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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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 2005 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: Berkshire Gas Company, Keyspan Energy Delivery New England (Boston Gas Company, Essex Gas Company, and Colonial Gas Company), Cape Light Compact, National Grid USA (Massachusetts Electric Company, New England Gas Company, NiSource Inc., NSTAR Electric & Gas Company, Northeast Utilities (Western Massachusetts Electric and Public Service of New Hampshire), Unitil (Fitchburg Gas and Electric Light Company, United Illuminating, Concord Electric Company and Exeter & Hampton Electric Company), the State of Maine, and the State of Vermont. Additional members of the Study Group include Connecticut Energy Conservation Management Board, Massachusetts Department of Telecommunications and Energy, Massachusetts Division of Energy Resources, Massachusetts Low-Income Energy Affordability Network (LEAN) and other Non-Utility Parties, New Hampshire Public Utilities Commission, and Rhode Island Division of Public Utilities and Carriers.

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 wholesale or spot 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. Transmission and distribution avoidable costs were considered under the electricity sector portion of this analysis.

To project wholesale market conditions going forward, ICF relied on the combination of the

NANGAS® natural gas market model to forecast delivered to New England market pricing and the IPM® power market model to forecast near- and long-term power market conditions. IPM® considers the entire time horizon (2005 – 2040) 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 commissioned by the AESC Study Group in 1999, 2001, and 2003. A comparison of currently available information from the most recent analysis is provided within this report. Sections of this analysis were not previously performed under the 2003 vintage study and will not be directly compared.

Among the Study Group's objectives for this analysis was 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 marginal pricing recently added to the New England electric market and locational capacity markets expected to be in place in New England shortly.

Summary of Results

Natural Gas

Retail avoided natural gas costs in New England are expected to decline in real terms through roughly 2015 before gradually increasing through 2025. Avoided retail gas costs are held flat thereafter. Exhibits ES-1 and ES-2 present the annual avoided retail gas costs for the residential and commercial sectors for Southern New England and Northern and Central New England.

Results for the residential sector are provided for existing heating, new heating, and hot water. Average results for all residential are also provided. Results for the commercial and industrial sector are provided are provided for non-heating and heating as well as the average for the sector.

Exhibit ES-1 Annual Avoided Retail Gas Costs Southern New England (2005$/MMBtu)

	Residential				Commercial & Industrial			All Retail
Year	Existing Heating	New Heating	Hot Water	All	Non Heating	Heating	All	
2005	12.60	12.49	12.46	12.51	11.17	11.20	11.18	11.92
2006	13.08	12.97	12.97	13.01	11.68	11.68	11.68	12.41
2007	12.64	12.54	12.61	12.60	11.32	11.25	11.28	12.01
2008	10.62	10.52	10.51	10.55	9.22	9.23	9.22	9.95
2009	9.62	9.52	9.47	9.54	8.18	8.23	8.21	8.94
2010	8.89	8.79	8.68	8.79	7.39	7.50	7.44	8.18
2011	8.95	8.85	8.75	8.85	7.46	7.56	7.51	8.25
2012	9.17	9.07	8.97	9.07	7.68	7.78	7.73	8.47
2013	9.38	9.28	9.17	9.28	7.88	7.99	7.93	8.67
2014	9.99	9.88	9.77	9.88	8.48	8.59	8.54	9.28
2015	9.55	9.45	9.35	9.45	8.05	8.16	8.11	8.85
2016	9.58	9.48	9.37	9.47	8.08	8.19	8.13	8.87
2017	9.55	9.45	9.34	9.45	8.05	8.16	8.10	8.84
2018	9.71	9.60	9.50	9.60	8.21	8.31	8.26	9.00
2019	9.90	9.80	9.69	9.80	8.40	8.51	8.45	9.19
2020	10.04	9.94	9.83	9.94	8.54	8.65	8.59	9.33
2021	10.36	10.25	10.14	10.25	8.85	8.96	8.91	9.65
2022	10.46	10.35	10.24	10.35	8.95	9.06	9.00	9.74
2023	10.83	10.73	10.61	10.73	9.32	9.44	9.38	10.12
2024	10.94	10.83	10.71	10.83	9.42	9.54	9.48	10.22
2025	11.45	11.34	11.22	11.34	9.93	10.05	9.99	10.73
2026-40	11.45	11.34	11.22	11.34	9.93	10.05	9.99	10.73
Levelized 2.03%	10.74	10.63	10.54	10.64	9.25	9.34	9.29	10.03

Exhibit ES-2 Annual Avoided Retail Gas Costs Northern and Central New England (2005 $/MMBtu)

	Residential				Commercial & Industrial			All Retail
Year	Existing Heating	New Heating	Hot Water	All	Non Heating	Heating	All	
2005	12.28	12.19	12.19	12.22	11.31	11.31	11.31	11.81
2006	12.76	12.67	12.70	12.71	11.82	11.79	11.80	12.30
2007	12.33	12.24	12.34	12.30	11.46	11.36	11.41	11.90
2008	10.34	10.25	10.27	10.29	9.39	9.37	9.38	9.88
2009	9.36	9.28	9.25	9.30	8.37	8.40	8.39	8.89
2010	8.63	8.55	8.48	8.55	7.60	7.67	7.63	8.14
2011	8.70	8.62	8.54	8.62	7.66	7.74	7.70	8.20
2012	8.91	8.83	8.75	8.83	7.87	7.95	7.91	8.42
2013	9.12	9.04	8.96	9.04	8.08	8.16	8.12	8.62
2014	9.72	9.63	9.55	9.63	8.67	8.75	8.71	9.22
2015	9.29	9.21	9.13	9.21	8.25	8.33	8.29	8.79
2016	9.31	9.23	9.15	9.23	8.27	8.35	8.31	8.82
2017	9.28	9.20	9.12	9.20	8.24	8.32	8.28	8.79
2018	9.44	9.36	9.28	9.36	8.40	8.48	8.44	8.94
2019	9.63	9.55	9.47	9.55	8.59	8.67	8.63	9.13
2020	9.77	9.68	9.60	9.69	8.72	8.80	8.76	9.27
2021	10.08	9.99	9.91	10.00	9.03	9.11	9.07	9.58
2022	10.18	10.09	10.01	10.09	9.13	9.21	9.17	9.68
2023	10.55	10.46	10.38	10.46	9.50	9.58	9.54	10.05
2024	10.65	10.56	10.47	10.56	9.59	9.68	9.64	10.15
2025	11.15	11.06	10.97	11.06	10.09	10.18	10.14	10.65
2026-40	11.15	11.06	10.97	11.06	10.09	10.18	10.14	10.65
Levelized								
2.03%	10.45	10.37	10.30	10.37	9.42	9.49	9.45	9.96

Exhibit ES-3 below summarizes the levelized costs by region, by period of levelization for all of the retail sectors.

Exhibit ES-3. Summary of Levelized Retail Avoided Coats (2005$/MmBtu)

	Residential				Commercial & Industrial			All Retail
Years Levelized	Existing Heating	New Heating	Hot Water	All	Non Heating	Heating	All	
Southern New England								
10	10.54	10.44	10.33	10.44	9.04	9.15	9.09	9.83
15	10.32	10.22	10.11	10.22	8.82	8.93	8.87	9.61
20	10.42	10.31	10.20	10.31	8.91	9.02	8.97	9.71
35	10.76	10.65	10.54	10.65	9.25	9.36	9.31	10.05
Northern & Central New England								
10	10.26	10.18	10.09	10.18	9.21	9.30	9.25	9.76
15	10.05	9.96	9.88	9.96	9.00	9.08	9.04	9.55
20	10.14	10.05	9.97	10.05	9.09	9.17	9.13	9.64
35	10.48	10.39	10.30	10.39	9.42	9.51	9.47	9.97
Vermont								
10	9.48	9.41	9.32	9.40	8.29	8.37	8.33	8.92
15	9.27	9.20	9.12	9.20	8.09	8.17	8.13	8.72
20	9.36	9.29	9.21	9.29	8.17	8.26	8.22	8.80
35	9.68	9.61	9.52	9.60	8.49	8.57	8.53	9.12

ICF also provided projections for LDC avoided gas costs. LDC avoided costs are expected to be at very high levels in the near-term and to drop significantly by 2010 in real dollars. A gradual increase in LDC avoided costs (in real dollars) is anticipated fro the remainder of the time horizon. Exhibit ES-4 and ES-5 provide summary results for LDC avoided costs. We present costs separately for Southern New England (Connecticut and Rhode Island) and Northern and Central New England (Massachusetts, Vermont, New Hampshire, and Maine).

Exhibit ES-4: Seasonal Wholesale LDC Avoided Gas Costs Southern New England (2005$/MMBtu)

Year	Annual Avg.	3 Month Winter	9 Month Summer	5 Month Winter	7 Month Summer	6 Month Winter	6 Month Summer	7 Month Winter	5 Month Summer	Peak Day
2005	9.66	12.51	8.39	11.15	8.34	10.80	8.32	10.46	8.27	247.01
2006	10.17	13.08	8.86	11.70	8.82	11.34	8.79	10.99	8.74	248.18
2007	9.81	12.68	8.53	11.31	8.48	10.95	8.45	10.61	8.40	247.35
2008	7.71	10.34	6.57	9.07	6.54	8.74	6.52	8.43	6.48	242.54
2009	6.68	9.18	5.61	7.96	5.58	6.97	5.56	7.36	5.53	240.17
2010	$5.90	$8.30	$4.87	$7.39	$4.86	$7.15	$4.85	$6.92	$4.82	238.37
2011	$5.96	$8.38	$4.93	$7.46	$4.92	$7.23	$4.91	$6.99	$4.88	238.52
2012	$6.18	$8.62	$5.14	$7.71	$5.13	$7.47	$5.11	$7.23	$5.08	239.02
2013	$6.38	$8.85	$5.33	$7.94	$5.32	$7.70	$5.30	$7.46	$5.27	239.49
2014	$6.99	$9.52	$5.89	$8.61	$5.87	$8.37	$5.85	$8.12	$5.82	240.87
2015	$6.56	$9.04	$5.49	$8.13	$5.48	$7.89	$5.46	$7.65	$5.42	239.89
2016	$6.58	$9.07	$5.51	$8.16	$5.50	$7.92	$5.48	$7.68	$5.45	239.94
2017	$6.55	$9.03	$5.48	$8.12	$5.47	$7.89	$5.45	$7.64	$5.42	239.87
2018	$6.71	$9.21	$5.63	$8.30	$5.62	$8.06	$5.60	$7.82	$5.56	240.23
2019	$6.90	$9.42	$5.81	$8.51	$5.79	$8.28	$5.77	$8.03	$5.74	240.67
2020	$7.04	$9.58	$5.94	$8.67	$5.92	$8.43	$5.90	$8.18	$5.87	240.99
2021	$7.35	$9.93	$6.23	$9.02	$6.21	$8.78	$6.19	$8.53	$6.15	241.71
2022	$7.45	$10.04	$6.32	$9.13	$6.30	$8.89	$6.28	$8.64	$6.24	241.93
2023	$7.83	$10.45	$6.67	$9.55	$6.65	$9.31	$6.63	$9.06	$6.59	242.79
2024	$7.93	$10.57	$6.76	$9.66	$6.74	$9.42	$6.72	$9.17	$6.68	243.02
2025	$8.43	$11.13	$7.23	$10.23	$7.21	$9.99	$7.19	$9.73	$7.14	244.18

Exhibit ES-5: Seasonal Wholesale LDC Avoided Costs Northern and Central New England
(2005$/MMBtu)

Year	Annual Avg.	3 Month Winter	9 Month Summer	5 Month Winter	7 Month Summer	6 Month Winter	6 Month Summer	7 Month Winter	5 Month Summer	Peak Day
2005	9.58	11.89	8.26	10.74	8.22	10.44	8.20	10.14	8.15	199.64
2006	10.08	12.45	8.73	11.28	8.68	10.97	8.66	10.66	8.61	200.80
2007	9.72	12.05	8.40	10.90	8.36	10.60	8.33	10.29	8.28	199.98
2008	7.66	9.75	6.49	8.69	6.46	8.42	6.44	8.15	6.40	195.22
2009	6.64	8.61	5.54	7.60	5.52	6.67	5.50	7.09	5.47	192.86
2010	$5.86	$7.75	$4.82	$7.03	$4.80	$6.84	$4.79	$6.64	$4.76	191.07
2011	$5.92	$7.82	$4.88	$7.10	$4.86	$6.92	$4.85	$6.71	$4.82	191.22
2012	$6.14	$8.06	$5.08	$7.34	$5.06	$7.16	$5.04	$6.95	$5.02	191.71
2013	$6.34	$8.28	$5.27	$7.56	$5.24	$7.38	$5.23	$7.17	$5.20	192.18
2014	$6.93	$8.94	$5.82	$8.23	$5.79	$8.04	$5.77	$7.83	$5.74	193.54
2015	$6.51	$8.47	$5.43	$7.75	$5.40	$7.57	$5.38	$7.36	$5.35	192.57
2016	$6.53	$8.50	$5.45	$7.78	$5.42	$7.60	$5.41	$7.39	$5.38	192.62
2017	$6.50	$8.47	$5.42	$7.75	$5.39	$7.56	$5.38	$7.36	$5.35	192.56
2018	$6.66	$8.64	$5.56	$7.92	$5.54	$7.74	$5.52	$7.53	$5.49	192.91
2019	$6.85	$8.85	$5.74	$8.13	$5.71	$7.95	$5.69	$7.74	$5.66	193.35
2020	$6.98	$9.00	$5.87	$8.28	$5.84	$8.10	$5.82	$7.89	$5.79	193.67
2021	$7.29	$9.34	$6.15	$8.63	$6.12	$8.45	$6.10	$8.23	$6.07	194.38
2022	$7.39	$9.45	$6.24	$8.74	$6.21	$8.55	$6.19	$8.34	$6.16	194.60
2023	$7.76	$9.86	$6.58	$9.15	$6.55	$8.97	$6.53	$8.75	$6.49	195.45
2024	$7.86	$9.97	$6.67	$9.26	$6.64	$9.08	$6.62	$8.86	$6.58	195.68
2025	$8.36	$10.53	$7.13	$9.82	$7.10	$9.63	$7.08	$9.41	$7.04	196.83

A detailed discussion of the avoided cost projections for natural gas can be found in Chapter One.

Electric Energy and Capacity

Avoided all-in costs forecasts are provided for sub-regions or zones within New England for the period 2005 through 2040 in Exhibit ES-6 below. The all-in price includes energy avoided costs, capacity avoided costs, and out-of-market avoided costs. In general, a somewhat cyclical movement in avoided costs is expected over time. In the near-term, costs are high, but are expected to decline in real terms through the 2010-2015 period. Thereafter, real costs begin to increase, before reaching highs in about 2030. From this point through 2040, costs are expected to decline.

Exhibit ES-6: All-in Avoided Electric Supply Costs by AESC Screening Zone ($/kW-yr)

Units :2005$/kWh	Maine	Boston	Rest of Massachusetts - Southeast, Central and Western Massachusetts	Boston & Southeast Massachusetts	New Hampshire	Rhode Island	Vermont	Norwalk (RTEP)	Southwest Connecticut (RTEP)	Rest of Connecticut
2005	0.063	0.066	0.066	0.066	0.064	0.066	0.068	0.076	0.075	0.072
2006	0.074	0.079	0.079	0.079	0.077	0.079	0.081	0.093	0.088	0.087
2007	0.076	0.082	0.082	0.082	0.080	0.082	0.084	0.095	0.091	0.090
2008	0.063	0.072	0.072	0.072	0.070	0.072	0.073	0.078	0.076	0.075
2009	0.051	0.060	0.060	0.060	0.058	0.060	0.060	0.065	0.064	0.062
2010	0.046	0.053	0.053	0.053	0.052	0.053	0.054	0.057	0.056	0.055
2011	0.050	0.056	0.055	0.055	0.054	0.055	0.055	0.059	0.058	0.057
2012	0.055	0.058	0.058	0.058	0.057	0.057	0.057	0.060	0.059	0.058
2013	0.055	0.059	0.058	0.058	0.057	0.058	0.058	0.060	0.060	0.059
2014	0.055	0.059	0.059	0.059	0.058	0.058	0.058	0.060	0.060	0.059
2015	0.056	0.060	0.059	0.060	0.058	0.059	0.059	0.060	0.060	0.059
2016	0.056	0.061	0.059	0.060	0.059	0.059	0.060	0.060	0.061	0.060
2017	0.058	0.062	0.061	0.062	0.061	0.061	0.061	0.062	0.062	0.062
2018	0.059	0.064	0.063	0.064	0.062	0.063	0.063	0.064	0.064	0.063
2019	0.061	0.066	0.065	0.066	0.064	0.065	0.065	0.066	0.066	0.065
2020	0.063	0.068	0.067	0.068	0.066	0.067	0.067	0.068	0.068	0.067
2021	0.064	0.069	0.067	0.068	0.067	0.067	0.068	0.068	0.068	0.068
2022	0.064	0.069	0.068	0.069	0.068	0.068	0.068	0.069	0.069	0.068
2023	0.065	0.070	0.069	0.069	0.068	0.069	0.069	0.070	0.070	0.069
2024	0.066	0.071	0.069	0.070	0.069	0.069	0.070	0.070	0.070	0.070
2025	0.067	0.071	0.070	0.071	0.070	0.070	0.071	0.071	0.071	0.070
2026	0.068	0.072	0.071	0.071	0.070	0.071	0.071	0.071	0.072	0.071
2027	0.069	0.073	0.071	0.072	0.071	0.072	0.072	0.072	0.072	0.072
2028	0.069	0.073	0.072	0.073	0.072	0.072	0.073	0.073	0.073	0.072
2029	0.070	0.074	0.073	0.074	0.073	0.073	0.074	0.073	0.074	0.073
2030	0.071	0.075	0.073	0.074	0.073	0.074	0.074	0.074	0.074	0.074
2031	0.071	0.074	0.073	0.074	0.073	0.073	0.074	0.074	0.074	0.073
2032	0.070	0.073	0.072	0.073	0.072	0.073	0.073	0.073	0.073	0.072
2033	0.070	0.073	0.071	0.072	0.071	0.072	0.073	0.072	0.072	0.072
2034	0.069	0.072	0.071	0.072	0.071	0.071	0.072	0.072	0.072	0.071
2035	0.069	0.072	0.070	0.071	0.070	0.071	0.071	0.072	0.072	0.071
2036	0.068	0.071	0.070	0.071	0.070	0.070	0.071	0.071	0.071	0.070
2037	0.068	0.071	0.069	0.070	0.069	0.070	0.070	0.071	0.071	0.070
2038	0.068	0.070	0.069	0.070	0.069	0.069	0.070	0.071	0.070	0.069
2039	0.068	0.070	0.069	0.069	0.069	0.069	0.070	0.070	0.070	0.069
2040	0.067	0.069	0.068	0.069	0.068	0.069	0.069	0.070	0.070	0.069
Levelized Values[1]	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2005-2040	0.063	0.068	0.067	0.067	0.066	0.067	0.067	0.070	0.069	0.068
2006-2040	0.063	0.068	0.067	0.067	0.066	0.067	0.067	0.070	0.069	0.068
2006-2010	0.062	0.070	0.070	0.069	0.068	0.069	0.071	0.078	0.075	0.074
2006-2015	0.058	0.064	0.064	0.064	0.063	0.064	0.064	0.069	0.068	0.067
2006-2020	0.059	0.064	0.064	0.064	0.063	0.063	0.064	0.068	0.067	0.066

Note: Southwest Connecticut (RTEP) does not include the Norwalk area.

1) Levelized using a 2.03 percent real discount rate

Background on the methodology and assumptions used to derive the electric avoided costs can be found in Chapter Two. Further detail on the electric energy avoided cost results, including a breakout of the component costs can be found in Chapter Three and Appendix Two. The material presented in these chapters is presented for separate costing periods as described in Appendix One.

Other Fuels

In Chapter Four, ICF provides avoided cost results for fuels other than natural gas. These include propane, residual fuel oil, distillate fuel oil, kerosene for heating, and wood. Summary results are provided below. The New England forecast is based on ICF's forecast of crude oil and principal product prices for the U.S. as a whole. Transportation and market based "basis" differentials were used to estimated delivered prices in New England. Where most of the fuels are forecast based on fundamental relationships with crude and product prices, the wood price forecast is based on current quoted prices, estimates of future price movement and economic indicators. ICF developed fuel oil price forecasts for three New England regions – Southern, Central and Northern. For kerosene, propane and wood, prices are forecast for all New England.

Exhibit ES-7: U.S. Crude and Product Price Forecast (2005$/MMBtu)

Year	Composite RAC Oil $/BBL	Composite RAC Oil	Average No.2 Distillate	Average No. 6 Resid < 1% S	Propane Wholesale	Kerosene Wholesale
2005	45.60	7.86	9.39	7.25	9.39	9.89
2006	46.40	8.01	9.54	7.40	9.54	10.04
2007	44.40	7.65	9.19	7.05	9.19	9.68
2008	43.30	7.47	9.01	6.87	9.01	9.51
2009	44.50	7.67	9.21	7.07	9.21	9.71
2010	47.20	8.14	9.68	7.54	9.68	10.17
2011	45.50	7.84	9.38	7.24	9.38	9.88
2012	43.80	7.55	9.09	6.95	9.09	9.59
2013	42.10	7.26	8.80	6.66	8.80	9.29
2014	40.40	6.97	8.51	6.37	8.51	9.00
2015	38.60	6.66	8.20	6.06	8.20	8.69
2016	38.90	6.71	8.25	6.10	8.24	8.74
2017	39.60	6.83	8.37	6.23	8.37	8.86
2018	40.30	6.95	8.49	6.35	8.49	8.99
2019	41.00	7.07	8.61	6.47	8.61	9.11
2020	41.70	7.19	8.73	6.59	8.73	9.23
2021	42.40	7.32	8.85	6.71	8.85	9.35
2022	43.10	7.44	8.98	6.84	8.97	9.47
2023	43.80	7.56	9.10	6.96	9.10	9.59
2024	44.60	7.68	9.22	7.08	9.22	9.72
2025	45.30	7.80	9.34	7.20	9.34	9.84

Exhibit ES-8: Southern New England Fuel Oils Forecast by Sector (2005$/MMBtu)

Year	US Composite RAC Oil Price	No. 2 Distillate					No. 6 LS Residual Fuel		No. 4 Fuel Oil	
		Wholesale	Retail				Wholesale	Retail	Wholesale	Retail
			Residential	Commercial	Industrial	Electrical				
2005	7.86	9.40	12.23	10.50	10.12	10.10	7.29	7.80	8.34	9.30
2006	8.01	9.54	12.38	10.65	10.27	10.25	7.44	7.95	8.49	9.45
2007	7.65	9.19	12.02	10.29	9.92	9.89	7.09	7.59	8.14	9.09
2008	7.47	9.01	11.84	10.11	9.74	9.71	6.91	7.42	7.96	8.91
2009	7.67	9.21	12.04	10.31	9.94	9.91	7.11	7.62	8.16	9.11
2010	8.14	9.68	12.51	10.78	10.40	10.38	7.58	8.08	8.63	9.58
2011	7.84	9.38	12.21	10.48	10.11	10.08	7.28	7.79	8.33	9.28
2012	7.55	9.09	11.92	10.19	9.82	9.79	6.99	7.50	8.04	8.99
2013	7.26	8.80	11.63	9.90	9.52	9.50	6.70	7.20	7.75	8.70
2014	6.97	8.51	11.34	9.61	9.23	9.21	6.40	6.91	7.46	8.41
2015	6.66	8.20	11.03	9.30	8.93	8.90	6.10	6.60	7.15	8.10
2016	6.71	8.25	11.08	9.35	8.97	8.95	6.14	6.65	7.19	8.15
2017	6.83	8.37	11.20	9.47	9.09	9.07	6.27	6.77	7.32	8.27
2018	6.95	8.49	11.32	9.59	9.22	9.19	6.39	6.90	7.44	8.39
2019	7.07	8.61	11.44	9.71	9.34	9.31	6.51	7.02	7.56	8.51
2020	7.19	8.73	11.56	9.83	9.46	9.43	6.63	7.14	7.68	8.64
2021	7.32	8.86	11.69	9.96	9.58	9.56	6.75	7.26	7.80	8.76
2022	7.44	8.98	11.81	10.08	9.70	9.68	6.87	7.38	7.93	8.88
2023	7.56	9.10	11.93	10.20	9.83	9.80	7.00	7.50	8.05	9.00
2024	7.68	9.22	12.05	10.32	9.95	9.92	7.12	7.63	8.17	9.12
2025	7.80	9.34	12.17	10.44	10.07	10.04	7.24	7.75	8.29	9.24
2026-2040	7.80	9.34	12.17	10.44	10.07	10.04	7.24	7.75	8.29	9.24
Levelized	7.55	9.09	11.92	10.19	9.82	9.79	6.99	7.50	8.04	8.99

Exhibit ES-9: Northern New England Fuel Oils Forecast by Sector (2005$/MMBtu)

Year	Crude	No. 2 Distillate					No. 6 Residual Fuel <= 1% Sulfur		No. 4 Fuel Oil	
		Wholesale	Retail				Wholesale	Retail	Wholesale	Retail
			Residential	Commercial	Industrial	Electrical				
2005	7.86	9.46	12.22	10.35	10.45	10.85	7.29	7.80	8.38	9.43
2006	8.01	9.61	12.37	10.50	10.60	11.00	7.44	7.95	8.52	9.58
2007	7.65	9.25	12.02	10.14	10.24	10.65	7.09	7.59	8.17	9.22
2008	7.47	9.07	11.84	9.97	10.06	10.47	6.91	7.42	7.99	9.04
2009	7.67	9.27	12.04	10.17	10.26	10.67	7.11	7.62	8.19	9.24
2010	8.14	9.74	12.51	10.63	10.73	11.13	7.58	8.08	8.66	9.71
2011	7.84	9.44	12.21	10.34	10.43	10.84	7.28	7.79	8.36	9.41
2012	7.55	9.15	11.92	10.04	10.14	10.55	6.99	7.50	8.07	9.12
2013	7.26	8.86	11.63	9.75	9.85	10.25	6.70	7.20	7.78	8.83
2014	6.97	8.57	11.34	9.46	9.56	9.96	6.40	6.91	7.49	8.54
2015	6.66	8.26	11.03	9.15	9.25	9.66	6.10	6.60	7.18	8.23
2016	6.71	8.31	11.07	9.20	9.30	9.70	6.14	6.65	7.23	8.28
2017	6.83	8.43	11.20	9.32	9.42	9.82	6.27	6.77	7.35	8.40
2018	6.95	8.55	11.32	9.45	9.54	9.95	6.39	6.90	7.47	8.52
2019	7.07	8.67	11.44	9.57	9.66	10.07	6.51	7.02	7.59	8.64
2020	7.19	8.80	11.56	9.69	9.78	10.19	6.63	7.14	7.71	8.76
2021	7.32	8.92	11.68	9.81	9.91	10.31	6.75	7.26	7.84	8.89
2022	7.44	9.04	11.81	9.93	10.03	10.43	6.87	7.38	7.96	9.01
2023	7.56	9.16	11.93	10.05	10.15	10.56	7.00	7.50	8.08	9.13
2024	7.68	9.28	12.05	10.18	10.27	10.68	7.12	7.63	8.20	9.25
2025	7.80	9.40	12.17	10.30	10.39	10.80	7.24	7.75	8.32	9.37
2026-2040	7.80	9.40	12.17	10.30	10.39	10.80	7.24	7.75	8.32	9.37
Levelized	7.55	9.15	11.92	10.05	10.14	10.55	6.99	7.50	8.07	9.12

Exhibit ES-10: Central New England Fuel Oil Forecast (2005$/MMBtu)

Year	Crude	No. 2 Distillate					No. 6 Residual Fuel <= 1% Sulfur		No. 4 Fuel Oil	
		Wholesale	Retail				Wholesale	Retail	Wholesale	Retail
			Residential	Commercial	Industrial	Electrical				
2005	7.86	9.39	12.33	10.30	10.22	10.66	7.29	7.80	8.34	9.37
2006	8.01	9.54	12.48	10.45	10.37	10.81	7.44	7.95	8.49	9.52
2007	7.65	9.19	12.12	10.10	10.02	10.45	7.09	7.59	8.14	9.17
2008	7.47	9.01	11.95	9.92	9.84	10.28	6.91	7.42	7.96	8.99
2009	7.67	9.21	12.15	10.12	10.04	10.48	7.11	7.62	8.16	9.19
2010	8.14	9.68	12.61	10.59	10.51	10.94	7.58	8.08	8.63	9.66
2011	7.84	9.38	12.32	10.29	10.21	10.65	7.28	7.79	8.33	9.36
2012	7.55	9.09	12.03	10.00	9.92	10.35	6.99	7.50	8.04	9.07
2013	7.26	8.80	11.73	9.71	9.63	10.06	6.70	7.20	7.75	8.78
2014	6.97	8.51	11.44	9.41	9.34	9.77	6.40	6.91	7.46	8.48
2015	6.66	8.20	11.13	9.11	9.03	9.46	6.10	6.60	7.15	8.18
2016	6.71	8.25	11.18	9.15	9.07	9.51	6.14	6.65	7.19	8.22
2017	6.83	8.37	11.30	9.28	9.20	9.63	6.27	6.77	7.32	8.35
2018	6.95	8.49	11.43	9.40	9.32	9.76	6.39	6.90	7.44	8.47
2019	7.07	8.61	11.55	9.52	9.44	9.88	6.51	7.02	7.56	8.59
2020	7.19	8.73	11.67	9.64	9.56	10.00	6.63	7.14	7.68	8.71
2021	7.32	8.85	11.79	9.76	9.68	10.12	6.75	7.26	7.80	8.83
2022	7.44	8.98	11.91	9.88	9.81	10.24	6.87	7.38	7.93	8.95
2023	7.56	9.10	12.03	10.01	9.93	10.36	7.00	7.50	8.05	9.08
2024	7.68	9.22	12.16	10.13	10.05	10.49	7.12	7.63	8.17	9.20
2025	7.80	9.34	12.28	10.25	10.17	10.61	7.24	7.75	8.29	9.32
2026-2040	7.80	9.40	12.17	10.30	10.39	10.80	7.24	7.75	8.32	9.37
Levelized	7.55	9.09	12.03	10.00	9.92	10.36	6.99	7.50	8.04	9.07

Exhibit ES-11: All New England Other Fuels Forecast (2005$/MMBtu)

Year	Propane				Kerosene		Wood	
	Wholesale	Retail			Wholesale	Retail	Retail	Retail
		Residential	Commercial	Industrial			Greenwood	Seasoned
2005	10.48	19.24	15.28	13.29	9.61	12.32	8.04	10.54
2006	10.63	19.39	15.43	13.44	9.57	12.27	8.21	10.75
2007	10.28	19.04	15.08	13.09	9.21	11.92	8.37	10.97
2008	10.10	18.86	14.90	12.91	9.03	11.74	8.54	11.19
2009	10.30	19.06	15.10	13.11	9.23	11.94	8.71	11.41
2010	10.76	19.52	15.57	13.58	9.70	12.41	8.88	11.64
2011	10.47	19.23	15.27	13.28	9.40	12.11	9.06	11.87
2012	10.18	18.94	14.98	12.99	9.11	11.82	9.24	12.11
2013	9.88	18.64	14.69	12.70	8.82	11.53	9.43	12.35
2014	9.59	18.35	14.40	12.41	8.53	11.24	9.61	12.60
2015	9.29	18.05	14.09	12.10	8.22	10.93	9.81	12.85
2016	9.33	18.09	14.14	12.15	8.27	10.97	10.00	13.11
2017	9.45	18.21	14.26	12.27	8.39	11.10	10.20	13.37
2018	9.58	18.34	14.38	12.39	8.51	11.22	10.41	13.64
2019	9.70	18.46	14.50	12.51	8.63	11.34	10.61	13.91
2020	9.82	18.58	14.62	12.63	8.75	11.46	10.83	14.19
2021	9.94	18.70	14.74	12.75	8.88	11.58	11.04	14.47
2022	10.06	18.82	14.87	12.88	9.00	11.71	11.26	14.76
2023	10.18	18.95	14.99	13.00	9.12	11.83	11.49	15.06
2024	10.31	19.07	15.11	13.12	9.24	11.95	11.72	15.36
2025	10.43	19.19	15.23	13.24	9.36	12.07	11.95	15.66
2026-2040	10.43	19.19	15.23	13.24	9.36	12.07	11.95	15.66
Levelized	10.18	18.94	14.98	12.99	9.12	11.83	10.47	13.72

Transmission and Distribution Capacity

ICF was asked to recommend a methodological approach which could be used by AESC study group participants to project avoided transmission and distribution capacity costs. The recommendation was intended to be designed to be able to be used by all participants individually. In order to accommodate this, ICF interviewed many of the participants to understand their current methodology and the data available to them. Based on this, ICF provided a recommended approach, and a spreadsheet tool which could be used to implement this approach, to the study group. The recommendation and tool are discussed in Chapter Five.

Demand Reduction Induced Price Effects

In addition to the core electric avoided costs described above, ICF was asked to determine if additional benefits may result from price response to demand reductions. Demand reduction induced price effects (DRIPE) reflect any change in addition to the avoided costs that occur due to a price response that results from the demand reduction. Exhibit ES-12 presents the results of the DRIPE analysis. A DRIPE Light scenario was also considered and is presented in Exhibit ES-13. Discussion of the DRIPE analysis and results is found in Chapter Six.

Exhibit ES-12. Incremental Benefit to New England Avoided Capacity Costs Resulting from Demand Reduction Induced Price Response

	FULL DRIPE BENEFIT 0.75% DEMAND REDUCTION FOR ALL NEW ENGLAND			
Units:	**2005$/kWyr**	**2005$/kWh**	**nominal $/kWyr[1]**	**nominal $/kWh[1]**
Comment:	Measured at Summer Coincident Peak	Expressed in $/kWh at 100% load factor	Measured at Summer Coincident Peak	Expressed in $/kWh at 100% load factor
2005 [2]	0.00	0.000	0.00	0.000
2006	612.51	0.070	626.29	0.071
2007	690.16	0.079	721.56	0.082
2008	53.75	0.006	57.46	0.007
2009	372.68	0.043	407.37	0.047
2010	289.32	0.033	323.37	0.037
2011	205.97	0.024	235.38	0.027
2012	122.61	0.014	143.27	0.016
2013	144.48	0.016	172.63	0.020
2014	166.35	0.019	203.23	0.023
2015	188.22	0.021	235.12	0.027
2016	210.09	0.024	268.35	0.031
2017	228.03	0.026	297.82	0.034
2018	245.98	0.028	328.49	0.037
2019	263.92	0.030	360.38	0.041
2020	281.87	0.032	393.54	0.045
2021	266.05	0.030	379.82	0.043
2022	250.24	0.029	365.29	0.042
2023	234.43	0.027	349.91	0.040
2024	218.62	0.025	333.65	0.038
2025	202.81	0.023	316.48	0.036
2026	186.99	0.021	298.37	0.034
2027	171.18	0.020	279.29	0.032
2028	155.37	0.018	259.20	0.030
2029	139.56	0.016	238.06	0.027
2030	123.75	0.014	215.83	0.025
2031	113.76	0.013	202.88	0.023
2032	103.77	0.012	189.23	0.022
2033	93.78	0.011	174.87	0.020
2034	83.80	0.010	159.76	0.018
2035	73.81	0.008	143.88	0.016
2036	63.82	0.007	127.21	0.015
2037	53.83	0.006	109.72	0.013
2038	43.85	0.005	91.37	0.010
2039	33.86	0.004	72.15	0.008
2040	23.87	0.003	52.01	0.006
Levelized[3]				
2005-2040	203.308	0.023	278.900	0.031
2006-2040	211.479	0.024	294.510	0.032
2006-2010	407.583	0.047	435.114	0.049
2006-2015	292.618	0.033	328.824	0.037
2006-2020	278.388	0.032	328.358	0.037

1. Assuming annual inflation rate of 2.25 percent.
2. The DRIPE scenarios did not include a demand curve response for 2005; no DRIPE value is therefore associated with 2005.
3. Real values are levelized at a 2.03 percent discount rate; nominal are levelized at a 4.32 percent discount rate.

Exhibit ES-13. Incremental Benefit to New England Avoided Capacity Costs Resulting from Demand Reduction Induced Price Response – Light Alternative

	DRIPE LIGHT BENEFIT 0.75% DEMAND REDUCTION FOR ALL NEW ENGLAND			
Units:	**2005$/kWyr**	**2005$/kWh**	**nominal $/kWyr[1]**	**nominal $/kWh[1]**
Comment:	Measured at Summer Coincident Peak	Expressed in $/kWh at 100% load factor	Measured at Summer Coincident Peak	Expressed in $/kWh at 100% load factor
2005 [2]	0.00	0.000	0.00	0.000
2006	67.09	0.008	68.60	0.008
2007	101.30	0.012	105.91	0.012
2008	64.78	0.007	69.25	0.008
2009	80.08	0.009	87.53	0.010
2010	70.20	0.008	78.46	0.009
2011	60.31	0.007	68.93	0.008
2012	50.43	0.006	58.93	0.007
2013	62.84	0.007	75.08	0.009
2014	75.25	0.009	91.93	0.010
2015	87.66	0.010	109.50	0.012
2016	100.06	0.011	127.81	0.015
2017	100.28	0.011	130.98	0.015
2018	100.51	0.011	134.22	0.015
2019	100.73	0.011	137.54	0.016
2020	100.95	0.012	140.95	0.016
2021	97.15	0.011	138.70	0.016
2022	93.35	0.011	136.27	0.016
2023	89.56	0.010	133.67	0.015
2024	85.76	0.010	130.88	0.015
2025	81.96	0.009	127.90	0.015
2026	78.16	0.009	124.72	0.014
2027	74.36	0.008	121.33	0.014
2028	70.57	0.008	117.72	0.013
2029	66.77	0.008	113.89	0.013
2030	62.97	0.007	109.83	0.013
2031	58.91	0.007	105.07	0.012
2032	54.86	0.006	100.04	0.011
2033	50.80	0.006	94.72	0.011
2034	46.75	0.005	89.12	0.010
2035	42.69	0.005	83.22	0.010
2036	38.63	0.004	77.01	0.009
2037	34.58	0.004	70.47	0.008
2038	30.52	0.003	63.61	0.007
2039	26.47	0.003	56.39	0.006
2040	22.41	0.003	48.83	0.006
Levelized[3]				
2005-2040	69.295	0.023	95.060	0.031
2006-2040	72.080	0.008	100.380	0.012
2006-2010	76.746	0.009	81.930	0.009
2006-2015	72.108	0.008	81.031	0.009
2006-2020	80.638	0.009	95.113	0.011

1. Assuming annual inflation rate of 2.25 percent.
2. The DRIPE Light scenarios did not include a demand curve response for 2005; no DRIPE Light value is therefore associated with 2005.
3. Real values are levelized at a 2.03 percent discount rate; nominal are levelized at a 4.32 percent discount rate.

ICF has also provided a list of sources used in developing the analysis in Appendix Three.

Chapter One: Avoided Gas Costs

This chapter presents the analysis of avoided gas costs. First we summarize the retail avoided gas costs for New England. Then we provide an overview of the New England gas market. The third section discusses the avoided cost methodology and the build up of the avoided cost estimates. The avoided costs by winter type and local distribution company avoided costs are in the third section. We then compare this with the previous avoided cost study. In the Appendices are found additional supporting calculations of avoided costs.

In the course of preparing this forecast, Hurricane Katrina struck the Gulf Coast and severely damaged natural gas production infrastructure. Natural gas prices soared. The forecast below takes into account the price impacts of Katrina, which are reflected in the early forecast years 2005 to 2009.

Summary of Avoided Gas Costs

Avoided natural gas costs are made up of two components, those costs avoidable by the local distribution companies (LDC) and the retail or end user avoided cost. 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. The avoided costs for end users also include the avoidable costs of distribution. The costs of serving a gas load vary depending on the season. Since all northern pipeline systems are designed to meet winter peak demand, avoided costs are higher in winter than in the summer. That is, a unit of gas saved in the winter allows LDCs to avoid the costs of pipe, storage, and peaking supply. In summer the avoided cost of gas service are limited to the cost of gas and the variable transportation and redelivery cost.

Below, we present a summary of our estimated avoided end user costs separately for Southern New England (Connecticut and Rhode Island) and Northern and Central New England (Massachusetts, New Hampshire, Maine). (Vermont costs are treated separately at the end of this chapter.) In the following sections, we provide an overview of the New England gas market and a description with supporting calculations of how these avoided gas cost estimates were built up. A comparison of the 2005 avoided cost calculations with the 2003 avoided cost calculations is also provided. ICF was asked to provide a separate calculation of avoided costs for Vermont given the limited market for gas in the state and the isolation from other states; a discussion of the approach used to capture the avoided costs in Vermont and the projections are included. Finally, we close with a discussion of the gas price forecasts as applied to the power sector modeling.

Exhibit 1-1 Annual Avoided Retail Gas Costs Southern New England (2005$/MMBtu)

	Residential				Commercial & Industrial			All Retail
Year	Existing Heating	New Heating	Hot Water	All	Non Heating	Heating	All	
2005	12.60	12.49	12.46	12.51	11.17	11.20	11.18	11.92
2006	13.08	12.97	12.97	13.01	11.68	11.68	11.68	12.41
2007	12.64	12.54	12.61	12.60	11.32	11.25	11.28	12.01
2008	10.62	10.52	10.51	10.55	9.22	9.23	9.22	9.95
2009	9.62	9.52	9.47	9.54	8.18	8.23	8.21	8.94
2010	8.89	8.79	8.68	8.79	7.39	7.50	7.44	8.18
2011	8.95	8.85	8.75	8.85	7.46	7.56	7.51	8.25
2012	9.17	9.07	8.97	9.07	7.68	7.78	7.73	8.47
2013	9.38	9.28	9.17	9.28	7.88	7.99	7.93	8.67
2014	9.99	9.88	9.77	9.88	8.48	8.59	8.54	9.28
2015	9.55	9.45	9.35	9.45	8.05	8.16	8.11	8.85
2016	9.58	9.48	9.37	9.47	8.08	8.19	8.13	8.87
2017	9.55	9.45	9.34	9.45	8.05	8.16	8.10	8.84
2018	9.71	9.60	9.50	9.60	8.21	8.31	8.26	9.00
2019	9.90	9.80	9.69	9.80	8.40	8.51	8.45	9.19
2020	10.04	9.94	9.83	9.94	8.54	8.65	8.59	9.33
2021	10.36	10.25	10.14	10.25	8.85	8.96	8.91	9.65
2022	10.46	10.35	10.24	10.35	8.95	9.06	9.00	9.74
2023	10.83	10.73	10.61	10.73	9.32	9.44	9.38	10.12
2024	10.94	10.83	10.71	10.83	9.42	9.54	9.48	10.22
2025	11.45	11.34	11.22	11.34	9.93	10.05	9.99	10.73
2026-40	11.45	11.34	11.22	11.34	9.93	10.05	9.99	10.73
Levelized 2.03%	10.74	10.63	10.54	10.64	9.25	9.34	9.29	10.03

Exhibit 1-2 Annual Avoided Retail Gas Costs Northern and Central New England (2005 $/MMBtu)

	Residential				Commercial & Industrial			All Retail
Year	Existing Heating	New Heating	Hot Water	All	Non Heating	Heating	All	
2005	12.28	12.19	12.19	12.22	11.31	11.31	11.31	11.81
2006	12.76	12.67	12.70	12.71	11.82	11.79	11.80	12.30
2007	12.33	12.24	12.34	12.30	11.46	11.36	11.41	11.90
2008	10.34	10.25	10.27	10.29	9.39	9.37	9.38	9.88
2009	9.36	9.28	9.25	9.30	8.37	8.40	8.39	8.89
2010	8.63	8.55	8.48	8.55	7.60	7.67	7.63	8.14
2011	8.70	8.62	8.54	8.62	7.66	7.74	7.70	8.20
2012	8.91	8.83	8.75	8.83	7.87	7.95	7.91	8.42
2013	9.12	9.04	8.96	9.04	8.08	8.16	8.12	8.62
2014	9.72	9.63	9.55	9.63	8.67	8.75	8.71	9.22
2015	9.29	9.21	9.13	9.21	8.25	8.33	8.29	8.79
2016	9.31	9.23	9.15	9.23	8.27	8.35	8.31	8.82
2017	9.28	9.20	9.12	9.20	8.24	8.32	8.28	8.79
2018	9.44	9.36	9.28	9.36	8.40	8.48	8.44	8.94
2019	9.63	9.55	9.47	9.55	8.59	8.67	8.63	9.13
2020	9.77	9.68	9.60	9.69	8.72	8.80	8.76	9.27
2021	10.08	9.99	9.91	10.00	9.03	9.11	9.07	9.58
2022	10.18	10.09	10.01	10.09	9.13	9.21	9.17	9.68
2023	10.55	10.46	10.38	10.46	9.50	9.58	9.54	10.05
2024	10.65	10.56	10.47	10.56	9.59	9.68	9.64	10.15
2025	11.15	11.06	10.97	11.06	10.09	10.18	10.14	10.65
2026-40	11.15	11.06	10.97	11.06	10.09	10.18	10.14	10.65
Levelized								
2.03%	10.45	10.37	10.30	10.37	9.42	9.49	9.45	9.96

Exhibit 1-3 below summarizes the levelized costs by region, by period of levelization for all of the retail sectors.

Exhibit 1-3. Summary of Levelized Retail Avoided Coats (2005$/MmBtu)

	Residential				Commercial & Industrial			All Retail
Years Levelized	Existing Heating	New Heating	Hot Water	All	Non Heating	Heating	All	
Southern New England								
10	10.54	10.44	10.33	10.44	9.04	9.15	9.09	9.83
15	10.32	10.22	10.11	10.22	8.82	8.93	8.87	9.61
20	10.42	10.31	10.20	10.31	8.91	9.02	8.97	9.71
35	10.76	10.65	10.54	10.65	9.25	9.36	9.31	10.05
Northern & Central New England								
10	10.26	10.18	10.09	10.18	9.21	9.30	9.25	9.76
15	10.05	9.96	9.88	9.96	9.00	9.08	9.04	9.55
20	10.14	10.05	9.97	10.05	9.09	9.17	9.13	9.64
35	10.48	10.39	10.30	10.39	9.42	9.51	9.47	9.97
Vermont								
10	9.48	9.41	9.32	9.40	8.29	8.37	8.33	8.92
15	9.27	9.20	9.12	9.20	8.09	8.17	8.13	8.72
20	9.36	9.29	9.21	9.29	8.17	8.26	8.22	8.80
35	9.68	9.61	9.52	9.60	8.49	8.57	8.53	9.12

Overview of New England Gas Market

Gas Consumption

New England has about 2.3 million natural gas customers. Of this number, 2.1 million are residential and the rest commercial and industrial. In 2004, New England consumed about 811 billion cubic feet (Bcf) of natural gas. Most of this gas is purchased from LDCs, however about 18,000 transportation service customers (those who buy gas from marketers and use LDCs or interstate pipelines to transport the gas) account for about 185 Bcf of the total consumption. (Northeast Gas Association, NEGA)Transportation customers tend to be electricity generators and large industrial or commercial entities.

Between 2001 and 2004, Massachusetts accounted for 52 percent of New England's gas consumption and Connecticut about 20 percent. Maine, which previously had only minor gas consumption now accounts for 11 percent as does Rhode Island.

From a national perspective, New England is a relatively small gas market. Historically this has been due largely to New England's distance from gas production and that few pipelines reached into the region. Distance from markets has led to high gas costs, relative to other markets. As such, gas' share of the heating market in New England is smaller than that of New York and many other states: gas accounts for 33 percent of the home heating market, oil for 49 percent. (NEGA)

Exhibit 1-4 below presents annual New England natural gas consumption by sector for 1990 through 2004. Total natural gas consumption since 1990 has almost doubled. While every sector has grown, the major growth has occurred in the use of gas for electric power generation.

