Avoided Energy Supply Costs in New England

Prepared for:

Avoided-Energy-Supply-Component (AESC) Study Group

Prepared by:

ICF CONSULTING

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Note:

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List of Exhibits

List Of Acronyms Used In Report

AC	Alternating Current
AGC	Automatic Generation Control
AGT	Algonquin Gas Transmission System
AESC	Avoided Energy Supply Component Study Group
Bcf	Billion Cubic Feet
CC	Combined Cycle
CMA	Central Massachusetts
CT	Combustion Turbine
DC	Direct Current
Dth	Decatherm, one million British thermal units (MMBtu)
ECAR	East-Central Area Reliability Council
EIA	Energy Information Administration
ERCOT	Electric Reliability Council of Texas
ES&D	Electricity Supply and Demand database – NERC
FERC	Federal Energy Regulatory Commission
FT	Firm Transmission
FTR	Firm Transmission Rights
GW	Gigawatt
GWH	Gigawatt-hour
HVDC	High Voltage Direct Current
ICAP	Installed Capacity
IGTS	Iroquois Gas Transmission System
IPM	Integrated Planning Model
ISO	Independent System Operator
ISO - NE	Independent System Operator – New England
kV	Kilovolt
LDC	Local Distribution Company
LMP or LBMP	Locational Marginal Pricing or Locational-Based Marginal Pricing
LNG	Liquefied Natural Gas
LSE	Load Serving Entity
MMBtu	Million British Thermal Units equivalent to a decatherm (Dth)
MW	Megawatt
MWh	Megawatt-hour
NANGAS	North American Natural Gas Analysis System
NEGA	New England Gas Association
NEMA	Northeast Massachusetts
NEPOOL	New England Power Pool
NERC	North America Electric Reliability Council
NPCC	Northeast Power Coordinating Council
NYISO	New York Independent System Operator
NYPP	New York Power Pool
OTR	Ozone Transport Region
PJM	Pennsylvania-Jersey-Maryland (ISO)
PNGTS	Portland Natural Gas Transmission System
RFP	Request for Proposals

List Of Acronyms Used in Report (continued)

RTEP	Regional Transmission Expansion Plan
SEMA	Southeast Massachusetts
SIP	State Implementation Plan
TCPL	TransCanada Pipeline
TETCO	Texas Eastern Transmission Company
TGP	Tennessee Gas Pipeline

Chapter One: Executive Summary

Study Background

As part of an ongoing review of expected avoided supply costs in New England, ICF Consulting (ICF) was retained by the 2003 Avoided-Energy-Supply-Component (AESC) Study Group to provide an analysis of the energy supply costs (electricity, natural gas, fuel oil, and wood) potentially avoided through the implementation of energy efficiency programs in New England. Ratepayer funds support energy-efficiency programs, which focus on reducing electricity and/or gas consumption. This study is intended to support energy-efficiency program planning and development by program administrators participating in the AESC group. In addition, this study is intended for use by AESC group members to support regulatory filings.

The primary target of the energy efficiency programs are electricity and gas use and are hence the primary focus of this report. Other fuels also considered are propane, residual fuel oil, distillate fuel oil, kerosene for heating, and wood.

The AESC Study Group includes a broad spectrum of electric and gas utilities or their representatives from Massachusetts, New Hampshire, Vermont, Rhode Island, Connecticut, and Maine. The sponsors of this project include: Bay State Gas Company, Berkshire Gas Company, Keyspan Energy Delivery New England (Boston Gas Company, Essex Gas Company, and Colonial Gas Company), Central Vermont Energy Corporation (Connecticut Valley Electric Company), Cape Light Compact, National Grid USA (Massachusetts Electric Company, Narragansett Electric Company, Granite State Electric Company, and Nantucket Electric Company), New England Gas Company, NSTAR Electric & Gas Company, Northeast Utilities (Western Massachusetts Electric and Public Service of New Hampshire), Unitil (Fitchburg Gas and Electric Light Company, Concord Electric Company and Exeter & Hampton Electric Company), the State of Maine, and representatives from Massachusetts non-utility party consultants.

The Modeling Approach

This analysis utilizes a detailed and integrated fundamentals modeling approach combined with actual market data to estimate the supply costs considered to be avoidable. To provide projections of wholesale or spot market fuel market prices and wholesale energy and capacity prices, ICF utilized a fundamentals based modeling approach for the gas and power markets. ICF further estimated the costs considered avoidable for retail power market services and gas services through estimating actual cost expenditures for these services. Avoided costs for other fuels were estimated in conjunction with the natural gas market analysis. Stage 1 of the analysis focused on estimating wholesale or spot market prices and generation costs while Stage 2 focused on estimating avoided costs.

`Stage 1 of the analysis utilizes the combination of ICF's NANGAS® natural gas market model to forecast delivered to New England market pricing and ICF's IPM® power market model to forecast near- and long-term power market conditions. IPM® considers the entire time horizon (2003 – 2037) to determine the optimal distribution and use of generation and transmission resources including the potential retirement, retrofitting, or addition of capacity. Similarly, NANGAS® is a fundamentals based model capturing reservoir level detail on the supply side and reflecting the demand side fundamentals through sectoral demand estimates and representation of the North American pipeline system.

Prior studies were performed for the AESC Study Group in 1999 and 2001. A comparison of currently available information from the most recent analysis is provided within this report.

With the addition of another two years of experience and data in the actual market place, the Study Group's objective is to revisit the estimation of marginal supply costs avoided by conservation savings, based on projected demand, available sources, and fuel prices for marginal supply sources, while also including the impacts of locational pricing expected to be in effect in the near future. The Study Group has determined that the upcoming AESC study should estimate avoided costs for electricity, natural gas (including propane), fuel oil (including retail distillate, #2, #6 fuel oil, and kerosene for heating), and wood (for heating usage).

Summary of Results

Exhibit 1-1:
Summary of Projected New England Avoided Power Costs for Retail Service ($/MWH)

Year	*2004$*	*Nominal$*[1]
2003	61.78	60.27
2004	64.07	64.07
2005	61.68	63.22
2006	59.28	62.28
2007	59.47	64.05
2008	59.67	65.86
2009	59.69	67.54
2010	59.71	69.25
2011	59.74	71.01
2012	59.76	72.81
2013	59.78	74.66
2014	60.12	76.96
2015	60.46	79.33
2016	60.80	81.78
2017	61.15	84.30
2018	61.50	86.89
2019	61.40	88.93
2020	61.30	91.01
2021	61.21	93.13
2022	61.11	95.31
2023	61.01	97.54
2024	60.92	99.82
2025	60.82	102.16
2026	61.14	105.26
2027	61.46	108.45
2028	61.78	111.75
2029	62.10	115.14
2030	62.43	118.63
2031	62.43	121.60
2032	62.43	124.64
2033	62.43	127.76
2034	62.43	130.95
2035	62.43	134.22
2036	62.43	137.58
2037	62.43	141.02

Note: Values represent avoided costs assuming a typical load shape
1. Inflation rate of 2.5 percent used to determine nominal dollars.

In the near-tern, avoided retail electricity costs are expected to be high, largely based on the production costs of generation resources. Production costs contribute significantly to retail avoided costs; total production costs account for roughly 70 percent of the total retail supply costs and are an even larger percent of the avoidable costs as much of the additional retail expenses are sunk costs. The marginal production cost (including energy and capacity) is the largest component of avoidable retail supply costs. Going forward, wholesale marginal production costs are expected to decrease in real terms as market structure stabilizes, as real gas prices decline, and as newer, more efficient generating units begin to operate in significant periods. In the mid-term, real wholesale prices decline for these reasons, hence driving retail avoided costs down.

In the long-term, wholesale prices again begin to rise as new capacity requirements grow in the market place. In this period, the market must support the investment costs of these new facilities in order to support the reliability requirements in the market place.

The results presented above represent the average prices in New England. Zonal and state results are provided in the detailed results chapter included within this document. Significant variations in pricing may occur across zones due to transmission constraints within New England. Transmission constraints are expected to have a greater impact on the near-term markets prior to planned investment in the grid. Note, this analysis considered zonal constraints in the energy markets. However, it did not consider the potential for sub-zonal capacity markets which are currently under consideration by the New England ISO and the Federal Energy Regulatory Commission. The consideration of sub-zonal capacity markets was initiated after this analysis was already in progress. Should sub-zonal markets be implemented, costs could be further concentrated on a zonal or sub-zonal level than considered herein.

The avoided gas costs of a local distribution company (LDC) consist of the cost of the gas itself (the Henry Hub price) as well as the non-gas costs of transportation, storage, and peak shaving. Below, we present our estimate of the avoided gas costs through 2025. For the years 2025 through 2037, we have held the avoided cost at the 2025 level.

Exhibit 1-2:
Seasonal Wholesale Avoided Gas Costs in Southern New England (2004$/MMBtu)

Year	*Annual Avg.*	*3 Month Winter*	*9 Month Summer*	*5 Month Winter*	*7 Month Summer*	*7 Month Winter*	*5 Month Summer*	*6 Month Winter*	*6 Month Summer*	*Heat Retrofit*	*New Heat*	*Water Heat*
2003	$7.19	$9.04	$6.29	$8.64	$6.15	$8.41	$6.00	$8.09	$5.94	$8.09	$8.64	$7.19
2004	$6.43	$8.18	$5.56	$7.81	$5.44	$7.58	$5.31	$7.27	$5.25	$7.27	$7.81	$6.43
2005	$5.95	$7.63	$5.10	$7.28	$4.99	$7.05	$4.87	$6.76	$4.82	$6.76	$7.28	$5.95
2006	$5.39	$6.99	$4.57	$6.66	$4.47	$6.44	$4.36	$6.16	$4.31	$6.16	$6.66	$5.39
2007	$5.20	$6.78	$4.39	$6.46	$4.30	$6.23	$4.19	$5.96	$4.14	$5.96	$6.46	$5.20
2008	$5.05	$6.60	$4.24	$6.29	$4.15	$6.06	$4.05	$5.79	$4.01	$5.79	$6.29	$5.05
2009	$4.86	$6.39	$4.06	$6.08	$3.97	$5.86	$3.88	$5.59	$3.84	$5.59	$6.08	$4.86
2010	$5.04	$6.59	$4.23	$6.28	$4.14	$6.05	$4.04	$5.78	$4.00	$5.78	$6.28	$5.04
2011	$4.46	$5.93	$3.68	$5.64	$3.60	$5.42	$3.51	$5.16	$3.47	$5.16	$5.64	$4.46
2012	$4.53	$6.01	$3.74	$5.72	$3.66	$5.49	$3.57	$5.23	$3.54	$5.23	$5.72	$4.53
2013	$4.63	$6.13	$3.85	$5.84	$3.76	$5.61	$3.67	$5.35	$3.63	$5.35	$5.84	$4.63
2014	$4.75	$6.27	$3.96	$5.97	$3.87	$5.74	$3.78	$5.47	$3.74	$5.47	$5.97	$4.75
2015	$4.68	$6.19	$3.89	$5.89	$3.81	$5.66	$3.71	$5.40	$3.68	$5.40	$5.89	$4.68
2016	$4.85	$6.37	$4.05	$6.07	$3.96	$5.84	$3.86	$5.58	$3.82	$5.58	$6.07	$4.85
2017	$4.86	$6.39	$4.06	$6.08	$3.97	$5.86	$3.88	$5.59	$3.84	$5.59	$6.08	$4.86
2018	$5.02	$6.58	$4.22	$6.26	$4.13	$6.04	$4.03	$5.77	$3.98	$5.77	$6.26	$5.02
2019	$4.97	$6.51	$4.16	$6.20	$4.07	$5.97	$3.97	$5.70	$3.93	$5.70	$6.20	$4.97
2020	$4.84	$6.36	$4.04	$6.06	$3.95	$5.83	$3.85	$5.56	$3.81	$5.56	$6.06	$4.84
2021	$4.78	$6.29	$3.98	$5.99	$3.90	$5.77	$3.80	$5.50	$3.76	$5.50	$5.99	$4.78
2022	$4.79	$6.31	$3.99	$6.01	$3.91	$5.78	$3.81	$5.51	$3.77	$5.51	$6.01	$4.79
2023	$5.02	$6.58	$4.22	$6.26	$4.13	$6.04	$4.03	$5.77	$3.98	$5.77	$6.26	$5.02
2024	$5.42	$7.02	$4.59	$6.69	$4.49	$6.46	$4.38	$6.19	$4.34	$6.19	$6.69	$5.42
2025	$5.43	$7.04	$4.60	$6.71	$4.51	$6.48	$4.39	$6.20	$4.35	$6.20	$6.71	$5.43

Exhibit 1-3:
Seasonal Wholesale Avoided Gas Costs in Northern and Central New England
(2004$/MMBtu)

Year	*Annual Avg.*	*3 Month Winter*	*9 Month Summer*	*5 Month Winter*	*7 Month Summer*	*7 Month Winter*	*5 Month Summer*	*6 Month Winter*	*6 Month Summer*	*Heat Retrofit*	*New Heat*	*Water Heat*
2003	$7.03	$8.77	$6.23	$8.34	$6.10	$8.14	$5.95	$7.85	$5.89	$7.85	$8.34	$7.03
2004	$6.28	$7.92	$5.52	$7.52	$5.41	$7.32	$5.27	$7.05	$5.22	$7.05	$7.52	$6.28
2005	$5.81	$7.37	$5.07	$7.00	$4.96	$6.80	$4.84	$6.54	$4.79	$6.54	$7.00	$5.81
2006	$5.26	$6.75	$4.54	$6.40	$4.45	$6.20	$4.34	$5.95	$4.30	$5.95	$6.40	$5.26
2007	$5.07	$6.54	$4.37	$6.20	$4.28	$6.00	$4.17	$5.75	$4.13	$5.75	$6.20	$5.07
2008	$4.92	$6.37	$4.22	$6.03	$4.13	$5.83	$4.03	$5.59	$3.99	$5.59	$6.03	$4.92
2009	$4.74	$6.15	$4.04	$5.83	$3.96	$5.63	$3.86	$5.39	$3.83	$5.39	$5.83	$4.74
2010	$4.91	$6.35	$4.21	$6.02	$4.12	$5.82	$4.02	$5.58	$3.98	$5.58	$6.02	$4.91
2011	$4.34	$5.70	$3.66	$5.39	$3.59	$5.20	$3.50	$4.96	$3.47	$4.96	$5.39	$4.34
2012	$4.41	$5.78	$3.73	$5.47	$3.65	$5.27	$3.57	$5.04	$3.53	$5.04	$5.47	$4.41
2013	$4.51	$5.90	$3.83	$5.58	$3.75	$5.39	$3.66	$5.15	$3.63	$5.15	$5.58	$4.51
2014	$4.63	$6.03	$3.94	$5.71	$3.86	$5.52	$3.77	$5.28	$3.73	$5.28	$5.71	$4.63
2015	$4.56	$5.95	$3.88	$5.63	$3.80	$5.44	$3.70	$5.20	$3.67	$5.20	$5.63	$4.56
2016	$4.72	$6.14	$4.03	$5.81	$3.95	$5.62	$3.85	$5.38	$3.81	$5.38	$5.81	$4.72
2017	$4.74	$6.15	$4.04	$5.83	$3.96	$5.63	$3.86	$5.39	$3.83	$5.39	$5.83	$4.74
2018	$4.90	$6.34	$4.20	$6.00	$4.11	$5.81	$4.01	$5.56	$3.97	$5.56	$6.00	$4.90
2019	$4.84	$6.27	$4.14	$5.94	$4.06	$5.74	$3.96	$5.50	$3.92	$5.50	$5.94	$4.84
2020	$4.71	$6.13	$4.02	$5.80	$3.94	$5.60	$3.84	$5.36	$3.80	$5.36	$5.80	$4.71
2021	$4.65	$6.06	$3.97	$5.74	$3.88	$5.54	$3.79	$5.30	$3.75	$5.30	$5.74	$4.65
2022	$4.67	$6.07	$3.98	$5.75	$3.89	$5.55	$3.80	$5.31	$3.76	$5.31	$5.75	$4.67
2023	$4.90	$6.34	$4.20	$6.00	$4.11	$5.81	$4.01	$5.56	$3.97	$5.56	$6.00	$4.90
2024	$5.28	$6.78	$4.57	$6.43	$4.47	$6.23	$4.36	$5.98	$4.32	$5.98	$6.43	$5.28
2025	$5.30	$6.79	$4.58	$6.44	$4.48	$6.24	$4.37	$5.99	$4.33	$5.99	$6.44	$5.30

Consistent with previous analyses, avoided gas costs are presented in three basic types: peak period, off peak period, and base load. Peak period corresponds with winter heating load demand represented as four winter types corresponding to the length of the heating season: 3, 5, 6, and 7 months. Off peak is the residual non-peak period corresponding to each of the winter definitions. Base load is the full 12-month period. We present costs separately for Northern and Central New England (Massachusetts, Vermont, New Hampshire, Maine) and Southern New England (Connecticut and Rhode Island). In chapter 4, present ICF's natural gas price forecast and separately, our treatment of non-gas costs (transportation, storage, LNG service). We also develop retail avoided costs based on the wholesale cost estimates. The avoided cost estimate for the new building heat corresponds to the five-month winter; old building retrofit heating avoided costs correspond to the seven-month winter; and hot water heating corresponds to the annual average avoided cost.

ICF has also developed avoided cost estimates for other fuels. These are presented in Exhibit 1-4 below.

Exhibit 1-4:
Other Fuel Avoided Costs

	Distillate Fuel Oil			Residual Fuel Oil		No. 4 Fuel Oil
Year	**Wholesale**	**Residential**	**Commercial**	**Wholesale**	**Industrial**	**Industrial**
2003	$6.80	$11.09	$8.91	$4.15	$4.94	$6.93
2004	$5.66	$9.22	$7.04	$3.55	$4.23	$5.64
2005	$5.09	$8.30	$6.12	$3.36	$4.00	$5.06
2006	$4.67	$7.62	$5.44	$3.24	$3.85	$4.64
2007	$4.49	$7.32	$5.14	$3.20	$3.80	$4.47
2008	$4.45	$7.25	$5.07	$3.20	$3.80	$4.43
2009	$4.41	$7.19	$5.01	$3.20	$3.80	$4.41
2010	$4.38	$7.14	$4.96	$3.20	$3.80	$4.38
2011	$4.40	$7.18	$5.00	$3.18	$3.79	$4.39
2012	$4.41	$7.19	$5.01	$3.17	$3.78	$4.40
2013	$4.45	$7.25	$5.07	$3.16	$3.76	$4.42
2014	$4.48	$7.30	$5.12	$3.15	$3.75	$4.44
2015	$4.50	$7.34	$5.16	$3.14	$3.74	$4.45
2016	$4.51	$7.35	$5.17	$3.15	$3.75	$4.46
2017	$4.53	$7.39	$5.21	$3.15	$3.75	$4.48
2018	$4.54	$7.41	$5.23	$3.15	$3.75	$4.49
2019	$4.57	$7.44	$5.26	$3.15	$3.75	$4.51
2020	$4.58	$7.46	$5.28	$3.15	$3.75	$4.52
2021	$4.58	$7.46	$5.28	$3.15	$3.75	$4.52
2022	$4.58	$7.46	$5.28	$3.15	$3.75	$4.52
2023	$4.58	$7.46	$5.28	$3.15	$3.75	$4.52
2024	$4.58	$7.46	$5.28	$3.15	$3.75	$4.52
2025	$4.58	$7.46	$5.28	$3.15	$3.75	$4.52

Exhibit 1-4.
Other Fuel Avoided Costs (contd.)

	Propane		*Wood*		*Kerosene*
Year	***Wholesale***	***Residential***	***($/MMbtu)***	***($/Cord)***	***Residential***
2003	$7.07	$13.92	$7.50	$150.00	$14.17
2004	$5.97	$11.77	$7.65	$153.00	$12.51
2005	$5.43	$10.70	$7.80	$156.06	$11.46
2006	$5.03	$9.92	$7.96	$159.18	$10.24
2007	$4.86	$9.57	$8.12	$162.36	$9.83
2008	$4.82	$9.49	$8.28	$165.61	$9.49
2009	$4.79	$9.43	$8.45	$168.92	$9.08
2010	$4.76	$9.37	$8.62	$172.30	$9.47
2011	$4.78	$9.41	$8.79	$175.75	$8.20
2012	$4.79	$9.43	$8.96	$179.26	$8.36
2013	$4.82	$9.49	$9.14	$182.85	$8.59
2014	$4.85	$9.55	$9.33	$186.51	$8.85
2015	$4.87	$9.59	$9.51	$190.24	$8.69
2016	$4.88	$9.61	$9.70	$194.04	$9.05
2017	$4.90	$9.65	$9.90	$197.92	$9.08
2018	$4.91	$9.68	$10.09	$201.88	$9.44
2019	$4.93	$9.72	$10.30	$205.92	$9.31
2020	$4.94	$9.74	$10.50	$210.04	$9.03
2021	$4.94	$9.74	$10.71	$214.24	$8.90
2022	$4.94	$9.74	$10.93	$218.52	$8.93
2023	$4.94	$9.74	$11.14	$222.89	$9.44
2024	$4.94	$9.74	$11.37	$227.35	$10.30
2025	$4.94	$9.74	$11.59	$231.90	$10.32

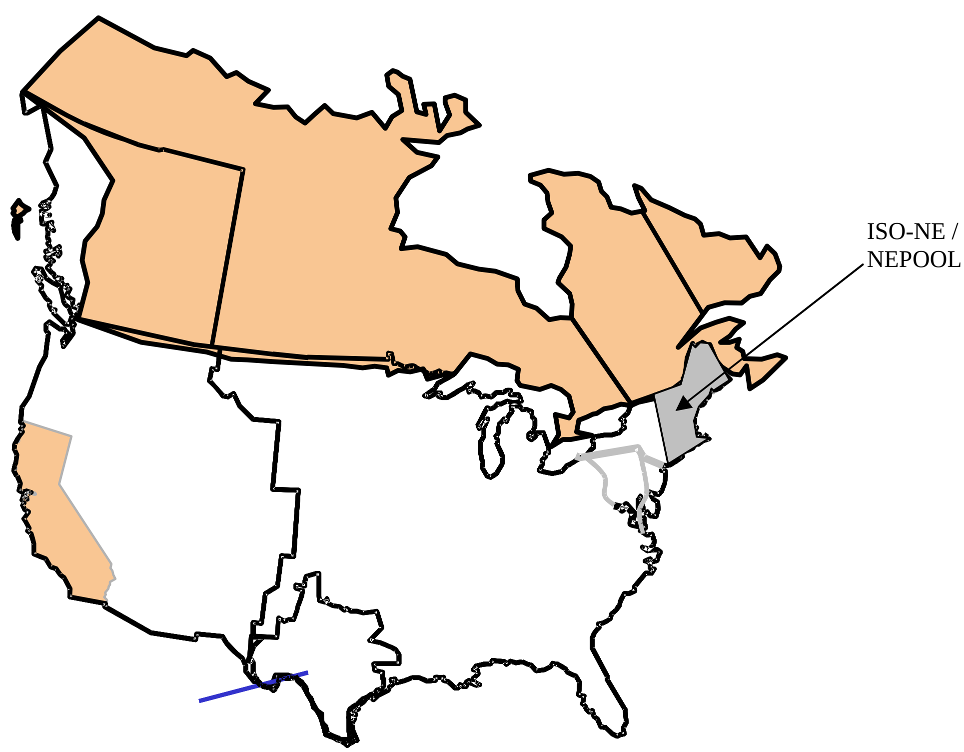
Chapter Two: New England Power Market Overview, Key Assumptions, and Regional Results

Introduction

The largest component of retail avoidable supply costs is the price for firm power available from the generation or wholesale sector. The marginal price (including energy and capacity value) represents the largest component of the retail supply costs that is considered variable. This Chapter will focus on the wholesale power market price and its derivation while the next chapter will focus on the additional components included in the avoidable retail supply cost.

This chapter provides an overview of the New England wholesale power market and describes key assumptions used to determine New England wholesale market prices in this analysis. The ISO New England (ISO-NE) or New England Power Pool (NEPOOL) marketplace is part of the Northeast Power Coordinating Council (NPCC), which encompasses the northeastern US and eastern Canada. ISO-NE includes the states of Maine, New Hampshire, Vermont, Connecticut, Massachusetts and Rhode Island. Although ISO-NE is electrically interconnected with several neighboring control areas (NYPP, Quebec, and New Brunswick), the region is relatively isolated when compared with other, larger US marketplaces. For this analysis, ISO-NE was modeled simultaneously with the entire US Eastern Interconnect and portions of Canada.

Exhibit 2-1:
The ISO-NE Marketplace



ISO-NE is a relatively small market in comparison to other power markets in the U.S. Net peak demand is approximately 25 GW as compared to approximately 60 GW for PJM and ERCOT. ISO-NE as a whole is summer peaking with a strong winter peak, resulting in a bi-modal load profile. Within New England, the load profile varies significantly across sub-regional markets. For example, Maine has a winter peak while Connecticut is summer peaking. The sub-regional load profiles have been modeled as such.

The following tables provide a summary outline of certain key criteria with respect to the ISO-New England power market.

Exhibit 2-2:
ISO-NE Marketplace Overview

Key Parameter	***ISO New England***
Market Maturity	Active Wholesale Market Trading ; SMD
Annual Load Growth[1]	2.14 percent
Actual Reserve Margin[2]	30 percent
Average Age of Generation [3]	22 years
Oil/Gas Capacity	New England's capacity mix is dominated by natural gas and oil fired units, most of which are switchable across both of these fuels.
Transmission Constraints	New England is somewhat isolated in terms of its electric power interconnections. New England has limited export/import capability in periods of excess/deficient capacity within New England. Intra-New England transmission constraints also exist as there are deficient load pockets in Southwest Connecticut as well as regions with locked in generation like Rhode Island, Southeast Massachusetts and Maine.

1. Source: NERC Electricity Supply and Demand (ES&D). Ten year rolling average 1979-2002 peak load growth. NE-ISO data was used for 2002
2. Source: NERC ES&D. Net of controllable, interruptible or curtailable load; includes imports from Hydro Quebec and New Brunswick.
3. Source: ICF.

Exhibit 2-3:
ISO New England Market Size

	1999	***2000***	***2001***	***2002***
Total Installed Capacity (GW)[1]	24	25	26	28
Peak Load (GW)[1]	23	22	25	22
Net Annual Energy Requirement (GWh)[1]	122	125	126	127
Import Capability (GW)[2]	N/A	N/A	N/A	3,600
Export Capability (GW)[2]	N/A	N/A	N/A	3,200

[1]Source: NERC ES&D. ISO New England for 2002
[2]Source: ICF Consulting; NERC Summer Assessments.

New England Power Market Development

Formed in 1971, the New England Power Pool (NEPOOL) is a voluntary association of electric power industry participants in New England. With the formation of NEPOOL, a single regional network to direct the operations of the major generating and transmission (bulk power system) facilities in the region was established. NEPOOL is part of the larger Northeast Power Coordinating Council (NPCC).

NEPOOL is a tight power pool that established a single regional network that, historically coordinated, monitored and directed the operations of virtually all of the major generation and transmission bulk power supply facilities in New England.

ISO New England was established as a not-for-profit, private corporation in 1997. The organization immediately assumed responsibility for managing the New England region's electric bulk power generation and transmission systems and administering the region's open access transmission tariff. ISO New England has a services contract with NEPOOL to operate the bulk power system and to administer the wholesale marketplace. NEPOOL continues to exist as the entity representing not only traditional electric utilities but also companies that will participate in the emerging competitive wholesale electricity marketplace. Since May 1, 1999, ISO New England has administered the wholesale electricity marketplace for the region. Six electricity products are bought and sold by market participants: Energy, ICAP (Installed Capacity), 10-minute spinning reserves, 10-minute non-spinning reserves, 30-minute operating reserves and automatic generation control (AGC).

Since March 1, 2003, the New England ISO began pricing energy using a locational marginal pricing (LMP) scheme similar to the pricing schemes used in New York and PJM markets.

Like all other Northeastern markets, there is a day ahead and real time energy market. This market has been the subject of price caps. Also like other Northeastern markets there is an installed capacity requirement. New England's ICAP has had a turbulent history, although the market has recently been undervalued due to recent capacity expansion. Unlike PJM, New England has operating reserve markets.

