Commonwealth of Massachusetts

Office of Consumer Affairs and Business Regulation

Market Monitor 2000
A Report by the Division of Energy Resources

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

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ACKNOWLEDGEMENTS

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

TABLE OF CONTENTS

TABLES

FIGURES

EXECUTIVE SUMMARY

With the passage of the Electric Industry Restructuring Act (the Act) in 1997, Massachusetts set out on an historic mission to use competitive market forces to reduce prices and provide customers with choice of their retail electricity supplier. The year 2000 marked the third year of electric industry restructuring in Massachusetts. Thus far, the results have been positive, though issues and challenges remain. For example, Massachusetts' electric customers have saved $1.7 billion through the transitional rate reductions mandated by the Act. However, wholesale market price volatility and uncertainty about market rule changes left retail competitive suppliers unsure of what strategies to pursue in Massachusetts. Several market initiatives need to be implemented to overcome market barriers and alleviate problems preventing a more competitive, robust wholesale and retail market. In this Executive Summary, the Division of Energy Resources outlines the highlights and significant events of 2000.

The Act requires the Division of Energy Resources (DOER) to monitor the changes in the electric industry each year. As prescribed by the Legislature, DOER reports on electricity prices and price disparities, competitive market developments, and electric system reliability (M.G.L. c 25A §§ 7, 11D, 11E). Below are the major findings for calendar year 2000.

2000 HIGHLIGHTS

1. Consumers Saved $775 Million in 2000.

As mandated by the Act, each local distribution company met the required fifteen percent rate reduction by September 1999. These reductions provided continuing savings to Massachusetts customers in 2000, even with inflation pressures. In 2000, customers saved $775 million over pre-restructuring rates. Residential customers saved $292 million, commercial customers $362 million, industrial customers $112 million, and other customers saved $9 million. When added to savings realized since March 1998, total savings are almost $1.7 billion.

2. Cape Light Compact Became First Approved Municipal Aggregation.

The Act allows municipalities to aggregate electricity purchases for their public buildings and interested electricity customers, including residential, commercial, and industrial customers. In 2000, the Cape Light Compact's plan was the first municipal aggregation plan approved by the Department of Telecommunication and Energy. The Cape Light Compact consists of 21 towns on Cape Cod, Barnstable County and Martha's Vineyard, representing approximately 185,000 customers. Using an aggregation approach to consolidate energy purchases into larger buying blocks will help many small consumers obtain lower prices and help suppliers reduce marketing and education costs.

3. New England Increased Power Capacity.

New England's electric generation capacity increased significantly in 2000, adding 1,466 megawatts at six new power plants. In Massachusetts, power plant development has been vibrant, in part, driven by a liberalization of power plant siting procedures. The restructuring legislation made it easier for merchant generation companies to enter the state. Maintaining sufficient generation capacity is critical for the electric system's reliability.

4. Massachusetts Avoided California's Electricity Problems.

During 2000, California confronted unprecedented electricity shortages, wholesale price spikes and a financial crisis among its electric distribution companies. Despite years of dramatically increasing demand for electricity, no new power plants were built in California after 1990. Instead, the state relied on electricity imports from adjacent states. New England avoided similar problems for several reasons. New England states, particularly Massachusetts, fostered a more stable and competitive electric marketplace, which encouraged developers to build new power plants and the natural gas pipelines necessary to supply fuel to the plants. Furthermore, Massachusetts encouraged utilities to divest generation assets and allowed its utilities to determine how best to buy power for their standard offer and default service consumers.

5. Wholesale Prices Exceeded Retail Prices.

The nationwide increase in the cost of natural gas in 2000 contributed to higher wholesale electricity prices. In New England, the monthly weighted-average price of wholesale electricity was $46.15 per megawatt-hour in 2000, a 37 percent rise over the 1999 monthly average price of $33.78. At the same time generation prices rose in the wholesale market, retail market generation prices for standard offer and default services barely increased. For most of 2000, the weighted-average of these prices was $41 per megawatt-hour.

6. Competitive Suppliers Withdrew From the Market.

During the first two years of restructuring, Massachusetts experienced an immature yet promising retail competitive market with a handful of retail competitive suppliers selling electricity. The number of competitive choices declined in 2000, although a few competitive suppliers continued doing business in the state. Contributing substantially to the contraction of the retail market was the fact that regulated generation prices (in retail rates) were lower than wholesale electricity generation prices.

7. Default Service Customers and Consumption Grew Substantially.

As competitive suppliers withdrew from the market or curtailed enrollment of new customers, the number of competitive supply customers fell from 9,471 to 5,682, during 2000. Default service customers represented 19.6 percent of total customers at the start of 2000, and 13 percent of electricity consumption. However, the number of default service customers grew each month. By December 2000, their number grew to 25 percent of total customers and their consumption grew to 20 percent of total demand.

8. Standard Offer and Default Service Rates Were Uncoupled.

During 2000, the utilities' costs for default service contracts increased, due to higher electric generation prices. As a result, default service was priced below cost. Under this condition, competitive suppliers could not sustain their retail offerings to beat default service prices. To compound the problem, the utilities saw the number of default service customers increase. As a result, utilities deferred the cost difference (known as deferrals) for default service and the deferrals grew. In 2000, the Department of Telecommunications and Energy allowed utilities to uncouple standard offer and default service rates and base the default service price on market-based costs. (Default service had been priced the same as standard offer service.)

9. New England Forms A Regional Transmission Organization (RTO) Plan.

In 2000, the Federal Energy Regulatory Commission (FERC) called for the creation of Regional Transmission Organizations (RTOs) in FERC Order 2000. They believed that large RTOs would foster wholesale market development, provide increased reliability and ultimately result in lower wholesale electricity prices. Even before Order 2000 was issued, New England already met many of the required characteristics and functions of a RTO. New England has the only competitive power pool in the United States with the characteristics of an interstate power pool where incumbent utilities have ceded control over the energy markets. Nonetheless, New England electric industry participants collaborated throughout the year to propose changes needed to satisfy all of FERC's RTO required characteristics and functions.

2000 MARKET MONITOR REPORT FOCUS

This is DOER's third annual assessment of electric restructuring progress in Massachusetts. It includes a discussion of electricity price and price disparities for each customer sector in Massachusetts. DOER closely examines the retail effects of high wholesale prices and low retail prices, and provides an overview of the resulting changes in customer migration on standard offer, default service, and competitive supply. The report highlights initiatives and regulatory actions taken to address and eliminate market barriers to competition at both the retail and wholesale levels. In addition, DOER presents an analysis of electricity demand in Massachusetts, New England, and the United States.

REPORT OUTLINE

Chapter I introduces the restructuring success stories that occurred during this year's transition toward more competitive markets.

Chapter II includes a review of wholesale electricity prices, overall retail prices, and regulated standard offer and default service generation prices. Price information shows that the companies continued to meet the mandated rate reductions and retail prices rose less than the rate of inflation. This chapter also places the Massachusetts retail prices within the context of the United States.

Chapter III provides a review of the retail customer migration in 2000. Data collected by DOER is presented to show how customers moved among standard offer, default service and competitive supply. This chapter provides an account of competitive suppliers' withdrawal from the market in 2000.

Chapter IV identifies retail and wholesale market barriers, and initiatives undertaken to overcome them. In this chapter, attention is given to changes in the acquisition and price of default service. Another section focuses on the need to examine whether or not some electric distribution companies' services such as metering and billing should be provided through the competitive market. Other issues include reducing distribution companies' cost while maintaining reliability; changes in wholesale market rules and design; and New England's proposal to create a Regional Transmission Organization.

Chapter V presents, for the first time in DOER's Market Monitor reports, an analysis of electricity demand. This evaluation presents the differences between the Massachusetts, New England and United States electricity markets. It also highlights the variations in electricity consumption among various sectors –residential, commercial, and industrial. The demand analysis illustrates what load profiles are attractive to marketers.

INTRODUCTION

This report reviews and analyzes electric restructuring activities during calendar year 2000, year three in the implementation of Massachusetts' Electric Restructuring Act (the Act).[1] Passed in 1997, implementation of the Act began in March 1998. The original proponents of this complex and far-reaching reform suggested a timeframe of seven years for full implementation. The Act directs the Massachusetts Division of Energy Resources (DOER) to report annually on the progress of restructuring. To that end, the *Market Monitor 2000* report is the third such report.

Energy events in California last year underscore the importance of continuing to monitor our restructuring efforts in Massachusetts. Though not the primary focus of this report, significant differences between Massachusetts' and California's restructuring processes are offered as the context for the *Market Monitor 2000.*

Despite years of dramatically increasing demand for electricity, no new power plants (capacity) were built in California since 1990. Instead, the state relied on power imports from adjacent states. These states also saw electricity demand grow quickly, reducing their ability to export power to California. Last winter, natural gas prices increased dramatically nationwide, driving wholesale electricity prices even higher. Problems resulting from capacity shortages were also compounded by high electricity demand during one of the hottest summers on record. By year-end, California faced "rolling blackouts" and few short-term solutions.

California's problems reflect weak energy policy decisions, bad weather and serious financial difficulties. In contrast to California, Massachusetts and New England witnessed a dramatic increase in new power plant construction, resulting in a 12% increase in regional power supplies for the year, almost six times the annual increase in demand. Massachusetts' restructuring process provided fertile territory for this new plant development in several ways. As restructuring began, incumbent local distribution companies (LDCs) sold existing plants to new competitors, thereby reducing concerns that LDCs would continue to control the power market. Also, the permitting process for new plants was streamlined. The resulting increase in power plants is the fundamental reason why Massachusetts is unlikely to see reliability problems or exploding wholesale prices, like California.

In addition, Massachusetts LDCs are allowed to enter into long-term electricity contracts to supply their customers rather than remain restricted to short-term "spot" purchases, as was the case in California. This provides Massachusetts' customers with greater stability in wholesale prices and supports several of the goals of restructuring.

The primary goals of restructuring in Massachusetts are lower prices for all customers, choice among competitive suppliers, improved air quality and increased fuel diversity. The law embraces a competitive market model to achieve these goals, while transitioning away from a regulated monopoly model. As highlighted in the *Market Monitor 1998* and *1999* reports, considerable achievements occurred during the first two years. These include:

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[1] Chapter 164 of the Acts of 1997: An Act Relative to Restructuring the Electric Utility Industry in the Commonwealth, Regulating the Provision of Electricity and Other Service, And Promoting Enhanced Consumer Protection Therein [hereinafter the Act].

- Mandated rate reductions saved retail consumers almost $1 billion on their electric bills.
- Vertically integrated utility companies sold power generation assets over book value, using the proceeds to reduce “stranded costs.”
- Distribution companies merged, realizing cost efficiencies through economies of scale.
- New power plants were built in Massachusetts and New England, enhancing reliability and wholesale competition.
- Redesigned wholesale electricity markets opened, rectifying many market imperfections and identifying others to be addressed. Wholesale market participants continue to work on the remaining market flaws.

Unfortunately, New England’s wholesale markets stability was not sustained during 2000 and wholesale electricity costs rose. In December 2000, the Department of Telecommunications and Energy (DTE) allowed some of these costs to be passed on to consumers as DTE approved retail price increases, which had been dropping steadily for two and a half years. The price increases are directly attributed to electric generation fuel cost increases. Most Massachusetts LDCs’ power contracts include provisions allowing suppliers to pass along extreme fuel price increases.

During 2000, natural gas prices throughout the United States increased more than four-fold, as did other fuels used to generate electricity. Given the extraordinary fuel price increases, most competitive suppliers were unable to purchase wholesale power at enough of a discount to compete with incumbent LDCs’ low standard offer and default service rates, which had not yet incorporated the increased wholesale costs. Many competitive suppliers could not sustain their retail offerings and withdrew from serving retail customers. Some suppliers focused their efforts only on large industrial customers and aggregations of commercial and institutional customers.

Further discussion on these issues can be found in the body of this report. Though this report presents a snapshot of year 2000, it should be noted that the full promise of restructuring in Massachusetts, though not far off, requires continued and deliberate attention to a host of issues, including:

- Maintaining and improving power system reliability.
- Keeping proposed new power plants and natural gas pipelines on schedule.
- Increasing the use of renewable energy.
- Further refining of wholesale power markets.
- Upgrading of power transmission systems.
- Protecting customers against price and supply problems.
- Maintaining and strengthening energy efficiency and peak demand reduction programs.

CHAPTER I: RESTRUCTURING PROGRESS

While a robust competitive retail market did not emerge in 2000, restructuring delivered several benefits. Mandated rate reductions provided continuing savings to customers, even with fuel adjustment charges and inflation pressures. Given the rate reductions, overall electricity prices in Massachusetts remained among the lowest in New England. An aggregation plan was approved for twenty-two Cape Cod communities and Martha's Vineyard, which holds promise of added savings for the aggregation's customers.

The addition of new power plants helped meet New England's increasing electricity demand. With this growth in electric generation capacity, the region was able to maintain wholesale electric reliability even during peak demand days. The substantial increase in new power plants was one of the fundamental reasons why New England did not suffer from the reliability problems that California experienced, starting in 2000. This chapter highlights those and other restructuring success stories that occurred during this year's transition toward more competitive markets.

Consumers Save on Electricity

Consumers saved $775 million in 2000 for total savings of almost $1.7 billion since March 1998. At the outset of restructuring, Massachusetts investor-owned distribution companies were required to reduce standard offer rates for each customer class at least 15 percent on or before September 1, 1999.[2] These reductions only applied to standard offer rates. Given that default service rates were equal to standard offer rates until December 2000, default service customers also benefited from rate reductions for most of the same time period. Table 1 presents cumulative savings attributed to the mandated rate reductions from March 1998-December 2000.

Table 1: Savings from Mandated Rate Reductions, 1998-2000

	Millions of Dollars				
	Residential	Commercial	Industrial	Other	All Customers
Mar-Dec 98	142	160	65	9	376
Jan-Aug 99	120	135	52	7	314
Sep-Dec 99	90	101	39	5	235
Jan-Dec 00	292	362	112	9	775
Totals, All Years	644	758	268	30	1,700
Net Savings*	638	754	262	29.9	1,684

Source: DOER, 1998-1999 Market Monitors; U.S. DOE/EIA, "Electric Power Annual, 2000"; Bureau of Labor Statistics

* Includes Default Service Price increases in December 2000.

[2] The Act required a 10 percent rate reduction from August 1997 rates on standard offer customers' bills in March 1998 and an additional 5 percent on or before September 1, 1999. However, the Act allowed companies to adjust rates for inflation from the August 1997 rates or another date determined by DTE as representative of 1997 rates for a company.

Retail Prices Increase Less than Inflation

Statewide retail electricity prices increased about 2 percent over 1999 prices (Table 2). This compares to an overall rate of inflation of about 3.4 percent.[3] Hence, prices actually decreased in real terms. Much of this change is likely explained by the LDCs' inflation adjustments to their rates, which are permitted under the Act. Municipal utilities' prices reflected similar increases, while remaining slightly lower than distribution company rates.[4]

Table 2: Average Prices for Local Distribution and Municipal Electric Companies

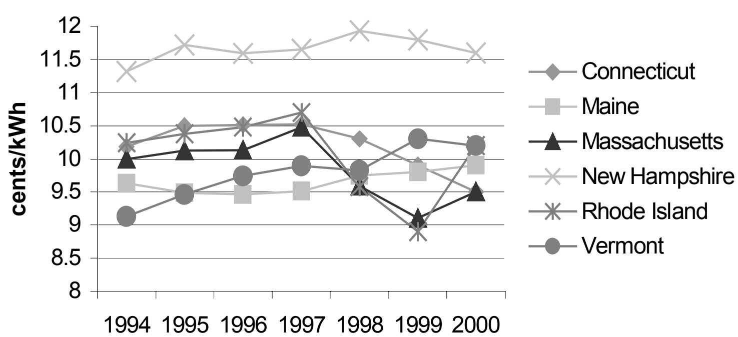
Utility Type	2000 (cents/kWh)	1999 (cents/kWh)	Percent Change
Distribution Companies	9.3	9.1	2.0
Municipal Companies	9.2	9.0	1.8
Entire State	9.3	9.1	1.9

Sources: U.S. DOE/EIA, "Electric Power Annual, 2000"; Municipal Utilities Annual Reports to Massachusetts Department of Telecommunications and Energy

Prices Lower than Pre-Restructuring and Lowest in New England

In 2000, Massachusetts reversed its declining retail electricity price path from previous years. Although the Massachusetts LDC average electricity price increased in 2000 over the 1999 level, the 9.3 cents per kilowatt hour (kWh) price was less than the pre-restructuring (1997) 10.5 cents per kWh price. Also, despite the increase, Massachusetts' average price in 2000 remained the lowest (same as CT's price) in New England (Figure 1).

Figure 1: New England Retail Electricity Prices by State



Source: U.S. DOE/EIA, "Electric Power Annual, 2000"

Cape Light Compact is First Municipal Aggregation

The Act allows municipalities to aggregate electricity purchases for their public buildings and interested electricity customers in all classes, including residential, commercial and industrial

[3] Consumer Price Index-Northeast Urban, Bureau of Labor Statistics.

[4] Seven investor-owned local distribution companies (LDCs) served Massachusetts customers —Boston Edison, Cambridge Electric, Commonwealth Electric, Fitchburg Gas and Electric Light, Massachusetts Electric, Nantucket Electric, and Western Massachusetts Electric during 2000—and 40 publicly owned municipal utilities, all with distinct service areas. In May of 2000, National Grid, USA purchased Eastern Edison and merged it into Massachusetts Electric's territory.

customers. Municipalities can also act jointly with other municipalities to consolidate their energy purchases into larger buying blocks.[5] Using such an approach can help many small consumers obtain lower prices and help suppliers reduce marketing and education costs. In 2000, two municipal aggregators consulted with DOER and presented municipal aggregation plans to the DTE for approval – the Cape Light Compact and the unified plan of the Cities of Haverhill and Easthampton.[6]

In August 2000, the DTE approved the Cape Light Compact's plan.[7] Based on a two-year competitive solicitation process, the Compact chose Select Energy as the competitive supplier for their Power Supply Program. Under the Power Supply Program schedule, consumers will be phased-in to the program. Large commercial/industrial and municipal accounts will be first, followed by additional municipal accounts, small commercial customers, and finally residential customers. The Plan allows Select Energy to delay the date on which the first group of customers receives generation service, if the market is not conducive to savings. However, once service is initiated for the first group, all customers must be phased in within a 24 month period. Under its Consumer Education Plan, the Compact will provide 60-day advance notice to electric consumers in its service area prior to the phase-in date for each customer class. It should be noted that under the Act, consumers are allowed to "opt-out" of an aggregation.

New England Increases Power Capacity

New England's electric generation capacity increased significantly in 2000, adding 1,466 megawatts at six new power plants (Table 3).

Table 3: New England 2000 Capacity Additions

Unit Name	State	Fuel	Summer Capacity (MWS)	Date
Maine Independence	**ME**	**Gas**	**470**	**5/1/2000**
Berkshire Power	**MA**	**Gas**	**267**	**6/19/2000**
Tiverton Power	**RI**	**Gas**	**256**	**8/18/2000**
Rumford Power	**ME**	**Gas**	**266**	**10/16/2000**
Androscoggin #3	**ME**	**Gas**	**38**	**12/28/2000**
Bucksport Energy	**ME**	**Gas**	**169**	**1/1/2001**
Total New Generation			**1,466**	

Source: ISO-NE

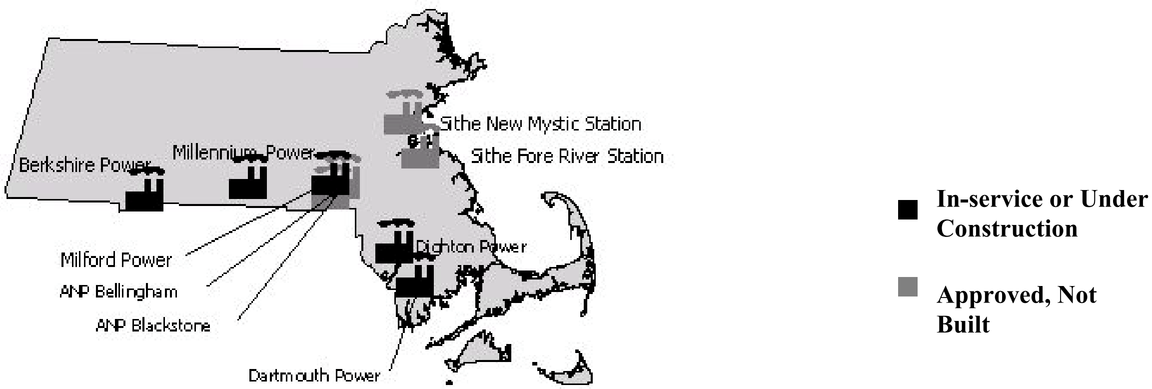
[5] M.G.L. c. 164, § 134 (a) authorizes any municipality or any group of municipalities acting together within the commonwealth to aggregate the electrical load of interested electricity consumers within its boundaries; provided; however, that the load is not served by a municipal lighting plant. Upon approval by its local governing entity, a municipality or group of municipalities may develop such an aggregation plan in consultation with DOER, providing detailed information to consumers on the process and consequences of the aggregation. M.G.L. c.134 (b) requires that a municipal aggregation plan provide for universal access, reliability, and equitable treatment of all classes of customers and meet any requirements established by law of the DTE concerning aggregated service.