Exhibit 1-4: Natural Gas Consumption by Sector in New England (Bcf)

Sector	1990	1995	2000	2003	2004
Residential	170.7	173.7	185.4	204.2	193.3
Commercial	96.9	143.8	139.1	138.9	122.8
Industrial	81.3*	184.7*	244.2*	126.1	124.6
Electric Power	66.2*	91.3*	13.0*	343.2	370.0
Total	415.1	593.5	581.6	812.3	810.7

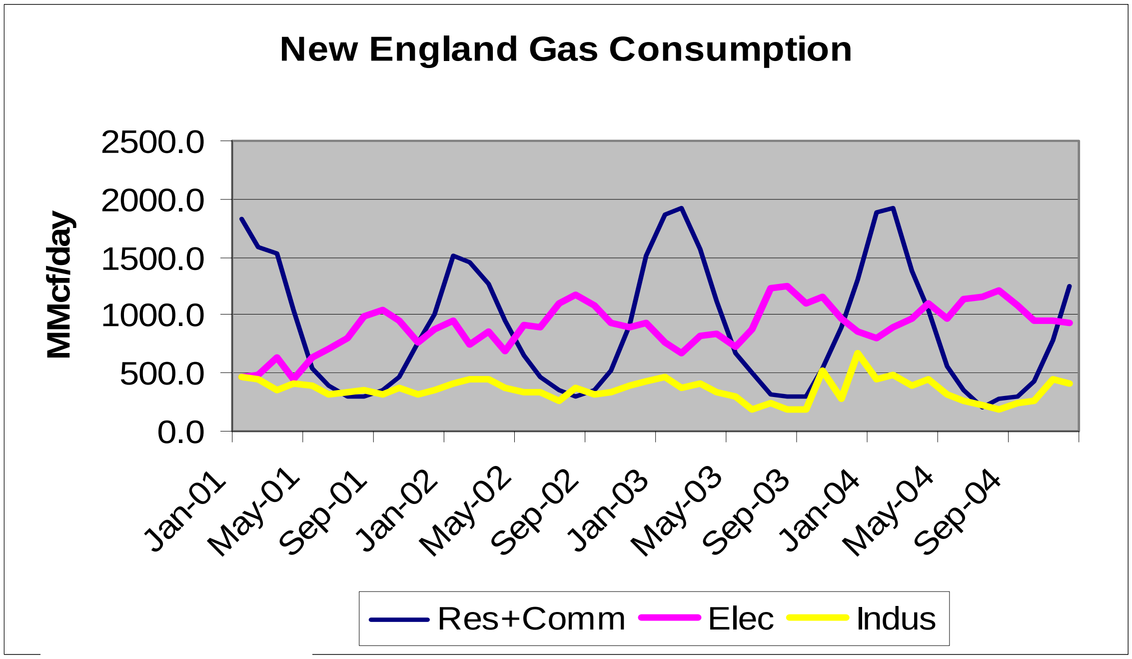
Source: EIA, 2005

*The EIA includes the data for the non-utility generation under the Industrial sector rather than in the Electric Utility sector.

Natural gas consumption is very seasonal, as Exhibit 1-5 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 consumption 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 is the cumulative number of days in a month or year by which the mean temperature falls below 18.3°C/65°F.) 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 13 percent from 1990 to 2004.

Exhibit 1-5: Pattern of Consumption in New England (MMcf per Day)



Source: EIA, 2005.

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. Commercial consumption in New England has increased 25 percent since 1990. Growth in natural gas use 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 keep gas usage relatively flat over the course of a year. Since 2001, industrial demand has been flat. (EIA reclassified industrial consumption beginning in 2001 and statistics before then are not comparable.)

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 2003, it was 31 percent (NEGA). The number of new gas plants has increased significantly in recent years, with the addition of over 4,000 MWs of new gas generation to the regional grid. Exhibit 1-5 illustrates another interesting facet of power demand for gas – it tends to be counter-seasonal, with more consumption in summer than in winter. This pattern allows pipelines to be used more efficiently. Nevertheless, despite lower consumption in winter than in summer, gas consumption for electric power generation is still significant. Thus the overall growth in power demand for gas is also contributing to peak period requirements.

The EIA Annual Energy Outlook for 2005 projects New England gas consumption will grow about 1.4 percent annually through 2025. Much of this growth will be in the power sector.

Gas Supply

Five interstate pipelines and one LNG import facility serve the New England market by bringing in gas supply from the U.S. Gulf Coast and both western and eastern Canada. LNG comes from a variety of areas, principally from Trinidad and Tobago. (See Exhibit 1-6.)

- 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. TGP has major interconnections for Canadian supplies at Niagara, New York, with TransCanada Pipelines (TCPL) and at Wright, New York with Iroquois Gas Transmission System (Iroquois).

- The Algonquin Gas Transmission System (AGT) and its upstream sister pipeline, Texas Eastern Transmission Company (TETCO), both owned by Duke Energy, serve much of southern New England and reaches to the Boston area. AGT via TETCO also has direct access to the Gulf Coast; with its interconnection with Iroquois it also has access to western Canadian gas. AGT in the last year has also become connected to the Maritimes and Northeast Pipeline (a Duke affiliate), via the Hub Line around Boston.

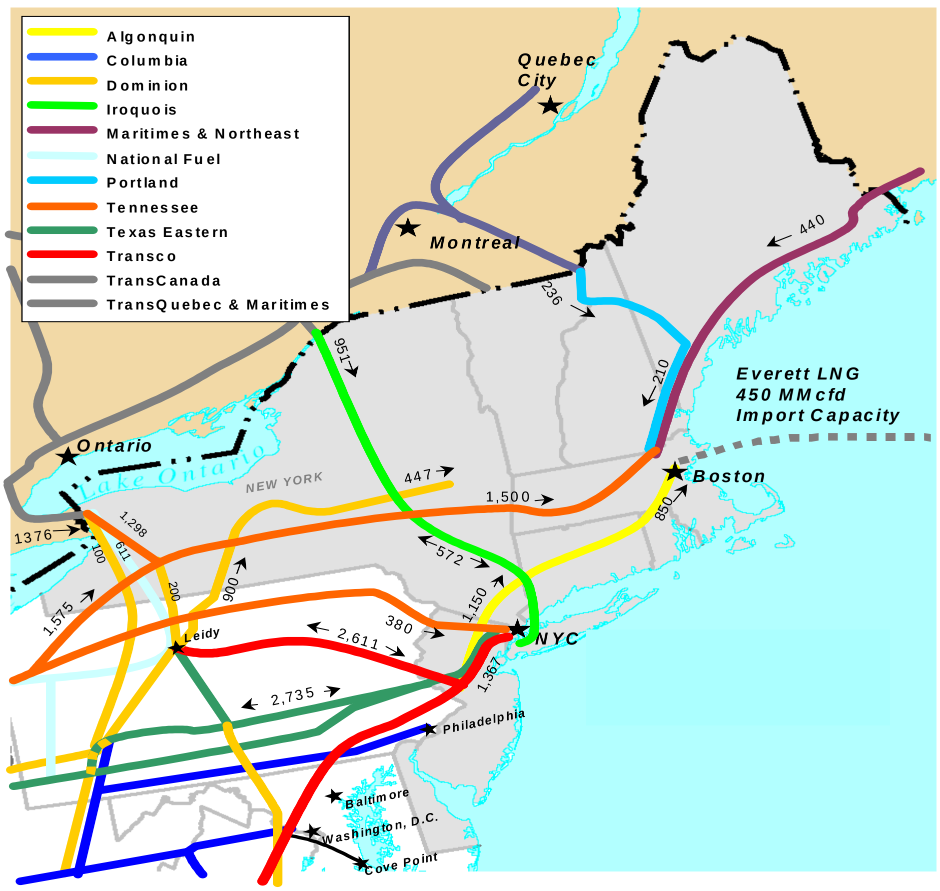
- Iroquois provides gas to both TGP and AGT and also serves LDCs directly in Connecticut. Iroquois is connected to TCPL at Waddington, New York, and terminates in Long Island. The Eastchester extension of Iroquois also reaches into New York City.

- The Portland Natural Gas Transmission System (PNGTS) enters New England from the northwest, providing direct access to western Canada via the upstream TransQuebec and Maritime Pipeline (TQM) and TCPL. The PNGTS provides gas to southern Maine, New Hampshire, and Massachusetts. For the last 101 miles, it shares pipeline space with Maritimes and Northeast.

- Maritimes and Northeast Pipeline enter New England from New Brunswick, Canada, and provide access to Sable Island gas supplies. Maritimes serves Maine but provides the bulk of its supply into the Boston market area at Dracut, Massachusetts, and via the Hub Line.

- Distrigas of Massachusetts (DOMAC), owned by Suez Energy Resources North America (formerly known as Tractebel), operates the U.S.'s oldest LNG import facility at 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.

Exhibit 1-6: Northeast Pipeline Infrastructure



The LDC markets in New England are heavily dominated by TGP and AGT, which provide 80 percent of the gas in New England.

Because of the highly seasonal nature of gas demand in New England, storage access is vital in supply planning. There is no storage in New England. New England has access to upstream storage in New York, via TGP, and in Pennsylvania, via AGT/TETCO and TGP. LNG is primarily a winter fuel in New England. LDCs operate about 15 Bcf of storage capacity in satellite LNG plants. DOMAC provides about 3.4 Bcf of additional storage.

LDCs shipping on these pipelines acquire firm transportation service (FT) and storage service. 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.

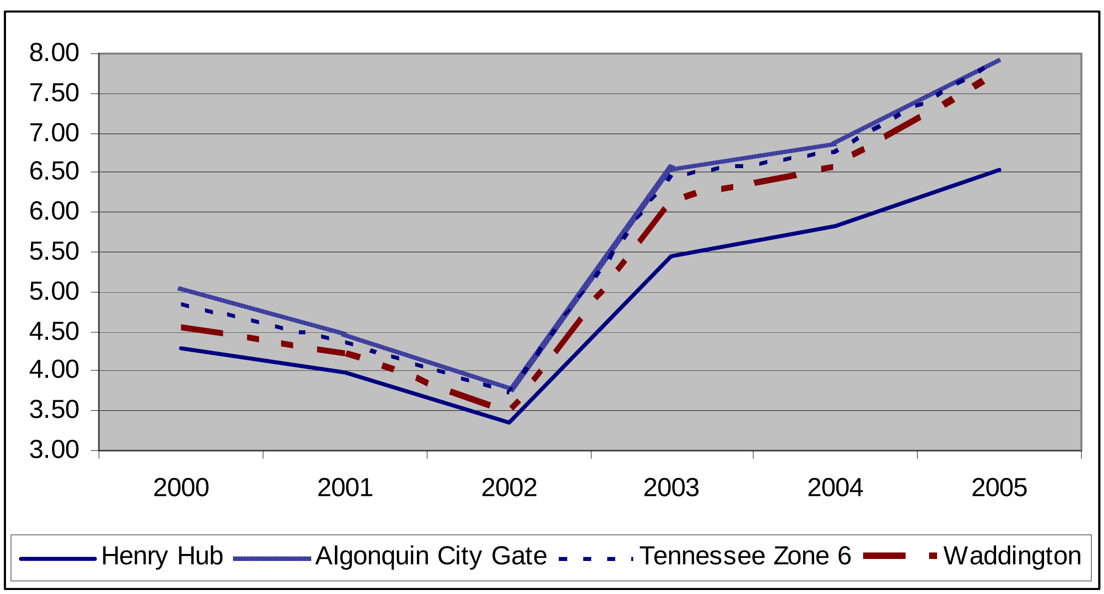
For purposes of estimating avoided costs, the marginal source of gas can be considered the U.S. Gulf Coast, as represented by Henry Hub prices. Supplies from other areas like Sable Island and LNG are priced in reference to Gulf Coast supply. For deliveries into New England, we have used the TGP and TETCO-AGT systems along with their storage services. For peaking supplies, we have used the Distrigas LNG facility.

Gas Prices

Natural gas prices have increased significantly in the last several years, as has the overall volatility of gas prices... In this section we address both issues and consider the implications of these developments for avoided gas costs.

Exhibit 1-7 presents annual average prices at four pricing points: Henry Hub (in Louisiana), the Algonquin City Gates, Waddington (Iroquois's connections with TCPL), and TGP's Zone 6 (New England). These are market hubs where gas trading takes place and for which prices are published by *Gas Daily* and other publications. LDCs will occasionally purchase or sell gas into these hubs to meet transient gas needs and the manage imbalances. The graph highlights two developments – the great increase in gas prices since 2002 and the expanding difference between the price of gas in Louisiana and the market price for gas at key New England pricing points.

Exhibit 1-7: Annual Average Gas Prices ($/MMBtu)



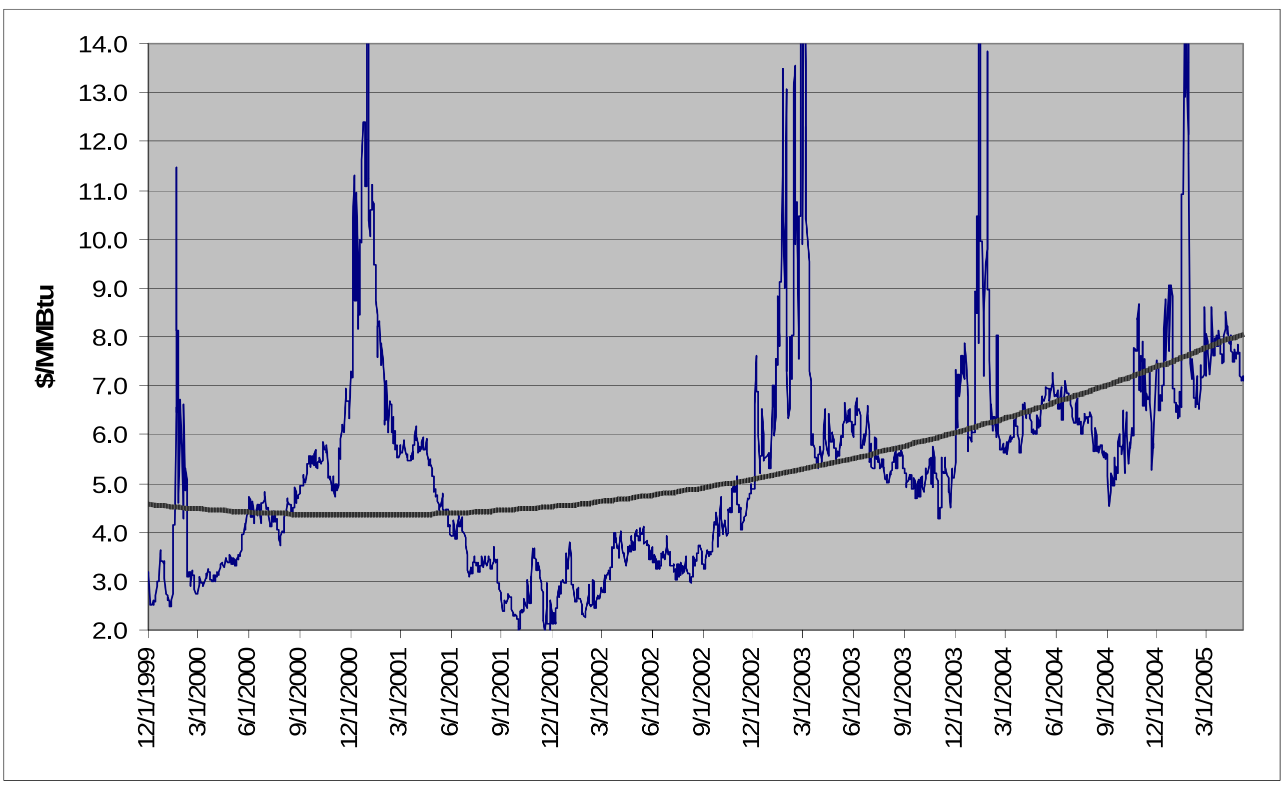
Source: Gas Daily, various issues. 2005 is through May

The overall gas price increase is due to the general tightening of gas supplies in North America and the strong demand for gas. This is reflected in all markets, and as shown here, gas prices in New England follow Henry Hub prices.

The second notable aspect of the data is the expanding spread between New England prices and Henry Hub – this is referred to as the basis spread. Since 2002, the basis between Henry Hub and various New England pricing points has increased from about $0.50/MMBtu to over $1.00/MMBtu. In part this is a result of the overall increase in the price of gas and the resulting fuel cost for delivering it to New England. A major cause of the higher basis is the demand on gas capacity, which has bid up the price of delivered gas in New England. Thus the expanding price difference suggests a need for additional pipeline capacity and supply.

Volatility is also a characteristic of the natural gas market. Exhibit 1-8 presents daily gas prices for TGP Zone 6. (To keep the graph less complicated, we do not show AGT prices – they are only a few cents different from TGP prices.) This graph illustrates the increasing volatility of gas prices around the trend line (also shown) and the general rise in prices shown by the trend line.

Exhibit 1-8: TGP Zone 6 Daily Pricing since Dec. 1999



Source: Gas Daily. Various Issues.

The spikes in gas prices correspond to winter periods when cold fronts sweep through New England. LDC pricing tends to reflect volatility at Henry Hub and not local volatility. This is because LDCs (and most marketers) purchase gas in the producing areas and use firm transportation to ship gas to New England. This gas is bought and priced at first of the month indices. Daily pricing reflects transient conditions in the market – weather, for example. LDCs may occasionally buy gas in this short term market to meet balancing obligations.

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 the section titled "Delivery Costs to New England." 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

Exhibit 1-9 shows the development of the Henry Hub forecast used for this study. NANGAS® was used to develop the "Base" outlook for gas prices. The "Blended" column shows the results of the blending of the "Base" forecast for the years 2005 through 2009 with current futures market forward prices. The blended price incorporates several elements: actual prices year-to-date (for 2005), futures prices, EIA's short term forecast, and the Base case forecast. Beginning in 2005, the reported price is a blend of actual prices, futures and the EIA short term forecast; in 2006, the price is a blend of EIA's short term forecast and futures; in 2007 the price is a blend of mostly futures and the base forecast; for 2008 and 2009, the base case is blended with futures prices, with the base assuming a larger share each year. The Henry Hub prices for 2010 and beyond are based on a pure model-generated outlook. This adjustment was made to reflect current market conditions that are not captured in a long term forecasting model such as NANGAS®. As noted earlier, the blending of the futures also reflects the recent impact of Katrina on near term gas prices through 2009.

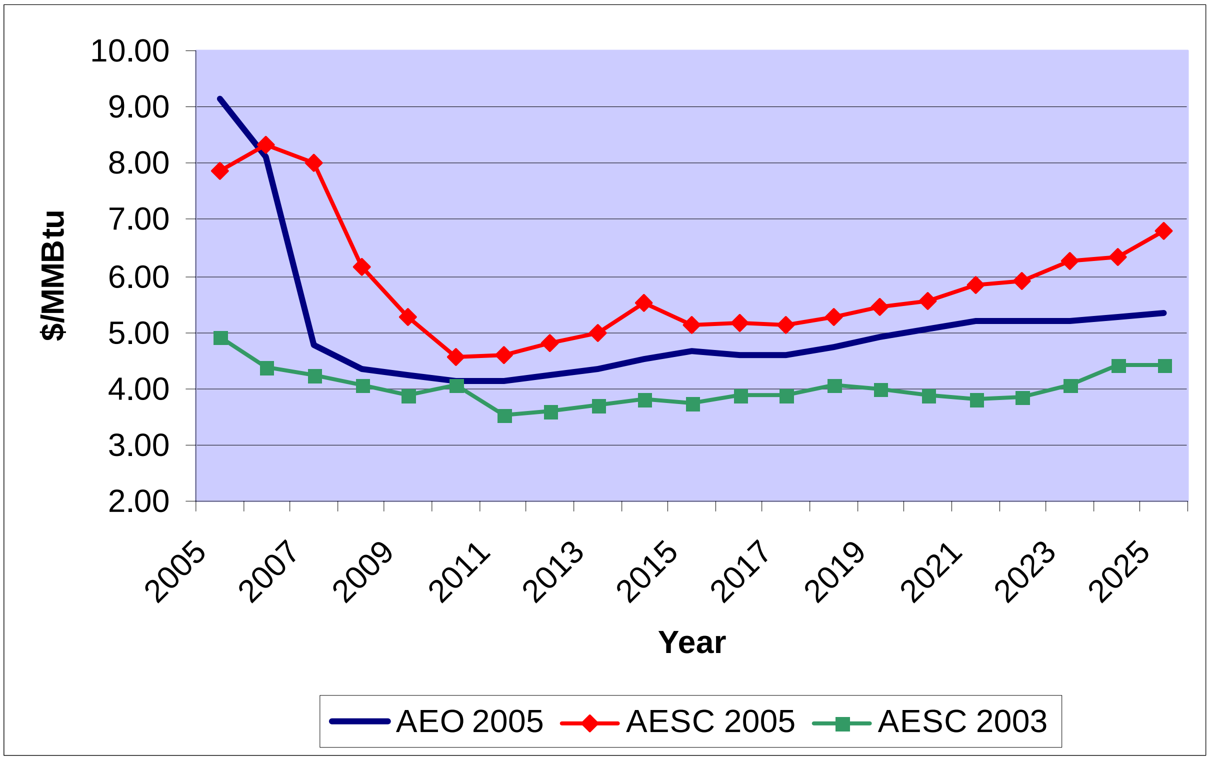
The "Adjustment" column is a multiplier that was determined by the ratio of a NANGAS® forecast using a pessimistic supply outlook case which yielded higher gas prices and the less pessimistic base case forecast. Beyond 2014, this adjustment increased the forecast prices by about 10 percent. The resulting forecast shown in the "New HH" column is the product of the "Blended" and "Adjustment" and should be considered an expected case, where some accounting is made for uncertainty around the future of LNG and sources of North American supply. The expected case forecast described above represents a consensus view of the AESC team.

Exhibit 1-9: Henry Hub Price Forecast with Adjustments (2005$/MMBtu)

	Base	Blended	Adjustment	New HH
2005	6.89	7.88	1.00	7.88
2006	6.50	8.33	1.00	8.33
2007	5.38	8.02	1.00	8.02
2008	4.44	6.16	1.00	6.16
2009	4.39	5.25	1.004	5.27
2010	4.52	4.52	1.007	4.55
2011	4.58	4.58	1.007	4.61
2012	4.64	4.64	1.035	4.80
2013	4.70	4.70	1.061	4.98
2014	5.03	5.03	1.096	5.51
2015	4.65	4.65	1.104	5.14
2016	4.68	4.68	1.101	5.16
2017	4.64	4.64	1.106	5.13
2018	4.77	4.77	1.104	5.27
2019	4.93	4.93	1.104	5.44
2020	5.03	5.03	1.106	5.56
2021	5.28	5.28	1.106	5.84
2022	5.36	5.36	1.106	5.92
2023	5.66	5.66	1.106	6.26
2024	5.73	5.73	1.106	6.34
2025	6.14	6.14	1.106	6.79

Exhibit 1-10 compares the “New HH” forecast with the current Energy Information Administration (EIA) 2005 Annual Energy Outlook (AEO) forecast, adjusted to 2005$ and to Henry Hub. (For reference, we also show the 2003 AESC forecast, converted to 2005$). The AEO forecast also includes adjustments for hurricane Katrina. The “New HH” forecast is higher than the AEO forecast except for 2005. The overall shape and trajectories of the forecasts are similar except in the near term.

Exhibit 1-10: EIA and AESC Henry Hub Forecast Comparison



The AESC forecast represents a view that natural gas prices will be moderated in the future by additional supply, principally LNG, but also new production from the Rockies and Gulf of Mexico, responding to today's high gas prices. Gas prices are expected to fall to below $5.00/MMBtu by 2009, bottoming out in 2010 at $4.55/MMBtu. Thereafter, prices increase as demand increases. The higher prices are a result of higher cost supply from unconventional settings, strong demand for gas in the power sector, and restrictions on the amount of LNG that enters the country. The spike in 2014 occurs just before the entry of Alaskan natural gas.

Summer/Winter Differentials

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. Exhibit 1-11 shows the annual average price and the percent 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 1-11: Forecast and Seasonal Henry Hub Gas Prices for Each Winter/Summer Type (2005$/MMBtu)

Year	"New HH" 2005$ /MMBtu	Winter=(Dec-Feb) Summer -3.57%	Winter=(Dec-Feb) Winter 10.71%	Winter=(Nov-Mar) Summer -4.12%	Winter=(Nov-Mar) Winter 5.76%	Winter=(Oct-Mar) Summer -4.46%	Winter=(Oct-Mar) Winter 4.46%	Winter=(Oct-Apr) Summer -5.05%	Winter=(Oct-Apr) Winter 3.61%
2005	7.88	7.60	8.73	7.56	8.34	7.53	8.24	7.49	8.17
2006	8.33	8.04	9.23	7.99	8.81	7.96	8.71	7.91	8.64
2007	8.02	7.73	8.87	7.69	8.48	7.66	8.37	7.61	8.30
2008	6.16	5.94	6.82	5.91	6.52	5.89	6.44	5.85	6.39
2009	5.25	5.06	5.81	5.03	5.55	5.02	4.89	4.99	5.44
2010	4.55	4.39	5.04	4.37	4.82	4.35	4.76	4.32	4.72
2011	4.61	4.45	5.10	4.42	4.88	4.41	4.82	4.38	4.78
2012	4.80	4.63	5.32	4.61	5.08	4.59	5.02	4.56	4.98
2013	4.98	4.81	5.52	4.78	5.27	4.76	5.21	4.73	5.16
2014	5.51	5.32	6.11	5.29	5.83	5.27	5.76	5.24	5.71
2015	5.14	4.95	5.69	4.92	5.43	4.91	5.37	4.88	5.32
2016	5.16	4.97	5.71	4.95	5.45	4.93	5.39	4.90	5.34
2017	5.13	4.95	5.68	4.92	5.43	4.90	5.36	4.87	5.32
2018	5.27	5.08	5.83	5.05	5.57	5.04	5.51	5.00	5.46
2019	5.44	5.25	6.02	5.22	5.75	5.20	5.68	5.17	5.64
2020	5.56	5.36	6.16	5.33	5.88	5.31	5.81	5.28	5.76
2021	5.84	5.63	6.46	5.60	6.17	5.58	6.10	5.54	6.05
2022	5.92	5.71	6.56	5.68	6.27	5.66	6.19	5.63	6.14
2023	6.26	6.03	6.93	6.00	6.62	5.98	6.53	5.94	6.48
2024	6.34	6.12	7.02	6.08	6.71	6.06	6.63	6.02	6.57
2025	6.79	6.55	7.52	6.51	7.18	6.49	7.09	6.45	7.04

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 perspective requires consideration of how avoidable costs appear to LDCs. LDCs typically purchase gas at first of the month index prices, usually at a reference point in the producing region, in this case at Henry Hub or other nearby areas along the Gulf of Mexico that reference Henry Hub. The gas is transported over pipelines under long-term firm transportation agreements. As such, LDCs' supply costs often do not reflect the wild daily gyrations in gas prices that characterize the northeastern markets. (LDCs do enter daily markets to supplement supplies and manage imbalances.)

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 an LDC avoids having to meet demand in the summer, it avoids only having to purchase and transport an incremental MMBtu of gas. Because capacity is in excess supply in the summer, the pipeline capacity value is nearly zero, and thus is not avoidable.

To estimate the non-gas delivery costs we used the tariffs of the major pipelines delivering gas to New England: TGP for northern and central New England and TETCO, and 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 1-12.

Exhibit 1-12: Pipeline and Storage Costs

Pipelines	Annual Fixed Cost/MMBtu of Demand	Commodity Rate/MMBtu	Fuel Percent
TETCO+Algonquin	$232.74	$0.088	9.45%
TETCO Storage	$74.40	$0.096	0
TGP	$181.80	$0.15	7.15 %
TGP Storage	$30.45	$0.02	2%
Distrigas LNG	$730.00	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 include:

- The gas cost (Henry Hub) as shown in Exhibit 1-11.
- 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. These costs, shown in column one of Exhibit 1-12, are allocated on a per unit basis by dividing the annual costs by the number of days in the appropriate winter periods.

- 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 as shown in the second column in Exhibit 1-12, above. The fuel charge is calculated as a percent of the cost of the natural gas and is included in the commodity rate.

Our general approach recognizes that reservation charges are incurred to meet peak winter demand. Thus, the winter avoided costs equal the sum of the Henry Hub price, the variable transportation costs on the appropriate pipeline, and the cost of a year's 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 simply the Henry Hub price and the variable costs of transportation.

One step in the analysis was determining the share of winter reservation costs that are attributable to pipeline, storage and peak shaving reservation charges. The mix of pipeline transported gas, storage, and LNG for a typical LDC is optimized around that LDC's particular load shape. That is, LDCs purchase a mix of capacity that allows them to meet peak loads at lowest cost. For example, the amount of storage capacity will be determined by its cost, relative to the cost of pipeline and peak shaving capacity for the LDC's particular load characteristics. Changes in the shape of the load due to conservation and load management (C&LM) programs thus have cost impacts across all supply options, and not just on the marginal supply source, such as LNG or storage. 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 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 1-13):

Exhibit 1- 13: Percent Weightings for Each Winter Type New England

Winter Type	Pipeline	Storage	LNG	Total
3 Month	77%	18%	5%	100.0%
5 Month	80%	15%	5%	100.0%
6 Month	82%	13%	5%	100.0%
7 Month	84%	12%	4%	100.0%
Annual	85%	11%	4%	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.

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 1-14, where the avoided costs are presented on a monthly basis and daily basis. Annual capacity costs are first allocated to the appropriate winter type on a monthly basis (that is the annual cost is divided by 3 for the 3 month winter, by 5, for the 5 month winter, and so on.) These costs are then allocated to the share of load met by the three service types to yield the winter weighted charges. The total is the sum of all the winter weighted reservation charges. The daily is the total reservation charges divided by the average number of days in the month, to which is added the sum of the variable costs. The results, along with the fuel percent are then used to calculate the total avoided costs in Exhibits 1-15 and 1-16. Pipeline tariffs are not escalated in real terms in the forecasts.

Exhibits 1-15 and 1-16 present the calculations of the wholesale avoided costs by winter type. This is the approach used in previous AESC reports. The winter types were then used to construct the avoided costs by end user categories shown in the exhibits at the first of this chapter, using the cross walk shown in Exhibit 1-17.

Exhibit 1-14a: 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%	$77.58	$0.088	$59.42	**$75.49** *($2.55)*	9.500%
	Storage	18%	$24.80	$0.000	$4.64		
	LNG	5%	$243.33	$0.000	$11.43		
5M Winter (Nov-Mar)	Pipeline	80%	$46.55	$0.088	$37.05	**$46.68** *($1.605)*	9.500%
	Storage	15%	$14.88	$0.000	$2.29		
	LNG	5%	$146.00	$0.000	$7.33		
6M Winter (Nov-Apr)	Pipeline	82%	$38.79	$0.088	$31.81	**$39.50** *($1.371)*	9.500%
	Storage	13%	$12.40	$0.000	$1.61		
	LNG	5%	$121.67	$0.000	$6.08		
7M Winter (Oct-Apr)	Pipeline	84%	$33.25	$0.088	$27.84	**$33.49** *($1.175)*	9.500%
	Storage	12%	$10.63	$0.000	$1.28		
	LNG	4%	$104.29	$0.000	$4.37		
Annual	Pipeline	85%	$19.40	$0.088	$16.49	**$19.60** *($0.719)*	9.500%
	Storage	11%	$6.20	$0.000	$0.68		
	LNG	4%	$60.83	$0.000	$2.43		

Exhibit 1-14b: Monthly Pipeline Costs Associated with Each Winter Type ($2004/MMBtu) Northern and Central New England

		Weightings	Winter Reservation Charges	Variable Charge	Winter Weighted Charges	Total* (daily)**	Fuel
3M Winter (Dec-Feb)	Pipeline	77%	$60.60	$0.15	$46.41	$59.74 *($2.08)*	7.100%
	Storage	19%	$10.15	$0.02	$1.90		2.000%
	LNG	5%	$243.33	$0.00	$11.43		
5M Winter (Nov-Mar)	Pipeline	80%	$36.36	$0.15	$28.94	$37.21 *($1.35)*	7.100%
	Storage	15%	$6.09	$0.02	$0.94		2.000%
	LNG	5%	$146.00	$0.00	$7.33		
6M Winter (Nov-Apr)	Pipeline	82%	$30.30	$0.15	$24.85	$31.62 *($1.17)*	7.100%
	Storage	13%	$5.08	$0.02	$0.66		2.000%
	LNG	5%	$121.67	$0.00	$6.11		
7M Winter (Oct-Apr)	Pipeline	84%	$25.97	$0.15	$21.75	$26.64 *($1.00)*	7.100%
	Storage	12%	$4.35	$0.02	$0.53		2.000%
	LNG	4%	$104.29	$0.00	$4.37		
Annual	Pipeline	85%	$15.15	$0.15	$12.88	$15.59 *($0.64)*	7.100%
	Storage	11%	$2.54	$0.02	$0.28		2.000%
	LNG	4%	$60.83	$0.00	$2.43		

Note: * The total is the sum of the "winter weighted charges". ** The daily is the total divided by average days per month (30.417) to which is added the variable charge. Calculations may not replicate exactly due to rounding.

Exhibit 1-15: Seasonal Wholesale LDC Avoided Gas Costs Southern New England (2005$/MMBtu)

Year	Annual Avg.	3 Month Winter	9 Month Summer	5 Month Winter	7 Month Summer	6 Month Winter	6 Month Summer	7 Month Winter	5 Month Summer	Peak Day
2005	9.66	12.51	8.39	11.15	8.34	10.80	8.32	10.46	8.27	247.01
2006	10.17	13.08	8.86	11.70	8.82	11.34	8.79	10.99	8.74	248.18
2007	9.81	12.68	8.53	11.31	8.48	10.95	8.45	10.61	8.40	247.35
2008	7.71	10.34	6.57	9.07	6.54	8.74	6.52	8.43	6.48	242.54
2009	6.68	9.18	5.61	7.96	5.58	6.97	5.56	7.36	5.53	240.17
2010	$5.90	$8.30	$4.87	$7.39	$4.86	$7.15	$4.85	$6.92	$4.82	238.37
2011	$5.96	$8.38	$4.93	$7.46	$4.92	$7.23	$4.91	$6.99	$4.88	238.52
2012	$6.18	$8.62	$5.14	$7.71	$5.13	$7.47	$5.11	$7.23	$5.08	239.02
2013	$6.38	$8.85	$5.33	$7.94	$5.32	$7.70	$5.30	$7.46	$5.27	239.49
2014	$6.99	$9.52	$5.89	$8.61	$5.87	$8.37	$5.85	$8.12	$5.82	240.87
2015	$6.56	$9.04	$5.49	$8.13	$5.48	$7.89	$5.46	$7.65	$5.42	239.89
2016	$6.58	$9.07	$5.51	$8.16	$5.50	$7.92	$5.48	$7.68	$5.45	239.94
2017	$6.55	$9.03	$5.48	$8.12	$5.47	$7.89	$5.45	$7.64	$5.42	239.87
2018	$6.71	$9.21	$5.63	$8.30	$5.62	$8.06	$5.60	$7.82	$5.56	240.23
2019	$6.90	$9.42	$5.81	$8.51	$5.79	$8.28	$5.77	$8.03	$5.74	240.67
2020	$7.04	$9.58	$5.94	$8.67	$5.92	$8.43	$5.90	$8.18	$5.87	240.99
2021	$7.35	$9.93	$6.23	$9.02	$6.21	$8.78	$6.19	$8.53	$6.15	241.71
2022	$7.45	$10.04	$6.32	$9.13	$6.30	$8.89	$6.28	$8.64	$6.24	241.93
2023	$7.83	$10.45	$6.67	$9.55	$6.65	$9.31	$6.63	$9.06	$6.59	242.79
2024	$7.93	$10.57	$6.76	$9.66	$6.74	$9.42	$6.72	$9.17	$6.68	243.02
2025	$8.43	$11.13	$7.23	$10.23	$7.21	$9.99	$7.19	$9.73	$7.14	244.18

Exhibit 1-16: Seasonal Wholesale LDC Avoided Costs Northern and Central New England (2005$/MMBtu)

Year	Annual Avg.	3 Month Winter	9 Month Summer	5 Month Winter	7 Month Summer	6 Month Winter	6 Month Summer	7 Month Winter	5 Month Summer	Peak Day
2005	9.58	11.89	8.26	10.74	8.22	10.44	8.20	10.14	8.15	199.64
2006	10.08	12.45	8.73	11.28	8.68	10.97	8.66	10.66	8.61	200.80
2007	9.72	12.05	8.40	10.90	8.36	10.60	8.33	10.29	8.28	199.98
2008	7.66	9.75	6.49	8.69	6.46	8.42	6.44	8.15	6.40	195.22
2009	6.64	8.61	5.54	7.60	5.52	6.67	5.50	7.09	5.47	192.86
2010	$5.86	$7.75	$4.82	$7.03	$4.80	$6.84	$4.79	$6.64	$4.76	191.07
2011	$5.92	$7.82	$4.88	$7.10	$4.86	$6.92	$4.85	$6.71	$4.82	191.22
2012	$6.14	$8.06	$5.08	$7.34	$5.06	$7.16	$5.04	$6.95	$5.02	191.71
2013	$6.34	$8.28	$5.27	$7.56	$5.24	$7.38	$5.23	$7.17	$5.20	192.18
2014	$6.93	$8.94	$5.82	$8.23	$5.79	$8.04	$5.77	$7.83	$5.74	193.54
2015	$6.51	$8.47	$5.43	$7.75	$5.40	$7.57	$5.38	$7.36	$5.35	192.57
2016	$6.53	$8.50	$5.45	$7.78	$5.42	$7.60	$5.41	$7.39	$5.38	192.62
2017	$6.50	$8.47	$5.42	$7.75	$5.39	$7.56	$5.38	$7.36	$5.35	192.56
2018	$6.66	$8.64	$5.56	$7.92	$5.54	$7.74	$5.52	$7.53	$5.49	192.91
2019	$6.85	$8.85	$5.74	$8.13	$5.71	$7.95	$5.69	$7.74	$5.66	193.35
2020	$6.98	$9.00	$5.87	$8.28	$5.84	$8.10	$5.82	$7.89	$5.79	193.67
2021	$7.29	$9.34	$6.15	$8.63	$6.12	$8.45	$6.10	$8.23	$6.07	194.38
2022	$7.39	$9.45	$6.24	$8.74	$6.21	$8.55	$6.19	$8.34	$6.16	194.60
2023	$7.76	$9.86	$6.58	$9.15	$6.55	$8.97	$6.53	$8.75	$6.49	195.45
2024	$7.86	$9.97	$6.67	$9.26	$6.64	$9.08	$6.62	$8.86	$6.58	195.68
2025	$8.36	$10.53	$7.13	$9.82	$7.10	$9.63	$7.08	$9.41	$7.04	196.83

Exhibit 1–17: End Use Consumption Crosswalk

End Use Consumption Cross Walk	
Commercial and industrial non-heating,	Annual
Commercial and industrial heating,	5 Month
Existing residential heating,	3 Month
New residential heating,	5 Month
Residential domestic hot water,	Annual
All commercial and industrial,	6 Month
All residential,	6 Month
All retail end uses.	5 Month

Retail Customer Avoided Costs

One of the key issues in C&LM 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 consist of the LDC's 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 1-14 and 1-15 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).

To estimate the average LDC distribution cost, we subtracted average city gate prices from average delivered end use prices. (The Energy Information Administration reports 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 1-18 for residential and commercial customers.

Exhibit 1-18: Estimated Avoidable LDC Margins 2000-2004 Average (2005$/MMBtu)

	Southern NE	Northern and Central NE
Average Citygate 2000-04	6.45	6.62
Ave. Residential Margin	5.60	5.24
Avoidable	*2.80*	*2.62*
Ave. Commercial Margin	3.02	3.48
Avoidable	*1.51*	*1.74*

The total retail avoided cost to the customers is calculated by adding the avoidable LDC margins in Exhibit 1-18, to the LDC avoided costs in Exhibits 1-15 and 1-16. This yielded average summer and winter avoided costs to customers. The calculation of annual average avoidable costs by sector involved several steps. We begin with the commercial non heating and the residential hot water end uses, which equal average, year-round consumption. For these sector uses, the annual avoidable cost already is set at the annual average wholesale price of gas plus the sector specific avoidable LDC margins (above). We used these sectors to establish the base, year round, avoidable cost. To calculate the annual average avoidable costs for the other sector end uses that involve other winter types and thus that have a large winter component, we calculated the monthly average incremental winter cost associated with each end use as the difference between the base year round cost and the winter cost and divided by 12. This yields an annual average cost. Within each sector (commercial/industrial and residential), the "All" category is a simple average of the other categories. For all retail, we calculated a weighted average of the two sectors, weighting the commercial sector at 45 percent and 55 percent for the residential sector. The annual avoided costs are presented in Exhibits 1-1 and 1-2 at the beginning of this chapter.

Comparison with Previous Avoided Cost Study

The avoided costs presented in this analysis are higher than the avoided costs presented in 2003. Direct comparison of retail avoided costs is difficult, since the 2003 study used a different set of end use categories. In Exhibit 1-19 we compare the levelized wholesale avoided cost from the current study with that of the previous 2003 analysis, adjusted to 2005$ and at the current discount rate of 2.03%, and levelized through 2037 as the previous study had done.

Exhibit 1-19: Comparison of 2003 and 2005 Studies:
Levelized Avoided Costs for LDCs
(2005$/MMBtu)

	3 month winter		5 month winter		6 month winter		7 month winter		
	winter	summer	winter	summer	winter	summer	winter	summer	Ann Ave
	Northern & Central NE								
2005 Study	$9.73	$6.48	$8.68	$6.44	$8.38	$6.42	$8.13	$6.39	$7.64
2003 Study	$6.58	$4.38	$6.24	$4.29	$6.03	$4.18	$5.78	$4.14	$5.10
	Southern NE								
2005 Study	$10.32	$6.56	$9.05	$6.53	$8.70	$6.51	$8.42	$6.47	$7.70
2003 Study	$6.83	$4.40	$6.50	$4.31	$6.27	$4.20	$5.99	$4.15	$5.23

Avoided Gas Costs in Vermont

Vermont has a small gas market. ICF was asked to prepare a separate calculation of avoided gas costs to Vermont. Vermont gas consumers are concentrated in the northern tier of the state around Burlington, and are served almost entirely by gas delivered from Canada via TCPL and TQM. To estimate avoided gas costs to Vermont we made several changes to our approach.

- Supply source. Instead of Henry Hub, we used Dawn, Ontario as the pricing point for gas supply into Vermont. Dawn is a major pricing hub, where gas is delivered into Canada, most of it for redelivery to the U.S. northeast, from Western Canada, the Midwest, and the Gulf Coast. The major pipelines serving Dawn are Great Lakes Gas Transmission (a subsidiary of TCPL), Vector, Panhandle Eastern Pipeline, MichCon, and Consumers. Union Gas of Ontario redelivers volumes from Dawn to TCPL which redelivers the gas to Vermont. As a practical matter the gas price at Dawn has tended to be about the same as at Henry Hub. This is primarily due to the dominance of Western Canadian gas volumes that are priced into Chicago below Henry Hub delivered volumes.

- Pipeline delivery. For pipeline delivery, we used the TCPL Dawn to Phillipsburg transportation cost. For storage and LNG costs, we used the same costs as for the rest of New England.

- Distribution margin. The distribution margins were also calculated from EIA, from Vermont state data and using the same approach as the rest of New England.

The exhibit below present the end user avoided costs for Vermont.

Exhibit 1-20 Annual Avoided Retail Gas Costs Vermont (2005$/MMBtu)

	Residential				Commercial & Industrial			All Retail
Year	Existing Heating	New Heating	Hot Water	All	Non Heating	Heating	All	
2005	11.50	11.42	11.32	11.41	10.29	10.38	10.34	10.93
2006	11.98	11.90	11.80	11.89	10.77	10.87	10.82	11.41
2007	11.64	11.56	11.46	11.55	10.43	10.52	10.48	11.07
2008	9.65	9.58	9.50	9.58	8.46	8.55	8.51	9.10
2009	8.67	8.60	8.53	8.60	7.49	7.57	7.53	8.12
2010	7.93	7.86	7.79	7.86	6.75	6.83	6.79	7.38
2011	7.99	7.92	7.85	7.92	6.81	6.89	6.85	7.44
2012	8.19	8.13	8.05	8.13	7.02	7.09	7.06	7.64
2013	8.39	8.32	8.24	8.32	7.21	7.29	7.25	7.84
2014	8.96	8.89	8.81	8.88	7.77	7.85	7.81	8.40
2015	8.55	8.48	8.41	8.48	7.37	7.45	7.41	8.00
2016	8.57	8.51	8.43	8.50	7.40	7.47	7.43	8.02
2017	8.55	8.48	8.40	8.48	7.37	7.44	7.41	7.99
2018	8.69	8.63	8.55	8.62	7.51	7.59	7.55	8.14
2019	8.88	8.81	8.73	8.80	7.70	7.77	7.73	8.32
2020	9.01	8.94	8.86	8.93	7.82	7.90	7.86	8.45
2021	9.30	9.23	9.15	9.23	8.12	8.20	8.16	8.75
2022	9.40	9.32	9.24	9.32	8.21	8.29	8.25	8.84
2023	9.75	9.68	9.59	9.67	8.56	8.64	8.60	9.19
2024	9.85	9.77	9.69	9.77	8.65	8.74	8.70	9.29
2025	10.32	10.25	10.16	10.25	9.13	9.22	9.17	9.76
2026-40	10.32	10.25	10.16	10.25	9.13	9.22	9.17	9.76
Levelized 2.03%	9.68	9.61	9.52	9.60	8.49	8.57	8.53	9.12

Avoided Gas Costs for Power Generation

Natural gas is the major fuel for power generation in New England, with gas-fired generators on the margin and setting the price of electricity in most hours. Natural gas is therefore a major component of energy prices. ICF adopted a different approach to estimating delivered gas prices to power generators from that used to estimate avoidable costs to LDCs and their customers. Most generators employ interruptible or released capacity on pipelines to meet their requirements or may purchase gas in the daily market in and near New England. Thus the price to generators more closely resembles the local pricing in New England as represented by TGP Zone 6 prices and Algonquin city gate prices, both of which are reported daily. ICF used average monthly pricing differences between these points and Henry Hub to estimate the delivered cost of gas into New England generators. These are shown in Exhibit 1-21. On average, in Southern New England, gas prices have been about $2.91/MMBtu higher than Henry Hub; $2.51/MMBtu higher in Central New England and in Maine, and $1.89/MMBtu higher in Vermont. In September, on average, Southern New England is about $0.31/MMBtu higher than Henry Hub, and so on for the other regions. (These averages are taken from five years of data reported in Platt's *Gas Daily* for pricing points in New England and Henry Hub. These pricing points include TGP Zone 6, Algonquin City Gates, and Iroquois Waddington.) For pricing gas to power generators, these differentials were added to Henry Hub prices to yield a regional price to power generators. A small distribution charge of $0.07/MMBtu was added to reflect our estimate of the average variable cost between the regional price and delivery to individual power plants over local pipeline laterals.

Exhibit 1-21: Basis Spreads for Power Generators

Month	Southern NE	Central NE	Maine	Vermont
1	2.91	2.51	2.51	1.89
2	1.31	1.20	1.20	0.90
3	0.77	0.72	0.72	0.66
4	0.50	0.45	0.45	0.39
5	0.41	0.37	0.37	0.32
6	0.35	0.29	0.29	0.23
7	0.40	0.32	0.32	0.23
8	0.37	0.30	0.30	0.24
9	0.31	0.30	0.30	0.26
10	0.37	0.32	0.32	0.27
11	0.50	0.46	0.46	0.44
12	1.14	0.86	0.86	0.53

Chapter Two: Wholesale Electricity Price Modeling Methodology, New England Power Market and Key Assumptions Overview

Introduction

The largest component of retail avoidable electricity costs is the price for firm (energy plus capacity) power available from the generation or wholesale sector. The marginal energy price plus the marginal capacity price captures this component. In order to forecast marginal energy and capacity prices for this avoided cost study, ICF relied on a fundamentals based computer simulation model, IPM®. This Chapter will focus on the methodology and assumptions driving the forecasts of the wholesale power market prices. For purposes of modeling the energy and capacity clearing prices, the analysis assumes that the markets will be perfectly competitive. Actual markets may tend to have some deviation from perfect competition which could results in higher market pricing. The remaining key components of retail avoidable electricity costs include out-of-market system reliability or congestion charges, transmission and distribution capacity costs, and distribution losses. An overview of out-of-market reliability and congestion costs are discussed in this chapter. Transmission and distribution elements will be addressed in Chapters 3 and 5. Additional retail service costs (such as customer support) are not considered to be directly avoidable as discussed in Chapter 3.