The New England market is currently in a transition phase. Since it's inceptions until earlier this year, the New England power pool has operated as a tight power pool with a single dispatch price. On March 2003, the ISO-NE formally began trading on a zonal pricing system. There are currently eight pricing zones within New England. In the next two years, New England is expected to fully transition to a LMP market pricing system.

Exhibit 2-4:
Conceptual Change in Wholesale Pricing for Load

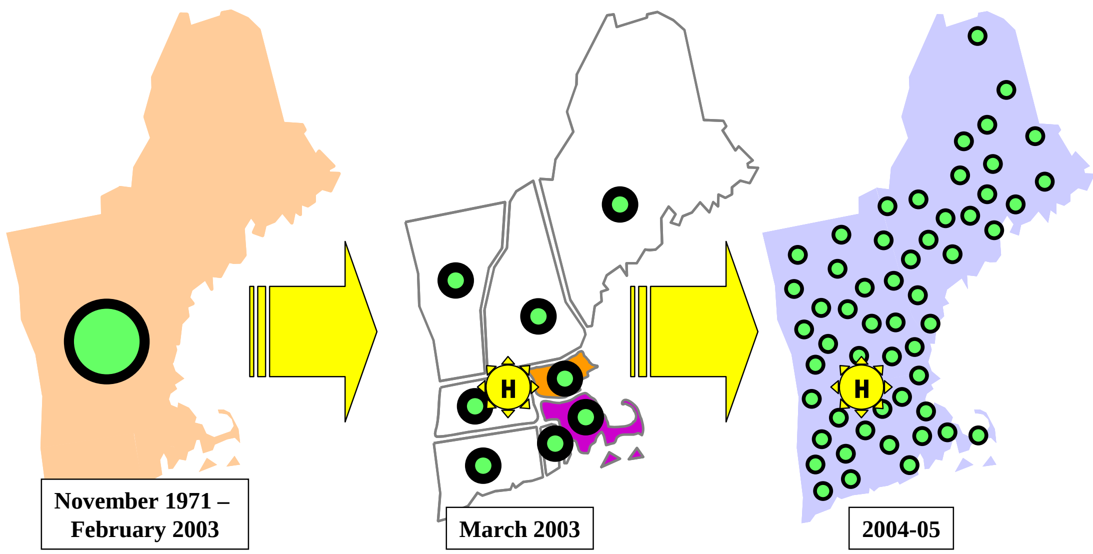
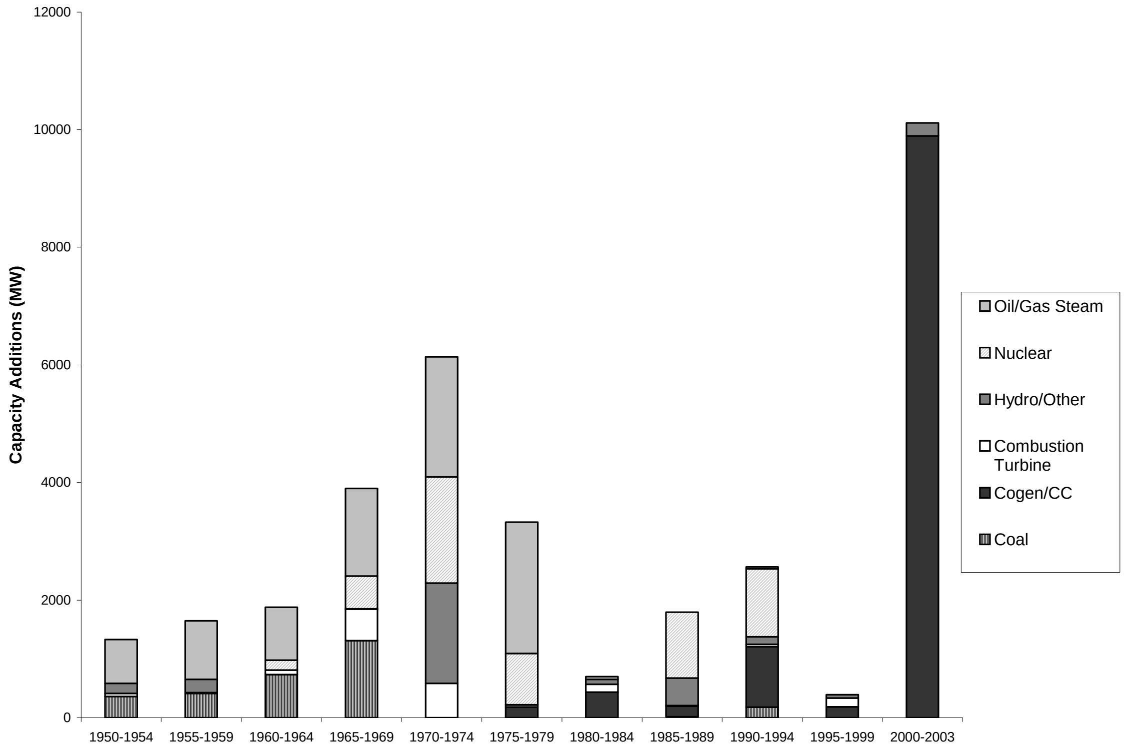


Exhibit 2-4 shows the planned change in pricing within New England. Earlier this year eight pricing zones were established and a central pricing hub is, currently, quoted as representative of locational nodes through parts of Massachusetts. Prices for power purchased of load serving entities (LSE) represent the average of the nodal prices within that zone, however, individual generators receive the prices for their nodal location. Forward plans include moving to a full LMP system on the buy and sell side.

Recent Market Developments

In recent years, the New England electric power market has experienced dramatic changes including changes in the market structure (as described above) and regulatory oversight, as well in the fundamental make-up of generating sources in the market. One key change in the fundamentals has been the addition of about 11 GW of new capacity between 2000 and 2004, an increase of nearly 35 percent. The large majority of this capacity has been natural gas-fired combined cycle units, increasing New England's reliance on gas-fired generation.

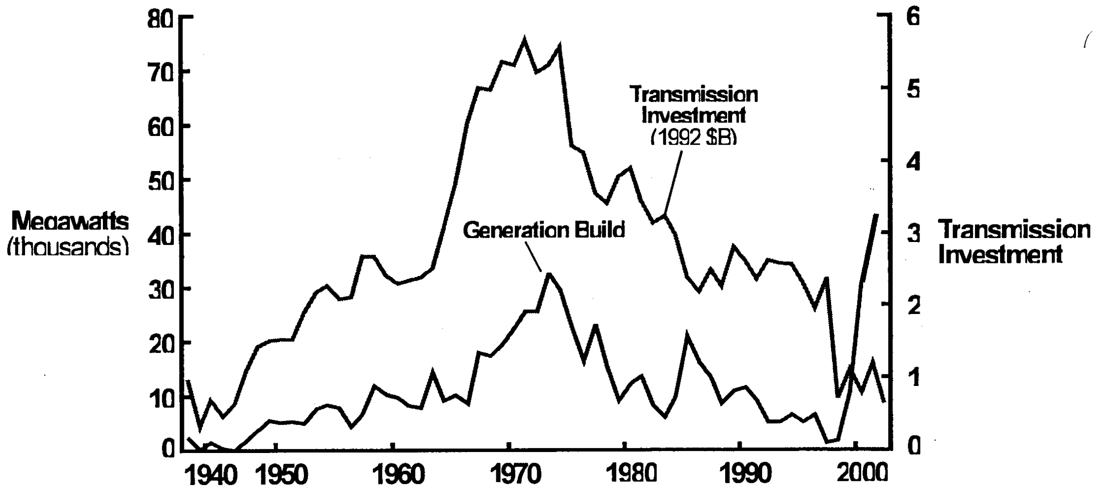
Exhibit 2-5:
Generation Investment Increased in ISO-NE Significantly in Recent Years



Source: Determined by ICF from NERC ES&D, EIA Inventory of Power Plants, and independent research.

Although there was this significant investment in capacity resources (see Exhibit 2-5), particularly in the 2000 to 2003 period, corresponding investment in transmission did not occur. This trend is not isolated to New England but is also true nationally as shown in Exhibit 2-6. The addition of capacity in New England without similar transmission investment has resulted in the exaggeration of weakness on the system, impacting both the ability to move power internally in the ISO-NE area and the ability to flow power into and out of neighboring systems.

Exhibit 2-6:
U.S. Transmission Investment Has Lagged Generation Investment



Source: Cambridge CERA Workshop

Although some transmission investment has occurred, there has not been an overarching approach examining the impact of new generation sources on the entire system considering the strain resulting from the simultaneous addition of all the units and the potential for severe contingencies that could result. Further, as new units have been constructed, the majority of existing units have continued to operate such that the load on the existing transmission network has increased. Serious concerns over the stability of the transmission grid have resulted, as have concerns over trapping or locking generation resources into a certain areas because of their inability to secure adequate transmission or their negative impact on the transmission grid. The ability to support single market pricing within New England has been questioned given an internally constrained network.

In contrast to the lack of investment in the transmission grid, there has been significant investment in the fuel transportation network to accommodate the large amount of new gas-fired generation resources. Recent expansions in the Northeast include the Iroquois pipeline, the Maritimes pipeline (and Sable Island supply), and the PNGTS system. With these multiple supply options, the generation sector is unlikely to face limitations in procuring fuel for operations, rather, plant operators will face more serious concerns related to transmission grid access.

ISO New England Electricity Transmission Overview

Inter-Regional Transmission

The primary physical interconnections between New England and neighboring systems consist of:

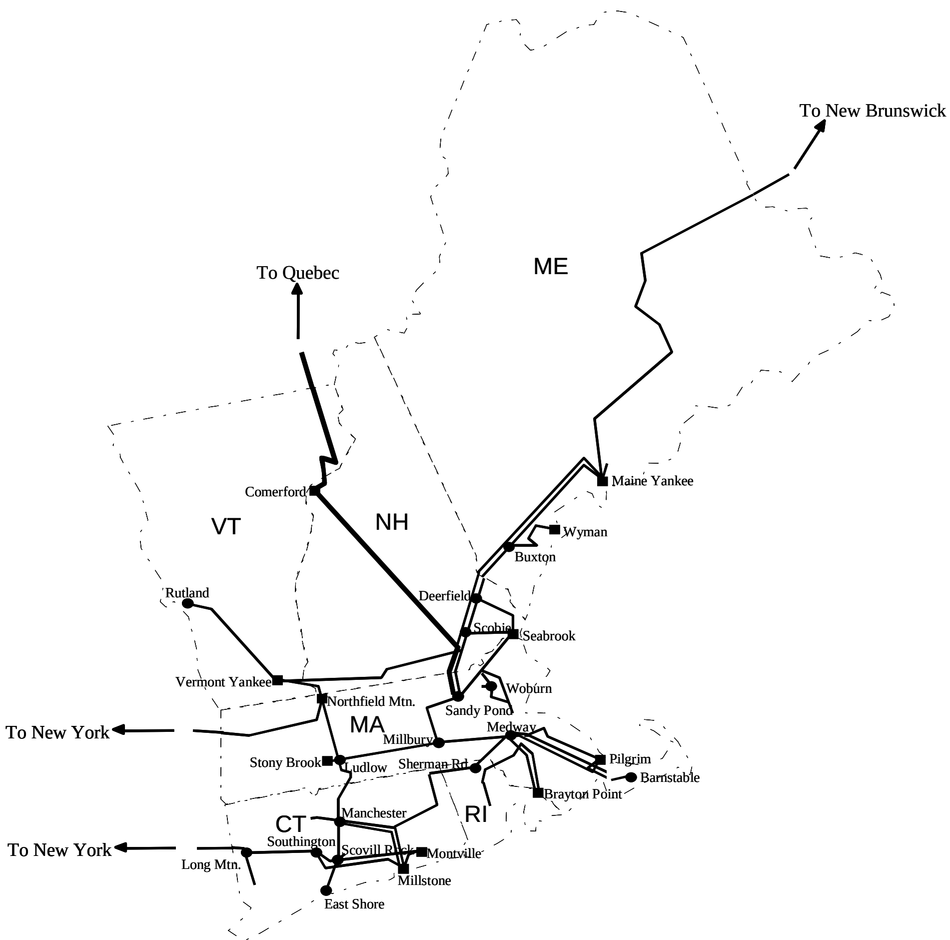
- Two high voltage DC interconnections with Hydro Quebec (Highgate and Phase II)
- One 345 kV interconnection with New Brunswick
- Two 345 kV interconnections with NYPP

The new 330 MW high voltage direct current (HVDC) transmission interconnection between New Haven, CT and Shoreham, NY has been completed. However, due to some environmental siting issues the Cross Sound Cable has not yet been utilized. Connecticut regulations currently block any use of the line, however, New York representatives are pushing to allow access for summer emergency periods. Additional requests for proposals (RFPs) for new transmission ties between Long Island, NY and neighboring regions (New England and PJM) have previously been issued. ICF includes neighboring regions and most of the Eastern Interconnect endogenously in our model in order to accurately capture the affect of imports and exports to the region.

Intra-Regional Transmission

ISO New England's annual transmission plan, the Regional Transmission Expansion Planning (RTEP) study, released in November 2002, found that almost 900 million dollars in transmission upgrades might be needed to maintain power system reliability and improve wholesale electricity market efficiency. The study concludes that southwest Connecticut is currently the largest area of concern, but transmission congestion also now exists in northwestern Vermont because of a lack of power plants in the area and weak transmission links. Proposed transmission projects in these two areas represent approximately $750 million in infrastructure investment.

Exhibit 2-7:
New England Inter-Regional Transmission

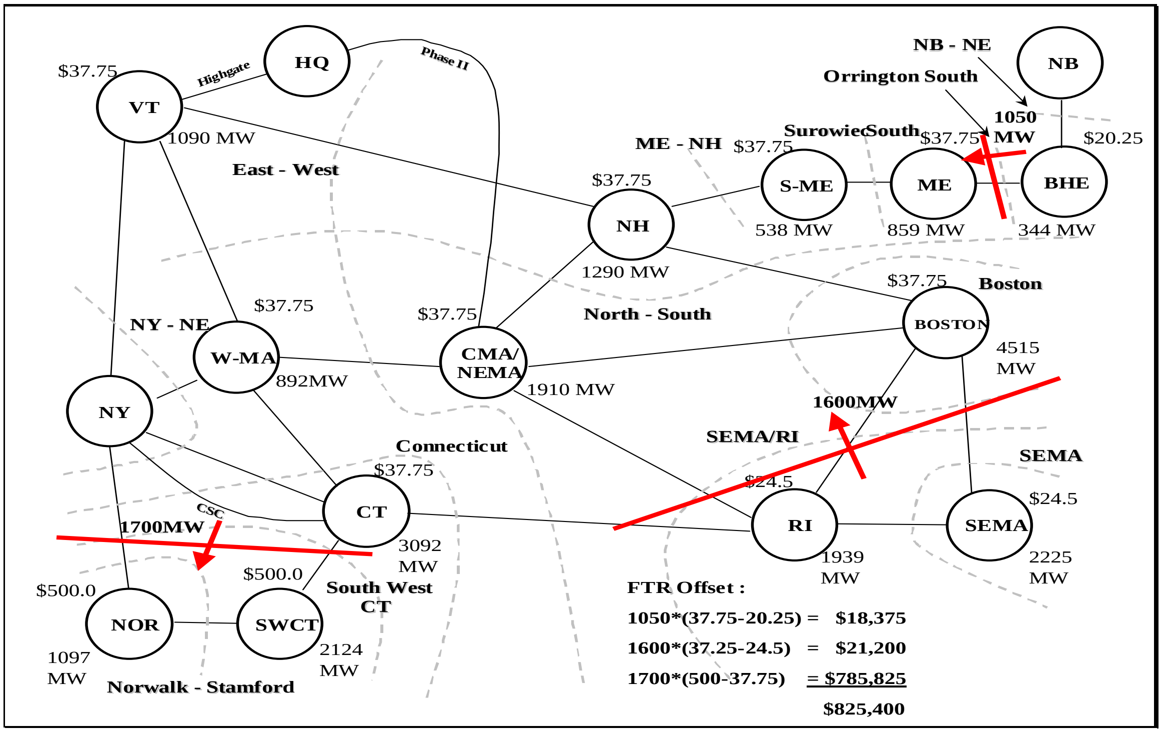


The major internal transmission lines within New England are shown in Exhibit 2-7. In addition, electricity now being produced in Maine, southeastern Massachusetts and Rhode Island is periodically "locked in" because transmission lines are not sufficient enough to carry it to high demand areas. Less expensive generation often sits idle in locked in areas because of inadequate or congested transmission lines. The current congestion situation is blamed on the recent addition of more than 8,000 megawatts of new generation since 2000 without similar investment in the transmission system.

The ISO-NE pricing zones are consistent with the RTEP study, however, they do not reflect the southwestern Connecticut market, Northern Maine or Boston/Central Massachusetts (CMA)/North and East Massachusetts (NEMA) markets distinctly. RTEP zones are shown in Exhibit 2-8). The largest pricing impact resulting from these additional constraints is in Southern Connecticut, however, the number of hours in which pricing is affected is expected to be limited such that the on-average pricing in these areas would be consistent with the larger region. Also, current transmission upgrades are planned to alleviate congestion into Southern Connecticut.

Although the Boston market has historically been among the most constrained areas in New England, recent transmission upgrades and new power plants in the Boston area have relieved transmission congestion for the next several years.

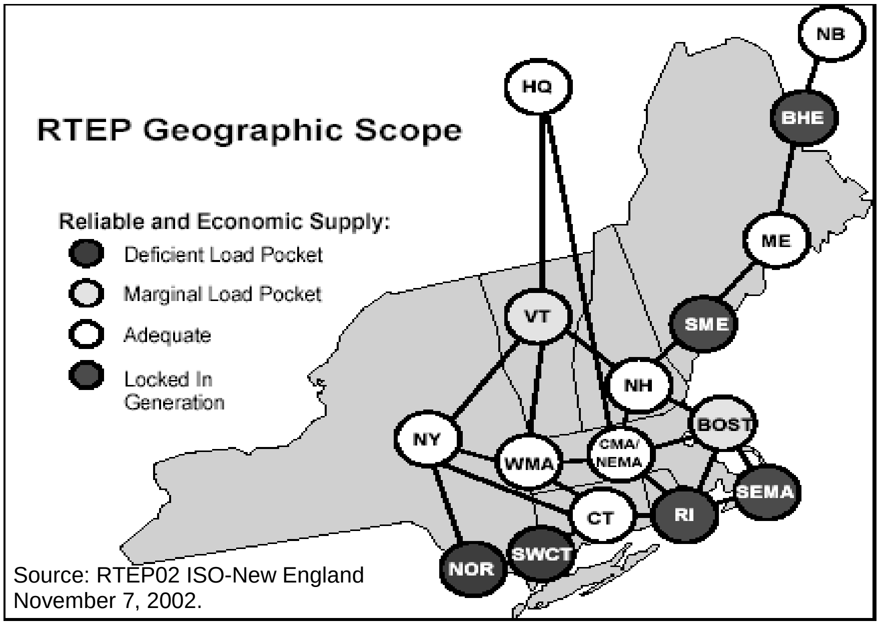
Exhibit 2-8:
Inter-Regional Constraints Have Been Increasing



Source: RTEP November 2002.

Exhibit 2-9 further illustrates these sub-areas as well as the potential for generating stations in these areas to be isolated from the remainder of the grid.

Exhibit 2-9:
Sub-Areas in New England and Commercially Significant Transmission Interfaces



Source: RTEP02 ISO-New England
November 7, 2002.

Modeling Sub-Regions within New England

ICF modeled New England as comprising 10 sub-regional markets of Maine, New Hampshire, Vermont, Western Massachusetts, Central/Northeast Massachusetts, Boston, Southeast Massachusetts, Connecticut, Southwest Connecticut and Rhode Island. Total transfer capabilities between these sub-regions were assumed to be consistent with those recognized by the ISO-NE in the 2002 RTEP study. This representation captures a reasonable set of constraints and transfer potential across areas and will capture major pricing or dispatch differentials across these areas.

Although the New England market is currently under a single capacity market, recent developments are likely to divide the market into several capacity pricing areas based on transmission congestion and local requirements. We have modeled three main areas to capture a local structure, however, the actual definition of local constraints has yet to be determined or approved. The three groups are Maine, New Hampshire, Central/Northeast Massachusetts and Boston; Vermont, Western Massachusetts, Connecticut and Southwest Connecticut; and Rhode Island and Southeast Massachusetts.

As mentioned earlier, ISO-NE has announced plans to adopt a Locational Marginal Pricing/Congestion Rights scheme for system-wide energy imbalance and congestion management. Several analyses have been done to estimate the commercial significance of the constraints identified and referenced above. Exhibit 2-10 illustrates the potential for price differentiation under high peak conditions. As can be seen, significant price differentials could occur by sub-area. In particular, high prices associated with a premium payment for reliability could occur in the deficient transmission constrained areas such as Southern Connecticut.

New England Sub-Regional Capacity Mix

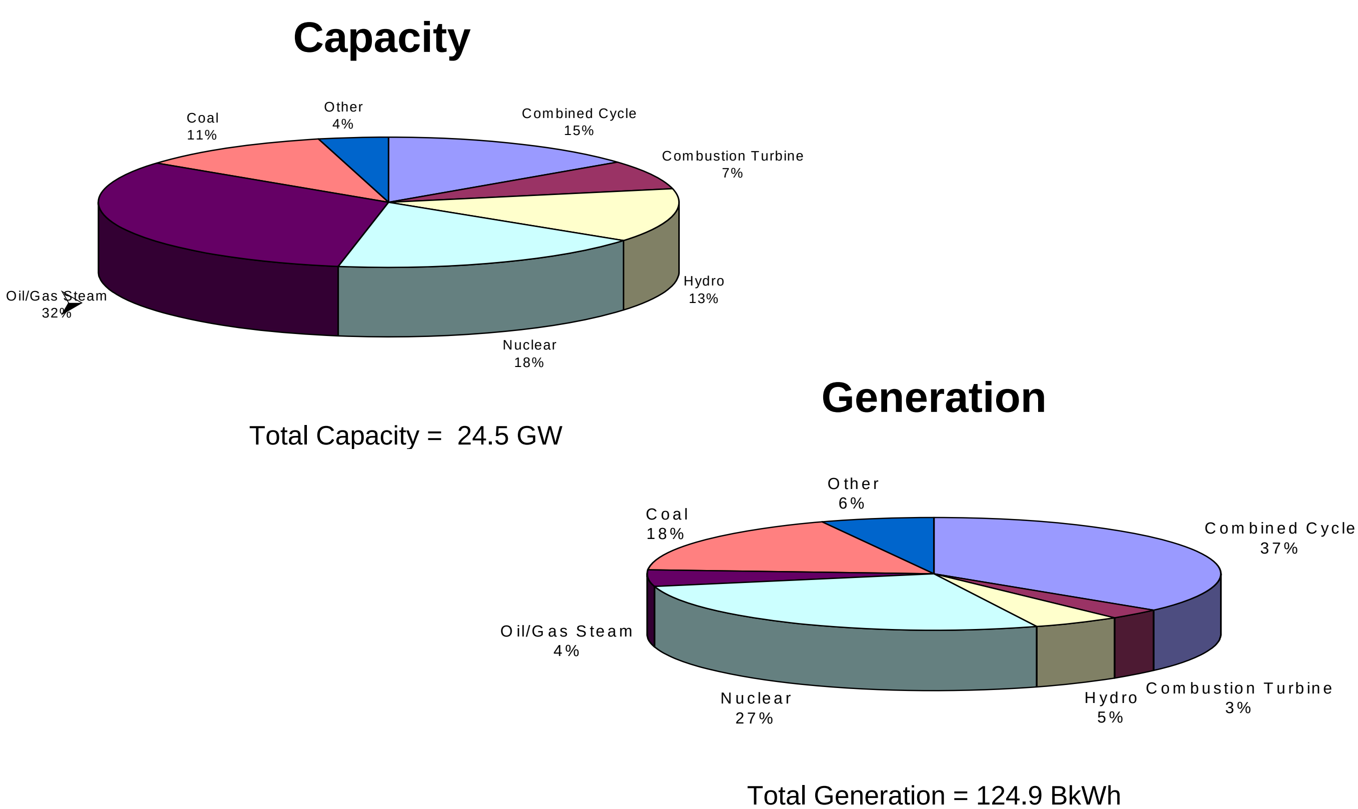
Oil/gas steam and nuclear units dominate the New England capacity mix. Oil/gas steam units are characterized by higher variable costs than most other plants. This situation is advantageous for new builds, especially combined cycles, which can take advantage of heat rate arbitrage that exists with respect to oil/gas steam units.

Oil/Gas Steam capacity tends to operate at lower utilization levels such that nuclear and coal resources have dominated the baseload generation. Off-peak pricing is highly influenced by costs associated with coal plant operation in particular. In the late 1990s nuclear generation declined significantly when several units went off line.

Gas and oil-fired units have dominated mid-merit and peak hours particularly in the recent past.

Exhibit 2-10:

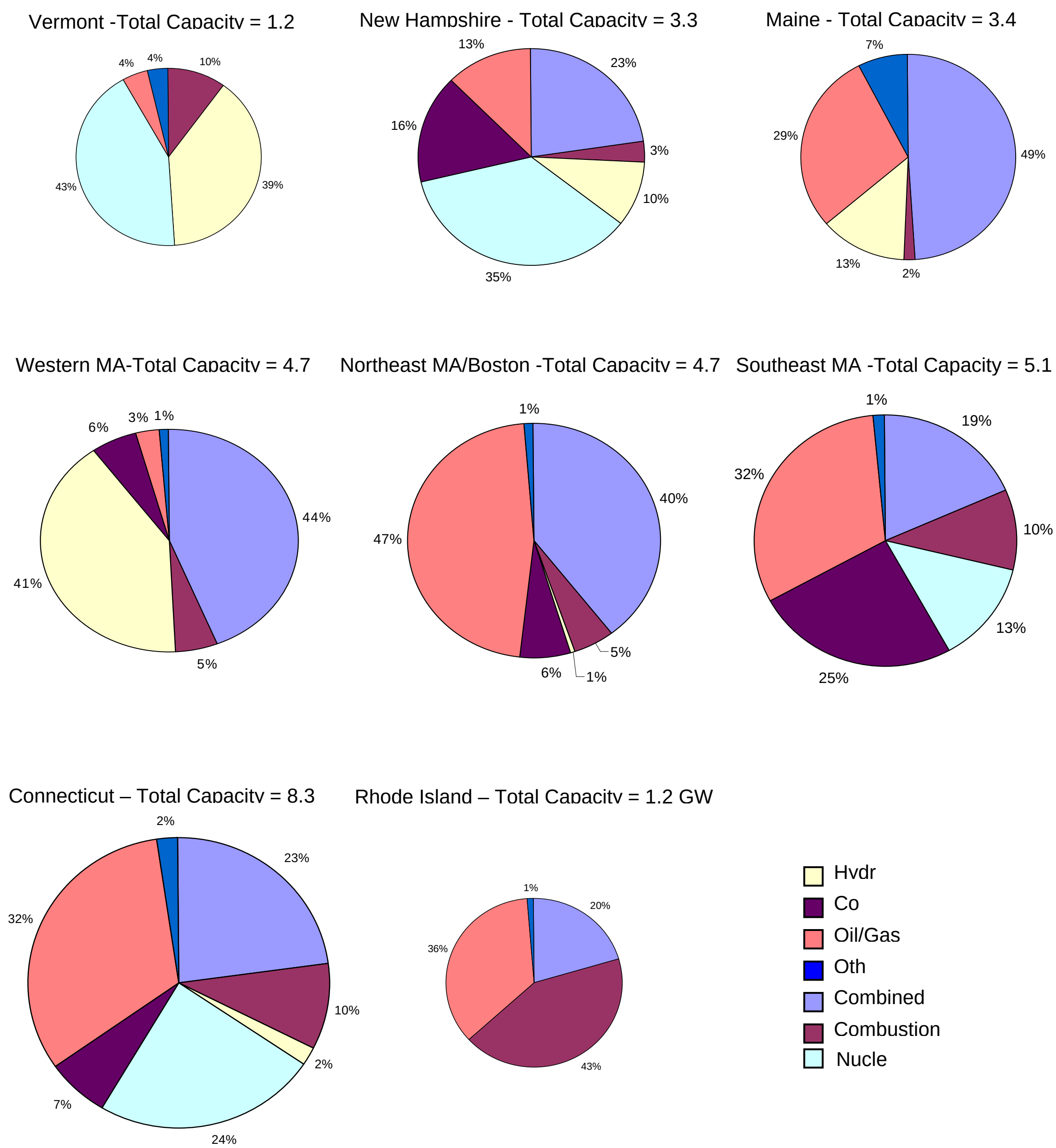
ISO New England Capacity and Generation – 2000



Note: Totals may not add due to rounding.
Source: Capacity taken from NERC ES&D; generation calculated from the EIA forms 759 and 900.

