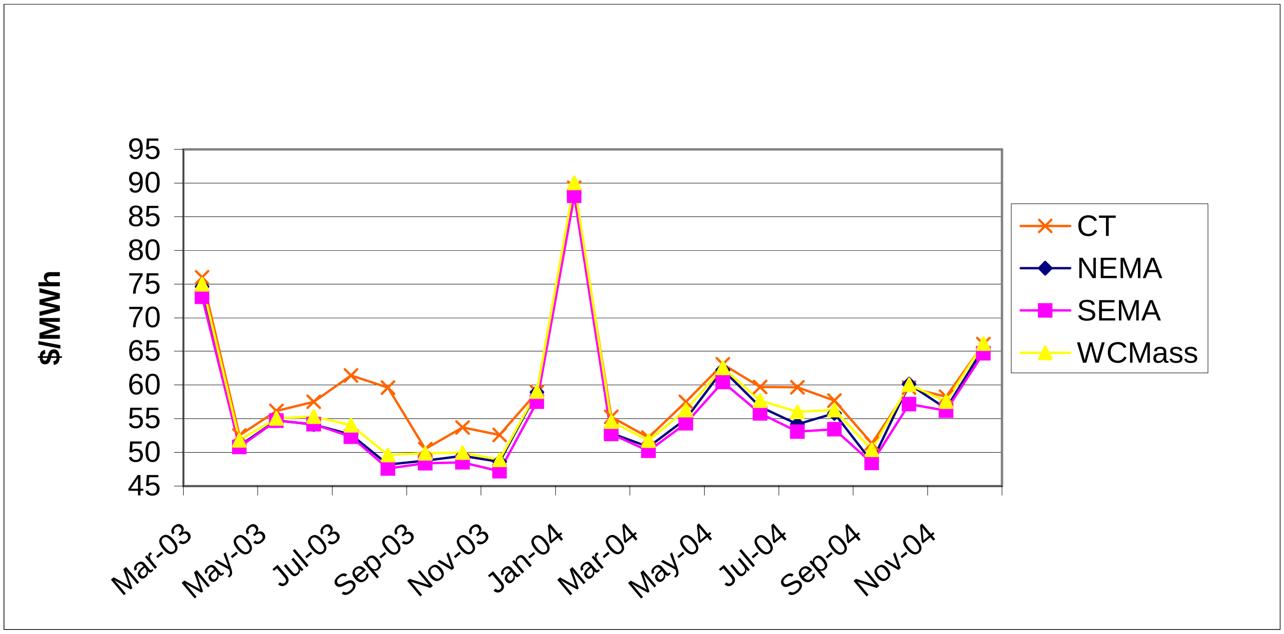
[14] See Appendix Table A-3 for monthly premium values by MA LMP zone.

Figure 2-5
Locational Marginal Prices in Massachusetts and Connecticut



(Real-Time On-Peak LMPs)

Source: ISO-NE

On-Peak/Off-Peak Energy Price Ratios

Data in Appendix Table A-4 shows the historical monthly on-peak to off-peak energy price relationship from 2002-2004. The Massachusetts load zones' on-peak prices were about 25-30% higher than their off-peak prices. (One exception was January 2004 when a winter cold snap hit New England. The difference then was about 50%. This price anomaly can be attributed to extreme cold weather conditions and vast unplanned plant outages.) The overall decrease in the ratio differences during this time period could be due to a couple of reasons such as milder summer weather in 2003 and 2004 and the increase in generation capacity.

Focusing on summer months, the on-peak/off-peak energy price difference was large during the high demand summer months in 2002. For example, the on-peak prices were 75% and 72% higher than off-peak prices in July and August, respectively. One reason for the extremes in summer 2002 may have been because of the unusual hot weather and thus increased demand. (The comparison of prices in the winter months, December through February, when electricity demand is not as high and does not spike as much as in summer, showed only about a 20% difference.)

Table 2-3 below enumerates the summer season on-peak/off-peak ratios for 2002-2004. The ratios have fallen since summer 2002 when the average ratio was 1.57 (this summer included two months of ratios of 1.72). On peak prices averaged $43.85/MWh in July 2002. This was 75% greater than off-peak prices which averaged $25.10/MWh. Since then, the two following summers have had individual monthly ratios reach only as high as 1.39 in one month, August 2004. The entire summer of 2003 did not produce a single month exhibiting a ratio higher than 1.28, which was in June.

Table 2-3
Summer Season (June – September) On-Peak/Off-Peak Ratios
2002-2004

	NE	NEMA	SEMA	WCMA
2002	1.57			
2003		1.25	1.25	1.26
2004		1.30	1.28	1.31

Source: ISO-NE and DOER calculations

One contributing factor to smaller price ratios seen over the past two years is the growth of off-peak prices relative to on-peak prices. Average annual off-peak prices grew 49% from 2002 to 2004 in NEMA/Boston, while on-peak prices grew 42% during the same period[15]. The off-peak prices are a function of base load fuel costs and other variable O&M costs such as emission allowances. Stable priced feedstock such as hydro, nuclear and coal typically fuel base load generation in the US power markets. Coal costs, however, have increased 40% to 100%[16] depending on the grade over the study period, while uranium, also heavily demanded, has increased over 100% since 2002[17]. Emission allowance prices almost quadrupled from 2003 to 2004.[18]

Opportunities Exist 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.

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[15] The average off-peak price in 2002 was $30.07/MWh and $44.86/MWh for the real time off-peak energy in 2004.
[16] WSJ, High Coal Prices Crimp Utilities, Big Energy Users; Impact Is Most Deeply Felt By Consumers Who Depend On Cheaper Off-Peak Power *Rebecca Smith*. WSJ (Eastern edition). New York, N.Y.: August 24, 2004, pg. A.2, "During the past 20 months, prices for Eastern coal have risen by as much as 40% to 100%, depending on the grade and market, according to Standard & Poor's credit-rating agency. Low-sulfur coal, which is preferred for power generation, has as much as doubled in price on the spot market since January 2003 to about $60 a ton. Prices quoted on multiyear contracts for low-sulfur coal from central Appalachia are up about 40% since early 2003, S&P said, to $38 to $45 a ton."
[17] Reuters, Soaring Prices Put Shine on U.S. Uranium, Sunday March 27, 2005, By Belinda Goldsmith
The price has spiked to about $22 a pound from $10 in 2002 as Asian nations build nuclear reactors to create electricity amid high oil prices and concerns over global warming.
[18] DJ Newswire, "High Coal Costs, Competitive Markets Squeeze US Power Companies", Matthew Dalton, June 23, 2005.

For several reasons, though, demand response is a difficult figure to estimate. A key 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 induced 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 investments that can be effective regardless of changing daily or monthly prices.

ISO-NE administers voluntary Load (demand) Response programs to provide opportunity and flexibility to end use customers to react to volatile real time generation prices. 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. Details of the Load Response programs and participation in them can be found at the ISO-NE website. The success of these programs will be influenced by the ratio of on-peak to off-peak prices.

Day-Ahead/Real-Time Energy Price Ratios

Day-Ahead Prices Have a Slight Premium Over Real Time Prices.

Convergence between Day-Ahead (DA) and Real Time (RT)[19] energy prices are an important goal of a Locational Marginal Pricing (LMP) marketplace. Generally, the expectation is that the generators incorporate a risk premium in their day-ahead energy price to insure for capacity commitments and outage risks prior to real time operation and performance. Significant price divergence would suggest a lack of efficient arbitrage using special financial instruments.[20] Reserve cost allocation issues impeding efficient use of virtual transactions were only corrected recently which should lead to greater use of these transactions in the future.

In summer 2003, Forward Contracting premiums were measured in a study released by ISO-NE's independent market advisor. That report's data show that NEMA exhibits about a 3% premium in the day-ahead prices, while the other MA zones have about a 1% to 2% day-ahead premium. Clearing price differences between day-ahead and real time were highest in NEMA/Boston compared to the other NEPOOL zones, but were still generally consistent.[21]

Appendix Table A-5 provides price ratios of day-ahead to real time over the period studied. Similar convergence results were realized in other multi settlement markets in NY and PJM,

[19] The Day-Ahead and Real Time markets make up the ISO-NE Multi-settlement System (MSS). The Day-Ahead Energy Market produces financially binding schedules for generators and load serving entities one day before the operating day. The market closes at 12 noon and re-offers must be made between 4 and 6 pm the day prior to the dispatch or plant operating day. The Real Time Energy Market reconciles differences between the Day-Ahead scheduled amounts of electricity and the actual real time demand. In 2004, 97% of energy load was covered through the Day-Ahead auction, while only 3% of load was assigned real time prices (ISO 2004 Annual Markets Report, page 7).

[20] Virtual transactions are instruments that create arbitrage opportunities based on price differences between the DA and RT markets.

[21] See the ISO-NE report "Six Month Review of SMD Electricity Markets in New England," page 16.

displaying a small premium for day-ahead settlements. Longer-term bilateral contracts[22] (as opposed to short term or day ahead trading) tend to have larger premiums, which are correlated to their contract duration and specific delivery terms.

Wholesale Price Components

Energy (Generation) Cost, the Largest Wholesale-Price Component, Increased by almost 7%.

Bulk power suppliers, competitive suppliers and default distribution utilities, must procure, in addition to energy, other services from ISO-NE administered markets. Energy prices are the dominant component in the wholesale power costs, but other components are necessary to maintain system integrity and resource adequacy. The data in Table 2-4 represents the components of the bulk power price in a percentage format.

The data show that energy prices have increased by 6.7% since 2002. The energy component increase can be attributed to the SMD power market design, which eliminated bid based reserve markets as well as poor performance of the capacity market.[23] Capacity market component costs fell to only 0.1% of 2004 all-in costs, from six percent in 2002. Uplift[24] fell in 2003 to 1.3% of costs, but increased to 2.2 percent in 2004.[25] A forward reserve market was implemented in 2004 accounting for the uptick in ancillary services costs from 1.1% to 1.7% of the "All-In" cost[26].

A new locational capacity (LICAP) commodity market is scheduled for implementation no earlier than October 2006 per an August 2005 FERC order.[27] A FERC Administrative Law Judge filed her initial decision in support of the ISO-NE's demand curve-based LICAP market which, if approved by FERC, could increase wholesale supply costs by $3 billion annually for the six state region.[28] This would increase the capacity cost component of the "all-in" price

[22] Bilateral contracts make up approximately 75% of the energy market whereas short term or day-ahead trades and spot market or real time contracting covers the remaining 25%.
[23] FERC ordered ISO-NE to implement a Peaking Unit Safe Harbor (PUSH) bidding scheme on June 1, 2003 to avoid having to negotiate out of market, cost-of-service agreements seeking compensation for Reliability Must Run (RMR) services. The Commission ordered ISO-NE to implement an approach using formulated PUSH bid ceilings to allow high-cost, seldom run units to recover levelized fixed costs and variable costs through their energy offers without mitigation risk to increase resources during scarcity events. The PUSH bidding scheme is to last until the implementation of a Locational Installed Capacity Market. The majority of cost recovery for PUSH units came from uplift. In 2004, twenty PUSH units recovered $25.5 Million in operating reserve credits (ORCs) (Economic and RMR) and special reliability payments. The implementation of PUSH has proven to be ineffective as only 3% of the PUSH units set the LMPs in 2003.
[24] Uplift is a general term for costs not included in the LMP energy market or reserve markets. Uplift is paid thru ORCs (Economic and RMR, day ahead and real time) and reactive power and special constraint reserve (SCR) tariff costs. RMR ORCs and SCR tariff costs are localized, where as Economic ORCs and Voltage support are socialized.
[25] Uplift refers to the costs borne from dispatching a plant out-of-economic merit order or for special local reliability purposes. Uplift is compensated with Operating Reserve Credits (ORCs) or designated tariff payments.
[26] The forward reserve market prices cleared about 1,900 MWs for the seasonal auction at prices between $3.75 and $4.50/kw-mo. For more information, visit the ISO-NE website.
[27] Devon Power, LLC, *et al*, Docket No. ER03-563-030, August 10, 2005, 112 FERC ¶61,179.
[28] Devon Power, LLC, *et al*, Docket No. ER03-563-030, June 15, 2005, 111 FERC ¶63,063

significantly.[29] The key question is whether increases in the capacity component would be offset by some decrease in the other components.

Table 2-4
Components of All-In Wholesale Price

	2002	2003	2004
ENERGY	90.4%	95.9%	96.0%
UPLIFT	2.3%	1.3%	2.2%
CAPACITY	6.0%	1.8%	0.1%
ANCILLARY SERVICES	1.3%	1.1%	1.7%
TOTAL	100%	100%	100%

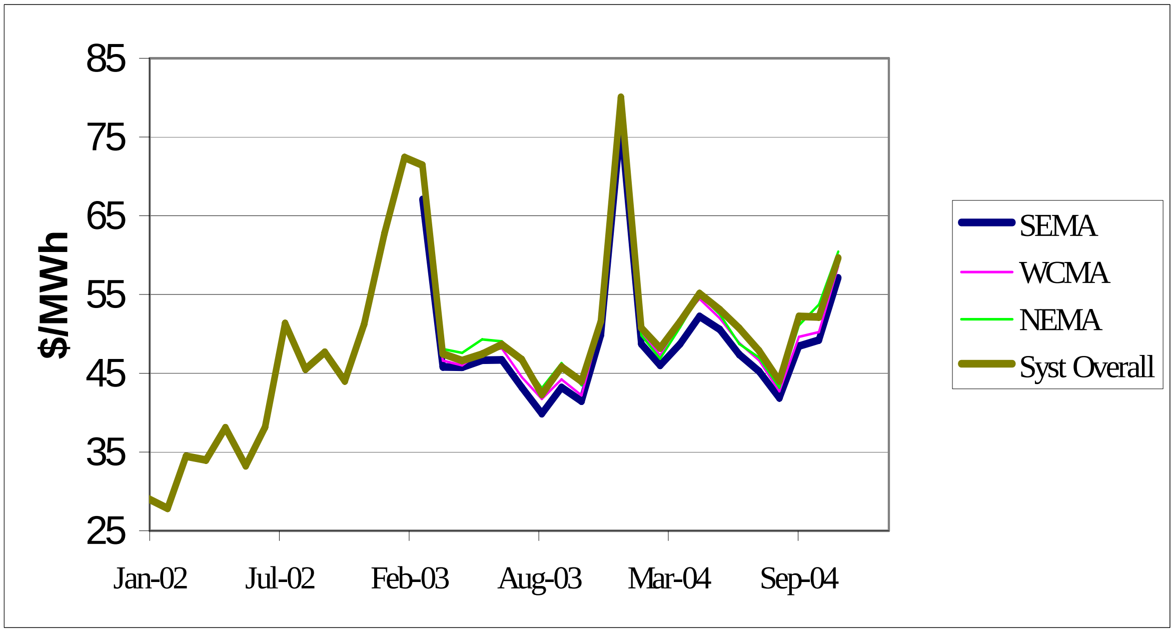
Source: ISO-NE State of the Markets reports, 2002-2004

<u>All-In Wholesale Price and Costs</u>

Figure 2-6 illustrates the monthly average "All-In" wholesale power prices for the New England region over the study period. The average monthly All-In prices are for around-the-clock (ATC) hours, as opposed to prices in Figure 2-2 which exhibits only average monthly on-peak hours. Similar to the on-peak hours, the same three peaks are evident in Figure 2-6, but the All-In prices are not as high as the on-peak prices. The average All-In cost for 2003 was $55.36 /MWh and $57.05/MWh in 2004. Data for 2002 are not discussed due to issues of comparability with post-SMD data.

[29] Per a 2003 FERC order, ISO-NE proposed a capacity market structure utilizing an administrative Demand Curve (DC), however many parties oppose the design. The demand curve prices the capacity commodity as a function of the installed capacity level in separate regions of New England (e.g. NEMA/Boston). The proposed Estimated Benchmark Cost of Capacity (EBCC) for NEMA/Boston is $8.16/kw-mo, which converts to $20.87/MWh, assuming a load factor of 60% and including a 12% required reserve capacity. This cost would account for 26.8% of the All-In cost in 2006, assuming other component prices are the same as realized in 2004. This increase in 2006 would be an immense change in component allocation from 2002-2004 levels, however, the DC price is not likely to reach the EBCC in the early years. Assuming the DC dictates a capacity cost of 25% of EBCC or $2.04/kw-mo, the capacity cost would still make up 8.4% of the all-in price at the converted $5.22/MWh.

Figure 2-6
All-In Price Metric for 2002-2004



Source: ISO-NE

Tables 2-5 and 2-6 illustrate the magnitude of the All-In wholesale costs for the entire New England regional market and the Massachusetts market over the past two years.