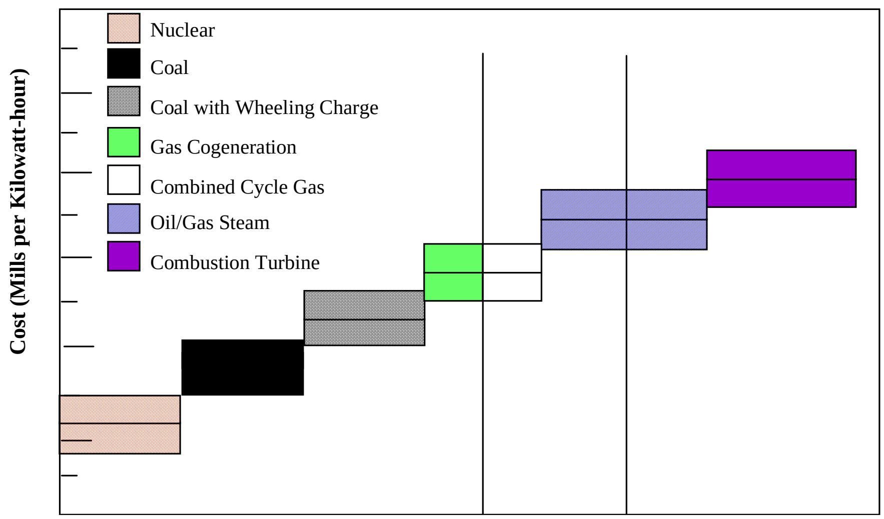
This Chapter is organized in three key sections. First we provide an overview of the modeling methodology. A detailed description of the New England wholesale power market follows, and includes a discussion of the New England LICAP (locational installed capacity) demand curves. This chapter concludes with a presentation of the key driving assumptions of the wholesale energy and capacity price forecasts.

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. A simplified example of this is shown in Exhibit 2-1. 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 on occasion may be associated with interruptible power (or energy only power). The New England power market utilizes a nodal pricing system which results in a distinct locational marginal price (LMP) or nodal price for energy at every node on the system. The LMP price reflects the marginal costs of generation plus the cost associated with losses and congestion relative to that node as described later in this chapter.

Exhibit 2-1: 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.

Marginal losses reflect the cost associated with transmission losses for an additional increment of load served. Marginal losses are utilized in order to send a proper price signal of the incremental costs of serving load. Congestion refers to the existence of system limitations on the capability to transmit power which result in a higher cost of energy than that which would occur in the

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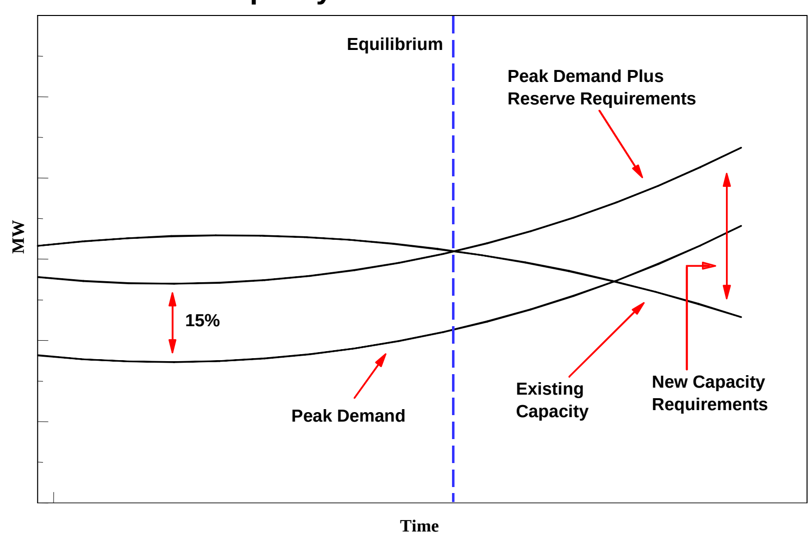
[1]The variable cost may incorporate compensation for lost profits during turndown hours of operation. When the price exceeds this level, it is defined as the hourly pure capacity price. See "pure" capacity pricing discussion.

absence of such limitations. Congestion is typically associated with lack of transmission capacity. However, it is often a reflection of a locational imbalance between generation, load, and transmission resources. For example, generation or load pockets may exist which stress the transmission system due to the location of the resources or visa versa limited transmission at the location of the load or generation source. Congestion costs are attributed directly to the node causing or relieving the congestion. Congestion costs are measured relative to a reference bus and may be either positive or negative. Should a generator relieve congestion, the value of this is appropriately reflected in the locational price for that generator as a premium to the reference bus, i.e. the generator is paid more for relieving congestion. A generator which causes congestion receives a price that is at a discount to the reference bus reflecting that the value of that generator is lowered due to its contribution to congestion. Note, adding transmission capacity is not a pure solution to relieving all congestion and reliability as the flow of resources, the loading of lines, and the voltages of the system all affect the overall system.

Capacity Pricing

Exhibit 2-2 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 capacity prices as determined by the IPM® model reflects equilibrium conditions under the construct of a locational or zonal, rather than regional, capacity market. ICF's forecast optimizes the total generation resources within any given zone in order to minimize total system costs.

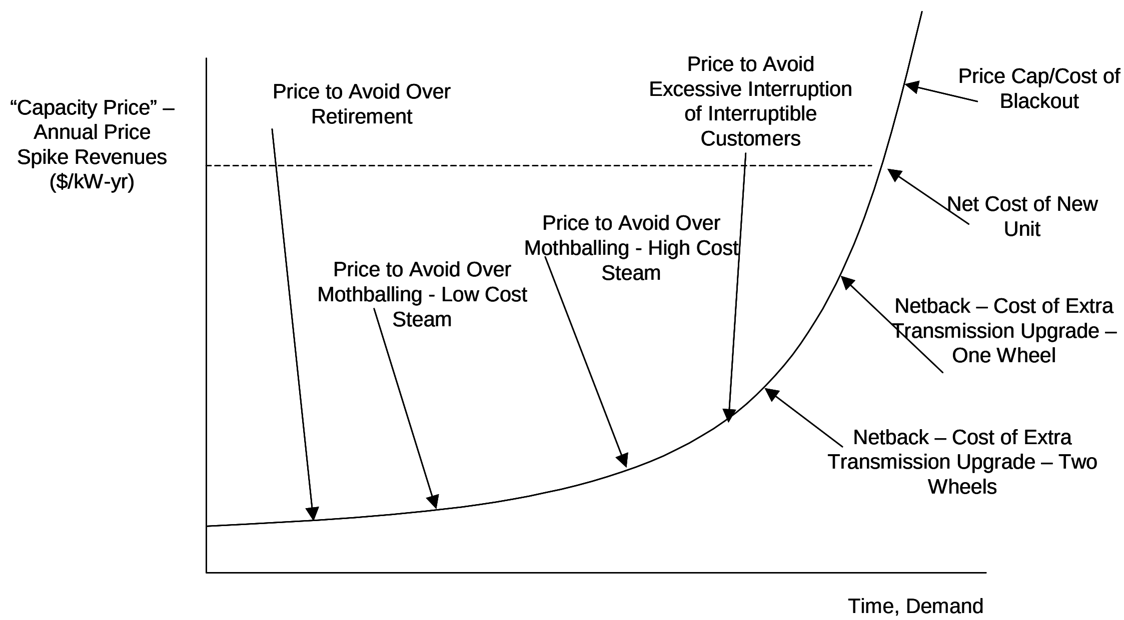
Exhibit 2-2: Equilibrium in the Capacity Market



Equilibrium is defined usually as a condition in which there is sufficient capacity to meet a planning reserve margin over expected system peak. Historically, New England has relied on a reserve margin requirement to ensure adequate system supply. An alternate proposal by ISO-NE for market clearing through a price based mechanism rather than an established reserve requirement is currently being considered. This proposal also introduces locational installed capacity markets (LICAP). This analysis assumed that a LICAP market would begin in January

2006 based on the perceived likelihood of the market design moving to some form of locational capacity clearing market in the future. The long-term equilibrium concept, or balance of supply and demand resources, is similar under either approach with the first (reserve margin) relying on a pre-set reserve standard and a deficiency charge if that standard is not met, and the latter relying on the market determining a price through a willingness to pay mechanism for reserves. Details of the actual ISO-NE LICAP market proposal and the LICAP market modeled is contained in later sections of this chapter.

Exhibit 2-3: Competitive Market Capacity Price Setting Mechanisms - Illustrative



Note: Wheel is a standard industry term indicating transfers across areas with tariff charges. A single wheel is between neighboring systems. Multiple wheels indicate that the origin of the transfer is more than one tariff charge away from the destination.

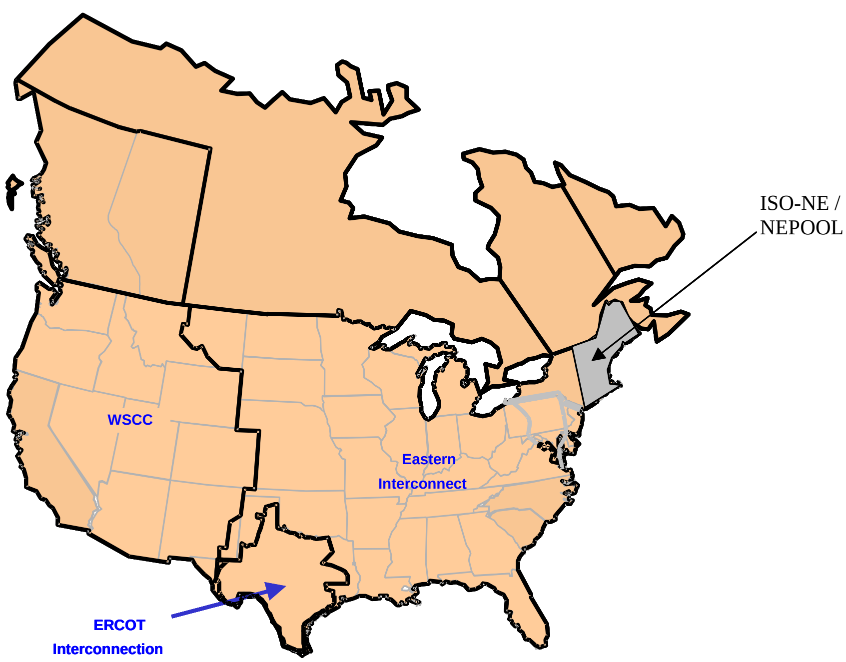
The capacity payments under LICAP (discussed in detail below) are intended to reflect a balanced market linking willingness to pay for capacity in a pre-designed demand curve with the actual supply-side resources. In situations where locational excesses of capacity may exist, prices in that region will reflect the willingness and ability of other markets to absorb the excess capacity. This will reflect a value equivalent to the cost of transferring the excess resources (e.g., at the minimum losses or transmission tariff charges and at the maximum transmission upgrades). As more capacity is available, the payments for capacity become lower. As the payments drop to very low levels, the capacity value will not support continued operation of the most costly and least efficient units. At these low levels, the capacity price will essentially reflect the cost to prevent excessive retirement and mothballing from occurring. In shortage periods, the capacity price will be at its highest, exceeding the compensation requirements of new generation.

The LICAP demand curves are designed to ensure that there is sufficient capacity to maintain reliability of the system. The curves themselves are designed to reflect the "pure" capacity (i.e., units which almost never operate and are available purely for reserve) value as the benchmark generator. The "pure" capacity market is not entirely separate from the energy market, but is linked. Capacity resources may earn energy revenues, the market design compensate for this by reducing payments from prices cleared on demand curve for economic rents (i.e. energy earnings) equivalent to the benchmark generator's expected energy earnings.

The New England Power Market

The ISO New England (ISO-NE) 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. ISO-NE is the independent system operator for this market area. Although ISO-NE is electrically interconnected with several neighboring control areas (New York Power Pool (NYPP) and New Brunswick and has asynchronous power ties to Quebec), the region is relatively isolated when compared with other, larger US marketplaces. The market's only transmission tie to the rest of the U.S. is to NYISO.

Exhibit 2-4: The ISO-NE Marketplace



ISO-NE is also a relatively small market in comparison to other power markets in the U.S. Net peak demand is approximately 28 GW (28,000 MW) as compared to approximately 130 GW for

PJM (PJM spans Pennsylvania, New Jersey, Maryland, Delaware, parts of Ohio, and parts of Illinois. FERC has been restructuring the ISO-NE market due to concerns that suppliers have market power. These concerns are fed by the fact that ISO-NE is relatively small and also because it is isolated from other markets as described above. This concern has also been fed by the existence of transmission constraints that create sub-markets within ISO-NE. As these concerns were not fully envisioned in the original ISO-NE market design, FERC and ISO-NE have spent the last few years reformulating the markets.

ISO-NE Markets Are Continually Undergoing Change

New England has a long history of multi-utility coordination which influenced ISO-NE's development. Formed in 1971, the New England Power Pool (NEPOOL) was a voluntary association of electric power industry participants in New England. NEPOOL established a single regional network to direct the operations of the major generating and transmission (bulk power system) facilities in the region.

Under this structure, NEPOOL distributed transmission congestion costs among the utilities via payment of out-of-merit dispatch costs as the operators worked around transmission problems by changing plant utilization patterns to include higher cost but more strategically located generators. Under the regulated market structure, numerous nuclear power plants serving broad-based customers and accompanying (though separately proposed) large transmission projects which decreased congestion had been built in the NEPOOL administered market.

NEPOOL's existence contributed to the quick establishment of a multi-utility marketplace when FERC Order 888 established open and comparable access to transmission. ISO New England (ISO-NE) 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-NE, also known as RTO NE (RTO – Regional Transmission Organization) is in many respects in the forefront of U.S. deregulation of the electric power industry. Nearly all electric utilities in New England have already fully divested their generation. Most New England states have created the potential for end-users to purchase power from other suppliers. ISO-NE power plants and the associated high voltage electricity transmission grids are regulated directly by FERC. There are practically no vertically integrated, traditional utilities and no major new rate-based regulated power plants have been built in New England in more than fifteen years. ISO-NE operates a power market for buyers (LSEs – Load Serving Entities) and generators, and coordinates grid operation.

Starting on May 1, 1999, ISO New England has been administering the wholesale electricity marketplace for the region subject to FERC regulation. Six electricity products were originally established for sale and purchase by market participants:

- Energy
- ICAP (Installed Capability Market),
- 10-minute spinning reserves,
- 10-minute non-spinning reserves,

- 30-minute operating reserves, and
- Automatic generation control (AGC).

This marketplace adopted many of the structures of NEPOOL including a single New England energy market. By end-1999, New England was the only one of the three Northeast Independent System Operators (New York ISO and PJM being the other two) without a location-based energy market. That is, only ISO-NE had a single electrical energy price for all buyers and sellers regardless of location and the generator's impact on grid congestion. Congestion derived re-dispatch costs were paid by the ISO and passed through to end-users. However, with the anticipation of deregulation and the transition to the ISO-NE market structure, the joint transmission projects of earlier years stopped. As electricity demand continued to grow, transmission congestion costs increased and internal transmission constraints began to contribute to load and generation pockets.

Under FERC pressure, this system was replaced with a location based pricing system for energy. Since March 1, 2003, the New England ISO began pricing energy using a locational marginal pricing (LMP) scheme similar to those used in New York, MISO (Midwest Independent System Operator), and PJM markets. Under the LMP pricing scheme, nodal prices that are received as payment to generators are lower for those generators contributing to congestion and higher for those reducing congestion than they otherwise would be if there were no congestion. Similarly, the price signals indicate the investment needed in generation itself. If a new power plant were to locate in an LMP market, the developer would consider the costs of transmission upgrades necessary to allow the plant to meet deliverability standards as part of the development costs of the project. Absent the LMP design, the generation owner would have received the market price regardless of its impact on congestion.

Another early feature adopted by ISO-NE was a separate installed capacity market. This was an outgrowth of NEPOOL's separation of energy and capacity products. On the energy side, NEPOOL centrally dispatched for energy in its power exchange. On the capacity side, NEPOOL addressed capacity via deficiency penalties for utilities without adequate reserves. In this respect, ISO-NE was similar to the other two Northeastern U.S. tight power pools (PJM and New York) which also separated the two products. Recognizing transmission limitations within its electrical grid, New York was the first of the three marketplaces to advance the concept of a locational capacity market. New England and PJM are now both pursuing locational capacity markets.

ISO-NE has significant internal transmission problems even within its small footprint. This has contributed to concerns that generation owners have market power. Unlike New York which based its original design on internal transmission problems and market power, the original ISO-NE capacity market design failed to differentiate sub-markets associated with transmission constraints and as such did not address market power mitigation fully. ISO-NE has needed to undergo a re-design process to address these problems. This process has been ongoing for a number of years; the FERC docket related to the capacity market redesign matters has extended from 2001 to 2005. As a temporary measure to assure that capacity receive adequate payment to reliably serve the market, ISO-NE has adopted a quasi re-regulation process known as Reliability Must-Run (RMR) which has become especially important in load pockets (transmission isolated areas) like Southwest Connecticut (SWCT).

ISO-NE's rules and market structure have been converging to a structure similar to that of NYISO and at the outset of this study was expected to be operating a very similar system by January 1, 2006. Key elements of this market are locational based marginal prices (LBMP), and LICAP markets utilizing demand curves as discussed below. Over the course of this study, the start date for LICAP type markets has been delayed to October 2006 at the earliest.

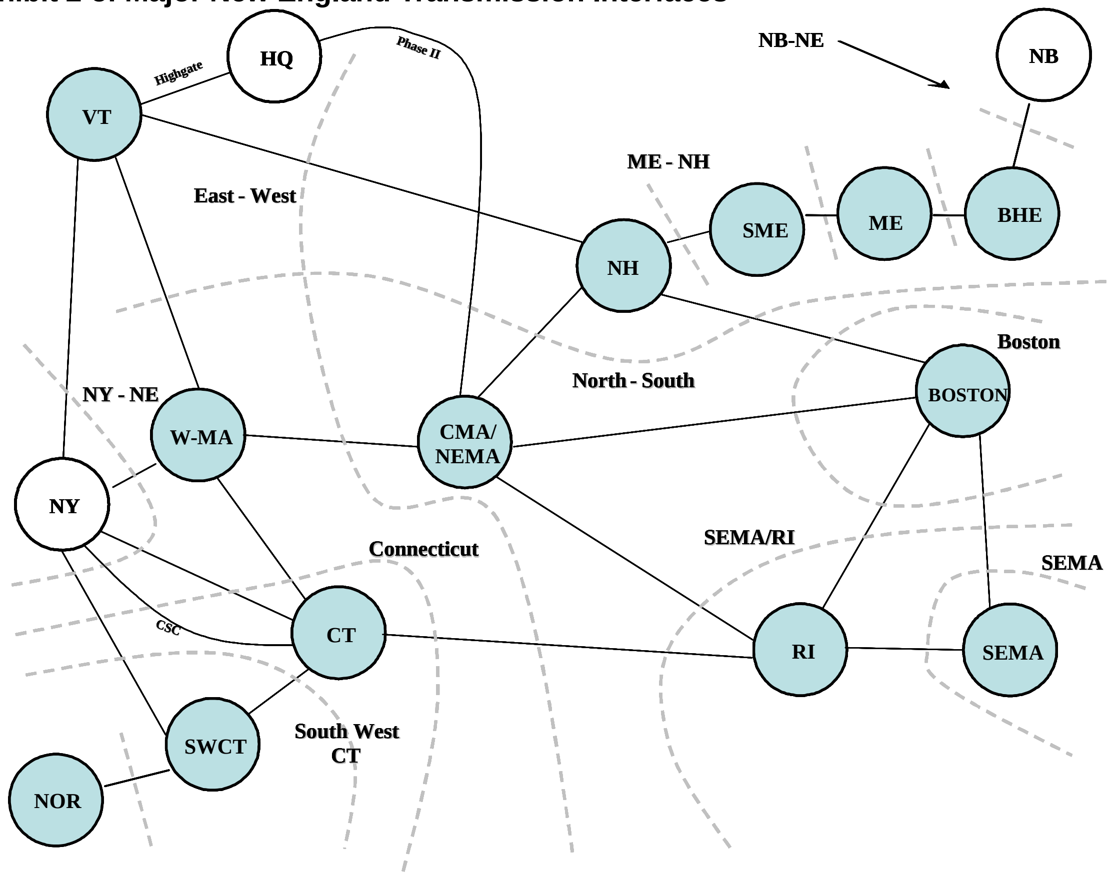
ISO-NE Energy Market

As noted, since March 2003, ISO-NE has had a locational spot energy market. Roughly 10 percent of the total energy volume currently contracts in the spot market as the majority of the volumetric transactions are based on bilateral contracts. In the locational spot market, electrical energy prices are determined each hour in day-ahead and real-time markets for each individual node on the grid. The day-ahead market in New England is the main clearing market while the real-time market is a balancing market. Suppliers of electrical energy submit bids in the day-ahead market to ISO-NE for generation output. ISO-NE reviews the bids and stacks them in order of increasing prices to determine the dispatch order and clearing price for each time interval. The clearing price is set at the point where the supply bids satisfy the projected demand. All competing suppliers whose bids are selected receive a single market clearing energy price ($/MWh). If selected, the supplier is responsible for providing the energy amount accepted from his bid. If a supplier is unable to supply when called, it is financially responsible for the costs of replacement power. A secondary real-time or balancing market also exists. Suppliers must participate in the day-ahead market, through submitting bids, in order to participate in the real-time markets. If not selected or selected for partial dispatch in the day-ahead market, a supplier can choose to make its output available for the real-time balancing market or to withdraw its bid.

There are approximately 1,000 nodes in ISO-NE and, hence, 1,000 electrical energy prices per hour per market (day-ahead and real-time). These prices explicitly reflect three components: (1) the energy price; (2) the congestion costs associated with that node; and (3) the marginal transmission losses associated with that node.

The ISO-NE has established 13 congestion zones (Congestion Management Zones) based on commercially significant transmission constraints. Exhibit 2-5 illustrates the constraints (indicated through the dotted lines) that define the transmission zones. Although some of these constraints are somewhat isolated such as the ME-NH constraint, most constraints are broader in nature and affect several areas of the grid. For example, the North-South constraint affects lines across the entire New England expanse.

Exhibit 2-5: Major New England Transmission Interfaces



The most limiting of the interfaces in New England is the East-West constraint. This interface limits energy and capacity transfers from Eastern New England to Western New England and tends to result in higher prices to the western zones than in the eastern zones. This constraint affects the ability to move power from the lower cost Rhode Island and Southeastern Massachusetts markets into Connecticut and also tends to isolate New Hampshire from Vermont and Central Massachusetts from Western Massachusetts.

High prices in individual zones relative to other zones often are the result of local shortages of generation supply. In a bundled market where energy and capacity value is recognized in a single product price, high prices (relative to neighboring markets) are a signal to developers to build new capacity (or transmission). These prices are usually revealed in a limited number of hours that have extremely high prices. Under this system, the potential for suppliers to exercise market power in the form of high prices is significant and difficult to monitor. New England has unbundled the energy and capacity markets and has also imposed a price cap of $1,000/MWh in the energy markets. This design attempts to avoid the price spikes and limit market power. In order to compensate rarely used but necessary peakers and to attract new units, capacity is valued as a separate product.

The IPM® model simulates zonal, rather than nodal pricing. The zonal representation captures the 13 ISO-NE transmission planning zones and captures the most commercially significant transmission constraints. Assumptions affecting the energy price projections are provided later in this chapter.

ISO-NE Installed Capacity Market

As mentioned, an ICAP market has existed in New England since the ISO-NE began operating the system. There have been capacity market precursors such as the NEPOOL deficiency charges for lack of reserve capacity that predate the ISO-NE current market. These deficiency charges were set based on the cost of peaking capacity and provided incentives to utilities to have enough supply to ensure generation adequacy.

Capacity markets are designed to shift scarcity value (the value for limited resources) for capacity from energy markets to a separate market. Under FERC regulation, and based on ISO-NE's experience with shortages in the late 1990s, increased emphasis was placed on having separate energy and capacity markets to facilitate attention on market power and prevent excessive price volatility. This was coincident with increasingly sophisticated treatment of transmission effects. However, separation of energy and capacity requires both markets to work properly if revenue is to be sufficient to allow for reliability while not being too high given FERC's market power concerns. This increases regulatory requirements, especially since FERC's efforts to develop a Standard Market Design (SMD) floundered during the 2001-2003 period. In the aftermath of the SMD effort, regulators needed to develop region by region solutions even while trying to decrease differences to facilitate integration.

The ISO-NE established target reliability levels reflects three factors: (1) customer willingness to pay to avoid a black-out is very high, and hence, the goal is to provide customers very high reliability levels that limit expected load shedding (i.e., rolling black-outs) to one day in ten years (0.99973 availability for power supply), (2) industry convention to estimate expected peak demand based on average weather conditions (as opposed to worst day in 100 years, etc.), and hence, one-half of the time peak electricity demand exceeds the expected level applying stress to the system, and (3) industry convention to estimate installed capacity at maximum output even though it is extremely rare that all units are available at maximum output.

Several features of the original ICAP Market include:

- **Monthly Bidding –** The original ICAP market was designed to settle prices on a monthly basis based on bids for the uncommitted capacity of the generator's participating in the ISO-NE. This bidding gives sellers the opportunity to raise bids above costs and potentially to exercise market power. This is especially true in small isolated markets. Since its inception, the ICAP market pricing has been a focus of FERC attention both in terms of reliability and market power.

- **Seasonal Allocations –** ISO-NE calculates the Summer Capability Period and Winter Capability Period Installed Capacity Requirements each year. The ISO-NE then converts the Installed Capacity Requirements into Unforced Capacity (UCAP) Requirements for the entire ISO-NE Control Area and allocates the requirements to Participants based upon their customers' contributions to the previous calendar year's ISO-NE Control Area coincident peak load. The UCAP amount represents the capacity that is shown to be available when called on or the installed capacity after accounting for the forced outage rate. Thus, every participant must shoulder its share of the reliability burden, i.e., the cost of keeping reserves.

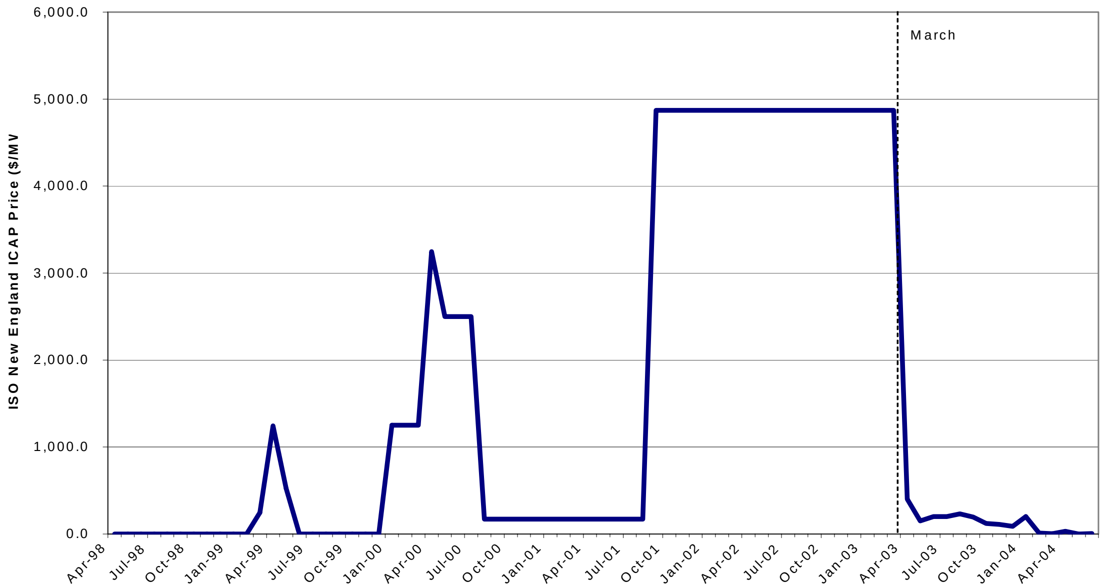
- **Load Shifting and Allocated ICAP Requirements –** All LSEs (Load Serving Entities) contribute to the NEPOOL peak, and therefore are allocated a UCAP requirement based on their coincident load. The UCAP obligation for each LSE (Participant) within New England is adjusted each month to reflect changes in obligation that result from load-shifting, as well as other changes in obligation. These monthly requirements are binding with regard to the Participant's obligation to procure UCAP for the following month. The obligation is calculated as the sum of all UCAP Peak Contributions for all customers served by that Participant, divided by the sum of all contributions. Participants may use this market to procure supplies to satisfy the Unforced Capacity requirement in advance of the next obligation month. Participant compliance may also include bilateral contracts, capacity credits or ownership of qualified resources.

- **Deficiency Charge –** Participants must demonstrate adequate supplies to ISO-NE; if not demonstrated, ISO-NE has the authority to impose sanctions on the Participant, or submit deficiency bids on behalf of the Participant. Under the Deficiency Auction, Participants with excess UCAP are required to offer or accept a $0.00 bid if they do not offer. Offers in the auction are capped at Deficiency Charge of $6.66/kW-month.

Historical ISO-NE Installed Capacity Market Failed to Compensate Generators

After its opening in April 1998, the ICAP market prices where at $0/kW-month for all but 3 months of the first 21 months of operation (through December 1999) (see Exhibit 2-6). For the 3 months experiencing prices, the market cleared at an average price of $0.67/kW-month.

Exhibit 2-6: ISO New England ICAP Prices – 1998 – 2004 ($1.5/kW-mo Average)



In January 2000, the market cleared at $1.25/kW-month; this price held through March 2000. In April 2000, ICAP market cleared at a price of $3.25/kW-month. ISO-NE suspected gaming behavior in the market and filed with the Federal Energy Regulatory Commission (FERC), proposing the abolishment of the market and the elimination of the ICAP requirements. FERC responded to ISO-NE's filing refusing to eliminate the ICAP requirements.

From May though June the market traded at $2.50/kW-month. Over the next several months, the ICAP pricing continued to be disputed and was subject to FERC involvement and rulings. In September 2000, the ISO intentionally delayed settlement since the market pricing was under dispute while waiting for guidance from FERC. In January 2001, FERC responded by ordering the ICAP market settlement price to be set at $0.17/kW- month ($170.00/MW month) beginning in August 2000. In March 2001, in response to a decision by the United States Court of Appeals for the First Circuit, the FERC ordered the re-establishment of the ICAP market deficiency charge of $0.17/kW- month for April 2001 and thereafter. The market price continued at this value through September 2001 when the deficiency cap was raised to $4.87/kW-month. The market continuously traded at this value through January 2003.

Coincident with the adoption of locational energy prices in March 2003, there were changes to the previous ICAP structure and the market began trading under these new rules without the $4.87/kW-month cap. Prices fell, but there was only a limited supply response (i.e., retirement, mothballing) as ISO-NE signed RMR contracts, as described below, providing regulated returns to selected plants, mostly gas-fired plants.

Reliability Must Run (RMR)

As FERC dealt with issues related to ICAP and market power in the 2001-2003 time period, and LICAP in the 2003 to 2005 time periods, payments to gas-fired units were depressed due to low ICAP prices and emphasis on market power concerns. Since power plants have fixed costs, even short periods without coverage of fixed costs can cause them to withdraw from the market, decreasing reliability. If many plants are similarly situated, this withdrawal can be large and lead to grid collapse. This can be especially problematic in load pockets like SWCT and Boston.

In light of the extreme need to resolve this problem faster than FERC, ISO-NE under FERC regulation created a parallel system of RMR contracts designed to enable generators to recover costs not otherwise obtained in the competitive capacity market. Initially, FERC allowed payment of going forward maintenance costs under RMR contracts and directed ISO-NE to permit selected peaking units to raise their bids (Peaking Unit Safe Harbor bids or PUSH bids) in order to recover fixed and variable costs through the market, and to allow these bids to set the energy price. PUSH bids exceed marginal cost by a net annual fixed cost component which includes both sunk and going-forward costs. This temporary rule was to be in place until ISO-NE could implement a locational ICAP market. The PUSH system failed to compensate units, and, as multiple units applied for RMR, cost-of-service RMR style agreements began to effectively re-regulate portions of the grid in SWCT, Connecticut and NEMA Boston. Payments are now in the $8/kW-month range (see Exhibit 2-7). However, this system was expected to be temporary and FERC approved contracts that generally had a sunset date to match the start of the LICAP market (since 12/31/05 was the day before LICAP Planned Start, some used this date while others simply referred to the LICAP start as the expiration date).

The first RMR filings occurred in 2001, though hearings on these initial requests generally continued through 2003 when the first RMR contracts were granted. A large increase in RMR applications occurred between 2003 and 2005 as many gas-fired units could not make money during this interim period.

Exhibit 2-7: ISO-NE RMR Contract Status as of April 2005

Annual Fixed Cost Summary - RMR Agreements (1)

Status Updates through 05/07/05

Unit	Owner	Cost Recovery Type	Annual Fixed Cost: In Effect prior to 01/27/05 $	Annual Fixed Cost: 2005 Annual Projected * $	2005 CELT Summer Capability MW	In Effect prior to 01/27/05 $/kW-month	2005 Annual Projected * $/kW-month	Effective Date	Termination Date	
NEMA/Boston										
New Boston 1 (2)	Exelon	COS RMR	30,000,000	30,000,000	350.00	$7.14	$7.14	01/01/02	12/31/06	
New Boston 1 (2)	Exelon	2004 Overhaul	7,445,450	-	350.00	$1.77	-	-	-	
Salem Harbor 1 - 4 (3)	Dominion	Environmental Upgrades	-	85,000,000	742.79	-	$9.54	-	-	
Kendall, Steam 1 (4)	Mirant	COS RMR	4,933,064	4,933,064	14.57	$28.21	$28.21	10/08/04	LICAP	
Kendall, Steam 2 (4)	Mirant	COS RMR	5,964,958	5,964,958	21.00	$23.67	$23.67	10/08/04	LICAP	
Kendall, Jet 1 (4)	Mirant	COS RMR	2,763,096	2,763,096	16.83	$13.68	$13.68	10/08/04	LICAP	
Sub-Total NEMA/Boston RMR Agreements			51,106,568	128,661,118	1,145.19 (13)	$10.58	$9.36			
Western Mass										
W.Springfield 3 (5)	ConEd	COS RMR	-	8,292,690	101.19	-	$6.83	-	LICAP	
Total Massachusetts RMR Agreements			**$51,106,568**	**136,953,808**	**1,246.38** (13)	**$10.58**	**$9.16**			
All Connecticut										
Devon 7 - 8 (6)	NRG		0	0				08/01/02	10/01/04	
Devon 11 - 14 (7)	NRG	COS RMR (8)	15,828,130	19,568,124	120.58	$10.94	$13.52	01/17/04	LICAP	
Devon 11 - 14	NRG	Reliability Tracker(9)	2,590,988	0	120.58	$1.79	-	02/27/03	12/31/05	(15)
Norwalk Harbor 1,2,10	NRG	Reliability Tracker(9)	9,135,526	0	341.93	$2.23	-	02/27/03	12/31/05	(15)
Middletown 2-4, 10	NRG	COS RMR (8)	47,401,620	49,617,744	770.12	$5.13	$5.37	01/17/04	12/31/05	(15)
Middletown 2-4, 10	NRG	Reliability Tracker(9)	9,267,280	0	770.12	$1.00	-	02/27/03	12/31/05	(15)
Montville 5,6,10&11	NRG	COS RMR (8)	22,003,982	23,032,716	493.70	$3.71	$3.89	01/17/04	12/31/05	(15)
Montville 5,6,10&11	NRG	Reliability Tracker(9)	15,551,750	0	493.70	$2.63	-	02/27/03	12/31/05	(15)
Milford 1 (10)	Milford Power	COS RMR	40,824,787	40,824,787	239.00	$14.23	$14.23	11/03/05	LICAP	
Milford 2 (10)	Milford Power	COS RMR	40,797,848	40,797,848	253.50	$13.41	$13.41	11/03/05	LICAP	
New Haven Harbor (11)	PSEG	COS RMR	47,368,806	47,368,806	447.89	$8.81	$8.81	01/17/05	LICAP	
Bridgeport Harbor 2 (11)	PSEG	COS RMR	19,012,116	19,012,116	130.49	$12.14	$12.14	01/17/05	LICAP	
Bridgeport Energy (12)	Bridgeport	COS RMR	-	57,825,915	451.22	-	$10.68	-	LICAP	
Total Connecticut RMR Agreements			**$269,782,833**	**$298,048,056**	**3,248.43** (14)	**$8.04**	**$8.55**			

* **Includes recent rate proposals as filed, as well as the 11/02/04 the NRG Settlement which was approved by FERC on 01/27/05**

Other Items

A. Wallingford 2-5 RMR Contract was rejected by FERC in early 2003. PPL's appeal is pending in Circuit Court. Annual Fixed Cost is about $25.7 million. Payment could be retroactive to 1/17/03.

B. Boston Generating applied for a Reliability Determination and RMR Agreement on 11/15/04 for Mystic 7 (554.85 MW), 8 (688.58 MW) and 9 (709.67 MW) (Summer Capacity per 2005CELT Report). On 12/13/04, ISO presented findings to NEPOOL Reliability Committee that the three Mystic units are needed for system reliability.

C. FPL Energy Wyman IV LLC (“FPL Energy”) applied for a Reliability Determination and RMR Agreement on 02/11/05 for W.F. Wyman Station Unit No. 4 (“Yarmouth 4”), (ID #642) (603.913 MW Summer Capacity per 2005 CELT Report). On 05/03/05, ISO presented its initial findings to the NEPOOL Reliability Committee.

Other Items cont'd. and NOTES ON PAGE 2

NE RMR Contract Status as of April 2005 (continued)

Other Items cont'd.

D. Ridgewood Power Management, LLC, as agent for the owners, applied for Reliability Determinations and RMR Agreements by several letters dated March 2-4, 2005 (Capacity per 2005 CELT Report, except as indicated):
Blackstone Hydro, Inc ("Blackstone"), Blackstone Hydro Tupperware Load Reducer ("Tupperware"), (ID #1057), (1.8 MW)
Indeck Maine Energy, LLC ("Indeck") -- Indeck West Enfield ("Enfield") (ID #445), (21.24MW); Indeck Jonesboro ("Jonesboro") (ID #446) (0.00 MW - potentially around 20 MW)
Ridgewood Rhode Island Generation, LLC ("RRIG"), Ridgewood Rhode Island Generation ("Ridgewood") (ID #10366)(2.4MW). On 05/03/05, ISO presented its initial findings to the NEPOOL Reliability Committee.

E. Lowell Cogeneration LLP ("LCCLP") applied for a Reliability Determination and RMR Agreement, dated 03/22/05, for Lowell Cogeneration ("Lowell Cogen"), (ID #1188) (25 MW Summer) Capacity. On 05/03/05, ISO presented its initial findings to the NEPOOL Reliability Committee.

F. Lowell Power LLC filed an I.3.9 (formerly 18.4) Application dated 03/21/05 for deactivation of Lowell Power ("Lowell Power"), (ID #461) (0.00 MW Summer Capacity). On 05/03/05 the NEPOOL Reliability Committee voted to recommend approval of the Application to place the unit in Deactivated Reserve.

G. Berkshire Power Company, LLC ("Berkshire Power") applied for a Reliability Determination and RMR Agreement dated 03/24/05 for Berkshire Power ("Berkshire "), (ID #1086) (229.540 MW Summer Capacity). On 05/03/05 ISO presented its findings that the station is needed for system reliability to the NEPOOL Reliability Committee. ISO subsequently notified Berkshire Power.

H. Millennium Power Partners, LLC ("Millennium Power") applied for a Reliability Determination and RMR Agreement dated 04/08/05 for Millennium Power ("Millennium"), (ID #1210) (334.289 MW Summer Capacity). ISO is evalutaing the request.

NOTES

(1) Actual payments are reduced by revenues in excess of variable costs. By doing so, "double-recovery" is eliminated and the generator receives its fixed and variable costs for the annual period.

(2) New Boston is not subject to refund. Overhaul was a one time expense that will be reimbursed through market revenues, with any outstanding balance due to Exelon at termination.

(3) Cost estimate filed by USGenNE with FERC was $85 million. Dominion purchased Salem Harbor effective 01/01/05. On 05/02/05 the FERC Settlement Judge reported that a settlement in principal had been reached and is expected to be filed on or before 05/27/05.

(4) Filed by Mirant on 10/07/04. By FERC Order dated 11/26/04 rates became effective on 10/08/04, subject to refund. Costs will be paid by NSTAR because reliability need is local. On 04/07/05, FERC ALJ announced an agreement on a term sheet and extended the settlement period until 06/07/05.

(5) Con Edison Energy of Massachusetts, Inc. ("CEEMI") applied for a Reliability Determination and RMR Agreement on 01/03/05 for West Springfield 3 ("WS-3") generating station (ID #633). On 04/29/05 Con Ed filed an RMR Agreement with the FERC requesting a 05/01/05 effective date.

(6) Devon 8 and Devon 7 were terminated from RMR Agreement effective 4/27/04 and 10/01/04, respectively, (due to the availability of Milford units) and deactivated by NRG on 6/4/04 and 10/05/2004, respectively.

(7) 2005 Annual Projected Column includes $3 million under NRG Settlement Agreement approved 01/27/05.

(8) 2005 Annual Projected column reflects Settlement filed on 11/2/04 and approved by FERC on 01/27/05. Settlement is based on LICAP $5.34/kw-month overall and eliminates seperate payment for maintenance. The Settlement of 11/02/04 does not address the refund of a portion of the amount collected under the Cost Tracker dated 2/27/03. The refund is subject to a separate Settlement (see Note 9 below).

(9) NRG Reliability Cost Tracker dated 2/27/03, as amended, provided for payment of costs for minor and major maintenance materials and services. For 2/27/03 through 3/31/04 costs were initially estimated for all four stations as $43,690,084, which sum was held in escrow by ISO and paid by ISO to vendors. On 1/25/05 NRG filed a Settlement Agreement providing for a refund of approximately $10 million of that $43.7 million which was approved by FERC on 03/07/05 and refunded out of escrow by ISO in April, 2005. Amounts shown as In Effect prior to 1/27/05 are for 4/1/04 - 3/31/05 and total $36,545,544 for all four stations. Under the Settlement filed 11/02/04 and approved by the Commission on 01/27/05, direct payment for maintenance expense incurred after 04/01/04 is capped at $30 million at which point payments under the Tracker stops. Consistent with its "true-up" Filing of 3/1/05, NRG has refunded $4,885,171 without interest. Subject to FERC approval, NRG will receive that same amount with interest during 2005 and will make another compliance filing before 3/1/06.

(10) Filed by Milford Power, LLC on 11/01/04. On 03/22/05, FERC issued an order making the rates effective 11/03/2004, subject to refund. By FERC Order of March 22, the case was assigned to an ALJ for Settlement Proceedings. Subsequent to a Settlement Conference on 04/14/05, certain Connecticut parties filed a Request for Rehearing, which is pending.

(11) Filed by PSEG on 11/17/04. By FERC Order of 01/14/05, the rates became effective 01/17/05, subject to refund. On 05/02/05 FERC issued an order terminating Settlement Procedures. A Prehearing Conference is scheduled for 05/17/05.

(12) On 04/20/05, FERC issued a deficiency letter to Bridgeport Energy.

(13) Duplicate MW are eliminated in total.

(14) Includes Norwalk Harbor MW but excludes MW duplicates. "2005 Annual Projected" average cost excludes Norwalk Harbor, which is only subject to true-up provisions of the Reliability Cost Tracker in 2005.

(15) Under the terms of the NRG "Cost Tracker" and "Cost-of-Service" Agreements, the termination date is the earlier of 12/31/05 or LICAP implementation. Because there are no present plans for LICAP implementation prior 1/1/06, the Agreements will almost certainly terminate on 12/31/05.

LICAP Hearings

As the number of RMR units was increasing, FERC and ISO-NE continued to work on the capacity market design to address locational and market power concerns. FERC recognized the capacity market structure as a high priority and began proceedings on capacity markets to coincide with the initiation of standard market design in the energy markets. These hearings were also related to earlier hearings on market power and ICAP prices in ISO-NE. This history contrasts with that of New York which started with the premises that: (1) capacity prices needed to be locational due to transmission problems, and (2) prices were subject to market power and needed caps and eventually demand curves.

In these hearings, ISO-NE initially proposed a concept similar to New York's which included locational demand curves. The use of demand curves was related to FERC concerns about potential market power among resource owners. The curves create prices without bids from capacity suppliers. The demand curves exist for each zonal or local ICAP (LICAP) and are designed to allow for new generators entering those market areas to earn a fair recovery on investment costs. One of the driving issues behind the development of locational capacity markets was the application to FERC by generation owners for RMR agreements to recover the full cost of power plants, especially those in Connecticut. Many of the FERC hearings from February 2003 through 2005 have focused on solutions for locational issues. They have shown a consistent emphasis on providing market signals for reliable infrastructure while not exacerbating market power and not using energy markets for this purpose. After much debate and re-design, in June 2005, FERC ruled on a LICAP structure to go forward. However, later events, including the inclusion of a sense of Congress in the 2005 Energy Act continued to delay the expected start date for the LICAP market. At the time of this writing, the earliest anticipated start date for the market is October 2006. A timeline of the events driving locational capacity markets is provided in Exhibit 2-8.

Exhibit 2-8: ISO-NE LICAP Design Proposal Timeline

Date	Event
February 26, 2003	Devon Power LLC et al. (collectively NRG) filed cost-of service RMR agreements covering 1,728 MW of generating capacity located within Connecticut and the SWCT Designated Congestion Areas (DCAs).
March 25, 2003	FERC Order accepted only a portion of the RMR agreements; allowed accepted holders of approved RMR agreements to collect funds for needed summer maintenance through a tracking mechanism administered by ISO-NE.
April 25, 2003	FERC Order addressed the entirety of the RMR agreements. FERC rejected the RMR agreements, and allowed collection of only going-forward maintenance costs through the tracking mechanism approved in the March 25 Order; directed ISO-NE to file no later than March 1, 2004 for implementation no later than June 1, 2004, a mechanism that implements location or deliverability requirements in the ICAP or resource adequacy market so that DCAs may be appropriately compensated for reliability.

Exhibit 2-8: ISO-NE LICAP Design Proposal Timeline (continued)

Date	Event
March 1, 2004	ISO-NE filed LICAP proposal. Highlights were: • Establish 4 LICAP regions (Maine, CT, NEMA/Boston, ROP) • Establish capacity transfer limits (CTLs) to limit the amount of ICAP that load serving entities in one region could purchase from another region. • Use a demand curve to establish the amount of ICAP which must be procured, and the price for that capacity. • Phasing in the demand curve over a five-year period • Include price caps during this phase-in period, as well as “transition payments” to low capacity factor units needed for reliability • Capacity transfer rights would be allocated to load or generators, depending on their location, to allow market participants to hedge against congestion costs; holders of capacity transfer rights between two ICAP regions would receive the difference in ICAP prices between those regions.
March 22, 2004	FERC Order accepted NRG’s second attempt in getting RMR agreements for Devon, Montville and Middletown generating units conditioned to expire at the start of LICAP market or delivery requirement.
June 2, 2004	• FERC Order delayed implementation of LICAP until January 1, 2006; agrees on NE-ISO proposal’s 2 broad concepts: (1) to have separate ICAP regions (but questions whether the proposed 4 are enough) and (2) to have a demand curve (but believes more information is needed to establish the appropriate parameters) • FERC directed ISO-NE to submit a further filing addressing whether the FERC should revise the LICAP proposal to create a separate ICAP region for SWCT. • FERC established a separate docket to determine whether a separate energy load zone should be created for SWCT, and whether it should be implemented in advance of LICAP. • FERC rejected NE-ISO’s price cap and phase-in period proposal. • FERC established hearing procedures to determine the appropriate demand curve parameters, the proper method for calculating capacity transfer limits, the appropriate method for determining the amount of capacity transfer rights to be allocated, and the proper allocation of capacity transfer rights.
July 2, 2004	NE-ISO filed proposal to recommend a separate SWCT ICAP region and a separate energy zone (to be no larger than the new SWCT ICAP region); also stated that it is not necessary to implement the energy zone prior to the implementation of LICAP and that both should be implemented simultaneously.
November 8, 2004	FERC Order ruled on a recommendation by ISO-NE to establish a separate SWCT ICAP region and corresponding energy load zone upon the implementation of the LICAP mechanism, and directed ISO-NE to establish the separate ICAP region and energy load zone.