Although ISO-NE as a whole is dominated by gas and oil fired generating stations, the distribution of type of capacity varies across sub-regions. The region analyzed in this report, ISO-NE-Maine (ME) is predominantly combined cycles and oil/gas steam units. These capacities account for over 80 percent of the region's capacity mix with hydro capability comprising the majority of the remaining capacity. The largest sub-region modeled is ISO-NE – Central, accounting for about 60 percent of ISO-NE's generation capacity in 2002. More than half of the capacity here consists of combined cycles and oil/gas steam units. A similar capacity mix is seen in the Connecticut sub-region although nuclear accounts for nearly one-fourth of the region's capacity.

Exhibit 2-11:
New England Sub-Market Capacity Mix - 2002



Source: ICF IPM® database.

The large increase in capacity in New England has resulted in an over-capacity situation. Exhibit 2-11 shows the capacity mix for New England divided into each state. New England historically relied heavily on oil/gas steam and nuclear generation sources and only recently added significant combined cycle capacity. Only Vermont and New Hampshire have capacity mixes with a composition of less then 50 percent gas-fired units. As can be seen, this capacity is a significant portion of the overall capacity now in New England and in certain submarkets, such as Maine, these units have become the dominant source of existing capacity. With these capacity additions, the New England market as a whole has capacity currently in excess of the equilibrium value. This general overbalance tends to drive the market price, resulting in less than equilibrium value on reliability or capacity. Ongoing capacity additions in 2003 are expected to further exaggerate this oversupply situation. Note, there may be further areas of congestion within the sub-regions or states that result in load pockets, these particular points will not be reflected in this analysis as pricing is at the sub-regional average level.

ISO-New England Historical Prices

Key features of historical New England wholesale electricity prices include:

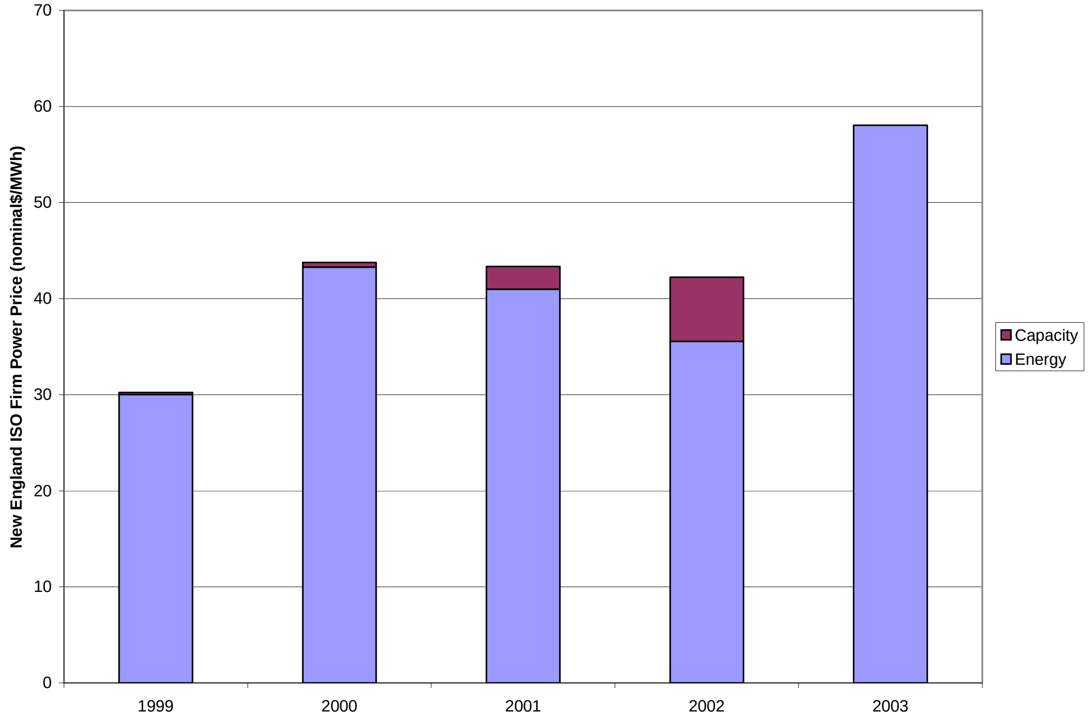
1. New England was very close to being in demand and supply balance after 1999. Prices increased dramatically in 2000 and 2001 associated with a combination of market tightening and higher fuel prices.

2. With the addition of new capacity to the market, and with a decrease in natural gas prices relative to the last couple of years, power prices have decreased on average in 2002 relative to 2000 and 2001.

3. Prices for 2003 YTD have been significantly higher than average prices in 2002. This is reflective of very high gas prices this year

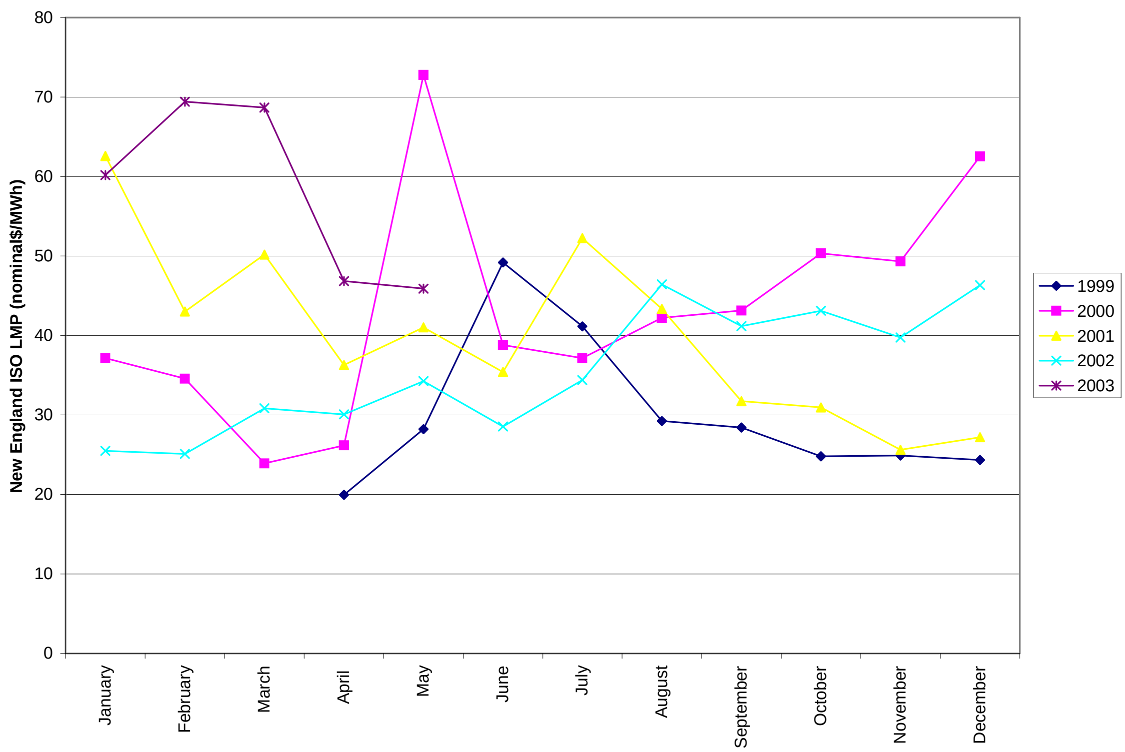
4. Billing problems had plagued the ICAP market. Many months have had no ICAP billing with sudden catch up following FERC rulings imposing prices derived from PJM. ICAP prices have been subject to long standing disputes between NEPOOL and FERC.

Exhibit 2-12:
New England Historical Prices ($/MWh)



Source**:** New England ISO
Note: 2003 YTD is through May 2003

Exhibit 2-13:
Historical Monthly New England Prices



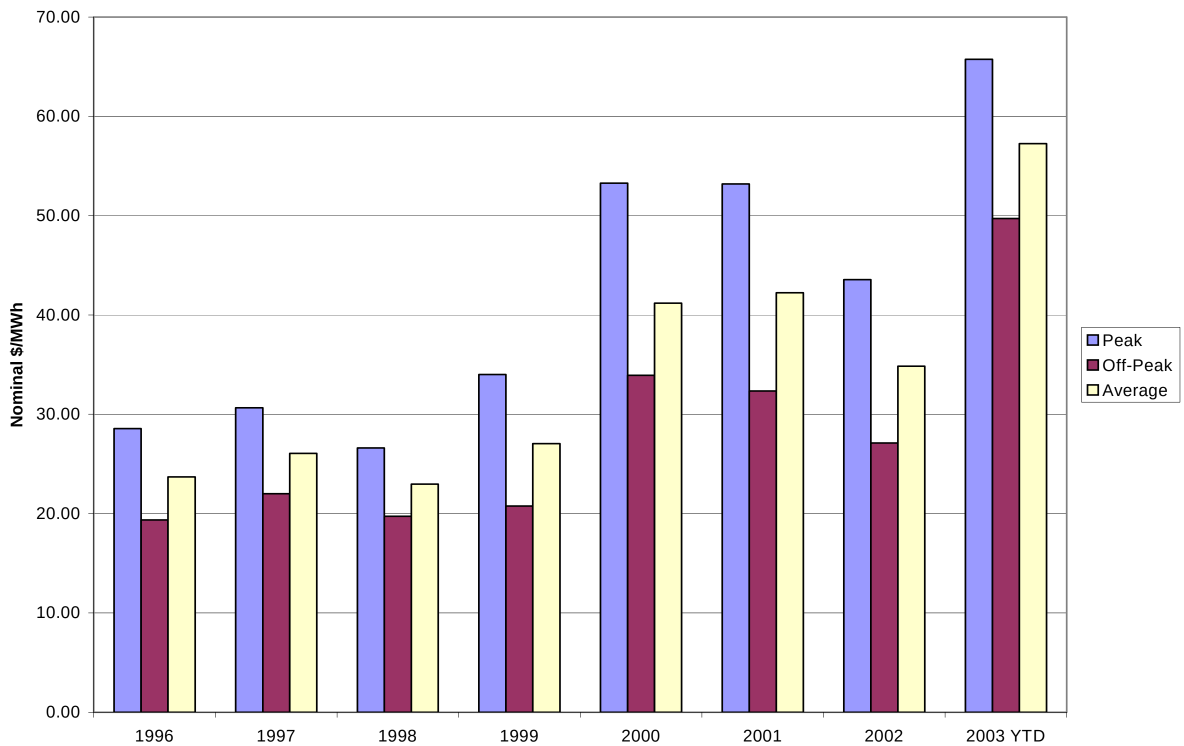
Source**:** New England ISO

Historical monthly average prices have shown significant volatility especially from 1999 through 2001. Monthly average prices were significantly higher in 2000 and 2001. This may be explained by several factors including high unit bids above variable cost and potential disequilibrium conditions. With the addition of new capacity to the market, and with a decrease in natural gas prices relative to the last couple of years, power prices have decreased on average in 2002 relative to 2000 and 2001.

Monthly average prices in 2000 ranged between $24/MWh and $73/MWh. Similarly for 2001, monthly average prices ranged from $26/MWh and $63/MWh. With the exception of the summer months of June and July where prices were $40/MWh and $50/MWh, the 1999 monthly average prices were in the $25/MWh to $30/MWh range.

Monthly prices in 2002 averaged $36/MWh. The year to date average for 2003 is much higher than the 2002 price at $58/MWh, in large part due to the price for natural gas.

Exhibit 2-14:
New England Historical Power Prices – Peak/Off Peak ($/MWh)



***Source*:** Power Markets Week; 2003 YTD – through June 16, 2003

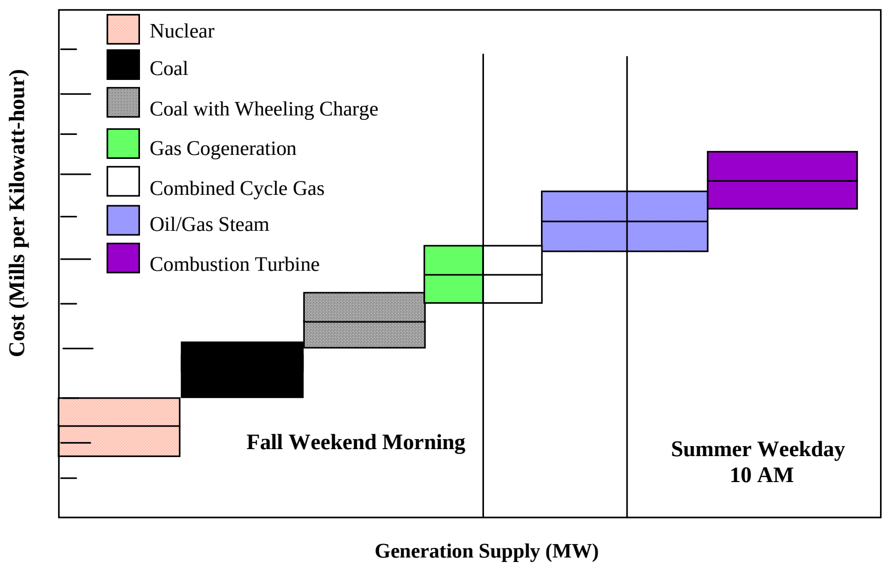
Peak/off-peak spreads have on average been between $12/MWh to $18/MWh since 1999. Prior to this period, peak/off-peak spreads had been within $10/MWh. The reason for this greater differential is the disequilibrium conditions experienced by New England and the Northeast markets and the price spikes during the summer seasons.

Wholesale Price Forecasting Methodology

Energy Pricing

Competitive wholesale or spot electric energy prices are determined on an hourly basis by the intersection of supply (the available generating resources) and demand (Exhibit 2-15). In each hour, the prevailing spot price of electric energy will be approximated by the short run marginal cost of production of the most expensive unit operating in that hour[1]. Thus, the spot electric energy price in the bulk power market in a given hour is equal to the marginal energy cost in that hour. Note that prices are determined hourly because power cannot be readily stored. These competitive electrical energy prices are also known in the industry as system lambdas, economy energy, and interruptible power.

Exhibit 2-15:
Illustrative Supply Curve for Electrical Energy



Note: Cogeneration units can have a wide range of heat rates. The most efficient gas cogeneration units are more competitive than gas-fired combined cycles. During certain seasons, gas-fired cogeneration and combined cycle units can be more competitive than select coal-fired units.

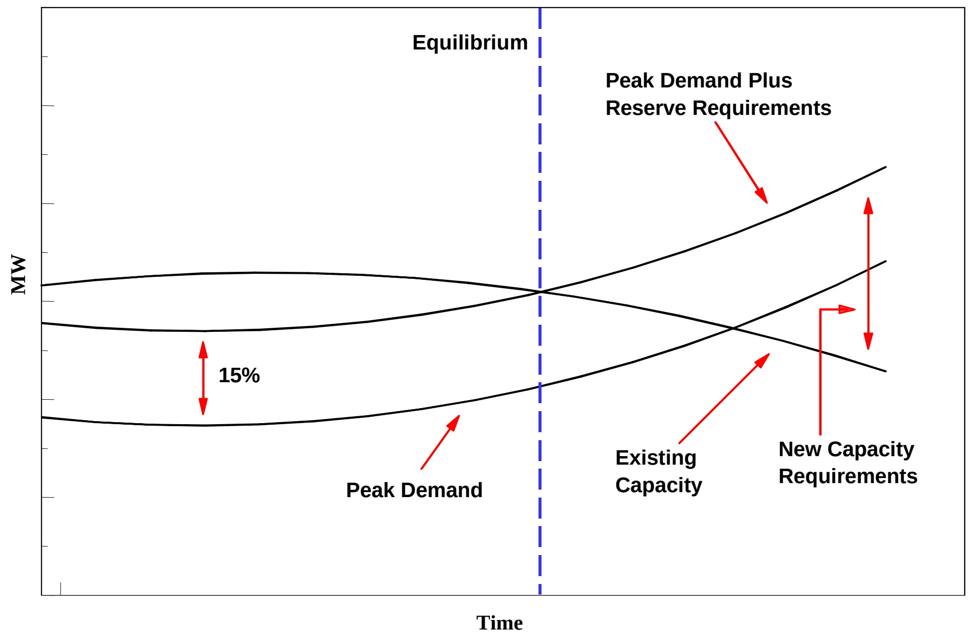
"Pure" Capacity (Price Spike Revenue) Pricing

The diagram below illustrates supply and demand equilibrium for megawatts, the point at which existing power plant supply is equal to the level of peak demand plus reserve requirements. Our derivation of pure capacity prices (described in this section) reflects

[1]The variable cost may incorporate compensation for lost profits during turndown hours of operation. When the price exceeds this level, it is defined as the hourly pure capacity price. See "pure" capacity pricing discussion.

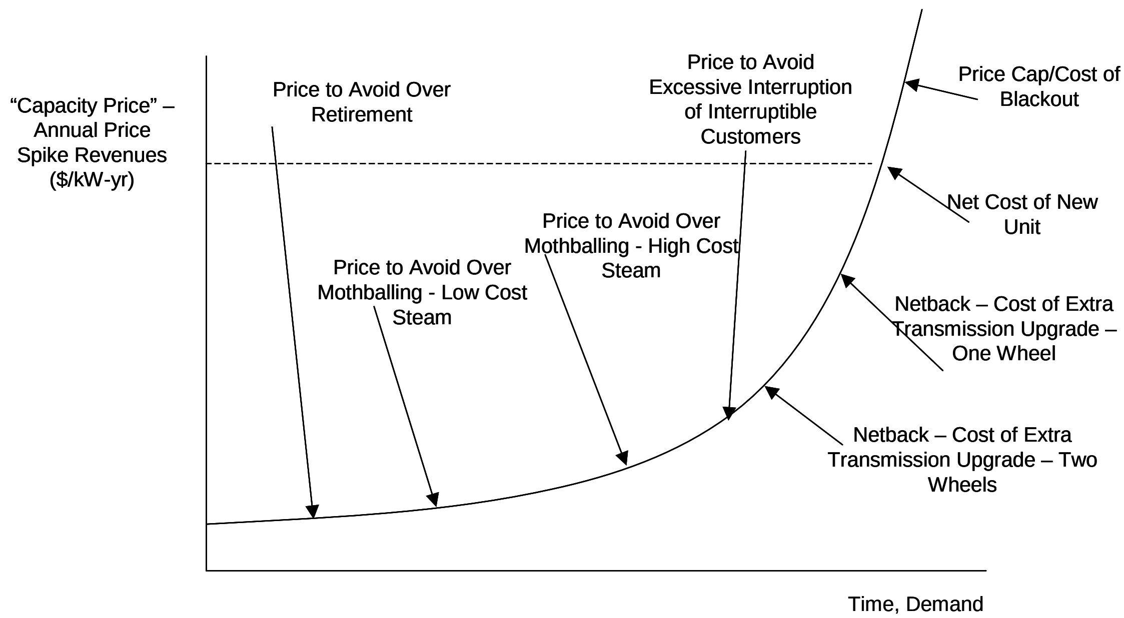
these equilibrium conditions. In other words, ICF's IPM® power model used here will build to meet reserve margin if the market is short of capacity and may retire if the region is long on capacity.

Exhibit 2-16:
Equilibrium in the Capacity Market



Equilibrium is defined usually as a condition in which there is sufficient capacity to meet a planning reserve margin over expected system peak. However, some regions rely more on operating reserve requirements than on planning reserve requirements. Either way, significant reserves are needed. That is, planning reserve requirements are set to ensure that enough reserve capacity exists to operate at peak. Thus, the fact that the model is estimating a separate capacity price is appropriate even for markets without separate planning reserve requirements.

Exhibit 2-17:
Price Spikes at the Peak in a Competitive Market



Capacity increases the reliability of electrical energy supply. Consequently, the power price structure must be high enough to ensure that sufficient "pure" capacity exists (i.e., units which almost never operate are available and are purely for reserve). To the extent that prices are above system lambda (i.e., above the competitive electrical energy price or the marginal variable cost of the last unit dispatched), this premium is the "pure" capacity price. The "pure" capacity market is not entirely separate from the energy market, but is linked.

ICF uses a sophisticated linear programming based computer modeling approach to forecasting capacity prices in which all model output is simultaneously determined. However, it is useful to describe this approach using seven steps.

1. Evaluate Near-term Capacity Balance: In Step 1, the potential for excess builds in the near-term is evaluated. Excess builds have the potential of creating a near-term over supply that could lower the market price of capacity.

2. Ensure Ongoing Cost Recovery: In Step 2, the annualized costs (capital related and annual fixed non-fuel O&M) of the least costly type of additional megawatts are estimated. In the model, these costs are calculated for numerous new plant options (e.g., simple and combined cycles, and coal plants).

3. Estimate Dispatch Profitability: Step 3 is to account for the energy sales profit of new power plants (i.e., the fact that new plants may not provide strictly "pure" capacity). For example, if a new power plant can make profit on electrical energy sales, this diminishes the price premium (i.e., the pure capacity price) required to build the necessary megawatts for reliability. For example, if a new combustion turbine can make $10/kW/yr in energy profit and it costs $57/kW/yr to build, the pure capacity price is $47/kW/yr.

The formula for the Step 3 adjustment is more complicated than Step 1 because all new potential entrants – e.g., both combined cycles and simple cycles - can profit from energy sales and both are marginal sources of megawatts. The "pure" capacity price is driven by the lower capacity price required of the two plants (or lower of other plants as well e.g. coal, LM6000s), as shown in the following, simplified formula:

If $(C_x - X) \leq (C_y - Y)$, then $P = C_x - X$
If $(C_x - X) \geq (C_y - Y)$, then $P = C_y - Y$

Where:

X = Energy sales profits of a new combustion turbine
Y = Energy sales profits of a new combined cycle
C_x = Annual fixed costs of a new combustion turbine
C_y = Annual fixed costs of a new combined cycle
P = "Pure" Capacity Price

4. Evaluate Firm Transmission: Under Step 4, the model makes decisions to import or export firm megawatts. Thus, the equilibrium in the capacity market is determined by simultaneously answering three questions: (i) how much reserves are required in a regional marketplace (with reference to planning reserve requirements and accounting for demand growth); (ii) how much can be traded; and (iii) what, if any, retirements or mothballing occur (see Step 5). We highlight trading of firm capacity rights for megawatts in the capacity pricing discussion because exporters are at a disadvantage to local generation since transmission charges are required on firm capacity purchases.

5. Account for Unit Shut-Down: In Step 5, we analyze whether the very last existing units in the dispatch order should be mothballed or retired if the pure capacity price is not sufficient to allow them to cover their net fixed, non-fuel, cash-going-forward costs after energy sales. In addition, the competitive market price for pure capacity will be less than the required capacity payment for new entrants in cases of excess capacity unless sufficient retirements occur to bring the market into equilibrium. In this case, the net cost of new plants must be greater than or equal to the cost of the most expensive units on a discounted multi-year basis. Our model is distinguished by its ability to make decisions including retirement decisions. It does this by incorporating expectations about the future through solving all years simultaneously.

6. Ensure Investment Cost Recovery : Step 6 addresses the multi-year nature of new power plant investment. The decision on whether to add new capacity to the system and the type of capacity to be added depend on the long term potential for recovery of costs associated with the investment. If the capital costs associated with new power plants are anticipated to be lower in the future such that the price of "pure" capacity in those years will also be lower, an additional premium in the early years would be warranted and necessary to compensate for lower profits in the out years. Otherwise, the price will be sufficient for the later entrants to recover costs and earn a return but not the earlier entrants. This issue exists with some saliency due to several factors including the possibility that the real costs of new gas power plants and their heat rates will continue to decrease.

7. Evaluate Curtailment Potential: Step 7 addresses the response to interruptible load. The interruptible load represents a significant force in maintaining price floors. Customers who may not be willing to pay full price for firm power, but are willing to pay some value above zero. Therefore, they help set a floor on capacity prices. Interruptible contracts also assist in maintaining stable peak prices by allowing interruptions in service levels in emergency situations. This element is captured in our modeling.

The history of interruptible contracts is complicated by the fact that they have been used to subsidize customers who in fact may best be considered as firm. In periods of fully available supply, regulators allow so-called interruptible consumers to pay below market price. In periods of limited supply availability, the interruptible consumers are then allowed to switch to firm rates freely. Because of this, consumers are somewhat allowed to misrepresent whether they are firm or interruptible customers. This contributes to explaining the large growth in interruptible load. This notwithstanding, we use historical estimates of interruptible load to be conservative.

Note that market power (the ability to manipulate the market pricing due to capacity withholding or bidding differently than cost of service) and forward contracts also contribute to capacity determination, although not explicitly captured in our modeling. Market power can be especially strong at the peak when all megawatts are needed in this situation, withholding capacity could result in artificially high prices. Forward contracts hedge against volatility including low capacity prices.

Additionally, the hourly loss of load probability could be evaluated to calculate the expected unserved energy on an hourly basis and hence, determine the timing and level of price spikes. This is especially relevant in the very near (12-18 months) when no capacity additions are possible.

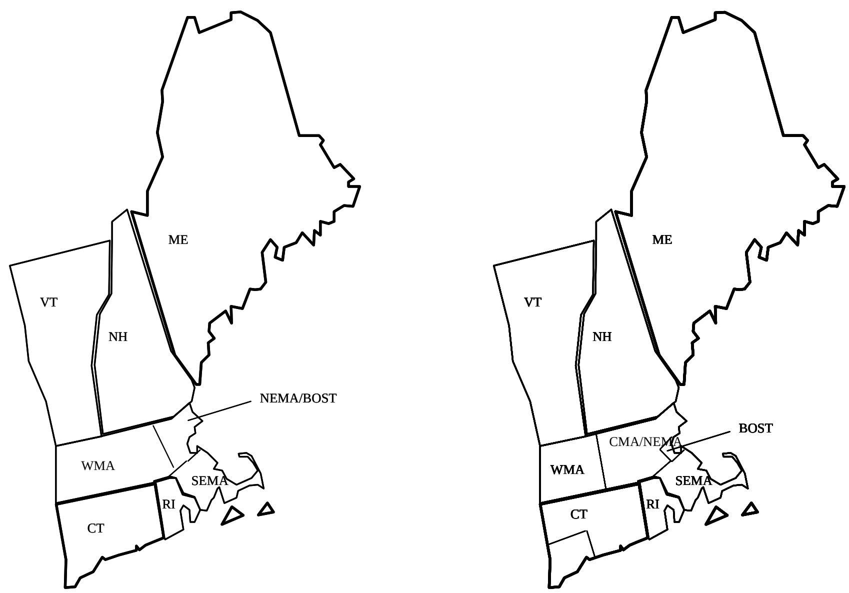
Detailed Wholesale Market Assumptions

The following section outlines key modeling assumptions, and the sources for and expected impact of these assumptions.

Geographic Scope

Exhibit 2-18:
Pricing Zones versus Transmission Zones

ISO-NEPOOL Pricing Regions   IPM Modeling Regions



ISO - NE Pricing Regions	IPM Modeling Regions
ME	ME
NH	NH
VT	VT
WMA	WMA CMA
CT	CT SWCT
RI	RI
SEMA	SEMA
NEMA/BOST	NEMA BOST CMA

ICF considers 10 transmission zones in this analysis. The 10 zones generally overlap the New England ISO 8 zonal pricing system currently in place. Differences include Connecticut where ICF has further broken out the pricing zone in order to capture effects of congestion on the Southwestern Connecticut market. Further, ICF has broken out the NEMA/Boston area to reflect potential constraints moving power into the Boston area. This breakout is intended to better capture the pricing impact in the New England submarkets.