Table 2-5
New England's All-In Wholesale Costs

	2003	2004
ENERGY	$6,943,035,407	$7,257,855,360
UPLIFT	$94,118,311	$166,325,852
CAPACITY	$130,317,661	$7,560,266
ANCILLARY SERVICES	$79,638,571	$128,524,522
TOTAL COSTS	$7,247,109,950	$7,560,266,000
NET LOAD (MWH)	130,778,000	132,520,000

Source: ISO-NE's State of the Markets Reports, CELT Report, DOER

The Massachusetts costs in Table 2-6 below are estimates. We assumed the same all-in cost component breakdown for the Commonwealth as for the entire region. This is a valid approximation, however, because the majority of localized (not allocated to the entire region) uplift costs are obligations of NEMA suppliers and transmission owners the costs are greatest in the Boston area and would increase the uplift component relative to the New England regional breakdown in Table 2-5

Table 2-6
Massachusetts' All-In Wholesale Costs (Estimates)

	2003	**2004**
ENERGY	$3,157,329,663	$3,285,313,248
UPLIFT	$42,800,089	$75,288,428
CAPACITY	$59,261,662	$3,422,201
ANCILLARY SERVICES	$36,215,460	$58,177,422
TOTAL COSTS	$3,295,606,875	$3,422,201,300
NET LOAD (MWH)	59,471,000	59,986,000

Source: ISO-NE's State of the Markets Reports, CELT Report, DOER

Retail Electricity Price Analysis

Retail electricity prices are composed of wholesale power costs and other costs of service. Since the energy supply cost is a predominant component (approximately 50%) 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. This section furnishes an overview of Massachusetts' retail electricity prices and provides some discussion of retail cost elements. One of these is known as transition or stranded costs, which are legacies of the regulated generation market. These costs can be significant depending on a customer's distribution utility. We first discuss the generation portion of a customers' retail bill.

<u>Overview of Default Service Prices by Load Zone</u>

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 MA 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 2-7 supplies data on the weighted, average residential default service prices in Massachusetts classified by Massachusetts' load zones procured by the different local distribution companies. As can be seen, the retail price differences among load zones decreased. Over a period of one and half years, the price differentials between NEMA, SEMA, and WCMASS load zones have decreased from 12% to 3% (NEMA/SEMA) and from 17% to 1.3% (NEMA/WCMASS).

Table 2-7
Average Residential Default Service Prices by Load Zone

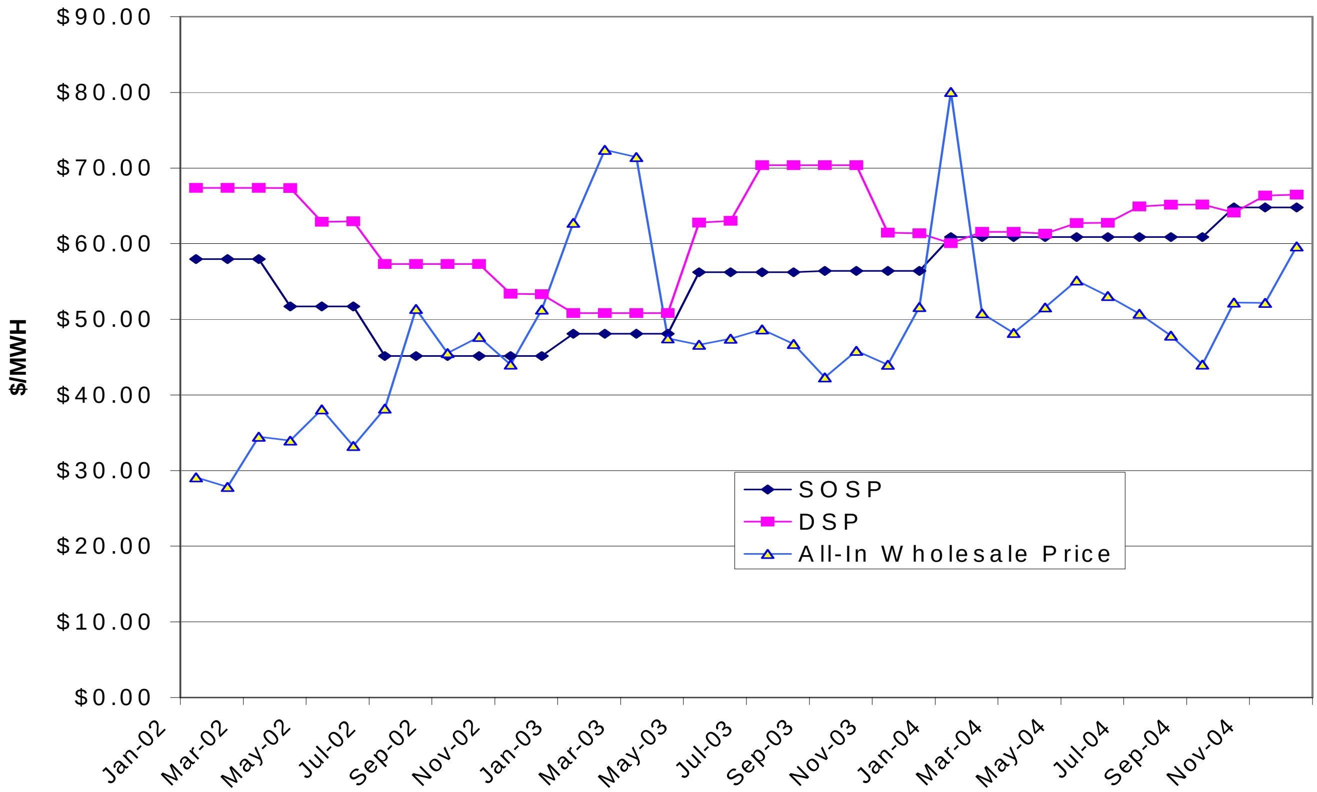
	NEMA Price	SEMA Price	WCMASS Price	NEMA/SEMA Ratio	NEMA/WCMASS Ratio
May-03	8.622	7.729	7.375	1.116	1.169
Jun-03	8.622	7.729	7.375	1.116	1.169
Jul-03	7.733	6.920	7.375	1.118	1.049
Aug-03	7.733	6.920	7.375	1.118	1.049
Sep-03	7.733	6.920	7.375	1.118	1.049
Oct-03	7.733	6.920	7.375	1.118	1.049
Nov-03	6.426	5.895	5.679	1.090	1.132
Dec-03	6.426	5.895	5.679	1.090	1.132
Jan-04	6.306	5.922	5.679	1.065	1.110
Feb-04	6.816	6.340	6.665	1.075	1.023
Mar-04	6.816	6.340	6.665	1.075	1.023
Apr-04	6.741	6.281	6.665	1.073	1.011
May-04	6.805	6.325	6.933	1.076	0.981
Jun-04	6.805	6.325	6.933	1.076	0.981
Jul-04	7.155	6.774	6.933	1.056	1.032
Aug-04	7.140	6.959	7.078	1.026	1.009
Sep-04	7.140	6.959	7.078	1.026	1.009
Oct-04	6.894	6.757	7.078	1.020	0.974
Nov-04	6.770	6.593	6.684	1.027	1.013
Dec-04	6.770	6.593	6.684	1.027	1.013

Source: Massachusetts Department of Telecommunications and Energy

Retail Default Service Lags All-In Wholesale Costs

According to Figure 2-7, 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 figure shows the wholesale power price hikes in January 2003 and January 2004 which were caused by increase in natural gas prices and above normal cold winter weather conditions. The wholesale price ranged between $30.00-$80.00 per MWh. The resulting, but lagged, retail prices ranged between $51.00-$71.00 per MWh. There may be opportunities for competitive suppliers to enter the retail marketplace when there are significant differences between default service prices and All-In wholesale prices.

Figure 2-7
Weighted Average Monthly Standard Offer and Default Service Prices
2003-2004



Other Retail Price Components

In addition to the generation portion of a retail customer's bill, there are a number of other retail price components: distribution, transmission, transition, and social-benefit charges (SBC) for energy efficiency and renewable electricity programs. We do not discuss distribution charges in this report, as these have been discussed extensively in prior Market Monitors and generally only change by a few percentage points (close to the rate of inflation) due to implementation of performance-based rate plans. We also do not discuss SBC charges since these are set at legislatively-determined levels. Transmission and Transition charges are discussed below.

Transmission Cost Analysis

Retail electricity suppliers must also procure bulk transmission service to deliver the electric supply to end use customers. The transmission portion of the bill is small (5-10%) but may increase with additions to the transmission network. Transmission expenses incurred by suppliers are regulated by FERC under three rate tariffs. Suppliers must take service under

NEPOOL's Open Access Transmission Tariff (OATT) Electric Tariff No. 1, a utility company FERC Electric Tariff No. 10[30], also known as local network service (LNS) and ISO-NE FERC Electric Tariff No. 1. There are several other types of transmission services and upgrades which require application submittal to the ISO-NE. Finally, some utilities may also allocate Reliability Must Run (RMR) contract costs to the Network Load of a reliability region where a generation need has been identified by ISO-NE.[31] Congestion costs were once included in transmission expenses, however, since the implementation of SMD on March 1, 2003, congestion costs are now a component of the energy commodity price known as the LMP discussed earlier in this chapter. In this section, we only provide data for OATT.

The OATT tariff provides access to the New England control area's regional transmission facilities greater than or equal to 69kV, commonly referred to as the Pool Transmission Facilities (PTF). The OATT tariff service is known as Regional Network Service (RNS) and recovery of costs is through the NEPOOL RNS rate. The NEPOOL tariff also provides Scheduling and Dispatch Service, Reactive power and Black start service.

The RNS rate is transitioning from zonal utility transmission rates to a single regional rate with the transition to be complete in 2008. The combined RNS rate[32] is calculated per a FERC approved formula and is shown for Massachusetts' utilities in Table 2-8 for the study period.[33] The data show that RNS rates have steadily increased since 2002. Over $337 million in costs were recovered through RNS rates from New England customers in 2004. This cost converts to an average of roughly $4.06/MWh considering the net energy of 132,520 GWh for the region and regional summer load factor of close to 63%.

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[30] The OATT and utility Tariff have been renamed effective February 1, 2005 per RTO-NE formation. The NOATT is now referred to as the ISO-NE Transmission, Markets and Services Tariff, FERC Electric Tariff No. 3, while the utility company FERC Electric Tariff No. 10 has been renamed to ISO-NE Transmission, Markets and Services Tariff.

[31] Only MA utilities serving customers in the NEMA zone had to allocate RMR contract costs during the study period. The Exelon New Boston Station in South Boston has operated under a RMR agreement to maintain downtown Boston reliability for several years, while the Mirant Kendall Station in Cambridge has been under an RMR agreement since 2004. The total 2004 RMR costs allocated to customers for NEMA reliability must run contracts totaled $43.6 Million, $30 Million of which were directed to the South Boston facility.

[32] Pre-1997 PTF and post 1996 PTF.

[33] One can convert the common RNS rate ($/kw-yr) to a variable rate realized by ratepayers of $/MWh or $/kWh by adjusting the annual RNS rate for capacity utilization or load factor. Typical utility load factors are about 60%.

Table 2-8
Regional Network Transmission Service
($/kw-yr)

Transmission Provider	Jun-02 Final/Total RNS Rate $/kw-yr	Jun-03 Final/Total RNS Rate $/kw-yr	Jun-04 Final/Total RNS Rate $/kw-yr
Boston Edison	16.72	16.55	17.88
Comm Electric	15.15	15.17	14.16
NGRID	16.61	16.29	17.53
NU - WMECO	13.41	13.78	15.32
Pool PTF	15.14	15.60	16.87

Source: ISO-NE

Transition Cost Balance Analysis

A major cornerstone of the Restructuring Act was that utility distribution companies were mandated to divest and sell their generation assets. Under the Act, distribution companies were allowed to recover prudently incurred costs, after all reasonable steps, including divestiture of generation assets, were taken to mitigate the investments. The remaining costs for generation-related assets are known as stranded costs or transition costs. Depending on the LDC, transition costs may account for up to 30% of a customer's bill, higher than distribution-related charges for some customers.

In many cases, the power plant sales exceeded remaining book values thereby mitigating the transition cost balances more than anticipated.[34] In some cases, utility sponsored divestitures did not produce an adequate sales price and utilities were forced to retain asset(s) and apply to the MA Department of Telecommunications and Energy (D.T.E.) for continued recovery of transition costs. Mitigation efforts by utilities have been an ongoing issue to reduce transition cost balances over the past six years. Savings efforts are important to reduce balances because, as illustrated in Table 2-9, cost balances are forecasted to last until 2023 in the case of Commonwealth Electric. The data in the table also exhibit the beginning transition cost balance and the most recent balances per utility transition cost reconciliation filings made to the D.T.E in 2004 or supplemental filings in 2005.[35]

[34] See MA DOER Market Monitor 2000.
[35] The NPV analysis assumes a 10% discount rate.

Table 2-9
MA Investor-Owned Utilities'
Transition Cost Balances as of 2004 DTE Filings
(Dollars)

	Initial 1998 Transition Charges (Excluding Reg. Assets)	Unrecovered Transition Charges as of 2004 Filing	Forecasted Year of Transition Charge Termination
Boston Edison	3,170,831,000	1,413,455,709	2016
Cambridge	190,221,000	78,838,576	2026
Commonwealth	1,197,040,000	707,297,437	2023
FG&E	87,986,000	49,547,625	2014
Mass. Electric	3,207,347,000	352,601,225	2010
WMECo	851,375,000	206,380,711	2013
Total (2005 US$)	8,704,800,000	2,808,121,282	

Source: DOER and Utility Reconciliation filings (initial and supplemental)

The above table shows the combined transition costs qualified for recovery by utility. A more detailed look at transition costs would show that the costs are classified as either fixed or variable costs. Fixed costs are unrecovered power plant asset investments that did not sell for a higher price than the book value. All power plant assets have been divested by utilities as of 2003**.** Variable costs are generally associated with above-market power purchase agreements (PPAs) which are considered uneconomic in today's bid-based market[36]. DOER will update this analysis on a yearly basis.

[36] In 2004, Nstar petitioned the MA DTE for approval to mitigate transition costs via several different PPA buy-outs or restructurings. Nstar also filed with the DTE to securitize costs of $675 Million for upfront buyout costs related to contracts with two plants (Masspower and Dartmouth Power). Although Nstar negotiated several deals to buyout nearly half of the 1,100 MW contracted thru 24 PPAs on the auction block, only two petitions were approved by the DTE in 2004. Boston Edison completed the Ocean State Power contract assignment (DTE 04-68).and Cambridge and Commonwealth Electric completed the Altresco-Pittsfield contract termination agreement (DTE 04-60). Savings estimated by Nstar for the Ocean State deal were $12 Million and $6 Million for the buyout of the Altresco contract.

Retail Prices by Massachusetts Electric Companies

Table 2-10 shows total retail prices for all customers for each of the local distribution companies and the municipal companies as a whole. The retail prices shown in the table (and in this section) result from adding all the retail price components discussed above and represent the actual prices paid, on average, by all consumers and businesses of the Commonwealth for their electricity purchases.

Table 2-10
Revenue per kWh for Massachusetts Electric Companies
2002-2004
(average price in cents/kwh)

	2002 Average Price	2003 Average Price	2004 Average Price	Change (2003-2004)
Boston Edison	10.4	10.6	10.5	-0.9%
Cambridge Electric	8.3	8.6	8.9	2.5%
Commonwealth Electric	11.4	11.4	11.6	2.1%
Fitchburg Gas & Electric	9.8	10.8	10.1	-6.1%
Massachusetts Electric	9.0	9.0	8.7	-2.6%
Nantucket Electric	10.7	13.0	11.8	-9.2%
Western Massachusetts Electric	8.9	9.1	8.9	-2.9%
Total: Distribution Company	10.2	9.7	9.6	-1.4%
Total:Municipal Company	9.4	9.5	9.6	1.1%
Total of Entire State	10.0	9.7	9.6	-1.1%

Source: FERC Form 1, Massachusetts Electric, EIA (for Massachusetts Electric & 2002 overall price), DOER

The data show that overall prices paid by all customers classes showed little change[37] over the 2002-2004 time period. The data also show that distribution companies overall price disadvantage over municipal companies has narrowed over the 2002-2004 time period. As shown in Table 2-11, however, municipal companies continue to provide electric service at cheaper rates for their residential customers.

[37] The 2004 overall price shown in Table 2-10 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 2-10 is a temporal analysis and utility specific.