Exhibit 2-8: ISO-NE LICAP Design Proposal Timeline (continued)

Date	Event
March 23, 2005	FERC denies the requests for rehearing and reaffirms its determination in the November 8 SWCT Order that a separate SWCT ICAP region and energy load zone are appropriate.
June 15, 2005	FERC's Initial decision accepting main components of the LICAP market proposal
September 20, 2005	LSE's assert in oral arguments at FERC that the demand curve prices are inappropriately high and in need of revision. They would like the imposition of an alternate capacity valuation scenario in the form of capacity payments.
October 21, 2005	FERC Interim Order Regarding Settlement Procedures and Directing Compliance Filing Issued
January 31, 2006	Closing date of settlement process. Alternatives to LICAP must be submitted by this date.
October 1, 2006	NE-ISO LICAP market implementation anticipated.

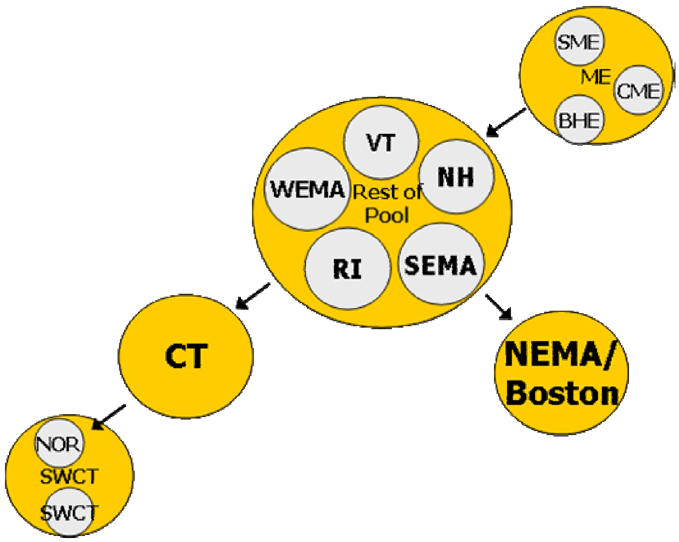
Note: As far as the design of the NE-ISO LICAP demand curve was concerned there were 2 camps of interveners. The first camp represented the "Capacity Suppliers" including DENA, FPL, Entergy, Mirant, Mystic, and Fore River and favored higher levelized costs of new entry relative to NE-ISO's proposal. The second camp represented load serving entities (LSEs), consumer representatives, state public utility commissions and attorney generals and favored lower levelized costs. This camp included National Grid USA; Wellesley Municipal Light Plant, Reading Municipal Light Department, and Concord Municipal Light Plant (collectively, "WRC"), the Connecticut Department of Public Utility Control, Connecticut Office of Consumer Counsel, Attorney General for the State of Connecticut, and Southwestern Area Commerce and Industry, Association of Connecticut (collectively the "CT Parties") and the Attorney General of Massachusetts, NSTAR, et al. (collectively "MA AG, et al.")

LICAP Structure

Under the proposed LICAP design, in October 2006, ISO-NE, under FERC regulation, will subdivide the installed capacity market into five sub-markets. Rather than accepting price bids monthly as under the current ICAP market, capacity would be declared as available to a given sub-regional market and the clearing price would determined by the LICAP demand curve. The five proposed LICAP markets are (see Exhibit 2-9):

- Southwest Connecticut (Southwest Connecticut and Norwalk)
- Rest of Connecticut
- NEMA/Boston (Northeast Massachusetts / Boston)
- Maine (Southern Maine, Bangor Hydro, and Central Maine)
- Rest of Pool (Western Massachusetts, Central Massachusetts, Rhode Island, Southeast Massachusetts, New Hampshire, and Vermont)

Exhibit 2-9: ISO-NE Locational Installed Capacity Market Zones and External Interconnects

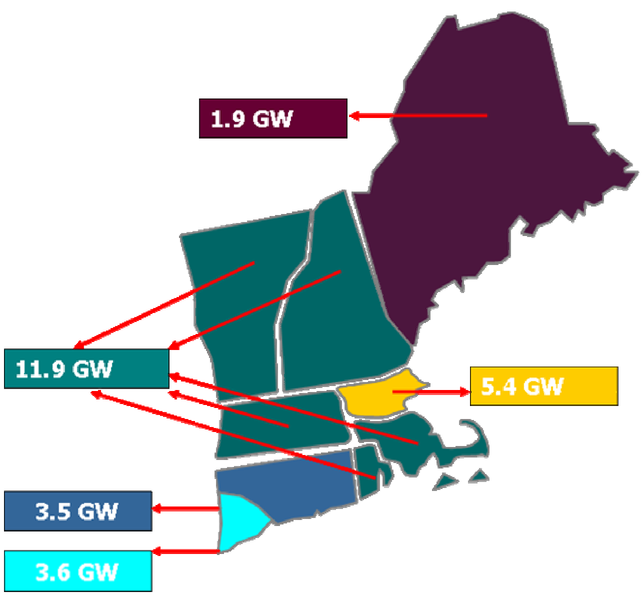


External Node Common Name	ICAP Region
NB-NE External Node	Maine
HQ Phase I/II External Node	Rest of Pool
Highgate External Node	Rest of Pool
NY-NE AC External	Rest of Pool
Cross Sound Cable External Node	Rest of Connecticut
1385 External Node[1]	SWCT
None	NEMA/Boston

1. Possible addition for new line anticipate in 2008.

Each zonal market would have an individual peak load obligation that can be met through local capacity resources or through capacity transfers consistent with the Capacity Transfer Limits (CTLs) available to each market zone. Exhibit 2-10 shows the approximate peak load for the LICAP markets.

Exhibit 2-10: ISO-New England Sample Locational Peak Requirements



- Maine
- NEMASS/Boston
- Connecticut
- Rest of Pool:
  - Vermont
  - New Hampshire
  - WEMA
  - SEMA
  - Rhode Island
- South West CT

LICAP Seasonality

The LICAP markets are expected to clear monthly based on the annual summer peak. The LICAP curve shape will be unchanged from month to month, but the objective capability (sometimes referred to as locational installed capacity requirement) may change from the summer peak level to account for some seasonal factors such as imports from Hydro Quebec. On a month to month basis, load obligations may be satisfied by LSE self-supply, bilateral transactions and demand response resource credits[2],[3]. Since the curves will be based on summer peak MWs, the capacity from generation resources will be considered at a summer adjusted rating.[4] The exact details of the seasonal markets are not fully known or finalized.

LICAP Demand Curves Construct

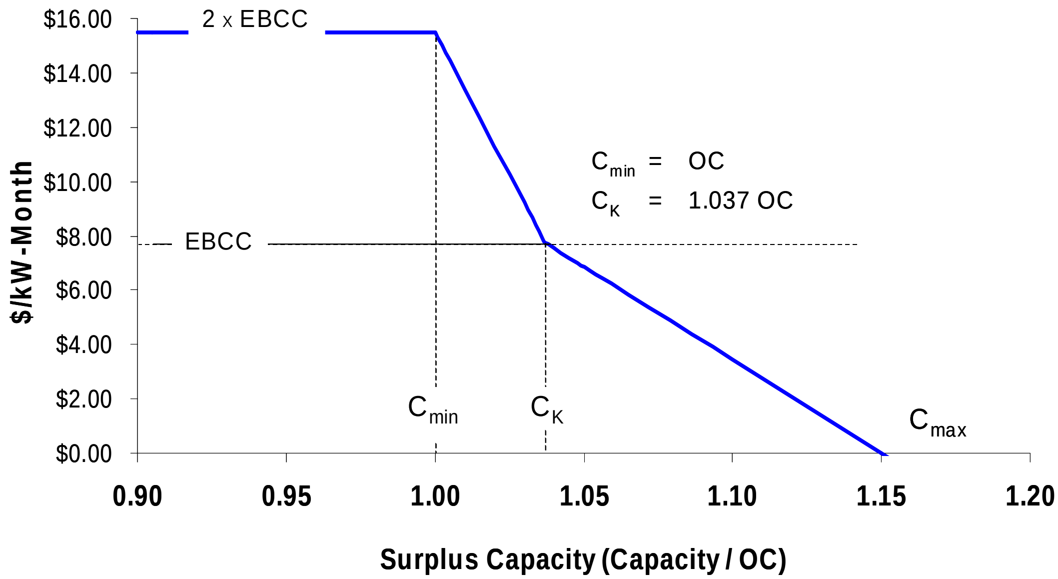
The ISO-NE demand curves have three sections as shown in Exhibit 2-11. They are designed to reflect the value to the system of capacity at given quantities just as demand curves reflect the value of quantities of a particular good and service to consumers. As the quantity of capacity made available increases, the incremental contribution to reliability falls, and the capacity price falls. However, rather than be revealed through consumer preference, the proposed capacity demand curves reflect the estimates of ISO-NE.

[2] Demand response resources will be able to participate in the LICAP markets. Current estimates for total megawatt contributions eligible are 454 MW though final approvals on all capacity are not yet in place. The vast majority of these resources are located in SWCT (roughly 47 percent). The remaining resources are split across areas All of MA is 90MW (20%), Rest of CT is 60 MW (13%), ME is 50 MW (11%), NH 19 MW (4%), VT 14 MW (3%) and RI 8 MW (2%). ISO New England/NEPOOL Demand Response Working Group Meeting, July 5, 2005. ICF's modeling counts only the ISO/CT GAP RFP resources as firmly available as per the ISO-NE LICAP demand curve proposal. Should resources become eligible in other market zones, particularly in Boston, prices may be below our forecast levels. Further discussion of the impact is provided in the results chapter.

[3] In addition, interveners in the LICAP hearings have suggested that a 50 MW Load Swap resource be allowed to participate in the Boston LICAP market. Neither the ISO proposal, nor the FERC administrative Law Judge Rule accepting the design includes the Load Swap resource. ICF modeling does not include the 50MW Load Swap as available to Boston.

[4] Capacity resources generally have a winter and summer rating; the winter rating will be used in the winter months, but will be adjusted to summer levels relative to other capacity.

Exhibit 2-11: LICAP Demand Curve



Source: LaPlante Testimony, August 2004. Docket No.: ER03-563-030

Variable and function definitions:

EBCC	The estimated fixed costs of the Benchmark Generator
C	Capacity
OC	Objective Capability, the minimum capacity needed for reliability (Based on LOLE of 0.1 day in 1 year, equal to 12% above peak under current proposal)
C_{Max}	The capacity value at which P(C) = 0
C_{Target}	Target long-run average C (Initially set to historical average)
SD	The estimated standard deviation of C
C_K	Capacity at the kink in demand curve
P	The Locational ICAP Price in $/kW-month
P(C)	The Locational ICAP Demand Curve

The formula for the demand curve is:

P(C) $= EBCC \times 2$, for $C < OC$
P(C) $= EBCC \times [1 + (C_K - C) / (C_K - OC)]$, for $C < C_K$
P(C) $= EBCC \times [1 + (C_K - C) / 3(C_K - OC)]$, for $C > C_K$
P(C) $= 0$, for $C > C_{Max}$

C_K is determined so that the expected value of P(C) = EBCC when C takes values that are normally distributed around C_{Target} with standard deviation SD. Note, prices are adjusted by the generator available (unforced).

Current relative values:

OC = 1.000
C_{Target} = 1.054
SD = 0.058
C_K = 1.038(calculated as described above.)

As shown above, each of the zonal curves includes three distinct segments. The first portion of the segment (i.e. the horizontal segment to the left) represents the maximum price that capacity is able to receive under shortage conditions. The second segment, the segment with the steepest slope, represents a price at levels above the objective capability targets for the locational markets. And the third segment, the rightmost segment having the lesser slope, represents prices available to capacity generally around or above the target reserve capacity in the locational market.

Like any economic demand curve, the capacity demand curves show quantity on the x-axis and price on the y-axis. In this context, the x-axis is further defined as the percent of installed capacity available to the marketplace. The downward slope of the curve indicates that market prices are higher when less installed capacity is available to the marketplace. As more capacity is added to the system, less value is associated with the available capacity and generation providers receive a lower payment for their available capacity.

Several important inputs used to derive the demand curve include the following: the price for new entry (estimated benchmark capacity cost or EBCC); the minimum resources needed for reliable operation (OC or objective capability); the target quantity of capacity resources desired (C_{target}); the maximum quantity of capacity resources that will receive compensation (C_{max}); and the quantity of capacity resources that are paid the maximum ceiling price (2xEBCC).

The EBCC reflects the expected fixed and investment costs for new capacity to be installed in local markets. The estimated EBCC value is built from a bottom up approach reflecting the equipment costs, financing costs, and locational cost elements. An example of the component cost assumptions used to determine the EBCC is shown in Exhibit 2-12. The exhibit shows the component costs for SWCT as an illustration of the cost build-up. In order to encourage the entry of new resources, the EBCC price is established to reflect the annual levelized cost of new entry for a simple cycle combustion turbine (CT). Other zones will have comparable calculations; however, each will have its own distinct values based on the installed equipment costs for that location.

Parameters that vary regionally include labor, land and taxes. Boston and SWCT have the highest labor and land costs. Connecticut has the highest property tax rates, but the lowest income tax rates.

Exhibit 2-12: Example of ISO-NE's Proposed Cost of New Entry –SWCT 170 MW Simple Cycle Turbine with SCR* Installed

Installed Costs	2005$/kW
- Equipment (CT + SCR*)	222
- Non-labor EPC (plus inventory, startup, and testing)	129
- Labor	112
- Interconnection (Gas pipeline + Electric Transmission**)	64
- Owner's cost (permitting, legal, community support, etc)	27
- Project Contingency	26
- Land	20
Total	602
Fixed O&M Costs	$/kW-yr
- Property Taxes	12.5
- Labor	3.4
- Other	9.8
Total	25.7
Financing Assumptions	
- Annual Inflation Rate	2.50%
- Federal Income Tax Rate	35%
- Debt Leverage	50%
- After-tax ROE	12%
- Cost of Debt	7%
- Interest During Construction	3.50%
- Investment Horizon	20
- MACRS Tax Life	15
- Corporate Income Tax Rate	7.50%
Estimated Fixed Costs of Benchmark Generator (EBCC)	
2005$ Levelized Costs ($/kW-mo)	8.08
2005$ Levelized Costs ($/kW-yr)	97

* Includes an average SCR (Selective Catalytic Reduction) cost of $40/kW for frame-based 170MW unit.

** Includes an average $30/kW electric transmission interconnection cost.

Source: Reed August 2004 testimony. Values are adjusted from 2006$ to 2005$ assuming 2.25 percent inflation. Docket No.: ER03-563-030

Another key input parameter in the demand curves involves setting the capacity goal (Ctarget). The capacity goal is the long term average amount of resources ISO-NE believes will establish adequate reliability. It is the intersection of points on the y and x axes that represent the benchmark peaker price (EBCC) and the capacity (quantity) goal. Traditionally, this capacity goal has been the quantity of capacity that will meet the "one day in ten years" loss of load event probability standard as approximated using a reserve margin requirement. The capacity goal value is a critical input to the demand curve and has significant cost/revenue impacts.

The ceiling price was selected to be symmetrical with the floor which is designed to underpay capacity by an amount equal to EBCC. The ceiling overpays capacity by this same amount. This is expected to be sufficient to send a strong investment signal to potential suppliers of capacity, so that when investors anticipate the market price approaching that level they will choose to invest in new capacity that becomes operable before that level is reached. Such timely investment should almost always prevent the ceiling price from being reached.

The kinked shape proposed by ISO-NE has a steeper slope when the locational capacity is below the capacity target. This allows for a sharper price movement as the locational capacity approaches levels that could compromise reliability.

The capacity target is designed to account for the difficulty in exactly meeting the minimum; on average the system should exceed the capacity minimum. Even as capacity available continues to rise above the target reserve margin, the capacity price stays above zero. The capacity price does not reach zero until supply exceeds roughly 29 percent of expected peak electricity demand in the regional market.

Exhibit 2-13: LICAP Zonal Demand Curve Parameters

Parameter	SWCT	Connecticut	NEMA/Boston	Maine	Rest of Pool
Benchmark Generator Installed Cost (2005$/kW)	602	559	606	548	558
After-Tax Equity Return (%)	12.0	12.0	12.0	12.0	12.0
WACC[1, 2, 3] (%)	9.24	9.24	9.17	9.19	9.17
EBCC (2005$/kW-mo)	8.1	7.9	8.0	7.1	7.5
Target Price[4] (2005$/kW-mo)	6.6	6.4	6.5	5.8	6.1
Annualized Target Price ($2005/kW-yr)	79.2	76.8	78.0	69.6	73.2

Notes:

1. WACC = weighted annual cost of capital is calculated as the share of equity times the equity rate plus the share of debt times the after-tax debt rate.
2. Assumes a 12 percent after-tax equity rate, 7 percent pre-tax debt rate, and a 50-50 debt-equity ratio.
3. Assumes a federal income tax of 35 percent, and a corporate state tax of 7.5 percent for CT, 8.9 percent for ME, 9.5% for MA, and 9.4% for Rest of Pool.
4. Price at 1.054 over the OC level.

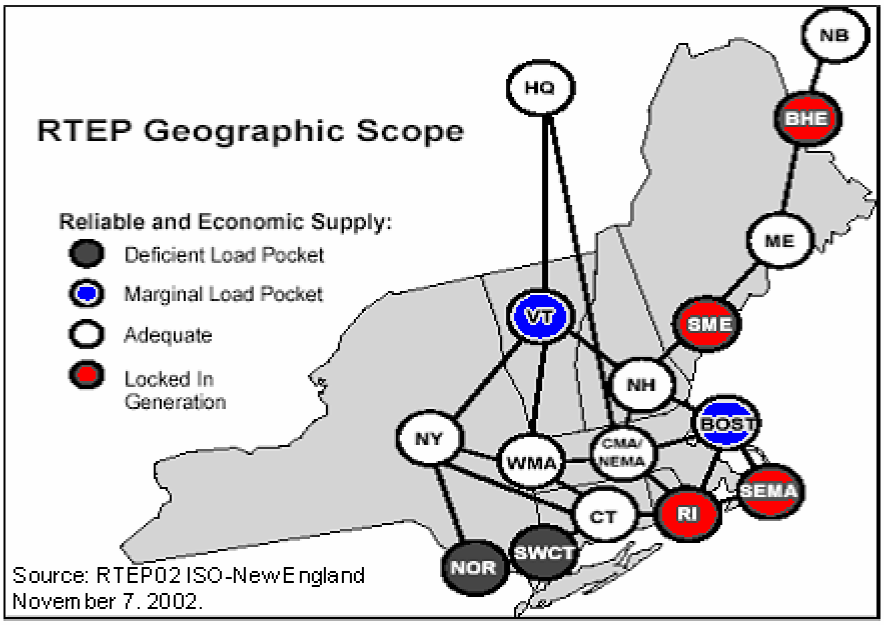
Source: Reed August testimony adjusted to 2005$ assuming 2.25 percent inflation.

LICAP Zonal Transmission Treatment

As ISO and FERC sought to modify the structure of the electricity markets to address concerns about market power, the transmission grid's problems were growing. These problems exacerbated market power concerns while also requiring additional changes to manage the effects of congestion. The current congestion situation is blamed on the recent addition of new generation since 2000 without similar investment in the transmission system. The problem was exacerbated by the lack of location specific price signals which contributed to the creation of generation pockets in areas like Maine, Southeastern Massachusetts and Rhode Island which now periodically experience instances of "locked in" generation resources.

Exhibit 2-14 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 2-14: Sub-Areas in New England and Commercially Significant Transmission Interfaces



As seen above, the Southwest Connecticut, and Norwalk (a sub-region within SWCT) areas are labeled as deficient load pockets while Boston and Vermont are marginally deficient. FERC ultimately chose a combination of these areas to become locational capacity markets.

As can be seen in Exhibit 2-16, the LICAP system has associated with it transmission limitations. Capacity Transfer Limits (CTLs) for each locational ICAP Interface will limit the amount of capacity that may be transferred across each interface in the direction indicated. CTLs can be adjusted during the course of the Capability Year to reflect transmission upgrades or other material changes in capacity transfer capability. ISO-NE will create Capacity Transfer Rights (CTRs) equal to the CTLs specified for each ICAP Interface. CTRs will allow Participants receiving CTR allocations to trade unforced capacity in regions other than the region in which their load or resource is located.

Exhibit 2-15: Transmission Capacity for Inter-Sub-Region Installed Capacity Transfers – 2006 (MW)

Receiving Region ► / External Source	SWCT	Rest of Conn	Rest of Pool	NEMA/Boston	Maine
SWCT	NA	2,132			
Rest of Conn	1,961	NA	1,726		
Rest of Pool		2,369	NA	3,111	1,500
NEMA/Boston			9,650	NA	
Maine			1,500		NA
Quebec			1,725		
New Brunswick					700
LILCO		300			
Rest of NY		800	970		
Total[1]	1,961	2,200	1,850	3,600	2,100

Notes:
1) Total transfer capabilities reflect binding constraint transfer limits into the receiving region. This value may be less than the sum of all transfer capabilities into the receiving region.
Source: Values are consistent with the Region Transmission Expansion Plan (RTEP) 2004.

Although total transfer capabilities (the sum of capabilities across individual interconnects) may be significant, CTLs are based on the most limiting interface, which is typically reflective of the binding limit of the combination of joint interconnected lines. For example, the maximum import capacity to Boston from all sub-zones in the Rest of Pool is 6.6GW; however, for LICAP (and energy transfer) purposes the total limit is 3.6 GW.

The IPM® model simulates the locational capacity markets as described above. The capacity demand curves are defined on the zonal basis as stepwise linear functions within the IPM® linear simulation model. Using this construct, IPM® will solve for the zonal capacity clearing prices which minimizes overall system costs while ensuring adequate supply to satisfy peak load requirements subject to zonal transmission constraints.

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Wholesale Market Modeling Assumptions Utilized in the Avoided Cost Analysis

The following section outlines key modeling assumptions for the major determinants influencing energy and capacity prices including:

Exhibit 2-16: Key Assumption Categories

Capacity Price Determinants	Energy Price Determinants
1. Load Growth 2. Reserve Margin 3. Capacity Expansion 4. Retirement and Mothballing 5. New Power Plant Characteristics 6. Financing of New Power Plants 7. Firm Transmission at peak	1. Fuel Prices - Gas - Coal 2. Environmental Compliance 3. Nuclear Plant Characteristics 4. Existing Unit Characteristics 5. Environmental Policies 6. Transmission

Note: Parameters to some extent affect both energy and capacity pricing; this table categorizes parameters by the dominant effect.

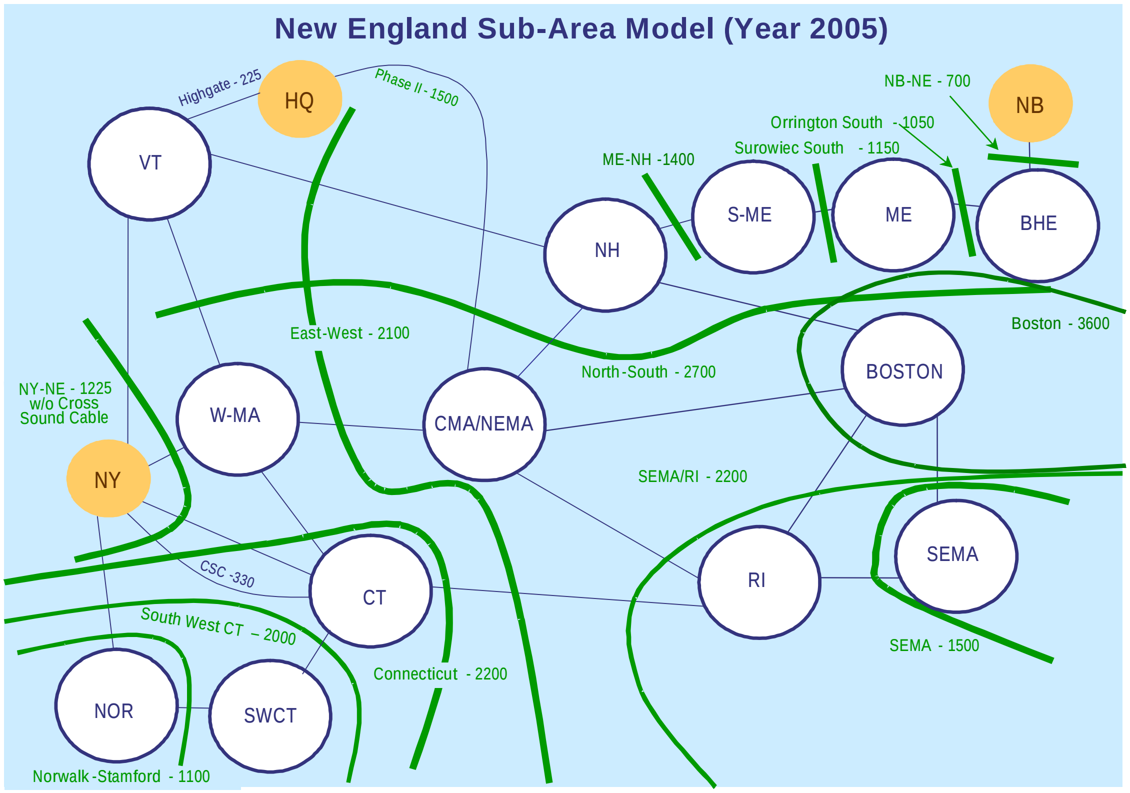
For this analysis, the full time horizon beginning in 2005 through 2040 is considered simultaneously.

New England Zonal Representation

As discussed in earlier chapters, transmission within New England can play a key role in dispatch decisions and pricing. External connections with NYPP, Quebec, and New Brunswick are limited and play a small role in the New England market[5]. Within New England transmission congestion does have a price impact, especially at peak. ICF has modeled a five zonal pricing structure to capture intra-New England congestion in the capacity markets consistent with the current LICAP design. We have modeled 13 transmission zones to reflect the energy constraints consistent with LICAP. This analysis makes use of the 2004 New England Regional Transmission Expansion Plan (RTEP) findings for total transfer capability (TTC) limitations between regions and across major interfaces, and Exhibit 2-17 shows the published limits as of November 2004.

[5] Imports from Quebec have the largest impact on the market place and may affect both the energy and capacity value. However, in recent years, the effect of Quebec has been reduced.

Exhibit 2-17: New England Zonal Transfer Limits



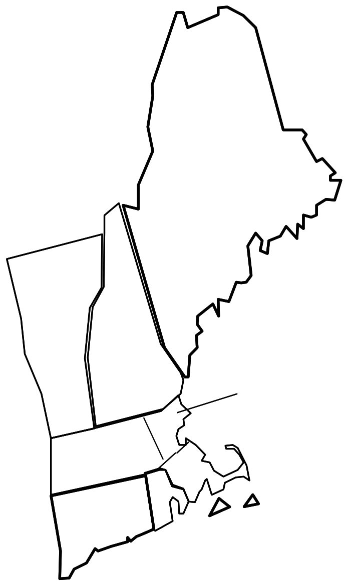
Source: New England RTEP 2004.

ISO-NE separately has identified 8 pricing zones[6] which are larger groupings of the transmission zones. The 8 pricing zones represent 8 major load zones (which generally correspond to commercially significant transmission constrained regions) that include hundreds of nodes. Each nodal price will reflect the underlying costs of generation, congestion, and losses at that point while obligations of physical loads will be based on average prices for that zone. The pricing zones are illustrated in Exhibit 2-18.

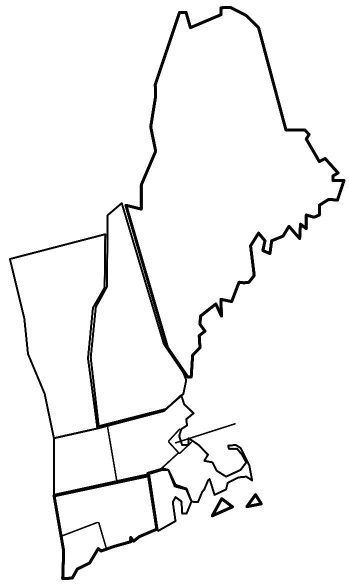
[6] There are currently 8 pricing or load zones. Beginning in 2006, Southwest Connecticut is expected to be separated into its own zone. This analysis provides results according to the 9 zone region beginning in 2006, however, the RTEP break-out is used for all periods considered in the forecast horizon.

Exhibit 2-18: Pricing Zones versus Transmission Zones

IS NEPOOL Pricing



IPM Modeling



ISO - NE Pricing Regions	IPM Modeling Regions
ME	BHE ME SME
NH	NH
VT	VT
WMA	WMA CNMA
CT	CT
SWCT[1]	SWCT NOR
RI	RI
SEMA	SEMA
BOST	BOST

1. SWCT will be considered a pricing or load zone beginning in January 2006.

Capacity and Demand Parameters

In order to isolate the effect of expected incremental demand savings due to demand side savings programs expected in the ISO-NE base forecast, this analysis relies on the ISO-NE unadjusted Reference Case forecast (which includes no projected demand side management (DSM)) and adjusts it for the 2004 DSM levels reported by ISO-NE. The 2004 DSM levels are held flat throughout the forecast to approximate a peak and energy level which does not include incremental DSM savings going forward. Exhibit 2-19 reflects the DSM adjustment in the Net Internal Demand values shown. The hourly load shape is reconciled to the annual peak and energy projected levels using hourly load reconciliation starting from an hourly historical year that experienced near normal weather conditions.

Exhibit 2-19: ISO-NE Demand Related Assumptions

Parameter	New England	Boston	Rest of Connecticut	SWCT	Rest of Pool	Maine
2005 Weather Normalized Peak Demand (MW)	27,917	5,746	3,718	3,812	12,540	2,100
2005 Adjusted Net Internal Demand[1] (MW)	26,400	5,434	3,516	3,605	11,859	1,986
Annual Peak (and NID) Growth						
2005-2006 AAGR	2.5	2.6	2.4	2.3	2.7	2.4
2007-2010 AAGR	1.5	1.5	1.4	1.3	1.6	1.4
2011-2020 AAGR	1.4	1.5	1.3	1.3	1.5	1.3
2021 – forward AAGR	1.6	1.6	1.4	1.4	1.7	1.4
2005 Weather Normalized Net Energy Load (GWh)	126,495	25,139	16,080	16,148	57,182	11,947
Annual Energy Growth						
2005-2006 AAGR	2.0	2.0	2.0	2.1	2.0	1.8
2007-2010 AAGR	1.5	1.5	1.5	1.6	1.6	1.4
2011-2020 AAGR	1.5	1.5	1.5	1.6	1.5	1.3
2021 – forward AAGR	1.6	1.5	1.5	1.7	1.6	1.4

Note: AAGR = Average Annual Growth Rate.

1. Net internal demand (NID) is equal to the peak load less interruptible load and demand-side management. An adjustment was made to the CELT forecast to adjust DSM to historical levels to reflect savings only from existing Measures rather than forecasted DSM savings.

Source: ISO-NE Capacity, Energy Loads and Transmission (CELT) Report April 2005; ICF.

Conservation and load management (C&LM) resources directly modeled in this analysis include the Southwest Connecticut GAP RFP resources which are considered to be responsive resources capable of satisfying high demand period requirements. The GAP resources are modeled as supply-side resources that will be called on to dispatch (representing load reduction) at an economic price level. In actuality, the SWCT GAP resources are a combination of supply-side and load reduction resources, with the majority of the resources being supply-side. Exhibit 2-20 reflects the distribution of SWCT GAP resources; both load reduction and emergency generation resources reflect price responsive resources. These units have established contracts with ISO-NE through 2007 with an optional one year extension. These resources can have a direct impact on the supply side resources available in the LICAP market through a capacity credit they receive.

Exhibit 2-20: SWCT GAP RFP Resources Modeled

	Available MW		
	2005	**2006**	**2007**
Emergency Generation[1]	153.1	153.7	153.7
Load Reduction[2,3]	64.7	95.3	100.8
Total	217.8	249.0	254.5

1) Includes 69 MW for the Waterside generators.
2) SWCT GAP RFP resources are equally split between Norwalk and Southwest Connecticut model regions.
3) Total cost for the SWCT GAP RFP from 2004-2007 is $492.9/kW (real 2005$).

Exhibit 2-21 shows the available capacity in 2005, which for all of New England represents a 21 percent reserve margin over the net internal demand measure shown in Exhibit 2-19. Of this total, more than 50 percent of the capacity is located in Rest of Pool and roughly 10 percent is located in Boston. In contrast roughly 45 and 20 percent of the coincident peak load occurs in Rest of Pool and Boston respectively (see Exhibit 2-19). As a result, a significant difference in local reserve percentages exist and the importance of capacity transfers across regions increases.

Exhibit 2-21: ISO-NE Capacity Related Assumptions by LICAP Zone as Modeled

Parameter	New England	Boston	Rest of Connecticut	SWCT	Rest of Pool	Maine
Total Available Summer Capacity[1] (MW) – 2005	31,915	3,810	4,031	2,897	17,470	3,707
Demand Response Resource Eligible for LICAP participation (MW)	254	0	0	254[2]	0	0
Local Reserve Margin (%)	21	-30	15	-20	47	87

1. Capacity shown is that available for energy dispatch. Certain resources may not be fully eligible to participate in the LICAP market due to reliability issues or de-ratings. As such, total local LICAP MWs may be below the value shown. This is particularly true in zones with large amounts of hydro-electric and renewable capacity which is not considered fully able to meet peak requirements. Totals shown for capacity include the GAP resources.
2. Included through 2007. Annual values may vary from this total which represents the capacity available in 2007.

Sources: Capacity based on CELT Report April 2005 and ICF unit level database. Demand response resources modeled represents the ISO/CT GAP RFP resources only.

Load growth is a key determinant of marginal energy costs. In any given year, higher load levels require the system to call on increasingly expensive units on the margin, thereby increasing the marginal energy cost. Likewise, peak load growth is a key determinant of the capacity value. Electricity demand growth projections are based on the New England Capacity Energy Loads and Transmission (CELT) April 2005 report. Going forward, reserve margin targets are captured in the modeling though the use of the LICAP demand curves.

The roughly 17-18 percent target level for surplus capacity targeted in the demand curves is determined based on ISO-NE's examination of historical reserves and the level of capacity consistent with maintaining reliable supply. According to ISO-NE, this is the equivalent of a long-term target of falling below OC no more than 17 percent of the time. The surplus target was determined through analysis of a 20 year time series of historical reserves rather than a full loss of load probability determination. The 17-18 percent is derived from the reserve margin objective of 12 percent and the LICAP target objective capability level of 1.054 (see Exhibit 2-11 C_{target}). The 12 percent reserve margin is built into the LICAP construct resulting in a target surplus capacity equivalent to about 18 percent reserve margin (1.12 * 1.054). The target objective capability is not considered a requirement. It is expected that capacity will vary, sometimes below and sometimes above that level.

Retirement/Mothballing Potential

Operators of a significant number of units in the New England markets have considered mothballing their plants because the power market has not been providing sufficient revenues to support their continued operation in the near term. To date, rather than mothball, many of these operators have sought reliability must-run contracts with ISO-NE. Exhibit 2-22 details the approved RMR units. Absent RMR revenues, it is likely that these units would not have been able to recover costs and would have been forced to retire, mothball, or accept operating losses.

Exhibit 2-22: RMR Units Currently Approved or Under Consideration by ISO-NE

RMR Units	
Unit	**Capacity (MW)**
New Boston 1	350.0
Kendall, Steam 1	14.6
Kendall, Steam 2	21.0
Kendall, Jet 1	16.8
West Springfield 3	101.2
Devon 11-14	120.6
Norwalk Harbor 1,2,10	341.9
Middletown 2-4, 10	770.1
Montville 5, 6, 10 & 11	493.7
Milford 1	239.0
Milford 2	253.5
New Haven Harbor	447.9
Bridgeport Harbor 2	130.5
Total Approved	**3,300.8**
Enfield	21.2
Jonesboro	20
Ridgewood	2.4
Tupperware	1.8
Salem Harbor 1-4	742.8
Millennium	334.3
Lowell Cogen	25
William F. Wyman 4	603.9
Bridgeport Energy	451.2
Total Under Consideration	**2,202.6**
Total	**5,503.4**

Source: ISO-NE as of April 2005.

The on-going potential for mothballing or retirement based on economics is determined endogenously within the model. We provide both retirement and mothballing options to units in New England. All oil/gas, coal and nuclear units in New England are given the option to retire. All oil/gas steam, simple cycle turbines, and combined cycle units are given the option to temporarily mothball, and return to service when market economics improve such that fixed costs recovery is guaranteed. Units are allowed to retire no earlier than 2008 in all market areas except those in Norwalk which are not allowed to retire until 2010.

The retirement and mothball options are chosen within the model based on projected discounted cash flows. That is, if a unit cannot recover projected fixed costs on a net present value basis over its remaining life, that unit will decide to exit the market and avoid forward losses. The physical costs to mothball, ongoing costs to maintain a mothballed state, and actual costs to return to service are all considered within this construct. The mothballing option is made on a shorter-term basis taking annual revenues and costs into consideration as well as the costs of a mothball unit returning to service. This analysis assumes that units are not allowed to retire from the grid until 2008 at the earliest throughout New England. These assumptions to delay possible retirements to at the earliest 2008 and 2010 were agreed upon by the AESC Study Group to reflect a fairly significant lead time for approval of retirements in general, and a severe need for local capacity in Norwalk.

In this analysis, units currently qualified as RMR are also given economic mothball and retirement options in this analysis, though if required for reliability they will not be allowed to mothball or retire until the reliability constraints are relieved. However, units required for reliability reasons are allowed to recover costs on a cost of service basis through out-of-market mechanisms (such as the existing RMR contracts) even after the LICAP market has begun.

The RMR assumptions are designed to reflect restrictions that are not entirely true to perfectly competitive markets. Since the RMR capacity is available to the market and the capacity contributes into the LICAP clearing level, the resulting LICAP price would be lower than had these units been allowed to mothball or retire based on their economics only. Since the units are forced to stay on (in most cases despite their own declaration of desire to mothball or retire), often to compensate for voltage stability issues, they are compensated through a separate payment which allows the units to receive cost recovery at rate of return deemed to be reasonable by FERC. The effect of allowing these units to retire in the modeling analysis performed would be to drive capacity prices up in those areas with RMR units. This pure economic effect was not considered due to issues such as voltage stability which were not directly modeled in the analysis. That is, in the real world, severe voltage stability issues could result if the units that when modeled would want to retire were allowed to actually exit the market. ISO-New England has historically allowed these units to capture costs and the LICAP design does permit this same RMR activity to continue into the future. As such, assumptions to prevent exit until the stability and reliability issues are addressed are reasonable.

Firmly Planned Supply Additions

Firm supply additions, that is generation builds either recently operational or currently under construction, are explicitly included in the model. Non-firm supply additions 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.

Additional announced capacity is not included in our model; however, optimal unplanned capacity expansion is determined within the model based on economics. The assumptions used for costs and potential timing of new (unplanned) units are described in the next section.

New Unit Characteristics

In order meet net internal peak demand, the IPM® model will optimize the generation mix to include required new capacity. Characteristics assumed for new unit options drive decisions on the mix of new builds and consequently affect prices. Combustion turbines have the lowest capital and fixed O&M costs among all of the new equipment options. However, this advantage is offset by its higher variable operating costs associated with higher heat rates and higher variable O&M costs. The decisions on what type of capacity, the amount of capacity, and the location of capacity are all internal to the modeling analysis. The modeling tool uses a linear optimization approach with the goal of minimizing costs over the entire time horizon subject to constraints such as ensuring adequate capacity to serve peak and hourly load. We assume costs for new units consistent with those in the ISO-NE demand curve construct.

ICF has explicitly included unplanned build options for the following capacity types in New England:

- Simple Cycle Combustion Turbines (consistent with costs in ISO proposal)
- Combined Cycles (derived from simple cycle costs)
- Cogeneration units (limited amounts of capacity are assumed available based on available sites)
- Renewables (Wind, Biomass, Landfill Gas)

ICF does not consider coal units as an option in New England due to high costs, environmental barriers, and siting limitations.

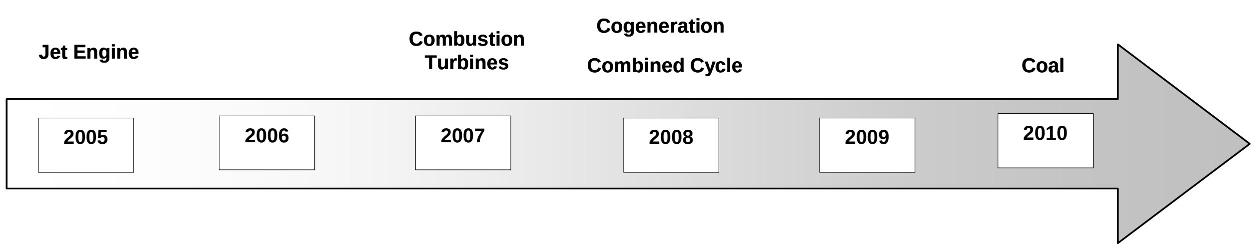
New simple cycle units are assumed to be available at a levelized cost that ranges from \$547/kW to \$620/kW (costs vary by region) in New England. New combined cycle and cogeneration costs are assumed to be available at a levelized cost that ranges from \$792/kW to \$914/kW (2005\$). New England costs on an equivalent megawatt basis are slightly higher than the US average when considered on an International Standards Organization (ISO) basis (69°F and sea-level) due to ambient conditions and labor costs. New England summer and site-specific altitude conditions result in a roughly 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.

ICF incorporates both the existing cogeneration capacity available to the grid and the potential for new facilities. In our forecast, cogeneration facilities are added only if determined to be economic by the model. The expansion of cogeneration by the model is limited to roughly 500 MW through all of New England, based on estimates of the potential for site development.

Over the market analysis period, we allow the model to optimize the selection of new units based on the economics of these new units and the overall system. Capital costs for similar equipment types are assumed to decline over time as technological advances are realized.

In the very near-term, only peaking capacity supply options are allowed as a typical combined cycle unit typically requires a lead-time of roughly 2 years prior to coming on-line. Therefore, unless already under construction, baseload gas additions are delayed until 2008, and unplanned coal units (outside of New England) are delayed until 2010. The timing when new resources of different types are able to enter the market is shown in Exhibit 2-23.

Exhibit 2-23: Unplanned Build Timeline



The geographic scope of the model includes most of the Eastern Interconnect (US and Canada) in order to capture the effects of imports and exports to and from New England. The cost assumptions for new units will vary regionally based on the local labor, site, and materials costs. Likewise the types of units available in other markets may vary from those allowed in New England (e.g. coal is not allowed in New England in this analysis, but is available in PJM).

The risks associated with the individual build options will vary and hence the financing costs available to units of different capacity types will vary. In a deregulated market, peaking plants are less leveraged due to a riskier and, more volatile revenue profile. Conversely, baseload plants are more leveraged due to a more stable cost and revenue profile. Exhibit 2-24 presents the financing assumptions by capacity type.

We assume that the average real levelized capital charge rate in NEPOOL for new combined cycle (baseload) plants is 12.9 percent. Wind plant financing assumes that available tax-credits (such as the production tax credit) are available through 2009. The financing assumptions are overall consistent with those assumed in the LICAP demand curve proposal for peaking units.

Exhibit 2-24: Capital Costs and Financing Assumptions

Parameter	Treatment			
	CC / Cogen	Combustion Turbine	LM6000	Wind
New Plant All-In Levelized Capital Cost (2005$/kW)				
Connecticut	855	574	1018	1906
Boston	914	606	1041	1969
Southwest Connecticut	892	596	1035	-
Rest of Pool	837	560	974	1844
Maine	792	547	960	1722
Financing Costs for New Unplanned Builds	CC / Cogen	CT/LM6000		Wind
Debt/Equity Ratio (%)	45/55	30/70		45/55
Nominal Debt Rate (%)	8	9		8
Nominal After Tax Return on Equity (%)	13	13		13
Income Taxes[1] (%)	41.0/39.9/40.8	41.0/39.9/40.8		41.0/39.9/40.8
Other Taxes[2,3] (%)	1.34/1.23/1.09	1.34/1.23/1.09		1.34/1.23/1.09
General Inflation Rate (%)	2.3	2.3		2.3
Levelized Real Capital Charge Rate[2] (%)	13.1/12.9/12.8	14.3/14.1/14.1		13.7/13.5/13.4

1. Reflects combined federal and state income taxes. Production tax and other tax credits assumed to be available through 2009. These taxes are included directly in the capital costs or capital charge rate.
2. Reflects primarily property taxes. 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.
3. Includes insurance costs of 0.3 percent for all the sub-regions.
Sources: ICF; ISO-NE LICAP proposal.

Note, although the costs of new combustion turbines are reflective of the ISO-NE LICAP, the financing assumptions are consistent with ICF assumptions which have been reviewed by market participants including developers, bankers, rating agencies, and equity investors as well as the AESC Study Group. The cost assumptions for combined cycles were developed by ICF as consistent with the simple cycle turbine costs. All other unit type cost and financing assumptions reflect ICF default assumptions.

Region-wide fixed and variable O&M costs assumed for new units are shown in Exhibit 2-25. Similar to construction costs, O&M costs for the new units vary across regions based on the labor costs according to the Means labor rate index. This is a similar approach as used by ISO-NE in the setting the EBCC price in the LICAP demand curves. ISO further includes property taxes as part of the O&M costs while ICF captures property taxes directly in the annual carrying charge rate. This leads to a difference in the O&M assumptions; however, the inclusion of regional variations for labor and taxes is reflected in both. Region specific O&M values for the three areas with significant differences from the region-wide values are presented in Exhibit 2-26.

Exhibit 2-25: Region-Wide New Unit O&M Costs

	Fixed O&M (2005$/kW-yr)	Variable O&M (2005$/MWh)	Total O&M (2005$/MWh)
Combustion Turbines			
2005 – 2030	6.3	7.7	8.5
Cycling Combined Cycles[1]			
2005 – 2009	15.7	2.4	4.2
2010 – 2030	12.5	2.7	4.2
Turndown Combined Cycles[1]			
2005 – 2009	30.3	1.0	4.5
2010 – 2030	26.1	1.0	4.1
Cogeneration			
2005 – 2030	28.2	1.2	4.4
LM6000			
2005 – 2030	11.5	2.6	4.0
Coal			
2005 – 2021	29.3	2.3	5.6

Note: Values shown assume 5 percent capacity factor for combustion turbines, 83 percent capacity factor for combined cycles, 80 percent capacity factor for cogen, 85 percent capacity factor for coal, and 5 percent capacity factor for LM6000 for illustrative purposes only. Actual variable O&M realized by any unit is determined as a function of dispatch.

1. Total costs for turndown and cycling combined cycles are similar. However, the ability of units to allocate costs to variable and fixed O&M for competitive bidding purposes differs as reflected here.

Source: ICF Consulting.