Capacity and Demand Parameters

Exhibit 2-19:
ISO-NE Demand and Capacity Related Assumptions

Parameter	*Treatment-Base Case*
2003 Weather Normalized Peak Demand (MW)	26,591
2003 Net Internal Demand[1] (MW)	24,936
Annual Peak Growth	
2003-2005 AAGR	2.14
2006-2010 AAGR	1.99
2011-2020 AAGR	1.84
2021 – forward AAGR	1.68
2003 Weather Normalized Net Energy Load (GWh)	127,967
Annual Energy Growth	
2003-2005 AAGR	1.77
2006-2010 AAGR	1.68
2011-2020 AAGR	1.59
2021 – forward AAGR	1.51
Planning or "Market Revealed" Reserve Margin (%)	
2003-2007	17
2008-2009	15
2010	14
2011-2020	13

1. Net internal demand is equal to the peak load less interruptible load.

Source: ICF Consulting projections unless other wise noted.

Electricity demand growth projections have been derived from a combination of historical growth trends and official utility forecasts. Generally, historical peak demand growth in ISO-NE has been lower than the U.S. average. The 10-year rolling average from 1979 to 2002 for the New England area is 2.1 percent for peak demand and 1.8 percent for energy. The current ISO New England forecast is quite low at 1.5 and 1.4 percent for annual peak and energy growth between 2003 and 2012, respectively. For the near-term, we assume growth rates consistent with the historical record. Thereafter, we give increased weighting to the utility forecasts, resulting in a gradually decreasing growth rate trajectory.

Currently, a 17 percent planning reserve margin is assumed for the New England market as set by the New England Reliability Committee. We project this to decline to 14 percent by 2010, with improving availability and reliability of new units. These levels can be market-driven reserve levels, i.e. any lower level results in above equilibrium price spike revenues and scarcity.

Firm builds to date, i.e., builds either recently operational or currently under construction, are explicitly included in the model. Non-firm builds are constructed internally by the model to ensure that reserve requirements are achieved through the addition of the most economical power plant technology option available.

Construction of new units in New England began at an accelerated pace as early as 1999 with the large majority of new construction occurring in 2000 and 2002. The majority of new builds have been gas fired combined cycle and cogeneration units. Much of the capacity has come on line in Connecticut with Northern Massachusetts and Maine also experiencing a significant amount of capacity additions. Additions shown in Exhibit 2-20 are shown for the regions in which their main interconnection is located as well as for the physical state location. Note, some units may be located within one state but are actually interconnected to the grid at a point that is on the opposite side of a major transmission constraint and are hence better electrically connected to another operating region. An example of this is the Lake Road facility located in Connecticut near the Rhode Island border, but interconnected on the Rhode Island side of the transmission constraint.

Exhibit 2-20:
Recently Operational and Firmly Planned Capacity

Region	*State*	*Project Status*	*Plant*	*Fuel*	*On-Line Date*	*Capacity*	*Plant Type*
Southwest CT	CT	Operating	Milford CT	Gas	2000	544	CC
Maine	ME	Operating	Androscoggin ME	Gas	2000	127.9	Cogen
Maine	ME	Operating	Maine Independence Station Project	Gas	2000	493.7	CC
Southwest CT	CT	Operating	Bridgeport Project	Gas	2000	480	CC
Western Massachusetts	MA	Operating	Agawam Project	Gas	2000	245.2	CC
Rhode Island	RI	Operating	Tiverton (Calpine)	Gas	2000	244.8	Cogen
Maine	ME	Operating	Rumford	Gas	2000	244.9	CC
Maine	ME	Operating	Bucksport	Gas	2000	164.8	CC
Maine	ME	Operating	Westbrook CC	Gas	2001	540	CC
Western Massachusetts	MA	Operating	Millennium Power Project	Gas	2001	337.8	CC
Rhode Island	CT	Operating	Lake Road CT	Gas	2001	690.9	CC
Rhode Island	MA	Operating	Blackstone Project	Gas	2001	444.2	CC
New Hampshire	NH	Operating	AES Londonderry	Gas	2002	742	CC
Southwest CT	CT	Operating	Wallingford	Gas	2002	220	Jet Engine
Western Massachusetts	MA	Operating	West Springfield CT	Gas	2002	85.6	CC
New Hampshire	NH	Operating	Newington CC	Gas	2002	528.5	CC
Rhode Island	MA	Operating	ANP Bellingham	Gas	2002	221.6	CC
Rhode Island	RI	Operating	RI Hope Energy	Gas	2002	515.5	CC
Boston	MA	Operating	Kendall Power Project	Gas	2002	230	CC
Boston	MA	Under Construction	MYSTIC	Gas	2003	1600	CC
Boston	MA	Under Construction	Fore River	Gas	2003	750	CC
Total Firmly Planned builds						9,451	

Capacity Expansion Costs

New combined cycle and cogeneration costs are assumed to be available at a levelized cost that ranges from $625/kW to $700/kW (2000$) in New England. New simple cycle units are assumed to be available at a levelized cost that ranges from $390/kW to $421/kW in New England. Coal plants are considerably more expensive on a capital cost basis, ranging from $1,414/kW to $1,559/kW (2000$) in New England. New England costs on an equivalent megawatt basis are slightly higher than the US average when considered on an ISO basis due to ambient conditions and labor costs. New England summer and site-specific altitude conditions result in a 4 percent derate for turbine-based capacity output relative to ISO conditions. The average summer temperature is 82 degrees Fahrenheit and the average altitude is 100 feet.

Capital costs are generally decreasing modestly in real terms from 2005 through 2020. The build mix is determined through economics.

We assume that the real levelized capital charge rate in NEPOOL for new combined cycle (baseload) plants is 14.1 percent, 16.5 percent for peaking plants, and 13.2 percent for new coal plants.

In a deregulated market, peaking plants are less leveraged due to a riskier and, more volatile revenue profile. Conversely, coal plants are more leveraged due to a more stable cost and revenue profile.

Exhibit 2-21:
Capital Costs and Financing Assumptions

Parameter	Treatment											
	CC / Cogen			Combustion Turbine			LM6000			Coal		
New Plant All-In Capital Cost (2000$/kW)[1]	Boston	CT	ME	Boston	CT	ME	Boston	CT	ME	Boston	CT	ME
2003	731	714	653	441	438	408	689	594	570	1,561	1,509	1,416
2005	731	714	653	441	438	408	689	594	570	1,561	1,509	1,416
2010	692	676	618	416	414	386	652	562	540	1,558	1,505	1,413
2015	659	643	588	396	394	367	620	534	513	1,558	1,505	1,413
2020	626	612	559	376	374	349	590	508	488	1,558	1,505	1,413

Financing Costs for New Unplanned Builds	CC / Cogen	CT/LM6000	Coal
Debt/Equity Ratio (%)	50/50	30/70	60/40
Nominal Debt Rate (%)	9	10	9
Nominal After Tax Return on Equity (%)	14	14	14
Income Taxes[2] (%)	40.7	40.7	40.7
Other Taxes[3] (%)	2.3	2.3	2.3
General Inflation Rate (%)	2.5	2.5	2.5
Levelized Real Capital Charge Rate[2] (%)	14.1	16.5	13.2

1 Adjusted for summer weather and altitude; un-degraded capacity. Values shown for major areas, further regional disaggregations may be included for zonal areas to capture differences in labor cost. Note, costs continue to decrease at the same rate through 2025. Boston represents the Northeast MA/Boston zone; CT represents the Connecticut, Rhode Island, Southeast MA and Western MA zones; ME represents the Maine, New Hampshire and Vermont zones.
3 Fixed O&M costs increase over time for CTs, CCs and Cogeneration units. CC costs represent cycling CCs.
4 Includes state taxes of 7.5, 8.9, 9.5, 8.5, 9.0 and 9.75 percent in Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont respectively.
5 Includes insurance costs of 0.3 percent for all the sub-regions.

Exhibit 2-22:
New Unit O&M Costs

Parameter	*Fixed O&M (2000$/kW-yr)*	*Variable O&M (2000$/MWh)*	*Total O&M (2000$/kW-yr)*
Combustion Turbines			
2003 – 2010	6.0	7.1	8.9
2011 – 2019	6.0	7.9	9.2
2020 – 2022	6.0	8.7	9.5
Cycling Combined Cycles			
2003 – 2007	14.4	2.3	31.1
2008 – 2016	14.4	2.6	33.3
2017 – 2022	14.4	2.8	34.8
Turndown Combined Cycles			
2003 – 2007	24.5	1.0	31.8
2008 – 2016	26.2	1.0	33.5
2017 – 2022	27.8	1.0	35.1
Cogeneration			
2003 – 2007	25.9	0.8	32.2
2008 – 2016	27.6	0.8	33.9
2017 – 2022	29.2	0.8	35.5
LM6000			
2003 – 2022	10.2	2.4	11.2
Coal			
2003 – 2022	26.5	2.0	27.4

1 Assumes 5 percent capacity factor for combustion turbines, 83 percent capacity factor for combined cycles, 90 percent capacity factor for cogen, 85 percent capacity factor for coal, and 5 percent capacity factor for LM6000. Variable O&M is a function of dispatch these values are illustrative.

Source: ICF Consulting.

Environmental Assumptions

For this analysis, we have modeled currently firm environmental regulations, namely Phase II of the Acid Rain Program for SO2, the NOX OTR and SIP Call policies as appropriate in the Eastern Interconnect. The OTR states are assumed to meet SIP limits in 2003 and the rest of the states (19 total) are assumed to meet SIP limits in 2004. Exhibit 2-23 outlines some additional environmental policies in some of the New England states and New York

Exhibit 2-23:
Modeled State Air Regulations in addition to Regional or Federal Programs

State	*Notes*	*Status*	*NOX*	*SO2*	*Mercury*	*Carbon*
Connecticut	Trading and Banking Allowed	Promulgated on 12/28/2000	Non-Ozone Cap@ 0.15 lb/MMBtu in '02	0.55 lb/MMBtu in '02 0.33 lb/MMBtu in '03 4:1 IP* only between 0.55 lb/MMBtu and 0.33 lb/MMBtu Trading ends in 2005	NA	NA
Massachusetts	All policies are facility specific (i.e. No trading)	Promulgated on 5/11/2001	1.5 lb/MWhr by '04	6 lb/MWhr by '06 3 lb/MWhr by '08 3:1 IP* only between 6 and 3 lb/MWhr	NA	1800 lb/MWhr by '06
New Hampshire	Trading and Banking Allowed	Passed House Committee on 11/28/2001	1.5 lb/MWhr by '07	3 lb/MWhr by '07	NA	1990 levels by '07
New York	Trading and Banking Allowed	Draft Pataki Regulations	Non-Ozone Cap @ 0.15 lb/MMBtu in '04 3:1 IP 39,908 tons	25 % below Phase II starting '05 50% starting '08	NA	NA

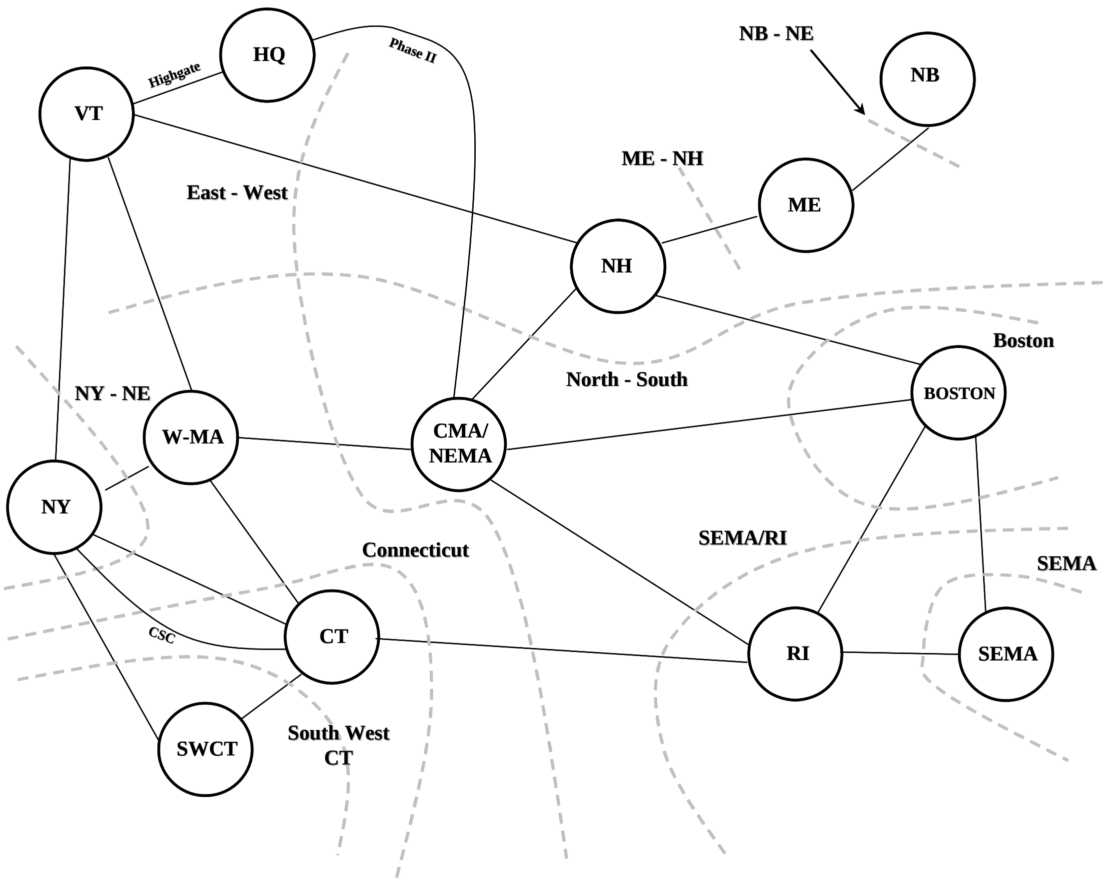
Source: Summarized by ICF Consulting from various existing policy proposals.

In addition to these pollution control programs, ICF considers the requirements for renewable resource portfolios within the New England states.

Transmission

Intra-Regional Transmissions

Exhibit 2-24:
New England Internal Transmission Constraints



Within New England there are several transmission limits that are occasionally binding. The most dominant of these is the East-West constraint that limits the transfer of resources from Eastern New England to Western New England and tends to result in higher prices to the west than to the east. The graphic above represents the constraints and transmission zones modeled for this analysis.

Inter-Regional Transmission

New England is directly interconnected with the New York ISO (NYISO) and New Brunswick and has a DC tie with Quebec. Transmission limits reflect ICF AC load flow studies as well as NERC studies.

New England as a whole can import up to 17 percent of its 2003 forecast peak demand through its interconnections with NYPP and Quebec. Similarly, New England can export up to 14 percent of its peak demand. This includes interconnections with New York, Hydro Quebec and New Brunswick.

Hydro Quebec has historically been a low-cost power provider to the New England market interconnecting through both Vermont and Central Massachusetts. Vermont has the capability to import or export 225 MW of capacity in the summer and 67.5 MW of capacity in the winter with Hydro Quebec. Central Massachusetts has a total import/export capability of 1500 MW of capacity in the summer and 450 MW of capacity in the winter with Hydro Quebec.

New Brunswick is more remote, interconnecting only through Maine, and has a more limited transfer capacity. The Maine to New Brunswick interconnection allows for movement of 700 MW of capacity in the summer and 210 MW of capacity in the winter.

Natural Gas Prices

Exhibit 2-25 shows ICF natural gas price forecasts for New England. Values used as inputs to the wholesale market price forecasts are consistent with those used in the natural gas avoided cost calculations.

Exhibit 2-25:
Delivered Natural Gas Prices to New England (2004 $/MMBtu)

	Natural Gas Prices (2004$/MMBtu)			
Year	***Henry Hub***	***Delivered Northern New England***	***Delivered Mid-New England***	***Delivered Southern New England***
2003	$5.96	$6.26	$6.42	$6.52
2004	$5.26	$5.64	$5.73	$5.79
2005	$4.82	$5.19	$5.28	$5.34
2006	$4.30	$4.68	$4.77	$4.83
2008	$3.99	$4.37	$4.46	$4.52
2010	$3.98	$4.36	$4.44	$4.51
2015	$3.65	$4.03	$4.11	$4.18
2020	$3.80	$4.18	$4.26	$4.33

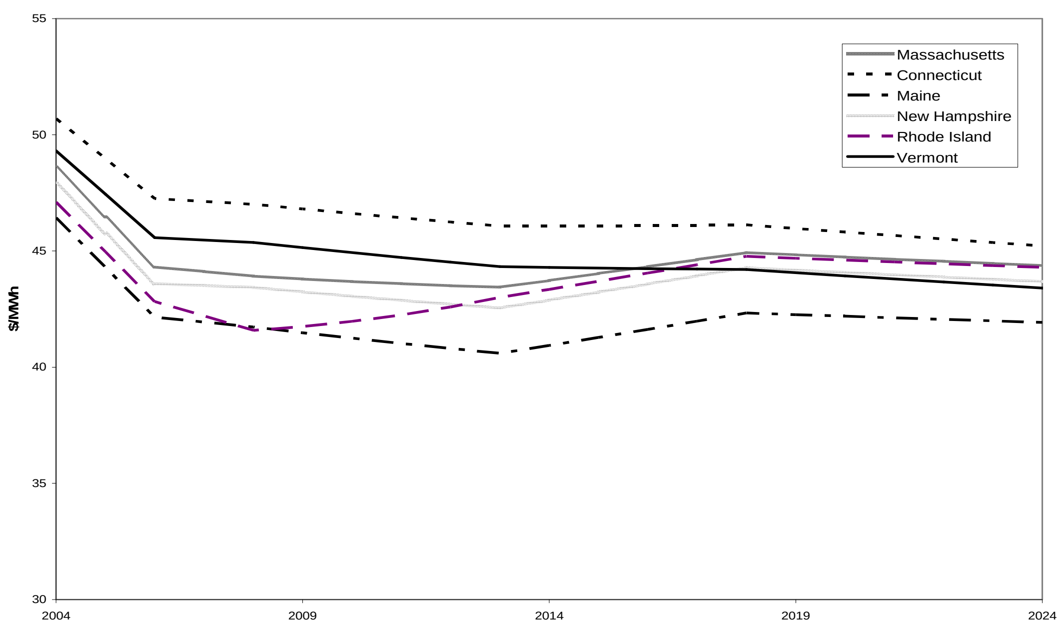
ICF forecasts for natural gas are derived from ICF's North American Natural Gas Analysis System (NANGAS). Near-term market prices reflect forward market prices that can currently be contracted for. Long-term forecasts reflect NANGAS output. Further discussion of gas and other fuel prices can be found in other sections of this document.

Delivered prices to power generators in ISO-NE for 2003 reflect spot market prices rather than firm supply. For spot purchases, basis differentials of $0.57 in Southern New England (RI, CT, MA), $0.47 in mid-New England (CT/MA), and $0.31/MMBtu in northern New England (VT, ME, NH) relative to Henry Hub are expected. Totals may not add due to rounding.

Summary of New England Wholesale Power Price Forecasts

Our forecast of firm (i.e., all-in all-hours average) price represents the price for unit contingent supply. The price shown provides for maximum revenues available to a plant in the market, i.e., a plant must be dispatched in all hours to realize this price. The firm price comprises the two unbundled products of electrical energy and capacity. Both components see only small changes in real terms through the forecast horizon, and thus, firm prices remain stable in real terms throughout the forecast horizon. This forecast includes the marginal value of energy and capacity.

Exhibit 2-26:
Sub-regional Summary of Firm Price Forecast ISO-NE (Real 2004$)



Source: IPM® modeling results.

Near-term prices are expected to be depressed, all else equal, due to high levels of power plant construction in recent years that has exceeded actual demand requirements. The market price trend shows a lower than YTD 2003 value in 2004 due to a moderate decrease in fuel prices and a depressed capacity market. Thereafter, prices recover as demand continues to grow and new power plant additions occur restoring the balance between supply and demand at the peak. This is the key factor in the recovery of prices. Additional price pressures in New England exist in the form of high gas prices and congestion costs.

This forecast is considered to be conservative for several reasons, including:

- Market Structure – This analysis assumes the market for generation is perfectly competitive and perfectly efficient. Since no market is truly perfectly competitive and efficient, this tends to understate prices, value, and price volatility, all else equal. Note, given the liquidity of the New England markets and the move to an even more liquid structure of LMP pricing, the divergence of pricing from competitive pricing based on the market structure is expected to be minimal.

- No Shortages – This analysis does not consider the potential for shortages of generation capacity to affect power prices even in distant future periods. In contrast, this analysis does consider the implications of potential excess capacity; if there is excess capacity, power prices are depressed in this modeling exercise below equilibrium levels.

- New Plant Costs and Performance – ICF assumes new plant costs decrease in real terms in later years while their thermal efficiencies improve. Thus, future competitors have better performance characteristics.

- Environmental Restrictions – The analysis assumes no change in environmental regulations, especially no tightening of environmental regulations. The market pricing may be higher if regulations tighten.

- Firm Transmission Rights – The additional expense of firm transmission rights to LSEs beyond allocated values are not considered. Again, the impact may be minimal as across the market the value of the FTR allocations will be the same since individual utilities may be sellers or purchasers of FTRs.

We consider ten separate zonal areas in ISO-NE based on congestion points. Detailed results to the zonal level are reported in the Appendix to this report.

Historical Prices

Understanding trends behind historical price movements is useful in understanding forecast results and applying them to real world markets. As such, we examine the New England market price over the last several years relative to the ICF 2004 price forecast. Power prices in New England have historically been high relative to the majority of the US. Prices rose in 1999 as scarcity raised implied system heat rates. In 2000, mild weather and new capacity additions to the grid resulted in a reduced implied system heat rate, however, fuel prices were strong and drove prices higher. In 2001, prices remained strong as warm weather and high fuel prices offset the greater availability of new generation capacity. Prices have trended downward since 2001 due to a relaxation in natural gas prices in the early winter months and the addition of more low cost generation resources. The ICF forecast projects that prices will continue to trend downward, to levels stronger than seen in 1999. This reflects the continued addition of new capacity resources and a decline in natural gas prices. These items tend to counteract increasing demand growth and the impact of rising emission allowance prices related to policies such as the SIP Call NO_x. This forecast may be somewhat conservative, as it does not consider the additional impact of state-level air quality programs that would impact the power sector. In 2003, several shifts occurred in the market place including the move to locational marginal pricing for generators and zonal pricing for LSEs beginning in March. Although a trial period had existed prior to the official start of the LMP system, market operator did experience a learning and adjustment period in adapting to the new system. Also, in 2003, natural gas prices have continued to reflect unexpectedly high values that have driven up energy pricing in New England. Related to this, the regional congestion management program is still undergoing changes that will affect the value of capacity in the market, likely based on particular congested zones. Current expectations for gas prices are for a decline in the upcoming months.

Exhibit 2-27:
New England Historical On-Peak and All-Hours Firm Prices vs. ICF Forecast (Nominal$)

Parameter		*1996*	*1997*	*1998*	*1999*	*2000*	*2001*	*2002*	*YTD 2003*[1]	*ISO-NE*[2] *Forecast*	
										2003 2nd Half	*2004 Firm Price*
ISO-NE Power Prices[3]	On-Peak ($/MWh)	28.5	30.7	26.6	34.0	53.3	53.2	43.6	62.8	55.1	53.8
	All-Hours ($/MWh)	23.7	26.1	23.0	27.0	41.2	42.2	34.9	56.2	47.2	48.9
ISO-NE Implied System Heat Rates[4]	On-Peak (Btu/kWh)	8,314	9,622	9,693	11,617	10,899	11,245	11,443	10,722	9,412	10,238
	All-Hours (Btu/kWh)	6,929	8,181	8,365	9,237	8,431	8,930	9,160	9,596	8,058	9,301

[1]YTD through June 30, 2003. Represents a simple average of zonal reported marginal pricing
[2]Forecast prices shown are a simple average of all New England sub-regions.
[3]Power Market Weeks prices are for ISO-NE from 1996 – 2003 YTD.
[4] Calculated as nominal power price divided by average regional gas price.

Exhibit 2-28:
Summary of New England Statewide Firm[1] Power Price Forecast (2004 $/MWh)

Year	*All-Hour Average Price*						
	Massachusetts	***Connecticut***	***Maine***	***New Hampshire***	***Rhode Island***	***Vermont***	***New England***
2003 1st Half Actual	$55.8	$57.0	$50.8	$54.7	$55.4	$56.3	$56.2
2003 2nd Half	$46.9	$48.4-	$45.6	$46.0	$46.7	$46.8	$47.2
2004	$48.6	$50.7	$46.4	$47.9	$47.1	$49.3	$48.9
2006	$44.3	$47.3	$42.2	$43.6	$42.8	$45.6	$44.9
2008	$43.9	$47.0	$41.7	$43.4	$41.6	$45.4	$44.5
2013	$43.4	$46.1	$40.6	$42.6	$43.0	$44.3	$43.9
2018	$44.9	$46.1	$42.3	$44.3	$44.8	$44.2	$45.0
2025	$44.3	$45.1	$41.9	$43.6	$44.2	$43.3	$44.2
2030	$45.7	$46.3	$42.8	$44.8	$45.7	$44.3	$45.5
2037	$45.7	$46.3	$42.8	$44.8	$45.7	$44.3	$45.5
Levelized Average[2]	$44.9	$46.5	$42.3	$44.1	$44.3	$44.7	$45.0

[1]Firm Price = Sum of Energy Price and Capacity Price at 100 percent load factor.
[2]Assumes 1.86 percent real discount rate.
Source**:** IPM® modeling results except as noted.

The second half of 2003 power prices assume that gas prices will follow the forward market prices and begin to move downward. Under normal demand conditions, prices are expected to drop from the first half of the year levels. On average, 2004 prices are expected to drop from the average levels in 2003, although they will be stronger than prices in the last 6 months of 2003.

ICF projections indicate that wholesale prices will be the highest in Connecticut, Massachusetts and Vermont over time. Rhode Island is also expected to have strong long-term average prices although near-term markets may be somewhat depressed due to the recent large influx of capacity to the small market area. Prices in Maine are expected to be among the lowest in New England due to the resource mix that includes significant hydro generation capacity and combined with the effect of the new capacity that has recently been added in the state.

Exhibit 2-29:
Summary of New England Zonal Firm[1] Power Price Forecast (2004 $/MWh)

Year	*All-Hour Average Price* SEMA	*BOST/NMA*	*WCMA*	*Conn-ecticut*	*Maine*	*New Hampshire*	*Rhode Island*	*Vermont*	*New England*
2003 1st Half Actual	$55.4	$55.8	$56.1	$57.0	$50.8	$54.7	$55.4	$56.3	$ 56.2
2003 2nd Half	$46.2	$46.8	$47.3	$48.4	$45.6	$46.0	$46.7	$46.8	$ 47.2
2004	$46.3	$48.9	$49.5	$50.7	$46.4	$47.9	$47.1	$49.3	$ 48.9
2006	$41.9	$44.6	$45.4	$47.3	$42.2	$43.6	$42.8	$45.6	$ 44.9
2008	$40.7	$44.4	$45.1	$47.0	$41.7	$43.4	$41.6	$45.4	$ 44.5
2013	$41.9	$43.6	$44.1	$46.1	$40.6	$42.6	$43.0	$44.3	$ 43.9
2018	$43.9	$45.3	$45.0	$46.2	$42.3	$44.3	$44.8	$44.2	$ 45.0
2025	$43.5	$44.6	$44.2	$45.1	$41.9	$43.6	$44.2	$43.3	$ 44.2
2030	$44.9	$46.1	$45.5	$46.3	$42.8	$44.8	$45.7	$44.3	$ 45.5
2037	$44.9	$46.1	$45.5	$46.3	$42.8	$44.8	$45.7	$44.3	$ 45.5
Levelized Average[2]	$43.4	$45.2	$45.2	$46.5	$42.3	$44.1	$44.3	$44.7	$ 45.0

[1]Firm Price = Sum of Energy Price and Capacity Price at 100 percent load factor.
[2]Assumes 1.86 percent real discount rate.
Source: IPM® modeling results except as noted.

In real dollars, the firm power prices in New England are expected to decrease beyond 2004 through about 2013 before beginning to slightly increase again, then declining through 2013 and stabilizing thereafter. In nominal dollars, prices are expected to continually increase over the time horizon.   As will be discussed below, the near-term markets are somewhat depressed in capacity value, primarily due to the recent capacity additions. The market is expected to recover from this oversupply, driving the increase in power prices through 2006. In the post-2006 period, the real price decline occurs as new units continue to increase in efficiency and investment costs decline.