Table 2-11
Comparison of Distribution Company and Municipal Company Prices
(2002-2004)

	2002	2003	2004
Residential			
Average LDC Company Price	10.9	11.7	11.9
Average Municipal Utility Price	9.4	9.9	9.96
Difference	-15.8%	-18.1%	-19.7%
Small Commercial or Industrial			
	2002	**2003**	**2004**
Average LDC Company Price	8.5	9.1	8.8
Average Municipal Utility Price	8.0	10.6	10.6
Difference	-5.9%	14.6%	16.5%
Large Commercial or Industrial			
	2002	**2003**	**2004**
Average LDC Company Price	6.8	9.1	6.3
Average Municipal Utility Price	10.2	10.6	8.5
Difference	34.0	14.6%	25.6%
Overall			
	2002	**2003**	**2004**
Average LDC Company Price	10.2	9.7	9.6
Average Municipal Utility Price	9.4	9.5	9.6
Difference	-7.8%	-2.3%	-0.3%

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 2-12 shows this analysis for the 2002-2004 time period. 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. In terms of year-to-year changes, it was less likely that price disparity changed (higher or lower) among the

LDCs between 2003-2004 than between 2002-2003, because the F-Tests[38] are higher for 2003-2004. The 2002-2003 data show that for the industrial class, this probability is only 47%, implying that it was more likely than not that price disparity changed, increasing from 8.0 cents/kWh to 14.6 cents/kwh. From 2003-2004, however, the F-Test shows that even though price disparity increased further to 17.1, there was an 85% chance that this change was not statistically significant.

Table 2-12
2002-2004 Price Disparity Among Distribution Companies

	Residential		**Commercial**		**Industrial**		**Overall**	
	2004	**2003**	**2004**	**2003**	**2004**	**2003**	**2004**	**2003**
Price Disparity	1.4	1.0	3.8	4.0	17.1	14.6	1.7	2.2
F-TEST		0.72	0.95		0.85		0.80	

	Residential		**Commercial**		**Industrial**		**Overall**	
	2003	**2002**	**2003**	**2002**	**2003**	**2002**	**2003**	**2002**
Price Disparity	1.0	1.7	4.0	2.5	14.6	8.0	2.2	1.7
F-TEST		0.58		0.58		0.47		0.75

Source: FERC, National Grid, DOER

Restructuring Savings Analysis

This final section compares retail electricity prices and bills incurred by Massachusetts consumers during periods prior to restructuring and after March 1, 1998, the start of retail choice. A comparison of electric prices and expenditures shows consumer savings after the start of electric restructuring.[39]

Changes in Price and Expenditure Levels

Table 2-13 shows retail electricity prices by sector over the 1990-2004 period.[40] The main point is that prices were constantly increasing from 1990-1997[41] (an 18% increase over that time), and then dropped precipitously in 1998 and 1999, largely due to the mandated rate discounts to customers. Since then, prices have risen (largely due to fuel-related increases), and most recently, prices are only slightly higher (in current dollars) than the prices in 1997 for all

[38] 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.

[39] The conclusions cannot be attributed to any particular program or event that is in place or has occurred during the post-March 1998 period, such as the mandatory 15% discounts and divestiture or fuel-clause surcharges, or similar events in the period prior to March 1, 1998. Rather, the analysis considers all events as a whole in each period.

[40] In order to simplify the analysis, DOER utilized EIA data by customer sector for the entire state of Massachusetts.

[41] Indeed one of the major objectives of restructuring efforts in Massachusetts and other high-cost states was to attempt to address the high costs of electricity.

customer groups except industrial customers.[42] Figure 2-8 provides a visual interpretation of the data, showing that initial lower prices due to restructuring have been reversed and the trend in the data is higher prices.

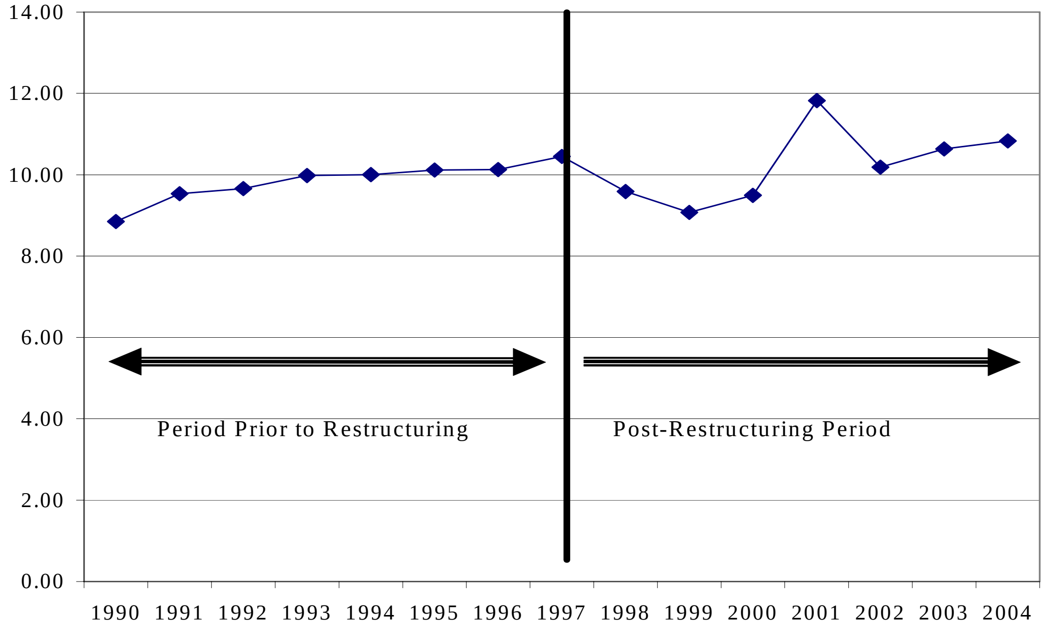
Table 2-13
Average MA Retail Electricity Rates
for Different Customer Groups
1990-2004
(cents/kWh)

	Residential	Commercial	Industrial	Average
1990	9.66	8.56	7.89	8.85
1991	10.40	9.22	8.52	9.53
1992	10.62	9.31	8.60	9.66
1993	11.00	9.67	8.66	9.98
1994	11.09	9.75	8.46	10.00
1995	11.26	9.93	8.41	10.12
1996	11.25	9.94	8.43	10.13
1997	11.59	10.29	8.69	10.45
1998	10.60	9.35	8.18	9.59
1999	10.09	8.82	7.57	9.07
2000	10.53	9.13	8.20	9.49
2001	12.48	11.94	10.05	11.82
2002	10.97	10.14	8.77	10.18
2003	11.68	10.48	9.11	10.63
2004	11.80	11.07	8.45	10.83

Source: EIA

[42] This may be due to the movement of many larger customers to the competitive market and the use of self-generation.

Figure 2-8
Massachusetts Electricity Prices, 1990-2004 (cents/kWh)



Source: Table 2-13

Annual Total Expenditures/Total Bills

The actual expenditures, the total bills, paid by each customer group is displayed in Table 2-14. The total column includes the three listed sectors, Residential, Commercial and Industrial, plus other sectors' (e.g. transportation) expenditures which are small and not catalogued separately. Total expenditures increased from about $4 billion in 1990 to about $5.5 billion in 2004. This increase was a function of increasing prices and increases in electricity demand. Within the timeframe, total expenditures fluctuated from year to year based on different demand levels (e.g. increased cooling demands during an extremely warm summer) and the prices in a particular year.

As with the price data, there was a large drop in expenditures in 1998 and 1999 after restructuring began compared to 1997 levels. Shown in the table, Massachusetts customers incurred the highest expenditures in 2001. This increase was mostly due to the application of fuel surcharges related to oil and natural gas prices, not necessarily due to increased demand since that year had relatively cool summer weather. By contrast, 2003 featured similarly high expenditures, but these were due to demand pressures rather than high prices.

Table 2-14
Total Electricity Expenditures by Customer Group
1990-2004
(Dollars)

	Residential	Commercial	Industrial	Total
1990	1,504,941,000	1,589,746,000	801,597,000	4,020,327,000
1991	1,599,159,000	1,707,623,000	834,697,000	4,270,460,000
1992	1,651,863,000	1,734,562,000	831,313,000	4,346,885,000
1993	1,737,123,000	1,827,747,000	832,126,000	4,518,345,000
1994	1,779,120,000	1,889,105,000	821,519,000	4,610,826,000
1995	1,800,174,000	1,975,875,000	843,112,000	4,704,725,000
1996	1,828,592,000	2,021,905,000	850,425,000	4,789,172,000
1997	1,886,625,000	2,144,520,000	881,571,000	5,002,787,000
1998	1,736,823,000	2,003,097,000	835,394,000	4,659,240,000
1999	1,754,849,000	1,896,086,000	753,959,000	4,481,797,000
2000	1,849,974,000	2,101,791,000	863,505,000	4,914,011,000
2001	2,252,843,000	2,601,803,000	929,347,000	5,877,821,000
2002	2,033,929,000	2,399,935,000	795,712,000	5,337,695,000
2003	2,252,562,000	2,683,966,000	870,798,000	5,819,274,000
2004	2,117,791,000	2,580,029,000	741,426,000	5,458,124,000

Source: EIA

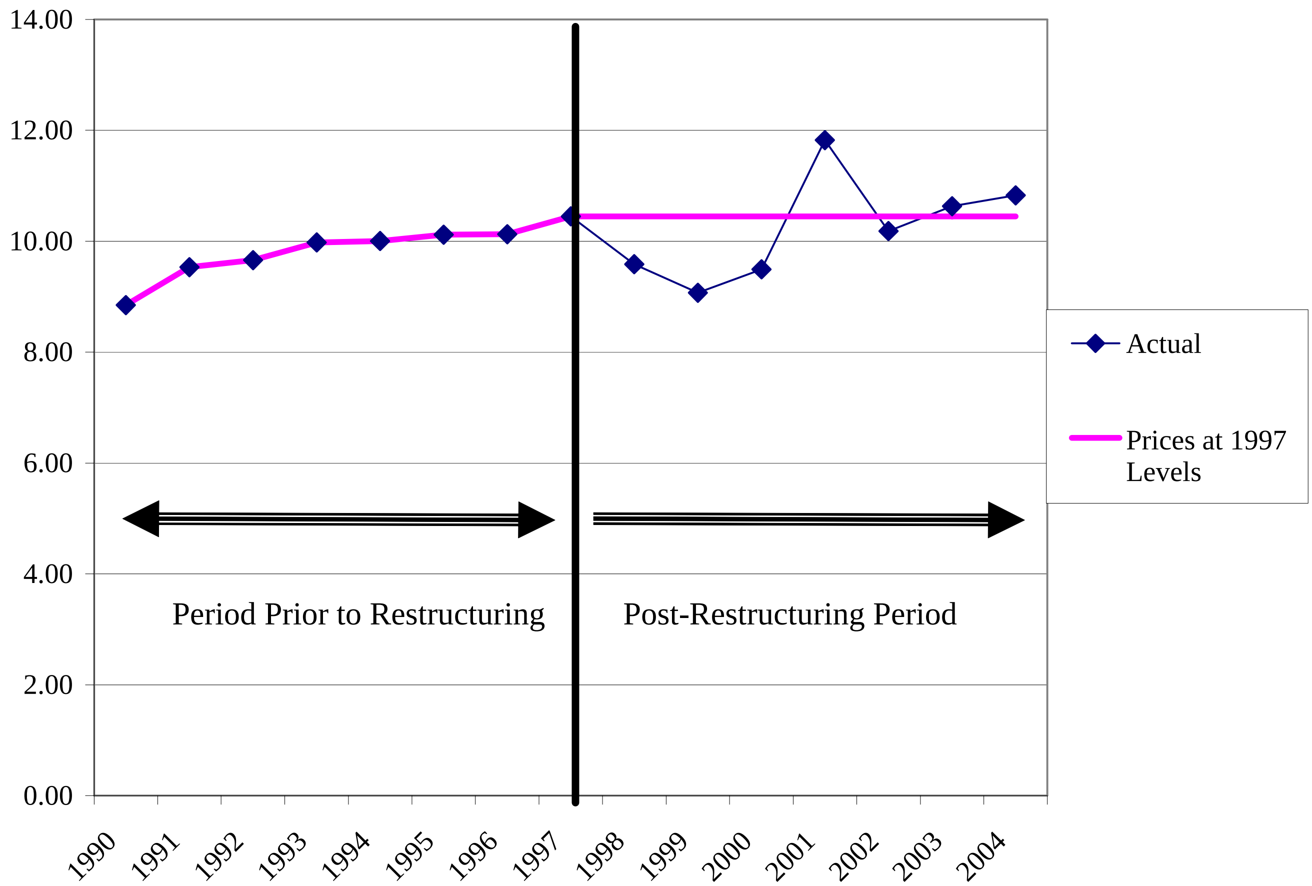
Calculating Bill Savings or Increases

This section calculates the impacts of restructuring on prices and bills by using the above actual prices and usage levels and comparing them to three different scenarios.

Scenario 1: Restructuring vs. prices fixed at pre-restructuring levels – consumers saved $750 million through restructuring.

This scenario assumes that prices remain at 1997 levels throughout the 1998 to 2004 time period. This would be similar to a rate freeze proposal, instead of the mandated discounts specified in the Act. Using a nominal (or current) dollar analysis of the price and expenditure impacts of restructuring, Figure 2-9 compares fixed 1997 prices to actual prices (see Figure 2-8) to depict how much prices changed since 1997, and how much less (or more) customers paid than they would have with a steady 1997 level. It shows that compared to 1997 levels, prices were lower for four of the seven years in the post-1997 period and close to 1997 levels for 2 other years; only 2001 was the much different (higher) than 1997 levels.

Figure 2-9
Massachusetts Electricity Prices, 1990-2004
Compared to Fixed 1997 Price Levels (cents/kWh)



Source: Table 2-14, DOER

Tables 2-15 shows the price impacts of this scenario in terms of these differences. As can be seen, these conclusions generally hold for individual customer sectors as well. The data shows that in 1998, restructuring reduced prices statewide by about a 0.9 cents/kWh and in 1999 by 1.4 cents/kWh. In 2001, prices increased by this same amount.

Table 2-15
Price Impacts Assuming 1997 Price Levels in the 1998-2004 Period
(Cents/Kilowatthour)

	Residential	Commercial	Industrial	Total
1998	-0.99	-0.94	-0.51	-0.86
1999	-1.50	-1.47	-1.12	-1.38
2000	-1.06	-1.17	-0.49	-0.96
2001	0.89	1.64	1.36	1.38
2002	-0.62	-0.16	0.08	-0.26
2003	0.09	0.19	0.43	0.18
2004	0.21	0.77	-0.23	0.38

Source: Table 2-14, DOER

Table 2-16 applies the 1997 price levels to the usage levels implied in Table 2-14 to generate a new set of expenditures and then subtracts actual expenditures to arrive at the bill impacts for this scenario. Though the results differ by customer group, overall, customers have saved over $750 million during the post-restructuring period under this scenario, with the largest savings enjoyed by residential customers.

Table 2-16
Bill Impacts of Assuming 1997 Price Levels in the 1998-2004 Period

	Residential	Commercial	Industrial	Total
1998	-162,517,700	-202,020,474	-51,710,033	-419,326,465
1999	-260,901,884	-315,899,829	-111,773,179	-680,386,431
2000	-185,473,157	-269,144,682	-51,489,622	-495,342,119
2001	160,441,877	358,487,588	125,703,817	683,817,816
2002	-115,792,097	-37,529,697	7,182,369	-138,174,428
2003	18,145,793	48,568,837	40,676,631	101,057,665
2004	37,568,503	180,597,441	-20,565,157	192,345,828
Total	-508,528,665	-236,940,816	-61,975,174	-756,008,135

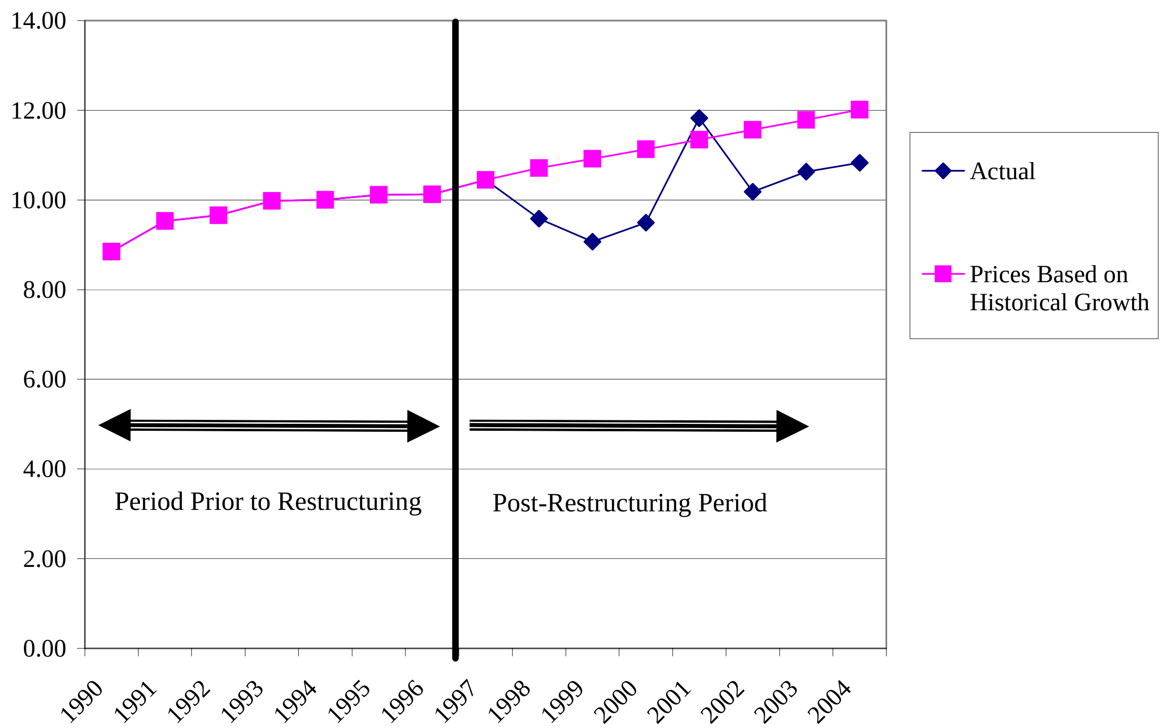
Source: EIA, DOER

This scenario, while useful, does not provide a complete analysis of the bill savings due to restructuring. That is because prices generally do not remain fixed as this scenario assumed. For some products, prices may go down, but generally, most product prices increase. The next two scenarios account for inflation in electricity prices.