Exhibit 2-26: Region-Specific New Unit O&M Cost Assumptions (2005$)

	Fixed O&M (2005$/kW-yr)			
Capacity Type	Boston	CT (including SWCT)	Maine	Variable O&M[1] ($/MWh)
Combustion Turbine	7.1	6.9	6.4	7.7
Cycling Combined Cycles[2]	18.0	17.3	15.0	2.4
Turndown Combined[2] Cycles	32.4	31.6	29.3	1.0
Cogeneration	30.1	29.3	27.0	1.2
LM6000	12.9	12.2	10.2	2.6
Coal	32.0	30.4	25.8	2.3
Wind (Class 4)	28.2	28.2	28.2	0.0
Wind (Class 5)	33.5	33.5	33.5	0.0
Wind (Class 6)	33.5	33.5	33.5	0.0
Landfill Gas	106.0	106.0	106.0	0.0
Biomass	49.0	49.0	49.0	0.4

1. Assumes 5 percent capacity factor for combustion turbines, 83 percent capacity factor for combined cycles, 80 percent capacity factor for cogeneration, 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.
2. Total costs for turndown and cycling combined cycles are similar; however, the ability of units to allocate costs to variable and fixed O&M for competitive bidding purposes differs as reflected here.

Source: Annual O&M for average unit adjusted by Means labor rate index.

Exhibit 2-27: New (Potential) Unit Heat Rate Forecast

On-line Year	Combined Cycle	Cogen	Combustion Turbine	LM 6000	Coal
2005	7,100	6,316	10,778	9,468	10,900
2010	6,800	6,144	10,547	9,265	10,900
2015	6,672	5,976	10,321	9,066	10,900
2020	6,553	5,813	10,100	8,872	10,900
2025	6,447	5,653	10,100	8,719	-
2030	6,342	5,653	10,100	8,719	-

Source: ICF Consulting.

Exhibit 2-27 presents the heat rate assumptions for new (unplanned) units. These heat rates factor into the cost determination for new units fuel expense.

Natural Gas Prices

Natural gas price projections used as inputs to the wholesale market price forecasts are consistent with those used in the natural gas avoided cost calculations.

Delivered natural gas prices to the New England are characterized for four sub-zones. The monthly basis differentials for these sub-zones are presented in Chapter One, Exhibit 1-21.

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 Chapters One and Four respectively.

Environmental Regulations

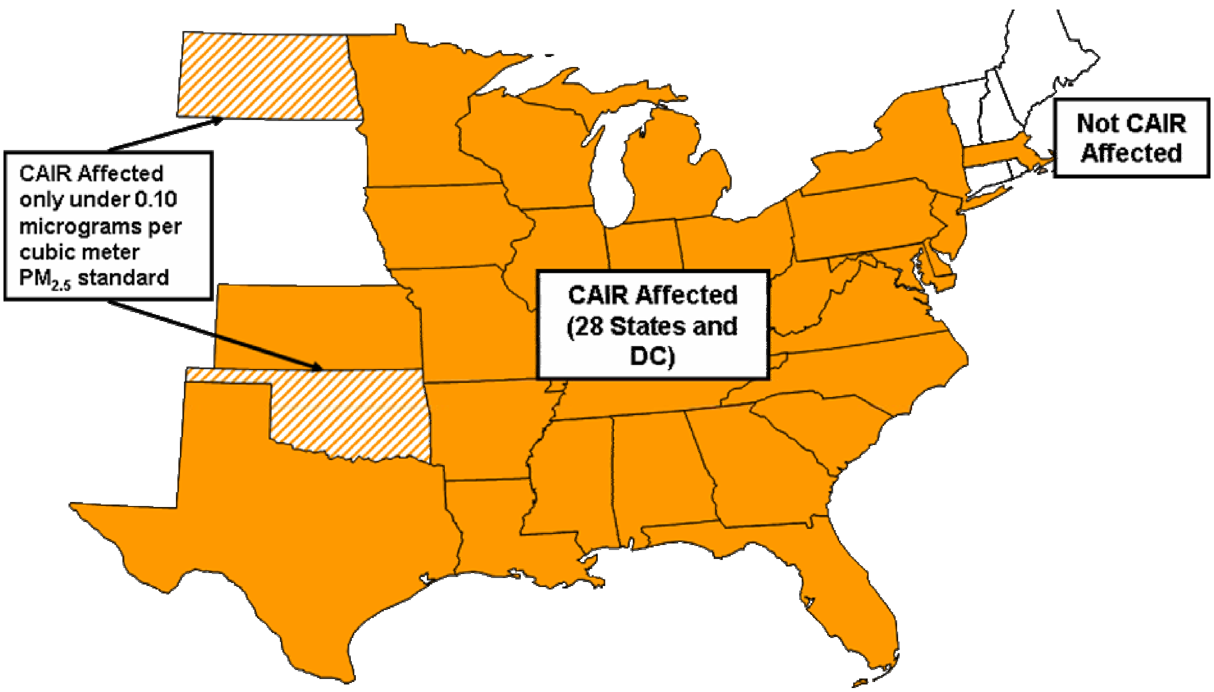
For this analysis, we have modeled currently firm environmental regulations including national policies for NO_x, Hg, and SO_2 as well as state and regional level policies. Exhibit 2-29 below outlines ICF's modeling assumptions of regional and national environmental policies.

Exhibit 2-29: Environmental Policies Captured in this Analysis

Parameter	Treatment
SO2 Regulations	Existing Phase II Acid Rain Policy and Clean Air Interstate Rule (CAIR) policies. Allowance prices commence with national prices close to $600/ton rising in real terms
NOx Regulations	NOx SIP Call; NOx Clean Air Interstate Rule (CAIR) policy. National allowance prices are in the $700 to $3,000/ton range
CO2 Regulations	Expected Federal Program beginning at mild levels in 2010; Regional Greenhouse Gas Initiative (RGGI) Policy affecting Northeast states assumed enacted in 2006 as a predecessor to the Federal Program.
Mercury Regulations	Clean Air Mercury Rule cap and trade program beginning in 2010.

EPA's CAIR would affect SO_2 and NO_X emissions in the eastern US as shown in the shaded states shown in Exhibit 2-30.

Exhibit 2-30: Clean Air Interstate Rule (CAIR) Program Coverage



EPA's proposed mercury rule affects the lower 48 states.[7]

Exhibit 2-31 outlines additional state level environmental policies in the New England states and in New York.

Exhibit 2-31: Modeled State Air Regulations in addition to Regional or Federal Programs

State	Notes	Status	NOX	SO2	Mercury	Carbon
Connecticut	Trading / facility	Promulgated on 12/28/2000	Non-Ozone Cap @ 0.15 lb/MMBtu in '02 (Trading)	0.55 lb/MMBtu in '02 0.33 lb/MMBtu in '03 (Facility)	0.6lb/TBtu or 90% from input, whichever is least stringent in '08 (Facility)	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	85% from input by 10/1/2006; 95% from input by 10/1/2012	1800 lb/MWhr by '06
New Hampshire	Trading and Banking Allowed	Passed House Committee on 11/28/2001	Annual Cap @ 1.5 lb/MWhr in '06 3,644 tons	Annual Cap @ 3.0 lb/MWhr in '06 7,289 tons	Cap level recommended in '04 (not implemented for analysis)	5.426 million tons in '06 to '10; Phase II cap recommende d in '04
New York	Trading and Banking Allowed	Passed on 3/26/03	Non-Ozone Cap @ 0.15 lb/MMBtu in '04 3:1 IP* 39,908 tons	25 % below Phase II starting '05 50% starting '08 3:1 IP*	NA	Under development

*IP=Import Penalty—ratio of upwind tons redeemed for a single in-state ton.
Source: Compiled by ICF from state policy requirements.

The forecast also assumes that a regional carbon policy will be in place prior to a national program.

The allowance cost assumptions associated with the national and large regional policies are shown in Exhibit 2-32. Allowance costs, were applicable, for trade-able state level programs are solved for endogenously by the IPM® model.

[7] Coal boiler/generators 25 MW and larger are affected.

Exhibit 2-32: Allowance Price Projections (2005$)

Emission Constraint	Units	2005	2008	2009	2012	2016	2020	2026	2030	2040
CAIR NOx Annual	$/Ton	0	0	698	848	1,109	1,442	2,203	2,436	3,132
Hg CAMR	$/Lb	0	0	0	19,629	25,684	33,410	51,055	54,292	62,644
National CO2	$/Ton	0	0	0	1	5	10	17	26	26
SO2 CAIR	$/Ton	622	709	811	986	1,288	1,676	2,304	2,304	2,304
RGGI CO2	$/Ton	0	0	2	2	0	0	0	0	0

Source: ICF Consulting.

In addition to these pollution control programs, ICF considers the requirements for renewable resource portfolios within the Northeastern states. The RPS (Renewable Portfolio Standards) are assumed consistent with the current and ongoing RGGI analysis which considers a combined Northeast RPS target and allows wind, biomass, and landfill gas units to satisfy the requirements shown in Exhibit 2-33. Targets shown are for new generation sources over time.

The regional RPS constraints considered in this analysis are set at such levels that they would satisfy the state levels described above. However, under the regional programs, the qualified resources that would be able to contribute to the generation standards may be expanded from state level programs since resources in the entire region are allowed to contribute to the standard. As such, although the regional generation targets would require the equivalent or more generation from renewable sources than the sum of the individual state programs, the generation sources themselves may be spread over a broader territory than would be the case in a state level program. This regional modeling provides for a sharing of resources from state to state such that resources will tend to locate in areas offering the greatest efficiency first.

Exhibit 2-33: Northeast Regional Renewable Portfolio Standard Annual Generation Targets

Year	Regional Renewable Portfolio Annual Target	
	GWh	~ % of Generation
2005 – 2006	1,500	0.6%
2007 - 2008	11,135	4.3%
2009 – 2010	24,889	9.3%
2011 - 2014	39,352	6.7%
2015 – 2018	41,690	6.6%
2019 - 2023	55,978	6.6%
2024 - 2028	60,187	6.7%
2029 - 2040	60,310	2.5%

Transmission

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 the New England RTEP, ICF AC load flow studies, and NERC studies.

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 ISO-NY
- Cross Sound Cable interconnection with ISO-NY (LIPA)

New England as a whole can import up to roughly 17 percent of its peak demand through its external interconnections. Similarly, New England can export up to 14 percent of its peak demand.

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.

The new 330 MW high voltage direct current (HVDC) transmission interconnection between New Haven, CT and Shoreham, NY has been completed and is energized. As part of the approval process for the Cross Sound Cable, a new transmission line ("1385") connecting Long Island and Norwalk is also anticipated to be complete by the summer of 2008. This new line replaces an existing line that has been leaking coolant oil.

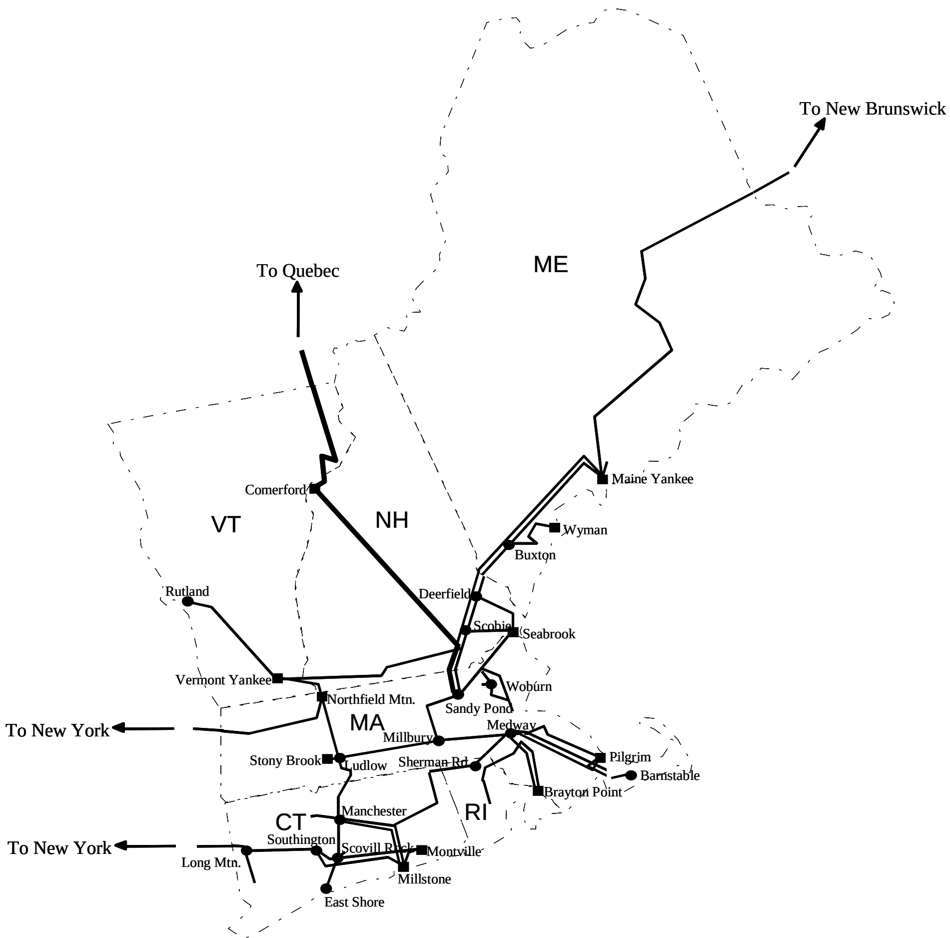
Intra-Regional Transmission

ISO New England's annual transmission plan, the Regional Transmission Expansion Planning (RTEP) study, released in 2004[8], found that almost 600 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. The RTEP 2004 proposed transmission projects in these two areas represent approximately $400 million in infrastructure investment. Current estimates for Southwest Connecticut (Phase I and Phase II) are now estimated at closer to $1 billion.

The major internal transmission lines within New England are shown in Exhibit 2-34 (Exhibit 2-17 presents zonal transfer limitations).

[8] RSP 2005 has been released but the modeling for this study was completed well before the release of the new report.

Exhibit 2-34: New England Inter-Regional Transmission



Select transmission upgrades are considered in the modeling analysis. These upgrades have the effect of increasing internal transfer limits from their current levels. Exhibit 2-35 presents the assumptions for major transmission upgrades or now transmission capacity affecting the zonal interface limits.

Exhibit 2-35: Firmly Planned Transmission Upgrades

Constraint[1]	Current Limit (MW)	Amount of Increase (MW)	Year	Project
SWCT Import Constraint	2000	575	2007	Southwest CT Reliability Project Phase 1
SWCT Import Constraint	--	825	2010	Southwest CT Reliability Project Phase 2
CT Import Constraint[2]	2200	800	2011	Southern New England Reinforcement Project
Norwalk Import Constraint	1100	200	2007	Southwest CT Reliability Project Phase 1
Norwalk Import Constraint	--	350	2010	Southwest CT Reliability Project Phase 2
Boston Import Constraint	3600	900	2009	NSTAR 345kV Transmission Reliability Project
Maine to New Hampshire	1400	100	2007	Northern New England Transmission Transfer Capability Enhancement
New Brunswick to Maine	700	300	2007	Northeast Reliability Interconnect Project
1385 – Long Island to Norwalk	--	200	2008	Replacement for existing leaking line agreed upon under Cross Sound Cable project
Orrigton South Export	1050	150	2007	Bucksport Impact System Study
Surowiec South Export	1150	100	2007	2000 Maine Operating Study

Notes:

1) Several planned projects were excluded from the TTC analysis. The Northwest Vermont Reliability Project will likely improve transmission transfer capabilities; however, the impact is unknown at this time. Similarly, the impact of the Monadnock, North Shore, and Central Massachusetts Transmission upgrades on transmission transfer capabilities are unknown at this time, but are expected to be minimal.

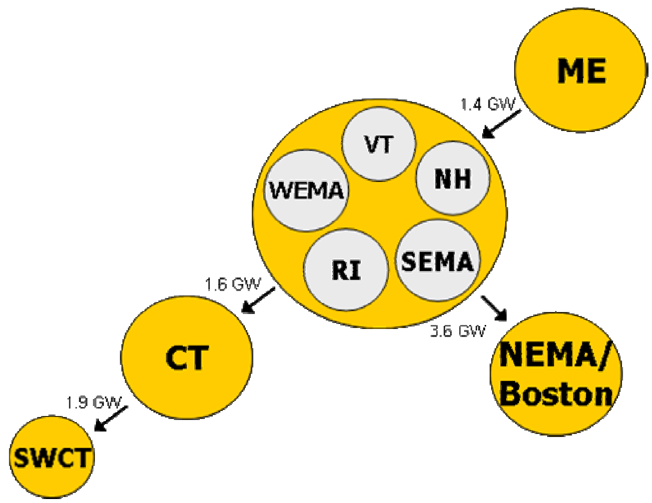
2) Timing estimated in CT Siting Council testimony.

Source: 2005 Regional Resource Plan – Incremental LOLE Analysis dated May 4th 2005, except as otherwise noted.

Capacity transfers are limited across LICAP zones. In general, the LICAP zones overlap with RTEP zones and utilize the most significantly binding constraints as the capacity transfer limit. However, with the design of the LICAP zones, there is potential that within Maine, Rest of Pool, and Southwest Connecticut, there may be binding internal capacity transfer limits (consistent with the RTEP limits above) that limit the ability of committed capacity to meet its obligations to supply under the LICAP structure. For example, units located around the New Haven area may be unable to supply MW to satisfy load obligations in the Norwalk area due to a binding transfer limit at peak. In these extreme conditions, market failure, in the form of loss of load service, or extremely high capacity prices (triggered by lack of transmission rather than generation), could result. Exhibit 2-36 presents the capacity transfer limits assumed in the analysis for 2006.

The upgrades shown in Exhibit 2-35 will affect the capacity limits as well as the energy limits.

Exhibit 2-36: LICAP Zone Intra-Regional Capacity Transfer Constraints Modeled, 2006



Source: Capability assumed consistent with ISO-NE RTEP 2004 report.

Discount Rate Calculation for Avoided Costs

For purposes of evaluating C&LM programs on a levelized basis, a discount rate has been utilized. The discount rate relies on the MA DTE 98-100 Guidelines which indicate that the yield on 30-year Treasury bonds should be utilized. Since 30-year Treasury bonds have not been issued for more than a year, current yields (June 2005) from the final six maturing Treasury bonds that were not inflation indexed were average and used as the discount rate. The nominal yield rate was adjusted to a real rate based on the assumed 2.25 percent inflation rate.[9] Exhibit 2-37 highlights the determination of the discount rate used on the avoided cost comparisons.

[9] ICF Resources standard inflation assumption is 2.25 percent annually. This is approximately equal to the long-term (15 to 20 year) historical general economy wide inflation rate.

Exhibit 2-37: Discount Rate Determination

U.S. 30 Year Treasury Bonds

30 Year US Treasury Bond 5.375 Maturity Date 2/15/2031		
Transaction Date	Price	Yield
06/27/2005	118-15	4.192
06/24/2005	117-30+	4.222
06/23/2005	117-13	4.253
06/22/2005	117-18+	4.243
06/21/2005	116-05	4.326
06/20/2005	115-03	4.388
AVERAGE		4.271

30 Year US Treasury Bond 5.50 Maturity Date 8/15/2028		
Transaction Date	Price	Yield
06/27/2005	118-07	4.254
06/24/2005	117-23	4.285
06/23/2005	117-06+	4.317
06/22/2005	117-12+	4.305
06/21/2005	115-31+	4.393
06/20/2005	114-31+	4.456
AVERAGE		4.335

30 Year US Treasury Bond 5.25 Maturity Date 11/15/2028		
Transaction Date	Price	Yield
06/27/2005	114-21	4.254
06/24/2005	114-06+	4.282
06/23/2005	113-21+	4.316
06/22/2005	113-28	4.303
06/21/2005	112-14+	4.393
06/20/2005	111-16	4.453
AVERAGE		4.334

30 Year US Treasury Bond 6.00 Maturity Date 2/15/2026		
Transaction Date	Price	Yield
06/27/2005	123-22+	4.261
06/24/2005	123-08+	4.289
06/23/2005	122-24	4.323
06/22/2005	122-29	4.313
06/21/2005	121-16+	4.402
06/20/2005	120-17+	4.466
AVERAGE		4.342

30 Year US Treasury Bond 5.25 Maturity Date 2/15/2029		
Transaction Date	Price	Yield
06/27/2005	114-26+	4.249
06/24/2005	114-11	4.279
06/23/2005	113-26	4.312
06/22/2005	114-00+	4.3
06/21/2005	112-19+	4.387
06/20/2005	111-20+	4.449
AVERAGE		4.329

30 Year US Treasury Bond 6.25 Maturity Date 5/15/2030		
Transaction Date	Price	Yield
06/27/2005	130-24+	4.237
06/24/2005	130-07	4.267
06/23/2005	129-20	4.299
06/22/2005	129-27+	4.287
06/21/2005	128-08+	4.375
06/20/2005	127-05+	4.436
AVERAGE		4.317

Nominal Interest Rate	**4.32%**
Real Interest Rate	**2.03%**

Notes:
1) Nominal rate is the average yield for six 30-year US Treasury Bills
2) Assumes a 2.25% inflation rate
3) Source: Bloomberg

Chapter Three: Avoided Electric Supply Component Cost Forecast Results

The avoided electric supply costs to be used in conservation and load management (C&LM) cost-effectiveness analyses are comprised of three main components: (1) wholesale energy supply costs, (2) wholesale capacity supply costs (both of which are tied to the costs of operating and maintaining power generators), and (3) out-of-market supply costs associated with system reliability or congestion.10 In addition to these components, certain transmission and distribution investments may be avoidable and additional benefits may be derived from price responsiveness to demand reduction. These additional elements are presented in Chapters 5 and 6.

Using the assumptions discussed in Chapter Two of this report, ICF developed a forecast for each of the three main components for each of the AESC screening zones identified in Exhibit 3-1. The AESC screening zones were identified by the sponsors and vary from the ISO-NE Pricing, RTEP, and LICAP zonal definitions also shown in Exhibit 3-1. This chapter provides summary results for the three component costs at the AESC screening zone level for reference purposes only. Full results for use in the AESC screening tools including a breakout by alternate zones and supplemental information on the component costs are provided in Appendix 2 and have also been provided to the Study Group in spreadsheet format.

Appendix 2 also provides definitional information for the parameters presented in the spreadsheet results and should be referred to as a guide to help interpret and use the results. All values are presented in real 2005$ unless otherwise noted.

[10] Out-of-market costs reflect RMR payments as discussed in Chapter Two. To qualify for these payments, a generator must be shown to be required to be on-line for an adequate reliability level to be maintained on the electric grid; hence the generator is valued for its capacity. These payments typically reflect a traditional cost-of-service recovery based on a regulated rate of return. A generator receiving these payments will recover full costs (variable and fixed) plus some allowed rate of return.

Exhibit 3-1. AESC Screening Zonal Breakout with Reference to Location of Results

<table>
<tr><th>Transmission Congested Zones (RTEP)
See Text Exh A2-5
Spreadsheet Exh 4</th><th>AESC Screening Zone
See Text Exh A2-2
Spreadsheet Exh 1</th><th>ISO-NE Pricing Zone
See Text Exh A2-4
Spreadsheet Exh 3</th><th>State
See Text Exh A2-3
Spreadsheet Exh 2</th><th>LICAP Zone</th></tr>
<tr><td>Bangor Hydro</td><td rowspan="3">Maine</td><td rowspan="3">Maine</td><td rowspan="3">Maine</td><td rowspan="3">Maine</td></tr>
<tr><td>Maine (Central)</td></tr>
<tr><td>Southeast Maine</td></tr>
<tr><td>Boston (Boston/ NEMA)</td><td>Boston / NEMA</td><td>Boston / NEMA</td><td rowspan="4">Massachusetts</td><td>Boston / NEMA</td></tr>
<tr><td>Southeast Massachusetts (SEMA)</td><td rowspan="3">Rest of Massachusetts</td><td>SEMA</td><td rowspan="6">Rest of Pool (ROP)</td></tr>
<tr><td>Central Massachusetts (CMA)</td><td rowspan="2">CNA/WMA</td></tr>
<tr><td>Western Massachusetts (WMA)</td></tr>
<tr><td>New Hampshire</td><td>New Hampshire</td><td>New Hampshire</td><td>New Hampshire</td></tr>
<tr><td>Rhode Island</td><td>Rhode Island</td><td>Rhode Island</td><td>Rhode Island</td></tr>
<tr><td>Vermont</td><td>Vermont</td><td>Vermont</td><td>Vermont</td></tr>
<tr><td>Norwalk (NOR)[1]</td><td>NOR[1]</td><td rowspan="2">Southwest Connecticut[2, 3]</td><td rowspan="3">Connecticut</td><td rowspan="2">SWCT (LICAP)[3]</td></tr>
<tr><td>Southwest Connecticut (SWCT)[1]</td><td>SWCT[1]</td></tr>
<tr><td>Rest of Connecticut (ROC)</td><td>ROC</td><td>ROC[2]</td><td>ROC</td></tr>
</table>

1. The Southwest Connecticut and Norwalk areas under the AESC screening zone definition represent distinct transmission constrained energy zones consistent with the zones defined for regional transmission system expansion planning.
2. Beginning in January 2006, ISO-NE is expected to expand from 8 to 9 pricing zones by splitting the Connecticut pricing zone into 2 areas, Southwest Connecticut and Rest of Connecticut.
3. Southwest Connecticut as defined for the ISO-NE pricing and LICAP zones will be comprised of the Southwest Connecticut and Norwalk RTEP zones.

This chapter also discusses distribution losses and retail costs. Distribution losses may be avoidable as a result of C&LM programs. Although the scope of this study did not include the calculation of avoidable distribution losses, a methodology for determining distribution losses is presented. Retail service costs (such as customer support) are not considered to be directly avoidable in this analysis. A comparison of results to the 2003 AESC analysis is provided in this chapter as well.

Wholesale Power Prices

Wholesale power prices in New England are unbundled into separate products for energy and capacity. Therefore, the avoided electric energy supply costs are presented for energy and capacity. The costing periods utilized are discussed in Appendix 1 of this report. For more detail regarding the avoided cost forecasts and the interpretation of specific parameters, refer to Appendix 2.

Avoided Energy Supply Costs

Marginal energy prices in New England are largely driven by gas-fired generating resources, particularly in the near-term. A large amount of combined cycle generation is available in the market and these resources tend to set prices in most hours. Higher cost oil and gas steam generation units will often be the marginal resource in higher priced peak-hours. This analysis reflects the post-Katrina natural gas price forecast presented in Chapter One of this report. All modeling analysis was completed in July prior to the impact of Katrina on fuel prices. In order to capture the impact of Katrina, an offline adjustment was made to the energy price forecasts for the near-term (the adjusted forecast period). To make this adjustment, the initial implied heat rate for peak and off-peak periods (which reflected use of gas resources on the margin) resulting from the model were kept constant and the energy price was recalculated using the revised gas delivered gas price forecast. Exhibit 3-2 reflects the post-Katrina[11] electric energy forecasts. This exhibit is a summary of the energy component price forecast for illustration and comparison purposes, and is not intended for use in cost-effectiveness analysis screening.

Beginning in the mid-term, new unit efficiency and environmental policies begin to affect marginal prices. The average efficiency of gas-fired capacity improves as new gas-fired units come online to meet growing demand, resulting in downward pressure on the implied heat rate and energy prices. Simultaneously, environmental polices become more stringent and have higher compliance costs. The higher environmental costs push energy prices upwards.

[11] The impact of Katrina on fuel prices was assumed to affect only the electric energy values. The electric capacity values were assumed to be unaffected given that fuel price impact did not affect the long-term and would be unlikely to affect capacity entry and exit decisions.

Exhibit 3-2: Avoided Annual Wholesale Energy Supply Costs by AESC Screening Zone ($/kWh)

	Maine (State)	Boston	Rest of Massachusetts - Southeast, Central and Western Massachusetts	Boston & Southeast Massachusetts	New Hampshire	Rhode Island	Vermont	Norwalk (RTEP)	Southwest Connecticut (RTEP)	Rest of Connecticut
2005	0.063	0.065	0.066	0.065	0.064	0.065	0.068	0.073	0.072	0.070
2006	0.071	0.074	0.075	0.074	0.072	0.075	0.077	0.084	0.083	0.081
2007	0.073	0.077	0.077	0.076	0.075	0.077	0.079	0.087	0.085	0.084
2008	0.061	0.065	0.065	0.064	0.063	0.065	0.065	0.070	0.069	0.067
2009	0.049	0.052	0.052	0.052	0.051	0.052	0.053	0.057	0.055	0.054
2010	0.043	0.045	0.045	0.045	0.044	0.045	0.046	0.048	0.048	0.047
2011	0.045	0.047	0.047	0.047	0.046	0.047	0.047	0.050	0.049	0.048
2012	0.047	0.049	0.049	0.049	0.048	0.049	0.049	0.051	0.050	0.050
2013	0.047	0.050	0.049	0.049	0.049	0.049	0.049	0.051	0.051	0.050
2014	0.048	0.050	0.050	0.050	0.049	0.050	0.050	0.051	0.051	0.050
2015	0.048	0.050	0.050	0.050	0.050	0.050	0.050	0.051	0.051	0.051
2016	0.048	0.051	0.051	0.051	0.050	0.050	0.051	0.051	0.051	0.051
2017	0.050	0.053	0.052	0.053	0.052	0.052	0.053	0.053	0.053	0.053
2018	0.052	0.055	0.054	0.055	0.054	0.054	0.055	0.055	0.055	0.055
2019	0.054	0.057	0.056	0.056	0.056	0.056	0.056	0.057	0.057	0.056
2020	0.056	0.059	0.058	0.058	0.058	0.058	0.058	0.059	0.059	0.058
2021	0.057	0.059	0.059	0.059	0.058	0.059	0.059	0.059	0.059	0.059
2022	0.057	0.060	0.059	0.060	0.059	0.059	0.060	0.060	0.060	0.060
2023	0.058	0.061	0.060	0.060	0.060	0.060	0.060	0.061	0.061	0.060
2024	0.059	0.061	0.061	0.061	0.060	0.061	0.061	0.061	0.061	0.061
2025	0.059	0.062	0.061	0.062	0.061	0.061	0.062	0.062	0.062	0.062
2026	0.060	0.063	0.062	0.062	0.062	0.062	0.063	0.063	0.063	0.062
2027	0.061	0.063	0.062	0.063	0.062	0.063	0.063	0.063	0.063	0.063
2028	0.061	0.064	0.063	0.064	0.063	0.064	0.064	0.064	0.064	0.063
2029	0.062	0.065	0.064	0.064	0.064	0.064	0.065	0.064	0.065	0.064
2030	0.063	0.066	0.064	0.065	0.064	0.065	0.065	0.065	0.065	0.065
2031	0.063	0.065	0.064	0.065	0.064	0.065	0.065	0.065	0.065	0.065
2032	0.063	0.065	0.064	0.065	0.064	0.065	0.065	0.065	0.065	0.065
2033	0.063	0.065	0.064	0.065	0.064	0.065	0.065	0.065	0.065	0.065
2034	0.063	0.065	0.064	0.065	0.064	0.065	0.065	0.065	0.065	0.065
2035	0.063	0.065	0.064	0.065	0.064	0.065	0.065	0.066	0.065	0.065
2036	0.063	0.065	0.064	0.065	0.064	0.065	0.065	0.066	0.065	0.065
2037	0.063	0.065	0.064	0.065	0.064	0.065	0.065	0.066	0.066	0.065
2038	0.063	0.065	0.064	0.065	0.064	0.065	0.065	0.066	0.066	0.064
2039	0.063	0.065	0.064	0.065	0.064	0.065	0.065	0.066	0.066	0.064
2040	0.063	0.065	0.064	0.065	0.064	0.064	0.065	0.066	0.066	0.064
Levelized Values[1]	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2005-2040	0.057	0.060	0.059	0.060	0.059	0.059	0.060	0.062	0.061	0.061
2006-2040	0.057	0.060	0.059	0.059	0.059	0.059	0.060	0.061	0.061	0.060
2006-2010	0.060	0.063	0.063	0.063	0.062	0.063	0.064	0.070	0.068	0.067
2006-2015	0.054	0.056	0.057	0.056	0.055	0.056	0.057	0.061	0.060	0.059
2006-2020	0.053	0.056	0.056	0.056	0.055	0.056	0.056	0.059	0.058	0.057

Note: Southwest Connecticut (RTEP) does not include the Norwalk area.
1) Levelized using a 2.03 percent real discount rate

On a zonal level, in the near-term, energy prices are higher in the import constrained regions of Norwalk, Southwest Connecticut and Norwalk. Overall, prices also tend to be higher in zones west of the East/West constraint[12].

Avoided Capacity Supply Costs

Capacity prices in the forecast reflect the assumption that a LICAP market structure will exist going forward[13]. Transmission constraints contribute to capacity value under LICAP. Locational value is created due to transmission constraints. In the most extreme cases, constraints will strand megawatts or will isolate load resulting in very low capacity value if the megawatts are stranded or very high capacity value if the load is isolated.

In the near term, much of New England has excess capacity and the locational capacity prices are depressed. Growth in peak demand and new unit costs drive the long-term capacity prices. Over time, as new units are required to serve growing demand, the equilibrium market capacity price will reflect the revenue required by developers to bring new capacity on-line. This revenue requirement reflects the return on and of investment for the developer less any revenues generated in the energy market. As technological improvements occur and the costs of building new units declines in real-terms, the real equilibrium capacity price will decline.

Exhibit 3-3 shows the avoided capacity value by zone—without energy or out-of-market costs. Because of the nature of the capacity market, there is no effect from Hurricane Katrina on the capacity market. Similar to Exhibit 3-2, this exhibit is a summary the capacity component of the price forecast for illustration and comparison purposes, and is not intended for use in cost-effectiveness analysis screening.

[12] Refer to Chapter Two Exhibit 2-5.

[13] The analysis reflects the assumption that LICAP would begin in January 2006, the proposed start date at the time this study was undertaken. Over the course of the study, delays have resulted in the earliest start date being moved to October 1, 2006. Out-of-market costs were also assumed to be unaffected, as fuel costs would be considered to be recoverable in the energy dispatch of the units driving out-of-market costs.

Exhibit 3-3: Avoided Wholesale Capacity Supply Costs by AESC Screening Zone ($/kW-yr)

	Maine (State)	Boston	Rest of Massachusetts - Southeast, Central and Western Massachusetts	Boston & Southeast Massachusetts	New Hampshire	Rhode Island	Vermont	Norwalk (RTEP)	Southwest Connecticut (RTEP)	Rest of Connecticut
2005 [2]	0.000	5.387	2.662	4.489	2.662	2.662	2.662	16.785	3.351	5.377
2006	23.304	35.258	34.548	35.024	34.548	34.548	34.548	57.244	44.207	47.881
2007	20.172	39.936	39.132	39.670	39.132	39.132	39.132	55.163	50.237	50.951
2008	19.462	63.709	62.436	63.287	62.436	62.436	62.436	66.341	66.341	63.709
2009	17.895	68.126	66.758	67.672	66.758	66.758	66.758	70.934	70.934	68.126
2010	27.761	71.124	69.696	70.649	69.696	69.696	69.696	73.561	73.561	71.124
2011	43.067	74.254	72.764	73.758	72.764	72.764	72.764	76.285	76.285	74.254
2012	66.810	77.523	75.967	77.004	75.967	75.967	75.967	79.110	79.110	77.523
2013	67.163	79.296	76.270	78.292	76.270	76.270	76.270	79.424	79.424	77.831
2014	67.517	81.109	76.575	79.603	76.575	76.575	76.575	79.739	79.739	78.141
2015	67.872	82.965	76.881	80.935	76.881	76.881	76.881	80.055	80.055	78.453
2016	68.230	84.862	77.188	82.289	77.188	77.188	77.188	80.373	80.373	78.765
2017	65.767	84.012	76.704	81.558	76.704	76.704	76.704	79.557	79.557	77.965
2018	63.392	83.170	76.222	80.834	76.222	76.222	76.222	78.749	78.749	77.172
2019	61.103	82.336	75.743	80.116	75.743	75.743	75.743	77.949	77.949	76.388
2020	58.896	81.511	75.267	79.404	75.267	75.267	75.267	77.157	77.157	75.612
2021	60.454	81.400	75.613	79.449	75.613	75.613	75.613	77.319	77.319	75.771
2022	62.053	81.288	75.960	79.493	75.960	75.960	75.960	77.482	77.482	75.931
2023	63.695	81.177	76.309	79.538	76.309	76.309	76.309	77.645	77.645	76.091
2024	65.380	81.066	76.660	79.583	76.660	76.660	76.660	77.809	77.809	76.251
2025	67.109	80.956	77.012	79.628	77.012	77.012	77.012	77.972	77.972	76.412
2026	68.885	80.845	77.365	79.673	77.365	77.365	77.365	78.137	78.137	76.573
2027	70.707	80.735	77.721	79.718	77.721	77.721	77.721	78.301	78.301	76.734
2028	72.577	80.624	78.078	79.763	78.078	78.078	78.078	78.466	78.466	76.895
2029	74.497	80.514	78.436	79.808	78.436	78.436	78.436	78.631	78.631	77.057
2030	76.468	80.404	78.796	79.853	78.796	78.796	78.796	78.796	78.796	77.220
2031	70.863	74.442	72.952	73.930	72.952	72.952	72.952	72.952	72.952	71.490
2032	65.669	68.922	67.541	68.447	67.541	67.541	67.541	67.541	67.541	66.185
2033	60.856	63.811	62.531	63.370	62.531	62.531	62.531	62.531	62.531	61.274
2034	56.395	59.079	57.893	58.670	57.893	57.893	57.893	57.893	57.893	56.727
2035	52.262	54.698	53.599	54.318	53.599	53.599	53.599	53.599	53.599	52.518
2036	48.431	50.642	49.623	50.290	49.623	49.623	49.623	49.623	49.623	48.621
2037	44.881	46.887	45.943	46.560	45.943	45.943	45.943	45.943	45.943	45.013
2038	41.591	43.410	42.535	43.106	42.535	42.535	42.535	42.535	42.535	41.673
2039	38.543	40.191	39.380	39.909	39.380	39.380	39.380	39.380	39.380	38.581
2040	35.718	37.211	36.459	36.949	36.459	36.459	36.459	36.459	36.459	35.718
Levelized Values [3]										
2005-2040	51.998	67.827	64.742	66.790	64.742	64.742	64.742	68.307	67.112	65.936
2006-2040	54.088	70.336	67.237	69.294	67.237	67.237	67.237	70.378	69.674	68.370
2006-2010	21.693	55.228	54.120	54.861	54.120	54.120	54.120	64.454	60.736	60.102
2006-2015	40.969	66.491	64.347	65.778	64.347	64.347	64.347	71.309	69.357	68.224
2006-2020	47.760	71.515	67.922	70.312	67.922	67.922	67.922	73.557	72.191	70.924

Note: Southwest Connecticut (RTEP) does not include the Norwalk area.
1) Levelized using a 2.03 percent real discount rate

Avoided Out-of-Market Capacity Supply Costs

Out-of-Market avoided capacity supply costs reflect the costs for maintaining generating units that are not profitable on the electric grid for purposes of reliability. These units are typically identified as Reliability Must Run (RMR) units. The cost recovery requirements were determined in a several step process. First, ICF identified units which under the Reference Case restrictions on retirement and mothballing, were losing money. The additional revenue requirements which would allow these units to break-even were then identified. Finally, the specific situation of the individual units was examined to determine whether those units would qualify for RMR payments. The scope of this analysis did not included detailed voltage or needs assessments that would typically be performed to determine whether a unit qualifies for RMR. Since such detailed modeling was not performed, ICF relied on publicly available information and proprietary power-flow modeling to assess whether units would qualify for RMR. In general, all currently operational generating units in the Norwalk and Southwest Connecticut zones were considered to be required for reliability based on voltage requirements in the Norwalk area. Select areas outside of Norwalk and Southwest Connecticut with known voltage issues also may have RMR units. The New England generating stations which were assigned RMR costs include Bridgeport Energy, Milford, Devon, Kendall Square, Cos Cob, Torrington, Norwalk Harbor, Montville, Mystic, New Boston, Canal, L Street, and Stony Brook. Several units were found to have losses (in some years) but were not considered to qualify for RMR. These include Wyman (which was earlier this year denied a basis for need), Lost Nation, Merrimack, and Flos Inn. Going forward, RMR unit revenue requirements were reduced as the market capacity price increased.

Exhibit 3-4 shows the avoided out-of-market costs by zone—without energy or capacity costs. As with the capacity market, there is no effect from Hurricane Katrina on the out-of-market component of the forecast. Similar to Exhibits 3-2 and 3-3, this exhibit is a summary the out-of-market component of the price forecast for illustration and comparison purposes, and is not intended for use in cost-effectiveness analysis screening.

Exhibit 3-4: Avoided Out-of-Market Capacity Supply Costs by AESC Screening Zone ($/kW-yr)

	Maine (State)	Boston	Rest of Massachusetts - Southeast, Central and Western Massachusetts	Boston & Southeast Massachusetts	New Hampshire	Rhode Island	Vermont	Norwalk (RTEP)	Southwest Connecticut (RTEP)	Rest of Connecticut
2005 [2]	0.000	4.835	0.954	3.555	0.954	0.954	0.954	10.071	23.505	8.265
2006	0.000	11.077	1.801	8.011	1.801	1.801	1.801	14.667	3.733	0.000
2007	0.000	9.630	2.151	7.154	2.151	2.151	2.151	14.312	1.226	0.000
2008	0.000	0.000	0.199	0.066	0.199	0.199	0.199	5.035	0.000	0.000
2009	0.000	0.000	0.204	0.068	0.204	0.204	0.204	4.889	0.000	0.000
2010	0.000	0.000	0.177	0.059	0.177	0.177	0.177	4.645	0.000	0.000
2011	0.000	0.000	0.154	0.051	0.154	0.154	0.154	4.412	0.000	0.000
2012	0.000	0.000	0.133	0.044	0.133	0.133	0.133	4.192	0.000	0.000
2013	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2014	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2015	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2016	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2017	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2018	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2019	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2020	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2021	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2022	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2023	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2024	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2025	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2026	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2027	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2028	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2029	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2030	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2031	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2032	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2033	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2034	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2035	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2036	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2037	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2038	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2039	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2040	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Levelized Values [3]										
2005-2040	0.000	0.964	0.215	0.716	0.215	0.215	0.215	2.287	1.095	0.319
2006-2040	0.000	0.808	0.186	0.602	0.186	0.186	0.186	1.975	0.194	0.000
2006-2010	0.000	4.270	0.927	3.164	0.927	0.927	0.927	8.828	1.027	0.000
2006-2015	0.000	2.242	0.515	1.671	0.515	0.515	0.515	5.478	0.539	0.000
2006-2020	0.000	1.568	0.360	1.169	0.360	0.360	0.360	3.832	0.377	0.000

Note: Southwest Connecticut (RTEP) does not include the Norwalk area.
1) Levelized using a 2.03 percent real discount rate

Wholesale Price Uncertainties

Uncertainties can and do exist in any forecasting exercise. Given the far reaching assumptions driving the forecast for wholesale power prices, various uncertainties can exist. To minimize the potential for bias towards the assumptions or beliefs of any individual participant in this study, ICF has relied on public sources of information where available. In cases where agreed upon public information was either not available or not reliable; ICF has relied on our own expert judgment. In general, the assumptions rely on a conservative approach to forecasting. Conservative elements of this forecast include:

- Transmission firmly planned upgrades – Rather than relying on a strict rule that transmission upgrades occur only based on those projects already started (ground broken), this forecast includes several announced projects that have a fair likelihood of going forward. These projects include SWCT Phase II; Southern New England Reliability Project (RI-CT); and the Boston/NEMA upgrade. This assumption results in lower wholesale energy and capacity prices than had the strict rule been applied.

- Peak Hour Volatility – All forecast years assume a weather normal pattern and that fuel is readily available. This assumption tends to reduce peak hour volatility which is largely due to weather conditions that vary from normal, fuel shortages or fuel price spikes (also often due to weather). Although average prices may not be affected, this tends to result in a muting of the super-peak period.

- Market Structure – As mentioned earlier, this analysis assumes that for the purposes of setting market clearing prices the market for generation is perfectly competitive and perfectly efficient. Since no market is truly perfectly competitive and efficient, this may either understate or overstate prices, value, and price volatility, all else equal. If sellers have market power, prices may be higher than shown here. This is true of the energy prices which assume bidding at variable cost levels. Likewise capacity markets assume all available capacity in the market contributes to full capability levels with no withholding. Capacity clearing prices may be depressed through the assumption that units may be required to stay on-line for Reliability Must-Run (RMR) reasons. Should these units (which are required to be on-line) be allowed to exit the market, the clearing price of capacity would be above the clearing price determined when these units contribute to the resource mix. That is, should these RMR units exit the market, the market capacity price would be higher since fewer resources would be available. To some extent this effect is corrected for through also capturing the compensation the RMR units receive (above the capacity price) as out-of-market costs.

- Excess Capacity versus Shortages – This analysis assumes any future above-equilibrium prices due to shortages of generation capacity will be exactly offset by periods of excess capacity once the current period of excess capacity ends (i.e. long-term average equilibrium conditions will exist going forward once reached). This is conservative in that one might expect the next phase of the industry cycle to involve shortages and very high prices above equilibrium levels. This would raise value on a present value basis even if it were followed by equal duration and amplitude cycles compared to the current analysis. An even more conservative approach would bias the cycle to even more excess, requiring developers and financiers to be constantly losing money and thus raises issues about the credibility of such a case.

- New Plant Costs and Performance – ICF assumes new plant costs decrease in real terms in later years while their thermal efficiencies improve. This is in spite of the technological challenges to significant future improvements in thermal efficiencies including the effects of extremely high turbine inlet temperature on power plant materials. Thus, future competitors have better performance characteristics. This assumption reduces longer term capacity and energy prices than had technology characteristics been held flat.

- Natural Gas Prices – The analysis herein assumes long-term natural gas prices will return to lower real equilibrium levels well below the currently traded price levels. These forward levels reflect optimistic supply side costs and fully functional economic markets for gas. Recent gas prices have been above the forecast levels. Note this is true of ICF's post Katrina forecast. Should the recent prices continue forward it would result in higher wholesale energy and capacity prices than the forecast projects.

Areas in which this forecast is not conservative include the environmental control assumptions facing the power industry. Rather than rely on programs already in place and promulgated, this analysis considers regional environmental control programs under consideration by the Northeast Regional Greenhouse Gas Initiative (RGGI). The RGGI process involves several Northeast states as direct participants. The control programs under consideration by RGGI would take a leading role in front of the federally implemented programs. For example, the RGGI program assumes a carbon emissions control program for the northeast would be in place in 2006 at relatively strong price levels. The RGGI program also assumes regional standard for renewable generation at levels above those currently targeted statewide.

Transmission and Distribution Adders

In addition to wholesale prices, transmission and distribution losses and investments in transmission and distribution may be avoidable. ICF's treatment of these items is discussed below.

Transmission Energy Losses

Consistent with the current New England locational marginal energy clearing prices, ICF's forecast for energy prices already includes three components, generation costs (including generator losses), congestion costs, and marginal transmission energy losses. A separate accounting for transmission energy losses should not be included in the program screening models.

Transmission energy losses in this forecast are determined relying on marginal transmission energy losses. Marginal losses rely on price signals to the market participants to encourage the optimal transmission flows and generation from individual sources in order to serve load.

Although transmission energy losses are directly accounted for in the wholesale price projections, an estimate of transmission energy losses was also provided for use by program administrators to estimate the approximate kilowatthours associated with those transmission energy losses and to compare with their own Company estimates of losses. We use a method consistent with loss computation in power markets.