[6] DTE remanded the plan for the Cities of Haverhill and Easthampton for further improvements.

[7] DTE-00-47. The Cape Light Compact is a municipal aggregation of 21 geographically contiguous towns on Cape Cod, Martha's Vineyard representing Barnstable and Dukes counties, representing approximately 185,000 customers.

Power plant development in Massachusetts has been vibrant, in part, driven by a liberalization of power plant siting procedures. The restructuring legislation has made it easier for merchant generation companies to enter the state. Figure 2 shows the locations of new and proposed power plants.

Figure 2: New Massachusetts Power Plants



Source: ISO-NE

System Reliability Improves for Peak Demand Days

Maintaining sufficient generation fuel diversity and generation capacity is critical for the electric system's stability. Two events in 2000 kept New England's capacity margins higher than the previous two years' margins. First, more generation was added to the region, as mentioned above. Second, despite continued economic growth in the region, summer demand did not reach forecasted levels, due to a cooler summer. The actual peak load of 21,912 MW for 2000 was 2.9 percent less than the 1999 peak load of 22,544 MW.[8]

Based on new capacity and peak load assumptions, the Independent System Operator of New England (ISO-NE) forecasts that capacity margins should continue to increase in future years. Figure 3 and Table 4 show actual and forecasted summer capacity, the weather-adjusted peak load, and capacity margins by year (1998-2004). As shown, the generation capacity reserve margin was 2,337 MWs in 2000, or about 10 percent of the load. The margin climbs to over 32 percent in 2002, assuming proposed power plants are built and come online as scheduled.

[8] For planning purposes the ISO-NE considers the "adjusted" peak load, which represents weather-normalized demand. Weather normalized load demand is a better gauge of capacity margin because the system must be planned to meet normal demand, and not demand caused by unusual weather patterns.

Figure 3: New England Summer Capacity and Peak Load Overview

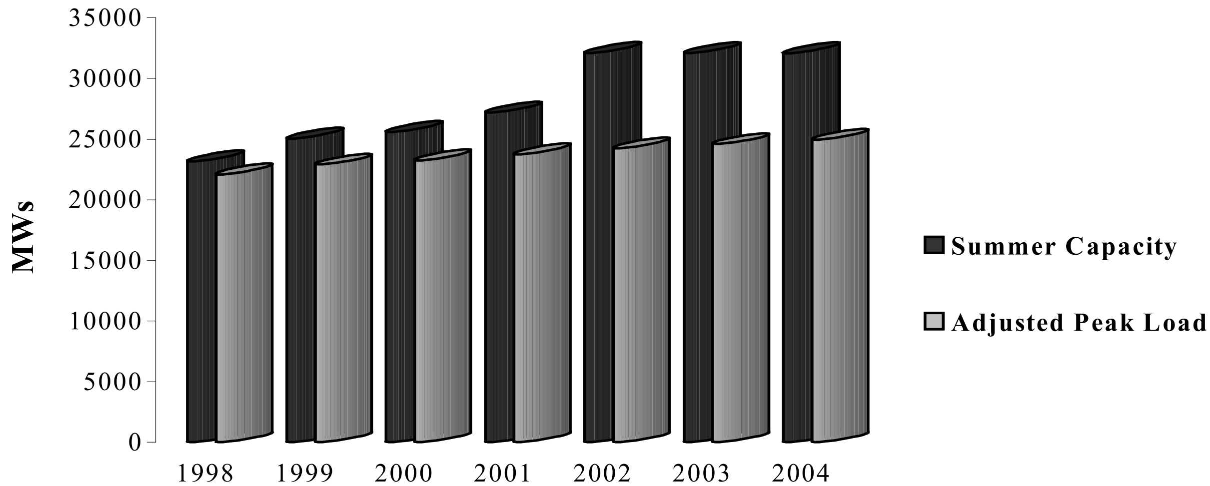


Table 4: New England Summer Capacity and Peak Load Overview

	1998	1999	2000	2001	2002	2003	2004
Summer Capacity MWs	23,171	25,052	25,579	27,182	32,097	32,090	32,084
Adjusted Peak Load MWs	22,091	22,902	23,242	23,742	24,233	24,586	24,954
Capacity Margin %	4.9	9.4	10.1	14.5	32.5	30.5	28.5

Source: ISO-NE

Historically, New England has benefited by having more generating capacity than is required to meet electricity demand and still maintain reserves. The ISO-NE is charged with the reliable operation of the New England bulk power system.[9] To accomplish this objective, ISO-NE and the New England Power Pool (NEPOOL) adhere to national and regional reliability criteria. Reliable operations require that sufficient electricity be generated and moved through the bulk power system to satisfy consumer demand and maintain sufficient reserve margins. Margins are maintained so that a failure of generation or transmission does not cause interruptions in service to customers.

However, there are times when available capacity is insufficient to meet customer demand, reserve requirements, and maintain adequate reserves. In these cases, the ISO-NE implements Operating

[9] ISO-NE is also charged with administering the energy and ancillary services markets efficiently and effectively.

Procedure Number 4 (OP 4) to increase system capacity.[10] This allows ISO-NE to procure emergency power from other power pools. It also allows additional actions, including public conservation appeals, to increase supply or decrease demand.

During 2000, ISO-NE implemented OP 4 procedures on six days. The ISO used different OP 4 measures each time because the system conditions and problem severity varied on each day. For example, on January 14, 2000, ISO-NE implemented only step 6 (emergency purchases from other power pools) for the state of Maine only. However, on May 8, 2000, ISO-NE called for steps 1-11. On May 8th and 9th, the New England and Northeast areas experienced record breaking temperatures, resulting in high loads. Simultaneously, 8,400 MWs of generation were unavailable due to maintenance. (Chapter II discusses the events of May 8th and 9th in-depth.) Table 5 lists the number of OP4 events from 1991-2000.

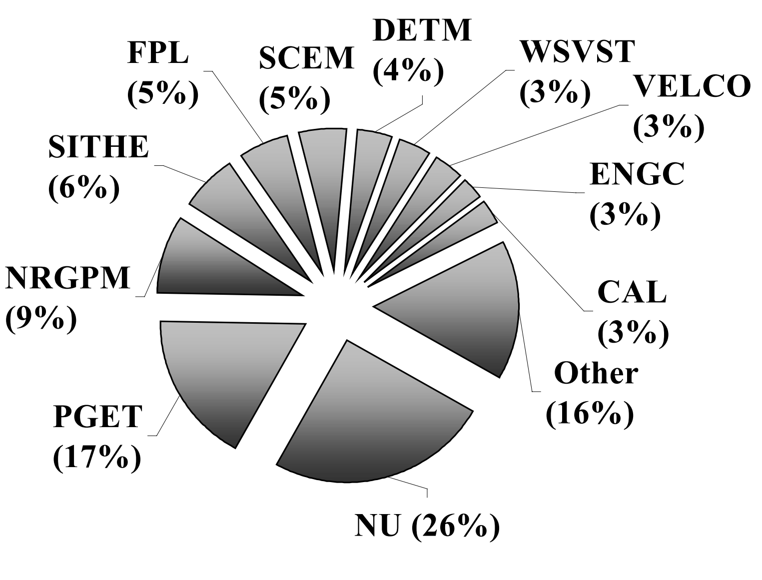
Table 5: OP 4 Events, 1991-2000

Year	Number of Events
1991	5
1992	2
1993	1
1994	2
1995	9
1996	2
1997	5
1998	5
1999	11
2000	6

Source: ISO-NE

Generation Ownership Diversifies

Figure 4: New England Summer Capacity Ownership



Source: ISO-NE

Restructuring encouraged LDCs to divest their generation assets in Massachusetts and other New England states. Therefore, the ownership of generation has changed dramatically. During 2000, Northeast Utilities, through its subsidiaries, retained the largest generation portfolio in New England with 26 percent of the region's capacity. The second largest power generating company in New England is PG&E with 17 percent. These percentages reflect a slight decrease from 1999 because other companies with smaller generation portfolios added new generation capacity in New England. Figure 4 shows the 2000 generation capacity ownership.

[10] OP 4, "Action During a Capacity Deficiency", includes 16 steps that can be implemented by ISO-NE, depending on the emergency situation. ISO-NE can implement any action necessary to resolve the problem and does not have to implement the actions in sequence.

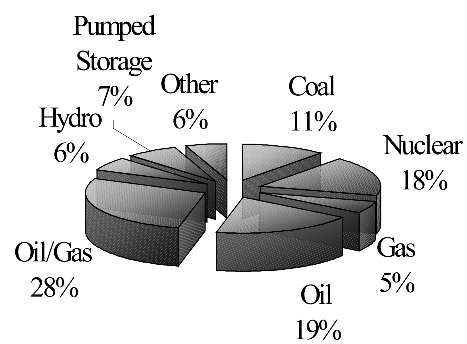
Diversification of generation ownership is an important element in restructuring. Sufficient competition in generation is necessary if customers are to benefit from competitive wholesale markets. Otherwise, there is continuing potential for market power abuse.[11] This year, some companies that invested in power plants or built merchant generation plants resold their investments. For example, Energy Management Inc. (EMI) announced it was selling plants in Dartmouth and Pawtucket (both 67 MW plants) to El Paso Merchant Energy Company, a business unit of El Paso Energy Corporation. El Paso is also the majority owner of a new 267 MW generator in Agawam, Massachusetts and has interest in two Connecticut plants. El Paso is also a major supplier of natural gas to other power plants in the region.

In October, EMI announced the sale of its shares in three recently constructed plants (a 170 MW plant in Dighton, Massachusetts, and 265 MW units in Tiverton, Rhode Island and Jay, Maine), to Calpine Corporation. In August 2000, Pennsylvania Electric (PECo) announced plans to buy a 49.9 percent share in Sithe Energies' North American electric generation businesses. Sithe owns major power plants in Massachusetts, including those in South Boston, Medway, North Weymouth, Framingham and Everett, which they purchased from Boston Edison two years ago. The purchase terms give PECo the option to buy the rest of the company within 2-5 years. The deal coincides with PECo's merger with Chicago based Unicom Corp. to form Excelon.

Fuel Mix Remains Diverse for Electricity Generation

Nearly all the new generation capacity in New England uses natural gas as its fuel. Several commercial advantages of gas-fired generation drive this trend. First, with low emissions, gas generation has lower environmental compliance costs than oil and coal. Second, owners of gas generation can easily arbitrage between the gas and electricity markets by selling gas entitlements back into the pipeline when electricity prices are low. Third, more gas pipeline capacity into New England has created a trading hub in the region[12] and lowered the price spread relative to the rest of the country. Increased gas-fired capacity is a national trend, with more than 342,000 MW of new gas capacity either in operation, construction or active development.[13]

Figure 5: New England Electric Generation Capacity Mix, 2000



Source: ISO-NE

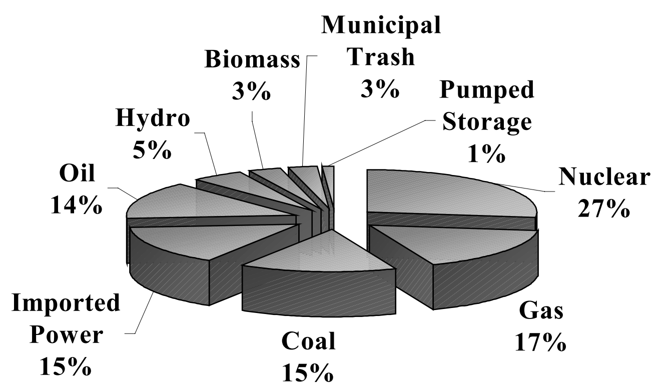
[11] Generation ownership will become increasingly important in the future as locational pricing within "zones" is implemented. Limited transmission capacity in the Boston area will create a sub-market dominated by Sithe/PECO, which currently owns two-thirds of the capacity in the zone. Because of the potential for a higher priced sub-market in the Boston area, NEPOOL agreed to fund $35 million in transmission facility upgrades to increase transmission capacity into Boston.

[12] Dracut Hub connects the Tennessee pipeline, which brings gas from the South, with the new Maritimes pipeline, which brings gas from Canada.

[13] *Tracking the Boom of New Power Plants in the U.S.,* Energy Venture Analysis, June 2001.

While gas-fired generation is increasing, oil-fired generation remains the largest source of capacity in New England. Figure 5 displays the region's generation capacity mix. As shown, if duel fuel (oil and gas) units are included, oil-fired generation constitutes 47 percent of the capacity internal to the region. Only 5 percent of the region's capacity is gas-only. Building sufficient and diversified gas transmission capacity becomes more important as the use of gas increases in the region. Figure 6 shows New England's actual fuel mix used to generate electricity in 2000.

Figure 6: New England Electric Generation Fuel Mix, 2000



Source: ISO-NE

Massachusetts Avoids California's Electricity Problems

During 2000, California confronted unprecedented electricity shortages, wholesale power price spikes and a financial crisis among its electric distribution companies. A mix of factors, some physical or financial and some attributable to California's electric restructuring legislation, caused or compounded their problems. Essentially, electricity demand exceeded supply, resulting in soaring wholesale costs, while a state-imposed retail rate freeze prevented utilities from passing the costs on to consumers.

Due to rapid population growth and a strong economy in recent years, California's electricity use grew dramatically. However, no new major generating plants were built in about a decade to accommodate the rising demand. Moreover, California became more dependent on neighboring states for electricity supplies. Meanwhile, demand in those states also increased thereby reducing California's ability to continue importing from its neighbors.

California's demand/supply problem came to a head when a series of heat waves sent summer demand soaring. Existing power plants ran at capacity limits throughout the summer as the Independent System Operator implemented emergency conservation measures and customer interruptions many times.[14] By fall, roughly 30 percent of the state's generators were offline for maintenance and repairs because they had run so hard in the summer. The state looked to its neighbors for more power, but they too experienced capacity problems. Dry weather reduced hydroelectric power supplies across the Northwest. Wholesale market electricity prices soared for the remaining supplies. Skyrocketing natural gas prices also increased California's wholesale electricity prices.

While wholesale prices increased, retail prices were frozen. California's restructuring law capped utilities' retail rates until 2002; therefore, utilities were unable to pass on rising wholesale costs to consumers. The original intent of California's electric restructuring was that utilities would buy cheap power in the competitive wholesale market, sell it to customers at higher fixed prices for a few years, and use the difference to pay down stranded costs on old investments. This may have worked when wholesale prices were low. However, when wholesale power prices increased, consumers were insulated from the increases at the retail price level and therefore had little reason to react to the situation.

During the summer, 50-60 percent of California's electricity needs was purchased in the spot market. (In comparison, New England purchases only about 20 percent of its electricity in the spot market. Furthermore, Massachusetts utilities can sign fixed price contracts to hedge against price volatility and price increases.) By not entering into long-term contracts, California utilities were overexposed to price volatility of the spot market and could do little to manage the risk.

During the first 9 months of the year, power on the Exchange averaged $90/MWh, triple the price of a year earlier. California's utilities lost money on that power because their retail rates were frozen at $54-65/MWh. The deficits exceeded $5 billion from June-September. By year-end, California's two largest utilities, Southern California Edison (SoCal Edison) and Pacific Gas and Electric (PG&E) estimated that they had not recovered approximately $9 billion.

In the fall, state and federal officials, industry representatives and others convened several times to manage and develop solutions to the crisis. The impending financial insolvency of distribution companies became a top priority. Securing electricity supplies also required immediate action.[15]

New England avoided similar problems for several reasons. New England states, particularly Massachusetts, streamlined the approval process for new power plants. New procedures concentrated on minimizing a generating plant's environmental impact, but left market forces to determine the need for new plants. As a result, the states eliminated years of delays and disputes, which typically plagued these proceedings when government predicted the need for new plants. California, on the other hand, did not change its permitting processes.

In addition, although both California and Massachusetts encouraged utilities to divest generation, Massachusetts allowed its utilities to determine how to buy power for their consumers. Options

[14] In summer 2000, ISO implemented Stage 1 emergency 32 times and Stage 2 emergency 17 times. In the November/December period, ISO implemented Stage 1 emergency 11 times, Stage 2 emergency 9 times and Stage 3 emergency once.

[15] In January 2001, California experienced rolling blackouts. To alleviate the situation, the state purchased about $500 million of electricity for utilities through the state's Department of Water Resources; implemented retail rate increases of about 7-15 percent; filed legislation for a comprehensive $10 billion plan to keep the state's utilities financially solvent; and implemented a comprehensive conservation program.

included fixed price and long term contracts as well as buying incremental needs off the spot market. As noted earlier, California discouraged such long-term contracts.

In New England, these changes fostered a more stable and competitive marketplace, which encouraged developers to build new plants. From May 1999 through 2000, nine plants were built in New England, increasing the region's power supply more than 12 percent.[16]

Another difference between New England and California is that New England built natural gas pipelines to deliver fuel to the new gas-fired generation plants. In fact, developers built two gas pipelines from Canada to bring gas supplies into New England and another company in Massachusetts increased its capacity to import more liquefied natural gas from Trinidad. In comparison, California saw no expansion of its gas import capabilities. While prices for natural gas rose nationwide in 2000, they rose less quickly in New England because of these new supplies.

CONCLUSION

There were several restructuring success stories in Massachusetts in 2000. While California's restructuring attempt failed, Massachusetts saw its efforts proceed fairly well. However, restructuring of the electric industry is a complex and far-reaching reform that will take time to complete. Despite successes, several areas still require attention and improvement.

One of the primary goals, the development of a robust, retail competitive market, remained elusive in 2000. A main reason for this situation was that wholesale generation prices were higher than regulated retail generation prices. Under these circumstances, competitive market suppliers could not make a profit and started to retreat from Massachusetts' retail market. The next chapter compares the difference between wholesale and retail generation prices and discusses factors contributing to the disparity. Subsequent chapters will discuss steps taken to provide for greater competition.

[16] At least 8 more plants will be completed in the next few years adding another 23 percent to New England's generation capacity. When these plants are all producing power, wholesale electricity prices are likely to fall.

CHAPTER II: PRICES AND PRICE DISPARITIES

As mentioned, Massachusetts experienced several positive benefits of electric restructuring in 2000. Nevertheless, some retail competitive suppliers withdrew from the market when their contracts ended, while others stopped accepting new retail customers. As a result, competitive supply customers returned to the LDCs' default services. A key reason for the reversion was that wholesale generation prices were higher than regulated retail generation prices.

As prices rose in the wholesale electricity market, the DTE continued to regulate standard offer and default service prices in the retail market.[17] Wholesale price increases were not immediately reflected on standard offer and default service customer bills under these regulated prices. LDCs that incurred higher wholesale costs in their standard offer and default service procurements were unable to immediately pass on the increases. Moreover, in the absence of a working competitive market during the first years of restructuring, the DTE directed LDCs to price default service the same as standard offer. Given this situation, competitive retail suppliers were generally unable to beat the LDCs' retail standard offer and default service prices.

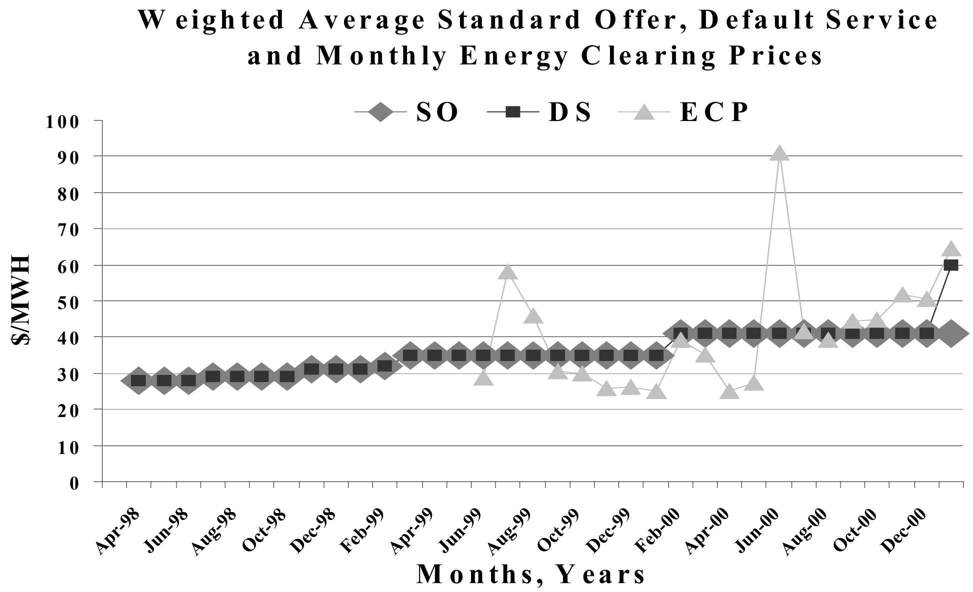
This chapter discusses wholesale electricity prices, overall retail prices, and regulated standard offer and default service prices. First, an overall picture of wholesale vs. retail electricity prices is presented, outlining differences between the two and revealing a lack of a direct relationship between the two markets. A detailed examination of retail and wholesale prices follow.