Capacity and Energy Price For Select Areas

Exhibit 2-30:
Annual Average All-Hours Energy and Capacity Prices - Eastern Massachusetts (2004 $/MWh)

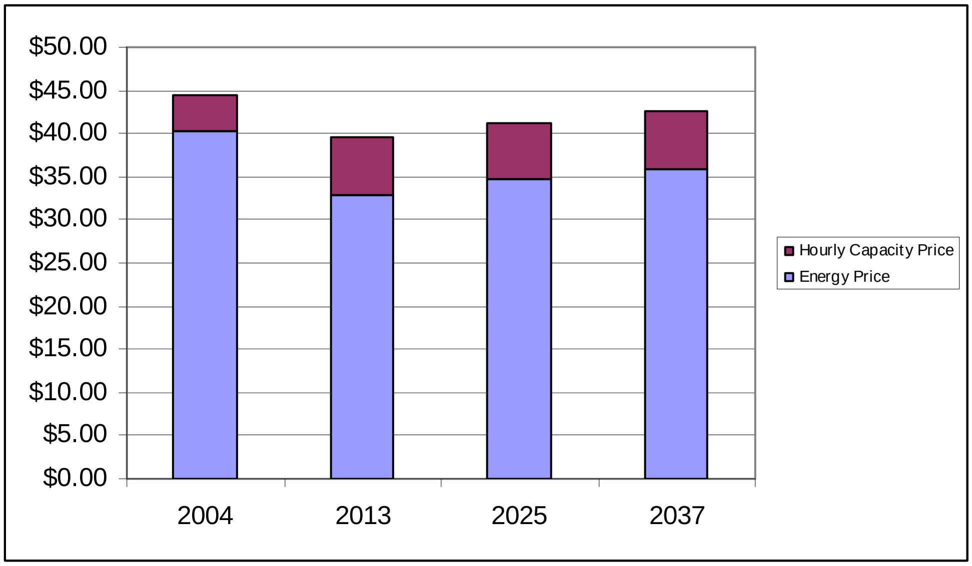


Exhibit 2-31:
Annual Average All-Hours Energy and Capacity Prices - Western Massachusetts (2004 $/MWh)

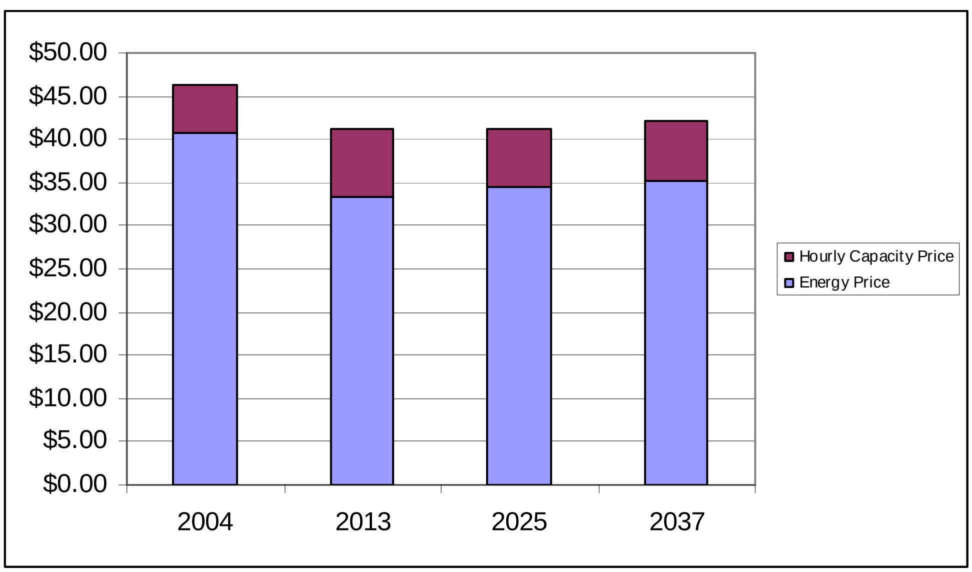


Exhibit 2-32:
Annual Average All-Hours Energy and Capacity Prices - Southwest Connecticut (2004 $/MWh)

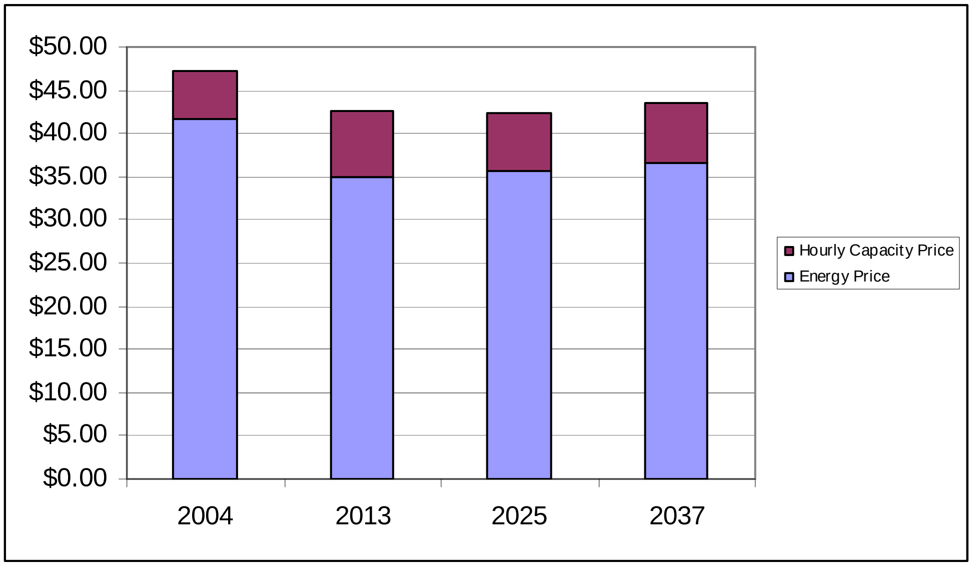
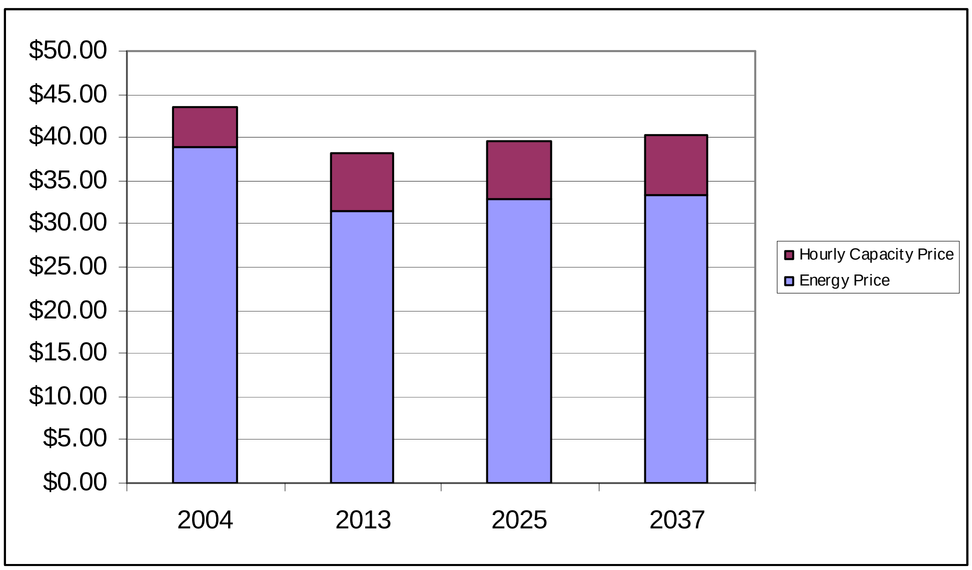


Exhibit 2-33:
Annual Average All-Hours Energy and Capacity Prices - Maine (2004 $/MWh)



As mentioned in the Methodology discussion above, firm wholesale prices are comprised of two unbundled components of "pure" capacity and electrical energy. Exhibits 2-30 through 2-33 illustrate the individual forecast component projections for select zones through 2037.

Competitive energy prices are a function of variable costs of the marginal unit in each hour, and hence, fuel costs and unit efficiency both heavily influence energy prices. Energy price forecasts are relatively stable at slightly above $35/MWh throughout the forecast due to a stable generation fleet (no significant additions needed before 2015), and consistent natural gas prices.

Energy prices are strong throughout the forecast horizon. Given the predominance of gas and oil fired generating stations in the market area.

Exhibit 2-34:
ISO-NE Statewide On-Peak Power Price Forecast (2004 $/MWh)

	On-Peak[1] Firm Price Forecast					
	Summer[2]					
Year	***Massachusetts***	***Connecticut***	***Maine***	***New Hampshire***	***Rhode Island***	***Vermont***
2004	$57.81	$62.46	$51.18	$56.69	$57.14	$59.00
2006	$55.19	$60.15	$48.72	$54.00	$53.96	$56.80
2008	$57.27	$62.62	$50.03	$56.39	$54.58	$59.14
2013	$58.50	$62.82	$49.85	$56.83	$59.68	$59.18
2018	$60.77	$62.69	$52.04	$59.50	$62.58	$59.09
2025	$60.64	$62.33	$52.31	$59.22	$62.44	$58.66
2030	$62.61	$63.90	$52.68	$59.80	$64.46	$59.13
2037	$62.61	$63.90	$52.68	$59.80	$64.46	$59.13
Levelized Average[4]	$59.55	$62.53	$51.36	$57.92	$60.28	$58.72
	Winter[3]					
Year	***Massachusetts***	***Connecticut***	***Maine***	***New Hampshire***	***Rhode Island***	***Vermont***
2004	$48.50	$49.67	$50.05	$48.07	$47.03	$48.90
2006	$41.36	$43.46	$43.41	$40.80	$40.25	$42.25
2008	$40.38	$42.25	$42.91	$39.90	$38.82	$41.36
2013	$39.20	$41.02	$42.06	$38.76	$37.22	$40.00
2018	$40.53	$41.84	$43.79	$40.12	$38.40	$40.47
2025	$40.34	$41.13	$43.38	$39.88	$38.50	$39.83
2030	$41.71	$42.22	$44.65	$41.27	$39.90	$40.94
2037	$41.71	$42.22	$44.65	$41.27	$39.90	$40.94
Levelized Average[4]	$41.59	$42.81	$44.26	$41.13	$39.84	$41.63

1. On-peak is defined as Monday through Friday 6am - 10pm, excluding Federal holidays.
2. Summer months are June, July, August and September.
3. Winter months are January, February, March, April, May, October, November and December.
4. Real discount rate of 1.86 percent used to calculate levelized values.

Exhibit 2-35:
ISO-NE Off-Peak Statewide Power Price Forecast (2004 $/MWh)

	Off-Peak[1] Firm Price Forecast					
	Summer[2]					
Year	***Massachusetts***	***Connecticut***	***Maine***	***New Hampshire***	***Rhode Island***	***Vermont***
2004	$47.86	$51.32	$41.87	$46.92	$46.56	$49.07
2006	$45.84	$49.92	$39.18	$44.91	$44.18	$47.56
2008	$46.90	$51.31	$39.53	$46.34	$43.89	$48.86
2013	$47.47	$50.87	$38.42	$46.04	$48.63	$48.42
2018	$49.08	$50.05	$40.28	$48.15	$50.80	$47.67
2025	$47.83	$48.47	$39.78	$46.89	$49.47	$46.40
2030	$49.12	$49.67	$40.37	$48.05	$51.00	$47.24
2037	$49.12	$49.67	$40.37	$48.05	$51.00	$47.24
Levelized Average[4]	$47.72	$49.76	$39.77	$46.72	$48.29	$47.44
	Winter[3]					
Year	***Massachusetts***	***Connecticut***	***Maine***	***New Hampshire***	***Rhode Island***	***Vermont***
2004	$39.80	$40.19	$41.47	$39.36	$37.99	$40.04
2006	$35.45	$36.61	$37.75	$35.10	$33.83	$36.25
2008	$33.46	$34.77	$36.28	$33.28	$31.80	$34.42
2013	$31.38	$32.74	$34.34	$31.19	$29.52	$32.38
2018	$32.33	$33.25	$35.70	$32.17	$30.49	$32.66
2025	$32.20	$32.75	$35.25	$31.98	$30.56	$32.22
2030	$33.11	$33.56	$35.99	$32.83	$31.49	$32.95
2037	$33.11	$33.56	$35.99	$32.83	$31.49	$32.95
Levelized Average[4]	$33.42	$34.25	$36.17	$33.17	$31.75	$33.78

1. Off-peak is defined as Monday through Friday 11pm-5am & all weekend hours, including Federal holidays.
2. Summer months are June, July, August and September.
3. Winter months are January, February, March, April, May, October, November and December.
4. Real discount rate of 1.86 percent used to calculate levelized values.

Exhibits 2-36 and 2-37 further differentiate pricing at the level of the New England eight pricing zones. Differentiation by the ICF ten modeling zones is available in the appendix.

Exhibit 2-36:
ISO-NE On-Peak Zonal Power Price Forecast (2004 $/MWh)

	On-Peak[1] Firm Price Forecast							
	Summer[2]							
Year	***SEMA***	***BOST/NMA***	***WCMA***	***Connecticut***	***Maine***	***New Hampshire***	***Rhode Island***	***Vermont***
2004	$54.38	$58.31	$58.84	$62.46	$51.18	$56.69	$57.14	$59.00
2006	$51.00	$55.91	$56.47	$60.15	$48.72	$54.00	$53.96	$56.80
2008	$51.69	$58.43	$58.85	$62.62	$50.03	$56.39	$54.58	$59.14
2013	$55.82	$58.96	$59.12	$62.82	$49.85	$56.83	$59.68	$59.18
2018	$58.65	$61.75	$60.41	$62.69	$52.04	$59.50	$62.58	$59.09
2025	$58.86	$61.50	$60.06	$62.33	$52.31	$59.22	$62.44	$58.66
2030	$60.91	$63.54	$61.77	$63.90	$52.68	$59.80	$64.46	$59.13
2037	$60.91	$63.54	$61.77	$63.90	$52.68	$59.80	$64.46	$59.13
Levelized Average[4]	$56.90	$60.34	$59.68	$62.53	$51.36	$57.92	$60.28	$58.72
	Winter[3]							
Year	***SEMA***	***BOST/NMA***	***WCMA***	***Connecticut***	***Maine***	***New Hampshire***	***Rhode Island***	***Vermont***
2004	$47.71	$48.36	$49.22	$49.67	$50.05	$48.07	$47.03	$48.90
2006	$40.97	$40.97	$42.14	$43.46	$43.41	$40.80	$40.25	$42.25
2008	$39.93	$39.99	$41.13	$42.25	$42.91	$39.90	$38.82	$41.36
2013	$39.28	$38.77	$39.73	$41.02	$42.06	$38.76	$37.22	$40.00
2018	$40.90	$40.08	$40.89	$41.84	$43.79	$40.12	$38.40	$40.47
2025	$40.99	$39.92	$40.46	$41.13	$43.38	$39.88	$38.50	$39.83
2030	$42.44	$41.33	$41.72	$42.22	$44.65	$41.27	$39.90	$40.94
2037	$42.44	$41.33	$41.72	$42.22	$44.65	$41.27	$39.90	$40.94
Levelized Average[4]	$41.77	$41.22	$41.95	$42.81	$44.26	$41.13	$39.84	$41.63

1. On-peak is defined as Monday through Friday 6am - 10pm, excluding Federal holidays.
2. Summer months are June, July, August and September.
3. Winter months are January, February, March, April, May, October, November and December.
4. Real discount rate of 1.86 percent used to calculate levelized values.

Exhibit 2-37:
ISO-NE Off-Peak Zonal Power Price Forecast (2004 $/MWh)

	Off-Peak[1] Firm Price Forecast							
	Summer[2]							
Year	*SEMA*	*BOST/NMA*	*WCMA*	*Connecticut*	*Maine*	*New Hampshire*	*Rhode Island*	*Vermont*
2004	$43.93	$48.59	$48.85	$51.32	$41.87	$46.92	$46.56	$49.07
2006	$41.29	$46.77	$47.16	$49.92	$39.18	$44.91	$44.18	$47.56
2008	$40.93	$48.31	$48.56	$51.31	$39.53	$46.34	$43.89	$48.86
2013	$44.36	$48.15	$48.19	$50.87	$38.42	$46.04	$48.63	$48.42
2018	$46.53	$50.30	$48.80	$50.05	$40.28	$48.15	$50.80	$47.67
2025	$45.53	$48.95	$47.56	$48.47	$39.78	$46.89	$49.47	$46.40
2030	$46.88	$50.31	$48.66	$49.67	$40.37	$48.05	$51.00	$47.24
2037	$46.88	$50.31	$48.66	$49.67	$40.37	$48.05	$51.00	$47.24
Levelized Average[4]	$44.60	$48.75	$48.02	$49.76	$39.77	$46.72	$48.29	$47.44
	Winter[3]							
Year	*SEMA*	*BOST/NMA*	*WCMA*	*Connecticut*	*Maine*	*New Hampshire*	*Rhode Island*	*Vermont*
2004	$39.10	$39.67	$40.33	$40.19	$41.47	$39.36	$37.99	$40.04
2006	$34.97	$35.13	$36.20	$36.61	$37.75	$35.10	$33.83	$36.25
2008	$32.86	$33.16	$34.30	$34.77	$36.28	$33.28	$31.80	$34.42
2013	$31.29	$30.94	$32.17	$32.74	$34.34	$31.19	$29.52	$32.38
2018	$32.57	$31.89	$32.88	$33.25	$35.70	$32.17	$30.49	$32.66
2025	$32.56	$31.80	$32.56	$32.75	$35.25	$31.98	$30.56	$32.22
2030	$33.56	$32.69	$33.37	$33.56	$35.99	$32.83	$31.49	$32.95
2037	$33.56	$32.69	$33.37	$33.56	$35.99	$32.83	$31.49	$32.95
Levelized Average[4]	$33.42	$33.06	$33.95	$34.25	$36.17	$33.17	$31.75	$33.78

1. Off-peak is defined as Monday through Friday 11pm-5am & all weekend hours, including Federal holidays.
2. Summer months are June, July, August and September.
3. Winter months are January, February, March, April, May, October, November and December.
4. Real discount rate of 1.86 percent used to calculate levelized values.

Due to the widespread use of natural gas fired capacity, off-peak market prices are expected be to strong relative to regions such as ECAR and PJM-West which rely heavily on coal and nuclear facilities in the off-peak. Peak prices are also expected to be tied to gas-fired capacity. However, in peak periods, older, less efficient oil/gas steam capacity is expected to be price setting in many hours. In addition, a capacity component is realized in the peak hours that drives the peak/off-peak price spread to even greater levels.

Over time, as the capacity component of prices becomes more valuable, the all-in market price increases in both real and nominal terms. This results in an increasing marginal system heat rate. Capacity prices are directly related to supply/demand at the peak and the costs of entry and exit. All plants contribute to reliability and are thus entitled to earn "pure" capacity or peak hour volatility revenues. In some periods, this reflects new entrant costs in the New England market and in other periods, this reflects entrant costs in other markets. In the near-term, since the market is in an oversupply situation, capacity prices reflect the on-going carrying costs of keeping existing units in the market. In cases where the units are not able to support their avoidable fixed costs through energy and capacity returns, units are projected to mothball for return to service at a later date or to retire permanently.

New England "pure" capacity prices rise significantly between 2004 and 2008 as demand growth catches up with recent capacity additions. In this period, the market is expected to require little, if any, additional capacity. Until the point of supply/demand equilibrium is reached, capacity value is expected to be depressed as participants are not willing to support an oversupply. Beyond 2008 capacity prices are expected to remain relatively flat at about a $65/kW-yr level (real 2004$). This value reflects the requirement for additional capacity to the grid for reliability purposes and thus is the equilibrium value of capacity. This capacity value is available to all power plants operating in the system in the long term. Exhibit 2-38 shows the expected capacity mothballing, retirements, returns to service and additions over the forecast horizon.

Exhibit 2-38:
Forecasted Retirement, Mothball and Capacity Additions by type in New England (MW)

Year Range	*Retirement*	*Mothball*	*Return to Service*	*Combined Cycle/ Cogeneration Additions*	*Combustion Turbine Additions*
2003-2004	26	2,070	329	0	0
2005-2006	111	0	1,102	0	0
2007-2008	0	0	258	0	0
2009-2010	0	0	124	0	0
2011-2015	0	0	0	308	1,214
2016-2020	0	0	0	1,726	1,086
Total	**137**	**2,070**	**1,813**	**2,034**	**2,327**

In the long-term, new units are required to meet the growing load in all regions of New England. In general, we see a faster recovery in Western ISO-NE than in the Eastern area, particularly in Rhode Island (RI) and Southeastern Massachusetts (SEMA) given the wider geographic expanse, and greater degree of interconnects with outside markets. Of the New England sub-regions analyzed, Eastern Massachusetts and Rhode Island are forecast to need the least amount of capacity additions in terms of megawatts and as a percent of local demand.

Summary of New England Wholesale Producer Cost Forecasts

Actual producer prices will vary from the marginal by the amount of energy served in any given hour. The annual producer price represents the generation weighted marginal energy price while the annual marginal energy cost is the simple average of each hour. That is, the marginal producer price reflects a volume weighed average price. Marginal firm producer prices expected in the pricing zones and in New England are shown below. Producer price forecasts are directly tied to the retail rate that consumers would be charged and hence are more reflective of costs saving that would be experienced on a consumer level than are marginal wholesale prices. Final avoided cost values presented in this report are representative of the standard load shape in the New England zones and on average in New England. However, should specific energy efficiency programs being evaluated not follow the typical load shape, the marginal price curve adjusted for retail avoided costs should be applied as the basis for the final avoided costs. Avoided costs are provided at the marginal and load-weighted level in the appendix to this report.

Exhibit 2-39:
Summary of New England Statewide Producer Cost Forecast (2004 $/MWh)

Year	All-Hour Cost						
	Massachusetts	***Connecticut***	***Maine***	***New Hampshire***	***Rhode Island***	***Vermont***	***New England***
2003 1st Half Actual	$55.97	$57.17	$51.00	$54.93	$55.62	$56.48	$56.45
2003 2nd Half	$50.21	$51.77	$48.56	$49.42	$49.26	$50.30	$50.37
2004	$51.83	$54.60	$49.78	$51.39	$49.21	$53.23	$52.24
2006	$47.65	$51.32	$45.70	$47.19	$44.96	$49.69	$48.33
2008	$47.98	$51.85	$45.91	$47.82	$44.19	$50.32	$48.65
2013	$48.22	$51.55	$45.19	$47.60	$46.27	$49.88	$48.74
2018	$50.14	$51.73	$47.17	$49.86	$48.39	$49.87	$50.14
2025	$49.73	$50.95	$46.51	$49.35	$48.17	$49.12	$49.59
2030	$51.23	$52.20	$47.41	$50.67	$49.43	$49.69	$50.90
2037	$51.23	$52.20	$47.41	$50.67	$49.43	$49.69	$50.90
Levelized Average[2]	$49.78	$51.93	$46.79	$49.33	$47.69	$50.08	$49.93

[1]Firm Price = Sum of Energy Price and Capacity Price at 100 percent load factor.
[2]Assumes 1.86 percent real discount rate.
Source**:** IPM® modeling results except as noted.

Exhibit 2-40:
Summary of New England Zonal Producer Cost Forecast (2004 $/MWh)

Year	*All-Hour Cost*								
	SEMA	***BOST/NMA***	***WCMA***	***Connecticut***	***Maine***	***New Hampshire***	***Rhode Island***	***Vermont***	***New England***
2003 1st Half Actual	$55.60	$56.04	$55.62	$57.17	$51.00	$54.93	$55.62	$56.48	$56.45
2003 2nd Half	$49.65	$50.05	$49.26	$51.77	$48.56	$49.42	$49.26	$50.30	$50.37
2004	$49.42	$51.95	$49.21	$54.60	$49.78	$51.39	$49.21	$53.23	$52.24
2006	$45.01	$47.67	$44.96	$51.32	$45.70	$47.19	$44.96	$49.69	$48.33
2008	$44.42	$48.25	$44.19	$51.85	$45.91	$47.82	$44.19	$50.32	$48.65
2013	$46.77	$47.98	$46.27	$51.55	$45.19	$47.60	$46.27	$49.88	$48.74
2018	$49.19	$50.21	$48.39	$51.73	$47.17	$49.86	$48.39	$49.87	$50.14
2025	$49.07	$49.81	$48.17	$50.95	$46.51	$49.35	$48.17	$49.12	$49.59
2030	$50.41	$51.62	$49.43	$52.20	$47.41	$50.67	$49.43	$49.69	$50.90
2037	$50.41	$51.62	$49.43	$52.20	$47.41	$50.67	$49.43	$49.69	$50.90
Levelized Average[2]	$48.32	$49.89	$47.69	$51.93	$46.79	$49.33	$47.69	$50.08	$49.93

[1]Firm Price = Sum of Energy Price and Capacity Price at 100 percent load factor.
[2]Assumes 1.86 percent real discount rate.
Source: IPM® modeling results except as noted.

Exhibits 2-41 and 2-42 present power market costs by State for peak and off-peak hours.

Exhibit 2-41:
ISO-NE Statewide On-Peak Producer Cost Forecast (2004 $/MWh)

	On-Peak[1] Cost Forecast					
	Summer[2]					
Year	***Massachusetts***	***Connecticut***	***Maine***	***New Hampshire***	***Rhode Island***	***Vermont***
2004	$58.90	$63.62	$51.56	$57.71	$58.20	$60.12
2006	$56.82	$61.84	$49.62	$55.58	$55.55	$58.47
2008	$59.29	$64.71	$51.18	$58.35	$56.55	$61.20
2013	$60.66	$65.03	$51.06	$58.95	$61.72	$61.30
2018	$63.03	$64.97	$53.25	$61.71	$64.73	$61.32
2025	$63.41	$65.23	$53.71	$61.87	$65.12	$61.39
2030	$65.24	$66.62	$53.66	$61.68	$66.98	$61.19
2037	$65.24	$66.62	$53.66	$61.68	$66.98	$61.19
Levelized Average[4]	$61.78	$64.83	$52.43	$59.93	$62.42	$60.80
	Winter[3]					
Year	***Massachusetts***	***Connecticut***	***Maine***	***New Hampshire***	***Rhode Island***	***Vermont***
2004	$49.10	$50.30	$50.51	$48.70	$47.49	$49.56
2006	$41.95	$44.09	$43.87	$41.42	$40.69	$42.91
2008	$41.16	$43.05	$43.55	$40.72	$39.37	$42.21
2013	$40.22	$42.09	$42.91	$39.85	$37.93	$41.08
2018	$41.60	$42.94	$44.67	$41.26	$39.13	$41.53
2025	$41.32	$42.17	$44.12	$40.91	$39.17	$40.83
2030	$42.72	$43.32	$45.40	$42.33	$40.61	$41.97
2037	$42.72	$43.32	$45.40	$42.33	$40.61	$41.97
Levelized Average[4]	$42.53	$43.79	$45.00	$42.11	$40.50	$42.60

1. On-peak is defined as Monday through Friday 6am - 10pm, excluding Federal holidays.
2. Summer months are June, July, August and September.
3. Winter months are January, February, March, April, May, October, November and December.
4. Real discount rate of 1.86 percent used to calculate levelized values.