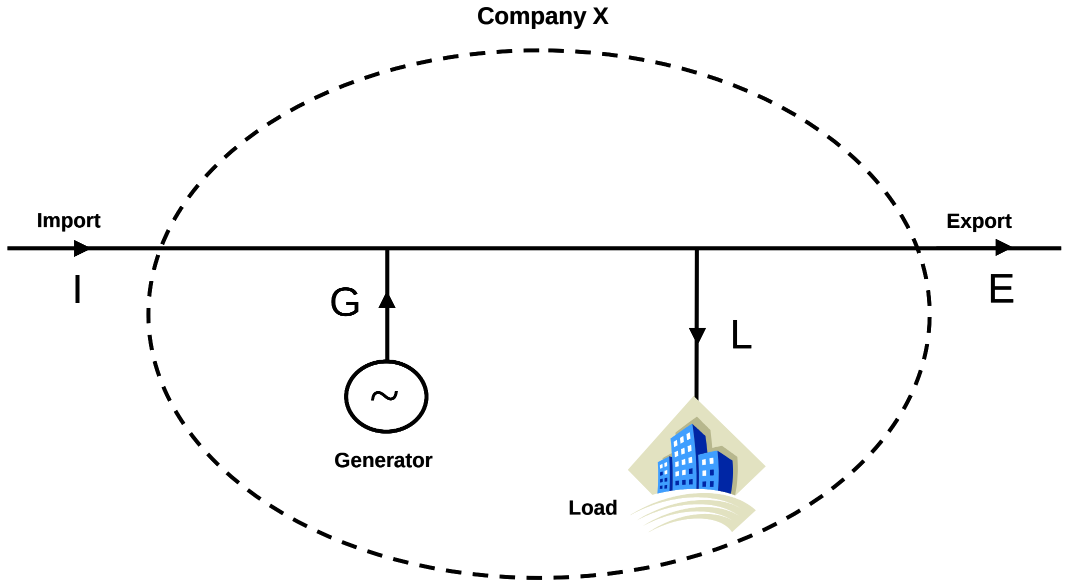
Our approach is to determine the net losses due to power transactions within a company or state footprint. This is illustrated in Exhibit 3-5 for a company; the same principle applies to a state or other clearly defined entity. For Company X, we determine the total power (G) produced by generation resources within Company X, and the total demand for power (D). The net interchange (NI) of power between Company X and neighboring regions is the difference between its net power exports (E) and net imports (I). The net loss (L) within Company X is determined as follows:

$$L = G - D + NI$$

Where $NI = I - E$

Losses for Company X are determined for each hour in the year, and the annual average loss multiplier is calculated as the ratio of total losses to total demand (D). To calculate a similar multiplier for the peak and off-peak periods, the hours in the year are separated into peak and off-peak hours. The peak (off-peak) loss multiplier is calculated as the ratio of total peak (off-peak) hour losses to total peak (off-peak) hour demand.

Exhibit 3-5: Determination of Company Losses



The loss factors presented in Exhibit 3-6 are representative of the losses in the individual states under a marginal transmission energy loss regime. Note the losses presented are the total losses that result from flows determined using marginal losses.

Exhibit 3-6: Estimated Transmission Losses by State

	Peak Hour[1]		Average Off-Peak[2]		Average Peak[3]		Average All-Hours[4]	
State	Loss as % of Load[5, 6]	Loss as % of Generation	Loss as % of Load[5, 6]	Loss as % of Generation	Loss as % of Load[5, 6]	Loss as % of Generation	Loss as % of Load[5, 6]	Loss as % of Generation
CT	2.64	2.57	1.85	1.82	2.22	2.17	2.02	1.98
MA	2.27	2.22	1.91	1.87	2.15	2.10	2.01	1.97
ME	2.77	2.70	2.12	2.08	2.54	2.48	2.30	2.25
NH	2.92	2.84	2.06	2.02	2.45	2.39	2.23	2.19
RI	2.08	2.03	1.51	1.49	1.76	1.73	1.63	1.60
VT	4.05	3.90	2.89	2.81	3.55	3.43	3.18	3.08

1. Peak Hour transmission loss represents the coincident peak period and applicable to summer period capacity prices.
2. Off-Peak Hours transmission losses span the period including weekday hours from 10pm - 6am and weekends and are applicable to energy prices.
3. Peak Hours transmission losses represent the period including weekday hours from 6am - 10pm and applicable to energy prices.
4. All Hours transmission losses are applicable to annual energy prices.
5. For use in screening models.
6. Load here includes distribution losses but not transmission losses.

Transmission energy loss estimates were compared to company specific data where available and found to be reasonable. Direct comparisons were not generally available as company modeling was generally either done using a power flow model which did not account for marginal losses and/or considered a snapshot hour representation only.

Distribution Energy Losses

The Study Group requested that ICF provide recommendations for the study group to determine the appropriate distribution energy losses to include in the AESC screening models. ICF's recommends that AESC participants rely on a power flow model of their distribution systems to determine approximate distribution energy losses.

Unlike transmission energy losses, distribution energy losses are not subject to marginal loss determination. As such, the distribution energy losses may be determined directly from a standard power flow model which does not consider the marginal costs of losses.

Transmission and Distribution Capacity Losses

Unlike transmission energy losses, transmission capacity losses are not included in the market capacity price. Rather, capacity prices are set at the generator capacity level. Distribution capacity losses are not included either. From the load meter, one would need to include transmission and distribution capacity losses to when determining the amount of capacity required to be purchased at the generator level. ICF has provided estimates of the transmission losses at the peak condition in Exhibit 3-6 above ("Peak Hour Loss as % of Load" and "Peak Hour Loss as % of Generation"). These values are based on power load flow modeling of the transmission grid. The peak hour condition is representative of the transmission capacity losses. ICF recommends using a peak condition load flow model of the distribution system (or actual distribution loss measurements at peak) to estimate the appropriate capacity losses at the distribution level.

Avoided Transmission and Distribution Capacity Costs

The Study Group requested that ICF provide recommendations for the study group on how to determine the appropriate avoidable transmission and distribution capacity costs to include in the screening models. A spreadsheet tool was developed and provided to the study group members for their own use. The tool is described in Chapter 5 in more detail.

Retail Price Adders

Retail prices charged to customers are designed to recover the full costs of the load serving entities including but not limited to the market costs discussed above (energy, capacity, transmission, distribution, and investment costs). In addition to wholesale prices, transmission and distribution energy losses and investments in transmission and distribution, certain additional costs at the retail level may be avoidable through C&LM measures. The Study Group requested an analysis of these additional costs in the interest of determining whether a retail adder should be applied to the avoided energy costs.

The sources for retail adder information analyzed here include the EIA 2005 Annual Energy Outlook for the New England region as well as FERC Form 1 data for individual utilities in Massachusetts and Rhode Island. These data exclude T&D investments that are already included in the avoided cost forecast. The data revealed that retail adders in

New England have been approximately 68 percent over the wholesale power price (including transmission) from 2002 through 2004. In addition, this adder is forecasted to rise in the near term to 99 percent by 2010. Exhibit 3-7 shows the historical as well as the forecasted retail adders from the 2005 Annual Energy Outlook.

Exhibit 3-7: 2005 AEO Retail Adder Forecast

Year	Retail Adder ()
2002	70.0
2003	67.3
2004	65.8
2005	68.8
2006	78.9
2007	89.0
2008	95.9
2009	97.8
2010	99.0

The retail adder from the FERC Form 1 data included categories such as Customer Accounts, Customer Service & Informational Expenses, Sales Expenses, Administrative & Total Expenses and Other Expenses. For the period 2002 through 2004 the retail adder for Massachusetts and Rhode Island utilities averaged 38 percent. As the AEO forecast does not provide any detailed account breakdown on how the retail component are estimated, a direct comparison of the EIA and FERC data is not possible.

ICF does not recommend the inclusion of a retail adder to the avoidable wholesale generation costs done in this analysis. Inspection of the expense types included in the EIA and FERC data show that the retail adder components are generally fixed costs which are typically associated with the number of customers or geographic expanse of the load provider, and thus fixed costs from an energy use perspective. The primary components of these costs do not necessarily vary based on the kW or kWh savings associated with C&LM programs as such programs would not (typically) lead to a reduction in the number of customers or geographic expanse. Therefore, retail adder components would not be avoidable. This recommendation is different than that in the 2003 study where reduction percentages were applied to some of the retail adder components.

Retail Price Adders for Massachusetts

The AESC Study Group had initially requested that information on the retail adder in Massachusetts be provided as part of this analysis. ICF utilized information reported on the EIA form 826 and the FERC Form 1 to estimate the retail adder for Massachusetts only. This resulted in an estimate of a retail price 1.7 times the wholesale power price as shown in Exhibit 3-8. ICF's recommendation, however, is that retail adders not be applied to the avoided costs presented here, for the reasons discussed above.

Exhibit 3-8: Massachusetts Retail Multiple

Source	Period	New England	Massachusetts
AEO 2005	2002-2003 (historical)	1.7	n/a
EIA 826	2003-2004	2.0	2.0
FERC FORM 1	2002-2004	n/a	1.4
AVERAGE		**1.9**	**1.7**

Source: Calculated as the price increment over the ISO reported energy and capacity price.

Comparison to 2003 Study

Due to differences in the reporting regions in the 2003 and 2005 study, results for all of New England are compared here. Comparisons are done for levelized values over like time periods and are levelized at a discount rate of 2.03 percent, the rate utilized in the current study[14].

Near-term energy market prices differ largely due to gas price assumptions. Capacity prices in the current analysis reflect the LICAP market design unlike the prior analysis and also result in differences. Retail cost items are not included as avoidable in the current analysis. The previous analysis considered some share of the costs as avoidable; however, use of these retail cost components was optional for the participants. The revised treatment in the 2005 analysis reflects a refinement in the analysis to more closely examine the contributing factors to the retail cost components. For example, in many cases, the retail costs were found to be tied to the number of customers, rather than the volume of load. Since C&LM programs would not impact the number of customers, these costs were considered to be fixed and therefore not avoidable. The cost components were discussed with the Study Group participants and a majority opinion

[14] See Chapter Two Exhibit 2-37.

was reached that the retail costs should not be treated as avoidable. The opinion was not unanimous among all participants. However, the impact on retail costs of C&LM programs was generally considered to me minimal. The comparison provided below show the 2005 results against the 2003 results presented with and without retail cost adders.

Exhibit 3-9 presents levelized annual price comparisons for all of New England including the retail adder in the 2003 results. The current analysis is provided for the period 2005 - 2040 while the 2003 study was for 2003 - 2037. The levelized values are presented for the forecast periods in common between the two studies, 2005 – 2037. The levelized results through 2012 are also compared as the 2003 analysis presented New England annual results through 2012 of the AESC Avoided Energy Supply Costs Appendix A spreadsheet Exhibit 5.1. Exhibit 3-10 provides a similar comparison, excluding the retail adder from the 2003 study.

Exhibit 3-9: Comparison of New England Avoided Electric Supply Levelized Cost Estimates Including Retail Adder for 2003 Study

	Current Analysis (2005$/MWh)	Previous Analysis (2005$/MWh)	Delta in $/MWh
Annual All-Hours Price Annuity (2005-2012)	$66.48	$61.24	+5.24 (+8.6%)
Annual All-Hours Price Annuity (2005-2037)	$66.93	$62.31	+$4.62 (+7.4%)
Seasonal On – Peak Annuity (2005-2037)			
Summer	$72.33	$75.51	-$3.18 (-4.2%)
Winter	$67.24	$51.68	+$15.56 (+30.1%)
Seasonal Off – Peak Annuity (2005-2037)			
Summer	$47.79	$40.52	+$7.27 (+17.9%)
Winter	$55.31	$40.43	+$14.88 (+36.8%)

Notes: Levelized (annuity) values were calculated using a 2.03 percent discount rate consistent with the 2005 analysis. Previous analysis results are inflated to 2005 dollars from 2004 dollars using a 2.25% annual inflation rate assumption. Comparisons do not include transmission and distribution capacity costs or DRIPE. The previous analysis included some retail costs in addition to wholesale market costs while the current analysis does not (the additional costs were the equivalent of a multiple of 1.23 above the wholesale costs for all of New England).

Exhibit 3-10: Comparison of New England Avoided Electric Supply Levelized Cost Estimates Excluding Retail Adder from 2003 Study

	Current Analysis (2005$/MWh)	Previous Analysis (2005$/MWh)	Delta in ($/MWh)
Annual All-Hours Price Annuity (2005-2012)	$66.48	$49.79	+$16.69 (+33.5%)
Annual All-Hours Price Annuity (2005-2037)	$66.93	$50.66	+$16.27 (+32.1%)
Seasonal On – Peak Annuity (2005-2037)			
Summer	$72.33	$61.39	+$10.94 (+17.8%)
Winter	$67.24	$42.02	+$25.22 (+60.0%)
Seasonal Off – Peak Annuity (2005-2037)			
Summer	$47.79	$32.94	+$14.85 (+45.1%)
Winter	$55.31	$32.87	+$22.44 (+68.3%)

Notes: Levelized (annuity) values were calculated using a 2.03 percent discount rate consistent with the 2005 analysis. Previous analysis results are inflated to 2005 dollars from 2004 dollars using a 2.25% annual inflation rate assumption. Comparisons do not include transmission and distribution capacity costs or DRIPE.

Exhibit 3-11 provides a comparison of the annual electric supply costs for each year through 2037.

Exhibit 3-11: Comparison of New England Avoided Electric Supply Cost Estimates 2005-2037 Annual and Levelized

Year	Current Analysis (2005$/MWh)	Previous Analysis including Retail Adder (2005$/MWh)	Previous Analysis excluding Retail Adder (2005$/MWh)
2005	$67.45	$63.07	$51.27
2006	$80.48	$60.61	$49.28
2007	$83.48	$60.81	$49.44
2008	$71.90	$61.01	$49.60
2009	$59.63	$61.03	$49.62
2010	$53.11	$61.05	$49.64
2011	$55.26	$61.08	$49.66
2012	$57.55	$61.10	$49.68
2013	$58.01	$61.13	$49.70
2014	$58.48	$61.47	$49.98
2015	$58.95	$61.82	$50.26
2016	$59.43	$62.17	$50.54
2017	$61.14	$62.53	$50.83
2018	$62.92	$62.88	$51.13
2019	$64.76	$62.78	$51.04
2020	$66.68	$62.68	$50.96
2021	$67.35	$62.59	$50.88
2022	$68.02	$62.48	$50.80
2023	$68.70	$62.38	$50.72
2024	$69.39	$62.29	$50.64
2025	$70.08	$62.19	$50.56
2026	$70.79	$62.52	$50.83
2027	$71.50	$62.84	$51.09
2028	$72.21	$63.17	$51.36
2029	$72.94	$63.50	$51.62
2030	$73.67	$63.83	$51.90
2031	$72.98	$63.83	$51.90
2032	$72.35	$63.83	$51.90
2033	$71.75	$63.83	$51.90
2034	$71.21	$63.83	$51.90
2035	$70.70	$63.83	$51.90
2036	$70.23	$63.83	$51.90
2037	$69.79	$63.83	$51.90
Levelized 2005-2012	$66.48	$61.24	$49.79
Levelized 2005-2037	$66.93	$62.31	$50.66

Notes: Levelized (annuity) values were calculated using a 2.03 percent discount rate consistent with the 2005 analysis. Previous analysis results are inflated to 2005 dollars from 2004 dollars using a 2.25% annual inflation rate assumption. Avoided Costs do not include transmission and distribution capacity or DRIPE. The previous analysis included some retail costs in addition to wholesale market costs while the current analysis does not (the additional costs were the equivalent of a multiple of 1.23 above the wholesale costs for all of New England).

Exhibit 3-12 provides a comparison of the seasonal and peak off-peak electric supply costs for select year as well as the levelized costs across the entire horizon.

Exhibit 3-12: Comparison of Seasonal New England Avoided Electric Supply Cost Estimates Select Years and Levelized

Year	On-Peak				Off-Peak			
	Current Analysis (2005$/MWh)		Previous Analysis (2005$/MWh)		Current Analysis (2005$/MWh)		Previous Analysis (2005$/MWh)	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
2006	84.77	86.05	74.60	53.44	59.90	72.37	42.24	44.36
2008	78.14	74.70	72.08	52.35	50.63	60.48	41.79	41.99
2013	61.46	57.00	75.89	51.21	38.72	45.81	39.54	39.25
2018	67.31	61.75	77.70	52.71	43.42	50.57	40.77	40.50
2025	76.12	68.78	78.81	52.16	50.65	57.08	41.24	40.63
2030	80.48	72.22	79.94	53.80	54.18	60.03	42.34	41.78
2037	79.58	72.18	80.60	53.80	53.10	58.94	42.34	41.78
Levelized 2005-2037 @ 2.03%	72.33	67.24	75.51	51.68	47.79	55.31	40.52	40.43

Notes: Levelized (annuity) values were calculated using a 2.03 percent discount rate consistent with the 2005 analysis. Previous analysis results are inflated to 2005 dollars from 2004 dollars using a 2.25% annual inflation rate assumption. Comparisons do not include transmission and distribution capacity costs or DRIPE. The previous analysis included some retail costs in addition to wholesale market costs while the current analysis does not (the additional costs were the equivalent of a multiple of 1.23 above the wholesale costs for all of New England).

Chapter Four: Other Fuel Avoided Costs

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 the exhibits below. In the following brief sections we describe our approach to estimating these avoided costs. The Energy Information Administration publication *Petroleum Marketing Monthly* was the source for all historical data, with the exception of data for firewood, which was obtained through calls to firewood dealers in New England and internet research. All costs are in 2005$/MMBtu.

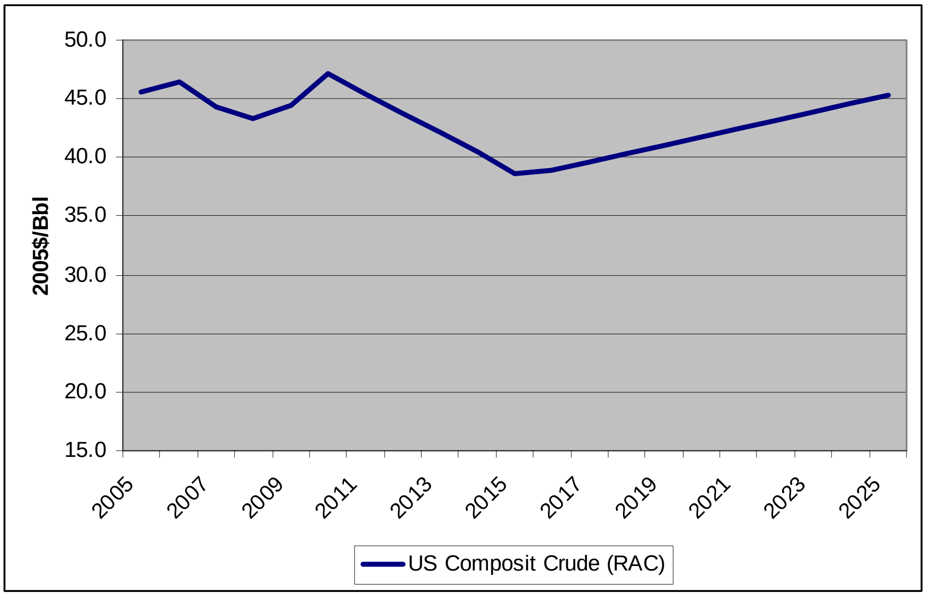
After analyzing the impacts of Hurricane Katrina on the oil markets, we conclude that it does not warrant any change to the oil price forecast. Indeed, the situation with oil highlights the stark differences between the oil and gas market and infrastructure. The U.S. Gulf Coast and the Gulf of Mexico are vital components of the oil supply infrastructure in the United States. The hurricane initially reduced oil supplies by an estimated 1.4 million barrels per day (mmb/d). In addition, about 1.9 mmb/d of crude oil refining capacity was shut down as Katrina approached[15]. But oil is a global market, and this volume is still a small fraction of a large world-wide oil market of approximately 82 million barrels per day. As was demonstrated by subsequent events, the oil price spike was transitory largely because other supplies rushed in to fill the shortfall. These other supplies included releases from the Strategic Petroleum Reserve (SPR) as well as crude and product deliveries from internationals sources. As of September 13, 2005, the prices for crude oil, heating oil and residual fuel oil were near or below their levels before Hurricane Katrina hit the Gulf Coast.

Crude Oil Price Forecast

The forecasted price of all petroleum products is driven by the forecast for crude oil prices used in the gas forecast and in the power forecasts. The crude oil price used is an ICF forecast. ICF expects the crude oil prices to stay near or just below their current levels in the near term until 2010 as the supply demand situation will remain tight. Between 2010 and 2015, the prices are expected to decline as investments made in oil production capacity in the next few years will be realized in increasing oil supply. However, by 2015, the demand growth catches up with oil production capacity and the crude oil prices increases steadily for the rest of the forecast. Exhibit 4-1 graphically presents the oil price forecast.

[15] *Short-Term Energy Outlook, September 2005*, Energy Information Administration, U.S. Department of Energy

Exhibit 4-1. Forecast Refiners Acquisition Cost (RAC) of Crude



Below in Exhibit 4-2, we present the national forecasts based on the above price path of crude and the principal product prices. Product prices are shown in dollars per MMBtu.

Exhibit 4-2: U.S. Crude and Product Price Forecast (2005$/MMBtu)

Year	Composite RAC Oil $/BBL	Composite RAC Oil	Average No.2 Distillate	Average No. 6 Resid < 1% S	Propane Wholesale	Kerosene Wholesale
2005	45.60	7.86	9.39	7.25	9.39	9.89
2006	46.40	8.01	9.54	7.40	9.54	10.04
2007	44.40	7.65	9.19	7.05	9.19	9.68
2008	43.30	7.47	9.01	6.87	9.01	9.51
2009	44.50	7.67	9.21	7.07	9.21	9.71
2010	47.20	8.14	9.68	7.54	9.68	10.17
2011	45.50	7.84	9.38	7.24	9.38	9.88
2012	43.80	7.55	9.09	6.95	9.09	9.59
2013	42.10	7.26	8.80	6.66	8.80	9.29
2014	40.40	6.97	8.51	6.37	8.51	9.00
2015	38.60	6.66	8.20	6.06	8.20	8.69
2016	38.90	6.71	8.25	6.10	8.24	8.74
2017	39.60	6.83	8.37	6.23	8.37	8.86
2018	40.30	6.95	8.49	6.35	8.49	8.99
2019	41.00	7.07	8.61	6.47	8.61	9.11
2020	41.70	7.19	8.73	6.59	8.73	9.23
2021	42.40	7.32	8.85	6.71	8.85	9.35
2022	43.10	7.44	8.98	6.84	8.97	9.47
2023	43.80	7.56	9.10	6.96	9.10	9.59
2024	44.60	7.68	9.22	7.08	9.22	9.72
2025	45.30	7.80	9.34	7.20	9.34	9.84

The following sections each describe our approach to developing fuel prices in New England. At the end of this section, we present a series of tables that show the results for southern (Connecticut and Rhode Island), northern (Maine) and central (Massachusetts, Vermont, New Hampshire) New England. Exhibits 4-3 through 4-5 present distillate and residual fuel price forecasts for each of the sub regions. Exhibit 4-6 presents kerosene, propane, and firewood prices for all New England.

Distillate Fuel Prices in New England

Distillate fuel oil is estimated based on historical observed price differences between wholesale No. 2 distillate fuel and U.S. Refiner's Acquisition Cost (RAC) of domestic and imported crude price. The average spread, or crude to wholesale price markup, was then added to the forecasted crude price to obtain the forecasted wholesale No. 2 distillate price. The average historical price spread between each retail sector and the wholesale price was added to the forecasted wholesale price to obtain the forecasted retail price. Prices are shown as an annual average. Price forecasts for distillate fuel delivered to New England power generation stations were used in IPM® to represent the price streams to those plants capable of burning distillate oil.

New England Residual Fuel Prices: No. 6 and No. 4

Our forecast of residual fuel oil is done in the same way as the distillate forecast with the exception that retail prices were not available for individual sectors and hence a single retail price is forecasted. For No. 6 residual fuel, an average crude-to-wholesale markup, and then an average wholesale to retail markup was calculated. The No. 4 fuel oil wholesale and retail prices are simple averages of No. 2 distillate and No. 6 residual prices. IPM® models oil-fired generation and uses the appropriate fuel oil type for each unit modeled. Oil-gas steam units typically are modeled as able to utilize regional wholesale No. 6 oil and natural gas with a small markup for inter-regional transportation..

Kerosene Prices in New England

Kerosene prices are based on historical observed differences in wholesale kerosene prices with wholesale No. 2 distillate prices. The resulting forecast represents the historical average spread applied to our forecast of No. 2 distillate prices. The prices shown in Exhibit 4 -7 are for all New England. The retail price forecast was obtained in the same fashion as retail prices for distillate and residual fuel; however, the retail price represents the price to all sectors. No sector specific pricing was available.

New England Propane Pricing

We used a similar approach for propane. Distillate and propane are highly correlated; therefore we applied the average spread between historic wholesale No. 2 distillate wholesale prices and wholesale propane prices to estimate future propane prices. Retail prices were generated using the same method as the other fuels. As with kerosene, historic price data were not available on the state level but only on the regional level. Propane prices shown are thus for all New England.

Firewood in New England

Wood prices are based on data collected through calls to firewood dealers throughout the New England region and internet research. Prices were gathered for green wood, which is not ready to burn, and seasoned wood, which is ready to burn. Average prices were escalated by two percent per year in real terms. The estimated long term increase in wood pricing reflects conversations with dealers and our view of the long term growth in real gross state product (as reported by the Bureau of Economic Analysis) for New England in general. This is the same growth rate used in the previous AESC study. Prices shown are the same for all New England sub-regions.

Comparison with Previous Avoided Cost Study

As with natural gas, fuel prices have increased in all categories since the 2003 AESC study. A comparison of the fuel prices is shown below for those categories of fuel that are common to both studies. As can be seen, in many categories, levelized fuel costs have almost doubled.

Exhibit 4-3: Comparison of 2005 and 2003 Studies:
32 Year Levelized Cost of Fuels (through 2037)
(2005$/MMBtu)

	Distillate Fuel Oil			Residual Fuel Oil		No. 4 Fuel Oil	Propane		Wood	Kerosene
	Whole.	Res.	Comm.	Whole.	Indus.	Indus.	Whole.	Res.		
2003										
	4.65	7.59	5.36	3.24	3.86	4.61	5.03	9.91	10.29	9.85
2005										
SNE	9.08	11.91	10.18	6.97	7.48	8.98	10.16	18.92	13.60	11.81
CNE	9.08	12.01	9.98	6.97	7.48	9.05	10.16	18.92	13.60	11.81
NNE	9.14	11.90	10.03	6.97	7.48	9.11	10.16	18.92	13.60	11.81

Note: SNE is Southern New England (CT and RI); CNE is Central New England (MA, VT, NH); NNE is Northern New England (ME).

Exhibits, 4-4 through 4-7 present the detailed annual and 35-year levelized cost for all of the fuels for all of the sub-regions. Exhibit 4-8 provides alternative levelized costs for all fuels for all regions by 10, 15, 20, and 35 year periods.

Exhibit 4-4 Southern New England Fuel Oils Forecast by Sector (2005$/MMBtu)

Year	US Composite RAC Oil Price	No. 2 Distillate					No. 6 LS Residual Fuel		No. 4 Fuel Oil	
		Wholesale	Retail				Wholesale	Retail	Wholesale	Retail
			Residential	Commercial	Industrial	Electrical				
2005	7.86	9.40	12.23	10.50	10.12	10.10	7.29	7.80	8.34	9.30
2006	8.01	9.54	12.38	10.65	10.27	10.25	7.44	7.95	8.49	9.45
2007	7.65	9.19	12.02	10.29	9.92	9.89	7.09	7.59	8.14	9.09
2008	7.47	9.01	11.84	10.11	9.74	9.71	6.91	7.42	7.96	8.91
2009	7.67	9.21	12.04	10.31	9.94	9.91	7.11	7.62	8.16	9.11
2010	8.14	9.68	12.51	10.78	10.40	10.38	7.58	8.08	8.63	9.58
2011	7.84	9.38	12.21	10.48	10.11	10.08	7.28	7.79	8.33	9.28
2012	7.55	9.09	11.92	10.19	9.82	9.79	6.99	7.50	8.04	8.99
2013	7.26	8.80	11.63	9.90	9.52	9.50	6.70	7.20	7.75	8.70
2014	6.97	8.51	11.34	9.61	9.23	9.21	6.40	6.91	7.46	8.41
2015	6.66	8.20	11.03	9.30	8.93	8.90	6.10	6.60	7.15	8.10
2016	6.71	8.25	11.08	9.35	8.97	8.95	6.14	6.65	7.19	8.15
2017	6.83	8.37	11.20	9.47	9.09	9.07	6.27	6.77	7.32	8.27
2018	6.95	8.49	11.32	9.59	9.22	9.19	6.39	6.90	7.44	8.39
2019	7.07	8.61	11.44	9.71	9.34	9.31	6.51	7.02	7.56	8.51
2020	7.19	8.73	11.56	9.83	9.46	9.43	6.63	7.14	7.68	8.64
2021	7.32	8.86	11.69	9.96	9.58	9.56	6.75	7.26	7.80	8.76
2022	7.44	8.98	11.81	10.08	9.70	9.68	6.87	7.38	7.93	8.88
2023	7.56	9.10	11.93	10.20	9.83	9.80	7.00	7.50	8.05	9.00
2024	7.68	9.22	12.05	10.32	9.95	9.92	7.12	7.63	8.17	9.12
2025	7.80	9.34	12.17	10.44	10.07	10.04	7.24	7.75	8.29	9.24
2026-2040	7.80	9.34	12.17	10.44	10.07	10.04	7.24	7.75	8.29	9.24
Levelized	7.55	9.09	11.92	10.19	9.82	9.79	6.99	7.50	8.04	8.99

Exhibit 4-5. Northern New England Fuel Oils Forecast by Sector (2005$/MMBtu)

Year	Crude	No. 2 Distillate					No. 6 Residual Fuel <= 1% Sulfur		No. 4 Fuel Oil	
		Wholesale	Retail				Wholesale	Retail	Wholesale	Retail
			Residential	Commercial	Industrial	Electrical				
2005	7.86	9.46	12.22	10.35	10.45	10.85	7.29	7.80	8.38	9.43
2006	8.01	9.61	12.37	10.50	10.60	11.00	7.44	7.95	8.52	9.58
2007	7.65	9.25	12.02	10.14	10.24	10.65	7.09	7.59	8.17	9.22
2008	7.47	9.07	11.84	9.97	10.06	10.47	6.91	7.42	7.99	9.04
2009	7.67	9.27	12.04	10.17	10.26	10.67	7.11	7.62	8.19	9.24
2010	8.14	9.74	12.51	10.63	10.73	11.13	7.58	8.08	8.66	9.71
2011	7.84	9.44	12.21	10.34	10.43	10.84	7.28	7.79	8.36	9.41
2012	7.55	9.15	11.92	10.04	10.14	10.55	6.99	7.50	8.07	9.12
2013	7.26	8.86	11.63	9.75	9.85	10.25	6.70	7.20	7.78	8.83
2014	6.97	8.57	11.34	9.46	9.56	9.96	6.40	6.91	7.49	8.54
2015	6.66	8.26	11.03	9.15	9.25	9.66	6.10	6.60	7.18	8.23
2016	6.71	8.31	11.07	9.20	9.30	9.70	6.14	6.65	7.23	8.28
2017	6.83	8.43	11.20	9.32	9.42	9.82	6.27	6.77	7.35	8.40
2018	6.95	8.55	11.32	9.45	9.54	9.95	6.39	6.90	7.47	8.52
2019	7.07	8.67	11.44	9.57	9.66	10.07	6.51	7.02	7.59	8.64
2020	7.19	8.80	11.56	9.69	9.78	10.19	6.63	7.14	7.71	8.76
2021	7.32	8.92	11.68	9.81	9.91	10.31	6.75	7.26	7.84	8.89
2022	7.44	9.04	11.81	9.93	10.03	10.43	6.87	7.38	7.96	9.01
2023	7.56	9.16	11.93	10.05	10.15	10.56	7.00	7.50	8.08	9.13
2024	7.68	9.28	12.05	10.18	10.27	10.68	7.12	7.63	8.20	9.25
2025	7.80	9.40	12.17	10.30	10.39	10.80	7.24	7.75	8.32	9.37
2026-2040	7.80	9.40	12.17	10.30	10.39	10.80	7.24	7.75	8.32	9.37
Levelized	7.55	9.15	11.92	10.05	10.14	10.55	6.99	7.50	8.07	9.12

Exhibit 4-6. Central New England Fuel Oil Forecast (2005$/MMBtu)

Year	Crude	No. 2 Distillate					No. 6 Residual Fuel <= 1% Sulfur		No. 4 Fuel Oil	
		Wholesale	Retail				Wholesale	Retail	Wholesale	Retail
			Residential	Commercial	Industrial	Electrical				
2005	7.86	9.39	12.33	10.30	10.22	10.66	7.29	7.80	8.34	9.37
2006	8.01	9.54	12.48	10.45	10.37	10.81	7.44	7.95	8.49	9.52
2007	7.65	9.19	12.12	10.10	10.02	10.45	7.09	7.59	8.14	9.17
2008	7.47	9.01	11.95	9.92	9.84	10.28	6.91	7.42	7.96	8.99
2009	7.67	9.21	12.15	10.12	10.04	10.48	7.11	7.62	8.16	9.19
2010	8.14	9.68	12.61	10.59	10.51	10.94	7.58	8.08	8.63	9.66
2011	7.84	9.38	12.32	10.29	10.21	10.65	7.28	7.79	8.33	9.36
2012	7.55	9.09	12.03	10.00	9.92	10.35	6.99	7.50	8.04	9.07
2013	7.26	8.80	11.73	9.71	9.63	10.06	6.70	7.20	7.75	8.78
2014	6.97	8.51	11.44	9.41	9.34	9.77	6.40	6.91	7.46	8.48
2015	6.66	8.20	11.13	9.11	9.03	9.46	6.10	6.60	7.15	8.18
2016	6.71	8.25	11.18	9.15	9.07	9.51	6.14	6.65	7.19	8.22
2017	6.83	8.37	11.30	9.28	9.20	9.63	6.27	6.77	7.32	8.35
2018	6.95	8.49	11.43	9.40	9.32	9.76	6.39	6.90	7.44	8.47
2019	7.07	8.61	11.55	9.52	9.44	9.88	6.51	7.02	7.56	8.59
2020	7.19	8.73	11.67	9.64	9.56	10.00	6.63	7.14	7.68	8.71
2021	7.32	8.85	11.79	9.76	9.68	10.12	6.75	7.26	7.80	8.83
2022	7.44	8.98	11.91	9.88	9.81	10.24	6.87	7.38	7.93	8.95
2023	7.56	9.10	12.03	10.01	9.93	10.36	7.00	7.50	8.05	9.08
2024	7.68	9.22	12.16	10.13	10.05	10.49	7.12	7.63	8.17	9.20
2025	7.80	9.34	12.28	10.25	10.17	10.61	7.24	7.75	8.29	9.32
2026-2040	7.80	9.40	12.17	10.30	10.39	10.80	7.24	7.75	8.32	9.37
Levelized	7.55	9.09	12.03	10.00	9.92	10.36	6.99	7.50	8.04	9.07

Exhibit 4-7. All New England Other Fuels Forecast (2005$/MMBtu)

Year	Propane				Kerosene		Wood	
	Wholesale	Retail			Wholesale	Retail	Retail	Retail
		Residential	Commercial	Industrial			Greenwood	Seasoned
2005	10.48	19.24	15.28	13.29	9.61	12.32	8.04	10.54
2006	10.63	19.39	15.43	13.44	9.57	12.27	8.21	10.75
2007	10.28	19.04	15.08	13.09	9.21	11.92	8.37	10.97
2008	10.10	18.86	14.90	12.91	9.03	11.74	8.54	11.19
2009	10.30	19.06	15.10	13.11	9.23	11.94	8.71	11.41
2010	10.76	19.52	15.57	13.58	9.70	12.41	8.88	11.64
2011	10.47	19.23	15.27	13.28	9.40	12.11	9.06	11.87
2012	10.18	18.94	14.98	12.99	9.11	11.82	9.24	12.11
2013	9.88	18.64	14.69	12.70	8.82	11.53	9.43	12.35
2014	9.59	18.35	14.40	12.41	8.53	11.24	9.61	12.60
2015	9.29	18.05	14.09	12.10	8.22	10.93	9.81	12.85
2016	9.33	18.09	14.14	12.15	8.27	10.97	10.00	13.11
2017	9.45	18.21	14.26	12.27	8.39	11.10	10.20	13.37
2018	9.58	18.34	14.38	12.39	8.51	11.22	10.41	13.64
2019	9.70	18.46	14.50	12.51	8.63	11.34	10.61	13.91
2020	9.82	18.58	14.62	12.63	8.75	11.46	10.83	14.19
2021	9.94	18.70	14.74	12.75	8.88	11.58	11.04	14.47
2022	10.06	18.82	14.87	12.88	9.00	11.71	11.26	14.76
2023	10.18	18.95	14.99	13.00	9.12	11.83	11.49	15.06
2024	10.31	19.07	15.11	13.12	9.24	11.95	11.72	15.36
2025	10.43	19.19	15.23	13.24	9.36	12.07	11.95	15.66
2026-2040	10.43	19.19	15.23	13.24	9.36	12.07	11.95	15.66
Levelized	10.18	18.94	14.98	12.99	9.12	11.83	10.47	13.72

Exhibit 4-8: Alternative Levelized Costs of Other Fuels (2005$/MMBtu)

Southern New England Levelized Costs									
Years Levelized	No. 2 Distillate					No. 6 Residual Fuel <= 1% Sulfur**		No. 4 Fuel Oil	
		Retail							
	Wholesale	Residential	Commercial	Industrial	Electrical	Wholesale	Retail	Wholesale	Retail
10	9.11	11.94	10.21	9.84	9.81	7.01	7.52	8.06	9.01
15	8.94	11.77	10.04	9.66	9.64	6.83	7.34	7.89	8.84
20	8.97	11.80	10.07	9.69	9.67	6.87	7.37	7.92	8.87
35	9.09	11.92	10.19	9.82	9.79	6.99	7.50	8.04	8.99
Northern New England Levelized Costs									
10	9.17	11.94	10.07	10.16	10.57	7.01	7.52	8.09	9.14
15	9.00	11.76	9.89	9.99	10.39	6.83	7.34	7.92	8.97
20	9.03	11.80	9.92	10.02	10.42	6.87	7.37	7.95	9.00
35	9.15	11.92	10.05	10.14	10.55	6.99	7.50	8.07	9.12
Central New England Levelized Costs									
10	9.11	12.05	10.02	9.94	10.38	7.01	7.52	8.06	9.09
15	8.94	11.87	9.84	9.77	10.20	6.83	7.34	7.88	8.91
20	8.97	11.90	9.88	9.80	10.23	6.87	7.37	7.92	8.95
35	9.09	12.03	10.00	9.92	10.36	6.99	7.50	8.04	9.07
All New England Forecast: Other Fuels									
	Propane				Kerosene		Wood		
		Retail					Retail	Retail	
	Wholesale	Residential	Commercial	Industrial	Wholesale	Retail*	Greenwood	Seasoned	
10	10.20	18.96	15.00	13.01	9.15	11.86	8.86	11.62	
15	10.02	18.78	14.83	12.84	8.97	11.68	9.29	12.18	
20	10.05	18.81	14.86	12.87	9.00	11.71	9.73	12.76	
35	10.18	18.94	14.98	12.99	9.12	11.83	10.47	13.72	

Chapter Five: Avoided Transmission and Distribution Capacity Costs

For the avoided energy supply cost analysis, ICF has recommended a methodological approach to determining avoided capacity costs for transmission and distribution and has provided a spreadsheet (Microsoft Excel) tool to allow individual Study Group members to implement the approach. The intent of this part of the analysis was to provide a common approach that could be adopted by all members of the Study Group in order to establish a consistent and defendable approach. The spreadsheet tool was provided to members of the AESC Study Group over the course of this analysis to allow for each company to enter company-specific data.

The initial step of this task was a data collection effort that ICF undertook to understand the approaches currently being used by the AESC Study Group members. After discussions and data exchange with several of the Study Group participants including National Grid, United Illuminating, NStar, and Unitil regarding their current methodology for determining avoided transmission and distribution capacity costs, it was apparent that a variety of approaches were used. However, in a number of cases, the results approximated the average system cost, rather than the incremental or avoidable costs (by dividing annual revenue requirements for T&D operations by the average annual peak over a historical period).

It was also apparent that the availability and quality of data necessary to develop reasonable estimates of marginal T&D costs varied from company to company. In order to accommodate this, ICF attempted to develop a methodology that largely relies on data which should be common to all companies in developing the tool, yet be flexible enough to utilize custom inputs that may be available at individual companies. Our method should produce a reasonable proxy for the marginal costs of such services.

This remainder of this chapter presents the approach and provides an overview of the tool. Note, all exhibits shown in this chapter are intended to be illustrative only and should not be relied on by any company.

Summary of Transmission and Distribution Avoided Capacity Cost Calculator

The transmission and distribution avoided cost calculator is comprised of four main schedules and one appendix schedule on which users provide critical inputs to feed the avoided cost calculation. The tool is created in Microsoft Excel, which was noted to be readily available to all participants. This Excel workbook allows participants to calculate their marginal costs by cataloging investments and expenses and peak demand growth over historical and forecast periods. The schedules contained in the workbook are

1. A summary schedule detailing the transmission and distribution avoided capacity costs resulting from the analysis
2. A schedule cataloging investments in T&D systems over a period of years
3. A schedule calculating the annual carrying charge of those investments based on

assumptions on taxes, financing costs, operational expenses, and other recurring costs.

4. A schedule cataloging peak demand growth over the same period of years

So long as participants have available to them the information needed to calculate marginal costs for the system (or are able to make reasonable assumptions for missing data elements) this proposal offers a way to calculate marginal costs appropriate to each participant's system. Much the required data is available directly from FERC Form 1. However, some data from the FERC Form 1 may need to be interpreted or adjusted to a definition consistent with the methodology. For example, a user must estimate directly the amount of transmission and distribution investment corresponding directly to load growth, a value not directly available from the FERC Form 1.

A description of each schedule is provided below.

Schedule 1 - Summary

Schedule 1 of the tool presents the results of the avoided cost calculation for both transmission and distribution capacity. The avoided costs in $ per kilowatt-year are here defined as the incremental investment that occurs over a period of time that can be attributed to load growth divided by the actual load growth in that period. This approach reflects a reasonable proxy for the incremental costs of investment associated with transmission and distribution. Schedule 1 is illustrated in Exhibit 5-1.

The time period over which data are available for and the quality of those data are very important to this calculation. ICF recommends that a 25 period be used (15 historical and 10 forecast) given the lumpiness in the transmission investment cycle. Since the amount and quality of data does vary, users of the tool can determine the number of years to be included in the analysis (noted in later schedules) and can enter the relative importance with which they would like the historical data be given in the cost determination versus that given to the forecast data. In Schedule 1, the single user input is an indication of the weighing that users would like to give to the historical and forecast data. For example, if a user believes the historical data to be faulty, yet reflective of the trend in investment costs, but believes the forecast data is of a higher quality, that user would weight the forecast data at a higher value than the historical data. The user provides his preferred weighting as a percent for the historical data in row 5 and the weighting for the forecast data will be determined as the difference to reach 100 percent total. The resulting weighted values for transmission and distribution avoided capacity costs are found in rows 6 and 6a respectively under the column heading "Avoided Capacity Costs – Weighted". Alternatively, if the user prefers to have no distinction in the forecast and historical series such that they would combine to be treated as one continuous time period, the values presented in the column titled "Avoided Capacity Costs – No Weighting" should be used.

Instructions for this schedule are provided in the "Source" column on the far right and possible errors will appear to the bottom of the sheet.

Exhibit 5-1. Illustrative Example of Schedule 1: Summary of Results

Summary Schedule 1

Purpose: Assuming detailed data on incremental transmission and distribution investments are available to participants as they assess avoided Transmission and Distribution expenses, this workbook provides a methodology for calculating marginal avoided costs. Schedule 1 performs that calculation using outputs from subordinate Schedules 2 through 4.

Note: Avoided capacity cost output should be applied to kW savings at the generation level. When applying values to savings measured at the customer meter, the savings must be escalated by the combined transmission and distribution losses to remain consistent with the methodology used here-in.

Inputs are Shaded in Light Green
Transmission Avoided Capacity Cost Output is shaded in Lavender
Distribution Avoided Capacity Cost Output is shaded in Tan

Line	Description	Units	Historical	Forecast	Avoided Capacity Costs - Weighted	Avoided Capacity Costs - No Weighting	Source
1	Incremental Investments in transmission systems caused by load growth	US$	$4,552,529	$8,093			Line 3 from Schedule 2
1a	Incremental Investments in distribution systems caused by load growth	US$	$1,338,193	$7,277			Line 3 from Schedule 2
2	Annual carrying charge of transmission capital investments	%/yr	19.7%	19.7%			Line 7 from Schedule 3 (TR)
2a	Annual carrying charge of distribution capital investments	%/yr	11.5%	11.5%			Line 7 from Schedule 3 (DS)
3	Incremental growth in peak demand	kW	94,941	55,160			Line 1 from Schedule 4
4	Marginal cost of transmission capacity - component	$/kW-yr	$9.42	$0.03			Line 1 * Line 2 / Line 3
4a	Marginal cost of distribution capacity - component	$/kW-yr	$1.62	$0.02			Line 1 * Line 2 / Line 3
5	Weighting of component costs	%	50%	50%			**Input** If only limited investment data is available, ICF recommends using the entire time period (Total column) for estimating marginal costs to reduce the effects of lumpiness in the investment cycle. Else, users may apply weightings to the component values. As a guideline, less than 4 years of forecast data or less than 8 years or total data should be considered limited data.
6	Marginal cost of transmission capacity - total	$/kW-yr			$4.73	$5.97	Σ (Line 4 * Line 5) for Components or Line 1*Line 2/ Line 3 for Total
6a	Marginal cost of distribution capacity - total	$/kW-yr			$0.82	$1.03	Σ (Line 4a * Line 5) for Components or Line 1a*Line 2a/ Line 3 for Total

IN CASE OF ERRORS USERS SHOULD VERIFY VALUES. TOTAL ERRORS FOUND: 0

Note: Weighting Factors are used to allow for component periods to be given greater or lesser importance in determining the marginal costs. Component periods should only be used in cases where adequate investment occurs in the component periods or in cases where the quality of the data for either component is unreliable.

Schedule 2 - Transmission and Distribution Investment

Schedule 2 allows users to enter capital investments made on transmission and distribution systems over a specific historical and/or future time period. The time period requires a duration over which a reasonable amount of investment occurred or is projected to occur; recommended is 25 years in length - 15 historical years and 10 forecast years.

The data on investment costs should be entered in the amount that was or is expected to be spent in each year in nominal dollars. These data are summed to determine the incremental investment which has occurred over the base year to the final year in the series. Users also specify the share (in a percentage) of the total investment which is believed to be related to load growth. The default for this is set to 50 percent of the transmission and distribution investment. This estimate was provided by one of the study participants and accepted by the Study Group as the default level.

The data are entered in nominal dollars but are converted to real dollars using the Handy-Whitman index for utility transmission and distribution costs trends for a long-term historical period. Transmission investment costs have increased at a rate above general inflation which is reflected in the Handy-Whitman derived escalation factor. Note, the historical relationship of transmission costs to general inflation is assumed to continue at the historical rate going forward.

The “Source” column provides an explanation of the calculations or instruction on the data input.

Exhibit 5-2. Illustrative Example of Schedule 2: Transmission and Distribution Investment Expense

Transmission Investment Schedule 2

Purpose: This schedule tracks capital investments made on transmission systems over a specific historical or future time period. (The same time period peak growth was tracked for Schedule 4.) The time period requires a duration over which a reasonable amount of investment occurred or is projected to occur; recommended is 25 years in length:- 15 historical years and 10 forecast years.