Wholesale Prices Exceed Retail Prices

The wholesale electric generation spot price, or energy clearing price (ECP),[18] increased in 2000 by 37 percent over 1999 levels. The weighted average monthly wholesale ECP rose from $33.78 per MWh in 1999 to $46.15 MWh in 2000. At the same time generation prices rose in the wholesale market, retail market generation prices for standard offer and default service barely increased. For most of 2000, the weighted average of these prices was $41 per MWh. Figure 7 shows the monthly, weighted average ECP compared to the standard offer and default service retail prices.[19]

[17] The prices for these retail services are regulated by the DTE. Standard offer prices are governed, in part, by the Act and, in part, by various settlement agreements and DTE approved regulatory cases. DTE approved standard offer and default service prices of LDCs through approved settlements or filings.
[18] See DOER's *Market Monitor 1998* and *1999* for explanations of wholesale markets.
[19] DOER uses the ECP as an indicator of wholesale energy prices because wholesale prices in bilateral contracts are not publicly published. Also, it should be noted that there are other price components in the wholesale electricity prices, such as costs for ancillary services. However, the energy market is the largest of all the wholesale market products and therefore, DOER uses the ECP in its retail and wholesale generation price comparisons. Standard offer and default service retail generation rates include all wholesale generation related costs.

Figure 7: Wholesale Versus Retail Prices in 2000



A. RETAIL PRICES & PRICE DISPARITIES

As reported in Chapter I, retail prices did not increase substantially in 2000. Over 1999 levels, they increased a mere 2 percent, lower than the overall rate of inflation of about 3.4 percent. Table 6 compares 2000 prices to 1999 prices for each investor-owned distribution company and the municipal utilities as a whole.

Table 6: Price per kWh for Massachusetts Electric Companies, 2000 vs. 1999

	2000 Average Price (cents/kWh)	1999 Average Price (cents/kWh)	% Change
Boston Edison	9.8	10.1	-2.30%
Cambridge Electric	6.5	7.6	-14.90%
Commonwealth Electric	11.0	10.5	4.90%
Eastern Edison	8.6	8.6	-0.30%
Fitchburg Gas & Electric	10.9	10.4	4.80%
Massachusetts Electric	8.7	8.0	8.00%
Nantucket Electric	12.6	11.8	6.00%
Western Massachusetts Electric	9.5	9.2	3.20%
Total: Distribution Company	9.3	9.1	2.00%
Total: Municipal Company	9.2	9.0	1.80%
Total of Entire State	9.3	9.1	1.90%

Sources: FERC Form 1, EIA Form 861, Municipal Reports to DTE, DOER, "1999 Market Monitor"

Table 7 provides more detail for the comparison of distribution and municipal company prices. As was shown in the *1998 Market Monitor*, municipal utilities hold price advantages over the LDCs for residential customers, but feature higher prices than the LDCs for commercial and industrial customers. In addition, the comparison between 1999 and 2000 also shows that, in general, the municipal utilities' advantage in residential rates has increased.

Table 7: Comparison of Distribution Company & Municipal Company Prices

	Residential	Small Commercial or Industrial	Large Commercial or Industrial	Overall
Average LDC Company Price	10.7	**8.7**	7.8	**9.3**
Average Municipal Utility Price	9.4	**10.1**	8.5	**9.2**
Municipal Utility Difference	**-14.70%**	**13.70%**	**8.50%**	**-1.00%**

Sources: FERC Form 1, EIA Form 861, Municipal Reports to DTE

Default Generation Rates Increase

Except for default service rates, overall electricity rates did not change dramatically in 2000. Despite the rise in wholesale electricity prices, LDCs' retail rates did not reflect the wholesale market costs. (The wholesale market is discussed later in this chapter). The mandated rate reduction imposed by the Act is one reason for continued regulation of the competitive generation portion of the electricity rates. With the notable exception of default rate changes in December 2000, there were fewer rate changes in 2000 than in 1999 for all companies, except Western Massachusetts Electric.

Table 8 identifies the components of an unbundled residential (non-electric heating) bill.[20] Most notable is the change in the generation portion of the bill, especially for default service. Using an example of 600 kWh (the average monthly use for a residential customer) default service customer's bill, the generation (or competitive) portion of the bill increased from 30-42 percent of the total bill to 41-54 percent of the bill.

Standard offer rates also increased, but by a much lower percentage. For six of the eight LDCs, rates equaled those in the original trajectories found in restructuring settlements or approved plans. Western Massachusetts Electric showed the highest percentage increase in standard offer rates, due to a move from artificially suppressed rates to market (competitively-procured) rates.

Conversely, most transition rates declined. This was the result of an inverse relationship between changes in generation and transition-cost rates[21], however; transmission rates rose due to changing congestion levels or constraints on the transmission system.

[20] Unlike the commercial and industrial classes, there is much more uniformity in the rate class definitions for residential customers among distribution companies, thus making a comparison more valid.
[21] Transition rates are required to decrease proportionately to increases in the Standard Offer rate. They do not apply to default service rates.

Table 8: Residential Customer R-1 Rate Structures, 2000

		Boston Edison	Cambridge Electric	Comm Electric	Eastern Edison	FG&E	Mass Electric	Western Mass
Generation								
SOS/DS	9/1/99 cents/kWh	3.69	3.5	3.5	3.5	3.5	3.707	3.1
SOS/DS	1/1/00 cents/kWh	4.5	3.8	3.8	3.8	3.8	3.8	4.557
DS	12/1/00 cents/kWh	6.28	6.28	6.28	N/A	5.206	6.37	4.557
Transition								
	9/1/99 cents/kWh	2.546	1.224	2.998	2	1.236	1.182	2.677
	1/1/00 cents/kWh	1.891	0.294	2.856	3.04	0.196	1.191	1.598
Transmission								
	9/1/99 cents/kWh	0.312	1.31	0.372	0.291	0.743	0.698	0.318
	1/1/00 cents/kWh	0.367	0.996	0.481	0.412	0.819	0.687**	0.318
Distribution								
	9/1/99 $/month	6.43	6.74	3.65	1.34	2.79	5.81	8.33
	9/1/99 cents/kWh	3.9	2.434	4.517	3.556	4.81	2.502	2.936
	1/1/00 $/month	6.43	6.87	3.73	1.34	2.84	5.81	8.53
	1/1/00 cents/kWh	3.9	2.434	4.524	3.556	4.002	2.459***	2.783
Energy Efficiency								
	1/1/99 cents/kWh	0.31	0.31	0.31	0.31	0.31	0.31	0.31
	1/1/00 cents/kWh	0.285	0.285	0.285	0.285	0.285	0.285	0.285
Renewables								
	1/1/99 cents/kWh	0.1	0.1	0.1	0.1	0.1	0.1	0.1
	1/1/00 cents/kWh	0.125	0.125	0.125	0.125	0.125	0.125	0.125
Total								
SOS/DS	9/1/99 $/month	6.43	6.74	3.65	1.34	2.79	5.81	8.33
	9/1/99 cents/kWh	10.858	8.878	11.797	9.757	10.699	8.499	9.441
	1/1/00 $/month	6.43	6.87	3.73	1.34	2.84	5.81	8.53
SOS	1/1/00 cents/kWh	11.068	7.934	12.071	11.218	9.227	8.547	9.666
DS	1/1/00 cents/kWh	11.068	7.934	12.071	11.218	9.227	8.547	9.666
	12/1/00 cents/kWh	12.848	10.414	14.551	N/A	10.633	11.117	9.666

** 719 from Jan-Apr; .687 May-Dec ***.2.511 from Jan-Apr; 2.459 May-Dec
Source: Distribution Company Filings

Standard Offer and Default Service Rates Uncoupled

Standard offer and default service rates were separated during 2000, the first time since restructuring began. The Act considers standard offer and default service as distinct generation products. The Act defines "default service" as provision of electricity to customers who are not receiving generation service either as part of standard offer service or from a competitive supplier. While standard offer is considered a transitional service, default service is intended to ensure that all customers have access to electricity, regardless of competitive market conditions. When standard offer service expires in 2005,[22] all standard offer service customers not receiving competitive supply will be eligible for default service.

[22] M.G.L. c. 164 § 193, Section 1(B)(b).

In implementing the Act, DTE required that default service rates not exceed the average monthly market price for electricity. However, in the absence of a fully developed market, DTE directed the LDCs to use their standard offer price as a proxy for the market price and as the basis for their standard offer price. Thus, standard offer and default prices were the same in 1998, 1999 and most of 2000.

However, by December 2000 the two products were priced and offered differently. Through a series of Orders,[23] DTE allowed the decoupling of default service from standard offer prices. On October 19, 2000 DTE issued a letter to MECo, NSTAR and FG&E, allowing default price increases to reflect actual market-based costs. The increases took effect December 1, 2000, marking the first time standard offer and default service customers saw different prices on the generation portion of their bills (Chapter IV discusses the price separation in detail.)

Price Disparity by Customer Class Increases Among LDCs

Unlike 1998 and 1999, it is likely that price disparity increased among the LDCs during 2000. This is not unexpected, given the diverse methods LDCs use to reduce transition costs and procure default service. Table 9 presents the data used for the disparity analysis, comparing 1999 and 2000 rate changes within companies, for each customer types. Residential customers received relatively larger increases in prices and relatively smaller decreases in prices.

Table 9: 2000 and 1999 Price Levels for Distribution Companies (cents/kWh)

.	Residential			Commercial			Industrial		
	2000	**1999**	**Change**	**2000**	**1999**	**Change**	**2000**	**1999**	**Change**
Boston Edison	11.7	11.8	-0.80%	9.1	9.4	-3.00%	8.6	8.9	-2.70%
Cambridge Electric	9.5	10.8	-12.10%	6.0	7.1	-15.60%	5.5	6.4	-15.40%
Commonwealth Electric	12.4	11.9	4.00%	10.0	9.5	5.30%	8.5	7.7	10.00%
Eastern Edison	9.3	9.3	-0.60%	8.0	8.0	-0.80%	8.0	7.9	1.20%
Fitchburg Gas & Electric	12.2	11.9	2.50%	11.9	11.3	4.80%	9.2	8.9	4.00%
Massachusetts Electric	9.8	8.8	11.00%	8.3	7.7	7.30%	7.3	6.8	7.00%
Nantucket Electric	12.3	11.5	7.10%	13.0	12.4	4.30%	15.5	17.5	-11.60%
Western Massachusetts	10.8	10.5	2.30%	9.3	9.0	3.30%	7.9	7.5	5.10%

Sources: FERC Form 1, EIA Form 861

Table 10 weights the disparity calculation by kWh sales. The 1999 data were recalculated from the *Market Monitor 1999*, resulting in slight changes but not altering the basic finding that price disparity did not change last year.[24] However, in 2000 price disparity increased from 2.1 to 3.8 cents per kWh.[25] Price differences were greatest for the industrial customer group (after removal of Nantucket Electric as an outlier). Increasing price disparity is not necessarily positive or negative. Prices

[23] See DTE Orders 99-60-A; 99-60-B and 99-60-C.

[24] Massachusetts LDCs filed revised FERC Form 1, EIA-861 after the publication of the *1999 Market Monitor Report*.

[25] Applying the F-Test to the unweighted data yield the following probabilities that price disparity *did not* change: 80 percent for Residential, 62 percent for Commercial, and 62 percent for Industrial.

among LDCs differ for a number of justifiable reasons, such as different customer bases and different restructuring trajectories.

Table 10: 2000 & 1999 Price Disparity Among Distribution Companies (cents/kWh)

	2000	1999
Residential	2.4	1.8
Commercial	5.5	3.7
Industrial*	1.6	0.9
Overall	3.8	2.1

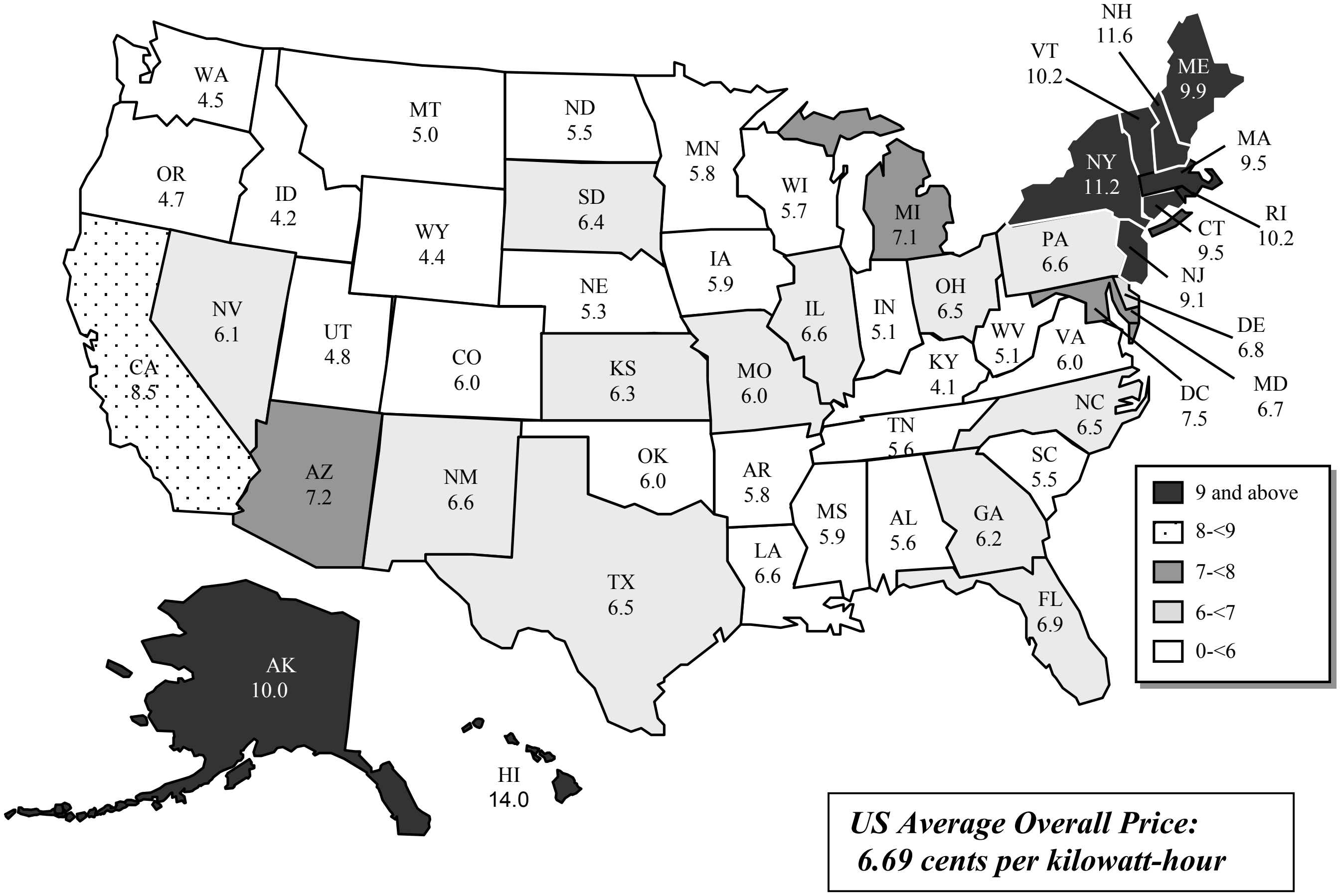
Sources: FERC Form 1, EIA Form 861, DOER
*Industrial does not include Nantucket Electric; Inclusion results in values of 12.7 for 1999 and 8.6 for 2000.

Massachusetts Electricity Prices Remain High Compared to the United States

Although Massachusetts' electricity prices have decreased during restructuring, Massachusetts' average price (9.5 cents/kWh) is among the higher Northeast states, and well above the national average of 6.69 cents/kWh. Figure 8 provides the electricity prices for each state.[26] Figure 9 depicts historical electricity prices for Massachusetts, New England and the Nation.

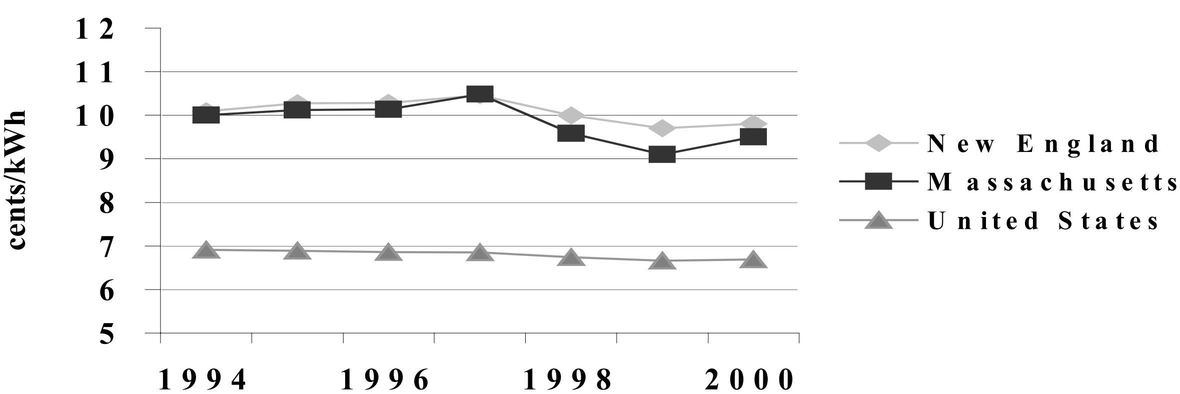
[26] The 2000 data in this figure and subsequent figures in this chapter were taken from preliminary data from the EIA. Hence, these data will probably be updated at a later date and may be different from the data collected and analyzed by DOER.

Figure 8: 2000 Average Overall Electricity Prices by State (cents/kWh)



Source: U.S. DOE/EIA "Electric Power Annual 2000"

Figure 9: Historical Electricity Prices for all Customer Sectors: MA, New England & the Nation



Source: U.S. DOE/EIA "Electric Power Annuals", 1994-2000

B. WHOLESALE PRICES

The re-designed New England wholesale electricity market completed its second year of operation in 2000. In the revamped market, buyers and sellers trade electricity at market prices, rather than traditional cost-of-service rates.[27]

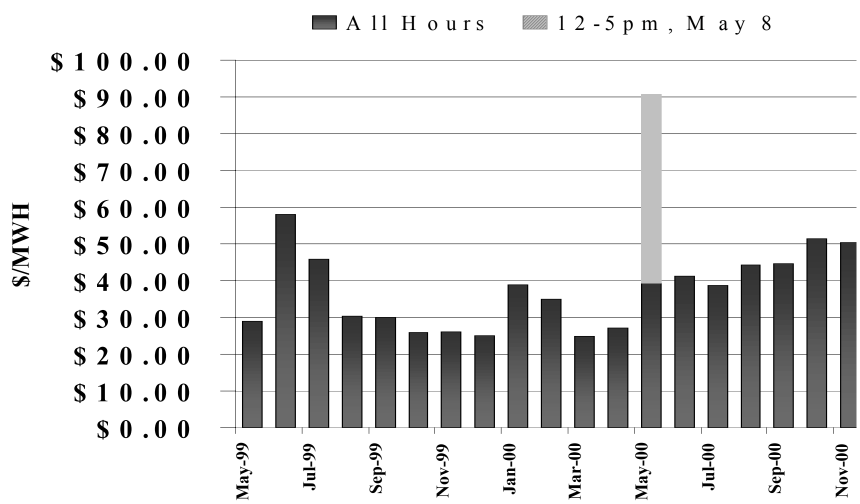
The wholesale market showed greater trading on the spot market and fewer market price correction problems in 2000 than in 1999.[28] However, as previously mentioned the wholesale electricity prices increased dramatically in 2000, much higher than retail generation (standard offer and default) rates. These increases were largely the result of higher natural gas costs that increased because of greater demand from gas-fired generators, and consumer demand during a cold fall coupled with tight natural gas supplies. Nationally, natural gas prices rose from about $2.50 per MMBTU[29] in December 1999 to more than $10 per MMBTU a year later.

Higher wholesale energy clearing prices also reflected market uncertainties regarding several market rule changes and continued market volatility. This market volatility increased prices in the spot market and also increased the value of bilateral contracts, because of the increased price risk premium.[30] The following section discusses factors affecting 2000 wholesale energy prices.