Scenario 2: Restructuring vs. prices growing at historical rates- consumers saved over $4 billion through restructuring.

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. Figure 2-10 compares these calculated prices to the actual prices during the post-1997 period. By assuming that prices would have grown at historical rates if restructuring had not occurred, Figure 2-10 shows that prices would have exceeded actual prices in all but one year (2001). Table 2-17 shows the differences in the above mentioned two sets of prices.

Figure 2-10
Massachusetts Electricity Prices, 1990-2004
Compared to Forecasted Prices (cents/kWh)



Source: Table 2-14, DOER

Table 2-17
Price Impacts of Assuming Historical Growth During 1998-2004 Period (Cents/Kilowatthour)

	Residential	Commercial	Industrial	Total
1998	-1.37	-1.23	-0.52	-1.13
1999	-2.15	-1.99	-1.19	-1.85
2000	-1.98	-1.93	-0.61	-1.64
2001	-0.31	0.63	1.18	0.48
2002	-2.11	-1.42	-0.15	-1.38
2003	-1.68	-1.34	0.14	-1.15
2004	-1.87	-1.02	-0.58	-1.18

Source: EIA, DOER

The calculated prices shown in Table 2-17 are then applied to actual usage levels to calculate bills that would have been incurred. Table 2-18 shows the bill impacts assuming that prices would have increased at the rate of historical growth by comparing the calculated prices to the actual prices found in Table 2-13.

Table 2-18
Bill Impacts of Assuming Historical Growth in Prices in 1998-2004 Period

	Residential	Commercial	Industrial	Total
1998	-225,222,328	-262,775,938	-52,762,216	-547,336,669
1999	-373,872,294	-423,554,151	-153,907,179	-912,720,798
2000	-347,468,710	-444,319,150	-119,093,184	-847,980,335
2001	-56,446,909	134,815,812	45,575,852	238,360,619
2002	-391,515,916	-345,012,401	-92,289,522	-722,638,062
2003	-324,644,119	-355,245,368	-86,520,441	-631,503,478
2004	-335,057,099	-253,595,744	-158,452,552	-596,987,008
Total	-2,054,227,374	-1,949,686,940	-617,449,241	-4,020,805,731

Source: EIA, DOER

Not surprisingly, assuming that prices would have grown at historical levels increases the bill savings dramatically from $750 million in Scenario 1 to over $4.0 billion saved in the years 1998-2004 period.

Scenario 3: Restructuring vs. prices growing at rates of consumer goods inflation – consumers saved 4.5 billion through restructuring.

In the third 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 2-19 shows the impact on total bills. 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 $4.5 billion for the same electricity product. Thus, using this assumption for growth in prices, consumers saved about $4.5 billion during the post-1997 period.

Table 2-19
Bill Impacts of Assuming Growth in Electric Prices same as Consumer Price Index
1998-2004
(Dollars)

	Residential	**Commercial**	**Industrial**	**Total**
1998	-189,715,896	-233,597,335	-64,413,193	-492,050,568
1999	-331,862,088	-393,768,066	-142,249,431	-862,110,072
2000	-328,780,295	-436,072,134	-115,910,485	-876,191,563
2001	-49,297,615	133,620,650	45,147,699	163,177,879
2002	-380,017,960	-337,122,614	-89,737,144	-811,222,818
2003	-327,148,836	-358,691,225	-87,605,848	-782,604,645
2004	-367,057,115	-286,117,767	-168,780,621	-831,904,580
Total	-1,973,879,805	-1,911,748,491	-623,549,023	-4,492,906,367

Source: EIA, BLS, DOER

Conclusion

Wholesale electricity markets underwent significant changes during the 2002 to 2004 timeframe. The energy marketplace was restructured per FERC order of SMD implementation from a single zone, single settlement system to a multi zone, multi settlement system similar to New York and the Mid-Atlantic markets. Electricity prices increased drastically due to fuel price increases from 2002 to 2004, not market restructuring, particularly increases in natural gas prices which fires a large percentage of new power plants in New England and other parts of the country.

Market participants encountered limited opportunities to employ demand response resources due to low peak to off-peak ratios during 2002-2004, but efforts continue to increase DR penetration at the wholesale level. The energy component continued to account for the vast majority of the all-in wholesale costs and is expected to continue that way in the near future. Capacity market costs dropped over the three years due to the capacity over-supply in the region, however, they should pick up as reserve margins begin to decrease due to little capacity addition, load growth and regulatory commitments to implement pricing structures to maintain resource adequacy.

Transmission costs remained relatively stable, increasing only slightly, over the study period, while transition costs will continue for several more years until the utility stranded cost balance is eliminated.

Despite the public claims and perceptions that restructuring efforts have not resulted in savings, a comparison of electric prices and expenditures in the periods immediately prior and after the start of retail access do show savings. This conclusion holds even if potential inflation in prices since 1997 are not accounted for, a scenario that is highly unlikely given historical trends and the lack of indigenous energy resources in or close to the Massachusetts and New England markets.

Restructuring, however, remains a work in progress. Trends in the post-restructuring period clearly show an upward trend in prices. If this trend continues, savings that have been earned to date may begin to erode dependent on the rate of growth in electricity prices. However, it is important to note that while prices increased by about 18% for all consumer goods during the 1998-2004 period according to the CPI,[43] the increase in electricity prices during that time was about 13%. If such a trend is sustained, consumers will continue to enjoy savings in real dollars.

[43] The index in 2004 was 200.2 compared to the 1998 value of 170.0.

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. Reliability may be measured by the frequency, duration and magnitude of adverse effects on the electric system. Electric system reliability can be addressed by considering two basic and functional aspects of the electric system – adequacy and security. Very generally, adequacy refers to the ability of the system to supply customer's demand. Security means the ability of the system to withstand disturbances or unanticipated losses of the electric system elements.[44] 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. Northeastern wholesale power markets typically require reserve margins between 12 and 18 percent, depending on their reliability modeling methodology. 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[45]. We discuss the application of these criteria at the conclusion of this section.

First we analyze characteristics of a reliable system including New England's generation capacity reserve margins, the system's overall reliability especially during extreme demand, fuel diversity and import/export capabilities.

Reserve Margins

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 needed to exceed 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. It is a major component of system reliability.

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[44] NPCC Document A-07, Glossary of Terms.

[45] 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

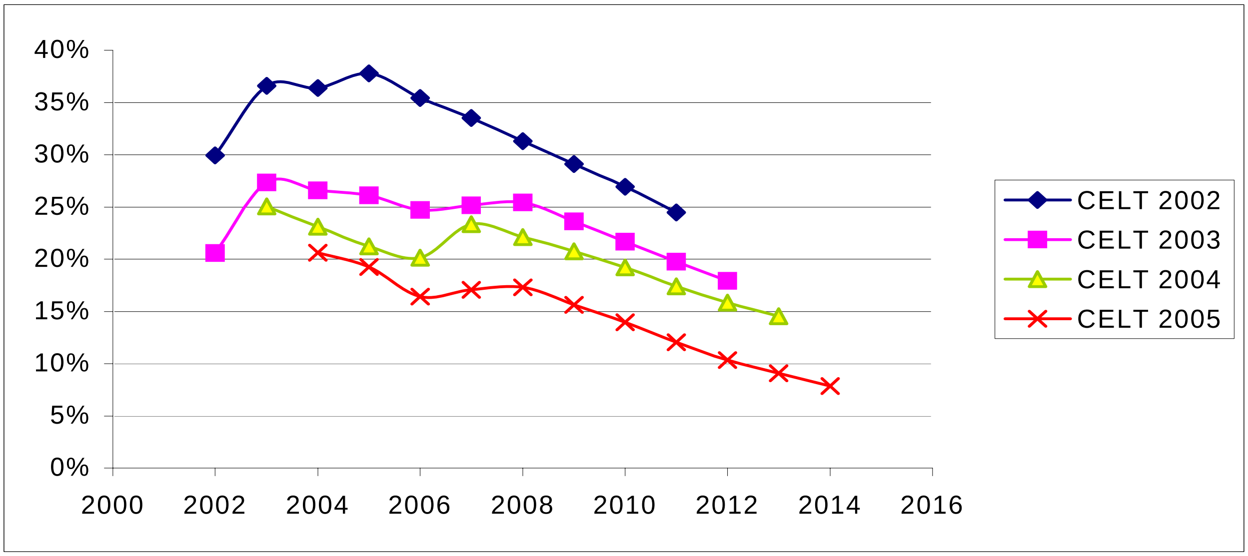
ISO-NE Over-Estimated Forecasted Reserve Margins Compared to Actuals

The reserve margin discussed in this report represents the percent of New England's installed capacity above the adjusted peak load forecast. 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 significantly over time. Interestingly, the forecasted reserve margins for 2004 are drastically higher than the 2004 actual reserve margins. For summer 2005, ISO-NE projected (in the CELT 2002 Report) a 38% reserve margin, while CELT 2005 projected a 19% margin for that summer. This 50% decrease in reserve margin over the CELT study period can be attributed to a decrease in projected installed capacity per 2002 projections and load projection increases since the CELT 2002 release.

ISO-NE 2004 Forecast Predicts Inadequate Reserve Margins in 2010

The data from the CELT 2005 Report, shown in Figure 3-1, indicate that in 2010 the reserve margin forecasted by ISO-NE falls below the historically considered reasonable reserve margin of 15%. As such, the situation for maintaining reliability will become dangerously inadequate. In fact, decisions about corrective actions are needed sooner than 2010 due to the long 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.

Figure 3-1
NEPOOL Summer Reserve Margins Forecasts, 2002-2014



Source: ISO-NE, Celt Reports for years 2002-2005

It is important to note that the role of transmission resources is not accounted for in evaluating the deterministic reserve margin levels. We discuss the interaction of generation and transmission resources in the LOLE discussion below.

System Reliability

Despite some extreme demand conditions during the study period, New England's grid system reliability has been strong. For example, in August 2002, New England hit a record peak demand of 25,348 MW, a record high, but ISO-NE was able to maintain system reliability. ISO-NE implemented emergency operating procedures 4 times that month, but still the system reliability was maintained. Over the next two summers, mild weather and a large capacity reserve margin helped minimize emergency supply events.

Massachusetts was largely unaffected on August 15, 2003 during the largest blackout in U.S. history, which affected approximately 50 million people from Michigan to New York to Ontario, Canada. Yet, only a small area in Connecticut and western MA were subject to this disturbance and fell under New England's emergency Operating Procedure #4 (OP4)[46].

Increased emergency events during winter months has been a growing trend over the past couple years. The January 2004 cold snap event produced extreme outages at gas-fired plants and a dangerously low capacity reserve margin. ISO-NE operating procedures for extreme cold weather incidents have since been designed through an ISO-NE Cold Snap Task Force. The appropriate calculation of payments to generators under the NEPOOL tariff for cost recovery for designated winter emergency events is currently pending before FERC.[47]

Table 3-1 illustrates the summer and winter peak loads, actual and weather normalized, as well as the number of OP4 events

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[46] 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.
[47] ISO New England, Inc. and New England Power Pool, Docket No. ER05-508-000, ER05-508-001, ER05-508-003, November 17, 2005, 113 FERC ¶61, 175.

Table 3-1 New England Peak Loads 2002 – 2004

Summer Peak	**Actual**	**Weather Normalized**	**OP4 Events**
	Peak (MW)	Peak (MW)	
2002	25,348	24,590	6
2003	24,685	25,170	1
2004	24,116	25,760	1
Winter Peak	**Actual**	**Weather Normalized**	**OP4 Events**
	Peak (MW)	Peak (MW)	
01/02	19,872	21,470	0
02/03	21,533	21,730	0
03/04	22,818	22,085	2
04/05	22,635	22,450	1

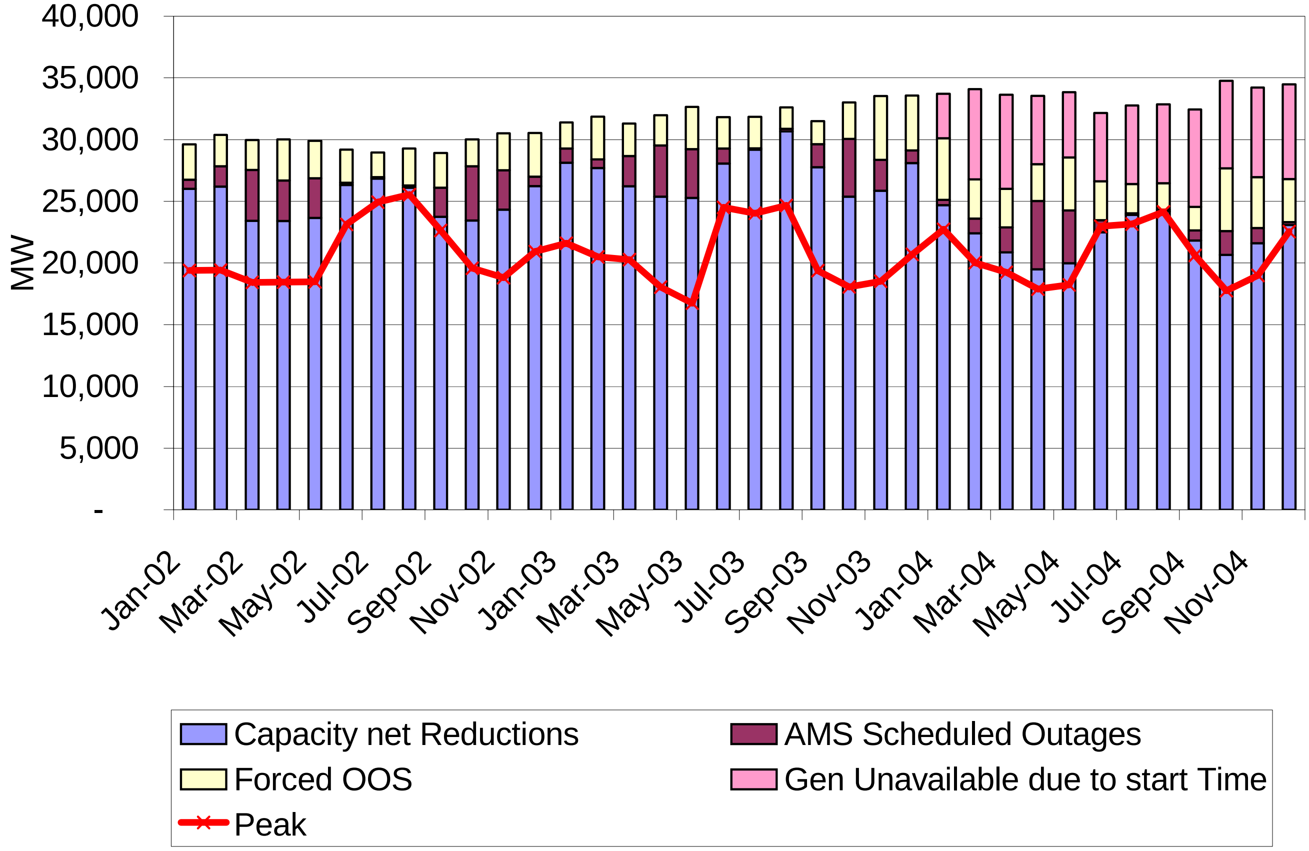
Source: ISO-NE

The regional view of system reliability during 2002-2004 is illustrated below in Figure 3-3[48]. The monthly peak loads, shown by the line, were compared to adjusted installed capacity in the region. To do this comparison, the 2002 and 2003 regional installed capacity was adjusted for each month's average maintenance scheduled (AMS) and unscheduled (forced) outages to give a more accurate reserve margin. The 2004 installed capacity adjustment included, in addition to Forced and Unforced Out-of-Service (OOS) capacity, a monthly average capacity unavailable due to start time. This unavailable capacity existed in 2002 and 2003, but was not reported by ISO-NE. If the 2002-2003 data accounted for the amount of generation capacity unavailable due to start time, it would show thinner reserve margins than those depicted in Figure 3-3.