Exhibit 2-42:
ISO-NE Off-Peak Statewide Producer Cost Forecast (2004 $/MWh)

	Off-Peak[1] Cost Forecast					
	Summer[2]					
Year	***Massachusetts***	***Connecticut***	***Maine***	***New Hampshire***	***Rhode Island***	***Vermont***
2004	$49.99	$53.74	$43.38	$49.13	$48.35	$51.27
2006	$47.66	$51.98	$40.33	$46.78	$45.70	$49.42
2008	$48.96	$53.61	$40.79	$48.41	$45.57	$50.96
2013	$49.69	$53.36	$39.78	$48.29	$50.41	$50.65
2018	$51.52	$52.74	$41.72	$50.64	$52.77	$50.12
2025	$50.44	$51.36	$41.22	$49.53	$51.59	$48.99
2030	$52.13	$52.92	$41.95	$51.02	$53.39	$50.13
2037	$52.13	$52.92	$41.95	$51.02	$53.39	$50.13
Levelized Average[4]	$50.20	$52.50	$41.23	$49.23	$50.29	$49.91
	Winter[3]					
Year	***Massachusetts***	***Connecticut***	***Maine***	***New Hampshire***	***Rhode Island***	***Vermont***
2004	$41.88	$42.43	$43.19	$41.61	$39.50	$42.23
2006	$36.83	$38.24	$38.75	$36.58	$34.88	$37.74
2008	$35.09	$36.62	$37.42	$35.00	$33.01	$36.17
2013	$33.15	$34.73	$35.53	$33.05	$30.82	$34.20
2018	$34.30	$35.46	$37.02	$34.26	$31.91	$34.68
2025	$34.37	$35.12	$36.66	$34.30	$32.14	$34.39
2030	$35.44	$36.07	$37.46	$35.35	$33.19	$35.27
2037	$35.44	$36.07	$37.46	$35.35	$33.19	$35.27
Levelized Average[4]	$35.44	$36.48	$37.55	$35.33	$33.22	$35.85

1. Off-peak is defined as Monday through Friday 11pm-5am & all weekend hours, including Federal holidays.
2. Summer months are June, July, August and September.
3. Winter months are January, February, March, April, May, October, November and December.
4. Real discount rate of 1.86 percent used to calculate levelized values.

Exhibits 2-43 and 2-44 present power market costs by pricing zone for peak and off-peak hours.

Exhibit 2-43:
ISO-NE On-Peak Zonal Producer Cost Forecast (2004$/MWh)

	On-Peak[1] Firm Price Forecast							
	Summer[2]							
Year	***SEMA***	***BOST/ NMA***	***WCMA***	***Connecticut***	***Maine***	***New Hampshire***	***Rhode Island***	***Vermont***
2004	$55.48	$59.46	$59.99	$63.62	$51.56	$57.71	$58.20	$60.12
2006	$52.69	$57.62	$58.15	$61.84	$49.62	$55.58	$55.55	$58.47
2008	$53.75	$60.54	$60.92	$64.71	$51.18	$58.35	$56.55	$61.20
2013	$58.01	$61.23	$61.32	$65.03	$51.06	$58.95	$61.72	$61.30
2018	$60.95	$64.15	$62.72	$64.97	$53.25	$61.71	$64.73	$61.32
2025	$61.71	$64.41	$62.85	$65.23	$53.71	$61.87	$65.12	$61.39
2030	$63.62	$66.29	$64.41	$66.62	$53.66	$61.68	$66.98	$61.19
2037	$63.62	$66.29	$64.41	$66.62	$53.66	$61.68	$66.98	$61.19
Levelized Average[4]	$59.17	$62.68	$61.94	$64.83	$52.43	$59.93	$62.42	$60.80
	Winter[3]							
Year	***SEMA***	***BOST/ NMA***	***WCMA***	***Connecticut***	***Maine***	***New Hampshire***	***Rhode Island***	***Vermont***
2004	$48.30	$48.99	$49.86	$50.30	$50.51	$48.70	$47.49	$49.56
2006	$41.60	$41.58	$42.77	$44.09	$43.87	$41.42	$40.69	$42.91
2008	$40.76	$40.80	$41.94	$43.05	$43.55	$40.72	$39.37	$42.21
2013	$40.37	$39.82	$40.78	$42.09	$42.91	$39.85	$37.93	$41.08
2018	$42.04	$41.18	$41.99	$42.94	$44.67	$41.26	$39.13	$41.53
2025	$42.03	$40.92	$41.48	$42.17	$44.12	$40.91	$39.17	$40.83
2030	$43.52	$42.37	$42.78	$43.32	$45.40	$42.33	$40.61	$41.97
2037	$43.52	$42.37	$42.78	$43.32	$45.40	$42.33	$40.61	$41.97
Levelized Average[4]	$42.77	$42.18	$42.93	$43.79	$45.00	$42.11	$40.50	$42.60

1. On-peak is defined as Monday through Friday 6am - 10pm, excluding Federal holidays.
2. Summer months are June, July, August and September.
3. Winter months are January, February, March, April, May, October, November and December.
4. Real discount rate of 1.86 percent used to calculate levelized values.

Exhibit 2-44:
ISO-NE Off-Peak Zonal Producer Cost Forecast (2004 $/MWh)

	Off-Peak[1] Firm Price Forecast							
	Summer[2]							
Year	***SEMA***	***BOST/NMA***	***WCMA***	***Connecticut***	***Maine***	***New Hampshire***	***Rhode Island***	***Vermont***
2004	$46.28	$50.71	$51.09	$53.74	$43.38	$49.13	$48.35	$51.27
2006	$43.32	$48.57	$49.08	$51.98	$40.33	$46.78	$45.70	$49.42
2008	$43.20	$50.34	$50.70	$53.61	$40.79	$48.41	$45.57	$50.96
2013	$46.82	$50.36	$50.49	$53.36	$39.78	$48.29	$50.41	$50.65
2018	$49.25	$52.72	$51.33	$52.74	$41.72	$50.64	$52.77	$50.12
2025	$48.46	$51.53	$50.25	$51.36	$41.22	$49.53	$51.59	$48.99
2030	$50.24	$53.29	$51.75	$52.92	$41.95	$51.02	$53.39	$50.13
2037	$50.24	$53.29	$51.75	$52.92	$41.95	$51.02	$53.39	$50.13
Levelized Average[4]	$47.36	$51.21	$50.59	$52.50	$41.23	$49.23	$50.29	$49.91
	Winter[3]							
Year	***SEMA***	***BOST/NMA***	***WCMA***	***Connecticut***	***Maine***	***New Hampshire***	***Rhode Island***	***Vermont***
2004	$41.37	$41.76	$42.57	$42.43	$43.19	$41.61	$39.50	$42.23
2006	$36.53	$36.49	$37.69	$38.24	$38.75	$36.58	$34.88	$37.74
2008	$34.71	$34.77	$36.03	$36.62	$37.42	$35.00	$33.01	$36.17
2013	$33.29	$32.69	$34.02	$34.73	$35.53	$33.05	$30.82	$34.20
2018	$34.80	$33.86	$34.96	$35.46	$37.02	$34.26	$31.91	$34.68
2025	$35.06	$33.96	$34.83	$35.12	$36.66	$34.30	$32.14	$34.39
2030	$36.24	$35.02	$35.82	$36.07	$37.46	$35.35	$33.19	$35.27
2037	$36.24	$35.02	$35.82	$36.07	$37.46	$35.35	$33.19	$35.27
Levelized Average[4]	$35.72	$35.07	$36.08	$36.48	$37.55	$35.33	$33.22	$35.85

1. Off-peak is defined as Monday through Friday 11pm-5am & all weekend hours, including Federal holidays.
2. Summer months are June, July, August and September.
3. Winter months are January, February, March, April, May, October, November and December.
4. Real discount rate of 1.86 percent used to calculate levelized values.

Further detail on the marginal price and load-weighted forecasts including seasonal valves can be found in the Appendix to this report.

Chapter Three: Retail Power Market Avoided Costs

Retail Avoided Supply Cost Derivation Methodology

To determine the retail market price, the analysis first derives the wholesale production costs within individual zones and states in New England and then considers the additional costs of retail service that could be avoided were energy efficiency programs to result in lowered demand for electricity.

Exhibit 3-1:
Companies with Available Information on Retail Service Costs by State

State	*Company*
Massachusetts	Massachusetts Electric Company Boston Edison Western Massachusetts Electric Company Commonwealth Electric Fitchburg Gas & Electric Light Co. Eastern Edison
Connecticut	No information consistently available
Rhode Island	No information consistently available
New Hampshire	Public Service Company of New Hampshire Granite State Electric Company Exeter & Hampton Concord Electric (NH) Connecticut Valley Electric (NH)
Maine	Central Maine Power Company (ME) Bangor Hydro Electric (ME)

Source: Companies filing FERC Form 1 consistently from 1999 through 2002.

Since complete information on the costs components considered by the individual AESC companies in deriving customer rates was not available, ICF has utilized the FERC Form 1 filings to determine the additional costs of service that may be avoidable. The FERC Form 1 indicates for each utility or their subsidiaries the costs of production and the additional costs of transmission and distribution. Exhibit 3-2 below indicates the line items considered for each of the companies listed in Exhibit 3-1 above. Note, data requested regarding the retail rate derivation and the historical retail market rates was limited and could not be determined.

Exhibit 3-2:
FERC Form 1 Retail Service Expense Line Items

Expense Type	*Line Item*
Transmission Expenses	Operation and Operation Supervision and Engineering Load Dispatching Station Expenses Overhead Lines Expenses Underground Lines Expenses Transmission of Electricity by Others Miscellaneous Transmission Expenses Rents Maintenance Maintenance Supervision and Engineering Maintenance of Structures Maintenance of Station Equipment Maintenance of Overhead Lines Maintenance of Underground Lines Maintenance of Miscellaneous Transmission Plant
Distribution Expenses	Operation and Operation Supervision and Engineering Load Dispatching Station Expenses Overhead Line Expense Underground Line Expenses Street Lighting and Signal System Expenses Meter Expenses Customer Installations Expenses Miscellaneous Expenses Rents Maintenance Maintenance Supervision and Engineering Maintenance of STRUCTURES Maintenance of Station Equipment Maintenance of Overhead Lines Maintenance of Underground Lines Maintenance of Line Transformers Maintenance of Street Lighting and Signal Systems Maintenance of Meters Maintenance of Miscellaneous Distribution Plant
Customer Account Expenses	Operation Supervision Meter Reading Expenses Customer Records and Collection Expenses Uncollectible Accounts Miscellaneous Customer Accounts Expenses
Customer Service and Informational Expenses	Operation Supervision Customer Assistance Expenses Information and Instructional Expenses Miscellaneous Customer Service and Information Expenses
Sales Expenses	Operation Supervision Demonstrating and Selling Expenses Advertising Expenses Miscellaneous Sales Expenses
Administrative and General Expenses	Operation Administrative and General Salaries Office Supplies and Expenses (Less) Administrative Expenses Transferred—Credit

Values were determined based on filings of the FERC Form 1 by the participating utilities from 1999 through 2002. To calculate the adder associated with retail markets, costs were calculated as a percentage of production expenses for the same filing periods. The average difference over all years was used to represent the expected value on a forward basis. No trends were apparent over the time period considered hence costs were assumed to remain flat in real terms on a forward basis.

The values available from the FERC Form 1 filings represent average rather than marginal costs. Dependent on the level of load saved, the full average costs of these components may not be realized by the individual companies purchasing power. This is particularly true for transmission and distribution expenses which include a large portion of fixed or sunk costs. Note that the sunk costs of T&D are recoverable through retail rates seen by consumers but because they are sunk, they are not avoidable unless owned lines are sold.

Exhibit 3-3:
Percentage of Production Costs for Retail Services by Cost Category

State	*Trans-mission*	*Distri-bution*	*Customer Accounts Expense*	*Customer Service Expense*	*Sales Expense*	*Administrative and General Expenses*	*Total*
Rhode Island	8.7%	8.6%	4.5%	5.6%	0.3%	9.5%	37.2%
Connecticut	8.7%	8.6%	4.5%	5.6%	0.3%	9.5%	37.2%
Massachusetts	8.7%	8.6%	4.5%	5.6%	0.3%	9.5%	37.2%
New Hampshire	3.3%	4.4%	1.9%	1.3%	0.0%	7.7%	18.7%
Vermont	3.3%	4.4%	1.9%	1.3%	0.0%	7.7%	18.7%
Maine	10.0%	13.7%	6.0%	4.2%	0.3%	13.1%	47.3%
All New England Average	8.2%	8.6%	4.3%	5.0 %	0.3%	9.6%	35.9%

Since retail costs above the wholesale costs will vary based on the service costs in each area, as such, we have derived the values based on state totals.

Exhibit 3-3 presents the average costs that would be included in the customer rate and final customer payment. Although this set of total costs are recoverable through the retail customer rate and hence avoidable to the consumer, the total set of costs are not necessarily avoidable by the load serving entity. For example, other expenses are considered to be avoidable as marginal expenses only. For example, customer account expenses may not be avoidable as meter readings and collection expenses will still be incurred, however, customer service expense and general expenses may experience partial reductions as energy efficiency programs expand. Sales expenses are minimal. As a conservative measure, we have not included customer account expense in the estimation of avoidable costs. Customer service, sales, and general expenses are included at an 80 percent discount.

Although presented, ICF does not consider T&D expenses as part of this analysis. Rather, individual utilities or agencies involved in this study will incorporate their own estimates of marginal T&D costs. In addition to the retail component, ICF has considered select additional price risks in the wholesale markets for fuel price risk and demand risk as discussed below.

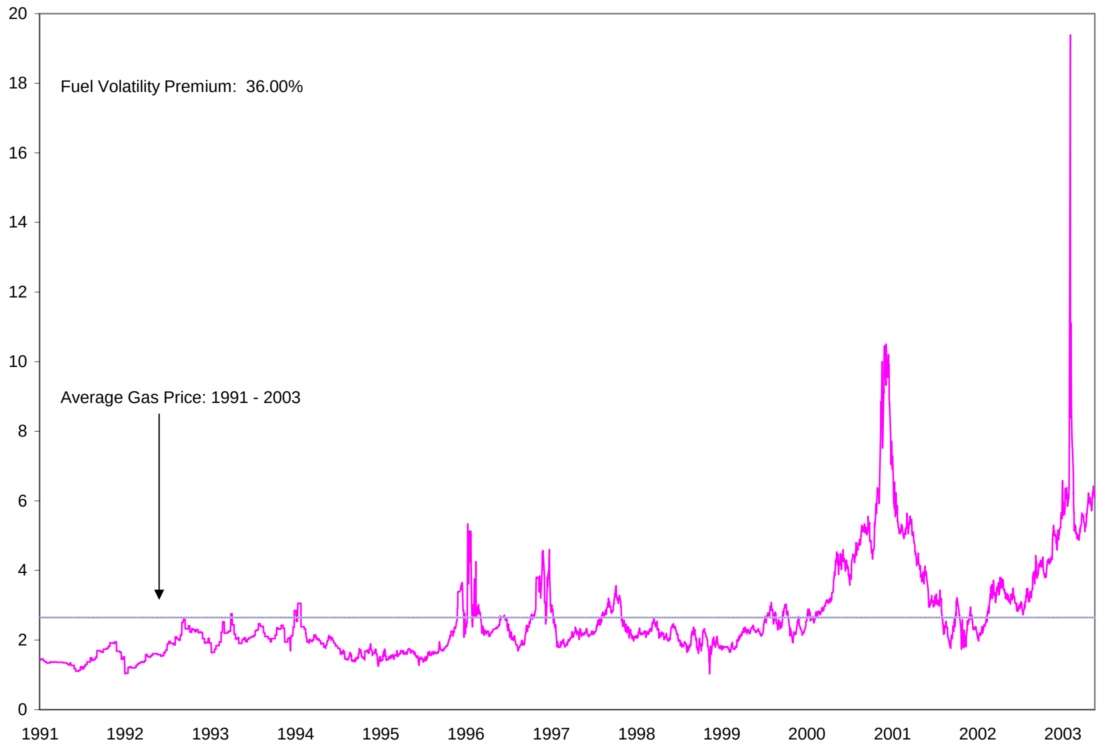
Price Risk Premiums in the Wholesale Market

Wholesale price risk was estimated for each of these parameters based on sensitivity cases to the Base case described in Chapter One. Wholesale market risks are used to adjust the wholesale market prices prior to incorporating the retail component.

Natural Gas Price Volatility

The forecasts above are based on expected market conditions under normal operating conditions. ICF has considered the additional potential for price fluctuations based on risks such as those in the fuel purchase price and on demand side risk associated with capacity shortages or extreme weather conditions.

Exhibit 3-4:
Historical Natural Gas Prices and Volatility (2004 $/MMBtu)

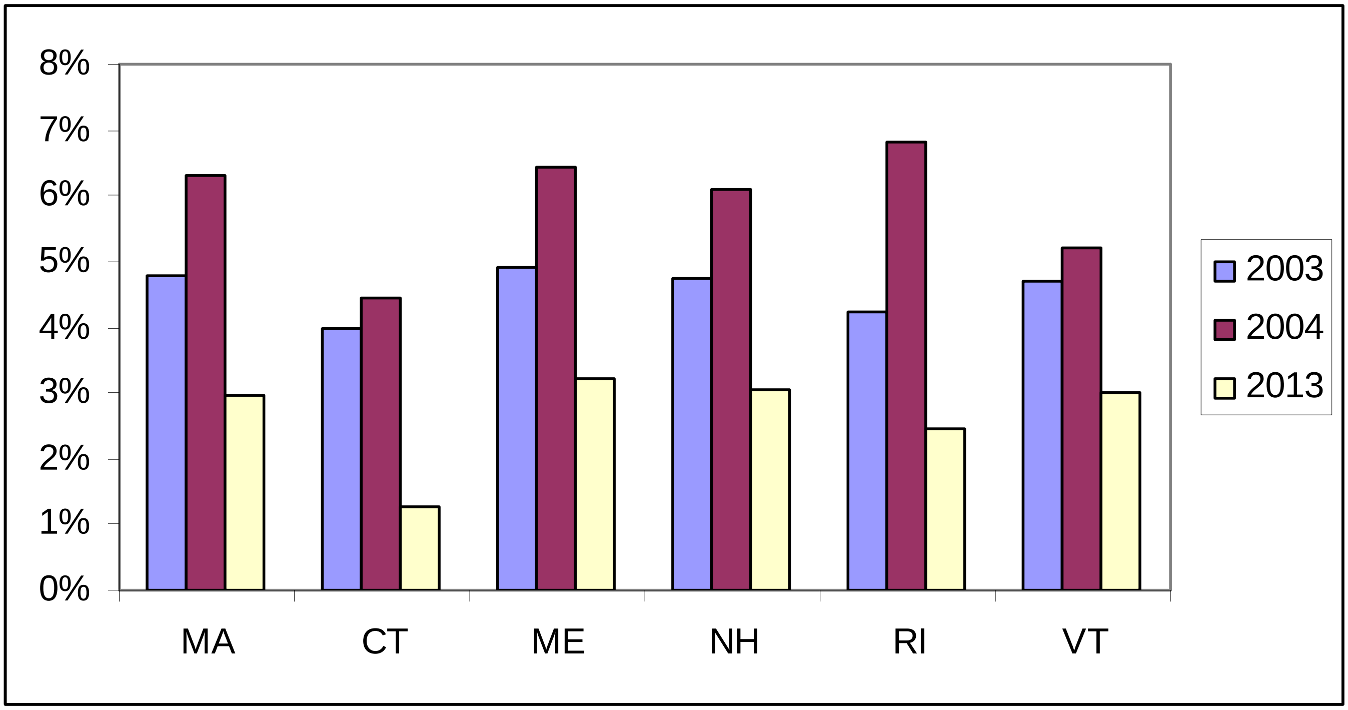


Since 1991, the average volatility in natural gas prices had been 36 percent. The volatility is calculated as the average of the change in daily gas prices over the period 1991 – 2003. The most significant changes in price have occurred in recent years under the combined effects of dramatic increase in natural gas demand from the electricity sector, extreme winter conditions, gas storage shortages, and artificial pressures keeping oil prices high.

ICF has utilized the long-term volatility to determine the sensitivity of wholesale market prices in New England to the potential fluctuations in gas price. ICF considers the long-term volatility to determine the risk associated with wholesale market prices as this study considers the long-term power markets. We believe this is reasonable representation of the fuel price volatility. Near-term fuel market prices already incorporate the high prices in the natural gas markets – expectations are for forward gas prices to decrease rather than increase. Indeed, increases in the already high prices are less likely given the already high price levels.

Exhibits 3-5 and 3-6 present expected changes in the wholesale market price. The analysis considers the impact of an unexpected change in natural gas prices equivalent to the natural gas price volatility presented above. Note that the expected changes are dependent on the level of the initial gas prices. That is, at higher gas prices, the wholesale power prices experience a greater percentage change than they would for the same percentage increase in a lower gas price starting point. Another way to say this is to say that the wholesale market price gas price relationship is more elastic at higher gas prices than it is at lower gas prices. This effect exists due to the potential for substitution to other resources at lower gas price or the presence of other resources in the marginal supply mix, however, at higher gas prices, gas dominates the value of the marginal energy price in significant hours. Hence, the average annual wholesale market price is more sensitive to gas prices when they are high.

Exhibit 3-5:
Percentage Difference Between Base Case Wholesale Market Price and High Gas Price Scenario



Overall, we have estimated that wholesale power prices may vary by about a five (5) percent under the average change in gas prices.

Exhibit 3-6:
Wholesale Market Place Price to Gas Price Volatility – Expected Percent Change under High Annual Gas Conditions

	Wholesale Energy Price Percent Change			*Wholesale Capacity Price Percent Change*			*Wholesale Power Price Percent Change*			*Expected Wholesale Power Price Percent Change*
	2003	*2004*	*2013*	*2003*	*2004*	*2013*	*2003*	*2004*	*2013*	
CT	3%	5%	2%	8%	3%	-1%	4%	4%	1%	5%
MA	5%	6%	4%	8%	6%	-1%	5%	6%	3%	
ME	5%	7%	4%	0%	3%	-1%	5%	6%	3%	
NH	5%	6%	4%	0%	3%	-1%	5%	6%	3%	
RI	4%	6%	3%	0%	21%	-1%	4%	7%	2%	
VT	4%	6%	4%	8%	3%	-1%	5%	5%	3%	

Volatility Due to Demand

ICF also considered the risk associated unexpected with higher demand levels or shortages in capacity. Values represent the typical change expected in the long-term rather than the average for any single point in time.

Exhibit 3-7:
Expected Change in Price Under Alternate Demand Conditions

	Wholesale Energy Price% Change	*Wholesale Capacity Price% Change*	*Wholesale Power Price% Change*	*Expected Wholesale Power Price% Change*
CT	0%	32%	5%	5%
MA	0%	33%	4%	5%
ME	0%	29%	4%	5%
NH	0%	29%	4%	5%
RI	0%	51%	5%	5%
VT	0%	32%	5%	5%

Both the fuel and demand premium are considered additive to the expected wholesale price to determine expected savings in the production costs.

Exhibit 3-8:
Summary of Retail Multiple by State

	Massachusetts / Rhode Island / Connecticut	*New Hampshire / Vermont*	*Maine*	*New England*
Fuel Risk Premium	5.00%	5.00%	5.00%	5.00%
Scarcity/Demand Risk Premium[1]	4.64%	4.64%	4.64%	4.64%
Transmission	8.73%	3.34%	9.99%	8.21%
Distribution	8.63%	4.44%	13.65%	8.58%
Customer Accounts[2]	4.47%	1.89%	6.00%	4.30%
Customer Service and informational expenses[3]	5.59%	1.28%	4.22%	4.96%
Sales Expenses[3]	0.28%	0.04%	0.28%	0.25%
Administrative and Total Expenses[3]	9.51%	7.72%	13.13%	9.62%
Total	**1.23**	**1.18**	**1.25**	**1.23**
Total Including Transmission & Distribution	**1.42**	**1.26**	**1.51**	**1.41**

Notes: Fuel Price Risk Premium is determined through analysis of sensitivity of the wholesale market prices to an increase in near-term gas prices.
1. Scarcity/Demand Risk Premium is measures as the impact in a single year of 3% higher peak demand requirements. Note, this scarcity premium does not account for additional risks that may be associated with transmission congestion within New England.
2. Excluded from avoided cost calculation
3. Included at 80% of value to capture marginal value.

The multiple presented in Exhibit 3-8 when applied to the load weighted wholesale producer cost (consumer purchase) price captures the expected avoided costs for programs designed to conserve consumption of electricity. Note, certain energy efficiency or demand-side management programs may not follow typical load patterns directly – to capture the costs of such programs, the retail multiple should be applied to the marginal wholesale power prices (marginal price includes energy and capacity) as in the appendix to this study.

Summary of New England Retail Avoided Electricity Cost Forecasts

Exhibit 3-9:
Summary of New England State Retail Avoided Electricity Cost Forecast (2004 $/MWh)

Year	All-Hour Average Price						
	Massachusetts	*Connecticut*	*Maine*	*New Hampshire*	*Rhode Island*	*Vermont*	*New England*
2003	$61.82	$63.75	$60.75	$58.10	$60.66	$59.14	$61.78
2004	$63.82	$67.23	$62.28	$60.42	$60.59	$62.58	$64.07
2006	$58.67	$63.19	$57.17	$55.48	$55.36	$58.42	$59.28
2008	$59.08	$63.84	$57.44	$56.22	$54.41	$59.16	$59.67
2013	$59.37	$63.47	$56.53	$55.96	$56.97	$58.64	$59.78
2018	$61.74	$63.70	$59.01	$58.62	$59.58	$58.63	$61.50
2025	$61.23	$62.74	$58.19	$58.02	$59.31	$57.75	$60.82
2030	$63.08	$64.28	$59.31	$59.57	$60.86	$58.42	$62.43
2037	$63.08	$64.28	$59.31	$59.57	$60.86	$58.42	$62.43
Levelized Average[2]	$61.30	$63.94	$58.54	$58.00	$58.72	$58.88	$61.24

[1]Firm Price = Sum of Energy Price and Capacity Price at 100% load factor.
[2]Assumes 1.86 percent real discount rate.
Source**:** IPM® modeling results except as noted.

Exhibit 3-10:
Summary of New England Zonal Retail Avoided Electricity Cost (2004 $/MWh)

Year	All-Hour Average Price								
	SEMA	*BOST/N MA*	*WCMA*	*Connec ticut*	*Maine*	*New Hamp-shire*	*Rhode Island*	*Vermont*	*New England*
2003	$61.14	$61.63	$60.66	$63.75	$60.75	$58.10	$60.66	$59.14	$61.78
2004	$60.85	$63.97	$60.59	$67.23	$62.28	$60.42	$60.59	$62.58	$64.07
2006	$55.42	$58.70	$55.36	$63.19	$57.17	$55.48	$55.36	$58.42	$59.28
2008	$54.70	$59.41	$54.41	$63.84	$57.44	$56.22	$54.41	$59.16	$59.67
2013	$57.59	$59.08	$56.97	$63.47	$56.53	$55.96	$56.97	$58.64	$59.78
2018	$60.57	$61.82	$59.58	$63.70	$59.01	$58.62	$59.58	$58.63	$61.50
2025	$60.42	$61.33	$59.31	$62.74	$58.19	$58.02	$59.31	$57.75	$60.82
2030	$62.07	$63.56	$60.86	$64.28	$59.31	$59.57	$60.86	$58.42	$62.43
2037	$62.07	$63.56	$60.86	$64.28	$59.31	$59.57	$60.86	$58.42	$62.43
Levelized Average[2]	$59.50	$61.43	$58.72	$63.94	$58.54	$58.00	$58.72	$58.88	$61.24

[1]Firm Price = Sum of Energy Price and Capacity Price at 100% load factor.
[2]Assumes 1.86 percent real discount rate.
Source**:** IPM® modeling results except as noted.