Average Monthly ECP Rises 37 Percent

The weighted average monthly wholesale ECP rose from $33.78 per MWh in 1999 to $46.15 in 2000, a 37 percent increase. Figure 10 shows the weighted average, monthly wholesale market electricity price in New England for each month from May 1999 to December 2000. (The cost of electricity from the hours 12 p.m. to 5 p.m. on May 8, 2000 is shaded to show the significant impact of that five-hour price spike on the month.)

Figure 10: Weighted Average Wholesale Spot Market Price for Electricity



Source: ISO-NE

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[27] See DOER's *Market Monitor 1998* and *1999* reports regarding the newly designed wholesale electricity market and its products.

[28] There were 620 administrative price corrections from May-December 1999 compared to 493 from January-December 2000.

[29] MMBTU means million british thermal units. A BTU is the heat required to raise the temperature of one pound of water by one degree Fahrenheit at or near 39.2 degrees Fahrenheit.

[30] A risk premium is the additional amount over the expected spot market price that a buyer will pay in order to insure against paying a higher price in the spot market because of volatility. The risk premium is a function of the amount of price volatility.

Record High Price Spike Leads to Price Volatility

A significant factor influencing wholesale prices in 2000 was a record high cost of $6000 per MWh for wholesale spot market electricity (the ECP) on May 8, 2000. The ECP stayed at $6000 for more than four hours, compared to an ECP between $30 and $40 per MWh for most May 2000 afternoons. There are several reasons for the high ECP. Unseasonably warm weather in the Northeast and New England on May 8 and 9, 2000 led to extremely high demand. The hot weather coincided with more than 8,400 MWs of unavailable capacity due to maintenance and capacity reductions. In addition, a market rule allowed a price that was tied to a capacity contract to set the ECP, rather than a lower cost resource to set it. (To remedy another such occurrence, NEPOOL changed several market rules; however, market uncertainty remained until such action was taken.)

Table 11 shows the historic loads during the week of May 8th in past years compared to May 8 and 9, 2000 demand.

Table 11: Peak Load Demand on May 8th

Time Period	Peak Load (MWs)
May-97	14,877
May-98	17,593
May-99	15,744
8-May-00	18,686
9-May-00	18,876

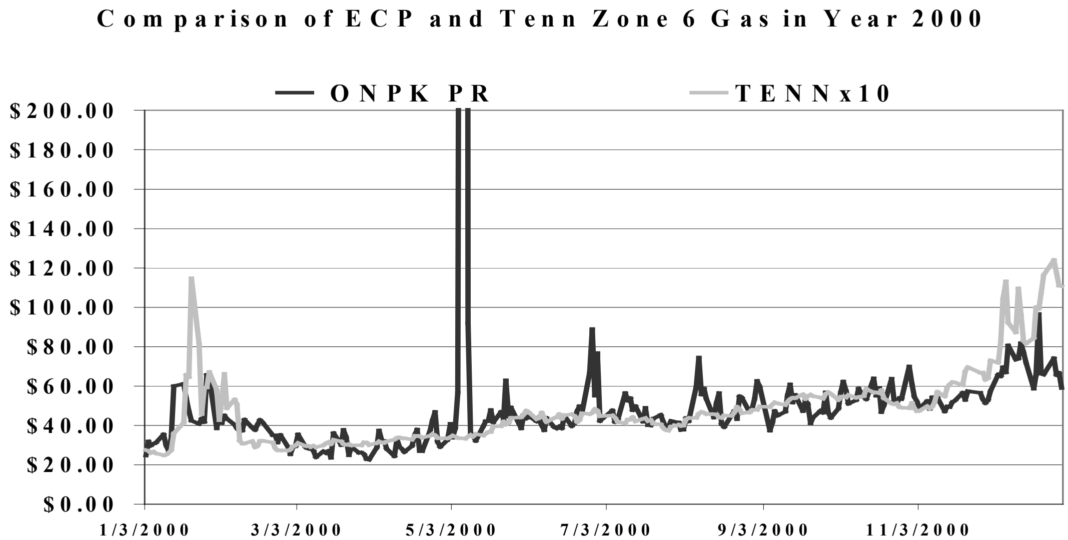
Source: ISO-NE

High Natural Gas Costs Increase Wholesale Generation Prices

Due to an increased number of natural gas fired generators in New England and the flexibility of running the new gas turbines, bids from gas fueled units often set the ECP in 2000. Thus, the price of electricity in New England is now more dependent on the cost of natural gas. The nationwide increase in the cost of natural gas therefore also contributed to the high 2000 ECP.

In the Boston area, the average monthly wholesale natural gas price rose from $2.81 per MMBTU in December 1999 to $6.93 per MMBTU in December 2000, a 246 percent increase. Generally, as natural gas prices increased, so did wholesale electricity prices, although electricity prices were more volatile. In December 2000, natural gas costs rose as high as $12 MMBTU, but electricity prices stayed in a range of $60-80 per MWh. Many dual-fueled (gas/oil) units switched from gas to oil in December 2000, thus the divergence in natural gas and electricity prices. Figure 11 shows the comparison of changes in wholesale electricity prices and natural gas prices in 2000.

Figure 11: Wholesale Electricity and Natural Gas Cost



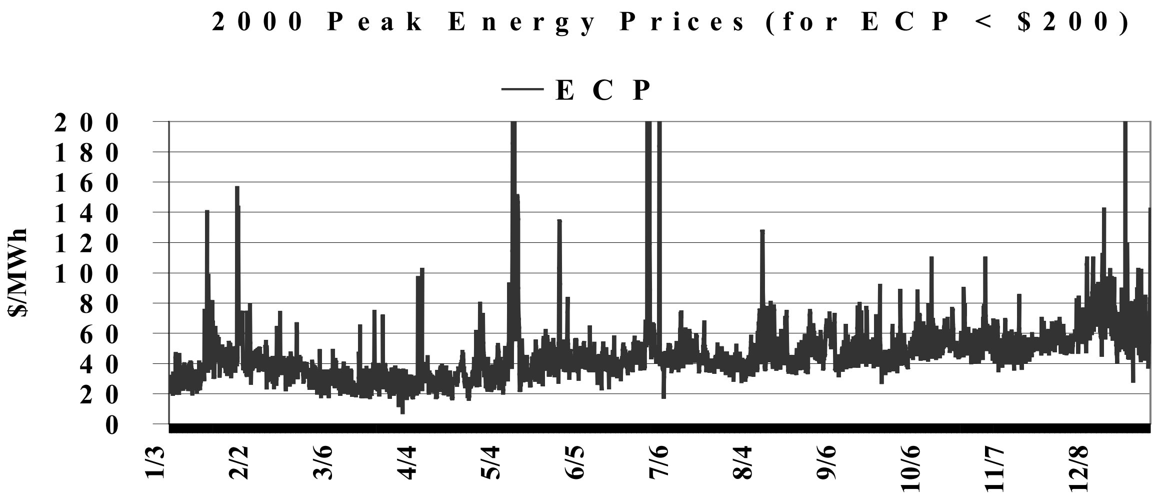
Source: ISO-NE; Gas Daily

Price Volatility Increases Reliance on the Spot Market

Spot market price volatility for electricity was very high in 2000. With the $6000 per MWh price on May 8th as significant outliers, the volatility of energy prices during peak hours was 365 percent.[31] Figure 12 depicts peak hour electricity price movements in 2000. Even with the May 8th outliers adjusted downward to $1000 per MWh (a later FERC imposed cap price), price volatility was 83 percent.[32] This compares to price volatility of 43 percent in the gas market,[33] which is considered as highly volatile.

[31] Volatility defined as the coefficient of variation, which is the standard deviation divided by the mean.
[32] The Federal Energy Regulatory Commission later imposed a $1000 price cap on the ECP.
[33] Henry Hub Price, Source Gas Daily

Figure 12: Peak Hour Electricity Price Movement



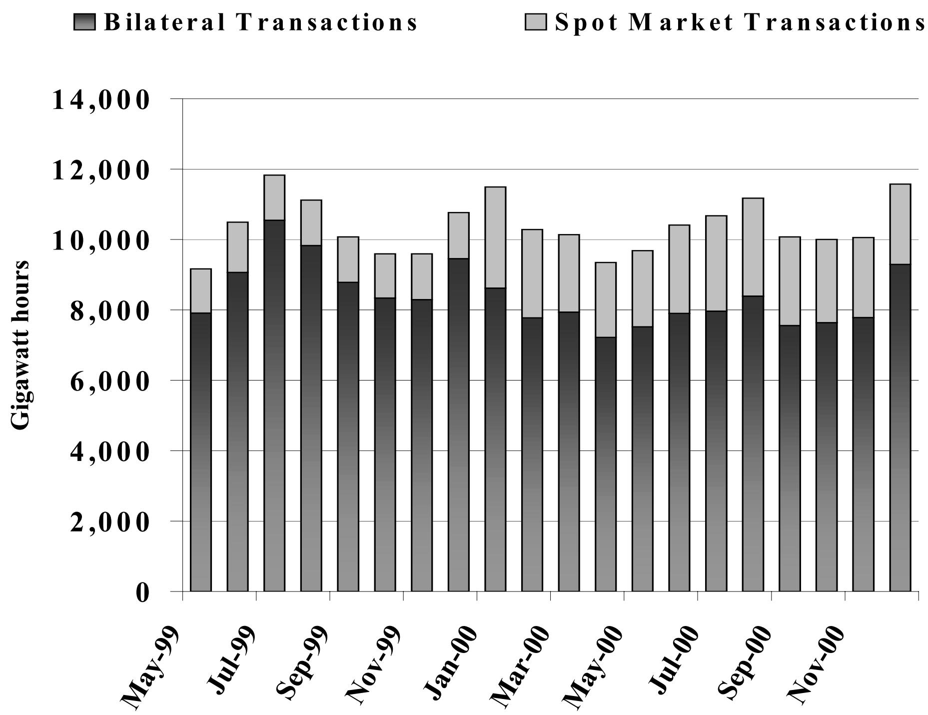
Source: ISO-NE

Spot Market Transactions Increase

This year, energy buyers increasingly relied on the spot market rather than the bilateral market.[34] Spot market transactions increased as a share of total energy transactions from 12.6 percent in 1999 to 23.56 percent in 2000 (Figure 13). This increase was caused, in part, by the expiration of some bilateral contracts and growing demand from the increasing pool of default service customers. (By not buying a bilateral contract to cover its obligations a load serving entity takes the risk that the future spot price will be less than the current bilateral market price.) Any buyer that does not cover their energy demand with bilateral contracts pays the energy clearing price for the difference, plus the load's share of the proportionate ancillary services and other costs. Thus, with higher and more volatile spot market prices this year, wholesale electricity prices increased.

[34] Buyers and sellers of electricity may contract for energy through short and long-term bilateral contracts or they can trade energy on the "open" spot market at market prices. Although ISO-NE administers spot market transactions, it must also know about bilateral contracts. Physical delivery of electricity is important for system reliability. Therefore, NEPOOL participants selling bilateral contracts must submit this contract information to ISO New England. If the electricity seller is not a NEPOOL participant, then the NEPOOL participant's buyer must submit the contract. Bilateral contracts usually specify price, quantity and time, and whether it is dispatchable (price sensitive) or non-dispatchable. Bilateral price data is difficult to obtain because most NEPOOL contracts are not traded on an open exchange.

Figure 13: New England Wholesale Energy Purchases (1999-2000)



Source: ISO-NE

CONCLUSION

Retail electricity customers were, for the most part shielded, from the volatility and price increases in wholesale electricity markets. Rate caps and other regulatory decisions insulated retail generation prices from higher, market-based wholesale generation costs.

Those retail competitive suppliers who purchased generation on the wholesale market immediately experienced the higher wholesale costs. They were unable to purchase wholesale power at enough of a discount to compete with the local distribution companies' standard offer and default service prices. They also faced some market rule uncertainty in the wholesale markets. As a result, retail competitive suppliers withdrew from the market and choices available to consumers during the first years of restructuring declined in 2000. The next chapter describes the retreat of some retail competitive suppliers and customer migration movement in the retail markets.

CHAPTER III: THE RETAIL COMPETITIVE MARKET

During the first two years of restructuring, Massachusetts experienced an immature yet promising, retail competitive market with a handful of retail competitive suppliers selling electricity. The number of competitive choices declined in 2000, although a few competitive suppliers continued doing business in the state. As discussed in the previous chapter, regulated retail generation prices were lower than wholesale electricity generation prices, contributing substantially to the stagnation in retail competition.

This chapter more closely examines the retail effects of low retail and high wholesale prices, providing an overview of changes by customer class--standard offer, default service or competitive supply. It highlights growth in the number of default service customers, some formerly customers of retail competitive suppliers. A general discussion of some retail suppliers' retreat from the Massachusetts market follows. Subsequent chapters will further clarify the reasons for the withdrawals and describe actions taken to restart the competitive market.

A. CUSTOMER MIGRATION

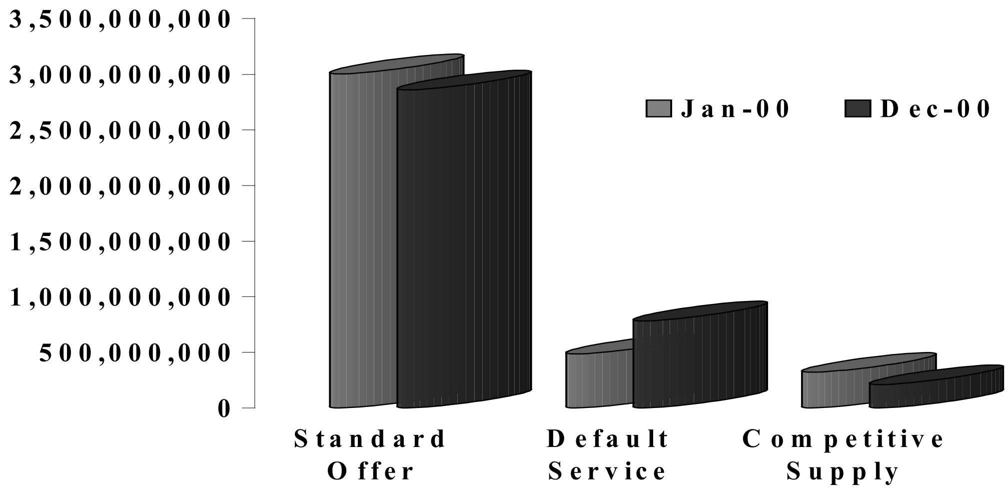
There was a steady increase in the number of default service customers during 2000. At the same time, the number of competitive electricity supply customers declined. Table 12 shows statewide totals of the number of customers on standard offer, default service and competitive service for distribution companies. (Company specific numbers are in Appendix A.) Table 12 also displays the electricity sales (kWhs) of the sectors and the state total. Figure 14 presents a graphic representation of LDC electricity sales.

Table 12: Distribution Company Customers

Customer Class	January 2000 Total Customers	January 2000 Total kWh Sales	December 2000 Total Customers	December 2000 Total kWh Sales
Standard Offer	2,030,838	3,004,174,345	1,875,101	2,859,629,603
Default Service	497,319	484,884,404	632,854	782,479,292
Competitive Supply	9,471	320,460,740	5,682	209,313,997
Total	2,537,628	3,809,519,489	2,513,637	3,851,422,891

Source: DOER 2000 Customer Migration Numbers

Figure 14: Composition of Distribution Company Sales (kWh): December 2000



Source: 2000 DOER Customer Migration Numbers

The total number of electric customers decreased during 2000 from 2,537,628 in January 2000 to 2,514,250 in December. Eighty percent were on standard offer at the beginning of the year, declining 5.4 percent to 74.6 percent of total customers by year-end. Based on January 2000 kWh sales data, standard offer customers consumed 79 percent of total electricity sales, declining to 74 percent by December.

Competitive Supply Customers and Consumption Dwindle

The total number of competitive supply customers peaked at 9,471 (.37 percent of the market) in January 2000. As suppliers withdrew or curtailed enrollment of new customers, the number of competitive supply customers dwindled to 5,682 customers or .2 percent by December 2000. These customers consumed 8 percent of total sales in January, decreasing to 5 percent by December.

Default Service Customers and Consumption Grow Substantially

Default service customers represented 19.6 percent of total customers at the start of 2000, and 13 percent of electricity consumption. The number of default service customers grew each month. By December 2000, their number swelled to 25 percent of total customers and their consumption also grew from 13 percent to 20 percent over the year.

B. COMPETITIVE SUPPLIERS

Competitive Suppliers Withdraw from the Market

Shortly after restructuring began, several companies entered Massachusetts' retail electricity market, using the Internet as their business platform. Some offered retail electricity service and other products,[35] while others acted as information "facilitators," selling consumer information on electricity prices and energy-related products. These companies, commonly called "dot.coms" generally targeted residential and small commercial customers.

Essential.com and *Utility.com* were among the Internet companies offering products and services in Massachusetts and other deregulated states. Initially, they offered a 10 percent discount off the utility company's power generation rate of a customer's monthly bill. In April 2000, *Utility.com* doubled its discount from 10 to a 20 percent discount. However, rising fuel costs for electricity generation in 2000, led to tighter profit margins, preventing them from offering consumer savings. By end of the year, *Essential.com* stopped offering electricity to new customers and *Utility.com* limited the number of new customers it would accept. Both companies were assessing whether to leave the Massachusetts retail market.

Other Internet companies, such as *ServiSense.com* used a different sales strategy. *ServiSense* organized customer-buying groups and then purchased services from providers for the pool. The company coupled electricity with other services, such as long distance telephone service, providing a discount on the entire product bundle. In 2000, they guaranteed 5 percent savings off the cost of buying electricity and other products separately. They were still marketing in Massachusetts at the end of the year.

Other Internet based companies offered information on electricity and energy-related products. For example, Nexus EnergyGuide operates the *Energyguide.com* website. The company does not sell retail electricity directly, but gives price comparison information on energy. It also provides links to suppliers and retail sites for energy-related services. The company is compensated based on the sales generated by energy-related service retailers and energy suppliers using its Energyguide Network and Merchant Partner Program service. *Energyguide.com* also develops licensing pacts with distribution companies, who then offer their customers the information.

Although Internet sales declined in Massachusetts, the reselling and bundling of consumer services via the Internet is prevalent in other deregulated states. Consumers who are interested in the convenience of one stop shopping and/or one bill for an array of services find these products attractive. Once price signal issues between the retail and wholesale market are fixed, it is very likely that Massachusetts consumers will see a variety of energy and energy related services. These services may include energy efficiency, home security, and real time pricing packages based on consumption. Consumers will need to compare the price and value of each service offered in such packages.

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[35] These companies are commonly referred to as either "resellers" of electricity or "bundlers" of electricity and other products. "Resellers" purchase services from suppliers and resell them as their services. The concept is to offer consumers a choice of "name brand" providers' products and offer a discount on prices. Often, resellers provide one bill, one-stop-shopping and a menu or a bundle of services for such items as Internet, electricity, wireless telecommunications, etc.

In addition to the Internet companies, PECO Energy Company, one of the first companies to sell power in Massachusetts, also withdrew from the market. Through contracts negotiated by the Massachusetts Education and Hospital Facilities Authority (HEFA), PECO agreed to sell electricity to non-profit institutions, such as colleges and hospitals. The contracts gave HEFA members discounts on their electric rates until 2001 or 2003, depending on the individual contracts. It is estimated that these contracts saved participating members $70 million in electric charges since deregulation began in March of 1998.

However, in February 2000, PECO announced it would no longer serve HEFA contracts once its contracts expire. The company did not attribute their withdrawal to a lack of retail success in Massachusetts. Rather, the company said it never committed to competing in the electric market here, but wanted to remain active in retail markets in other deregulated states.

HEFA issued a formal request for proposals in the last quarter of 2000 and received eight responses. However, increased fuel costs for electricity appeared to threaten HEFA's ability to offer participants future savings. In the event the HEFA aggregation fails to receive a satisfactory proposal for 2001, a substantial percentage of the state's competitive generation customers will likely return to default service.

One Retail Supplier Expands its Retail Market Base

NewEnergy, the successor to National Energy Choice, LLC, expanded operations in Massachusetts in 2000. The Massachusetts High Technology Council chose NewEnergy as its exclusive supplier of electricity and energy-related services for participants in the council's energy buying plan. Furthermore, the Chamber Energy Coalition, a group of 10 chambers of commerce in western Massachusetts, also chose *NewEnergy* to market electricity to their business members.

CONCLUSION

The retail competitive market contraction in 2000 led to a substantial increase in the number of default service customers. Default service customers, especially residential default service customers, were left with few, if any, competitive supply offers. As previously mentioned, wholesale market price volatility and uncertainty about market rule and design changes also left retail competitive suppliers unsure of their next strategies for Massachusetts.

Despite these setbacks, several initiatives were implemented to overcome market barriers and alleviate problems preventing a more competitive, robust wholesale and retail market. The next chapter discusses these market developments and their potential for achieving Massachusetts' goals of providing competitive choices to all customers and lowering electricity prices.