This system reliability analysis shows one disturbing trend - the increase in unscheduled or forced outages. Such outages jeopardize system reliability. The outages during the Cold Snap of January 2004 are an example. The 2004 average of forced outages jumped 22% relative to the 2002 figure with over 3,400 MW of capacity claiming forced outages were necessary on a daily basis.

[48] The underlying data in the figure is shown in Table A-6 in the Appendix.

Figure 3-2
Installed Capacity net Average Monthly Reductions
versus Monthly Peak Load
2002-2004



Source: ISO-NE, DOER

Fuel Diversity

An important part of system reliability is an adequate and diverse fuel portfolio because it means the system does not depend on any one fuel. A multi-fuel portfolio can help to lower electricity costs for the region due to fuel competition and can lower volatility in electricity prices. Due to New England's geography and the states' stringent environmental regulations, the region is challenged to acquire the most economically optimal mix of fuel and, in recent years, has come to heavily rely on natural gas. The ISO-NE and the NEPOOL Generation Information System (GIS) report on the generation fuel mix.

Table 3-2 uses ISO-NE data to examine the New England fuel mix over the past three years[49]. The data show that diversity has been stable during the 2002-2004 period after declining in the

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

prior period. Virtually all of the 9,480 MWs of new generation resources constructed and operating since the market began operating in 1999 are fueled with natural gas. Currently, natural gas accounts for almost 30% of the fuel mix as opposed to only 15.7% in 1999. Nuclear and coal account for about 27% and 12% of fuel portfolio, respectively. Oil-fired plants have remained a considerable contributor in the region at 10-12% oil use, but that percentage has fallen since 1999 when oil-fired plants' fuel use accounted for 19% of the mix.

Table 3-2
New England Generation Fuel Mix By ISO-NE Data
2002-2004

	2002	2003	2004
Natural Gas	28.9%	30.5%	28.9%
Oil	3.6%	5.6%	4.0%
Oil/Gas	9.6%	10.1%	11.9%
Nuclear	26.6%	26.6%	27.6%
Coal	12.3%	11.9%	11.4%
Coal/Oil	2.6%	1.3%	2.9%
Hydro	5.0%	5.8%	5.4%
Wood/Refuse	5.1%	4.8%	4.9%
Small Generation	0.7%	0.6%	0.6%
Pumping Load	1.8%	1.4%	1.4%

Source: ISO-NE

The NEPOOL GIS also reports fuel mix statistics, as shown in Table 3-3. GIS accounts for each megawatt of electricity production in New England and for the fuel usage from dual-fueled technology. According to the 2003 and 2004 data (2002 data were unavailable), natural gas fuel usage in those years was about 34%. This percentage is 5% greater than the ISO-NE data which embeds this data in its oil/gas fuel statistics. (Note that coal fires about 15% of New England generation, which is greater than the 12% reported by ISO-NE.

Table 3-3 New England Generation Fuel Mix By NE-GIS Data
2003 and 2004

	2003	2004
Coal	15.1	15.1
Natural Gas	33.7	34.0
Nuclear	27.7	28.5
Oil	11.1	12.1
Hydroelectric/Hydropower	5.4	5.2
Other	7.0	5.0
	100.0	100.0

Note: Average annual % figures derived from NE-GIS quarterly reporting data Oil also includes diesel and jet fuel. "Other" fuels include digester gas, fuel cell, landfill gas, municipal solid waste, photovoltaics, wind, and biomass.

Source: NEPOOL GIS

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 by stable-priced fuels (i.e. low fuel price risk) including coal and nuclear power which accounted for 88.9% fuels for total electricity in 2004, while natural gas accounted for only 7%.[50] As a result, the energy prices in PJM are markedly lower and less volatile than those in New England and New York. As noted earlier, during 2002-2004, gas-capable plants set prices in 81% of price intervals, thus exposing electric prices to much higher price risk than PJM. Neighboring New York's power market also suffers from a limited quantity of stable priced fuel for their generation mix relative to PJM. Since all three markets operate under very similar SMD structures with LMPs, most of the price differential among the three power pools can be attributed to the cost of the fuel mix.[51]. Recently, the three independent system operators of these northeastern power markets entered into an MOU to support one another during gas supply shortage events.

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 Objective Capability (OC) requirements. This accounting helps to ultimately reduce the cost for resources in the region. The Tie Reliability Benefits (TRBs) assumed in the OC calculations are as follows: 1,200 MWs for Hydro-Quebec, 200 MWs for New Brunswick and 600 MWs from New York.

Over the past few years, however, New England has used a decreasing supply of imports from neighboring pools, as shown in Table 3-4. The total imported power accounted for almost 8% of New England's needs in 2002, but fell to 3.7% in 2004. Canadian net imports have fallen by about 50% since 2002. Total net imports from neighboring regions in 2004 amounted to 4,907,000 MWhs, representing 3.7% of the annual New England load. The net power import value represents an average power import of 560 MWs per hour in 2004, down from over 1,100 MWs in 2002.

Hydro Quebec (HQ) ships the majority of the net imported power into New England via the Phase I/II and Highgate interfaces. The HQ power represented about 75% of the total net imports in 2004, or about 421 MWs on an hourly basis. In 2002, HQ delivered an average of 838 MWs on an hourly basis. The 2004 New Brunswick Keswick interface transmitted the

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[50] PJM 2004 State of the Market Report, page 44.

[51] PJM average all hour day ahead prices in 2003 and 2004 were $36.92 and $42.91, NY average all hour day ahead prices in 2003 and 2005 were $53.07 and $55.64 compared to New England prices of $48.72 and $53.12. Source: ISO-NE Annual Markets Reports 2003 (pg 13) and 2004 (pg 38).

remaining net imported power of about 152 MWs, while New England exported an average of 13 MWs an hour to New York via the Roseton and Cross Sound Cable ties.

Table 3-4 New England Generation Sources, 2002-2004

	2002	2003	2004
Total Native Power	94.5%	97.3%	97.7%
Total Net Power Imported	7.7%	4.2%	3.7%
Total NE Power Consumption (includes load needed for pumped storage)	102.2%	101.4%	101.4%

Source: ISO-NE

Future Wholesale Reliability

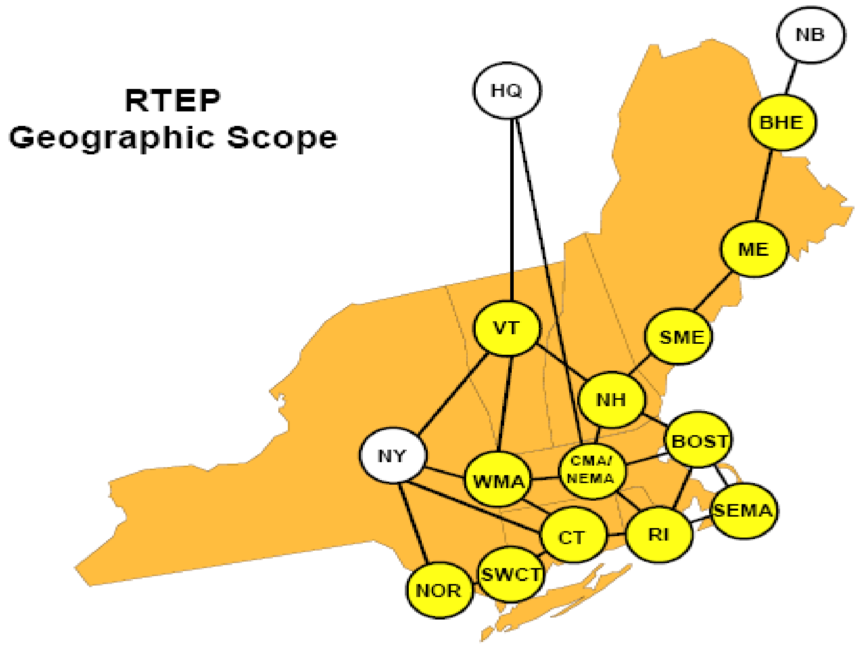
Unlike the deterministic Reserve Margin analysis discussed earlier in this chapter, probabilistic resource planning and reliability projections completed by the ISO-NE show improvements in reliability over the study period. Reliability improvements are measured by the LOLE metric. This measure accounts for the transmission interfaces throughout the region which allow control areas to rely upon one another for resources. Deterministic generating capacity reserve margin analysis 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.

ISO-NE performs bulk power system reliability assessments or resource adequacy assessments (RAA) on an annual basis and publishes these results in their Regional Transmission Expansion Plan (RTEP)[52]. The assessment attempts to identify the expected reliability of the NEPOOL bulk power system when reflecting expected transmission constraints. As mentioned, the New England control area must conform with NPCC basic criteria for design and operation of interconnected power grids.

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 RTEP sub areas: Boston, CMA/NEMA, WMA, and SEMA. Boston is the only zone in Massachusetts which is import constrained and vulnerable to reliability problems. Nevertheless, based on the study periods RAAs, all of Massachusetts, including Boston, is in good condition with regard to wholesale reliability.

[52] Since 2001, ISO New England has also conducted annual resource adequacy assessments for the ISO New England Regional Transmission Expansion Plans

Figure 3-3
New England RTEP Subareas



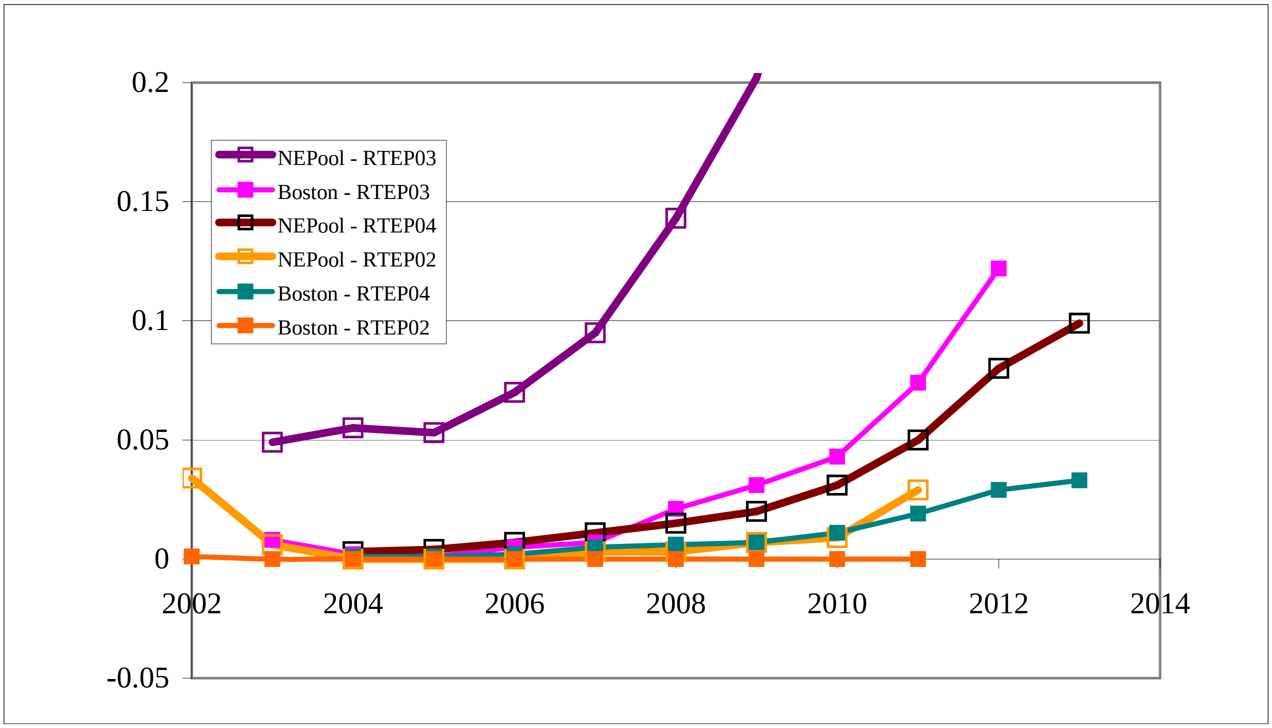
The LOLE assessment of generation resource adequacy represents a relatively limited assessment of system reliability. The method does not address operational and local transmission problems internal to the Sub-areas which could result in other reliability problems. Even if this type of analysis indicates 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.

The latest RAAs conducted examine RTEP/RSP sub areas for 2002 through 2012. The analysis assessed the adequacy of generating resources and transmission facilities to meet forecasted Sub-area loads, based on planning assumptions. ISO-NE also conducted sensitivity analysis, based on various loads, generation, and transmission facility assumptions. ISO-NE assessed specific reliability improvements from proposed upgrades, and showed the incremental impact of new resources, resource retirements, and/or load growth.

Figure 3-4 illustrates the study periods RTEP reliability assessments for the New England region as a whole and the import constrained Boston Load Pocket separately. According to the 2004 RTEP RAA, the figure shows that the entire region and Boston sub area are projected to be sufficiently reliable as the LOLE is no more than 0.1 days per year through 2013. These scenarios are base cases which assume existing supply remains available through 2013 and updated demand projections grow at historic growth rates.

Figure 3-4 also shows that the region as a whole was most vulnerable, per the RTEP 2003 base case, due to the lack of Southwest CT infrastructure. The LOLE would violate the 0.1 days per year criteria beginning in 2008. The 2003 base case assumes that the proposed Phase I transmission upgrade is not constructed. According to RTEP 2003, the SWCT Phase I upgrade is expected to increase import limits in SWCT and NOR and improve reliability by 71%.

Figure 3-4
NEPOOL System & Boston SubArea Annual Loss of Load Expectation (days/yr)
(NPCC reliability criteria < 0.1 day in 1 yr or 1 day in 10 yr)



Source: ISO 2002, 2003, 2004 RTEPs

The NEPOOL region as a whole and Boston sub area are considered very reliable per the 2004 ISO assessment. The 2004 NEPOOL base case assumes Southwest Connecticut demands will be met with the emergency RFP and transmission resources without any material construction delays. The 2004 Boston sub area assessment assumes the Boston Edison transmission line increases import capability beginning in 2007 for phase I and 2008 and 2009 for Phase II and III**.**

On the other hand, there are scenarios where retirements of existing power generating resource do occur and could impact sub area or regional reliability, but, overall reliability in the Boston area is not expected to be a problem under normal conditions.

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>

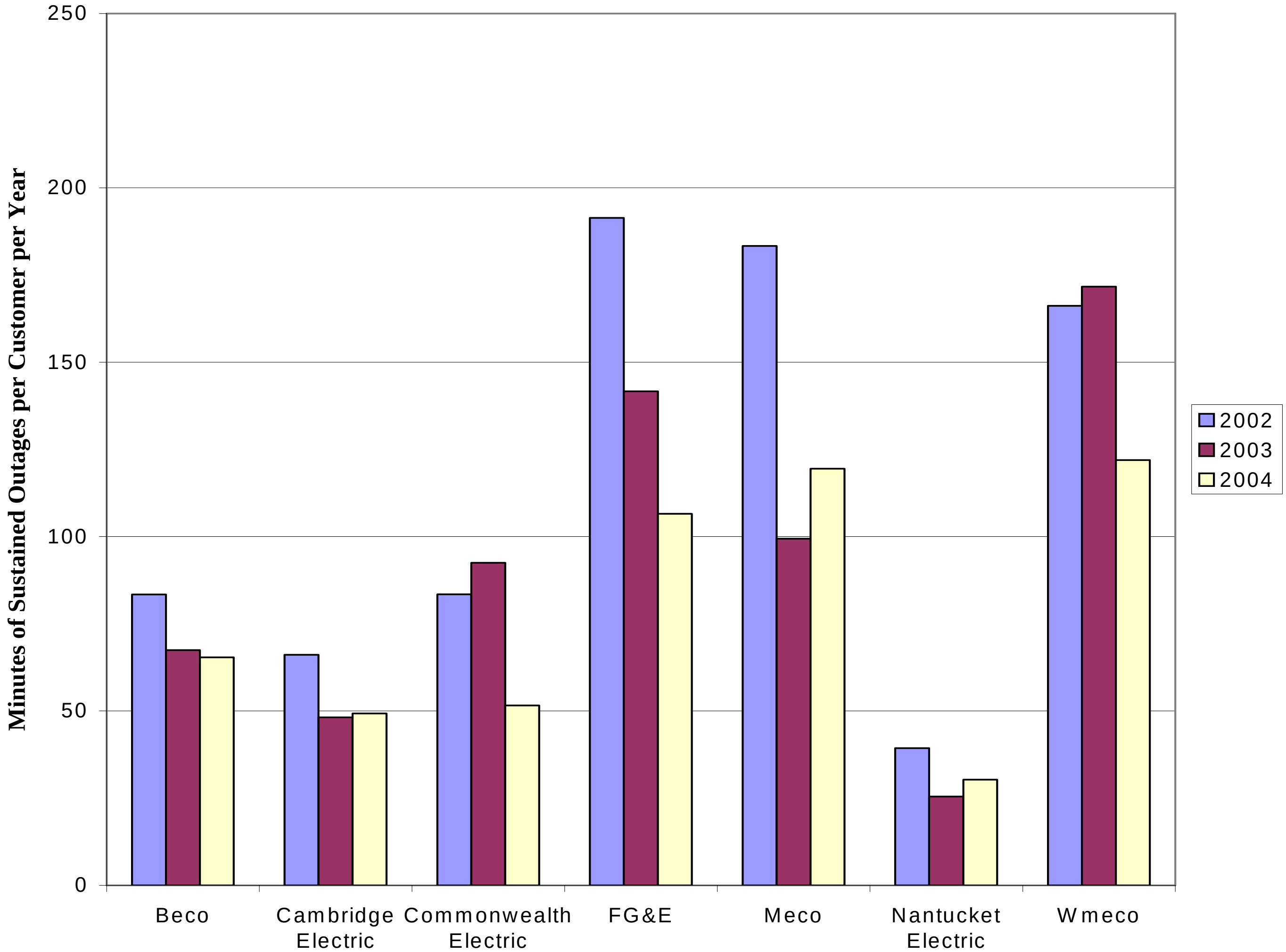
The System Average Interruption Duration Index (SAIDI) is a measure that determines the length of time the average customer is without electric service during a prescribed period of time. The measurement used is the total minutes of sustained customer interruption durations divided by the total number of customers, and is expressed in minutes per year. The SAIDI figures reported by LDCS do not include Excludable Major Events[53].