Inputs are Shaded in Light Green

Line	Description	Units	TRANSMISSION Nominal$	TRANSMISSION Real$	DISTRIBUTION Nominal$	DISTRIBUTION Real$	Source
1	**Incremental Investments into transmission systems - Historical**	**US$**	**6,898,300**	**9,105,057**	**2,137,500**	**2,676,386**	**Sum of lines 1c-1q**
1a	**Incremental Investments into transmission systems - Forecast**	**US$**	**20,000**	**16,186**	**15,000**	**14,553**	**Sum of lines 1r-1aa**
1b	**Incremental Investments into transmission systems - Total**	**US$**	**6,918,300**	**9,121,243**	**2,152,500**	**2,690,939**	**Sum of lines 1c-1aa**
c	Capital Investment: Year 1 (Historical)	US$	2,085,125	3,040,058	10,000	14,580	
d	Capital Investment: Year 2 (Historical)	US$	25,500	36,190	127,500	180,952	
e	Capital Investment: Year 3 (Historical)	US$	0	0	0	0	
f	Capital Investment: Year 4 (Historical)	US$	862,675	1,160,133	0	0	
g	Capital Investment: Year 5 (Historical)	US$	0	0	0	0	
h	Capital Investment: Year 6 (Historical)	US$	0	0	0	0	
i	Capital Investment: Year 7 (Historical)	US$	3,925,000	4,868,677	2,000,000	2,480,854	
j	Capital Investment: Year 8 (Historical)	US$	0	0	0	0	
k	Capital Investment: Year 9 (Historical)	US$	0	0	0	0	Under the Real$ column, historical investment costs
l	Capital Investment: Year 10 (Historical)	US$	0	0	0	0	are inflated to Year 15 (Baseline Year) using the
m	Capital Investment: Year 11 (Historical)	US$	0	0	0	0	historical escalation rate. The historical escalation rate
n	Capital Investment: Year 12 (Historical)	US$	0	0	0	0	is an average of 10-year rolling averages of
o	Capital Investment: Year 13 (Historical)	US$	0	0	0	0	Transmission Plant Cost Index from the Handy
p	Capital Investment: Year 14 (Historical)	US$	0	0	0	0	Whitman Index for the 1991-2004 period and is
q	Capital Investment: Year 15 (Historical) - Last	US$	0	0	0	0	unadjusted for general inflation.
r	Capital Investment: Year 16 (Forecast)	US$	0	0	15,000	14,553	Under the Real$ column, forecast investment costs
s	Capital Investment: Year 17 (Forecast)	US$	0	0	0	0	are deflated to Year 15 (Baseline Year) using the
t	Capital Investment: Year 18 (Forecast)	US$	0	0	0	0	forecast escalation rate. The forecast escalation rate
u	Capital Investment: Year 19 (Forecast)	US$	0	0	0	0	is based on an average of 10-year rolling averages of
v	Capital Investment: Year 20 (Forecast)	US$	0	0	0	0	Transmission Plant Cost Index from the Handy
w	Capital Investment: Year 21 (Forecast)	US$	0	0	0	0	Whitman Index for the 1991-2004 period and is
x	Capital Investment: Year 22 (Forecast)	US$	20,000	16,186	0	0	adjusted for general inflation calculated for the same
y	Capital Investment: Year 23 (Forecast)	US$	0	0	0	0	time period. A 2.25% percent forecast general inflation
z	Capital Investment: Year 24 (Forecast)	US$	0	0	0	0	rate is added to the adjusted cost index to come up
aa	Capital Investment: Year 25 (Forecast)	US$	0	0	0	0	with forecast escalation rate
ab	Historical Escalation Rate (incl. general inflation)	%	2.73%				Handy Whitman for 1991-2004
ac	Forecast Escalation Rate (incl. general inflation)	%	3.07%				Handy Whitman adjusted as per notes above
2	**Percentage Assumed to be Related to Increasing Load**	**%**		**50%**		**50%**	**Reasonable given responses from participants**
3	**Incremental Investments in Transmission Systems caused by Load Growth - Historical**	**US$**		**4,552,529**		**1,338,193**	**Line 1 times Line 2**
3a	**Incremental Investments in Transmission Systems caused by Load Growth - Forecast**	**US$**		**8,093**		**7,277**	**Line 1a times Line 2**
3b	**Incremental Investments in Transmission Systems caused by Load Growth - Total**	**US$**		**4,560,622**		**1,345,470**	**Line 1b times Line 2**

Schedule 3 – Carrying Charge Rate

Separate worksheets are provided to calculate the carrying charges for transmission and distribution capacity. The carrying charge includes insurance, taxes, depreciation, interest, and operations and maintenance.

The values input by users for each of these line items should reflect the costs associated with new investment which can be avoided. In several cases such as insurance and property tax expense, the full value associated with that item would be avoidable and it is appropriate to apply the share of the costs associated with that line item calculated as a percent of the total existing costs as the avoidable amount   However, in the case of operations and maintenance cost, new investment projects benefit substantially through economies of scale gained from existing investment. Given these economies, the O&M for new investments would be a much smaller share of the total project costs than the existing O&M expenses are of the current existing plant. To allow users to better define the avoidable O&M expenses, a separate calculation for O&M inputs to the carrying charge rate calculation is provided in Appendix 1 as discussed below.

The standard data for the carrying charge calculation largely rely on FERC Form 1 as shown in the “Source” column. The formulas for each of the line items are shown in the “Source / Notes” column to the right of the schedule.

As with all other inputs in this spreadsheet, the carrying charge is required to be in real dollars. Values entered in nominal dollars will be converted to real dollars using the inflation rate input in row 8. The default annual inflation rate is set at 2.25 percent, roughly consistent with the historical long-term inflation rate and used elsewhere in the study.

Exhibit 5-3 below provides an illustrative example of the carrying charge calculation for transmission capacity. A schedule for distribution capacity having identical formulation and format is included in the tool though it is not shown here.

Exhibit 5-3. Illustrative Example of Schedule 3: Carrying Charge

Carrying Charge Schedule 3 - Transmission

Purpose: Schedule 1 tracks large long-termed investments in transmission and distribution systems. This Schedule calculates the factor used to determine the annual cost of those investments. Annual costs include obligations to debt holders and shareholders for those long-term investments, as well as taxes, insurance, and other recurring expenses. In calculating an annual charge we can get from $/kW reductions to $/kW-yr reductions, valuing DSM programs over their useful life.

Inputs are Shaded in Light Green

Line	Description	Units	Source		Source / Notes
1	**Real After Tax Cost of Financing (WACC)**	**%**	Formula	**6.15%**	**[(1-Line 1a)*(Line 1c)]+[(Line 1a)*(Line 1b)*(1-Line 1f)]**
a	Share of project financed through debt	%	NA	50.00%	
b	Real Interest Rate on Debt	%	NA	4.65%	**(1+ Line 1b1) / (1+Line 8)-1 or enter real value**
b1	Nominal Interest Rate on Debt	%	NA	7.00%	If nominal value only is available, the value should be converted to real (above) using the inflation rate
c	Expected After Tax Real Return on Equity	%	NA	9.54%	**(1+Line 1c1) / (1+Line 8)-1 or enter real value**
c1	Expected After Tax Nominal Return on Equity	%	NA	12.00%	If nominal value only is available, the value should be converted to real (above) using the inflation rate
d	State Income Tax Rate	%	NA	8.56%	
e	Federal Income Tax Rate	%	NA	35.00%	
f	Effective State and Federal Income Tax Rate	%	Formula	40.56%	**Line 1d + Line 1e * (1-1d)**
2	**Property Taxes Expense**	**%**	Formula	**0.15%**	**Line 2a / Line 2c or if transmission related property taxes are not available, Line 2a / Line 2d)**
a	Total Plant Annual Property Taxes	MM$	Form 1 Taxes Accrued, Prepaid and Charged During the Year (pg 263 column i transmission share) where available, else Form 1 Taxes Accrued, Prepaid and Charged During the Year (pg 263 column i total)	0.01	Line 2b must be consistent with data entered for Line 2a. If no response given for 2b, formula will default to total property tax available only.
b	Property Tax Transmission Share Available? (Yes or No)	--	Input	Yes	
c	Net Book Value of Transmission Plant	MM$	See Line 5b	5.57	
d	Net Book Value of Total Plant	MM$	See Line 3b	6.25	
3	**Insurance Expense**	**%**	Formula	**0.70%**	**Line 3a / Line 3b**
a	Total Plant Annual Insurance Costs	MM$	Form 1 Electric Operation and Maintenance Expenses (pg 323 line 156)	0.04	
b	Net Book Value of Total Plant	MM$	Form 1 Summary of Utility Plant and Accumulated Provisions for Depreciation, Amortization and Depletion (pg 200 line 15)	6.25	
4	**Depreciation Expense (using Sinking Fund Factor Approach)**	**%**	Formula	1.232%	**Line 1/ ((1+ Line 1) ^ Line 4a -1)**
a	Depreciation Life of Transmission Plant	Yr		30	
5	**Operation and Maintenance Expense**	**%**	Formula	**9.71%**	**Line 5a / Line 5b**
a	Annual Transmission Operation and Maintenance Expenses	MM$	Form 1 Electric Operation and Maintenance Expenses as per Appendix 1	0.54	
b	Net Book Value of Transmission Plant	MM$	Formula	5.57	**Line 5c - Line 5d**
c	Electric Plant in Service	$	Form 1 Electric Plant in Service (pg 207 line 58)	90,490,946	
d	Accumulated Depreciation	$	Accumulated Provision for Depreciation of Electric Utility Plant (pg 219 line 25)	84,916,778	
6	**Income Taxes Expense**	**%**	Formula	**1.72%**	**(Line 1f / Line 6a)*(Line 1+Line 4-1/Line 4a)*(1-Line 1a*Line 1b / Line 1)**
a	Gross up factor for taxes	%	Formula	59.44%	**1 - Line 1f**
7	**Annual Real Carrying Charge of Capital Investments**	**%**	Formula	**19.65%**	**(Line 1+Line 2+Line 3+Line 4+Line 5+Line 6)**
8	General Inflation	%	Input	2.25%	

Schedule 4 – Peak Growth

Schedule 4 tracks peak demand growth over a specific historical and/or future time period consistent with the investment data entered in Schedule 2. The peak demand data are used to determine the incremental load growth for which transmission and distribution investments are planned.

When entering peak demand data, users should give special consideration to the following:

1. Since peak demand can vary widely from year to year, as seasonal temperatures affect consumption during peak periods, it is important to consider the effect weather may have had on historical information used in this analysis. Users should further consider if inconsistencies may exist between the historical and forecast period if the planning exercise utilizes extreme period growth instead of normal weather conditions. Provided a sufficient time period is used (to cover the period for which the investment proved to be sufficient), such differences will be minimized.

2. When using historical and forecast demand data, users should verify that the point of measurement (load versus generator) is consistent.

3. The peak load for the forecast period should reflect the driver of the forecast investment data entered in Schedule 2. For example, if planning is done to an extreme peak load condition rather than a normal peak load condition, the forecast demand data should be entered for the extreme case that is consistent with the investment dollars.

4. If peak is measured at the generation point, transmission and distribution losses will need to be added to the values to capture the $/kW-yr incremental costs savings at the load level.

The “Source” column provides an explanation of the calculations and instruction on the inputs.

Exhibit 5-4. Illustrative Example of Schedule 4: Peak Growth

Peak Growth Schedule 4

Purpose: This schedule tracks peak demand growth over a specific historical or future time period. (The same time period transmission investment was tracked for Schedule 2 except that the starting year is a year prior to the transmission investment.) The time period requires a duration over which a reasonable amount of investment occurred or is projected to occur; recommended is 25 years in length: 15 historical years and 10 forecast years. Please note: Peak demand can vary widely from year to year, as seasonal temperatures affect consumption during peak periods. If historical information is used for this analysis, please ensure that the starting and ending points are relatively weather normal.

Inputs are Shaded in Light Green

Line	Description	Units		Source
1	**Incremental growth in peak demand - Historical**	**kW**	**94,941**	**Maximum Value (Lines 1c - 1r) minus Line 1c**
1a	**Incremental growth in peak demand - Forecast**	**kW**	**55,160**	**Maximum Value (Lines 1r - 1ab) minus Line 1s**
1b	**Incremental growth in peak demand - Total**	**kW**	**150,101**	**Maximum Value (Lines 1c - 1ab) minus Line 1c**
c	Peak Demand: Year 0 (Historical)	kW	309,000	
d	Peak Demand: Year 1 (Historical)	kW	315,000	
e	Peak Demand: Year 2 (Historical)	kW	320,000	
f	Peak Demand: Year 3 (Historical)	kW	324,000	
g	Peak Demand: Year 4 (Historical)	kW	328,000	
h	Peak Demand: Year 5 (Historical)	kW	333,000	
i	Peak Demand: Year 6 (Historical)	kW	338,000	
j	Peak Demand: Year 7 (Historical)	kW	344,760	Form 1 page 401 Monthly Peaks and Output, line highest of lines 29-40
k	Peak Demand: Year 8 (Historical)	kW	351,655	
l	Peak Demand: Year 9 (Historical)	kW	358,688	
m	Peak Demand: Year 10 (Historical)	kW	365,862	
n	Peak Demand: Year 11 (Historical)	kW	373,179	
o	Peak Demand: Year 12 (Historical)	kW	380,643	
p	Peak Demand: Year 13 (Historical)	kW	388,256	
q	Peak Demand: Year 14 (Historical)	kW	396,021	
r	Peak Demand: Year 15 (Historical)	kW	403,941	
s	Peak Demand: Year 16 (Forecast) = Forecast Base Year	kW	403,941	
t	Peak Demand: Year 17 (Forecast)	kW	412,020	
u	Peak Demand: Year 18 (Forecast)	kW	420,261	FERC Form 714 Peak Demand Forecast or Company Specific Forecast Data. Peak forecast data used should be consistent with the company planning policy (for example if transmission and distribution investment is based on extreme weather expectations, the extreme weather peak forecast should be used. For consistency with the historical data, the forecast should be at the generation level.
v	Peak Demand: Year 19 (Forecast)	kW	428,666	
w	Peak Demand: Year 20 (Forecast)	kW	437,239	
x	Peak Demand: Year 21 (Forecast)	kW	424,138	
y	Peak Demand: Year 22 (Forecast)	kW	432,621	
z	Peak Demand: Year 23 (Forecast)	kW	441,274	
aa	Peak Demand: Year 24 (Forecast)	kW	450,099	
ab	Peak Demand: Year 25 (Forecast)	kW	459,101	

Transmission and Distribution Capacity Appendix 1 – Transmission and Distribution Avoidable O&M Determination

Appendix 1 enables users to determine the expenses associated with T&D operations and maintenance which are considered avoidable when using FERC Form 1 to calculate costs. The appendix allows users to input the total amounts listed with individual accounts on the Form 1 and to enter their estimate of the share of these costs which are avoidable. Avoidable O&M costs are those costs for new incremental transmission or distribution capacity which are driven by load growth. For example, a new project would have little to no effect on the maintenance costs for the fleet services or tree trimming, and hence, these costs are not considered as avoidable. In the appendix, default values are provided for each O&M line item contained on the FERC Form 1, and notes are provided to explain the rationale for the default values. The default values are based on the expert judgment of ICF and have been reviewed and accepted as reasonable by the AESC Study Group participants.

Exhibit 5-5. Illustrative Example of Appendix 1: Transmission and Distribution O&M Avoidable Cost Calculator

Appendix 1: Transmission and Distribution Operation and Maintenance Cost Avoidable Expenses

Inputs are Shaded in Light Green

	Category	FERC Form 1 Operation and Maintenance Expenses page 321	Share Avoidable	Share Not Avoidable	Avoidable Costs ($)	Notes
Source:		**Enter Value in $ Directly from Form 1**	**Assumption**	**Assumption**	**Calculation**	
TRANSMISSION EXPENSES - OPERATION						
Operation	(560) Operation Supervision and Engineering		0%	100%	-	
Operation	(561) Load Dispatching		0%	100%	-	
Operation	(562) Station Expenses		10%	90%	-	Majority of expenses will be considered fixed and will not be affected by normal new investment in equipment.
Operation	(563) Overhead Lines Expenses		20%	80%	-	Majority of expenses will be considered fixed and will not be affected by normal new investment in equipment.
Operation	(564) Underground Lines Expenses		20%	80%	-	Majority of expenses will be considered fixed and will not be affected by normal new investment in equipment.
Operation	(565) Transmission of Electricity by Others	541134	100%	0%	541,134	Share will vary considerable based on situation of individual companies and purpose of the transmission investment
Operation	(566) Miscellaneous Transmission Expenses		50%	50%	-	Items included in this category may be vary from company to company or year to year and may span variable and fixed costs. A 50% split is used as a proxy.
Operation	(567) Rents		0%	100%	-	Rents are considered fixed
TRANSMISSION EXPENSES - MAINTENANCE						
Maintenance	(568) Maintenance Supervision and Engineering		0%	100%	-	
Maintenance	(569) Maintenance of Structures		20%	80%	-	Majority of expenses will be considered fixed and will not be affected by normal new investment in equipment.
Maintenance	(570) Maintenance of Station Equipment		20%	80%	-	Majority of expenses will be considered fixed and will not be affected by normal new investment in equipment.
Maintenance	(571) Maintenance of Overhead Lines		20%	80%	-	Majority of expenses will be considered fixed and will not be affected by normal new investment in equipment.
Maintenance	(572) Maintenance of Underground Lines		20%	80%	-	Majority of expenses will be considered fixed and will not be affected by normal new investment in equipment.
Maintenance	(573) Maintenance of Miscellaneous Transmission Plant		50%	50%	-	Items included in this category may be vary from company to company or year to year and may span variable and fixed costs. A 50% split is used as a proxy.
AVOIDABLE TRANSMISSION O&M					541,134	
DISTRIBUTION EXPENSES - OPERATION						
Operation	(580) Operation Supervision and Engineering		0%	100%	-	
Operation	(581) Load Dispatching		0%	100%	-	
Operation	(582) Station Expenses		10%	90%	-	Majority of expenses will be considered fixed and will not be affected by normal new investment in equipment.
Operation	(583) Overhead Line Expenses		20%	80%	-	Majority of expenses will be considered fixed and will not be affected by normal new investment in equipment.
Operation	(584) Underground Line Expenses		20%	80%	-	Majority of expenses will be considered fixed and will not be affected by normal new investment in equipment.
Operation	(585) Street Lighting and Signal		0%	100%	-	
Operation	(586) Meter Expenses		0%	100%	-	
Operation	(587) Customer Installations Expenses		0%	100%	-	
Operation	(588) Miscellaneous Expenses		50%	50%	-	Items included in this category may be vary from company to company or year to year and may span variable and fixed costs. A 50% split is used as a proxy.
Operation	(589) Rents		0%	100%	-	
DISTRIBUTION EXPENSES - MAINTENANCE						
Maintenance	(590) Maintenance Supervision and Engineering		0%	100%	-	
Maintenance	(591) Maintenance of Structures	8762940	20%	80%	1,752,588	Majority of expenses will be considered fixed and will not be affected by normal new investment in equipment.
Maintenance	(592) Maintenance of Station Equipment		10%	90%	-	Majority of expenses will be considered fixed and will not be affected by normal new investment in equipment.
Maintenance	(593) Maintenance of Overhead Lines		20%	80%	-	Majority of expenses will be considered fixed and will not be affected by normal new investment in equipment.
Maintenance	(594) Maintenance of Underground Lines		20%	80%	-	Majority of expenses will be considered fixed and will not be affected by normal new investment in equipment.
Maintenance	(595) Maintenance of Line Transformers		20%	80%	-	Majority of expenses will be considered fixed and will not be affected by normal new investment in equipment.
Maintenance	(596) Maintenance of Street Lighting and Signal		0%	100%	-	
Maintenance	(597) Maintenance of Meters		0%	100%	-	
Maintenance	(598) Maintenance of Miscellaneous Distribution Plant		50%	50%	-	Items included in this category may be vary from company to company or year to year and may span variable and fixed costs. A 50% split is used as a proxy.
AVOIDABLE DISTRIBUTION O&M					1,752,588	

Notes:
Shares are based on expert judgment unless noted. Shares for individual companies may vary from the average value presented here-in.
Transmission of Electricity by Others should be reviewed by each company for the appropriate share avoidable. Companies with offsetting payments (Account 045656, Class 287) may consider entering the net of these values and leave the share unchanged as a proxy for the avoidable expense.

Chapter Six: Demand Reduction Induced Price Effects

In this chapter, we describe our approach to estimating potential benefits related to demand reduction induced price effects (DRIPE). The results of this analysis are presented as well. All results are presented in 2005$ unless otherwise noted.

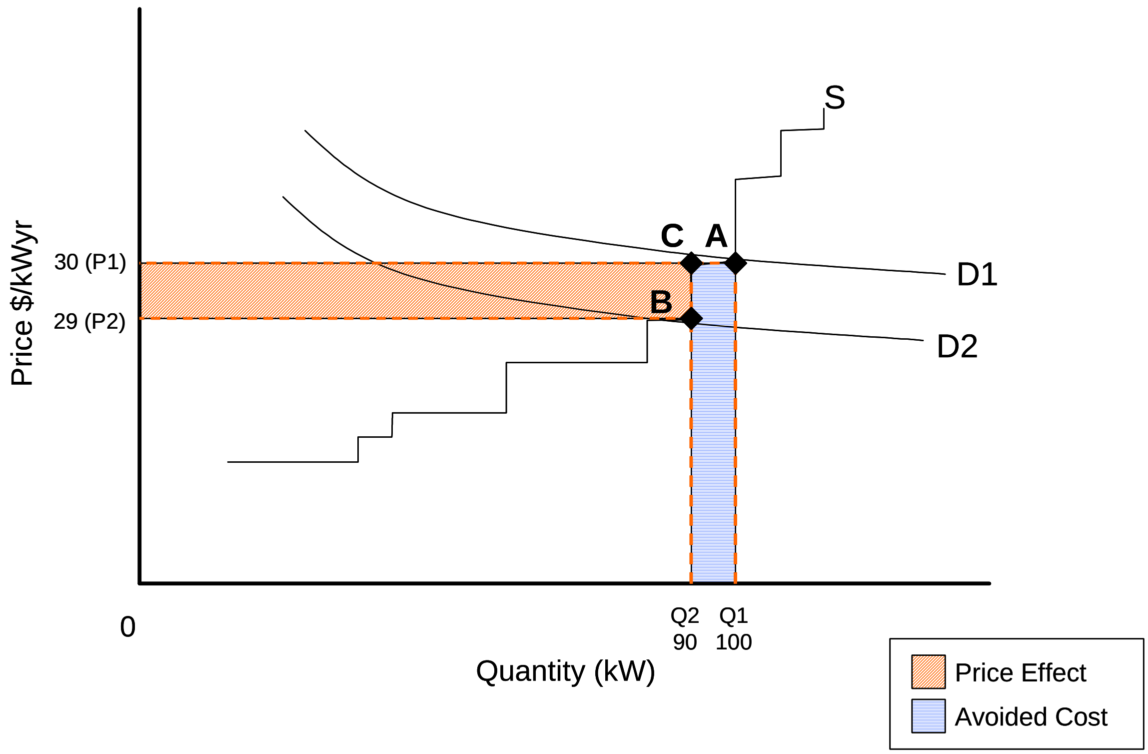
DRIPE Benefits

Avoided costs for firm power as described in Chapter 3 represent the savings associated with reductions in demand based on the price that power (or electrical energy) would have cost absent the demand reduction.

For example, in a market where the total peak hour load is 100 kW and the marginal cost of power purchases are $30/kWyr, if a savings of 10kW is realized in that peak hour through C&LM programs, and if the supply resources are also reduced by the same 10 kW, the benefit associated with those programs is $300/yr ($30/kWyr * 10kW demand reduction). This is the equivalent of the total expenses before the demand reduction minus the expenses after the demand reduction ((100kW * $30/kWyr) – (90kW * $30/kWyr) = $3000/yr - $2700/kWyr = $300/kWyr). This approach to determining avoided costs based on the marginal cost applies to energy as well as to capacity supply costs.

Demand reduction induced price effects (DRIPE) reflect any additional change in costs that occur due to a price response that results from the demand reduction. In the above example, if the marginal capacity price is reduced from $30/kWyr to $29/kWyr through the consumption of fewer resources, the total benefit which above was $300/yr becomes $390/yr. As above, this total benefit is calculated as the total expenses before the demand reduction minus the expenses after the demand reduction ((100kW * $30/kWyr) – (90kW * $29/kWyr) = $3000/yr - $2610/yr = $390/yr). The direct price effect of the kW savings can be determined through isolating the savings directly attributable to the change in price which in this example is $90/yr ($390/yr - $300/yr). The $90/yr reflects the incremental benefit associated with the demand reduction attributable to the price response. This is illustrated in Exhibit 6-1 below.

Exhibit 6-1. Illustrative Example of Avoided Cost and Demand Reduction Induced Price Effect for Capacity Payments



In the above exhibit, the demand curve shifts downward by the quantity of 10 kW due to a demand reduction. As a result, the quantity of supply moves downward to the left (supply reduction) such that the total equilibrium market clearing quantity is reduced by 10 kW (Q1-Q2) and the clearing price is reduced by $1/kWyr (P1-P2). The direct avoided cost is the cost that would have been spent had the initial demand condition (D1) continued to exist less the direct reduction in costs associated with the 10kW savings. This is reflected by the area A-Q1-Q2-C. The additional DRIPE benefit is the MWs purchased at the new price times the change in price (Q2*(P1-P2)) reflected as the area P1-C-B-P2.

Approach Summary and Results

In order to capture DRIPE benefits, ICF utilized a modeling approach to create scenarios around the Reference Case as described in Chapter Two. The scenario approach utilized was designed to capture the change in marginal capacity prices resulting from a predetermined change in the total load. The AESC Study Group and ICF agreed on three scenarios to examine:

1) Scenario 1: Reference Case minus 1 percent peak load,
2) Scenario 2: Reference Case minus 0.75 percent peak load, and
3) Scenario 3: Reference Case plus 1 percent peak load.

Scenarios 1 and 2 (minus 1 and 0.75 percent) were considered by the AESC Study Group as highly probable levels of peak demand reduction. Scenario 3 (plus 1 percent) was performed to demonstrate the sensitivity of the model. The percent change of peak load was meant to approximate the aggregated demand savings of the sponsors' energy efficiency programs.

These scenarios, through their design to reduce peak load only, focus on the change in capacity price and out-of-market costs. ICF conducted an additional scenario analysis that included a 1 percent reduction for all hours (8760 hours) of the year to reflect the potential change in energy as well. Since this analysis did not reflect significant changes in the marginal energy values, it was not utilized for the calculation of DRIPE.

In all the scenario analyses, all zones were considered to have simultaneous load reductions of the same percentage. The scenarios utilized the same modeling construct as the Reference Case and as such reflect zonal price results directly comparable to that of the Reference Case.

The AESC Study Group reviewed the energy and capacity price results of the sensitivities and decided that the preferred scenario to estimate the benefits due to DRIPE to be Scenario 2 (0.75 percent reduction). Based on the design of the scenarios, the DRIPE measures only the effect of permanent demand reductions. The scenarios reflect a shift in the LICAP demand curve that results from measurable energy efficiency programs affecting peak demand. As such, the DRIPE effect does not consider short-term demand responsiveness either directly in the energy markets or related to temporary load response (such as OP4 events) or other demand response programs. DRIPE values should only be applied to demand savings from energy efficiency programs and not demand response or distributed generation.

The DRIPE benefits for all of New England are shown in Exhibit 6-2 below. These benefits are incremental and therefore additive to the avoided capacity values presented in Chapter 3. The New England DRIPE benefits represent the sum of the zonal benefits. These values are presented for reference purposes only and not for use in the screening tools. Zonal DRIPE benefits, for use in the screening tools, are presented in Appendix 2.

Exhibit 6-2. Incremental Benefit to New England Avoided Capacity Costs Resulting from Demand Reduction Induced Price Response

	FULL DRIPE BENEFIT 0.75% DEMAND REDUCTION FOR ALL NEW ENGLAND			
Units:	2005$/kWyr	2005$/kWh	nominal $/kWyr[1]	nominal $/kWh[1]
Comment:	Measured at Summer Coincident Peak	Expressed in $/kWh at 100% load factor	Measured at Summer Coincident Peak	Expressed in $/kWh at 100% load factor
2005 [2]	0.00	0.000	0.00	0.000
2006	612.51	0.070	626.29	0.071
2007	690.16	0.079	721.56	0.082
2008	53.75	0.006	57.46	0.007
2009	372.68	0.043	407.37	0.047
2010	289.32	0.033	323.37	0.037
2011	205.97	0.024	235.38	0.027
2012	122.61	0.014	143.27	0.016
2013	144.48	0.016	172.63	0.020
2014	166.35	0.019	203.23	0.023
2015	188.22	0.021	235.12	0.027
2016	210.09	0.024	268.35	0.031
2017	228.03	0.026	297.82	0.034
2018	245.98	0.028	328.49	0.037
2019	263.92	0.030	360.38	0.041
2020	281.87	0.032	393.54	0.045
2021	266.05	0.030	379.82	0.043
2022	250.24	0.029	365.29	0.042
2023	234.43	0.027	349.91	0.040
2024	218.62	0.025	333.65	0.038
2025	202.81	0.023	316.48	0.036
2026	186.99	0.021	298.37	0.034
2027	171.18	0.020	279.29	0.032
2028	155.37	0.018	259.20	0.030
2029	139.56	0.016	238.06	0.027
2030	123.75	0.014	215.83	0.025
2031	113.76	0.013	202.88	0.023
2032	103.77	0.012	189.23	0.022
2033	93.78	0.011	174.87	0.020
2034	83.80	0.010	159.76	0.018
2035	73.81	0.008	143.88	0.016
2036	63.82	0.007	127.21	0.015
2037	53.83	0.006	109.72	0.013
2038	43.85	0.005	91.37	0.010
2039	33.86	0.004	72.15	0.008
2040	23.87	0.003	52.01	0.006
Levelized[3]				
2005-2040	203.308	0.023	278.900	0.031
2006-2040	211.479	0.024	294.510	0.032
2006-2010	407.583	0.047	435.114	0.049
2006-2015	292.618	0.033	328.824	0.037
2006-2020	278.388	0.032	328.358	0.037

1. Assuming annual inflation rate of 2.25 percent.
2. The DRIPE scenarios did not include a demand curve response for 2005; no DRIPE value is therefore associated with 2005.
3. Real values are levelized at a 2.03 percent discount rate; nominal are levelized at a 4.32 percent discount rate.

The fields included in this table are shown in a $/kWyr and a $/kWh (taken at 100 percent load factor) in real and nominal dollars. Field descriptions are provided below for the $/kWyr and $/kWh values. The interpretation is the same whether in real or nominal dollars.

DRIPE 0.75% Incremental Benefit at Summer Coincident Peak ($/kW-yr): The incremental benefit related to price and supply responsiveness to an expected reduction in peak demand. The value represents the incremental savings above the avoided cost attributable to a 0.75 percent peak load reduction at summer coincident peak and is not applicable to energy savings. The DRIPE benefit is not applicable to short-term demand response resources since these resources would not provide a permanent load reduction expectation. The DRIPE benefit presented should only be applied to those energy efficiency programs which can be demonstrated to impact peak load.

DRIPE 0.75% Capacity Price ($/kWh): The annual avoided costs for DRIPE are converted to $/kWh at 100 percent load factor. This field represents the average savings for every hour (8760 hours). This value reflects only capacity savings and should not be applied to potential energy savings. This value is presented for informational purposes only at the request of the Study Group.

Scope of the Analysis

In general, the DRIPE equilibrium capacity benefit analysis presented herein is not conservative in nature because of the assumptions driving the results. The analysis assumes that the DRIPE benefit based on the savings in total expenditures for capacity is realized immediately once the demand savings are realized. However, two contributing factors may delay the responsiveness. First, since the energy efficiency benefits must be demonstrated before they are recognized as a coincident peak reduction, the benefit would be delayed up to one year if the LICAP peak demand curve is set annually. That is, the peak reduction and associated shift in the demand curve would be recognized only after the fact, delaying the price responsiveness until the point at which a new demand curve is established. Second, since approximately 90 percent of the current demand for capacity is satisfied through bilateral contracts, one would expect that some lagged effect would be in place to the extent that those contracts are not indexed to the market. As the LICAP market matures and existing contracts expire and are replaced by new agreements, the lag would become more and more abbreviated.

In addition, the DRIPE benefit captures both the direct price effect (illustrated in Exhibit 6-1) and the potential effect associated with reducing the requirement for reliability must run (RMR) units. Since RMR units are considered as required units to maintain system stability in peak conditions, a measurable reduction in peak demand will affect the need for these units. Hence the costs of maintaining these units to load serving entities has the potential to be reduced through demand savings and is included in the DRIPE values presented for coincident peak savings.

To some extent, this lack of conservatism is countered by the narrow scope considered for DRIPE. As discussed earlier, the DRIPE analysis does not consider the potential for price responsiveness in the energy markets and as such may understate the total benefit. Also, the choice of use of the demand reduction of 0.75%, as opposed to 1.0%, was a conservative assumption. However, the assumptions reflecting the immediate realization of the DRIPE benefit are by far the dominant assumption.

Since this analysis did not measure the potential lag effects on the DRIPE benefit, an alternate benefit calculation, which the Study Group termed “DRIPE Light”, was calculated and is presented in the following section. This is followed by a discussion of the methodology used to calculate the Incremental DRIPE effect.

DRIPE Light Benefits

The DRIPE benefits presented in Exhibit 6-2 represent the capacity payments that would be saved if all load cleared in the spot market. Since many load serving entities currently have bilateral contracts in place and are expected to cover positions at least to some extent going forward, it is possible that Load Serving Entities (LSE) may not be able to realize the full price response associated with demand reduction. DRIPE Light assumes that only those capacity transactions which occur on the spot market are able to realize the savings associated with price response. To estimate the share of capacity cleared in the spot market, ICF relied on the ISO New England's 2004 Annual Markets Report and the ISO New York annual market reports, which indicated that roughly 10 percent of the market transacted in the spot market. Based on this information, the DRIPE savings were calculated for only 10 percent of the total MW.

Savings under DRIPE Light may also affect out-of-market costs. Unlike capacity prices, the out-of-market savings associated with the peak demand reductions in the DRIPE Light scenario are equivalent to those in the full DRIPE scenario.

DRIPE Light is a much more conservative approximation of DRIPE than is the "Full DRIPE" scenario. Although it is likely that bilateral transactions will continue to occur for capacity transactions, it is also likely that these contracts will be indexed to the market in some form or will be shorter-term transactions. As such, it is unlikely that all capacity currently contracted bilaterally will be unaffected should spot market capacity clearing prices fall due to demand reductions over the long-term horizon of this study. It is more likely that all capacity will be affected to some extent, but even the capacity which is contracted bilaterally will experience some lagging effect following the spot market changes. Given the confidential nature of bilateral contracts, it is not possible to estimate without significant research or broad based assumptions, the quantity of capacity with long-term contracts that are currently indexed to market. Nor is it possible to estimate the term periods associated with current contracts.

DRIPE Light savings are presented in Exhibit 6-3 for all of New England for reference purposes. Zonal savings to be used in the screening models are presented in Appendix 2.

Exhibit 6-3. Incremental Benefit to New England Avoided Capacity Costs Resulting from Demand Reduction Induced Price Response – Light Alternative

	DRIPE LIGHT BENEFIT 0.75% DEMAND REDUCTION FOR ALL NEW ENGLAND			
Units:	**2005$/kWyr**	**2005$/kWh**	**nominal $/kWyr[1]**	**nominal $/kWh[1]**
Comment:	Measured at Summer Coincident Peak	Expressed in $/kWh at 100% load factor	Measured at Summer Coincident Peak	Expressed in $/kWh at 100% load factor
2005[2]	0.00	0.000	0.00	0.000
2006	67.09	0.008	68.60	0.008
2007	101.30	0.012	105.91	0.012
2008	64.78	0.007	69.25	0.008
2009	80.08	0.009	87.53	0.010
2010	70.20	0.008	78.46	0.009
2011	60.31	0.007	68.93	0.008
2012	50.43	0.006	58.93	0.007
2013	62.84	0.007	75.08	0.009
2014	75.25	0.009	91.93	0.010
2015	87.66	0.010	109.50	0.012
2016	100.06	0.011	127.81	0.015
2017	100.28	0.011	130.98	0.015
2018	100.51	0.011	134.22	0.015
2019	100.73	0.011	137.54	0.016
2020	100.95	0.012	140.95	0.016
2021	97.15	0.011	138.70	0.016
2022	93.35	0.011	136.27	0.016
2023	89.56	0.010	133.67	0.015
2024	85.76	0.010	130.88	0.015
2025	81.96	0.009	127.90	0.015
2026	78.16	0.009	124.72	0.014
2027	74.36	0.008	121.33	0.014
2028	70.57	0.008	117.72	0.013
2029	66.77	0.008	113.89	0.013
2030	62.97	0.007	109.83	0.013
2031	58.91	0.007	105.07	0.012
2032	54.86	0.006	100.04	0.011
2033	50.80	0.006	94.72	0.011
2034	46.75	0.005	89.12	0.010
2035	42.69	0.005	83.22	0.010
2036	38.63	0.004	77.01	0.009
2037	34.58	0.004	70.47	0.008
2038	30.52	0.003	63.61	0.007
2039	26.47	0.003	56.39	0.006
2040	22.41	0.003	48.83	0.006
Levelized[3]				
2005-2040	69.295	0.023	95.060	0.031
2006-2040	72.080	0.008	100.380	0.012
2006-2010	76.746	0.009	81.930	0.009
2006-2015	72.108	0.008	81.031	0.009
2006-2020	80.638	0.009	95.113	0.011

1. Assuming annual inflation rate of 2.25 percent.
2. The DRIPE Light scenarios did not include a demand curve response for 2005; no DRIPE Light value is therefore associated with 2005.
3. Real values are levelized at a 2.03 percent discount rate; nominal are levelized at a 4.32 percent discount rate.

The fields presented for DRIPE Light are consistent with the description provided for Full DRIPE following Exhibit 6-2 above.

Methodology

As discussed earlier, the DRIPE savings are estimated using a scenario based modeling approach. This approach includes four main steps.

The first step is to determine the change in capacity price from the Reference Case and the 0.75 percent Peak Demand Reduction Case. Both cases rely on the same construct for the LICAP market including the use of LICAP demand curves[16]. The change in capacity price is identified for the 5 LICAP regions: Southwest Connecticut; Rest of Connecticut; Boston; Maine; and Rest of Pool. Movements in the capacity price result from shifts in the demand curve (direct DRIPE effect) for the LICAP zone and from shifts in the supply for the LICAP zone as a whole. The shift in LICAP supply resources results from the market reaction to the lower peak demand levels. Supply-side changes may include changes in capacity transfers across regions, changes in unit retirements; change in mothball activity; and/or changes in the construction of new capacity. Step 1 does not vary between DRIPE and DRIPE Light.

A sample of the market reaction to demand reductions at peak is shown in Exhibits 6-4 and 6-5 for Southwest Connecticut. Note the exhibits present the values for Southwest Connecticut produced directly from the IPM modeling analysis. Exhibit 6-4 is an illustration of the SWCT LICAP demand curve showing the price at varying levels of objective capability and is provided for reference purposes. The implied market reserve margin at the varying levels of capability, based on a 12 percent reserve requirement, is also shown in the exhibit. The shape of this curve does not vary from the Base (Reference Case) to the Sensitivity (0.75% Demand Reduction Scenario). Exhibit 6-5 illustrates the clearing point for the capacity price in the Southwest Connecticut LICAP zone. The market clearing capacity price is determined by the point at which supply and demand are equal. Based on the amount of surplus capacity supplied (RM Capacity in Exhibit 6-5), the resulting reserve margin is calculated. One can estimate the expected clearing price by finding the price for the implied reserve margin in Exhibit 6-4. The actual clearing prices resulting form the full linear optimization modeling exercise are provided labeled as “Price from Run” in Exhibit 6-5. The values shown as “Price from Run” are used to determine the DRIPE benefit discussed below. Results are shown for actual model run years for both cases. Appendix 2 provides results for the complete set of calendar years over the planning horizon; the calendar year results are interpolated from the run year results presented here.

The second step is to calculate the difference in total locational payment for capacity in dollars between the Reference Case and 0.75 Peak Demand Reduction Scenario. In any

[16] See Chapter Two Exhibit 2-11 and related discussion.

given scenario, this total payment is calculated as the megawatts of supply side resources multiplied by the capacity price ("Price from Run" in Exhibit 6-5). The difference between the total capacity payment in each scenario is then calculated (shown as column h in Exhibit 6-6). This total benefit is comprised of two key components: 1) the avoided cost associated with the demand reduction (area A-Q1-Q2-C in Exhibit 6-1); and 2) the price response effect. The avoided cost is calculated as the total load reduction times the initial Reference Case price (column (i) in Exhibit 6-6). To determine the price response effect, the avoided cost is subtracted from the total benefit identified earlier (column (h) – column (i) in Exhibit 6-6). Alternately, one can isolate the price effect as the new supply quantity times the change in price. However, since the avoided costs are measured using the change in demand rather than the change in the market clearing quantity of capacity[17], one must also determine if any indirect effects are present that contribute to DRIPE related to changes in the supply. These calculations are illustrated in Exhibit 6-6 for the full DRIPE scenario for Southwest Connecticut.

[17] Under the LICAP design a change in the peak demand for capacity will not necessarily result in the same change in the quantity of capacity cleared in the marketplace. That is, since the reserve margin is not required to be constant, the change in the quantity of capacity supplied at the equilibrium price may vary from the change in demand.

Exhibit 6-4. Example of Change in Capacity Price Due to Demand Reduction – Demand Curve for Southwest Connecticut

Actual Demand Curves Capability	Implied Reserve Margin	Market Implied Annual Price (2005$/kW-yr) SWCT/ NOR
0	0.000	188.24
1.000	1.120	152.77
1.013	1.134	132.28
1.025	1.148	111.79
1.038	1.163	91.31
1.040	1.165	89.52
1.042	1.167	87.73
1.045	1.170	85.93
1.047	1.172	84.14
1.049	1.175	82.35
1.051	1.177	80.56
1.053	1.180	78.77
1.056	1.182	76.98
1.058	1.185	75.19
1.060	1.187	73.40
1.062	1.190	71.61
1.064	1.192	69.82
1.067	1.195	68.03
1.069	1.197	66.24
1.071	1.199	64.45
1.073	1.202	62.66
1.075	1.204	60.87
1.078	1.207	59.08
1.080	1.209	57.29
1.082	1.212	55.50
1.084	1.214	53.71
1.086	1.217	51.92
1.089	1.219	50.13
1.091	1.222	48.34
1.093	1.224	46.55
1.095	1.227	44.76
1.097	1.229	42.97
1.099	1.231	41.18
1.102	1.234	39.39
1.104	1.236	37.60
1.106	1.239	35.81
1.108	1.241	34.02
1.110	1.244	32.23
1.113	1.246	30.44
1.115	1.249	28.64
1.117	1.251	26.85
1.119	1.254	25.06
1.121	1.256	23.27
1.124	1.258	21.48
1.126	1.261	19.69
1.128	1.263	17.90
1.130	1.266	16.11
1.132	1.268	14.32
1.135	1.271	12.53
1.137	1.273	10.74
1.139	1.276	8.95
1.141	1.278	7.16
1.143	1.281	5.37
1.146	1.283	3.58
1.148	1.286	1.79
1.150	1.288	0.00

EBCC (2005$/kWmo	1.038	8.08
Target price (2005$/kWmo)	1.054	6.60
EBCC (2005$/kWyr	1.038	96.94
Target price (2005$/kWyr)	1.054	79.20

Note: Prices are shown after benchmark generator rent (i.e. discounted $0.47/kWmo). All prices shown in real 2005$; original LICAP curves converted from 2006$ using a 2.25% annual inflation rate.

Exhibit 6-5. Example of Change in Capacity Price Due to Demand Reduction – Capacity Price Change in Southwest Connecticut

2006

LICAP Zone Aggregation	**SWCT - Base**	**SWCT - Sens**
PEAK DEMAND	3,676	3,648
RM CAPACITY	4,480	4,460
DRIVER		transfer / capacity change: mothball more, import less - supply decrease 19-20 MW
Calculated Reserve Margin	1.2187	1.2224
Estimated Price from demand curve	51.02	47.44
Price from Run	48.86	47.48

2007

LICAP Zone Aggregation	**SWCT - Base**	**SWCT - Sens**
PEAK DEMAND	3,722	3,694
RM CAPACITY	4522	4486
DRIVER		transfers marginal, MW decrease carryover: import less - supply decrease 32 MW total due to mothball in prior year
Calculated Reserve Margin	1.2149	1.2144
Estimated Price from demand curve	52.81	52.81
Price from Run	51.99	51.99

2008

LICAP Zone Aggregation	**SWCT - Base**	**SWCT - Sens**
PEAK DEMAND	3,771	3,743
RM CAPACITY	4501	4482
DRIVER		MW decrease carryover: - supply decrease 19 MW total due to mothball in prior year
Calculated Reserve Margin	1.1936	1.1975
Estimated Price from demand curve	68.93	65.35
Price from Run	66.34	66.19

2009

LICAP Zone Aggregation	**SWCT - Base**	**SWCT - Sens**
PEAK DEMAND	3,820	3,791
RM CAPACITY	4543	4524
		MW decrease carryover: - supply decrease 19 MW total due to mothball in prior year
Calculated Reserve Margin	1.1893	1.1932
Estimated Price from demand curve	72.51	68.93
Price from Run	70.93	69.07

2012

LICAP Zone Aggregation	**SWCT - Base**	**SWCT - Sens**
PEAK DEMAND	3,986	3,956
RM CAPACITY	4688	4692
DRIVER		Builds delayed, earlier mothball fail to return to service, capacity decrease supplemented by additional imports from CT: supply increases by 4 MW
Calculated Reserve Margin	1.1761	1.1860
Estimated Price from demand curve	81.46	74.30
Price from Run	79.11	78.10

2016

LICAP Zone Aggregation	**SWCT - Base**	**SWCT - Sens**
PEAK DEMAND	4,182	4,151
RM CAPACITY	4917	4889
DRIVER		Earlier delayed builds occur, total import increases to supplement for units that did not retrun to service: supply decrease total of 28 MW
Calculated Reserve Margin	1.1758	1.1779
Estimated Price from demand curve	81.46	79.67
Price from Run	80.37	78.81

2020

LICAP Zone Aggregation	**SWCT - Base**	**SWCT - Sens**
PEAK DEMAND	4,414	4,381
RM CAPACITY	5209	5181
DRIVER		Less capacity retires (had expected retirements in Base Case, in Sensitivity, less MW retire), total import increases: supply decrease total 28 MW
Calculated Reserve Margin	1.1801	1.1826
Estimated Price from demand curve	77.88	76.09
Price from Run	77.16	75.67

2030

LICAP Zone Aggregation	**SWCT - Base**	**SWCT - Sens**
PEAK DEMAND	5,052	5,014
RM CAPACITY	5963	5955
DRIVER		Carryover of MW, total import increases: supply decrease total 8 MW
Calculated Reserve Margin	1.1803	1.1876
Estimated Price from demand curve	77.88	72.51
Price from Run	78.80	77.74

NOTES: Estimated Price and Actual model result will not match due to 1) rounding; 2) step-wise linear approximation of the demand curve in the modeling analysis; 3) simple average approximation used in the estimate; 4) simplistic estimate of economic rent. The values are illustrative in nature only, used only to demonstrate the expected movement in the resulting capacity price due to the reduction of peak load (0.75 percent) from the Base (Reference Case) to the Sensitivity (0.75% Demand Reduction Scenario).