CHAPTER IV: MARKET DEVELOPMENTS

Progress was made during 2000 to eliminate market barriers to competition at both the retail and wholesale levels. Efforts undertaken dealt with expanding the range of competitive options available and with correcting market flaws. In addition to market problems identified earlier in this report, this chapter identifies further problems and highlights initiatives and regulatory actions taken to address them. Further, this section considers several steps taken in both markets to increase market efficiency, thereby laying the groundwork to lower costs and ultimately electricity prices.

A. RETAIL MARKET BARRIERS AND INITIATIVES TO OVERCOME THEM

For Massachusetts, there were several retail issues that were addressed that will have a large impact on the future development of the retail market to make the market more competitive.

Customers Need Appropriate Price Signals for Cost of Default Service

One issue was that default service was priced below cost. During the year, the LDCs' costs for default service contracts increased as the result of higher electric generation prices. To compound the problem, the LDCs also saw the number of default service customers increase. Yet, under current DTE default service pricing rules, LDCs charged default service customers the same generation price as standard offer customers.[36] As a result, LDCs deferred the cost difference (known as deferrals) for default service and these deferrals grew.

This was problematic for several reasons. First, it impedes the development of a robust, competitive market and the ability of competitive suppliers to develop attractive products. In the absence of competitive options, default service customers would likely stay on default service, which perpetuates the under-recovery (deferral) problem. Second, deferrals would grow to a level that might threaten the financial viability of LDCs. Third, costs not recovered now would likely be recovered from all future customers through increases in distribution rates.

1. Default service set at market based rates

Ultimately, DTE separated standard offer and default service and based the default service price on market-based costs.[37] Through a series of Orders,[38] DTE set new guidelines for default service pricing and procurement, including:

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[36] During the first years of restructuring, in the absence of a competitively workable market, DTE directed LDCs to price default service the same as standard offer. Default service, however, is intended to be a basic service that provides consumers with the appropriate incentives to turn to the competitive market for more sophisticated or advantageous service offerings. It was thought that customers would compare the price and terms of default service to other generation service options made available to them by competitive suppliers. When restructuring began, LDCs entered long-term contracts for standard offer customers through much of the standard offer period. For default service, LDCs generally solicited short-term contracts more reflective of market-based prices.

[37] The Act required LDCs to competitively procure default service, but to not exceed the average monthly market price of electricity. DTE and other interested parties, such as DOER, wanted to satisfy the Act's requirement, while ensuring that the availability of default service not inhibit the development of a robust retail market for generation services.

[38] DTE 99-60-A, B, and C.

- A six-month fixed price option, available at the beginning date of each six-month supply term, for default customers or those who move into the territory after the beginning date.
- A variable price option (changes monthly).
- A provision ensuring that customers who take fixed price default service and leave part way through the six-month term are charged the full costs of service during their stay.[39]

Another important aspect of the guidelines is that LDCs solicit default service proposals with separate bids for three customer groups: 1) residential 2) commercial and 3) industrial. DTE concluded that the cost of risk associated with customer migration should be allocated to the customer classes associated with the risk. DTE directed the companies to submit their proposed default service solicitation schedules by end of July 2000,[40] for power to be delivered on or after January 1, 2001. (DTE also accepted many working group recommendations for default service customer education about the changes.)

2. DTE allows default service prices to increase in December

Prior to the new guidelines, some LDCs filed new default service tariffs with DTE. They petitioned the Department to allow the tariffs to go into effect before the January 1, 2001 effective date of DTE Order 99-60-B. DTE allowed the early increases in October, believing there was no advantage to maintaining default prices below market rates. (As noted in Table 7 in Chapter II, the default service prices for Massachusetts Electric Company, NStar and Fitchburg Gas and Electric Company changed in December 2000.) In its ruling, DTE also acknowledged that default prices did not reflect the recent dramatic fuel price increases,[41] resulting in revenues significantly less than costs.[42] These under-recoveries were placed in a deferral account to be recovered, with interest, from customers at a later date.

Standard Offer Service Prices Need to Reflect Extraordinary Fuel Costs

Many LDCs held supply contracts with fuel index adjustment provisions, allowing the power supplier to increase its price for power when the price hits a fuel trigger, whereby natural gas and oil prices increase significantly. As fuel prices increased throughout 2000, the triggers were met and suppliers began charging the LDCs. However, under DTE rules, the LDCs were unable to recover these costs by passing them on to standard offer customers. The question before DTE became whether standard offer customers pay for these costs now or later (with interest).

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[39] The guidelines stipulate that the LDCs initially assign residential and small commercial and industrial customers to the fixed price option. (Placing smaller customers on the fixed price option minimizes confusion for them.) These customers can then elect the variable price option if they choose. Medium and large commercial and industrial customers, as well as customers receiving service under the street light tariff, will be assigned to the variable price option and may also elect a fixed price option.

[40] DTE set a minimum procurement period for default service of six months and a maximum of one year. It also ordered the LDCs to stagger the solicitations. The goal behind this is that allowing more opportunities for suppliers to supply default service will foster a more competitive market. In addition, staggered solicitations will avoid the possibility of higher prices that may result from simultaneous solicitations for significant electrical load.

[41] Default service is supposed to be a pass-through cost of only those costs incurred to provide it.

[42] For example, DTE stated in the October 19, 2000 letter order that Boston Edison Company's total default service cost under-recovery was increasing at a rate of approximately $10 million per month.

1. DTE allows LDCs to implement fuel adjustment clauses.

In 2000, DTE received requests from LDCs to increase their standard offer service rates to account for increased fuel costs. After investigating the matter,[43] DTE issued an Order in December 2000, recognizing that pricing standard offer below costs was undermining the development of a competitive market. It also posed financial risks to LDCs and to all future customers, who will still pay for these costs. For these reasons, DTE allowed the LDCs to implement the fuel adjustment, but to delay standard offer rate increases to January 1, 2001, to give customers and competitive suppliers time to adjust to the changes.

In its decision, the DTE found the Act's 15 percent rate reduction requirement to be separate and distinct from the fuel cost changes. Therefore, DTE treated the fuel adjustment as a surcharge, also outside the inflation adjustment of the Act, and established a mechanism for calculating the charge. DTE further directed the companies to adjust their standard offer service rates annually as part of their reconciliation filing,[44] using the most recent twelve-month data available to calculate the fuel surcharge. (DTE also requested the LDCs to report their deferral balances by July 1, 2001, so it could determine the need for an interim adjustment.) And finally, DTE required all LDCs to file another report on their cost mitigation efforts undertaken since March 1, 1998 and planned for 2001.[45]

Competitive Services for Metering, Billing and Information Services Need to Be Examined

Historically, the electric companies provided customers with a bundle of services with a single price, including metering, billing and information services (MBIS). The Act directed DTE, in conjunction with DOER,[46] to study traditional MBIS methods and determine whether these services should be unbundled and provided through a competitive market. DTE was to assess whether unbundling these services could produce substantive consumer savings without jeopardizing LDC staffing levels. Additionally, the Act required DTE to analyze whether the exclusivity of service territories enjoyed by distribution companies should be "maintained, terminated or altered."

1. DTE considers metering, billing and information services (MBIS) and service territories

DTE opened its investigation (DTE 00-41) into MBIS on June 12, 2000 by requesting written comments from interested parties. DTE defined metering and billing services as follows.

[43] DTE Dockets #s 00-66, 00-67, and 00-70.
[44] Each year, the companies must submit their costs and revenues for standard offer service to DTE.
[45] DTE also noted that future decreases in natural gas and oil generation fuel costs will translate into adjustments or elimination of the standard offer fuel adjustment.
[46] DOER intervened in the proceeding and submitted comments to DTE.

Table 13: DTE Metering and Billing Services Defined

Metering Services	Billing Services
Installation of metering equipment	Bill calculation based on metered consumption data and the applicable prices
Periodic equipment maintenance/inspection	Invoice preparation and distribution
Equipment replacement	Billing data transmission to applicable competitive generation suppliers
Meter reading	Account payables receiving and disbursement to LDCs and generation providers
Data inspection and error editing	
Meter data transmission for billing	
Data storage for customer access	
Daily data reporting to ISO-NE for wholesale load management in the Commonwealth	

After reviewing comments and conducting a public hearing and technical session, DTE made four recommendations to the Legislature in a report filed December 29, 2000:

Recommendation 1: ***DTE recommended no legislative action to allow competitive metering-related services because no substantive savings would result to customers in the near term.***

DTE determined that competitive metering would not produce substantive customer savings in the near term. Competitive metering service would cause significant staffing disruptions at distribution companies. DTE argued that long term savings would only be realized if competitive metering suppliers could provide metering services more efficiently than distribution companies. Competitive metering would also require the development of rules and standards. The Department reasoned that the time needed to develop and implement such rules could delay advanced metering technology. DTE also noted the lack of experience in other states undertaking competitive metering, including the difficulty of unbundling metering charges on distribution company bills.

Recommendation 2: ***DTE will open a proceeding to establish terms and conditions for distribution companies to offer advanced metering services.***

While DTE acknowledged the potential of competition to spur technological advances and value-added products, it also determined that potential alone did not justify moving away from time-honored practices. Nevertheless, DTE intends to open a new proceeding to establish the terms and conditions by which distribution companies would offer advanced metering services[47] for customers' homes and facilities.

Recommendation 3: ***DTE recommended no legislative action to allow competitive billing-related services at this time. DTE will open a proceeding in 2001 to further study the issue.***

In general, DTE rejected the prospect of competitive billing at this time. In this proceeding, DTE considered whether a competitive billing framework was superior to the existing regulatory

[47] Advanced metering equipment is capable of recording customers' electricity usage at 15-minute intervals or less.

framework.[48] Supporters of competitive billing argue that it provides the opportunity for competitive suppliers to send a single electric bill to their customers. DTE saw the value of a supplier single-bill option in assisting the development of a competitive generation market. Consequently, while recommending against competitive billing now, the DTE intends to open a proceeding in early 2001 to look into allowing competitive suppliers the option of sending customers a combined bill.

Recommendation 4: ***DTE recommended no legislative action to alter the service territories of distribution companies.***

Historically, the investor-owned utilities distributed electricity within geographically defined service territories. In exchange for this franchise type protection, distribution companies assumed certain obligations, among them, the obligation to serve all customers within the territory who apply for and are willing to pay for service. Further, the company will provide customers with safe, reliable and adequate power. When DTE presented the issue of territory exclusivity, some commenters framed the subject as one of market power and anti-competitiveness. One proposed amendment would allow another utility or entity to build and operate a distribution system within an undeveloped section of an incumbent's system. However, DTE found merit in other commenters concerns that a developer might not be willing or able to meet obligations to serve and that their financial incentives might be inadequate to maintain such a system. DTE held that the legislature did not intend for there to be "pocket" utilities.

Distribution Companies Costs Need to be Reduced, But Reliability Maintained

In order to reduce distribution company service costs, while maintaining reliability, the Act authorized DTE to promulgate rules and regulations for establishing performance based rates (PBR) for electric and gas distribution companies. Such a rate scheme would replace the current system for setting distribution company rates, which guarantees that distribution companies recover their costs plus a rate of return.

PBR is a structure to provide incentives to reduce costs. Under PBR, distribution company efficiencies are rewarded, while poor performance is penalized. To judge or measure performance, the DTE would establish service quality indicators (SQI) for a variety of service quality categories, including customer satisfaction service outages, distribution facility upgrades, repairs and maintenance, telephone service, billing service, and public safety.[49] (SQI is used to insure that services do not degrade as costs are reduced.) The indicators serve as a baseline or benchmark for performance.

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[48] Currently, distribution companies are required to offer two billing options to customers and competitive suppliers: 1) *a complete billing* option, whereby the customer receives a single bill from the company for both distribution company-related charges and supplier-related charges or 2) a *pass-through* billing option whereby customers receive one bill from their distribution company and another bill from their competitive supplier.

[49] The Act contains stipulations governing labor levels. Any affected company that makes a PBR filing with DTE after the effective data of the Act cannot engage in labor displacement or reductions below staffing levels in existence on November 1, 1997, unless such levels are part of a collective bargaining agreement or otherwise agreed to by the DTE. DTE must hold an evidentiary hearing whereby the company must demonstrate that such staffing reductions would not adversely disrupt service quality standards established by DTE. The Act also authorized DTE to levy a penalty against any affected company that fails to meet the service quality standards. This penalty is an amount up to and including the equivalent of 2% of the company's transmission and distribution service revenues for the previous calendar year.

1. DTE issues interim order on service quality indicators

DTE issued its interim order (DTE 99-84) on the service quality indicators August 17, 2000. SQIs are to be included in performance-based rate plans for electric and local gas distribution companies.[50] DTE clarified its decisions on initial questions posed in the Notice of Inquiry (NOI). It also raised further questions in the interim order on issues, such as data collection and penalty provisions.

The interim order previewed probable contents of the final order.[51] For example, DTE proposed continuing to set performance benchmarks based on historical performance of the distribution company. While the DTE does not require the use of national, regional, or statewide distribution company performance data, it may revisit the issue in the future. The DTE concluded, however, that performance data from other industry types would not be appropriate benchmarks for distribution companies. The interim order's guidelines on measurements included the following:

- DTE proposed adopting telephone call answering, service call performance, and on-cycle reading as performance measures for customer service and billing.
- DTE's Consumer Division will use data on complaint cases and billing adjustments to determine customer satisfaction.
- Consumer surveys will be used as an informational measure only, with no penalty.
- Staffing benchmarks will be established on a company-specific basis and determined by the then in-force collective bargaining agreement for each company.
- Safety performance measures will include a lost work-time accident rate for each company, based on its ten-year average of historic lost work-time data.
- Reliability performance measures will also be included in a company's service quality plan. Electric companies will include a reliability performance measure called the system average interruption duration index (SAIDI), expressed in minutes of outage per customer per year.[52]

[50] DTE issued a Notice of Inquiry/Generic Proceeding (NOI) in October 1999 with the intent to address two issues associated with two components of a PBR plan: 1) the service quality plan and 2) the penalty mechanism. DTE solicited comments by December 1999.

[51] DTE held a technical session on November 28, 2000 to solicit specific information from distribution companies on issues, such as a company's ability to record and report momentary interruptions; the use of a password protected website for accident and outage reporting; the use of Restricted Work Days as a safety metric; and the updating of benchmarks during the term of a PBR plan. Interested parties submitted comments on these issues at the end of 2000. DTE is expected to issue a final order with guidelines in 2001.

[52] In the interim order, the DTE does not propose reliability measures for power quality. However, DTE encouraged distribution companies and customers to look into power quality arrangements and offered to assist in developing and executing such agreements. DTE sought more information about how distribution line loss measurements could be standardized. DTE also acknowledged that severe weather type benchmarks might merit consideration in a future proceeding.

B. WHOLESALE MARKET BARRIERS AND INITIATIVES TO OVERCOME THEM

In the wholesale market, several issues were dealt with through changes to market design and market rules to create more price certainty, lower costs, and send better market signals to market participants.

End-use customers need a voice in wholesale market changes

1. End User sector is activated in NEPOOL's Governance structure

On April 7, 2000 the End User sector was activated and now controls 20 percent of the NEPOOL vote. Some of the Massachusetts consumers groups represented in the End User sector are Associated Industries of Massachusetts, The Massachusetts Health and Educational Finance Authority and The Energy Consortium. Consumers of electricity like owners of transmission and sellers of electricity now have a vote in the development of market rules and changes.[53]

Wholesale market flaws need corrections and market participants need more certainty about the rule changes

In the restructured wholesale market, buyers and sellers trade electricity at market prices, rather than at traditional cost-of-service rates.[54] ISO-NE began operations of the revamped, wholesale electricity and ancillary services markets on May 1, 1999. As the wholesale market proceeded, some market rules had unintended negative consequences. For example, ISO-NE and NEPOOL were warned in advance to expect the failure of the market for Installed Capability (ICAP). ISO-NE's economic consultant warned that capacity owners could easily manipulate the ICAP market, and recommended that it be abolished.[55] Other market failures were completely unexpected, such as the May 8th price spike which exposed the need for more flexibility for importing power, and the need to coordinate policies with neighboring power pools. During the year 2000, ISO-NE and NEPOOL made progress to address market flaws in the market rules.[56] The following describes one of the most contentious market rule changes.

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53 The New England Power Pool (NEPOOL) is a voluntary association of market "participants" that are engaged in the electric power business in the six New England states. NEPOOL delegates the operation and administration of the electric power system and wholesale markets to the Independent System Operator of New England (ISO-NE). NEPOOL retains the rights under the Federal Power Act to develop the market products and rules and determines the transmission tariffs in New England. Since ISO-NE maintains the integrity of the system it has authority to request market rule changes in an emergency. All rules and tariffs must be approved by the FERC. NEPOOL members vote on changes to the rules or the tariff through the governing board known as the Participants Committee. The Participants Committee is represented by five sectors of market participants: Generation, Transmission, Suppliers/Marketers, Publicly-Owned/Municipal Power, and End Users.

54 See DOER's 1998 and 1999 Market Monitor Reports for an explanation of the newly designed wholesale electricity market and its products.

55 *A Review of ISO New England's Proposed Market Rules,* Cramton and Wilson, September 9, 1998.

56 For a complete list of market rule changes filed with FERC, see ISO-NE's website at www.ISO-NE.com.

1. The Installed Capability (ICAP) Market was eliminated, but the ICAP requirement remained. However, the uncertainty regarding the ICAP deficiency charge caused concern for market participants.

The Installed Capability (ICAP) market is intended to insure the reliability of the electric power system by providing incentive to construct sufficient generation capacity to cover the New England region's peak demand.[57] At the heart of this matter, however, is the question on whether LSEs or "the load" should directly contribute to the capital cost of generators so that excess capacity will be available to meet peak load, or should power plant owners recover their capital costs through the energy and ancillary services markets.

Generators claimed they need the income they derive from the Installed Capability payments, in addition to energy market payments, to finance new plant construction. LSEs thought the fees were unnecessary and sometimes too high. Furthermore, in the restructured retail markets LSEs no longer could recover all their generation–related costs through rates. This provided LSEs with a disincentive to over-purchase ICAP sometimes leaving them exposed to ICAP deficiencies and subject to penalties.

After the ICAP market flaws came to light in 2000,[58] ISO-NE proposed to FERC to eliminate the ICAP market, effective December 31, 2001 and proposed to study possible alternative market-based reliability assurance mechanisms. Subsequently, ISO-NE modified its initial proposal and requested FERC to allow elimination of the market by June 1, 2000. ISO-NE claimed that the ICAP auction market was not workably competitive and the ICAP requirement was no longer required in a competitive market. Although many parties supported ISO-NE's position other parties opposed it and requested FERC to order ISO-NE to retain ICAP until an alternative was developed and implemented.

In its Order Conditionally Accepting Congestion Management and Multi-Settlement Systems (CMS/MSS) released June 28, 2000, FERC approved the elimination of the ICAP auction market effective August 1, 2000 and ordered ISO-NE to revert to the administratively determined sanctions for failure to meet the ICAP requirement.

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[57] When NEPOOL began the process of creating a deregulated wholesale market for electricity, NEPOOL decided that the pool would continue to require that each LSE meet the Installed Capability (ICAP) requirement. NEPOOL rules mandate that each LSE within NEPOOL have sufficient installed capability that it owns or controls to meet its peak load plus a reserve margin to meet defined levels of contingencies. LSEs who fail to satisfy this requirement are assessed an ICAP deficiency charge. In order to determine a market-based price for the ICAP deficiency charge, NEPOOL established an ICAP market that was implemented on April 1, 1998. Unlike the other hourly markets administered by ISO-NE, the ICAP Market was set up as a monthly market. It is also a residual market. In other words, only the difference between a LSE's installed capability resources and its installed capability obligation is traded through ISO-NE. LSEs generally buy ICAP requirements through bilateral contracts. In the monthly ICAP auction, holders of excess ICAP would offer to sell ICAP and LSEs that were short on their ICAP obligations would offer to buy ICAP. The market would settle at a price where the bids and offers cleared. That price constituted the ICAP deficiency charge.

[58] For the first twenty months of implementation, the ICAP auction market cleared at or near zero dollars. In January 2000, however, there was a noticeable change in the bidding in the ICAP Market. In particular, in January 2000, the ICAP clearing price was $10,000 per megawatt. The ISO-NE, which has the role of market monitor, determined that there was insufficient competition in the market for ICAP and settled the market at zero dollars per megawatt for the month.

On July 28, 2000 the ISO-NE made its initial compliance filing to the CMS/MSS order. Although ISO-NE believed the marginal cost of the ICAP product was zero dollars, ISO-NE proposed a $.17 per kilowatt-month (or $170 per megawatt for the month) charge for ICAP deficiency to comply with the FERC order. ISO-NE based this proposed charge on the weighted average clearing price of the ICAP auction market during 1999. In doing so, ISO-NE reasoned that the ICAP payments do not contribute to system reliability and, as the marginal cost of ICAP is zero, any ICAP deficiency charge above zero is an inefficient subsidy paid by one group of market participants to another. Several interested parties disagreed with this proposed deficiency charge claiming it was too low.