Figure 3-5 shows the SAIDI measurements by LDC for 2002-2004. From the data, the year 2002 had the most minutes of sustained outages per customer per year across most LDCs. In 2004, on the other hand, SAIDI statistics show much improved performance over 2002 data.

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. For example, even though Boston Edison has shown good performance over the 2002-2004 time period, there may be pockets within the service territory that had much higher incidences of outages than shown in the data in Figure 3-6. Unfortunately, such data are not publicly available.

[53] 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.

Figure 3-5
Electric System Average Interruption Duration Index, SAIDI (Exclude Major Events)



Source: Massachusetts Department of Telecommunications and Energy

SAIFI

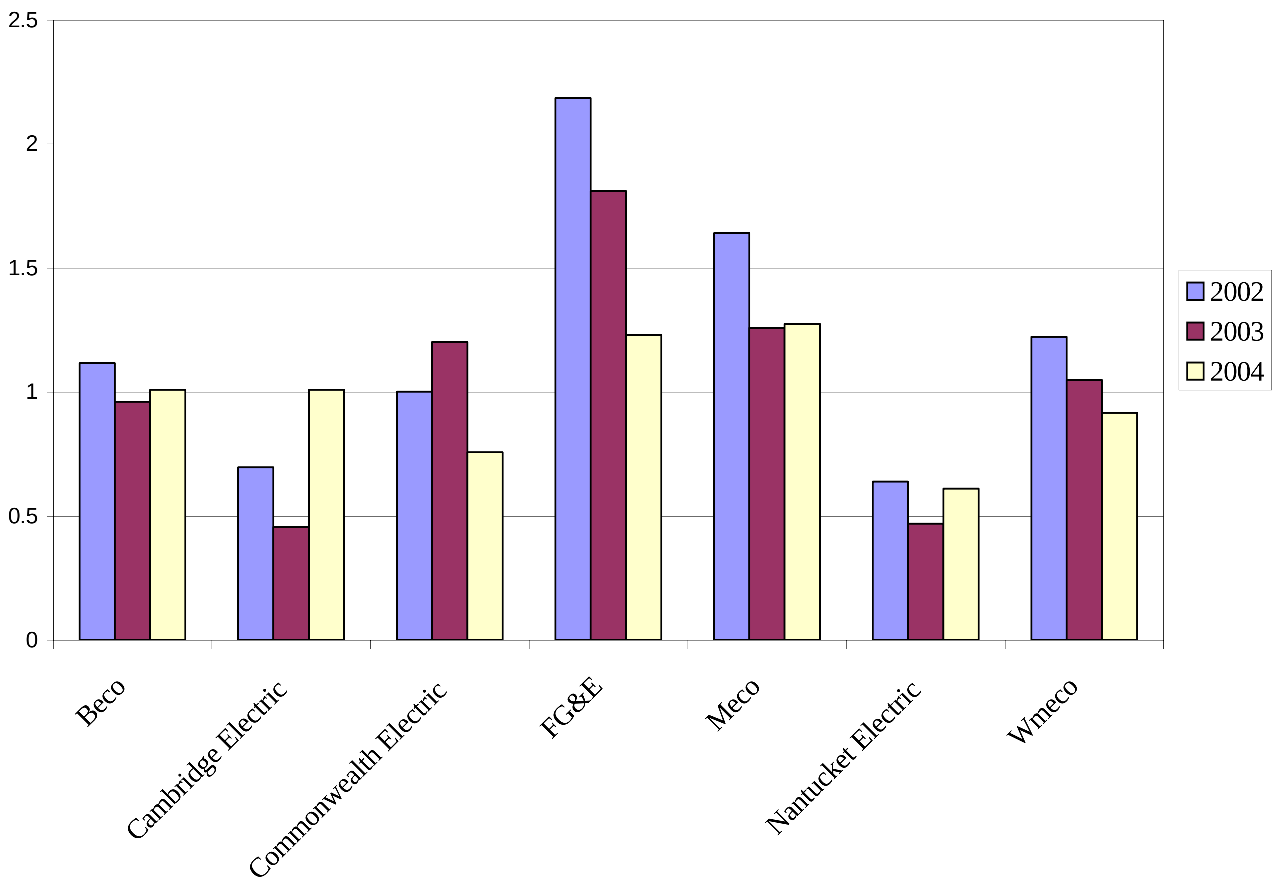
The System Average Interruption Frequency Index (SAIFI) is a measure that determines the number of times (frequency) the average customer experiences a loss of electric service that lasts at least five minutes (sustained outage) and is not classified as a momentary outage. It is measured by the total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

Figure 3-6 shows the 2002-2004 SAIFI data with 2002 having the most frequent interruptions. That year, Fitchburg, Massachusetts Electric and Western Mass. Electric Companies had the most frequent interruptions. Boston Edison , Commonwealth, Cambridge and Nantucket Electric Companies had the least frequent interruptions. In 2003,Commonwealth Electric Company is the only electric company with more frequent interruptions than in 2002. In 2004, Boston Edison, Cambridge Electric, Massachusetts Electric, and Nantucket Electric had an increase in frequency of interruptions but still showing improvement from 2002 levels.

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.

Finally, the SAIDI and SAIFI totals without adjusted criteria that incorporate D.T.E. assumptions for calculating electric reliability measures, including the definition of excludable major events in 2004 for Fitchburg Electric Co. are twice and nine times the adjusted SAIDI and SAIFI, respectively. Data for other LDCs are not available in this fashion. This order of magnitude difference illustrates further that the reported SAIDI and SAIFI figures underestimate the actual minutes of sustained outages and frequent interruptions.

Figure 3-6
Electric System Average Interruption Frequency Index, SAIFI (Exclude Major Events)



Source: Mass Department of Telecommunications & Energy

One Day In Ten Years Loss of Load Expectation (LOLE)

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 3-5 shows the multiplication of SAIDI and SAIFI, which corresponds to the average total loss of load in one year. The data show that in 2002, Fitchburg Electric Company, Massachusetts Electric Company and Western Mass Electric Company did not meet the one day in ten years reliability standard criterion (more than 144 minutes of interruptions a year). In 2003, Fitchburg Electric Company and Western Mass Electric Company and, in 2004, Massachusetts Electric did not meet the one day in ten years reliability standard. During the 2002-2004 service period, the LDCs, did not meet, as a group, the one in ten years reliability standard 29% (6/21) of the time, which is much worse than the performance of the wholesale electricity network, as measured by LOLE over the past 3 years.

Table 3-5
One Day In Ten Years Loss of Load Expectation (LOLE)

	SAIFI * SAIDI (minutes per year)			1 in 10 Standard		
	2002	2003	2004	2002	2003	2004
Beco	93	65	66	Under	Under	Under
Cambridge Electric	46	22	50	Under	Under	Under
Commonwealth Electric	83	111	39	Under	Under	Under
FG&E	418	256	131	Over	Over	Under
Massachusetts Electric	301	125	152	Over	Under	Over
Nantucket Electric	25	12	19	Under	Under	Under
Wmeco	203	173	112	Over	Over	Under

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

Conclusion

ISO-NE has maintained short term system reliability adequately over the 2002-2004 period. Installed capacity reserve margins are acceptable, however, have dropped from highs in 2002 due to little new capacity development and load growth exceeding ISO-NE projections. The region’s reliance on natural gas continues to be a concern and potentially jeopardize the health of the electricity system. Increasing the region’s use of nuclear, coal and renewables should be a priority for the regional authorities. Until a greater share of more stable fuels can penetrate the New England market, ISO-NE operating procedures and market rules were established to avoid risk of infrastructure over-reliance during peak winter heating season which strains the pipeline delivery system in the Northeast.

The region’s long term resource adequacy appears acceptable beyond 2010 at which point the loss of load expectation begins to creep higher and close to violating the acceptable standard.

Resource adequacy could become compromised only in the event of several plant retirements, unexpected long-term outages or significant delays in transmission line construction.

The SAIDI, SAIFI and one day in ten years reliability data showed successive performance improvements in the service territories from year 2002 to year 2004. These performance improvements could be attributable to better weather condition, i.e. the demand for heating and cooling energy being normal or below normal, application of better technology, financial incentives (avoidance of possible financial penalties for poor SAIDI and SAIFI statistics) and possible emphasis towards more transparent data based consumer service oriented management style.

Finally, data show that despite the improvement in SAID and SAIFI, there is still incidence of higher—and unacceptable levels based on NPCC criteria—LOLE in the reliability of the distribution system compared to the wholesale electric grid. This difference in reliability levels may require a shift in policy emphasis or attention to reliability problems at local, rather than region wide, levels.

Chapter 4 – Markets

Market Overview

There are almost 3 million electric customers in Massachusetts. In terms of customer sales (MWh), local distribution companies (LDCs) meet 86 percent of Massachusetts' electricity demand, while municipal utilities deliver the remaining 14 percent. In terms of number of customers, competitive suppliers could conceivably serve over 2.5 million customers. [54] The bulk of the retail electricity demand in 2004 was divided among eight distribution companies, as shown in Table 4-1. Two LDCs, NStar's Boston Edison Company and NGrid's Massachusetts Electric Company, account for 67 percent of all electricity demand in the state. In 2004, the Massachusetts electric industry collected about $5.3 billion in revenues. LDC revenues totaled about $4.6 billion, and assuming that generation revenues are approximately 60% of total revenues, yields approximately $2.8 billion as a measure of the revenue potential for competitive suppliers.

Table 4-1
Composition of Massachusetts Demand, 2004

Distribution Company	Number of Customers (Yearly Average)	Electric Revenue ($ Millions)	Customer Sales (MWh)
Boston Edison	697,198	1,596,915,537	15,200,803
Cambridge Electric	47,611	144,532,078	1,633,125
Commonwealth Electric	361,660	493,987,873	4,243,907
Fitchburg Gas & Electric	27,713	55,633,126	549,168
Massachusetts Electric	1,217,349	1,902,413,116	21,757,295
Nantucket Electric	11,153	16,278,014	137,460
Western Massachusetts Electric	202,058	362,829,123	4,088,831
Total: Distribution Companies	2,564,742	4,572,588,867	47,610,589
Total: Municipal Companies	386,955	733,735,903	7,666,413
TOTAL OF ENTIRE STATE	2,951,697	5,306,324,770	55,277,002

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

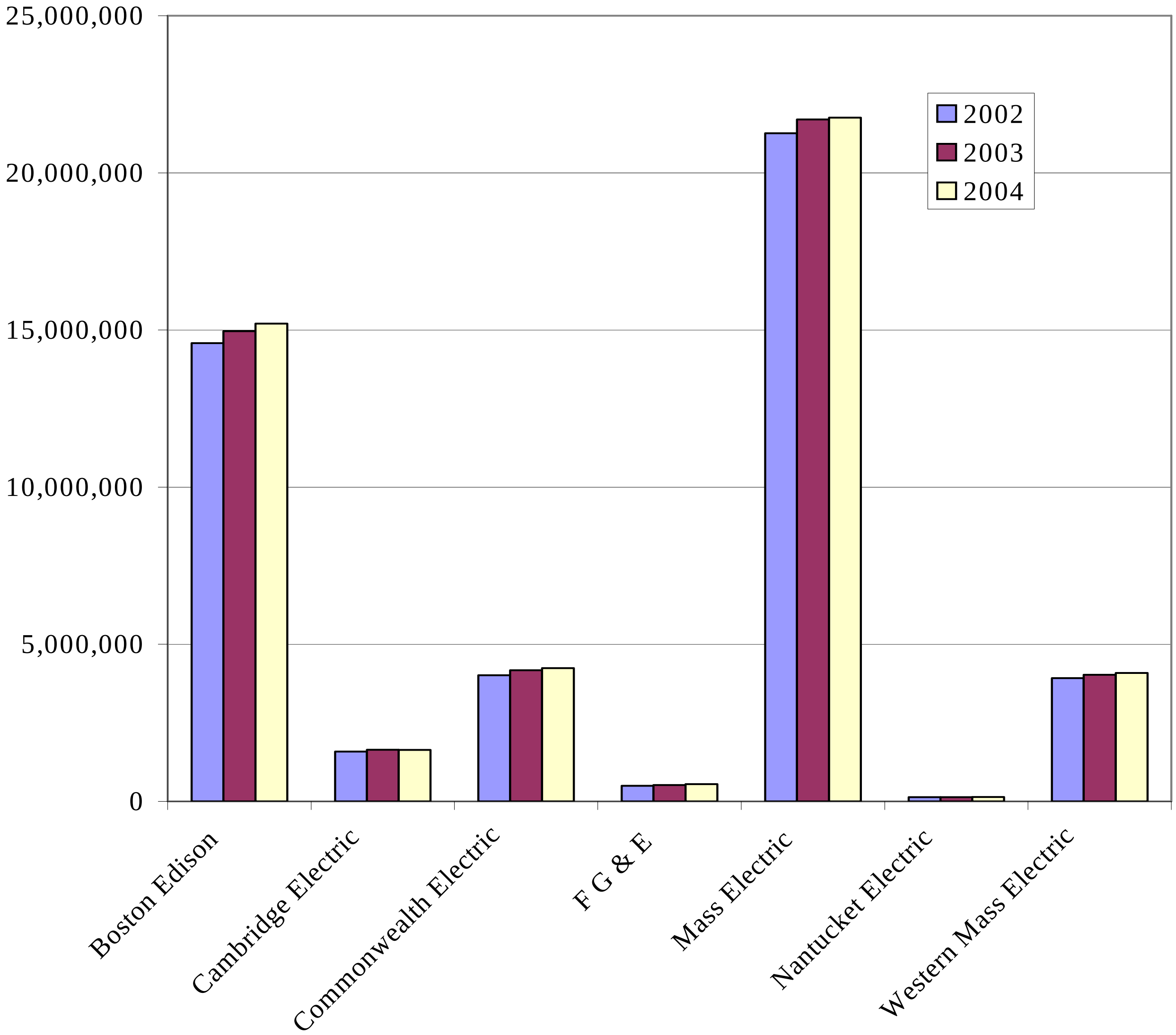
Electricity Demand Has Increased

Electricity demand, as measured by MWh sales, has increased during 2002-2004 for the eight investor-owned LDCs. Load has consistently grown over the study time period, which results in

[54] Municipal company customers and revenues are not included because these service territories are closed to competitive suppliers.

additional revenues to LDCs and municipal companies but also additional opportunities for sales to competitive suppliers.