Exhibit 3-11:
ISO-NE Statewide On-Peak Retail Electric Avoided Cost Forecast (2004 $/MWh)

	On-Peak[1] Forecast					
	Summer[2]					
Year	***Massachusetts***	***Connecticut***	***Maine***	***New Hampshire***	***Rhode Island***	***Vermont***
2004	$72.53	$78.34	$64.50	$67.85	$71.66	$70.68
2006	$69.96	$76.15	$62.08	$65.34	$68.40	$68.74
2008	$73.01	$79.68	$64.03	$68.60	$69.63	$71.95
2013	$74.69	$80.07	$63.88	$69.31	$76.00	$72.07
2018	$77.61	$80.00	$66.62	$72.55	$79.70	$72.09
2025	$78.08	$80.32	$67.19	$72.74	$80.18	$72.18
2030	$80.33	$82.03	$67.13	$72.52	$82.47	$71.94
2037	$80.33	$82.03	$67.13	$72.52	$82.47	$71.94
Levelized Average[4]	$76.07	$79.83	$65.59	$70.46	$76.86	$71.48
	Winter[3]					
Year	***Massachusetts***	***Connecticut***	***Maine***	***New Hampshire***	***Rhode Island***	***Vermont***
2004	$60.46	$61.94	$63.19	$57.26	$58.48	$58.27
2006	$51.65	$54.29	$54.88	$48.70	$50.10	$50.45
2008	$50.68	$53.01	$54.48	$47.87	$48.48	$49.63
2013	$49.52	$51.83	$53.68	$46.85	$46.70	$48.30
2018	$51.22	$52.87	$55.88	$48.51	$48.18	$48.83
2025	$50.88	$51.92	$55.20	$48.10	$48.23	$48.00
2030	$52.60	$53.34	$56.80	$49.77	$50.00	$49.34
2037	$52.60	$53.34	$56.80	$49.77	$50.00	$49.34
Levelized Average[4]	$52.37	$53.92	$56.30	$49.51	$49.87	$50.08

1. On-peak is defined as Monday through Friday 6am - 10pm, excluding Federal holidays.
2. Summer months are June, July, August and September.
3. Winter months are January, February, March, April, May, October, November and December.
4. Real discount rate of 1.86 percent used to calculate levelized values.

Exhibit 3-12.
ISO-NE Off-Peak Statewide Retail Avoided Electricity Cost Forecast (2004 $/MWh)

	Off-Peak[1] Forecast					
	Summer[2]					
Year	***Massachusetts***	***Connecticut***	***Maine***	***New Hampshire***	***Rhode Island***	***Vermont***
2004	$61.55	$66.17	$54.27	$57.76	$59.53	$60.28
2006	$58.68	$64.00	$50.45	$55.00	$56.27	$58.10
2008	$60.29	$66.01	$51.03	$56.91	$56.11	$59.91
2013	$61.18	$65.70	$49.77	$56.77	$62.07	$59.55
2018	$63.44	$64.94	$52.19	$59.54	$64.98	$58.93
2025	$62.11	$63.24	$51.57	$58.23	$63.52	$57.60
2030	$64.19	$65.16	$52.48	$59.98	$65.74	$58.94
2037	$64.19	$65.16	$52.48	$59.98	$65.74	$58.94
Levelized Average[4]	$61.81	$64.64	$51.58	$57.88	$61.92	$58.68
	Winter[3]					
Year	***Massachusetts***	***Connecticut***	***Maine***	***New Hampshire***	***Rhode Island***	***Vermont***
2004	$51.57	$52.25	$54.03	$48.92	$48.64	$49.65
2006	$45.35	$47.09	$48.48	$43.01	$42.95	$44.37
2008	$43.21	$45.09	$46.81	$41.15	$40.65	$42.52
2013	$40.82	$42.76	$44.45	$38.86	$37.95	$40.21
2018	$42.23	$43.66	$46.31	$40.28	$39.29	$40.77
2025	$42.32	$43.24	$45.86	$40.33	$39.57	$40.43
2030	$43.64	$44.41	$46.86	$41.56	$40.87	$41.47
2037	$43.64	$44.41	$46.86	$41.56	$40.87	$41.47
Levelized Average[4]	$43.64	$44.92	$46.98	$41.54	$40.90	$42.15

1. Off-peak is defined as Monday through Friday 11pm-5am & all weekend hours, including Federal holidays.
2. Summer months are June, July, August and September.
3. Winter months are January, February, March, April, May, October, November and December.
4. Real discount rate of 1.86 percent used to calculate levelized values.

Exhibit 3-13:
ISO-NE On-Peak Zonal Retail Avoided Electricity Costs (2004 $/MWh)

	On-Peak[1] Forecast							
	Summer[2]							
Year	***SEMA***	***BOST / NMA***	***WCMA***	***Connecticut***	***Maine***	***New Hampshire***	***Rhode Island***	***Vermont***
2004	$68.31	$73.21	$73.87	$78.34	$64.50	$67.85	$71.66	$70.68
2006	$64.88	$70.95	$71.60	$76.15	$62.08	$65.34	$68.40	$68.74
2008	$66.18	$74.54	$75.01	$79.68	$64.03	$68.60	$69.63	$71.95
2013	$71.43	$75.39	$75.50	$80.07	$63.88	$69.31	$76.00	$72.07
2018	$75.05	$78.99	$77.23	$80.00	$66.62	$72.55	$79.70	$72.09
2025	$75.99	$79.31	$77.39	$80.32	$67.19	$72.74	$80.18	$72.18
2030	$78.34	$81.62	$79.31	$82.03	$67.13	$72.52	$82.47	$71.94
2037	$78.34	$81.62	$79.31	$82.03	$67.13	$72.52	$82.47	$71.94
Levelized Average[4]	$72.86	$77.18	$76.27	$79.83	$65.59	$70.46	$76.86	$71.48
	Winter[3]							
Year	***SEMA***	***BOST/NMA***	***WCMA***	***Connecticut***	***Maine***	***New Hampshire***	***Rhode Island***	***Vermont***
2004	$59.47	$60.32	$61.39	$61.94	$63.19	$57.26	$58.48	$58.27
2006	$51.22	$51.20	$52.66	$54.29	$54.88	$48.70	$50.10	$50.45
2008	$50.19	$50.24	$51.64	$53.01	$54.48	$47.87	$48.48	$49.63
2013	$49.71	$49.03	$50.21	$51.83	$53.68	$46.85	$46.70	$48.30
2018	$51.76	$50.71	$51.70	$52.87	$55.88	$48.51	$48.18	$48.83
2025	$51.75	$50.39	$51.08	$51.92	$55.20	$48.10	$48.23	$48.00
2030	$53.59	$52.17	$52.68	$53.34	$56.80	$49.77	$50.00	$49.34
2037	$53.59	$52.17	$52.68	$53.34	$56.80	$49.77	$50.00	$49.34
Levelized Average[4]	$52.66	$51.94	$52.86	$53.92	$56.30	$49.51	$49.87	$50.08

1. On-peak is defined as Monday through Friday 6am - 10pm, excluding Federal holidays.
2. Summer months are June, July, August and September.
3. Winter months are January, February, March, April, May, October, November and December.
4. Real discount rate of 1.86 percent used to calculate levelized values.

Exhibit 3-14:
ISO-NE Off-Peak Zonal Retail Avoided Electricity Costs (2004 $/MWh)

	Off-Peak[1] Forecast							
	Summer[2]							
Year	***SEMA***	***BOST/NMA***	***WCMA***	***Connecticut***	***Maine***	***New Hampshire***	***Rhode Island***	***Vermont***
2004	$56.99	$62.44	$62.91	$66.17	$54.27	$57.76	$59.53	$60.28
2006	$53.34	$59.81	$60.43	$64.00	$50.45	$55.00	$56.27	$58.10
2008	$53.19	$61.98	$62.43	$66.01	$51.03	$56.91	$56.11	$59.91
2013	$57.65	$62.01	$62.17	$65.70	$49.77	$56.77	$62.07	$59.55
2018	$60.64	$64.92	$63.20	$64.94	$52.19	$59.54	$64.98	$58.93
2025	$59.67	$63.45	$61.87	$63.24	$51.57	$58.23	$63.52	$57.60
2030	$61.86	$65.62	$63.72	$65.16	$52.48	$59.98	$65.74	$58.94
2037	$61.86	$65.62	$63.72	$65.16	$52.48	$59.98	$65.74	$58.94
Levelized Average[4]	$58.32	$63.06	$62.29	$64.64	$51.58	$57.88	$61.92	$58.68
	Winter[3]							
Year	***SEMA***	***BOST/NMA***	***WCMA***	***Connecticut***	***Maine***	***New Hampshire***	***Rhode Island***	***Vermont***
2004	$50.94	$51.42	$52.42	$52.25	$54.03	$48.92	$48.64	$49.65
2006	$44.98	$44.93	$46.41	$47.09	$48.48	$43.01	$42.95	$44.37
2008	$42.74	$42.81	$44.36	$45.09	$46.81	$41.15	$40.65	$42.52
2013	$40.99	$40.25	$41.89	$42.76	$44.45	$38.86	$37.95	$40.21
2018	$42.85	$41.69	$43.05	$43.66	$46.31	$40.28	$39.29	$40.77
2025	$43.17	$41.82	$42.89	$43.24	$45.86	$40.33	$39.57	$40.43
2030	$44.62	$43.12	$44.11	$44.41	$46.86	$41.56	$40.87	$41.47
2037	$44.62	$43.12	$44.11	$44.41	$46.86	$41.56	$40.87	$41.47
Levelized Average[4]	$43.98	$43.18	$44.43	$44.92	$46.98	$41.54	$40.90	$42.15

1. Off-peak is defined as Monday through Friday 11pm-5am & all weekend hours, including Federal holidays.
2. Summer months are June, July, August and September.
3. Winter months are January, February, March, April, May, October, November and December.
4. Real discount rate of 1.86 percent used to calculate levelized values.

Comparison of Results to Previous Analysis

Exhibit 3-15:
Summary of Projected New England Wholesale Forecast Power Prices ($/MWH)

Year	*Current Analysis Results*		*2001 Study Results*[2]	
	2004$	**Nominal$**[1]	**2004 $**	**Nominal**
2003	$47.24	$46.09	$36.32	$35.44
2004	$48.91	$48.91	$36.32	$36.32
2005	$46.88	$48.06	$36.87	$37.79
2006	$44.86	$47.13	$37.08	$38.96
2007	$44.67	$48.10	$37.63	$40.52
2008	$44.47	$49.09	$38.72	$42.73
2009	$44.34	$50.16	$39.69	$44.91
2010	$44.21	$51.27	$41.00	$47.55
2011	$44.09	$52.41	$40.67	$48.35
2012	$43.99	$53.59	$41.33	$50.35

1. Inflation rate of 2.5 percent used to determine nominal dollars.
2. Analysis prepared for previous Avoided Cost Study.

For the current analysis, forecasts for wholesale market power prices are derived from the IPM® fundamentals based production cost forecasting model. Energy and capacity market prices were simultaneously optimized over the entire time frame of the study using the IPM® model. Although the previous analysis had considered a production cost methodology to derive energy prices, capacity additions and the required market price premium to add capacity to the market were not directly considered in the modeling framework. This improvement in modeling approach tends to better capture long-term trends. Off-line estimates generally lead to overestimates of capacity value over production costs values since energy earnings from the addition of new units cannot be projected, nor can the adequate mix of new resources to the generation supply. For example, a low cost peaking unit may adequately supply the market, however, if cost estimates are based on baseload combined cycle units, they will overestimate supply prices. Differences in long-term projections are largely based on the change in methodology to simultaneously consider the energy and capacity markets over the entire time period. This difference is highlighted in long-term forecasts where downward price pressures are captured in the current analysis but not in the previous work. Note, the IPM® model has been used by ICF to project turning points in the market place resulting in both increased and depressed market prices. These forecasts are publicly documented.

Further enhancements in the modeling approach include the ability to capture the impact of retirements and mothballing to the resource base in New England. This effect is quite strong in the near and mid-term markets as the New England suppliers are considering options to reduce operating costs. Note, several New England facilities are currently petitioning to be allowed to mothball. This market turnaround is directly reflected in our modeling results. This largely affects the near- and mid-term markets when units may be mothballed and returned to service when demand increases sufficiently.

Other key differences are based on fundamental differences in assumptions between the analyses. The four major differences are i) assumptions regarding new capacity additions,

ii) gas prices, iii) cost and characteristics of new capacity, and iv) internal transmission constraints.

- ICF's forecasts consider the latest available market information on new capacity additions and thus include a larger resource base in the supply mix.
- Gas prices reflect the current market levels in the near-term, which are significantly higher than projections used in the previous analysis.
- Costs of new capacity are considered only for combined cycle in the prior analysis, are not compared to the potential for energy earnings, and technological improvements are not considered to occur over time (i.e., costs are assumed to be flat). The current analysis reflects all of these items.
- The current analysis considers internal transfer constraints in New England and the resulting price differentiation by zone. The prior analysis reflects an unconstrained internal market place.

Exhibit 3-16:
Comparison of Retail Adder/Multiple

Zones	***Current Analysis Results***	***Previous Analysis Results***
	Retail Multiple Value	**Retail Adder Value**
Massachusetts	1.42	-
Connecticut	1.42	-
Rhode Island	1.42	-
New Hampshire	1.26	-
Vermont	1.26	-
Maine	1.51	-
New England	1.41	1.20

Note: Transmission and Distribution are included in the current value in order to directly compare to the prior analysis.

Both the current and previous analyses consider the additional costs related to serving the retail customers as multiples to the wholesale market price. The current analysis further reflects sub-regional differentiation in costs that were not captured in the previous results. Further, the previous analysis relied on a limited number of bid prices for select areas to represent the entire market. For the current analysis, operating costs were determined sub-regionally through review of the realized historical costs of retail services.

Exhibit 3-17:
Summary of Projected New England Avoided Power Costs for Retail Service ($/MWH)

Year	*Current Analysis Results*		*2001 Study Results*[2]	
	2004$	**Nominal$**[1]	**2004 $**	**Nominal**
2003	$61.78	$60.27	$50.18	$49.68
2004	$64.07	$64.07	$50.47	$51.23
2005	$61.68	$63.22	$53.11	$55.26
2006	$59.28	$62.28	$55.23	$58.90
2007	$59.47	$64.05	$57.74	$63.10
2008	$59.67	$65.86	$59.06	$66.17
2009	$59.69	$67.54	$60.50	$69.47
2010	$59.71	$69.25	$62.27	$73.29
2011	$59.74	$71.01	N/A	N/A
2012	$59.76	$72.81	N/A	N/A

1. Inflation rate of 2.5 percent used to determine nominal dollars.
2. Analysis prepared for previous Avoided Cost Study.

Near-term retail avoided costs are expected to be higher than the previous study had indicated, however, the rate of increase over time is expected to be slower such that long-term avoided costs are slightly below those previously anticipated.

Chapter Four: Avoided Gas Costs

This chapter summarizes avoided gas costs. First we present the estimate of avoided gas costs for local distribution companies (LDCs) and our methodology used to make this estimate. We then compare this with the previous avoided cost study. Finally we show the potential avoided costs for LDC customers. In the Appendices are found additional supporting calculations of avoided costs.

Summary of Avoided Gas Costs

The avoided gas costs of a LDC consist of the cost of the gas itself as well as the non-gas costs of transportation, storage and peak shaving. In this section of the report, we present our estimate of the avoided gas costs for local distribution companies in New England through 2025.

Consistent with previous analyses, avoided gas costs are presented in three basic types: peak period, off peak period, and base load. Peak period corresponds with winter heating load demand represented as four winter types corresponding to the length of the heating season: 3, 5, 6, and 7 months. Off peak is the residual non-peak period corresponding to each of the winter definitions. Base load is the full 12-month period. Below, we present a summary of our estimated avoided costs separately for Northern and Central New England (Massachusetts, Vermont, New Hampshire, Maine) and Southern New England (Connecticut and Rhode Island). In the following sections, we provide a description of our gas price forecast and separately, our treatment of non-gas costs (transportation, storage, LNG service). We then show how we construct the avoided cost estimates for the winter types and for heating (new building and old building) and hot water heating.

Exhibit 4-1:
Seasonal Wholesale Avoided Gas Costs Southern New England (2004$/MMBtu)

Year	*Annual Avg.*	*3 Month Winter*	*9 Month Summer*	*5 Month Winter*	*7 Month Summer*	*7 Month Winter*	*5 Month Summer*	*6 Month Winter*	*6 Month Summer*	*Heat Retrofit*	*New Heat*	*Water Heat*
2003	$7.19	$9.04	$6.29	$8.64	$6.15	$8.41	$6.00	$8.09	$5.94	$8.09	$8.64	$7.19
2004	$6.43	$8.18	$5.56	$7.81	$5.44	$7.58	$5.31	$7.27	$5.25	$7.27	$7.81	$6.43
2005	$5.95	$7.63	$5.10	$7.28	$4.99	$7.05	$4.87	$6.76	$4.82	$6.76	$7.28	$5.95
2006	$5.39	$6.99	$4.57	$6.66	$4.47	$6.44	$4.36	$6.16	$4.31	$6.16	$6.66	$5.39
2007	$5.20	$6.78	$4.39	$6.46	$4.30	$6.23	$4.19	$5.96	$4.14	$5.96	$6.46	$5.20
2008	$5.05	$6.60	$4.24	$6.29	$4.15	$6.06	$4.05	$5.79	$4.01	$5.79	$6.29	$5.05
2009	$4.86	$6.39	$4.06	$6.08	$3.97	$5.86	$3.88	$5.59	$3.84	$5.59	$6.08	$4.86
2010	$5.04	$6.59	$4.23	$6.28	$4.14	$6.05	$4.04	$5.78	$4.00	$5.78	$6.28	$5.04
2011	$4.46	$5.93	$3.68	$5.64	$3.60	$5.42	$3.51	$5.16	$3.47	$5.16	$5.64	$4.46
2012	$4.53	$6.01	$3.74	$5.72	$3.66	$5.49	$3.57	$5.23	$3.54	$5.23	$5.72	$4.53
2013	$4.63	$6.13	$3.85	$5.84	$3.76	$5.61	$3.67	$5.35	$3.63	$5.35	$5.84	$4.63
2014	$4.75	$6.27	$3.96	$5.97	$3.87	$5.74	$3.78	$5.47	$3.74	$5.47	$5.97	$4.75
2015	$4.68	$6.19	$3.89	$5.89	$3.81	$5.66	$3.71	$5.40	$3.68	$5.40	$5.89	$4.68
2016	$4.85	$6.37	$4.05	$6.07	$3.96	$5.84	$3.86	$5.58	$3.82	$5.58	$6.07	$4.85
2017	$4.86	$6.39	$4.06	$6.08	$3.97	$5.86	$3.88	$5.59	$3.84	$5.59	$6.08	$4.86
2018	$5.02	$6.58	$4.22	$6.26	$4.13	$6.04	$4.03	$5.77	$3.98	$5.77	$6.26	$5.02
2019	$4.97	$6.51	$4.16	$6.20	$4.07	$5.97	$3.97	$5.70	$3.93	$5.70	$6.20	$4.97
2020	$4.84	$6.36	$4.04	$6.06	$3.95	$5.83	$3.85	$5.56	$3.81	$5.56	$6.06	$4.84
2021	$4.78	$6.29	$3.98	$5.99	$3.90	$5.77	$3.80	$5.50	$3.76	$5.50	$5.99	$4.78
2022	$4.79	$6.31	$3.99	$6.01	$3.91	$5.78	$3.81	$5.51	$3.77	$5.51	$6.01	$4.79
2023	$5.02	$6.58	$4.22	$6.26	$4.13	$6.04	$4.03	$5.77	$3.98	$5.77	$6.26	$5.02
2024	$5.42	$7.02	$4.59	$6.69	$4.49	$6.46	$4.38	$6.19	$4.34	$6.19	$6.69	$5.42
2025	$5.43	$7.04	$4.60	$6.71	$4.51	$6.48	$4.39	$6.20	$4.35	$6.20	$6.71	$5.43

Exhibit 4-2:
Seasonal Wholesale Avoided Costs Northern and Central New England (2004 $/MMBtu)

Year	*Annual Avg.*	*3 Month Winter*	*9 Month Summer*	*5 Month Winter*	*7 Month Summer*	*7 Month Winter*	*5 Month Summer*	*6 Month Winter*	*6 Month Summer*	*Heat Retrofit*	*New Heat*	*Water Heat*
2003	$7.03	$8.77	$6.23	$8.34	$6.10	$8.14	$5.95	$7.85	$5.89	$7.85	$8.34	$7.03
2004	$6.28	$7.92	$5.52	$7.52	$5.41	$7.32	$5.27	$7.05	$5.22	$7.05	$7.52	$6.28
2005	$5.81	$7.37	$5.07	$7.00	$4.96	$6.80	$4.84	$6.54	$4.79	$6.54	$7.00	$5.81
2006	$5.26	$6.75	$4.54	$6.40	$4.45	$6.20	$4.34	$5.95	$4.30	$5.95	$6.40	$5.26
2007	$5.07	$6.54	$4.37	$6.20	$4.28	$6.00	$4.17	$5.75	$4.13	$5.75	$6.20	$5.07
2008	$4.92	$6.37	$4.22	$6.03	$4.13	$5.83	$4.03	$5.59	$3.99	$5.59	$6.03	$4.92
2009	$4.74	$6.15	$4.04	$5.83	$3.96	$5.63	$3.86	$5.39	$3.83	$5.39	$5.83	$4.74
2010	$4.91	$6.35	$4.21	$6.02	$4.12	$5.82	$4.02	$5.58	$3.98	$5.58	$6.02	$4.91
2011	$4.34	$5.70	$3.66	$5.39	$3.59	$5.20	$3.50	$4.96	$3.47	$4.96	$5.39	$4.34
2012	$4.41	$5.78	$3.73	$5.47	$3.65	$5.27	$3.57	$5.04	$3.53	$5.04	$5.47	$4.41
2013	$4.51	$5.90	$3.83	$5.58	$3.75	$5.39	$3.66	$5.15	$3.63	$5.15	$5.58	$4.51
2014	$4.63	$6.03	$3.94	$5.71	$3.86	$5.52	$3.77	$5.28	$3.73	$5.28	$5.71	$4.63
2015	$4.56	$5.95	$3.88	$5.63	$3.80	$5.44	$3.70	$5.20	$3.67	$5.20	$5.63	$4.56
2016	$4.72	$6.14	$4.03	$5.81	$3.95	$5.62	$3.85	$5.38	$3.81	$5.38	$5.81	$4.72
2017	$4.74	$6.15	$4.04	$5.83	$3.96	$5.63	$3.86	$5.39	$3.83	$5.39	$5.83	$4.74
2018	$4.90	$6.34	$4.20	$6.00	$4.11	$5.81	$4.01	$5.56	$3.97	$5.56	$6.00	$4.90
2019	$4.84	$6.27	$4.14	$5.94	$4.06	$5.74	$3.96	$5.50	$3.92	$5.50	$5.94	$4.84
2020	$4.71	$6.13	$4.02	$5.80	$3.94	$5.60	$3.84	$5.36	$3.80	$5.36	$5.80	$4.71
2021	$4.65	$6.06	$3.97	$5.74	$3.88	$5.54	$3.79	$5.30	$3.75	$5.30	$5.74	$4.65
2022	$4.67	$6.07	$3.98	$5.75	$3.89	$5.55	$3.80	$5.31	$3.76	$5.31	$5.75	$4.67
2023	$4.90	$6.34	$4.20	$6.00	$4.11	$5.81	$4.01	$5.56	$3.97	$5.56	$6.00	$4.90
2024	$5.28	$6.78	$4.57	$6.43	$4.47	$6.23	$4.36	$5.98	$4.32	$5.98	$6.43	$5.28
2025	$5.30	$6.79	$4.58	$6.44	$4.48	$6.24	$4.37	$5.99	$4.33	$5.99	$6.44	$5.30

Overview of New England Gas Market

From a national perspective, New England is a relatively small gas market due largely to the fact that it has been at the end of the pipeline network. Gas costs are high and gas competes with distillate and residual fuel oil in the key heating market. Between 1990 and 2000, New England experienced a substantial growth in natural gas infrastructure, including three new pipelines from Canada. New England added more than 200,000 new natural gas customers in the 1990s and consumption has risen steadily (NEGA, 2002). In the past decade, Massachusetts accounted for 58% of New England's gas consumption and Connecticut about 22%. During the same period, Maine has been the least developed gas market accounting for only one% of consumption (EIA, 2002).

Exhibit 4-3 below presents annual New England natural gas consumption by sector for 1990 through 2000 and the forecasted data for 2000 through 2020 obtained from the EIA. Total natural gas consumption over the past decade in New England grew about 40%

between 1990 and 2000. (Gas consumption between 1997 and 2000 declined due to warmer than normal weather.) Natural gas consumption used in non-utility generation is not included in the Electric Utility sector but is included in the Industrial sector for 1990 through 2000 data. It is included under the Electric Utility sector between 2000 and 2020. A substantial growth of about 60% is going to occur in this sector as evidenced by the Electric Utility sector data between 2000 and 2020.

The large increase between 2000 and 2005 in total natural gas consumption reflects EIA's belief that gas demand will grow sharply in the industrial and electric generating sectors. Sectoral growth patterns are discussed in the following subsections.

Exhibit 4-3.
Natural Gas Consumption by Sector in New England (Bcf)

Sector	***1990***	***1995***	***2000***	***2005***	***2010***	***2015***	***2020***
Residential	170.7	173.7	185.4	186.7	187.4	193.0	200.4
Commercial	96.9	143.8	139.1	127.6	135.4	145.8	158.5
Industrial	81.3*	184.7*	244.2*	248.4	262.1	274.6	287.2
Electric Utility	66.2*	91.3*	13.0*	285.5	350.8	424.2	456.3
Total	415.1	593.5	581.6	848.2	935.7	1037.7	1102.4

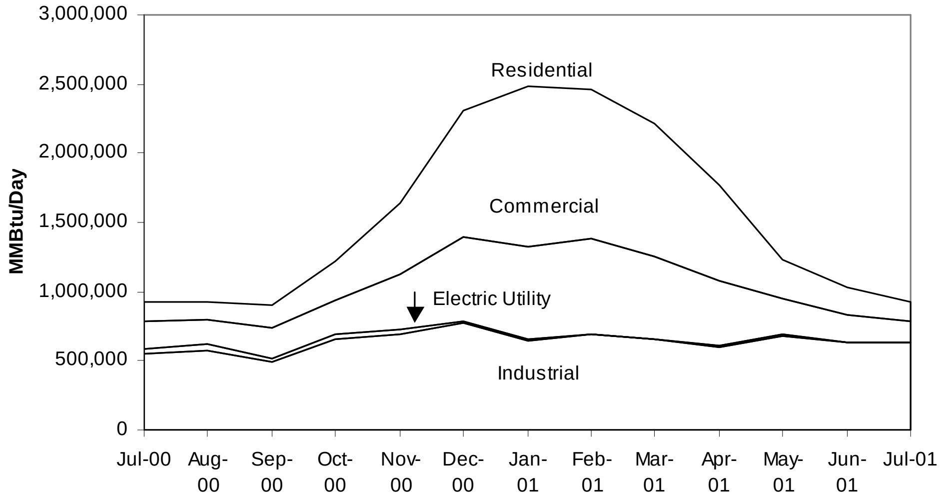
**The EIA includes the data for the non-utility generation under the Industrial sector rather than in the Electric Utility sector. For the forecast, EIA places all electricity generation in the electric utility sector. Source: EIA, 2001, 2002*

Natural gas consumption is very seasonal as the following Exhibit 4-3 below illustrates. Consumption is significantly greater in the winter than in the summer. In the yearly cycle shown in the exhibit, September is the lowest consuming month and January is the highest. The ratio of firm residential and commercial average demand with peak demand reflects the high heating season requirements during the winter season.

Residential gas demand is the most weather-sensitive. Consumption in any one year depends on the number of heating degree-days. The number of heating-degree days are the cumulative number of days in a month or year by which the mean temperature falls below 18.3°C/65°F. Heating-degree days provide a way to relate each day's temperatures to the demand for fuel to heat buildings. Over the longer term, residential gas demand is driven by housing starts, the market share of gas in new units, conversion to gas in older units, efficiency of new and existing gas equipment, relative prices of alternate fuels and accessibility and proximity to the gas system. Gas consumption in this sector grew about 9% from 1990 to 2000. The forecast is for demand to grow by 8% over the next 20 years.

The number of residential customers in New England as reported by the New England Gas Association is just over 2 million. In 2001, residential sector consumption represented about 183 billion cubic feet (Bcf) of natural gas, or about 37% of total LDC sales. In the residential market, gas accounts for about 33% of home heating, oil is the dominant heating fuel. For Maine specifically, in 2000 natural gas represented only 3.5% of home heating fuel in the region, compared to fuel oil/kerosene at 80.2%. Thus natural gas has the potential to capture a significant amount of the home heating fuels market in Maine. (NEGA, 2002b).

Exhibit 4-4:
Pattern of Consumption in New England (MMBtu per Day)



Source: EIA, 2002

Gas use in commercial establishments is mainly for space heating, cooking, and hot water, and as such is also highly seasonal. The long-term growth in gas consumption in the commercial sector is driven by the economy. Future commercial demand will be more dependent on general economic conditions, with the majority of new energy demand met with natural gas consumption. Consumption in this sector is projected to grow by 14% over the next 20 years.