The FERC addressed the $.17 per kilowatt-month proposed ICAP deficiency charge in its Order on Compliance Filing, issued December 15, 2000. In the Order, the FERC stated that to be meaningful, "the penalty for failing to meet NEPOOL's ICAP requirement must be something more than a token payment of $.17 per kilowatt-month. The FERC instituted an ICAP deficiency payment of $8.75 per kilowatt-month, retroactive to August 1, 2000. The FERC reasoned that this amount "represents an approximation of the cost to install a peaking unit and represents a reasonable basis for setting a level to incent the construction of new generation." ISO-NE was given until December 30, 2000 to submit its compliance filing. However, the FERC received several motions seeking a rehearing and a stay of the December 15th Order.

The lack of closure to the ICAP issue prolonged the uncertainty of ICAP costs for market participants and therefore raised prices to suppliers and consumers who had not contracted for it with generators. In those cases, a risk premium was added because of the uncertainty of the value of the deficiency charge administered by ISO-NE. (The 2001 Market Monitor will discuss subsequent events and impacts.)

Consumers need to see future and real-time cost of energy consumption and the financial benefit of responding to price signals

One of the flaws of the current wholesale market is the single settlement system. Under the single-settlement system the markets are settled one time, during the system dispatch (the "real time"). Offers to supply energy must be submitted in the day-ahead and re used to anticipate the real time market, and its prices. Units are scheduled to run accordingly. However, buyers and sellers using the real-time market do not know the price of electricity until the actual dispatch. This settlement system reduces participant's options for managing demand and supply. For example, an electric generator may start its unit in the morning expecting a high energy-clearing price (ECP) based on the day-ahead dispatch schedule. In the real-time, however, the generator may find that the price for energy is significantly less, making it difficult for the generator to recover start-up costs. Single settlement also reduces the opportunity for consumers to manage their electrical load. Because the dispatch process begins with the ISO-NE estimating the next day's electrical load rather than allowing customers to bid in their demand, consumers become price takers in this market.

Another flaw is the lack of price transparency for transmission congestion costs. Electricity, because of constraints and losses on the transmission system, varies in cost from location to location in New England. When an additional kilowatt of energy cannot move across a transmission line because of these constraints, the line is congested. Congestion costs are caused when ISO-NE dispatches a generator inside a transmission congested zone whose bid price is higher than a generator outside the zone. Under the current system the cost difference between the energy clearing price and the price of the generator dispatched out of merit due to congestion is socialized among the entire power pool through the transmission tariff. (This difference is commonly referred to as "uplift.")[59] This system hides energy costs and sends the wrong price signals to consumers. Therefore, locational pricing that will directly allocate congestion related energy costs and revenues is needed to send the correct price signal to both buyers and sellers.[60]

1. ISO-NE filed a Congestion Management/Multi-Settlement System (MMS/MSS) proposal with the FERC which FERC Conditionally Accepted

To address these problems (and others) FERC ordered NEPOOL to develop a Congestion Management System and a Multi-Settlement System (CMS/MSS). These rule changes are needed to improve the market price signals to suppliers and to buyers, and to allow NEPOOL to better conform to the new market rules in the neighboring New York Power Pool (NYPP) and Pennsylvania-New Jersey-Maryland (PJM) Power Pool.

On March 26, 2000 ISO-NE filed a CMS/MSS proposal with the FERC.[61] On June 28, 2000 the FERC issued an order whereby they approved certain new market design elements contained in the ISO-NE's CMS/MSS proposal, rejected others, and requested further information regarding still other elements.[62] The following summarizes the FERC's order on the proposed major changes to NEPOOL rules. (DOER will continue to report on the outcome of these changes in next year's Market Monitor.)

Multi-settlement System - The current day-ahead, single-settlement system will be replaced by a multi-settlement (two-settlement) system involving a day-ahead market and a real-time market for energy and ancillary services. A day in advance of operations, scheduled quantities for each market product and clearing prices will be established based on day-ahead bids for energy and demand. Binding financial settlements will occur based on these quantities and prices. Real-time settlement will continue to exist, but it is intended to be a "residual" or "balancing" market to adjust for any under-scheduling or over-scheduling in the day-ahead market. Separate prices will be determined for real time operations, and a second financial settlement will be made based on changes in the real time

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59 When NEPOOL prepared to implement a market-based dispatch system its consultant determined that there was no congestion in New England. Therefore, the pool members agreed to share any congestion uplift through the pool's transmission charge. In reality the congestion uplift has become a significant cost, nearly $70 million for the Boston area in 2000. The congestion management system is designed to eliminate congestion uplift by replacing the single, pool-wide ECP with zonal prices. This system will not be in place until 2002 at the earliest. The transmission owning entities, faced with larger congestion costs that anticipated are pushing the pool to adopt the congestion management system as soon as possible.

60 Locational pricing is the norm for competitive industries as marginal cost varies dependent upon local costs for production, transportation and transactions.

61 The ISO New England made the filing because the NEPOOL participants were not able to get a two-thirds majority vote to approve a CMS/MSS. The ISO-NE filing was nearly identical to the CMS/MSS plan approved by the majority of NEPOOL participants.

62 After the CMS/MSS changes were approved by the FERC the ISO-NE expected that it would be able to implement most of the major changes, including the day-ahead market and congestion management by the fourth quarter of 2001. The implementation plan included purchasing some software from the PJM power pool to speed development. However, the implementation plan was then changed in favor of developing proprietary dispatch software rather than using an off-the-shelf product. This change pushed the implementation schedule back to late 2002. However, by the end of 2000 the ISO was again considering adopting a modified PJM system termed the "Standard Market Design (SMD)."

from the day-ahead schedule. Thus, buyers and sellers will be allowed to adjust supply and demand in response to price signals.

Three-part Bids - Generators will supply information on their start-up and no-load[63] costs, along with prices for blocks of energy. ISO-NE will then use this information to model the least cost dispatch for all its resources over the entire day. This is necessary because some generation units have high start-up costs and cannot be dispatched economically for short periods of time. However, for the real-time market, generators will bid a single price because there is no opportunity to optimize the daily dispatch in real-time.

Congestion Management – With CMS generators will identify their injection bus[64] when bidding to supply electricity and be paid the locational marginal price (LMP). Consumers (the load) will have the option of paying the LMP of their withdrawal bus or pay the average LMP in their load zone. The load zones will either be defined by distribution utility territory, or by the physical constraints on the transmission system. This system will create hundreds of electricity prices through New England, where only one price for energy (the Energy Clearing Price) exists today. To facilitate the trading of power by suppliers and boost liquidity in the market ISO-NE will be specifying trading hubs that will represent the average of the LMPs in an area. ISO-NE will calculate and publish nodal and the zonal prices in each trading hub both day-ahead and in real time.

With locational pricing there will be price separation between some load injection points and load withdrawal points during some hours as transmission lines become congested. Therefore, the system operator will be paying a lower price for the injection than is being collected for the withdrawal. To allocate this differential NEPOOL is adopting a system of Financial Congestion Rights (FCR). The holder of an FCR between node (or zone) A and node (or zone) B will receive revenues in proportion to the energy price differential. To obtain FCRs between any two points on the system energy suppliers will bid to purchase from either an open auction or bilaterally from an FCR holder. The amount of FCRs to be auctioned to suppliers in New England will be determined by ISO-NE, based on the feasible transmission capacity. Revenues from FCR auctions will be allocated to consumers through an Auction Revenues Rights mechanism.

As competitive electric markets mature, the need for greater coordination beyond traditional control area boundaries will grow. The development of regional and inter-regional markets can lead to increased reliability and lower wholesale electric costs.

With the development of competitive wholesale and retail electricity markets, it had become clear to the FERC that the continued management of transmission grids by vertically integrated utilities would be inadequate and perhaps discriminatory in providing needed services to the revamped markets. Further changes were needed to support the transition from proprietary transmission access to workably competitive markets.[65]

In 1999, the FERC proposed to amend its regulations under the Federal Power Act to facilitate the formation of Regional Transmission Organizations (RTOs). The FERC used the comments received

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[63] No-load is the state of running generation without injecting the power into the system. This cost is used to model the value of holding reserves.
[64] A bus is an electrical conductor that serves as a common connection to two or more electrical circuits.
[65] FERC had already mandated an Open Access Same-Time Information System (OASIS) in Order No. 888 to provide all participants access to information on the availability of transmission capacity.

from its Proposed Rule to develop required characteristics and functions for an RTO and in December 1999 issued several parameters in FERC Order No. 2000 (Order 2000).[66] Basically, an RTO is an electric transmission system operator that is independent of power market participants, controls the electric transmission facilities within a region of appropriate scope and configuration, and has specific responsibilities for ensuring that those facilities are used to provide reliable, efficient and non-discriminatory transmission service.[67] RTO creation is further intended to stimulate the expansion and upgrading of the transmission systems themselves.

Order 2000 gave guidance to transmission owners on transmission ratemaking and incentive-based ratemaking. More importantly, Order 2000's "open architecture" approach allowed flexibility in complying with the required RTO characteristics and functions. In other words, an RTO proposal should not contain provisions that would limit the RTO’s ability to evolve in ways that would improve its efficiency.[68]

1. New England already met many of the required characteristics and functions of an RTO

New England has the only competitive power pool in the United States with the characteristics of an interstate power pool where the incumbent utilities have ceded control over the energy markets.[69] Even before Order 2000 was issued, New England already met many of the required characteristics and functions of an RTO. The New England region has a discreet regional power pool with an independent system operator having operational authority over short-term transmission services and short-term reliability. New England already has a centralized market for ancillary services, OASIS, a pool-wide planning and expansion process, interregional coordination and a market monitor. Nonetheless, in the New England region, more changes were needed to satisfy Order 2000's four required characteristics and eight functions.
The FERC called for voluntary participation in RTOs, but required all public utilities that own, operate or control interstate transmission to file a plan on how they intended to participate in an RTO. Deadlines for all transmission owners to submit proposals about how they were going to comply with Order 2000 requirements were established. Members of FERC approved ISOs, such as ISO-NE, had to file by January 15, 2001.

To help stakeholders meet this deadline several collaborative efforts were undertaken. The FERC hosted a series of workshops in March and April 2000 so stakeholders could share information and views on the development of RTOs. ISO-NE, NEPOOL and the New England Counsel of Public

[66] Order 2000 was issued on December 20, 1999. 65 FR 810 (January 6, 2000); FERC Stats. & Regs. ¶ 31,089 (2000).
[67] Order No. 2000 established the following required characteristics: (1) Independence, (2) Scope and Regional Configuration, (3) Operational Authority, and (4) Short-term Reliability, and the following required functions: (1) Tariff Administration and Design, (2) Congestion Management, (3) Parallel Path Flow, (4) Ancillary Services, (5) OASIS and Total Transmission Capability (TTC) and Available Transmission Capability (ATC), (6) Market Monitoring, (7) Planning and Expansion, and (8) Interregional Coordination, 65 FR 12110 (2000).
[68] The FERC reiterated its RTO objectives in Order 2000-A, issued February 25, 2000. In that order, the Commission clarified its intent to eliminate undue discrimination in transmission services. Further, the Commission restated some of the goals to be achieved through the creation of RTOs. These included: improved efficiencies in transmission grid management; improved grid reliability; removing opportunities for discriminatory practices; improved market performance; and facilitating light-handed regulation.
[69] California and New York are single-state pools and PJM is still dominated by the incumbent, vertically integrated utilities.

Utilities Commissioners (NECPUC) organized several meetings, referred to as the New England RTO (NERTO) process to promote input into the RTO design process. This collaborative effort worked to define the RTO structure most beneficial to New England stakeholders over the Summer and Fall of 2000, culminating in negotiating sessions in December facilitated by staff from the FERC's Alternative Dispute Resolution Department.[70] Many of the parties moved closer to agreement; however, there was not unanimous agreement on all the issues.

In order to meet the deadline established by Order 2000, on January 16, 2001 ISO-NE and the New England Transmission Owners (Joint Petitioners)[71] filed a Joint Petition for Declaratory Order To Form the New England Regional Transmission Organization. The Joint Petition proposed integrating two separate entities, an investor-owned independent transmission company (ITC) and the ISO-NE, the independent system operator, to create a binary RTO. The ITC would have primary responsibility for the New England Open Access Transmission Tariff (NOATT), along with the responsibility for arranging construction of new transmission facilities and generator interconnections. The ISO-NE, as the system operator for the New England control area, would administer the Open Access Same Time Information System (OASIS) and the wholesale markets in the region and would provide ancillary services under its tariff. (Much of the wholesale chapter in the 2001 Market Monitor will focus on FERC's decisions on RTO proposals and the impacts on the New England wholesale market.)

CONCLUSION

Many of the actions discussed in this chapter will help advance the competitive retail and wholesale markets. Although some impacts will be felt almost immediately upon implementation, others may not be readily appreciated for some time. Next year's Market Monitor will discuss, in particular, the effects on the retail competitive markets from the allowed changes to default service pricing and standard offer fuel charges. Additionally, they should help reduce the volatility in the wholesale market allowing retail prices to better reflect market conditions.

[70] Background information and materials on RTO activities can be found on FERC's website at www.FERC.com and the NERTO website at www.nerto.com.

[71] The New England Transmission Owners joining in the Joint Petition for Declaratory Order to Form the New England Regional Transmission Organization are Bangor Hydro-Electric Company, Central Maine Power Company, National Grid USA, Northeast Utilities Service Company, The United Illuminating Company, and the Vermont Electric Power Company, Inc.

CHAPTER V: ELECTRICITY DEMAND

When electricity marketers and suppliers decide to enter a deregulated electricity market, they consider a number of factors such as straightforwardness of market rules, the cost of acquiring new customers, and profit margins. In doing so, they also look at the market size and types of customers, customer demand or load, and the timing of the demand. Their reasons for entering a market depend on their particular business strategies.

Earlier chapters in this report reviewed electricity supply and price information in year 2000 and the market changes implemented to lead to more robust competitive wholesale and retail markets. This chapter completes the economic equation with the addition of demand information.

The analysis presented confirms the differences in size of electricity markets and in annual electricity demand between Massachusetts, New England and the United States. It highlights variations in electricity consumption among the various sectors - residential, commercial and industrial. For example, New England's industry mix differs from other parts of the country, influencing the extent and type of industrial electricity demand. The chapter also examines for the different sectors during peak and off-peak demand times.

An evaluation of electricity demand and trends suggests a number of implications for Massachusetts' retail electricity market development. For example, unlike other parts of the country, Massachusetts and New England do not have a lot of high energy use manufacturing industries for which energy, including electricity prices, are a large part of their operating costs. Those types of companies with high usage and growing demand will seek out competitive marketers to save money. Massachusetts is dominated by low energy use industries. Although these companies want electricity cost savings, they may favor non-price factors such as reliability and power quality. That is why Performance Based Rates (PBR) and Service Quality Indices (SQI) initiatives discussed in Chapter IV are very important. Therefore, competitive suppliers may need to offer value-added service in addition to price savings to Massachusetts customers.

The demand analysis helps explain why some suppliers prefer customers with favorable demand and load profiles such as industrial customers. Therefore, policy-makers will need to develop initiatives to make residential and small commercial customers attractive to suppliers or suppliers will need to develop products to entice these sectors to switch to competitive suppliers. The analysis can also help trace the effects of changes in market rules and initiatives such as the impacts of demand response initiatives in the wholesale and retail markets.

A. OVERVIEW OF DEMAND

Massachusetts' Electricity Demand Differs from United States' Demand

Electricity demand in Massachusetts (and to a lesser extent in New England) differs significantly from the United States (See Table 14). For the last decade, the commercial sector has been the largest electricity consumer in New England (39 percent) and Massachusetts (44 percent). New England residential (36 percent) and industrial consumption (24 percent) follow. The ten-year average for Massachusetts also shows residential consumption at 34 percent (lowest of the three groupings), and industrial consumption at 21 percent. In contrast, the residential sector (35 percent) consumes the largest share of electricity in the United States as a whole, followed by the industrial (33 percent) and commercial sectors (31 percent).

Table 14: Electricity Demand as a Percent of Total Electricity Demand

	Massachusetts		New England		United States	
	2000	10-Year Average	2000	10-Year Average	2000	10-Year Average
Residential	33.2	34.35	35.66	35.86	34.97	34.53
Commercial	44.59	43.71	38.93	39.22	30.41	31.02
Industrial	20.99	21.26	23.95	24.4	31.38	33.45

Source: U.S. DOE/EIA "Electric Power Annuals", 1991-2000, Vol.1

Several possible explanations for the consumption disparities follow.

1. **Residential electricity end-uses differ in Massachusetts and New England than those across the nation**

New England households consume less than 17 percent of total use on heavy end-use electric appliances, such as air conditioning. This compares to 31 percent nationwide. New England also lags behind the nation in terms of its proliferation of households with electric air conditioning, increasing from 42-49 percent compared to 57-72 percent from 1980-1997 for the nation.[72]

2. **Massachusetts and New England feature lower growth in population and households that the U.S. as a whole**

Table 15 shows population data for both regions and the nation, and per-capita data. As shown, Massachusetts' population growth is less than half that of U.S. growth. Consequently, in terms of consuming units, overall residential electricity demand should be lower in Massachusetts. Reinforcing this fact is a lower per-unit consumption or demand rate. Massachusetts has lower average consumption of electricity per capita than New England and the United States.

Table 15: Population & Per Capita Energy Consumption, 1990-2000

	Massachusetts	New England	United-States
Population 2000	6,349,097	13,922,517	281,421,906
Population, % Change, 1990-2000	5.50%	6.20%	13.10%
Daily Per Capita Consumption (kWh)	20	21	29

Sources: U.S. Census, U.S. DOE's EIA

[72] Energy Information Administration, New England Appliance Report, 2001.

3. **The industry mix in Massachusetts differs from that in New England and, especially in the U.S.**

Differences in industry mix influence the relationship between commercial and industrial sector consumption. Table 16 lists Massachusetts and United States top ten and bottom ten industry concentration. The data confirm higher concentrations of advanced manufacturing and some commercial sectors, such as education, credit and finance, and professional services in Massachusetts. Alternatively, Massachusetts is weak in many of the heavy manufacturing sectors, the heaviest electricity users.[73]

Table 16: Location Quotients --Massachusetts, 2000

Top Ten		Bottom Ten	
Education	2.57	**Tobacco Manufacturing**	0.015
Instruments	2.34	**Mining**	0.049
Misc. Manufacturing	2.34	**Motor Vehicles**	0.05
Leather	2.09	**Farm**	0.147
Credit &Finance	1.87	**Petroleum Products**	0.218
Local and Interurban Transport	1.61	**Lumber**	0.228
Electric Equipment	1.52	**Furniture**	0.417
Fabricated Metals	1.41	**Primary Metals**	0.43
Misc. Professional Services	1.38	**Chemicals**	0.478
Rubber	1.27	**Food**	0.479

Sources: REMI Model, DOER

4. **Massachusetts' industries produce much more dollar value of product per kWh than industries as a whole in the U.S.**

Finally, Massachusetts features high-value industries. Table 17 compares Massachusetts to the United States in terms of changes in gross regional product (GRP) per kWh for the years 1990 and 2000. The data show that Massachusetts industries produce much more dollar value per kWh of product than the U.S. This advantage increased from 1990 to 2000 as shown by examining the ratio row. For the year 2000, Massachusetts industries produced $4.44 per each kWh used. This number will vary by industry, but does show that energy intensity (the inverse of GRP/kWh) is much higher for the nation. In addition, the value for Massachusetts shows that electricity cost, at about $0.10 per kWh, is a smaller percentage of revenues, and a less critical cost element, in Massachusetts than for the nation.

[73] According to EIA, high-energy manufacturing industries include the following: food, paper, chemicals, petroleum, stone, clay, and glass, and primary metal. Low-energy industries include textiles, apparel, leather, and rubber.

Table 17: GRP/kWh, Massachusetts and U.S. 1990, 2000

	1990 GRP (bill of fixed 92$)	millions of kWh	2000 GRP (bill of fixed 92$)	millions of kWh	1990 GRP/kWh	2000
MA	171.852	45,441	227.281	51,197	$3.78	$4.44
US	6140.936	2,712,555	8567.588	3,412,766	$2.26	$2.51
				Ratio MA to US	1.67	1.77

Sources: REMI Model, U.S. DOE's EIA, DOER

B. DEMAND BY SECTOR

Massachusetts' Electricity Demand Lags New England's and that of the United States

While the previous sector showed overall electricity demand comparisons for Massachusetts, New England and the U.S., this section provides demand by sector in the same regions.

Electricity demand in Massachusetts lags New England and the United States overall and among all sectors. Table 18 displays the ten year (1990-2000) average annual growth rate for electricity demand for all three-sectors in Massachusetts, New England, and United-States. The U.S. growth rate is almost twice that of Massachusetts. As noted earlier, growth rates in both the residential and industrial sectors in Massachusetts and New England increased at lower rates than in the United States.