Figure 4-1
Load (MWh) by Distribution Company, 2002-2004

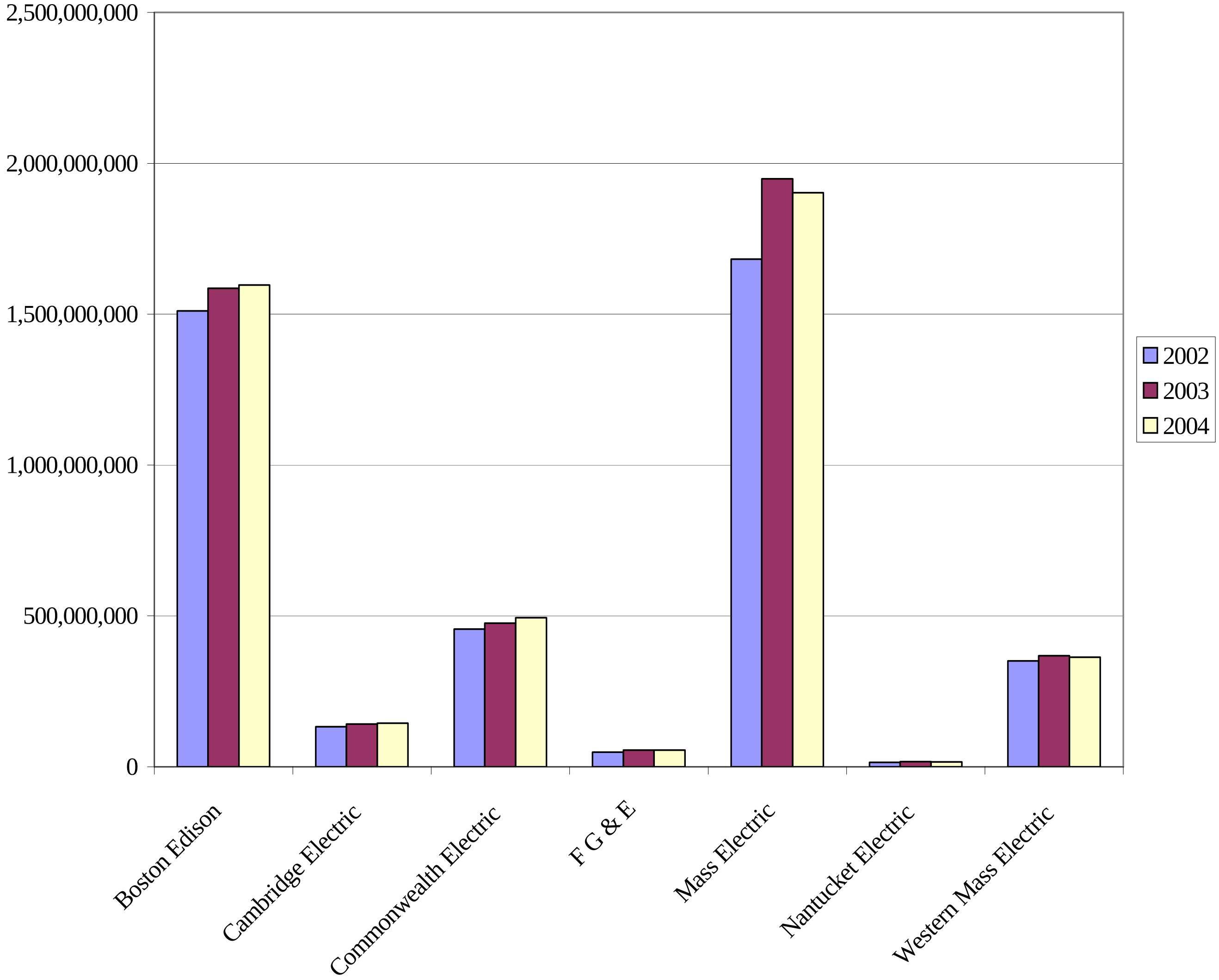


Sources: FERC Form 1, Municipal Reports to DTE, Massachusetts Electric

Revenues Are More Volatile Than Sales

During 2002-2004, 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' potential purchased-energy costs and revenues in MA also to be somewhat volatile.

Figure 4-2
Revenues by Distribution Company, 2002-2004



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

Competitive Market Migration Analysis

A look at the retail electricity market in the period 2002 through 2004 shows that competitive service captured a similar share of the total MWh or load in 2002 and 2003, and an increasing share in 2004. Competitive generation as a percentage of the total was 21% in 2002, 20.2% in

2003, and 25.5% in 2004. The increase in 2004 can be attributed to an increase in the number of customers receiving Default Service set at a market rate and the enrollment of a significant number of large customers into competitive service. Table 4-2 enumerates in MWH the size of the Utility vs. Competitive Service during 2002-2004.

Table 4-2
Utility vs. Competitive Service, MWh
2002-2004

	2002	**2003**	**2004**
Utility Service	36,314,115	37,490,158	35,256,628
Competitive Service	9,734,044	9,488,537	11,978,495
Total	46,048,158	46,978,695	47,235,123

Source: DOER Migration Data

The development of a competitive market is often measured using either the number of customers receiving competitive service or the amount of load provided by competitive suppliers. Figures 4-3 and 4-4 show these data. Generally, number of customers is a more relevant metric when examining residential or small C&I customers because they have smaller and more similar loads. In this report we will look at both the number of customers and the amount of load that has migrated to competitive service.

In addition, there are characteristics of different customer groups that make them attractive as potential customers. The most common characteristics are size, load shape and geographical location. Size or usage is a major factor because the cost of marketing and providing service to a large customer is a small percentage of the total cost and can be justified given the total dollar sale of electricity. Load shape can also make a customer with sufficient size attractive because if the load shape is better than the load shape for its rate class there can be savings due to less need to procure balancing services that smooth out peaks in demand. Finally, geography or location can be a factor. For example, one distribution company's generation rates can be higher than another's relative to the all-in wholesale price, thus providing greater opportunity for a competitive supplier to beat a specific utility's regulated price.

Here we will look at the MA market as three segments; Residential and Small Commercial and Industrial, Medium Commercial and Industrial, and Large Commercial and Industrial.[55]

[55] 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.

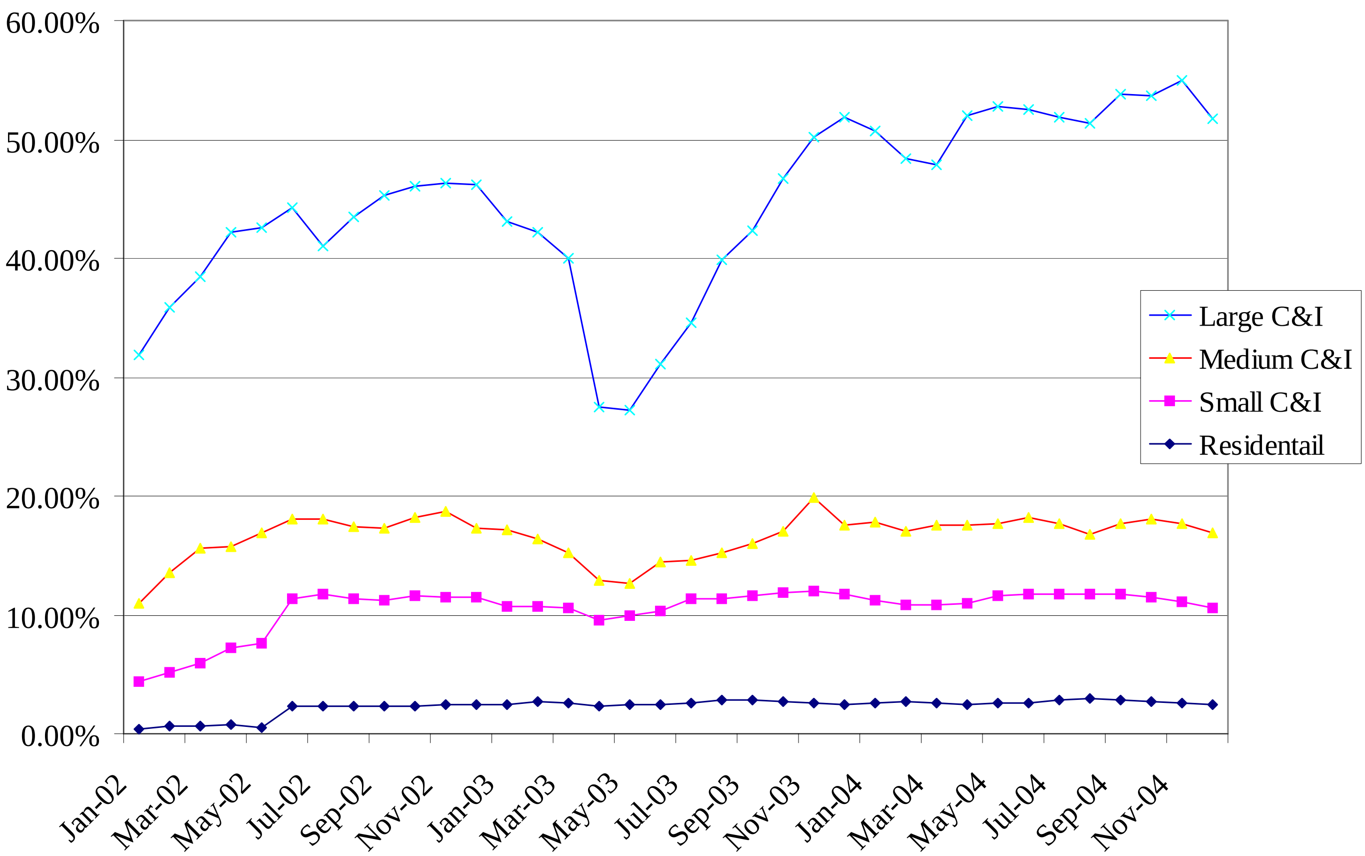
Residential and Small Commercial and Industrial Customers

May 2002 Rise in Competitive Customers and Load – Entry of the 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.

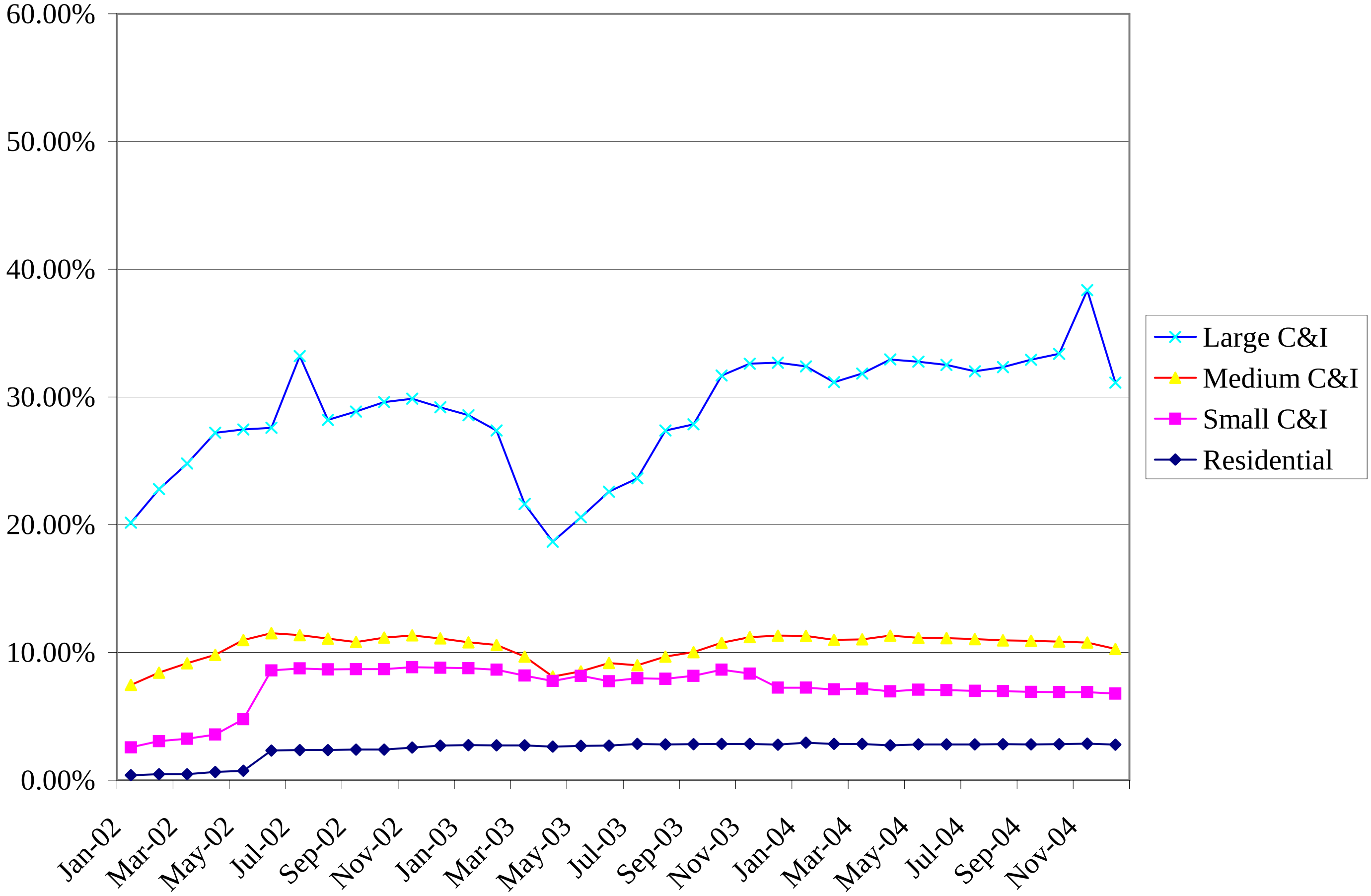
The percentage of customers and load in the residential and small commercial and industrial sectors on competitive service was low and relatively stable through the three-year period. The exception was after May 2002 when the Cape Light Compact (CLC), a regional aggregation of 21 towns in Barnstable County, initiated a pilot program to provide competitive generation service for 41,000 default service customers. Although the Cape Light Compact represented all customer classes, a substantial majority is residential and small commercial customers. The rise in June 2002 migration figures for residential and small commercial and industrial customers, from 0.46% in May 2002 to 2.4% in June 2002 can be attributed almost solely to this aggregation. In addition, the number of Cape Light Compact customers increased throughout the remainder of 2003 and 2004, to 53,000 customers in December 2004.

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



Source: LDCs, DOER

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



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 have less accurate load information than larger customers. This lack of interval data makes it more difficult for suppliers to accurately price the supply to meet customer load and lowers a supplier's margins.

The Medium Commercial and Industrial customers enjoyed a degree of success in the period 2002-2004. Competitive load for the period was consistently around 17% and around 11% of the customers. The larger load number at 17% can also be an indication of the fact that customers with larger than the average load for the group are migrating to competitive service. Like the Large C&I customers, in May 2003, medium customers reacted to the implementation of SMD by leaving competitive service for regulated service. The percent of customers on competitive service dipped to 8% in April 2003, and the load dipped to 12% in May 2003.

In general it is the medium sized customers' characteristics of substantial load size and price sophistication that identify it as the most likely target for future market development.

Large Commercial and Industrial Customers

These Customers Had Most Success in Migration

The Large Commercial and Industrial Customers are seen 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. The Large Commercial and Industrial customers bottomed in May 2003 at 21% of the customers and 27% of the load, and peaked in November 2004 with 38% of the customers and 52% of the load.

March 2003 Decrease – Large C&I and Medium C&I - ISO NE Standard Market Design

In the period January through March 2003, the competitive load for Large Commercial and Industrial customers, and to a lesser extent for Medium Commercial and Industrial customers, experienced a major decline. One reason is attributed to the implementation of SMD by the ISO-NE on March 1, 2003. The new wholesale market design caused great uncertainty for participants in both the wholesale and retail markets. Suppliers and customers were unaccustomed to assessing the risk involved with the new market design and congestion pricing. In addition, as pointed out in Figure 2-7, there was a marked increase in the All-In power prices in the period prior to March 1st while the regulated Standard Offer and Default Services prices were $20 to $25 lower per MWh. As a result large numbers of customers returned to the security of regulated service.

Post March 2003 Increase – The Market Adapts to SMD and Competitive Load Rises for Large Customers

In the period May through December 2003, the competitive load for Large Commercial and Industrial customers climbed steadily from a March 2003 low of 27% to 52% in December. The rapid increase is also present, but to a lesser degree, for medium Commercial and Industrial customers. The constant rise can be associated with the familiarity suppliers and customers developed for SMD and their increased confidence in the ability of contracts to reflect the costs and assign the risks appropriately. Finally, there was a rise in the prices of utility-provided service compared to competitive service with energy purchased from the wholesale market (see Figure 2-7).