Growth in the commercial and residential sectors will drive the need for peak season and peak day capacity, due to their high correlation with the temperature.

Industrial loads in New England are less seasonal. Industrial uses are for process heat and steam, which keeps gas usage relatively flat over the course of a year. The outlook for industrial demand depends mostly on continued expansion of the economy, with a smaller portion coming from successful competition with alternate fuels. Consumption in the industrial sector is projected to grow by 18% over the next 20 years.

The major driver of gas consumption growth has been the electric power sector. Historically, gas consumption in the New England electric utility sector has been very small. In 1980, less than 1% of the electricity generated came from gas-fired units. By 2001, this had grown to 20% (NEGA). The number of new gas plants has increased significantly in recent years. Over 4,000 MWs of new gas generation has been added to the regional grid in recent years.

Four major pipelines serve the New England market. The major pipeline serving New England is Tennessee Gas Pipeline (TGP). TGP supplies gas from the U.S. Gulf Coast, and has interconnections with upstream pipelines with access to western Canada and the U.S. Midwest. TGP is owned by El Paso Corp. The Algonquin Gas Transmission System (AGT) and its upstream sister pipeline, Texas Eastern Transmission Company (TETCO), both owned by Duke Energy, serves much of southern New England and reaches to the Boston area. AGT via TETCO also has direct access to the Gulf Coast, but with its interconnection with Iroquois Gas Transmission System (IGTS), it also has access to western Canadian gas. The Portland Natural Gas Transmission System (PNGTS) enters New England from the northwest, providing direct access to western Canada via the upstream TransCanada Pipeline system (TCPL). Maritimes and Northeast Pipeline (also owned by Duke) enters New England from New Brunswick, Canada, and provides access to Sable Island gas supplies.

The LDC markets in New England are heavily dominated by TGP and AGT. Both of these pipelines provide access to the major supply sources of North America (the Gulf Coast, Mid Continent, western Canada) as well as storage. Because of the highly seasonal nature of gas demand in New England, storage access is vital in supply planning. LDCs shipping on these pipelines acquire firm transportation service (FT) and storage service. Other services may also be purchased. FT requires LDCs to commit under long term contracts to a given amount of pipeline capacity, expressed as Maximum Daily Quantity or MDQ. LDCs pay for this capacity year round, even when it is only fully utilized during the heating season. LDCs can release or resell capacity into a secondary market for prices up to the rates charged by the pipeline. When considering the avoided costs of meeting peak demand, the full annual cost of pipeline capacity is taken into account, as explained more fully below.

Many LDCs supplement peak season requirements with liquefied natural gas (LNG). The major source for LNG is the Distrigas LNG Terminal in Everett, Massachusetts. The terminal is interconnected with the pipeline system and also ships LNG via truck to satellite LNG storage and re-gasification facilities throughout the state.

For purposes of estimating avoided costs, the marginal source of gas can be considered the U.S. Gulf Coast, as represented by Henry Hub prices. For deliveries into New England, we have used the TGP and TETCO-AGT systems along with their storage services. For peaking supplies, we have used the Distrigas LNG facility. In the following sections, we provide our estimates of the avoided costs separately for gas and for transportation, storage, and LNG services.

Methodology

Our approach to estimating the avoided cost is to identify the costs avoided by a LDC from not having to buy a marginal Mcf of gas. The components of the avoided costs are the cost of gas, transportation, winter storage, and winter peaking LNG. The forecast cost of gas as described below is estimated from ICF's North American Natural Gas Analysis System (NANGAS®). This generated a Henry Hub price. We used historic seasonal volatility to estimate the summer/winter differentials for each of the winter types stipulated for the avoided cost study. The costs of transportation, storage, and LNG service are calculated from the tariffs of the TGP and TETCO-AGT pipelines, their respective storage services, and the Distrigas LNG tariff. For each winter type, we estimated the share of service provided by pipeline gas, storage, and LNG, as described below in section E. Annual capacity charges were allocated to the appropriate winter types by dividing by the number of days in each type. Thus, the avoided cost for any winter type represents the avoidance of the marginal Mcf of gas and the allocation of the avoided capacity costs to that winter type.

Henry Hub Prices

Gas prices are presented as Henry Hub with seasonal adjustments. The gas price forecast for calculating avoided gas costs and for input into the electric power analysis are from ICF's North American Natural Gas Analysis System (NANGAS®). NANGAS® is a large linear program of the North American gas market and is used to develop market forecasts of supply, demand, prices and pipeline flows. NANGAS® generates long-term annual average Henry Hub prices. The NANGAS® forecast was adjusted for 2003 and the subsequent two years to reflect current gas market conditions. These adjustments were made using actual prices for the first half of the year and average NYMEX futures prices for the rest of 2003 and the next two years.

ICF's forecast (Exhibit 4-4) represents a view that natural gas prices will be moderated in the future by additional supply responding to today's high gas prices. We forecast gas prices falling from 2003 of around $5.95/MMBtu (2004$) to $4.81 by 2005. By 2011, gas prices will decline further to about $3.45/MMBtu, remaining flat to slowly increasing through the end of the forecast period, breaking the $4.00 barrier in 2024. Our view is that the U.S. natural gas resource base is substantial, with over 1,280 Tcf of technically recoverable gas resources and an additional 535 Tcf in Canada. Despite the maturity of the conventional resource base, much of future production will come from unconventional resources: deep gas (greater than 10,000 feet), deep offshore in the Gulf of Mexico, Rockies, and coal bed methane. I

In the near term we see gas prices moderating to around $4.00/MMBtu, until about 2011, when we believe Alaskan gas will enter the market at around 4.5 Bcf per day and reduce prices throughout North America. We also believe that liquefied natural gas imports will increase 5 fold from today's levels. Over our forecast period (to 2025) these sources and production from unconventional resources will moderate prices. Gas prices will eventually recover by the end of the period as gas demand continues to grow. Overall, our view is a more optimistic interpretation of the ability of technology to allow producers to find and produce gas at these price levels. We believe that gas prices over $4.00 will be difficult to sustain due to competition from coal in the power sector, deterioration of demand in the process feedstock sectors, and by the fact that at this level, substantial reserves can be developed and produced.

To reflect seasonal price swings the annual average price forecast was adjusted to show winter and summer gas prices. This was done using five years of daily gas prices at Henry Hub. Our forecast in Exhibit 4-4 shows the annual average price and the% change from the average annual price for the corresponding winter and summer definitions. Thus, for the three-month winter, we evaluated the seasonal price swing for the December – February period relative to the annual average price over each of the last five years. Correspondingly, off peak period represents the price adjustment for the remaining nine months, relative to the average annual price.

Exhibit 4-4:
Forecast and Seasonal Gas Prices for Each Winter/Summer Type at Henry Hub
(2004$/MMBtu)

Winter Type:		*3 Month Winter*		*5 Month Winter*		*6 Month Winter*		*7 Month Winter*	
	Annual	**Summer/Winter Δ**		**Summer/Winter Δ**		**Summer/Winter Δ**		**Summer/Winter Δ**	
	Henry Hub	-4.48%	13.90%	-6.55%	9.52%	-8.92%	9.35%	-9.89%	7.17%
2003	$5.95	$5.69	$6.78	$5.56	$6.52	$5.42	$6.51	$5.37	$6.38
2004	$5.26	$5.02	$5.99	$4.91	$5.76	$4.79	$5.75	$4.74	$5.63
2005	$4.81	$4.60	$5.48	$4.50	$5.27	$4.39	$5.27	$4.34	$5.16
2006	$4.30	$4.11	$4.90	$4.02	$4.71	$3.92	$4.70	$3.88	$4.61
2007	$4.13	$3.95	$4.70	$3.86	$4.52	$3.76	$4.52	$3.72	$4.43
2008	$3.99	$3.81	$4.54	$3.73	$4.37	$3.63	$4.36	$3.59	$4.28
2009	$3.82	$3.64	$4.35	$3.57	$4.18	$3.47	$4.17	$3.44	$4.09
2010	$3.98	$3.80	$4.53	$3.72	$4.36	$3.62	$4.35	$3.58	$4.26
2011	$3.45	$3.29	$3.92	$3.22	$3.77	$3.14	$3.77	$3.10	$3.69
2012	$3.51	$3.35	$4.00	$3.28	$3.85	$3.20	$3.84	$3.16	$3.76
2013	$3.61	$3.45	$4.11	$3.37	$3.95	$3.29	$3.95	$3.25	$3.87
2014	$3.72	$3.55	$4.23	$3.47	$4.07	$3.39	$4.07	$3.35	$3.98
2015	$3.65	$3.49	$4.16	$3.41	$4.00	$3.33	$3.99	$3.29	$3.91
2016	$3.80	$3.63	$4.33	$3.56	$4.17	$3.47	$4.16	$3.43	$4.08
2017	$3.82	$3.64	$4.35	$3.57	$4.18	$3.47	$4.17	$3.44	$4.09
2018	$3.97	$3.79	$4.52	$3.71	$4.35	$3.61	$4.34	$3.57	$4.25
2019	$3.91	$3.74	$4.46	$3.66	$4.29	$3.56	$4.28	$3.53	$4.19
2020	$3.79	$3.62	$4.32	$3.55	$4.15	$3.46	$4.15	$3.42	$4.07
2021	$3.74	$3.57	$4.26	$3.49	$4.10	$3.41	$4.09	$3.37	$4.01
2022	$3.75	$3.58	$4.27	$3.50	$4.11	$3.42	$4.10	$3.38	$4.02
2023	$3.97	$3.79	$4.52	$3.71	$4.35	$3.61	$4.34	$3.57	$4.25
2024	$4.33	$4.13	$4.93	$4.04	$4.74	$3.94	$4.73	$3.90	$4.64
2025	$4.34	$4.14	$4.94	$4.05	$4.75	$3.95	$4.74	$3.91	$4.65

In calculating the avoided costs, we begin with the Henry Hub forecast price and add to that the specific pipeline costs of bringing gas into New England. The treatment of these non-gas costs is addressed in the next section.

Delivery Costs to New England

The avoided cost analysis adopts the point of view of the local distribution company (LDC). Adopting this accounting stance requires consideration of how avoidable costs appear to LDCs. LDCs purchase gas and transport gas over pipelines under long-term firm transportation agreements. To meet winter demands, LDCs supplement pipeline-transported supplies with storage and peak shaving, the latter in New England being largely liquefied natural gas (LNG). LDCs purchase capacity on an annual basis and pay the reservation charges (or demand charges) for each MMBtu of reserved capacity (or maximum daily quantity – MDQ) for an entire year, payable in twelve monthly payments.

Thus, when a LDC avoids having to meet demand in the winter, the LDC can in turn avoid the capacity reservation charges associated with meeting an incremental unit of demand for the peak period. (Despite being under long-term contracts for service, reservation charges are avoidable because of the capacity release market. LDCs can release un-needed capacity usually at full rates for winter service.) However, when a LDC avoids having to meet demand in the summer (and not the winter), it avoids only having to purchase and transport an incremental MMBtu of gas, but it still must reserve capacity for the winter peak period.

To estimate the non-gas delivery costs we used the tariffs of the major pipelines delivering gas to New England: Tennessee Gas Pipeline (TGP) for northern and central New England and Texas Eastern Transmission Company (TETCO) and Algonquin Gas Transmission (AGT) for southern New England. TGP and TETCO also have storage services used by New England LDCs. Peaking services are assumed to be liquefied natural gas, principally Distrigas LNG. Non-gas delivery costs consist of the capacity reservation charges, the variable costs charged per unit of gas transported, and the fuel percentage (used to operate compressors) specified in the respective tariffs. The costs of the various transportation, storage and LNG services are shown in Exhibit 4-5.

Exhibit 4-5:
Pipeline and Storage Costs

	Annual Fixed Cost/MMBtu of Demand	*Commodity Rate/MMBtu*	*Fuel Percent*
TETCO+Algonquin	$229.92	$0.087	8.9%
TETCO Storage	$73.97	$0.096	0
TGP	$181.80	$0.15	7.3 %
TGP Storage	$92.40	$0.10	3.3%
Distrigas LNG	$492.75	Gas Cost*	0

* Tariff refers to East Louisiana gas price delivered to NE. We used the Henry Hub.

To summarize, the elements of avoidable gas costs are as follows:

- The gas cost (Henry Hub)
- The variable costs associated with transportation, storage and LNG. This consists of the commodity or usage rate and the fuel charge from the pipeline transportation, storage, and LNG tariffs.
- Pipeline, storage and LNG capacity reservation costs (demand charges). Storage service reservation costs are listed separately for injection, withdrawal, and storage capacity. LNG reservation costs include a re-gasification capacity charge and a storage space charge.

Our general approach treats the avoided costs in the following way: The winter avoided costs equal the Henry Hub price, plus the variable transportation costs on the appropriate pipeline, plus the cost of a years' worth of capacity payments for transportation, storage and LNG allocated to the winter days for each winter type. The avoided cost in the summer is the Henry Hub price plus the variable costs of transportation.

The mix of pipeline transported gas, storage, and LNG for a LDC are optimized around that LDC's particular load shape. Changes in the shape of the load due to DSM programs have cost impacts across all supply options, and not just on the marginal supply source. This is because LNG service or storage service is sized in conjunction with pipeline capacity. A reduction in the need for a marginal unit of LNG or storage gas affects the amount of pipeline capacity needed. For this analysis, therefore, we approximated this optimization across LDCs in New England, by reducing all service options – pipeline, storage, LNG – roughly in the proportion to how these services are normally deployed by the LDCs to meet winter loads. For this we used data provided by NSTAR and KeySpan that showed for each month of the year which services were deployed to meet the system sales sendout. In general, we saw the following relationships for each of the winter types (Exhibit 4-6).

Exhibit 4-6:
Percent Weightings for Each Winter Type New England Cost Weightings

Winter Type	*Pipeline*	*Storage*	*LNG*	*Total*
3 Month	76.6%	18.7%	4.7%	100.0%
5 Month	79.6%	15.4%	5.0%	100.0%
6 Month	81.7%	13.7%	4.6%	100.0%
7 Month	83.7%	12.1%	4.2%	100.0%
Annual	85.0%	11.0%	4.0%	100.0%

These percentages were used to weight the costs of each service for calculating the mix of services reduced for each winter type. The total costs were also divided by the number of months in the winter type. The one exception to this approach is the estimate of pipeline costs for the three-month winter. Pipeline capacity in New England

Using these data, we then developed the avoided transportation-related costs for each of the winter types and the annual average. This is shown in Exhibit 4-7 where the avoided costs are presented on a monthly basis and daily basis. The daily basis was used to calculate the total avoided costs in Exhibits 4-1 and 4-2. We do not escalate the real cost of the pipeline tariffs.

Exhibit 4-7:
Monthly Pipeline Costs Associated with Each Winter Type ($2004/MMBtu)

Southern New England

		Weightings	Winter Reservation Charges	Variable Charge	Winter Weighted Charges	Total (daily)	Fuel
3M Winter (Dec-Feb)	Pipeline	77%	$45.98	$0.091	$35.22	**$47.55 ($1.56)**	9.000%
	Storage	19%	$24.66	$0.096	$4.63		
	LNG	5%	$164.25	$0.000	$7.71		
5M Winter (Nov-Mar)	Pipeline	80%	$45.98	$0.091	$36.68	**$43.92 ($1.44)**	9.000%
	Storage	15%	$14.79	$0.096	$2.29		
	LNG	5%	$98.55	$0.000	$4.95		
6M Winter (Nov-Apr)	Pipeline	82%	$38.32	$0.091	$31.50	**$37.22 ($1.22)**	9.000%
	Storage	13%	$12.33	$0.096	$1.62		
	LNG	5%	$82.13	$0.000	$4.11		
7M Winter (Oct-Apr)	Pipeline	84%	$32.85	$0.091	$27.58	**$31.82 ($1.05)**	9.000%
	Storage	12%	$10.57	$0.096	$1.29		
	LNG	4%	$70.39	$0.000	$2.95		
Annual	Pipeline	85%	$19.16	$0.091	$16.36	**$18.69 ($0.61)**	9.000%
	Storage	11%	$6.16	$0.096	$0.69		
	LNG	4%	$41.06	$0.000	$1.64		

Northern and Central New England

		Weightings	Winter Reservation Charges	Variable Charge	Winter Weighted Charges	Total (daily)	Fuel
3M Winter (Dec-Feb)	Pipeline	77%	$36.36	$0.150	$27.85	**$41.33 ($1.36)**	7.250%
	Storage	19%	$30.80	$0.104	$5.78		3.250%
	LNG	5%	$164.25	$0.000	$7.71		
5M Winter (Nov-Mar)	Pipeline	80%	$36.36	$0.150	$29.06	**$36.87 ($1.21)**	7.250%
	Storage	15%	$18.48	$0.104	$2.86		3.250%
	LNG	5%	$98.55	$0.000	$4.95		
6M Winter (Nov-Apr)	Pipeline	82%	$30.30	$0.150	$24.97	**$31.09 ($1.02)**	7.250%
	Storage	13%	$15.40	$0.104	$2.02		3.250%
	LNG	5%	$82.13	$0.000	$4.11		
7M Winter (Oct-Apr)	Pipeline	84%	$25.97	$0.150	$21.88	**$26.43 ($0.87)**	7.250%
	Storage	12%	$13.20	$0.104	$1.61		3.250%
	LNG	4%	$70.39	$0.000	$2.95		
Annual	Pipeline	85%	$15.15	$0.150	$13.01	**$15.51 ($0.51)**	7.250%
	Storage	11%	$7.70	$0.104	$0.86		3.250%
	LNG	4%	$41.06	$0.000	$1.64		

Note: Calculations may not replicate exactly due to rounding.

For estimating the avoided cost associated with heating buildings, we used the 5 month winter for the new building and the 7 month winter for the old building. For the water heating base load, we used the 12-month average cost.

For purposes of calculating the total avoided costs shown in Exhibits 4-1 and 4-2, the monthly non-gas fixed costs, divided by the days in the month, were added to the gas costs for each season, including the fuel percentage, and the pipeline variable charges.

Comparison with Previous Avoided Cost Study

The avoided costs presented in this analysis are somewhat higher than the avoided costs presented in the previous submissions dated 1999 and 2001. (See "Avoided Energy-Supply Costs for Demand Side Management Screening in Massachusetts" resource Insight and Synapse Energy Economics, 1999 and "Updated Avoided Energy Supply Costs," 2001.) Exhibit 4-8 presents the comparison. The 2001 study estimates were escalated to $2004 to facilitate the comparison. Both the previous study and this study present avoided costs from the standpoint of the LDC. The major source of the difference lies in ICF's higher gas price forecast and the allocation of fixed costs to winter periods based on actual tariff rates.

Exhibit 4-8:
2010 Comparison of ICF with 2001 Study Avoided Costs (2004$/MMBtu)

	ICF		
Year	***South NE***	***North/Central NE***	***2001 Study***
Annual Average	$5.04	$4.91	$3.89
3 Month Winter	$6.59	$6.35	$5.33
9 Month Summer	$4.23	$4.21	$3.44
5 Month Winter	$6.28	$6.02	$4.71
7 Month Summer	$4.14	$4.12	$3.32
7 Month Winter	$6.05	$5.82	$4.33
5 Month Summer	$4.00	$4.02	$3.30
Heat Retrofit	$5.78	$5.58	$5.06
New Heat	$6.28	$6.02	$5.66
Water Heater	$5.04	$4.91	$4.18

Retail Customer Avoided Costs

One of the key issues in DSM is the fact that consumers make decisions based on average costs while LDCs purchase gas and make investment decisions based on marginal costs. Price signals from the market are thus not well translated to consumers. In this section, we use average costs to estimate retail customer avoided costs.

The retail customer avoided costs consists of the LDCs regulated rate per unit of gas sold. This cost reflects an average cost of gas plus any avoidance of LDC gas distribution costs. For this analysis we assume that the annual average avoided LDC cost shown in Exhibits 4-1 and 4-2 plus the average LDC margin over its city gate price (i.e., the cost of gas and transportation to the point of interconnection between the transmission pipeline system and the distribution system) represents the total cost to retail customers. Of this amount we assume that one half of the LDC distribution margin is also avoidable (based on discussion with AESC members).

We have used Energy Information Administration data on average city gate gas prices by state and average gas prices to residential and commercial customers by state for the New England states since 1995. The difference between average city gate prices and average customer prices reflects an average LDC distribution margin. These results are presented in Exhibit 4-9 for residential and commercial customers.

Exhibit 4-9:
Estimated Avoidable LDC Margins 1995-2002 Average ($2004/MMBtu)

	Southern NE	Central NE	Northern NE
Average Citygate	$5.31	$5.00	$4.34
Ave. Residential Margin	$5.57	$4.99	$4.98
Avoidable	*$2.79*	*$2.50*	*$2.49*
Ave. Commercial Margin	$2.47	$2.63	$2.93
Avoidable	*$1.24*	*$1.31*	*$1.47*

Calculating total avoided cost to the customers will entail adding to the annual average LDC avoided cost in Exhibits 4-1 and 4-2, the avoided cost associated with distribution in Exhibit 4-9. The results are presented below in Exhibit 4-10.

Exhibit 4-10:
Estimated Customer Avoided Costs ($2004/MMBtu)

Year	Southern New England		Central New England		Northern New England	
	Residential	***Commercial***	***Residential***	***Commercial***	***Residential***	***Commercial***
2003	9.98	8.43	9.53	8.34	9.52	8.50
2004	9.22	7.67	8.78	7.60	8.77	7.75
2005	8.73	7.19	8.30	7.12	8.30	7.27
2006	8.18	6.63	7.75	6.57	7.75	6.72
2007	7.99	6.44	7.57	6.39	7.57	6.54
2008	7.83	6.29	7.42	6.24	7.41	6.39
2009	7.65	6.10	7.23	6.05	7.23	6.20
2010	7.82	6.27	7.41	6.22	7.40	6.38
2011	7.24	5.69	6.84	5.65	6.83	5.81
2012	7.31	5.76	6.91	5.72	6.90	5.88
2013	7.42	5.87	7.01	5.83	7.01	5.98
2014	7.54	5.99	7.13	5.95	7.12	6.10
2015	7.47	5.92	7.06	5.88	7.05	6.03
2016	7.63	6.08	7.22	6.04	7.22	6.19
2017	7.65	6.10	7.23	6.05	7.23	6.20
2018	7.81	6.26	7.39	6.21	7.39	6.37
2019	7.75	6.20	7.34	6.16	7.33	6.31
2020	7.62	6.07	7.21	6.03	7.20	6.18
2021	7.56	6.01	7.15	5.97	7.15	6.12
2022	7.57	6.02	7.16	5.98	7.16	6.13
2023	7.81	6.26	7.39	6.21	7.39	6.37
2024	8.20	6.65	7.78	6.60	7.78	6.75
2025	8.21	6.66	7.79	6.61	7.79	6.76

Chapter Five: Avoided Costs of Other Fuels

In this section, we describe our approach to estimating avoided costs for distillate fuel oil, residual fuel oil, kerosene, propane and wood. Our findings are shown in Exhibit 5-1. In the following brief sections we describe our approach to estimating these avoided costs.

Exhibit 5-1:
Other Fuel Avoided Costs

	Distillate Fuel Oil			Residual Fuel Oil		No. 4 Fuel Oil
Year	Wholesale	Residential	Commercial	Wholesale	Industrial	Industrial
2003	$6.80	$11.09	$8.91	$4.15	$4.94	$6.93
2004	$5.66	$9.22	$7.04	$3.55	$4.23	$5.64
2005	$5.09	$8.30	$6.12	$3.36	$4.00	$5.06
2006	$4.67	$7.62	$5.44	$3.24	$3.85	$4.64
2007	$4.49	$7.32	$5.14	$3.20	$3.80	$4.47
2008	$4.45	$7.25	$5.07	$3.20	$3.80	$4.43
2009	$4.41	$7.19	$5.01	$3.20	$3.80	$4.41
2010	$4.38	$7.14	$4.96	$3.20	$3.80	$4.38
2011	$4.40	$7.18	$5.00	$3.18	$3.79	$4.39
2012	$4.41	$7.19	$5.01	$3.17	$3.78	$4.40
2013	$4.45	$7.25	$5.07	$3.16	$3.76	$4.42
2014	$4.48	$7.30	$5.12	$3.15	$3.75	$4.44
2015	$4.50	$7.34	$5.16	$3.14	$3.74	$4.45
2016	$4.51	$7.35	$5.17	$3.15	$3.75	$4.46
2017	$4.53	$7.39	$5.21	$3.15	$3.75	$4.48
2018	$4.54	$7.41	$5.23	$3.15	$3.75	$4.49
2019	$4.57	$7.44	$5.26	$3.15	$3.75	$4.51
2020	$4.58	$7.46	$5.28	$3.15	$3.75	$4.52
2021	$4.58	$7.46	$5.28	$3.15	$3.75	$4.52
2022	$4.58	$7.46	$5.28	$3.15	$3.75	$4.52
2023	$4.58	$7.46	$5.28	$3.15	$3.75	$4.52
2024	$4.58	$7.46	$5.28	$3.15	$3.75	$4.52
2025	$4.58	$7.46	$5.28	$3.15	$3.75	$4.52

Exhibit 5-1.
Other Fuel Avoided Costs (contd.)

	Propane		Wood		Kerosene
Year	*Wholesale*	*Residential*	*($/MMbtu)*	*($/Cord)*	*Residential*
2003	$7.07	$13.92	$7.50	$150.00	$14.17
2004	$5.97	$11.77	$7.65	$153.00	$12.51
2005	$5.43	$10.70	$7.80	$156.06	$11.46
2006	$5.03	$9.92	$7.96	$159.18	$10.24
2007	$4.86	$9.57	$8.12	$162.36	$9.83
2008	$4.82	$9.49	$8.28	$165.61	$9.49
2009	$4.79	$9.43	$8.45	$168.92	$9.08
2010	$4.76	$9.37	$8.62	$172.30	$9.47
2011	$4.78	$9.41	$8.79	$175.75	$8.20
2012	$4.79	$9.43	$8.96	$179.26	$8.36
2013	$4.82	$9.49	$9.14	$182.85	$8.59
2014	$4.85	$9.55	$9.33	$186.51	$8.85
2015	$4.87	$9.59	$9.51	$190.24	$8.69
2016	$4.88	$9.61	$9.70	$194.04	$9.05
2017	$4.90	$9.65	$9.90	$197.92	$9.08
2018	$4.91	$9.68	$10.09	$201.88	$9.44
2019	$4.93	$9.72	$10.30	$205.92	$9.31
2020	$4.94	$9.74	$10.50	$210.04	$9.03
2021	$4.94	$9.74	$10.71	$214.24	$8.90
2022	$4.94	$9.74	$10.93	$218.52	$8.93
2023	$4.94	$9.74	$11.14	$222.89	$9.44
2024	$4.94	$9.74	$11.37	$227.35	$10.30
2025	$4.94	$9.74	$11.59	$231.90	$10.32

Distillate Fuel

Distillate fuel oil is estimated from ICF's NANGAS® model. The model takes the crude oil price forecast (an input to the model) and applies average refinery margins and transportation cost differentials to estimate regional wholesale prices. We adjusted the 2003 wholesale price to reflect actual data and the 2004 and 2005 prices to reflect futures market outlook. The estimates of the residential and commercial prices of distillate are based on historical observed price differences as reported by the Energy Information Administration (EIA). Prices are shown as an annual average.

Residual Fuel

Our forecast of residual fuel oil is done in the same way as the distillate forecast. In this case, we used the low sulfur resid wholesale price and estimated the delivered industrial price based on the historical margins shown in EIA data. The No. 4 fuel oil price is a simple average of the Commercial Distillate and the Industrial Resid price.

Kerosene

Kerosene prices are based on a regression analysis of historical kerosene prices with natural gas and distillate. The resulting forecast represents the historical relationship applied to our forecast of distillate and gas prices.

Propane

We used a similar approach for propane. Distillate and propane are highly correlated, therefore, we developed a regression between historic distillate wholesale prices and wholesale propane prices and used the resulting relationship to estimate future propane prices.

Firewood

Wood prices are based on advertised prices of $150 for a mixed cord of oak, hickory and maple. We escalate the price by two percent per year in real terms. (This is not an inflation adjustment.)