However, it should be noted that there was an economic downturn during the time period covered by the data (1991-1992). These downturns tend to suppress annual growth rates for Massachusetts, New England, and the United States. Later years highlight much higher growth rates. For example, the overall annual growth rates for 1994-2000 are 1.77, 2.46, and 2.55 percent, respectively for Massachusetts, New England and the U.S. Although Massachusetts' growth rate is still less than the other regions, it narrowed the gap.

TABLE 18: Average Annual Growth Rate of Electricity Demand by Sectors, 1990-2000

Sectors	Residential	Commercial	Industrial	All-Sector
Massachusetts	0.87	1.58	0.57	1.2
New England	1.57	1.97	0.81	1.67
United-States	2.55	2.16	1.25	2.32

Sources: U.S. DOE's EIA, DOER

C. MASSACHUSETTS' ELECTRICITY DEMAND

Local Distribution Companies Deliver Most of Massachusetts' Electricity, but Customer Bases Differ Among Distribution Companies

Local distribution companies distribute 86 percent of Massachusetts' electricity demand, while municipal utilities deliver the remaining 14 percent. Retail electricity demand in 2000 was divided across eight LDCs (Table 19). With the merger of Eastern Edison's customer base into Massachusetts Electric's territory, two LDCs (National Grid's LDC holdings and NStar's Boston Edison) account for over 65 percent of all electricity demand in the state. This share is more noteworthy, given NStar's other holdings--Commonwealth and Cambridge Electric.

Table 19: Composition of Massachusetts Demand, 2000

Distribution Company	Number of Customers (Yearly Average)	Electric Revenue ($ Millions)	Customer Sales (GWh)
Boston Edison	687,933	1,425.40	14,502.90
Cambridge Electric	47,008	96.5	1,495.40
Commonwealth Electric	352,012	422.3	3,822.90
Eastern Edison	197,282	81.9	952.6
Fitchburg Gas & Electric	25,878	51.3	472.5
Massachusetts Electric	1,118,793	1,697.80	19,537.90
Nantucket Electric	10,588	14.9	119
Western Massachusetts Electric	198,356	369.4	3,882.30
Total: Distribution Companies	2,440,568	4,159.60	44,785.20
Total: Municipal Companies	367,423	646.7	7,029.20
TOTAL STATE	*2,807,991*	*4,806.30*	*51,814.40*

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

An examination of kilowatt-hours by four broad customer sectors further underscores differences in customer bases among the LDCs (Table 20). A comparison of municipal and distribution company data show higher concentrations of residential, industrial, and other customer sectors (which refer mainly to streetlighting and other government accounts) in municipal companies. Cambridge Electric features the lowest percentage of residential demand while, not surprisingly, Nantucket Electric has the highest residential demand.

Customer mix is a key cost determinant for distribution and other rate components. As mentioned in the *Market Monitor 1998*, systems with a high proportion of load concentrated in large-usage customers are less costly to serve and tend to exhibit lower prices. Price comparisons and corresponding customer mix figures for each LDC indicate some correlation between low industrial/large commercial customer mix and higher rates. Cambridge Electric, for example, has many large commercial customers and low residential demand. It also has the lowest rates in the state. Customer mix, however, is only one factor. It does not consider density of customers (customers per mile), which can also have an impact.

Table 20: Massachusetts Demand by LDC & Customer Group, 2000

	Percentage			
	Residential	Commercial	Industrial	Other
Boston Edison	27	61	11.1	0.9
Cambridge Electric	12.3	82.8	4.4	0.6
Commonwealth Electric	47.9	41.4	10.3	0.4
Eastern Edison	44.6	39.5	15.2	0.6
Fitchburg Gas & Electric	31.6	23.1	4.4	1.2
Massachusetts Electric	36.4	40.6	22.5	0.5
Nantucket Electric	64	35.7	0	0.2
Western Massachusetts Electric	35.6	37.7	26	0.6
All Distribution Company	33.7	48.2	17.5	0.6
All Municipal Company	36.4	19.2	36.7	7.8
Entire State	34	44.3	20.1	1.6

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

D. PEAK DEMAND

Peak Demands and Load Factors Vary by Sectors (rate class) and Other Conditions

The preceding sections reviewed electricity demand from a macro view, looking at entire customer sectors or companies over an extended period of time. At a macro level, demand is affected by changes in economic growth or population. The next section examines demand from a more micro-level, looking at rate class data and how demand changes based on peak/off-peak conditions, such as day of week and weather. (Price can also be a micro-level factor but is not considered here due to lack of data.)

For instance, electricity demand varies seasonally, primarily because of weather changes. Generally, electricity demand soars during a very hot summer or severe cold winter period because electric appliances, such as air conditioners, or electric heaters are used extensively. Winter weather in the Northeast Region is colder than the U.S. average, demanding more electricity than the national average. Similarly, summer weather in the Northeast is milder than the U.S. average and electricity demand (e.g., cooling load) is expected to be somewhat lower than the national average. Demand can also vary by day of the week, with demand shifting based on whether individuals are at work or at home.

The following analysis uses Massachusetts Electric Company (MECo) data to study variations in electricity demand by rate classes during the course of the day.[74] Electricity demand is represented by load curves, varying by time of day for each region and season. January, July and April represent peak winter, peak summer, and shoulder demand months, respectively, for the year 2000. Average load rate data for each hour produced load curves for each month. Average and peak hourly loads of each rate class were applied to determine the load factor. (Load Factor = Average Load/Peak Load.)

[74] The load data shown are a result of sampling and thus are statistically representative of the particular rate classes, except for the G-3 rate class data, which were taken from all G-3 customers.

Finally, load factors for 2000 are compared to 1999 to determine whether or not there is a significant change in load factors.

1. Residential demand load curves and load factors

Table 21 presents Massachusetts Electric Company's residential customers hourly load in kilowatts (kWs) for the three months and day of week for both 1999 and 2000. Peak and average load levels are included with the load factor calculation for two residential rate classes: general use (R-1) and time-of-use (R-4).

A number of conclusions can be drawn from the data, such as the average customer size of the rate class and changes in usage during the year. However, a review of the load factor columns indicates that time-of-use customers generally have higher load factors than general residential customers. This is not unusual, given that time-of-use rates include incentive structures, favoring flatter load curves. However, the differences are not pronounced for the summer months, which may indicate that time-of-use customers are more likely electric-heating customers.[75] If true, this would tend (in the winter months) to increase the average load, thereby improving the load factor. A comparison of the 1999 and 2000 load factors yields inconclusive results (load factors are no better or worse) as some factors increase and some decrease.

Table 21: Residential Load Factors

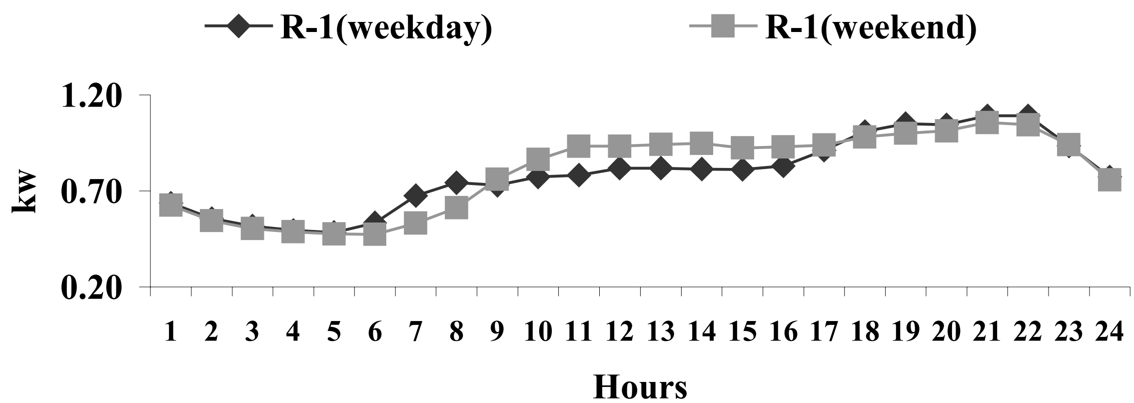
Class	R-1						R-4					
	Peak (kW)		Average (kW)		Load Factor		Peak (kW)		Average (kW)		Load Factor	
JANUARY	***Jan-99***	***Jan-00***	***Jan-99***	***Jan-00***	***Jan-99***	***Jan-00***	***Jan-99***	***Jan-00***	***Jan-99***	***Jan-00***	***Jan-99***	***Jan-00***
Average Weekday	1.36	1.49	0.93	0.99	0.68	0.67	10.69	10.83	8.39	8.99	0.78	0.83
Average Saturday	1.31	1.49	0.98	1.11	0.76	0.74	10.34	11.36	8.72	10.13	0.84	0.89
Average Sunday	1.35	1.49	0.99	1.07	0.73	0.71	10.07	10.48	8.15	8.9	0.81	0.84
APRIL	***Apr-99***	***Apr-00***	***Apr-99***	***Apr-00***	***Apr-99***	***Apr-00***	***Apr-99***	***Apr-00***	***Apr-99***	***Apr-00***	***Apr-99***	***Apr-00***
Average Weekday	0.96	1.1	0.62	0.74	0.64	0.67	5.96	6.47	4.26	5.06	0.72	0.78
Average Saturday	1.02	1.03	0.75	0.75	0.73	0.73	6.2	6.25	4.95	4.77	0.8	0.76
Average Sunday	1.08	1.17	0.74	0.77	0.68	0.66	5.95	6.74	4.75	4.56	0.8	0.68
JULY	***Jul-99***	***Jul-00***	***Jul-99***	***Jul-00***	***Jul-99***	***Jul-00***	***Jul-99***	***Jul-00***	***Jul-99***	***Jul-00***	***Jul-99***	***Jul-00***
Average Weekday	1.25	1.12	0.9	0.79	0.72	0.7	4.83	4.32	3.59	3.27	0.74	0.76
Average Saturday	1.37	1.01	1.04	0.77	0.76	0.77	5.41	4.35	3.995	3.21	0.73	0.74
Average Sunday	1.37	1.18	1.02	0.83	0.75	0.7	5.14	4.71	3.84	3.44	0.75	0.73

Sources: Massachusetts Electric Company, DOER

[75] Notice that winter peaks are much higher than summer peaks.

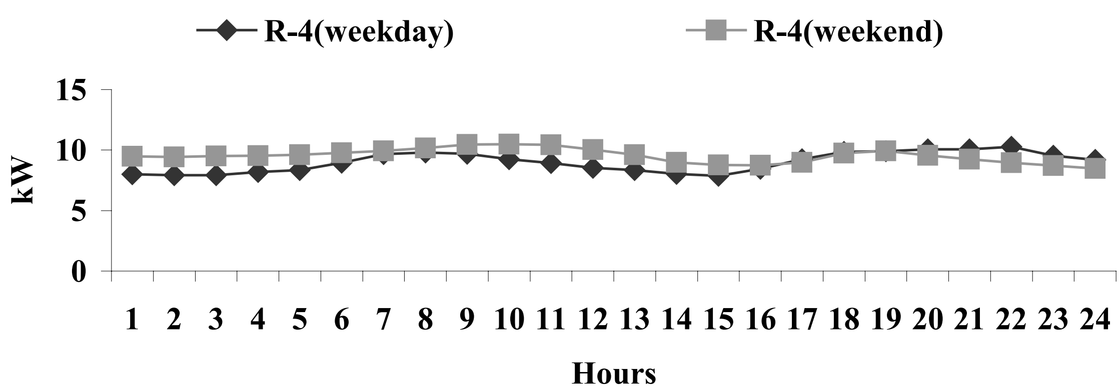
Figures 15 and 16 represent R-1 July 2000 and R-1 January 2000 load curves hour of the day. Though the scales are different, it is the shape or peakiness of the curves that is important. The higher the load factor, the flatter the curve. (A flatter curve means that the electricity is being used more evenly in time and thus more efficiently. A peaky curve means more power plants are needed to meet the peak.) As mentioned, time-of-use customers show more efficient demand behavior in the form of higher load factors.

Figure 15: July 2000 R-1 Load Curves



Sources: Massachusetts Electric Company, DOER

Figure 16: January 2000 R-4 Load Curves



Sources: Massachusetts Electric Company, DOER

Any change in electricity demand alters the amount of electricity supply provided by the generators. Electricity generating companies must meet increased demand by increasing electricity supply. Because excess marginal supply is lower when demand increases, competitive generator companies tend to raise prices in response to high demand, which allows them to capture scarcity rents. Consequently, rational customers can respond to price increases and reduce their electric bills by altering the timing of their electricity.

2. Commercial demand load curves and load factors

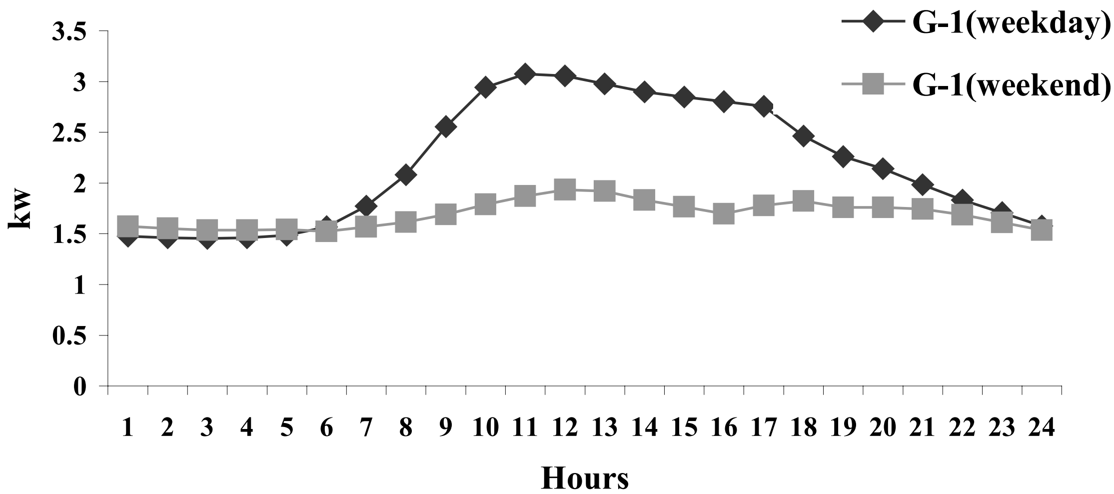
Table 22 presents Massachusetts Electric Company's small commercial and industrial (G-1) and streetlighting (S-0) hourly loads (in kWs). The G-1 rate class represents businesses with either less than 10,000 kWh of electricity use per month or less than 200 kWs of demand. As expected, streetlighting load factors are very low. This is not surprising given the nature of the service—that is, streetlights are either completely on or completely off. Small C&I load factors are slightly better than R-1 residential load factors on weekdays. They improve dramatically during weekends when loads are lower. Nevertheless, the low load factors of both the R-1 and G-1 classes are a major reason why these customers are less attractive to competitive supply marketers. Figures 17 and 18 represent the load curves for the G-1 and S-0 customers.

Table 22: Small Commercial and Industrial and Streetlighting Demand Load Factors

Class	G-1						S-0					
	Peak (kW)		Average (kW)		Load Factor		Peak (kW)		Average (kW)		Load Factor	
JANUARY	***Jan-99***	***Jan-00***	***Jan-99***	***Jan-00***	***Jan-99***	***Jan-00***	***Jan-99***	***Jan-00***	***Jan-99***	***Jan-00***	***Jan-99***	***Jan-00***
Average Weekday	3.06	3.09	2.18	2.19	0.71	0.71	2.72	2.38	1.59	1.39	0.58	0.59
Average Saturday	2.31	2.29	1.82	1.82	0.79	0.8	2.72	2.37	1.59	1.39	0.58	0.59
Average Sunday	1.83	1.73	1.6	1.57	0.87	0.9	2.72	2.38	1.59	1.39	0.58	0.59
APRIL	***Apr-99***	***Apr-00***	***Apr-99***	***Apr-00***	***Apr-99***	***Apr-00***	***Apr-99***	***Apr-00***	***Apr-99***	***Apr-00***	***Apr-99***	***Apr-00***
Average Weekday	2.53	2.7	1.74	1.85	0.69	0.69	2.52	2.46	1.05	1.03	0.42	0.42
Average Saturday	1.86	1.9	1.4	1.4	0.76	0.76	2.52	2.46	1.05	1.03	0.42	0.42
Average Sunday	1.42	1.46	1.18	1.22	0.83	0.84	2.52	2.46	1.05	1.03	0.42	0.42
JULY	***Jul-99***	***Jul-00***	***Jul-99***	***Jul-00***	***Jul-99***	***Jul-00***	***Jul-99***	***Jul-00***	***Jul-99***	***Jul-00***	***Jul-99***	***Jul-00***
Average Weekday	1.25	1.12	0.9	0.79	0.72	0.7	4.83	4.32	3.59	3.27	0.74	0.76
Average Saturday	1.37	1.01	1.04	0.77	0.76	0.77	5.41	4.35	3.995	3.21	0.73	0.74
Average Sunday	1.37	1.18	1.02	0.83	0.75	0.7	5.14	4.71	3.84	3.44	0.75	0.73

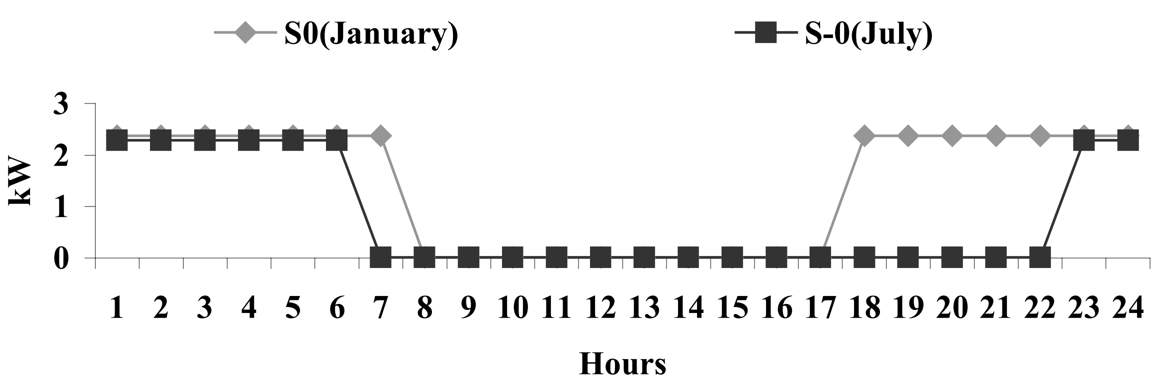
Sources: Massachusetts Electric Company, DOER

Figure 17: January 2000 G-1 Load Curves



Sources: Massachusetts Electric Company, DOER

Figure 18: January and July 2000 S-0 Load Curves



Sources: Massachusetts Electric Company, DOER

3. Industrial demand load curves and load factors

Table 23 presents load factors applied to G-2 and G-3 customers: greater than 10,000 kWh per month but does not exceed 200 kWs of demand (G-2), and over 200 kWs (G-3). The largest commercial and industrial sectors show a high load factor with G-3 showing the highest load factors. A comparison of 1999 and 2000 data reveals no strong conclusions and little change in the data.