Post November 2004 Decrease – Uncertainty at the End of Standard Offer

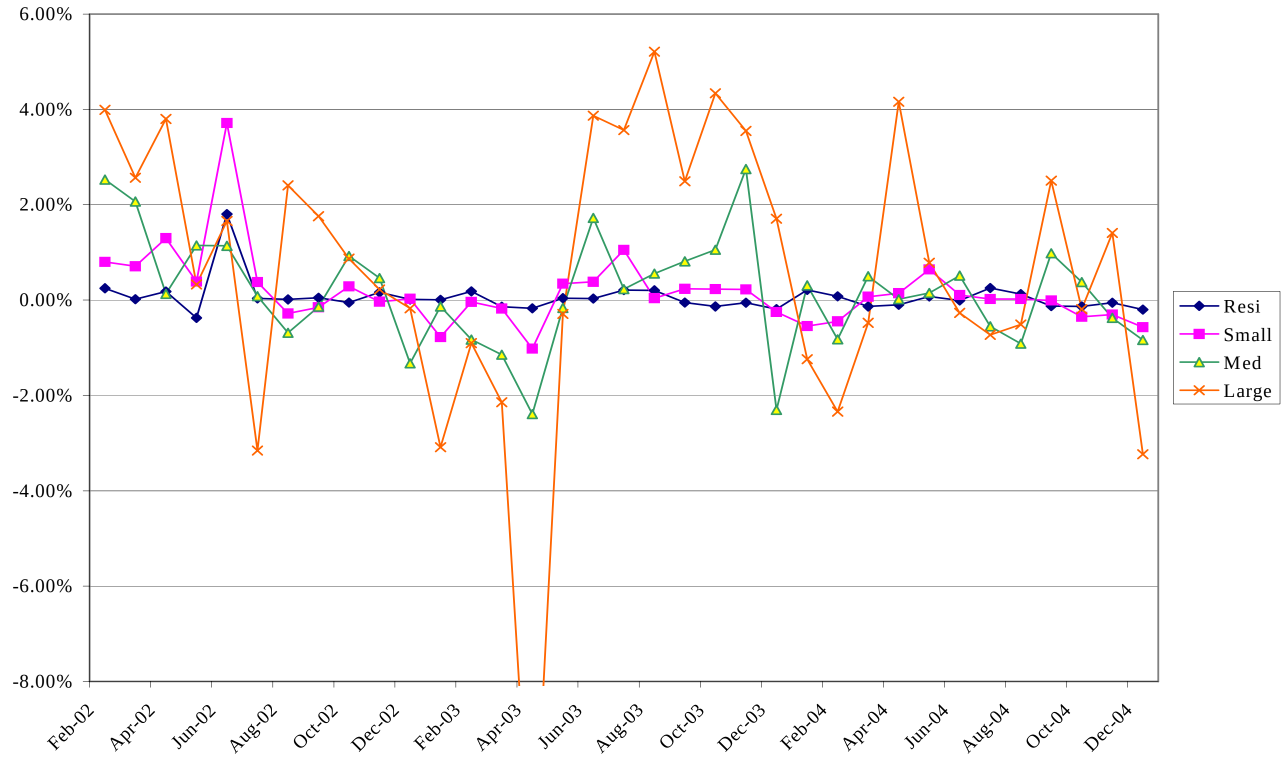
Although the data for 2004 is not conclusive in itself, the decline in Large Commercial and Industrial customers receiving competitive service at the end of 2004 may be attributable to regulatory uncertainty. The Massachusetts Restructuring Act set March 1, 2005 as the end of the transition period from regulated to a deregulated market. On March 1 the utility offered standard offer service was scheduled to end and all customers were to continue on Default Service at a market rate. It was not clear that in the last months leading up to this date the legislature or the MA DTE would not change the design of the post standard offer service and customers and suppliers waited to see what would happen. In November, 38% of the customers and 55% of the load were on competitive service. This declined to 31% of the customers and 52% of the load in December 2004.

Monthly Switching and Return Rates

Figure 4-5 illustrates the rate of change in the customer load on a monthly basis for the period 2002-2004 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. Large customers registered the highest gains and declines, showing a minus 12% change in April 2003 and a 5% gain in August 2003. The minus 12% in April corresponds to the implementation of Standard Market Design in May 2003 by ISO New England. The 5% change in August 2003 shows competitive service load growth after the implementation of Standard Market Design.

Medium customers switching rates generally track the large customers throughout the period, exhibiting less dramatic swings in the rate but simultaneous increases and decreases. Residential and small commercial and industrial customers never exceed a 2% change in any month and are generally positive and negative when the other sectors are. All customer groups show a negative switching rate from October through December 2004. This may be attributed to regulatory uncertainty surrounding the end of the Standard Offer period on March 1, 2005.

Figure 4-5
Monthly Switching Rates



Source: LDCs, DOER

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. Lots of entrants into a market are an indication that opportunity exists to make money. 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.[56] It presents the change in supplier licenses issued by DTE between 2004 and 2005. In

[56] See complete list of brokers and suppliers licensed in MA in Appendix Table A-7.

2005, of the 19 electricity brokers licensed, 3 indicated the intention to work in the residential market, 16 brokers chose the commercial market, and 15 the industrial market.

Three competitive suppliers entered the Massachusetts market in 2005. Only 1 supplier was interested in the residential market, while 2 stated a preference for commercial and 1 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, with 13 Electricity Brokers and 7 suppliers' licenses selecting this market. Also, the new supplier for residential customers was not noted as "active" in all distribution company service areas, thus limiting the availability of competitive supply to fewer residential customers.

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

	Total Licenses Issued	For Residential	For Commercial	For Industrial
2004				
Brokers	28	10	28	24
Suppliers	19	6	17	16
Total	47	16	45	40
2005				
Broker	47	13	44	39
Supplier Licenses	22	7	19	17
Total	69	20	63	56
Net Change				
Brokers	19	3	16	15
Suppliers	3	1	2	1
	22	4	18	16

Source: MA DTE

Competitive Suppliers' Market Share

The top 3 competitive market suppliers held 78.1% and 84.1% market share in 2003 and 2004. Table 4-4 shows 2003-2004 (data were unavailable for 2002) market share data illustrating the concentration of the largest players in the market. Smaller suppliers are aggregated in a second group.[57] The data show increased concentration of market share among the 3 largest suppliers. DOER will continue to track market share in future PRM reports.

[57] DOER compiled confidential data available from NEPOOL GIS data to derive competitive supplier's market share positions. DOER compiled individual companies' shares and subsequently aggregated the largest three or four suppliers per year to illustrate the dominant positions of the largest MA competitive suppliers. Efforts were made to

Table 4-4
Market Share of Suppliers

	2003	2004
Top 3 Suppliers	78.1%	84.1%
Remaining Suppliers	21.9%	15.9%
Total # of Suppliers	11	9

Source: NEPOOL GIS, DOER

Conclusion

During the period 2002-2004 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 the institution of Standard Market Design in April 2003. 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 was the medium commercial and industrial customers for whom some progress was made but no clear pattern has emerged.

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. DOER will conduct periodic survey of the retail competitive suppliers to monitor the market and identify issues or barriers to market development.

Finally, though there was significant entry of potential providers of competitive supply in 2005, market share data show high concentration among 3 major suppliers, implying that there is a significant difference between being licensed to operate and actually operating in the Massachusetts market.

check the accuracy of the annual NEPOOL GIS load data with DOER customer migration data. Due to supplier unfamiliarity with NEPOOL GIS accounting and compliance, 2002 data does not agree with DOER competitive data, thus 2002 data is not illustrated.

Appendix

Data Tables

Table A-1

Natural Gas Prices
2002-2004
$/MMBtu or $/Mcf

	Henry Hub	Tenn Zone 6	Dracut into TN	Algonquin
2002	3.34	3.82	3.61	3.80
2003	5.45	6.47	6.37	6.54
2004	5.85	6.77	6.66	6.85

Table A-2

Wholesale System Peaks, Summer and Winter
2002-2004

Summer Peak

	Date	Day	Hour Ending	Actual Peak (MW)	Wthr Norm Peak (MW)
2002	August 14, 2002	Wednesday	15:00	25,348	24,590
2003	August 22, 2003	Friday	15:00	24,685	25,170
2004	August 30, 2004	Monday	16:00	24,116	25,760

Winter Peak

	Date	Day Type	Hour Ending	Actual Peak (MW)	Wthr Norm Peak (MW)
2001/2002	December 17, 2001	Monday	18:00	19,872	21,470
2002/2003	January 22, 2003	Wednesday	19:00	21,533	21,730
2003/2004	January 15, 2004	Monday	19:00	22,818	22,085
2004/2005	December 20, 2004	Monday	19:00	22,635	22,450

Source: ISO-NE

Table A-3

MA Zones/NEPool HUB Premium
NEMA, SEMA, WCMass

	NEMA/NEPool HUB	SEMA/NEPool HUB	WCMass/NEPool HUB
3/1/2003	1.00	0.98	1.00
4/1/2003	0.99	0.98	1.00
5/1/2003	0.99	0.99	1.00
6/1/2003	0.98	0.98	1.00
7/1/2003	0.98	0.97	1.01
8/1/2003	0.97	0.96	1.00
9/1/2003	0.99	0.98	1.01
10/1/2003	0.99	0.97	1.00
11/1/2003	1.00	0.97	1.00
12/1/2003	1.00	0.97	1.00
1/1/2004	0.98	0.97	1.00
2/1/2004	0.98	0.97	1.01
3/1/2004	0.98	0.97	1.00
4/1/2004	0.98	0.97	1.00
5/1/2004	1.00	0.97	1.00
6/1/2004	0.99	0.97	1.01
7/1/2004	0.98	0.96	1.01
8/1/2004	1.01	0.97	1.02
9/1/2004	0.99	0.98	1.02
10/1/2004	1.00	0.95	1.00
11/1/2004	0.98	0.98	1.00
12/1/2004	0.99	0.98	1.00
Average Premium	0.988	0.973	1.005

Table A-4
On-Peak vs. Off-Peak Price Ratios

	NEPool ECPs on/off ratio	NEMA Real Time prices	SEMA Real Time prices	WCMA Real Time prices
Jan-02	1.35			
Feb-02	1.21			
Mar-02	1.27			
Apr-02	1.35			
May-02	1.47			
Jun-02	1.52			
Jul-02	1.75			
Aug-02	1.72			
Sep-02	1.28			
Oct-02	1.23			
Nov-02	1.27			
Dec-02	1.22			
Jan-03	1.16			
Feb-03	1.20			
Mar-03		1.18	1.17	1.18
Apr-03		1.21	1.21	1.22
May-03		1.44	1.43	1.44
Jun-03		1.28	1.30	1.31
Jul-03		1.22	1.22	1.23

	NEPool ECPs on/off ratio	NEMA Real Time prices	SEMA Real Time prices	WCMA Real Time prices
Aug-03		1.24	1.22	1.25
Sep-03		1.24	1.24	1.25
Oct-03		1.27	1.27	1.27
Nov-03		1.27	1.26	1.27
Dec-03		1.34	1.33	1.33
Jan-04		1.49	1.50	1.49
Feb-04		1.20	1.21	1.22
Mar-04		1.23	1.23	1.23
Apr-04		1.25	1.24	1.25
May-04		1.34	1.33	1.34
Jun-04		1.30	1.29	1.30
Jul-04		1.26	1.25	1.27
Aug-04		1.39	1.34	1.38
Sep-04		1.25	1.25	1.28
Oct-04		1.36	1.32	1.35
Nov-04		1.30	1.30	1.30
Dec-04		1.31	1.31	1.31

Table A-5

Day Ahead vs. Real Time Prices
NEMA, SEMA, WCMass

Mar 2003-December 2004

	DA Peak/RT Peak NEMA	DA Peak/RT Peak SEMA	DA Peak/RT Peak WCMass
Mar-03	105%	103%	104%
Apr-03	102%	100%	101%
May-03	96%	96%	96%
Jun-03	110%	102%	102%
Jul-03	104%	104%	103%
Aug-03	112%	105%	105%
Sep-03	97%	96%	96%
Oct-03	100%	101%	101%
Nov-03	100%	99%	99%
Dec-03	98%	99%	99%
Jan-04	111%	111%	111%
Feb-04	105%	103%	103%
Mar-04	102%	102%	102%
Apr-04	104%	104%	104%
May-04	102%	102%	102%
Jun-04	105%	106%	105%
Jul-04	102%	103%	101%
Aug-04	94%	97%	96%
Sep-04	103%	102%	101%
Oct-04	97%	98%	96%
Nov-04	108%	103%	103%
Dec-04	106%	100%	100%
mean	103%	102%	101%
min	94%	96%	96%
max	112%	111%	111%

Table A-6
Installed Capacity net Average Monthly Reductions
versus Monthly Peak Load
(MWs)

	Total Capacity	Capacity net Reductions	Reductions: AMS Scheduled Outages	Reductions: Forced OOS	Gen Unavailable due to start Time	Forced Out of Service	Peak
Jan-02	29,600	26,011	739	2,850	0	2,850	19,389
Feb-02	30,371	26,181	1,646	2,544	0	2,544	19,406
Mar-02	29,976	23,428	4,106	2,441	0	2,441	18,416
Apr-02	30,018	23,386	3,293	3,339	0	3,339	18,438
May-02	29,908	23,646	3,216	3,046	0	3,046	18,460
Jun-02	29,189	26,311	190	2,688	0	2,688	23,124
Jul-02	28,945	26,846	100	1,999	0	1,999	24,935
Aug-02	29,265	26,089	190	2,986	0	2,986	25,524
Sep-02	28,905	23,738	2,350	2,817	0	2,817	22,621
Oct-02	30,019	23,453	4,384	2,183	0	2,183	19,567
Nov-02	30,495	24,309	3,197	2,990	0	2,990	18,814
Dec-02	30,534	26,227	781	3,526	0	3,526	20,920
Jan-03	31,385	28,113	1,148	2,124	0	2,124	21,597
Feb-03	31,860	27,695	700	3,465	0	3,465	20,488
Mar-03	31,301	26,214	2,452	2,635	0	2,635	20,279
Apr-03	31,978	25,383	4,143	2,452	0	2,452	18,036
May-03	32,648	25,256	3,958	3,434	0	3,434	16,741
Jun-03	31,811	28,057	1,213	2,540	0	2,540	24,500
Jul-03	31,843	29,183	100	2,561	0	2,561	24,026
Aug-03	32,587	30,672	203	1,712	0	1,712	24,664
Sep-03	31,500	27,767	1,853	1,880	0	1,880	19,374
Oct-03	33,014	25,382	4,681	2,951	0	2,951	18,064
Nov-03	33,521	25,841	2,500	5,181	0	5,181	18,514
Dec-03	33,565	28,103	1,016	4,446	0	4,446	20,698

	Total Capacity	Capacity net Reductions	Reductions AMS Scheduled Outages	Forced OOS	Gen Unavailable due to start Time	Forced Out of Service	Peak
Jan-04	33,711	24,672	429	5,005	3,604	8,609	22,727
Feb-04	34,092	22,409	1,197	3,163	7,323	10,486	20,013
Mar-04	33,634	20,862	2,023	3,124	7,626	10,750	19,233
Apr-04	33,552	19,479	5,530	2,991	5,553	8,543	17,881
May-04	33,845	19,987	4,255	4,305	5,298	9,603	18,218
Jun-04	32,151	22,466	1,007	3,134	5,545	8,679	22,960
Jul-04	32,750	23,889	148	2,347	6,365	8,712	23,142
Aug-04	32,843	24,184	145	2,117	6,397	8,514	24,146
Sep-04	32,436	21,826	797	1,914	7,899	9,813	20,598
Oct-04	34,761	20,651	1,942	5,082	7,086	12,168	17,753
Nov-04	34,220	21,603	1,233	4,117	7,267	11,384	18,985
Dec-04	34,455	23,092	210	3,486	7,668	11,154	22,552

Table A-7

Active Retail Electricity Brokers and Suppliers

Active Retail Electricity Brokers -5/2005

	Active in these service areas			
	NSTAR	FG&E	MECO	WMECO
Absolute Energy Services			X	X
Acela Energy Group	X			
Affiliated Power Purchasers				X
American Power Net Services	X		X	X
Axesses Energy Group	X		X	X
Bay State Consultants	X			
Better Cost Council	X			
Chamber Energy Coalition	X	X		
Competitive Energy Services –MA	X		X	X
DSR Energy	X			
Energy Rebate	X		X	X
Global Companies	X	X	X	X
James Devaney Fuel Co.	X		X	
LowCost Energy			X	
Market Direct	X		X	X
Metromedia Power	X		X	X
Northeast Energy Partners	X		X	X
Patriot Energy	X	X	X	X
Pay Less Utilities			X	
Power Mgmt Co.-New England			X	X
SourceOne	X		X	X
Supreme Energy	X		X	
Usource	X		X	X
World Energy Solutions	X		X	

		Active in These Service Areas			
	Total	NSTAR	FG&E	MECO	WMECO
	24	19	3	18	14
New Entrants since 5/2004	6	3	0	4	1

Source: Distribution Company Active Lists

*Companies in the MECO Green Up Program are not Included

Retail Electricity Suppliers 5/2005

	Active in these service areas			
	NSTAR	FG&E	MECO	WMECO
APS Energy Corp.	X			X
ConEdison Solutions	X		X	X
Constellation NewEnergy	X	X	X	X
Dominion Retail Energy Mkting	X		X	X
Gexa Energy			X	
Mirant Americas Retail	X		X	
MXENERGY			X	
Select Energy	X	X	X	X
Sempra Energy Solutions	X		X	
Sprague Energy	X			X
Strategic Energy	X		X	X
Suez Energy Resources f/k/a Tractabel	X	X	X	X
TransCanada Power Mkting	X	X	X	X

		Active in These Service Areas			
	Total	NSTAR	FG&E	MECO	WMECO
	13	11	4	11	9
New Entrants since 5/2004	1	0	1	2	0

Source: Distribution Company Active Lists

Note: Con Ed Solutions and Suez entered additional areas since 5/2004