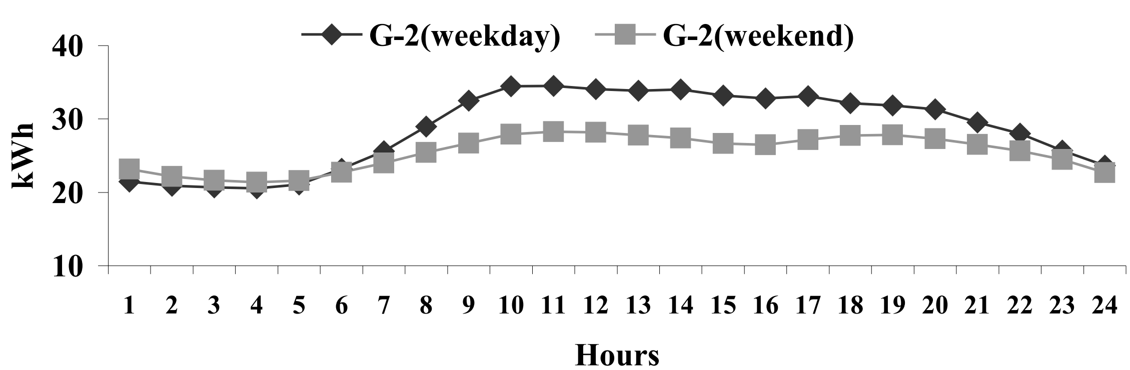
Table 23: Industrial Load Factors

Class	G-2						G-3					
	Peak (kW)		Average (kW)		Load Factor		Peak (kW)		Average (kW)		Load Factor	
JANUARY	***Jan-99***	***Jan-00***	***Jan-99***	***Jan-00***	***Jan-99***	***Jan-00***	***Jan-99***	***Jan-00***	***Jan-99***	***Jan-00***	***Jan-99***	***Jan-00***
Average Weekday	32.61	34.83	26.84	28.63	0.82	0.82	440.4	457.4	379.9	395.6	0.86	0.86
Average Saturday	28.33	30.64	24.68	26.7	0.87	0.87	327.6	336.7	303	313.3	0.92	0.93
Average Sunday	25.62	26.92	22.6	24.22	0.88	0.9	288.3	296.6	278.4	287.8	0.97	0.97
APRIL	***Apr-99***	***Apr-00***	***Apr-99***	***Apr-00***	***Apr-99***	***Apr-00***	***Apr-99***	***Apr-00***	***Apr-99***	***Apr-00***	***Apr-99***	***Apr-00***
Average Weekday	28.92	30.87	23.09	25.01	0.8	0.81	437.3	435.67	369.3	373.38	0.84	0.86
Average Saturday	24.63	26.09	21.07	22.36	0.86	0.86	309.04	322.75	284.6	296.41	0.92	0.92
Average Sunday	21.04	22.72	18.63	19.99	0.89	0.88	267.59	278.32	253.84	263.75	0.95	0.95
JULY	***Jul-99***	***Jul-00***	***Jul-99***	***Jul-00***	***Jul-99***	***Jul-00***	***Jul-99***	***Jul-00***	***Jul-99***	***Jul-00***	***Jul-99***	***Jul-00***
Average Weekday	39.56	36.82	30	27.98	0.76	0.76	486.7	455.8	407.9	385.4	0.84	0.85
Average Saturday	35.43	27.41	28.2	22.96	0.8	0.84	369.9	349.7	337.3	316.5	0.91	0.91
Average Sunday	30.05	27.41	25.08	22.96	0.83	0.84	325.5	313.02	299.9	219.06	0.92	0.93

Sources: Massachusetts Electric Company, DOER

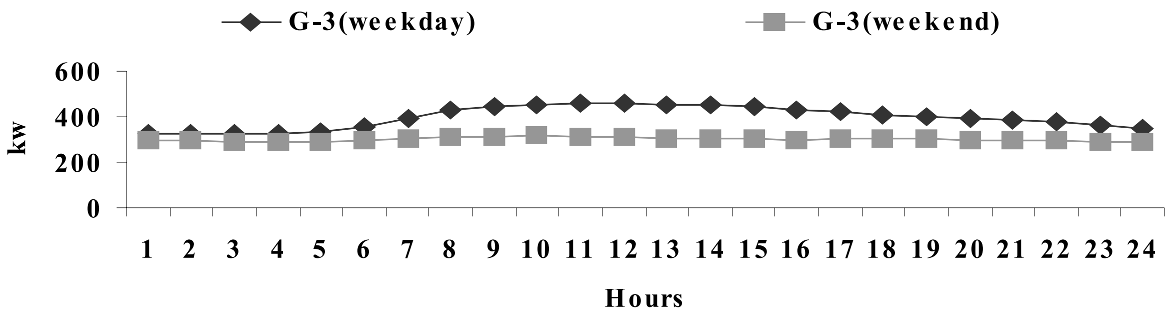
Figure 19 and Figure 20 represent January 2000 load curves for G-2 and G-3 customers, respectively. Similar to the small commercial and industrial customers, electricity demand peaks during core business hours on weekdays, and declines during early morning and late evening on weekdays and weekends.

Figure 19: January 2000 G-2 Load Curves



Sources: Massachusetts Electric Company, DOER

Figure 20: January 2000 G-3 Load Curves



Source: Massachusetts Electric Company, DOER

CONCLUSION

With the partly deregulated electricity market in Massachusetts, generation service (standard offer and default) rates do not fluctuate with demand use or "load curves," as they might in a fully competitive market. At the production level, wholesale electricity prices oscillate on an hourly basis, but retail prices are fixed. Thus, there are no incentives for customers to reduce their electricity consumption over the course of a day or when wholesale prices are high.

Enhanced metering and billing for all Massachusetts customers can help create the environment for proper retail pricing. The presence of appropriate retail price signals will create incentives for all customers to reduce or shift their electricity demand and ultimately to reduce their utility bills.

OUTLOOK FOR 2001

The events during the third year of restructured electric markets in Massachusetts delivered several benefits for consumers. However, one of the significant challenges is the development of robust retail competitive market. Despite some setbacks, several initiatives were implemented to overcome market barriers and alleviate problems preventing more competitive wholesale and retail markets.

The *Market Monitor 2001* will continue DOER's examination of the persevering progress of electric industry restructuring. Specific events and topics that will be addressed in the 2001 report include the following:

Short Term Market Pricing for Default Service

At the end of 2000, the DTE separated standard offer and default service, and set new guidelines for default service pricing and procurement, basing the default service price on market-based costs. In 2001, utility prices for default service will better reflect market forces. (It is also expected that natural gas prices and thus wholesale electricity prices should fall in 2001.) Thus, competitive retail suppliers should be able to start offering competitive choices to default service customers.

Retail Competitive Market Initiatives

By December 2000, the number of default service customers had swelled to 25 percent of total customers and their consumption grew from 13 percent to 20 percent over the year. Many, interested market participants and regulatory decision-makers began discussions on the necessity to expand the range of competitive options available to consumers. The *Market Monitor 2001* will highlight steps taken.

Advanced Metering Services and Competitive Billing

DOER will review the DTE proceedings to establish terms and conditions for distribution companies to offer advanced metering services and DTE's proceeding on competitive billing.

Renewable Portfolio Standards

In 2001, DOER will begin the public review process for the renewable portfolio standards (RPS). The Act directs DOER to establish a RPS for all retail electricity suppliers selling electricity to end-use consumers in Massachusetts. Beginning in 2003, each supplier must obtain at least 1 percent of its supply from qualified new renewable generation units. Each year thereafter, the standard increases by one-half percent (0.5%) through 2009 when it reaches 4 percent of each supplier's sales in that year. After 2009, the standard may increase by one percent per year until DOER modifies or suspends it. In the next Market Monitor, DOER will report on the regulatory developments.

Regional Transmission Organization

On January 16, 2001, ISO-NE and the New England Transmission Owners filed with FERC a Joint Petition for Declaratory Order To Form the New England Regional Transmission Organization (RTO). DOER's *Market Monitor 2001* will focus on FERC's decisions on RTO proposals and the impacts on the New England wholesale market.

Customer Migration Figures, January and December 2000

BOSTON EDISON

January 2000						
Customer Type	**Standard Offer Customers**	**Standard Offer kWh/Month**	**Default Service Customers**	**Default Service kWh/Month**	**Competitive Generation Customers**	**Competitive Generation kWh/Month**
Residential-- Non Low Income	412,787	283,235,315	145,044	70,375,587	1,359	1,511,635
Residential -- Low Income	27,614	14,422,504	4,207	2,139,354	0	0
Small Commercial & Industrial	43,482	35,046,072	12,549	9,948,947	1,087	929,184
Medium Commercial & Industrial	21,600	179,219,737	4,849	30,804,014	1,096	12,102,133
Large Commercial & Industrial	1,803	356,115,458	456	70,017,558	372	119,955,708
Street Lights	6,666	12,208,238	403	182,729	634	2,528,906
Farms*						
Total Sales	**51,3925**	**880,247,324**	**167,508**	**185,608,136**	**4,548**	**137,027,566**

December 2000						
Customer Type	**Standard Offer Customers**	**Standard Offer kWh/Month**	**Default Service Customers**	**Default Service kWh/Month**	**Competitive Generation Customers**	**Competitive Generation kWh/Month**
Residential-- Non Low Income	376,608	248,126,865	183,718	89915357	1,335	1,477,385
Residential -- Low Income	31,891	15,914,007	28	1,523,301	0	0
Small Commercial & Industrial	40,602	32,333,262	17,806	8,195,596	995	750,816
Medium Commercial & Industrial	19,711	171,183,311	6,721	25,926,781	986	11,354,146
Large Commercial & Industrial	1,702	337,851,476	614	47,256,972	353	113,367,368
Street Lights	6,735	11,586,948	1072	172,801	634	2,566,017
Farms*						
Total Sales	**477,249**	**816,995,869**	**209,959**	**142,443,379**	**4,303**	**129,515,732**

Source: DOER Form 110

*Farms are included in the Commercial & Industrial Numbers, Boston Edison serves 175 farms
Source MA Department of Food & Agriculture

Customer Migration Figures, January and December 2000

CAMBRIDGE ELECTRIC

January 2000

Customer Type	Standard Offer Customers	Standard Offer kWh/Month	Default Service Customers	Default Service kWh/Month	Competitive Generation Customers	Competitive Generation kWh/Month
Residential-- Non Low Income	27,673	14,371,944	14,845	5,301,811	0	0
Residential -- Low Income	1,452	561,979	44	12,558	0	0
Small Commercial & Industrial	3,994	3,857,356	777	699,331	16	16,756
Medium Commercial & Industrial	1,869	21,217,373	441	4,469,985	8	46,138
Large Commercial & Industrial	288	66,818,722	93	15,381,328	2	118,476
Street Lights	230	642,982	59	15,931	1	194
Farms*						
Total Sales	**33,506**	**107,470,356**	**16,259**	**25,880,944**	**27**	**181,564**

December 2000

Customer Type	Standard Offer Customers	Standard Offer kWh/Month	Default Service Customers	Default Service kWh/Month	Competitive Generation Customers	Competitive Generation kWh/Month
Residential-- Non Low Income	21,583	10,437,636	16,309	5,978,925	45	27,200
Residential -- Low Income	1,305	518,665	41	18,568	0	0
Small Commercial & Industrial	3,448	3,083,172	957	787,913	0	0
Medium Commercial & Industrial	1,710	14,242,387	583	15,611,978	0	0
Large Commercial & Industrial	260	64,277,677	112	17,849,454	0	0
Street Lights	212	646,015	58	20,387	0	0
Farms*						
Total Sales	**28,518**	**93,205,552**	**18,060**	**30,267,225**	**45**	**27,200**

Source: DOER Form 110

*Farms are included in the Commercial & Industrial Numbers, Cambridge Electric serves 52 farms
Source MA Department of Food & Agriculture

Customer Migration Figures, January and December 2000

COMMONWEALTH ELECTRIC

January 2000

Customer Type	Standard Offer Customers	Standard Offer kWh/Month	Default Service Customers	Default Service kWh/Month	Competitive Generation Customers	Competitive Generation kWh/Month
Residential-- Non Low Income	268,045	151,666,176	52,273	26,808,529	2	147
Residential -- Low Income	15,014	8,227,990	496	294,187	0	0
Small Commercial & Industrial	34,125	70,564,345	7,277	10,904,033	461	2,106,481
Medium Commercial & Industrial	419	39,161,883	28	3,179,474	29	3,679,822
Large Commercial & Industrial	63	38,370,780	2	177,840	6	6,728,040
Street Lights	5,277	2,107,849	489	79,807	73	50,279
Farms*						
Total Sales	**322,943**	**310,099,023**	**60,565**	**1,443,870**	**571**	**12,564,769**

December 2000

Customer Type	Standard Offer Customers	Standard Offer kWh/Month	Default Service Customers	Default Service kWh/Month	Competitive Generation Customers	Competitive Generation kWh/Month
Residential-- Non Low Income	226,781	128,780,064	61,762	31,297,398	0	0
Residential -- Low Income	15,948	8,638,716	177	57,128	0	0
Small Commercial & Industrial	29,625	64,175,503	9,659	17,133,766	5	0
Medium Commercial & Industrial	377	34,453,754	72	7,715,935	5	753,240
Large Commercial & Industrial	59	28,545,269	9	4,602,940	0	0
Street Lights	4,661	2,071,165	705	161,536	0	0
Farms*						
Total Sales	**277,451**	**266,664,471**	**72,384**	**60,968,703**	**5**	**753,240**

Source: DOER Form 110

*Farms are included in the Commercial & Industrial Numbers, Commonwealth Electric serves 692 farms
Source MA Department of Food & Agriculture

Customer Migration Figures, January and December 2000

EASTERN UTILITIES

January 2000

Customer Type	Standard Offer Customers	Standard Offer kWh/Month	Default Service Customers	Default Service kWh/Month	Competitive Generation Customers	Competitive Generation kWh/Month
Residential-- Non Low Income	125,879	82,276,196	23,851	10,547,474	2	1,198
Residential -- Low Income	13,576	6,573,913	379	168,926	0	0
Small Commercial & Industrial	13,355	8,209,753	3,664	1,925,629	150	389,088
Medium Commercial & Industrial	5,879	57,998,041	901	6,406,886	114	1,810,227
Large Commercial & Industrial	121	40,266,849	8	664,120	1	399,000
Street Lights	Unmetered	2,534,680	Unmetered	94,148	Unmetered	259,930
Farms	128	187,042	6	184,884	0	0
Total Sales	**158,938**	**207,904,688**	**28,809**	**19,992,067**	**267**	**2,859,443**

April 2000

Customer Type	Standard Offer Customers	Standard Offer kWh/Month	Default Service Customers	Default Service kWh/Month	Competitive Generation Customers	Competitive Generation kWh/Month
Residential-- Non Low Income	123,798	66,677,284	25,132	9,678,040	0	0
Residential -- Low Income	13,993	5,716,893	1,014	386,166	0	0
Small Commercial & Industrial	13,065	7,573,325	4,181	2,367,215	40	50,948
Medium Commercial & Industrial	5,797	67,211,278	1,094	10,839,989	34	322,056
Large Commercial & Industrial	121	45,485,921	9	1,321,960	0	0
Street Lights	Unmetered	1,834,041	Unmetered	262,749	0	0
Farms	132	234,991	9	4,313	0	0
Total Sales	**156,906**	**198,552,760**	**31,439**	**25,279,833**	**74**	**387,852**

Source: DOER Form 110

Note: Eastern Edison merged with Massachusetts Electric in May of 2000.

Customer Migration Figures, January and December 2000

FITCHBURG GAS AND ELECTRIC

January 2000						
Customer Type	**Standard Offer Customers**	**Standard Offer kWh/Month**	**Default Service Customers**	**Default Service kWh/Month**	**Competitive Generation Customers**	**Competitive Generation kWh/Month**
Residential-- Non Low Income	18,999	12,966,356	3,009	1,632,711	1	893
Residential -- Low Income	1,030	651,254	9	34,889	0	0
Small Commercial & Industrial	1,205	588,400	139	79,943	14	6,255
Medium Commercial & Industrial	1,471	7,941,750	183	810,979	18	184,009
Large Commercial & Industrial	36	16,390,882	0	0	0	0
Street Lights	644	313,959	39	9,213	9	19,191
Farms*						
Total Sales	**23,385**	**38,852,601**	**3,379**	**2,567,735**	**42**	**210,348**

December 2000						
Customer Type	**Standard Offer Customers**	**Standard Offer kWh/Month**	**Default Service Customers**	**Default Service kWh/Month**	**Competitive Generation Customers**	**Competitive Generation kWh/Month**
Residential-- Non Low Income	17,290	10,700,999	4,870	2,527,086	0	0
Residential -- Low Income	1,543	638,682	2		0	0
Small Commercial & Industrial	1,196	421,864	255	109025	0	0
Medium Commercial & Industrial	1,314	7,623,594	274	1,130,950	0	0
Large Commercial & Industrial	40	15,601,793	6	722,670	1	63,833
Street Lights	541	155,005	72	44,525	0	0
Farms	54	165,504	0	0	0	0
Total Sales	**21,978**	**35,307,441**	**5,479**	**4,534,256**	**1**	**63,833**

Source: DOER Form 110

Customer Migration Figures, January and December 2000

MASSACHUSETTS ELECTRIC

January 2000

Customer Type	Standard Offer Customers	Standard Offer kWh/Month	Default Service Customers	Default Service kWh/Month	Competitive Generation Customers	Competitive Generation kWh/Month
Residential-- Non Low Income	673,013	506,729,224	160,603	92,407,981	576	610,653
Residential -- Low Income	46,467	34,181,205	65	233,516	4	21,655
Small Commercial & Industrial	75,020	104,117,855	19,775	26,103,480	2,512	3,733,589
Medium Commercial & Industrial	8,871	165,738,787	1,264	23,969,610	531	11,818,756
Large Commercial & Industrial	1,675	364,846,135	234	35,129,510	287	148,977,206
Street Lights	671	8,529,998	29	340,909	106	2,452,575
Farms*						
Total Sales	**805,717**	**1,184,143,204**	**181,970**	**178,185,006**	**4,016**	**167,614,434**

December 2000

Customer Type	Standard Offer Customers	Standard Offer kWh/Month	Default Service Customers	Default Service kWh/Month	Competitive Generation Customers	Competitive Generation kWh/Month
Residential-- Non Low Income	751,149	541,198,067	239,754	134,080,582	505	645,615
Residential -- Low Income	58,943	35,023,820	66	210,367	4	25,268
Small Commercial & Industrial	84,506	112,126,573	33,822	44,127,848	956	1,724,583
Medium Commercial & Industrial	12,530	203,029,556	2,813	48,015,422	187	5,123,075
Large Commercial & Industrial	1,972	454,642,227	509	148,137,024	172	75,718,722
Street Lights	839	11,751,929	205	2,999,931	26	543,391
Farms*						
Total Sales	**909,939**	**1,357,772,172**	**277,169**	**377,571,174**	**1,850**	**83,870,654**

Source: DOER Form 110

*Farms are included in the Commercial & Industrial Numbers, Massachusetts Electric serves 926 farms
Source MA Department of Food & Agriculture

Customer Migration Figures, January and December 2000

NANTUCKET ELECTRIC

January 2000 Customer Type	Standard Offer Customers	Standard Offer kWh/Month	Default Service Customers	Default Service kWh/Month	Competitive Generation Customers	Competitive Generation kWh/Month
Residential-- Non Low Income	7,511	5,773,619	1,863	1,429,565	0	0
Residential -- Low Income	35	36,359	0	0	0	0
Small Commercial & Industrial	889	1,324,678	285	707,526	0	0
Medium Commercial & Industrial	51	900,925	0	0	0	0
Large Commercial & Industrial	4	420,832	0	0	0	0
Street Lights	2	27,254	2	86	0	0
Farms*						
Total Sales	**8,492**	**8,483,667**	**2,150**	**2,137,177**	**0**	**0**

December 2000 Customer Type	Standard Offer Customers	Standard Offer kWh/Month	Default Service Customers	Default Service kWh/Month	Competitive Generation Customers	Competitive Generation kWh/Month
Residential-- Non Low Income	6,927	5,687,749	2,508	2,012,790	0	0
Residential -- Low Income	55	49,159	0	0	0	0
Small Commercial & Industrial	798	1,286,506	360	529,699	0	0
Medium Commercial & Industrial	50	998,664	1	35,760	0	0
Large Commercial & Industrial	4	506,624	1	144,600	0	0
Street Lights	2	29,780	2	92	0	0
Farms*						
Total Sales	**7,836**	**8,558,482**	**2,872**	**2,722,941**	**0**	**0**

Source: DOER Form 110

*Farms are included in the Commercial & Industrial Numbers, Nantucket Electric serves 9 farms
Source MA Department of Food & Agriculture

Customer Migration Figures, January and December 2000

WESTERN MASSACHUSETTS ELECTRIC

January 2000

Customer Type	Standard Offer Customers	Standard Offer kWh/Month	Default Service Customers	Default Service kWh/Month	Competitive Generation Customers	Competitive Generation kWh/Month
Residential-- Non Low Income	128,692	89,749,972	33,299	17,844,202	0	0
Residential -- Low Income	15,879	10,149,700	3	2,234	0	0
Small Commercial & Industrial	14,202	34,033,602	2,939	4,769,838	0	0
Medium Commercial & Industrial	1,105	37,022,725	139	3,389,598	0	0
Large Commercial & Industrial	256	98,523,640	11	2,587,032	0	0
Street Lights	1041	1,810,586	205	85,184	0	0
Farms	532	1,250,116	26	148,743	0	0
Total Sales	**171,509**	**255,523,633**	**25,674**	**14,116,855**	**10**	**95,435**

December 2000

Customer Type	Standard Offer Customers	Standard Offer kWh/Month	Default Service Customers	Default Service kWh/Month	Competitive Generation Customers	Competitive Generation kWh/Month
Residential-- Non Low Income	121,730	81,917,636	42,134	22,813,800	0	0
Residential -- Low Income	14,814	9,012,836	0	0	0	0
Small Commercial & Industrial	13,327	34,574,131	4,247	7,764,351	0	0
Medium Commercial & Industrial	1,080	43,007,860	202	4,851,403	0	0
Large Commercial & Industrial	250	109,458,630	38	6,728,367	2	0
Street Lights	762	1,732,139	285	276,580	0	0
Farms	520	1,303,695	32	399,219	0	0
Total Sales	**152,483**	**281,006,927**	**46,906**	**103,386,720**	**2**	**0**