Exhibit 6-6. Example of Calculation of Difference in Total Market Payments for Capacity under Full DRIPE for Southwest Connecticut

Zone	Year	Base Case Capacity Value ($/kW)	Sensitivity Case Capacity Value ($/kW)	Base Case Supply (kW)	Senstivity Case Supply (kW)	Total Change in Demand from Base to Sensitivity Case (kW)	Base Case Capacity Payment ($)	Sensitivity Case Capacity Payment ($)	Total Change in Capacity Payments due to Demand Reduction ($)	Avoided Capacity Cost Credited to Demand Reduction ($)	Dollar Impact of Change in Capacity Price Due to Demand Reduction ($)	Dollar Impact of Change in Supply Due to Demand Reduction ($)	Full Incremental Market Value of Demand Reduction above Avoided Cost ($)	Total Change in Capacity Payments due to Demand Reduction ($/kW)	Dollar Impact of Change in Capacity Price Due to Demand Reduction ($/kW)	Dollar Impact of Change in Supply Due to Demand Reduction ($/kW)	Full Incremental Market Value of Demand Reduction above Avoided Cost ($/kW)
		(a)	(b)	(c)	(d)	(e)	(f) = (a) * (c)	(g) = (b) * (d)	(h) = (f) - (g)	(i) = (a) * (e)	(j) = (d) *[(a)-(b)]	(k) = {[(g)-(h)]-(e)}*(a)	(l) = (j) + (k) = (h) - (i)	(m) = (h) / (e)	(n) = (j) / (e)	(m) = (k) / (e)	(o) = (n) + (m)
Norwalk (RTEP)	2006	48.86	47.48	369,000	350,000	9,848	18,030,336	16,619,582	$ 1,410,754	$ 481,175	$ 482,363	$ 447,216	$ 929,578	143.26	48.98	45.41	94.40
Norwalk (RTEP)	2007	51.99	51.99	371,000	352,000	9,960	19,290,116	18,302,213	$ 987,904	$ 517,869	$ -	$ 470,034	$ 470,034	99.19	-	47.19	47.19
Norwalk (RTEP)	2008	66.34	66.19	476,000	457,000	10,087	31,578,083	30,250,813	$ 1,327,270	$ 669,210	$ 66,800	$ 591,260	$ 658,060	131.58	6.62	58.61	65.24
Norwalk (RTEP)	2009	70.93	69.07	517,000	498,000	10,208	36,673,105	34,394,641	$ 2,278,463	$ 724,063	$ 930,709	$ 623,691	$ 1,554,400	223.21	91.18	61.10	152.28
Norwalk (RTEP)	2012	79.11	78.10	1,320,000	1,249,000	10,627	104,424,598	97,542,892	$ 6,881,705	$ 840,737	$ 1,264,928	$ 4,776,041	$ 6,040,969	647.54	119.02	449.40	568.43
Norwalk (RTEP)	2016	80.37	78.81	1,650,000	1,587,000	11,122	132,615,243	125,066,332	$ 7,548,911	$ 893,947	$ 2,485,420	$ 4,169,544	$ 6,654,964	678.71	223.46	374.87	598.33
Norwalk (RTEP)	2020	77.16	75.67	1,496,000	1,470,000	11,708	115,427,058	111,241,571	$ 4,185,487	$ 903,317	$ 2,179,402	$ 1,102,768	$ 3,282,170	357.50	186.15	94.19	280.35
Norwalk (RTEP)	2030	78.80	77.74	1,653,000	1,618,000	13,297	130,250,319	125,786,242	$ 4,464,077	$ 1,047,794	$ 1,706,206	$ 1,710,077	$ 3,416,283	335.71	128.31	128.60	256.91
Norwalk (RTEP)	2040	36.46	36.15	1,653,000	1,618,000	15,105	60,266,876	58,484,014	$ 1,782,862	$ 550,715	$ 506,794	$ 725,354	$ 1,232,147	118.03	33.55	48.02	81.57
SWCT (RTEP)	2006	48.86	47.48	4,111,000	4,110,000	17,722	200,874,553	195,161,376	$ 5,713,177	$ 865,969	$ 5,664,314	$ (817,106)	$ 4,847,208	322.37	319.61	(46.11)	273.51
SWCT (RTEP)	2007	51.99	51.99	4,151,000	4,134,000	17,955	215,830,924	214,947,010	$ 883,914	$ 933,569	$ -	$ (49,655)	$ (49,655)	49.23	-	(2.77)	(2.77)
SWCT (RTEP)	2008	66.34	66.19	4,025,000	4,025,000	18,195	267,020,551	266,432,215	$ 588,336	$ 1,207,066	$ 588,336	$ (1,207,066)	$ (618,729)	32.34	32.34	(66.34)	(34.01)
SWCT (RTEP)	2009	70.93	69.07	4,026,000	4,026,000	18,442	285,582,049	278,057,883	$ 7,524,166	$ 1,308,208	$ 7,524,166	$ (1,308,208)	$ 6,215,958	407.98	407.98	(70.93)	337.05
SWCT (RTEP)	2012	79.11	78.10	3,368,000	3,443,000	19,267	266,440,944	268,887,252	$ (2,446,309)	$ 1,524,243	$ 3,486,907	$ (7,457,459)	$ (3,970,552)	(126.97)	180.97	(387.05)	(206.08)
SWCT (RTEP)	2016	80.37	78.81	3,267,000	3,302,000	20,242	262,578,180	260,219,929	$ 2,358,252	$ 1,626,948	$ 5,171,302	$ (4,439,999)	$ 731,304	116.50	255.47	(219.34)	36.13
SWCT (RTEP)	2020	77.16	75.67	3,713,000	3,711,000	21,398	286,484,402	280,828,210	$ 5,656,191	$ 1,650,970	$ 5,501,877	$ (1,496,655)	$ 4,005,222	264.34	257.13	(69.95)	187.18
SWCT (RTEP)	2030	78.80	77.74	4,310,000	4,337,000	24,592	339,612,145	337,166,212	$ 2,445,933	$ 1,937,799	$ 4,573,434	$ (4,065,299)	$ 508,135	99.46	185.97	(165.31)	20.66
SWCT (RTEP)	2040	36.46	36.15	4,310,000	4,337,000	28,267	157,138,679	156,764,629	$ 374,050	$ 1,030,607	$ 1,358,446	$ (2,015,003)	$ (656,557)	13.23	48.06	(71.28)	(23.23)
SWCT (LICAP)	2006	48.86	47.48	4,480,000	4,460,000	27,570	218,904,888	211,780,958	$ 7,123,931	$ 1,347,145	$ 6,146,677	$ (369,891)	$ 5,776,786	258.39	222.95	(13.42)	209.53
SWCT (LICAP)	2007	51.99	51.99	4,522,000	4,486,000	27,915	235,121,040	233,249,223	$ 1,871,817	$ 1,451,438	$ -	$ 420,379	$ 420,379	67.05	-	15.06	15.06
SWCT (LICAP)	2008	66.34	66.19	4,501,000	4,482,000	28,283	298,598,634	296,683,028	$ 1,915,606	$ 1,876,275	$ 655,136	$ (615,806)	$ 39,330	67.73	23.16	(21.77)	1.39
SWCT (LICAP)	2009	70.93	69.07	4,543,000	4,524,000	28,650	322,255,154	312,452,524	$ 9,802,630	$ 2,032,272	$ 8,454,876	$ (684,517)	$ 7,770,358	342.15	295.11	(23.89)	271.22
SWCT (LICAP)	2012	79.11	78.10	4,688,000	4,692,000	29,895	370,865,541	366,430,145	$ 4,435,397	$ 2,364,980	$ 4,751,835	$ (2,681,418)	$ 2,070,417	148.37	158.95	(89.69)	69.26
SWCT (LICAP)	2016	80.37	78.81	4,917,000	4,889,000	31,365	395,193,423	385,286,260	$ 9,907,163	$ 2,520,895	$ 7,656,722	$ (270,455)	$ 7,386,267	315.87	244.12	(8.62)	235.49
SWCT (LICAP)	2020	77.16	75.67	5,209,000	5,181,000	33,105	401,911,459	392,069,781	$ 9,841,678	$ 2,554,287	$ 7,681,279	$ (393,887)	$ 7,287,392	297.29	232.03	(11.90)	220.13
SWCT (LICAP)	2030	78.80	77.74	5,963,000	5,955,000	37,890	469,862,464	462,952,454	$ 6,910,010	$ 2,985,593	$ 6,279,640	$ (2,355,222)	$ 3,924,418	182.37	165.73	(62.16)	103.57
SWCT (LICAP)	2030	36.46	36.15	5,963,000	5,955,000	43,372	217,405,555	215,248,643	$ 2,156,912	$ 1,581,322	$ 1,865,240	$ (1,289,649)	$ 575,590	49.73	43.01	(29.73)	13.27

The third step of the DRIPE calculation is to determine if any change in out-of-market costs occurs between the two scenarios and how much of this change is considered incremental to the avoided cost. Any incremental benefit will be directly related to a cost savings in the out-of-market expenses rather than a price response in the market. The out-of-market cost determination is consistent in the Reference and the 0.75 percent Peak Demand Reduction Cases and utilizes the methodology described in Chapter 3. Since out-of-market costs are independent of the megawatts cleared in the spot and bilateral markets, these costs do not vary across the DRIPE and DRIPE Light benefit. The per kilowatt dollar value is calculated as the total change in out-of-market costs in dollars divided by the change in the peak demand between the two cases.

Exhibit 6-7 presents the difference in out-of-market costs for the Southwest Connecticut area.

Exhibit 6-7. Southwest Connecticut Sub-regional Out-of-Market Cost Change Due to Demand Reduction

Zone	Year	OUT OF MARKET COST CHANGE DRIVER	Total Out-of-Market Cost Base Case ($/kWyr)	Change in Total Out-of-Market Cost due to Demand Reduction ($)	Change Peak Demand (kW(per yr))	Avoided Out of Market Cost due to Demand Reduction ($)	Incremental Change in Out-of-Market Payments due to Demand Reduction ($)	Incremental Impact due to Demand Reduction ($/kW)
			(a)	(b)	(c)	(d)= (c) *(a)	(e) = (b) - (d)	(f) = (e) / (c)
Norwalk	2006	Greater Mothball - > less fixed cost requirements, out of market costs decrease (fewer resources paid at lower capacity price)	14.667	$ 6,388,733	9,848	144,430	6,244,302	634.10
Norwalk	2007	Carryover of Prior Year Mothball - > less fixed cost requirements, out of market costs decrease	14.312	$ 6,397,548	9,960	142,549	6,254,999	642.32
Norwalk	2008	Carryover of Prior Year Mothball - > less fixed cost requirements, out of market costs decrease	5.035	$ 6,397,548	10,087	50,793	6,346,755	634.21
Norwalk	2009	Carryover of Prior Year Mothball - > less fixed cost requirements, out of market costs decrease	4.889	$ 6,410,770	10,208	49,906	6,360,864	628.05
Norwalk	2012	Carryover of Prior Year Mothball - > less fixed requirements, out of market costs decrease	4.192	$ 5,976,882	10,627	44,548	5,932,334	562.40
Norwalk	2016	Out of Market costs no longer exist		$ -	11,122	-	-	0.00
Norwalk	2020	Out of Market costs no longer exist		$ -	11,708	-	-	0.00
Norwalk	2030	Out of Market costs no longer exist		$ -	13,297	-	-	0.00
Norwalk	2040	Out of Market costs no longer exist		$ -	15,105	-	-	0.00

The final step to determine the value of DRIPE combines the change in out-of-market costs and capacity costs attributable to the demand reduction. This involves summing the previously calculated difference in market based capacity expenditures (Exhibit 6-6 column (l)) and the out-of market payments (Exhibit 6-7 column (e)) between the Reference Case and the 0.75% Demand Reduction Scenario by area. This amount is divided by the change in peak demand between the cases to determine the $/kW savings per year. Exhibit 6-8 illustrates this calculation for the full DRIPE sensitivity for Southwest Connecticut.

Exhibit 6-8. Example of the Calculation of DRIPE for Southwest Connecticut

Zone	Year	Total Change in Market Capacity Payments ($)	Total Change in Out-of-Market Payments ($)	Total Change in Payments ($)	Total Change in Demand (kW)	Total Dollar Impact of Change in Capacity Price ($/kW)	Full Incremental Market Value of Demand Reduction above Avoided Cost ($)	Incremental Change in Out-of-Market Payments due to Demand Reduction ($)	Dollar Impact of Change in Capacity Price ($/kW)
		(a)	(b)	(c) = (a) + (b)	(d)	(e) = (c) / (d)	(f)	(g)	(h) = [(f) + (g)] / (d)
Norwalk (RTEP)	2006	$ 1,410,754	$ 6,388,733	$ 7,799,487	9,848	792.03	$ 929,578	$ 6,244,302	728.50
Norwalk (RTEP)	2007	$ 987,904	$ 6,397,548	$ 7,385,451	9,960	741.51	$ 470,034	$ 6,254,999	675.20
Norwalk (RTEP)	2008	$ 1,327,270	$ 6,397,548	$ 7,724,817	10,087	765.78	$ 658,060	$ 6,346,755	694.41
Norwalk (RTEP)	2009	$ 2,278,463	$ 6,410,770	$ 8,689,234	10,208	851.26	$ 1,554,400	$ 6,360,864	775.44
Norwalk (RTEP)	2012	$ 6,881,705	$ 5,976,882	$ 12,858,588	10,627	1,209.94	$ 6,040,969	$ 5,932,334	1,126.63
Norwalk (RTEP)	2016	$ 7,548,911	$ -	$ 7,548,911	11,122	678.71	$ 6,654,964	$ -	598.33
Norwalk (RTEP)	2020	$ 4,185,487	$ -	$ 4,185,487	11,708	357.50	$ 3,282,170	$ -	280.35
Norwalk (RTEP)	2030	$ 4,464,077	$ -	$ 4,464,077	13,297	335.71	$ 3,416,283	$ -	256.91
Norwalk (RTEP)	2040	$ 1,782,862	$ -	$ 1,782,862	15,105	118.03	$ 1,232,147	$ -	81.57
SWCT (RTEP)	2006	$ 5,713,177	$ -	$ 5,713,177	17,722	322.37	$ 4,847,208	$ -	273.51
SWCT (RTEP)	2007	$ 883,914	$ -	$ 883,914	17,955	49.23	$ (49,655)	$ -	(2.77)
SWCT (RTEP)	2008	$ 588,336	$ -	$ 588,336	18,195	32.34	$ (618,729)	$ -	(34.01)
SWCT (RTEP)	2009	$ 7,524,166	$ -	$ 7,524,166	18,442	407.98	$ 6,215,958	$ -	337.05
SWCT (RTEP)	2012	$ (2,446,309)	$ -	$ (2,446,309)	19,267	(126.97)	$ (3,970,552)	$ -	(206.08)
SWCT (RTEP)	2016	$ 2,358,252	$ -	$ 2,358,252	20,242	116.50	$ 731,304	$ -	36.13
SWCT (RTEP)	2020	$ 5,656,191	$ -	$ 5,656,191	21,398	264.34	$ 4,005,222	$ -	187.18
SWCT (RTEP)	2030	$ 2,445,933	$ -	$ 2,445,933	24,592	99.46	$ 508,135	$ -	20.66
SWCT (RTEP)	2040	$ 374,050	$ -	$ 374,050	28,267	13.23	$ (656,557)	$ -	(23.23)
SWCT (LICAP)	2006	$ 7,123,931	$ 6,388,733	$ 13,512,664	27,570	490.12	$ 5,776,786	$ 6,244,302	436.02
SWCT (LICAP)	2007	$ 1,871,817	$ 6,397,548	$ 8,269,365	27,915	296.23	$ 420,379	$ 6,254,999	239.13
SWCT (LICAP)	2008	$ 1,915,606	$ 6,397,548	$ 8,313,154	28,283	293.93	$ 39,330	$ 6,346,755	225.80
SWCT (LICAP)	2009	$ 9,802,630	$ 6,410,770	$ 16,213,400	28,650	565.91	$ 7,770,358	$ 6,360,864	493.24
SWCT (LICAP)	2012	$ 4,435,397	$ 5,976,882	$ 10,412,279	29,895	348.29	$ 2,070,417	$ 5,932,334	267.70
SWCT (LICAP)	2016	$ 9,907,163	$ -	$ 9,907,163	31,365	315.87	$ 7,386,267	$ -	235.49
SWCT (LICAP)	2020	$ 9,841,678	$ -	$ 9,841,678	33,105	297.29	$ 7,287,392	$ -	220.13
SWCT (LICAP)	2030	$ 6,910,010	$ -	$ 6,910,010	37,890	182.37	$ 3,924,418	$ -	103.57
SWCT (LICAP)	2040	$ 2,156,912	$ -	$ 2,156,912	43,372	49.73	$ 575,590	$ -	13.27

The DRIPE Light analysis differs from the full DRIPE scenario in the assumption relating to participation in the spot market. DRIPE Light assumes that 10 percent of the market transacts at the spot value while the remainder of the market transacts at fixed bilateral contract prices. With the exception of the volumes, the methodology used to determine the DRIPE Light benefit is consistent with that used for Full DRIPE. Exhibit 6-9 combines the steps presented above to illustrate the DRIPE Light calculation. Here, the assumption is that the capacity under contract in the Base Case is equal to 10 percent of the total market clearing capacity under the LICAP curve in each year. It is further assumed that the sensitivity case does not affect the contracted capacity value. Hence the total quantity that participates in the spot market is equal to the total Sensitivity case supply minus the Base Case supply under contract where the Base Case supply under contract is equal to 90 percent of the total Base Case supply. Once the quantity participating in the spot market is determined, the total change in capacity expenses is calculates as the Base Case spot market payments less the Sensitivity Case spot market payments. As in the full DRIPE, the total change in out-of-market expenses is added to the total market change to determine the total benefit (column (l) in Exhibit 6-9). As in the full DRIPE, the avoided cost (demand reduction times capacity avoided cost from the Base Case) is then subtracted from the total benefit to determine the amount associated with the price and out-of market cost response. This is then divided by the demand reduction to determine a $/kW value.

Exhibit 6-9. Example of the Calculation of DRIPE Light for Southwest Connecticut

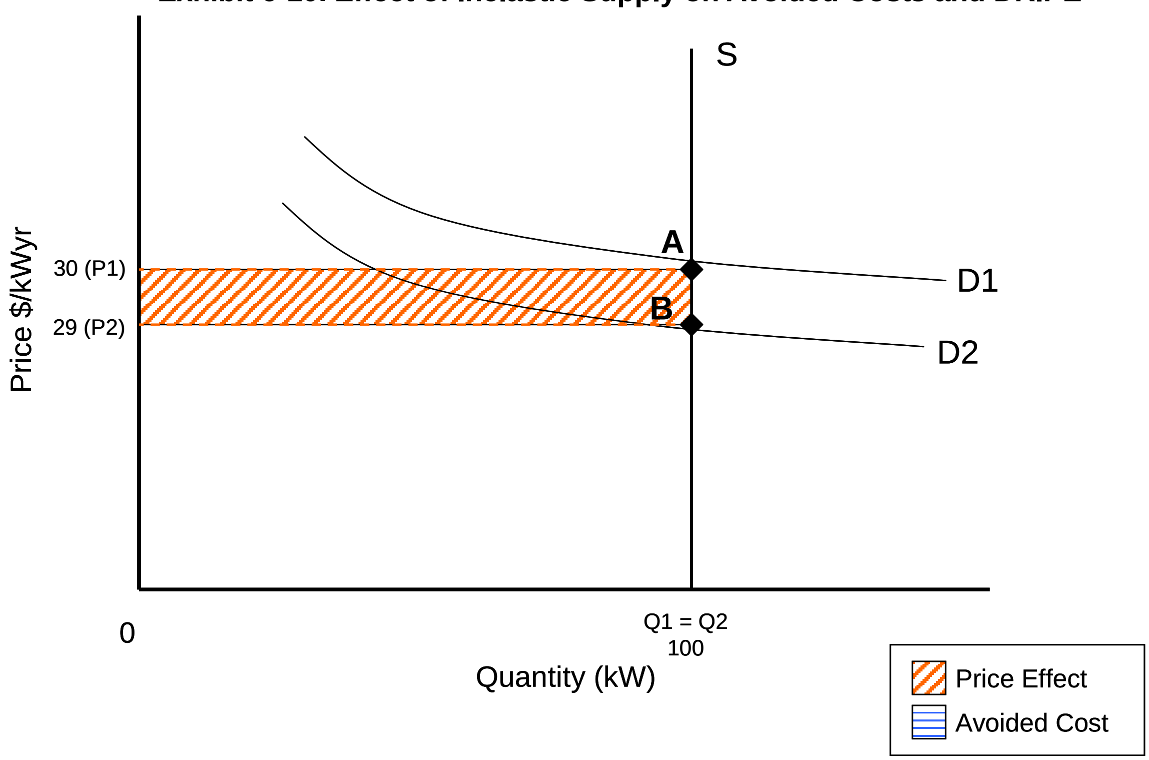
Zone	Year	Base Case Capacity Value ($/kW)	Sensitivity Case Capacity Value ($/kW)	Base Case Supply (kW)	Senstivity Case Supply (kW)	Total Change in Demand from Base to Sensitivity Case (kW)	Total Sensitivity Case Demand In Spot Market	Base Case SPOT Capacity Payment ($)	Sensitivity Case SPOT Capacity Payment ($)	Total Change in Market Capacity Payments ($)	Total Change in Out-of-Market Payments ($)	Total Change in Market and Out-of-Market Payments ($)	Total Dollar Impact of Change in Capacity Price ($/kW)	Avoided Capacity Cost Credited to Demand Reduction ($)	Full Incremental Market Value of Demand Reduction above Avoided Cost ($)	Incremental Change in Out-of-Market Payments due to Demand Reduction ($)	Dollar Impact of Change in Capacity Price ($/kW)
		(a)	(b)	(c)	(d)	(e)	(f)	(g) = (a) * [(c) *.1]	(h)=(b)*{(d)-(c)*.9]}	(i) = (g) - (h)	(j)	(k) = (i) + (j)	(l) = (k) / (e)	(m) = (a) * (e)	(n) = (i) - (m)	(o)	(p) = [(n) + (o)] / (e)
							Assumes Base Case Contract demand is not affected	*10% of Base Supply paid contract price*	*Assumes 90% of Base Supply paid contract price*					*Assumes 90% of initial demand participates in spot*			
	2006	48.86	47.48	369,000	350,000	9,848	121,453	1,803,034	849,973	$ 953,061	$ 6,388,733	$ 7,341,794	745.55	$ 481,175	$ 471,885	$ 6,244,302	682.02
	2007	51.99	51.99	371,000	352,000	9,960	122,840	1,929,012	941,108	$ 987,904	$ 6,397,548	$ 7,385,451	741.51	$ 517,869	$ 470,034	$ 6,254,999	675.20
	2008	66.34	66.19	476,000	457,000	10,087	124,412	3,157,808	1,893,158	$ 1,264,650	$ 6,397,548	$ 7,662,198	759.57	$ 669,210	$ 595,440	$ 6,346,755	688.20
	2009	70.93	69.07	517,000	498,000	10,208	125,893	3,667,310	2,258,443	$ 1,408,867	$ 6,410,770	$ 7,819,637	766.07	$ 724,063	$ 684,804	$ 6,360,864	690.24
Norwalk (RTEP)	2012	79.11	78.10	1,320,000	1,249,000	10,627	131,072	10,442,460	4,763,904	$ 5,678,556	$ 5,976,882	$ 11,655,438	1,096.72	$ 840,737	$ 4,837,819	$ 5,932,334	1,013.42
	2016	80.37	78.81	1,650,000	1,587,000	11,122	137,178	13,261,524	8,038,290	$ 5,223,235	$ -	$ 5,223,235	469.61	$ 893,947	$ 4,329,287	$ -	389.24
	2020	77.16	75.67	1,496,000	1,470,000	11,708	144,393	11,542,706	9,353,373	$ 2,189,333	$ -	$ 2,189,333	187.00	$ 903,317	$ 1,286,016	$ -	109.85
	2030	78.80	77.74	1,653,000	1,618,000	13,297	164,002	13,025,032	10,129,757	$ 2,895,275	$ -	$ 2,895,275	217.73	$ 1,047,794	$ 1,847,481	$ -	138.93
	2040	36.46	36.15	1,653,000	1,618,000	15,105	186,295	6,026,688	4,709,807	$ 1,316,881	$ -	$ 1,316,881	87.18	$ 550,715	$ 766,166	$ -	50.72
	2006	48.86	47.48	4,111,000	4,110,000	17,722	218,577	20,087,455	19,473,402	$ 614,054	$ -	$ 614,054	34.65	$ 865,969	$ (251,915)	$ -	(14.21)
	2007	51.99	51.99	4,151,000	4,134,000	17,955	221,445	21,583,092	20,699,179	$ 883,914	$ -	$ 883,914	49.23	$ 933,569	$ (49,655)	$ -	(2.77)
	2008	66.34	66.19	4,025,000	4,025,000	18,195	224,405	26,702,055	26,643,222	$ 58,834	$ -	$ 58,834	3.23	$ 1,207,066	$ (1,148,232)	$ -	(63.11)
	2009	70.93	69.07	4,026,000	4,026,000	18,442	227,457	28,558,205	27,805,788	$ 752,417	$ -	$ 752,417	40.80	$ 1,308,208	$ (555,792)	$ -	(30.14)
SWCT (RTEP)	2012	79.11	78.10	3,368,000	3,443,000	19,267	237,632	26,644,094	32,160,259	$ (5,516,164)	$ -	$ (5,516,164)	(286.29)	$ 1,524,243	$ (7,040,407)	$ -	(365.40)
	2016	80.37	78.81	3,267,000	3,302,000	20,242	249,657	26,257,818	28,504,406	$ (2,246,588)	$ -	$ (2,246,588)	(110.98)	$ 1,626,948	$ (3,873,536)	$ -	(191.36)
	2020	77.16	75.67	3,713,000	3,711,000	21,398	263,903	28,648,440	27,946,607	$ 701,833	$ -	$ 701,833	32.80	$ 1,650,970	$ (949,136)	$ -	(44.36)
	2030	78.80	77.74	4,310,000	4,337,000	24,592	303,307	33,961,215	35,605,747	$ (1,644,533)	$ -	$ (1,644,533)	(66.87)	$ 1,937,799	$ (3,582,331)	$ -	(145.67)
	2040	36.46	36.15	4,310,000	4,337,000	28,267	348,633	15,713,868	16,554,807	$ (840,940)	$ -	$ (840,940)	(29.75)	$ 1,030,607	$ (1,871,547)	$ -	(66.21)
	2006	48.86	47.48	4,480,000	4,460,000	27,570	340,030	21,890,489	20,323,374	$ 1,567,114	$ -	$ 1,567,114	56.84	$ 1,347,145	$ 219,970	$ 6,244,302	234.47
	2007	51.99	51.99	4,522,000	4,486,000	27,915	344,285	23,512,104	21,640,287	$ 1,871,817	$ -	$ 1,871,817	67.05	$ 1,451,438	$ 420,379	$ 6,254,999	239.13
	2008	66.34	66.19	4,501,000	4,482,000	28,283	348,818	29,859,863	28,536,380	$ 1,323,484	$ -	$ 1,323,484	46.80	$ 1,876,275	$ (552,792)	$ 6,346,755	204.86
	2009	70.93	69.07	4,543,000	4,524,000	28,650	353,350	32,225,515	30,064,232	$ 2,161,284	$ -	$ 2,161,284	75.44	$ 2,032,272	$ 129,012	$ 6,360,864	226.52
SWCT (LICAP)	2012	79.11	78.10	4,688,000	4,692,000	29,895	368,705	37,086,554	36,924,163	$ 162,391	$ -	$ 162,391	5.43	$ 2,364,980	$ (2,202,589)	$ 5,932,334	124.76
	2016	80.37	78.81	4,917,000	4,889,000	31,365	386,835	39,519,342	36,542,696	$ 2,976,647	$ -	$ 2,976,647	94.90	$ 2,520,895	$ 455,751	$ -	14.53
	2020	77.16	75.67	5,209,000	5,181,000	33,105	408,295	40,191,146	37,299,980	$ 2,891,166	$ -	$ 2,891,166	87.33	$ 2,554,287	$ 336,880	$ -	10.18
	2030	78.80	77.74	5,963,000	5,955,000	37,890	467,310	46,986,246	45,735,504	$ 1,250,742	$ -	$ 1,250,742	33.01	$ 2,985,593	$ (1,734,851)	$ -	(45.79)
	2040	36.46	36.15	5,963,000	5,955,000	43,372	534,927	21,740,556	21,264,614	$ 475,941	$ -	$ 475,941	10.97	$ 1,581,322	$ (1,105,380)	$ -	(25.49)

The DRIPE Light case illustrates an interesting phenomenon that, although present in the Full DRIPE case, is not evident due to the larger size of the total benefits associated with demand reduction.

The phenomenon is associated with the supply response to a demand reduction. Since the market clearing may occur at varying levels of reserves, the change in supply capacity does not need to match a given change in total load due to demand reduction. Supply may in fact be entirely inelastic, which given a demand reduction would result in a higher reserve margin and hence lower capacity price. In such a case, a clear price response exists. However, a disconnect occurs between the measure of avoided cost as used in the program screening models and the actual realized avoided cost.

Exhibit 6-10 illustrates the phenomenon. In this example, the peak demand curve utilized for LICAP shifts downward due to the demand reduction. The quantity supplied, however, does not change. As a result, the market experiences a higher reserve margin at the clearing point and a lower market price. From a pure economic perspective, since the market clearing quantity does not change, avoided costs (measured as the change in market clearing quantity times the initial price) are zero. However, a clear benefit in the form of a total cost reduction occurs because of the downward movement in price. The savings shown in Exhibit 6-10 are attributable entirely to a price response resulting from a demand reduction. The total benefit (equal to the price response) is equal to the change in price, $1/kWyr, times the market clearing capacity, 100kW or $100/yr. This is illustrated as the rectangular area P1-A-B-P2.

Exhibit 6-10. Effect of Inelastic Supply on Avoided Costs and DRIPE



Since the supply response and hence the change in the market clearing quantity can not be known in advance, to measure the avoided costs the AESC screening tools utilize the load savings achieved through the demand reduction program. Avoided costs are calculated as the change in peak demand (associated with the energy efficiency program) times the initial price. In the earlier example, the demand reduction of 10kW (see Exhibit 6-1) times the initial price of $30/kWyr would produce an avoided cost of $300/yr.

In contrast, the total benefit is $100/yr, resulting in an overstatement of avoided costs by $200/yr. Since total savings in the DRIPE Light case are significantly below that in the DRIPE case, the potential for such an overstatement to occur increases. Such instances are indicated in the DRIPE Light results when the incremental DRIPE value becomes negative.

A real life illustration of this is seen in the SWCT RTEP zone 2008 DRIPE and DRIPE LIGHT incremental savings shown in Exhibits 6-8 and 6-9 respectively. In the full DRIPE scenario, the total savings in market capacity payments are $7.5 million. In the DRIPE Light scenario, when only 10 percent of the capacity is assumed to transact in the spot market, the total savings are reduced to one tenth of this value at $752,417. Although the market clearing quantity is unchanged between the Reference Case and 0.75% Peak Demand Reduction scenario, the avoided costs calculated in the screening tools would consider avoided costs equal to the 18 MW of demand reduction times the marginal capacity value of $70.93/kWyr or $1.3 million. Since the full DRIPE savings are well above the avoided cost calculated based on the demand reduction, the incremental DRIPE value appears reasonable at $337.05/kW for the year. However, the calculated avoided costs are nearly double the total benefit associated with DRIPE Light. Based on the approach described in the methodology section, the incremental DRIPE Light will compensate for this overstatement by setting the increment DRIPE Light value equal to the amount that was over credited in the avoided cost calculation. Hence the DRIPE Light for SWCT becomes -$30.14/kW in 2009.

Appendix One: Electric Power Costing Periods

Introduction

The AESC Study Group is a multi-member organization each with responsibilities in the delivery of energy efficiency and load management programs in New England. Many Study Group members are associated with Program Administrators (PAs) who implement and manage energy efficiency programs. Since the nature of individual programs may vary, the demand savings and the time in which savings are expected can vary significantly from program to program and from PA to PA. As such, the avoided cost for any particular PA may differ from other PAs not only in the magnitude of the program but also in the timing of the demand savings. Given this potential variation, it may not be appropriate to apply broad time-period based savings estimates to each of the AESC PA programs to determine the avoided costs of that program.[18] To determine if significant variations may result, ICF has collected information from participants regarding their programs' scheduling periods and compared this to historical data as well as results of our wholesale power price modeling. Based on comparisons of the program periods to the reporting time-periods included in the analysis for wholesale energy prices, ICF recommends the set of periods presented in Exhibit A1-1 for all regions.

Exhibit A1-1: Energy Costing Periods Fine Breakout

<table>
<tr><th rowspan="2">Season Group</th><th colspan="3">Hour Group</th></tr>
<tr><th>High-peak</th><th>Peak</th><th>Off-peak</th></tr>
<tr><td>January</td><td rowspan="5">4pm – 8pm weekdays</td><td rowspan="5">7 am – 4pm and 8pm – 10pm weekdays; 9am – 1pm and 4pm – 10pm weekends</td><td rowspan="5">All other hours</td></tr>
<tr><td>February – March</td></tr>
<tr><td>April, October, November, December</td></tr>
<tr><td>May, June, July, August</td></tr>
<tr><td>September</td></tr>
</table>

[18] Error may be introduced if that program implementation varies significantly from the standard reporting periods of summer and winter, peak and off-peak as presented in the body of this report.

This break-out of costing periods may be difficult to utilize for several reasons, including the difficulty of adjusting the individual utility spreadsheets, the manageability and volume of the data, as well as the fact that the program savings estimated through impact evaluations may not coincide with the costing periods. Input from the sponsors was solicited to determine the number of periods that could be readily utilized in their program analyses. Based on this feedback, the four costing periods (2 seasons * 2 hour groups) shown in Exhibit A1-2 were identified as having the most significant impact on pricing definitions and recommended for use to the sponsors. Exhibit A1-3 presents the difference in savings between the recommended (Exhibit A1-1) and used (Exhibit A1-2).

Exhibit A1-2: Energy Costing Periods Breakout for Program Analysis

Season Group	**Hour Group**	
	Peak	***Off-peak***
Summer: June through September	*6am-10pm Weekdays*	*All other hours*
Winter: October through April		

Exhibit A1-3: Estimated Savings Differences in MA: Recommended and Adopted Costing Periods

Program	% Delta in Savings Between the Recommended and Adopted
Residential Cooling	-3.6%
Residential Lighting	2.8%
Refrigeration	-0.4%
C&I Lighting	-1.8%
C&I Cooling	-6.1%

Energy Costing Period Analysis

<u>Hourly Definitions</u>

The first phase of the energy costing period analysis was to examine historical zonal ISO-NE energy price data from March 2003 through December 2004. These data were grouped into day-type, i.e. either weekday or weekend. For each hour in each day-type a distribution was determined based on the percentage of prices in that hour that were below the monthly mean and the percentage that was above the monthly mean. Based on this distribution, an hour was considered a peak hour if the majority of prices (greater than 50%) was above the monthly mean. Exhibit A1-4 illustrates these findings for Boston.

Exhibit A1-4: Distribution of Historical Prices by Hour by Day-Type (Boston)

Hour	2004 Weekday		2004 Weekend		2003 Weekday		2003 Weekend	
	% below the mean	% above the mean	% below the mean	% above the mean	% below the mean	% above the mean	% below the mean	% above the mean
12 to 1	98.5%	1.5%	98.1%	1.9%	96.3%	3.7%	95.5%	4.5%
1 to 2	98.9%	1.1%	99.0%	1.0%	96.3%	3.7%	95.5%	4.5%
2 to 3	99.2%	0.8%	100.0%	0.0%	96.3%	3.7%	95.5%	4.5%
3 to 4	99.2%	0.8%	100.0%	0.0%	96.3%	3.7%	96.6%	3.4%
4 to 5	98.9%	1.1%	100.0%	0.0%	95.9%	4.1%	95.5%	4.5%
5 to 6	93.5%	6.5%	99.0%	1.0%	94.0%	6.0%	95.5%	4.5%
6 to 7	66.8%	33.2%	97.1%	2.9%	65.1%	34.9%	93.2%	6.8%
7 to 8	39.3%	60.7%	96.2%	3.8%	38.1%	61.9%	79.5%	20.5%
8 to 9	31.3%	68.7%	83.7%	16.3%	34.9%	65.1%	65.9%	34.1%
9 to 10	16.0%	84.0%	49.0%	51.0%	20.2%	79.8%	48.9%	51.1%
10 to 11	12.2%	87.8%	30.8%	69.2%	16.1%	83.9%	36.4%	63.6%
11 to 12	11.5%	88.5%	28.8%	71.2%	12.8%	87.2%	31.8%	68.2%
12 to 1	20.2%	79.8%	43.3%	56.7%	14.7%	85.3%	29.5%	70.5%
1 to 2	25.2%	74.8%	51.9%	48.1%	16.5%	83.5%	38.6%	61.4%
2 to 3	29.0%	71.0%	58.7%	41.3%	20.6%	79.4%	48.9%	51.1%
3 to 4	30.2%	69.8%	58.7%	41.3%	20.2%	79.8%	51.1%	48.9%
4 to 5	11.5%	88.5%	39.4%	60.6%	9.6%	90.4%	36.4%	63.6%
5 to 6	3.8%	96.2%	17.3%	82.7%	10.1%	89.9%	28.4%	71.6%
6 to 7	3.8%	96.2%	12.5%	87.5%	12.4%	87.6%	29.5%	70.5%
7 to 8	6.9%	93.1%	9.6%	90.4%	15.6%	84.4%	30.7%	69.3%
8 to 9	9.5%	90.5%	15.4%	84.6%	17.4%	82.6%	31.8%	68.2%
9 to 10	37.8%	62.2%	47.1%	52.9%	52.3%	47.7%	52.3%	47.7%
10 to 11	82.1%	17.9%	90.4%	9.6%	86.2%	13.8%	87.5%	12.5%
11 to 12	93.1%	6.9%	96.2%	3.8%	95.4%	4.6%	95.5%	4.5%

Further analysis was conducted to determine if the peak period could be further disaggregated into a subset of hours where very high prices consistently occurred. ICF looked at the distribution of prices that were more than one standard deviation away from the mean. Again, this was done by day-type and by hour. Based on this analysis, we found that approximately one third of these prices occurred in the 4 p.m. to 8 p.m. weekdays. The remainder of these prices was more evenly distributed among the other hours of the peak period. Exhibit A1-5 illustrates these findings for Boston.

Exhibit A1-5: Distribution of Prices More Than One Standard Deviation from the Mean by Hour by Day-Type (Boston)

Hour	2004		2003	
	Weekday	Weekend	Weekday	Weekend
12 to 1	0.1%	0.0%	0.2%	0.0%
1 to 2	0.0%	0.1%	0.1%	0.0%
2 to 3	0.0%	0.0%	0.1%	0.0%
3 to 4	0.0%	0.0%	0.1%	0.0%
4 to 5	0.1%	0.0%	0.1%	0.0%
5 to 6	0.1%	0.0%	0.1%	0.0%
6 to 7	0.9%	0.0%	0.7%	0.0%
7 to 8	2.2%	0.0%	3.1%	0.0%
8 to 9	2.6%	0.1%	3.9%	0.1%
9 to 10	3.2%	0.4%	5.7%	0.7%
10 to 11	5.0%	0.9%	5.9%	0.9%
11 to 12	5.8%	1.3%	5.9%	0.7%
12 to 1	5.0%	1.1%	5.3%	0.4%
1 to 2	6.1%	0.9%	5.5%	0.2%
2 to 3	6.1%	0.9%	5.7%	0.2%
3 to 4	6.1%	0.9%	5.2%	0.2%
4 to 5	7.3%	1.2%	8.1%	1.8%
5 to 6	10.4%	2.4%	9.5%	2.5%
6 to 7	8.7%	2.1%	9.1%	2.9%
7 to 8	7.6%	1.5%	6.4%	2.6%
8 to 9	5.2%	1.7%	2.9%	1.5%
9 to 10	1.7%	0.2%	1.0%	0.5%
10 to 11	0.1%	0.0%	0.2%	0.0%
11 to 12	0.1%	0.0%	0.1%	0.0%

ICF also analyzed 2005 forecast prices to verify if the characterization based upon historical prices is consistent with ICF's power price forecast. With very slight differences between model regions, the weekday peak definition is very consistent with the historical findings. The weekend peak definition resulted in larger differences regionally with the typical trend showing the occurrence of a weekend afternoon peak (e.g. 4 p.m. to 9 p.m. or 5 p.m. to 10 p.m.) but not always a weekend morning peak as with the historical data. Exhibit A1-6 highlights the forecast data for Boston.

In addition, the forecast also illustrated that a "super" peak period occurs during the 4 p.m. to 8 p.m. weekdays as 30 to 40 percent of the prices that are more than one standard deviation away from the monthly mean occur during this period.

Exhibit A1-6: Distribution of Forecast Prices by Hour by Day-Type (Boston)

Hour	2005 Weekday		2005 Weekend	
	% below mean	% above mean	% below mean	% above mean
12 to 1	98.8%	1.2%	99.0%	1.0%
1 to 2	98.8%	1.2%	99.0%	1.0%
2 to 3	99.2%	0.8%	100.0%	0.0%
3 to 4	99.2%	0.8%	100.0%	0.0%
4 to 5	99.6%	0.4%	100.0%	0.0%
5 to 6	98.8%	1.2%	100.0%	0.0%
6 to 7	74.2%	25.8%	100.0%	0.0%
7 to 8	20.4%	79.6%	97.1%	2.9%
8 to 9	10.0%	90.0%	88.6%	11.4%
9 to 10	7.3%	92.7%	72.4%	27.6%
10 to 11	5.4%	94.6%	65.7%	34.3%
11 to 12	6.2%	93.8%	58.1%	41.9%
12 to 1	6.9%	93.1%	61.0%	39.0%
1 to 2	8.5%	91.5%	66.7%	33.3%
2 to 3	10.8%	89.2%	70.5%	29.5%
3 to 4	10.0%	90.0%	74.3%	25.7%
4 to 5	6.5%	93.5%	68.6%	31.4%
5 to 6	3.1%	96.9%	58.1%	41.9%
6 to 7	4.6%	95.4%	49.5%	50.5%
7 to 8	7.3%	92.7%	46.7%	53.3%
8 to 9	11.2%	88.8%	46.7%	53.3%
9 to 10	17.3%	82.7%	58.1%	41.9%
10 to 11	52.3%	47.7%	88.6%	11.4%
11 to 12	90.0%	10.0%	97.1%	2.9%

Seasonal Definitions

To determine appropriate seasonal definitions, ICF relied primarily on 2004 historical data as 2003 was only partial year data. We overlaid the hourly analysis with a monthly component to determine how the hourly distributions varied by month. Exhibit A1-7 shows the hourly distribution from the monthly mean for each month and Exhibit A1-8 shows the distribution of prices that were more than one standard deviation away from the monthly mean. From this analysis, it is evident that certain months have very similar distributions while others do not. January and September in particular were not like any other month. February and March were similar, April, October, November and December were similar and May, June, July and August were similar.

Exhibit A1-7: Monthly Distribution of Historical Prices (Boston)

Month	2004		2003	
	% below the mean	% above the mean	% below the mean	% above the mean
January	18%	82%	N/A	N/A
February	66%	34%	N/A	N/A
March	82%	18%	29%	71%
April	54%	46%	57%	43%
May	42%	58%	52%	48%
June	51%	49%	55%	45%
July	61%	39%	53%	47%
August	72%	28%	61%	39%
September	86%	14%	86%	14%
October	62%	38%	66%	34%
November	57%	43%	73%	27%
December	34%	66%	44%	56%

Exhibit A1-8: Monthly Distribution of Historical Prices More than One Standard Deviation from the Monthly Mean (Boston)

Month	2004		2003	
	less than 1 std dev	more than 1 std dev	less than 1 std dev	more than 1 std dev
January	0%	50%	N/A	N/A
February	0%	2%	N/A	N/A
March	4%	0%	2%	57%
April	3%	1%	2%	4%
May	0%	2%	9%	1%
June	3%	3%	11%	6%
July	5%	0%	2%	6%
August	19%	0%	9%	8%
September	35%	0%	23%	1%
October	18%	7%	17%	0%
November	13%	12%	17%	0%
December	0%	23%	7%	16%

Capacity Value Period Analysis

The Locational ICAP market is a monthly market - prices for capacity in New England are expected to vary from month to month based on the supply and demand conditions for that month. Although prices may vary by month, the bulk of the value associated with capacity is expected to be determined by the summer peak conditions consistent with the determination of the objective capability (OC)[19] level. In other words, avoided capacity costs depend on the capability to reduce summer peak load. Regardless of whether prices vary monthly, the load reduction at peak will reduce the total cost of supply.

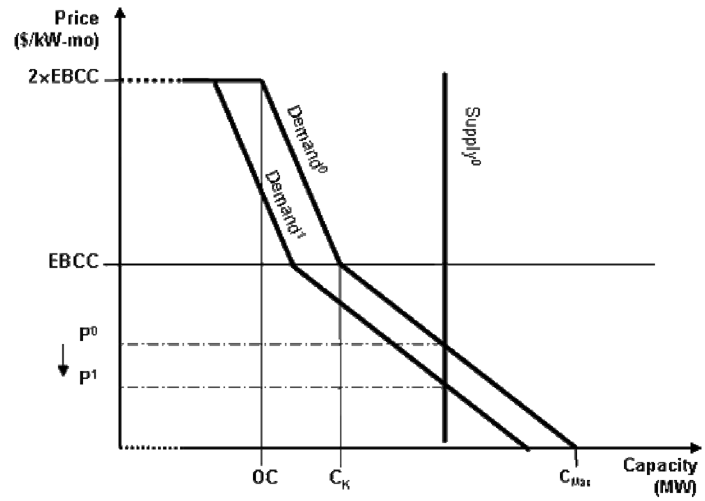
The rationale for the costing periods is that required investment in capacity will be reduced as a function of peak load reduction and LR regardless of price fluctuations.

Given this design in the LICAP curves, there are effectively two ways to impact capacity prices. First, shifts in the demand curve based on shifts in the OC from year to year will fundamentally alter the clearing prices in each month of the following year. This effect is independent of the direct avoided costs estimates and is reflected in the DRIPE analysis[20]. Second, shifts in the monthly supply curve or the quantity supplied will affect the monthly price. The supply driven changes (and their impact on the market clearing quantity and price) are also captured in the DRIPE analysis. Other variations may exist and affect the monthly markets; however, these two are the key drivers which can be directly impacted by demand reductions.

[19] Objective Capability is the ISO term. This is also sometimes referred to as the locational installed capacity requirement.

[20] See Chapter Six for discussion of DRIPE.

Exhibit A1-9: LICAP Market Adjusts to Changes in Peak Demand



Example 0 – Reference State, Demand^0 and Supply^0:
Peak demand = 1,000 MW
OC = 1,000 MW *1.12 = 1,120 MW
C_k = OC *1.038 = 1,163 MW
C_{Max} = OC *1.15 = 1,337 MW
At Supply^0, Capacity Price = P^0
When Supply = 1,120 MW, Capacity Price = 2*EBCC
When Supply = 1,163 MW, Capacity Price = EBCC
When Supply = 1,337 MW, Capacity Price = 0

Example 1 – Peak Demand Reduced. Demand^1 and Supply^0:
Peak demand = 990 MW
OC = 990 MW *1.12 = 1,109 MW
C_k = OC *1.038 = 1,151 MW
C_{Max} = OC *1.15 = 1,323 MW
At Supply^0, $P^1 < P^0$
When Supply = 1,120 MW, Capacity Price < 2*EBCC and > EBCC
When Supply = 1,163 MW, Capacity Price < EBCC
When Supply = 1,337 MW, Capacity Price = 0

With the exception of the ends of the curve, capacity prices would fall should the summer peak obligation be reduced, all else equal. This effect would result from reductions in the Summer Peak Demand projections

In the example shown in Exhibit A1-9 above, the LICAP price is affected by shift in the demand curve resulting from a reduction in the targeted annual coincident peak load for all of New England. As can be seen, a reduction in load will have the effect of reducing prices from P^0 to P^1. In this scenario, supply resources are held constant. As both the demand curve and the LSE obligations for the following year are established based on the summer coincident peak for all months of the prior year, the impact of a shift in peak conditions will be reflected in the capacity price for each month of the next year. As such, we consider this a first order impact, having a much larger potential change than the supply side variations discussed below. That is, the effect of shifting peak coincident load is larger than month to month variations in supply conditions.

Exhibit A1-10: LICAP Monthly Clearing Price Affected by Available Supply Side Resources

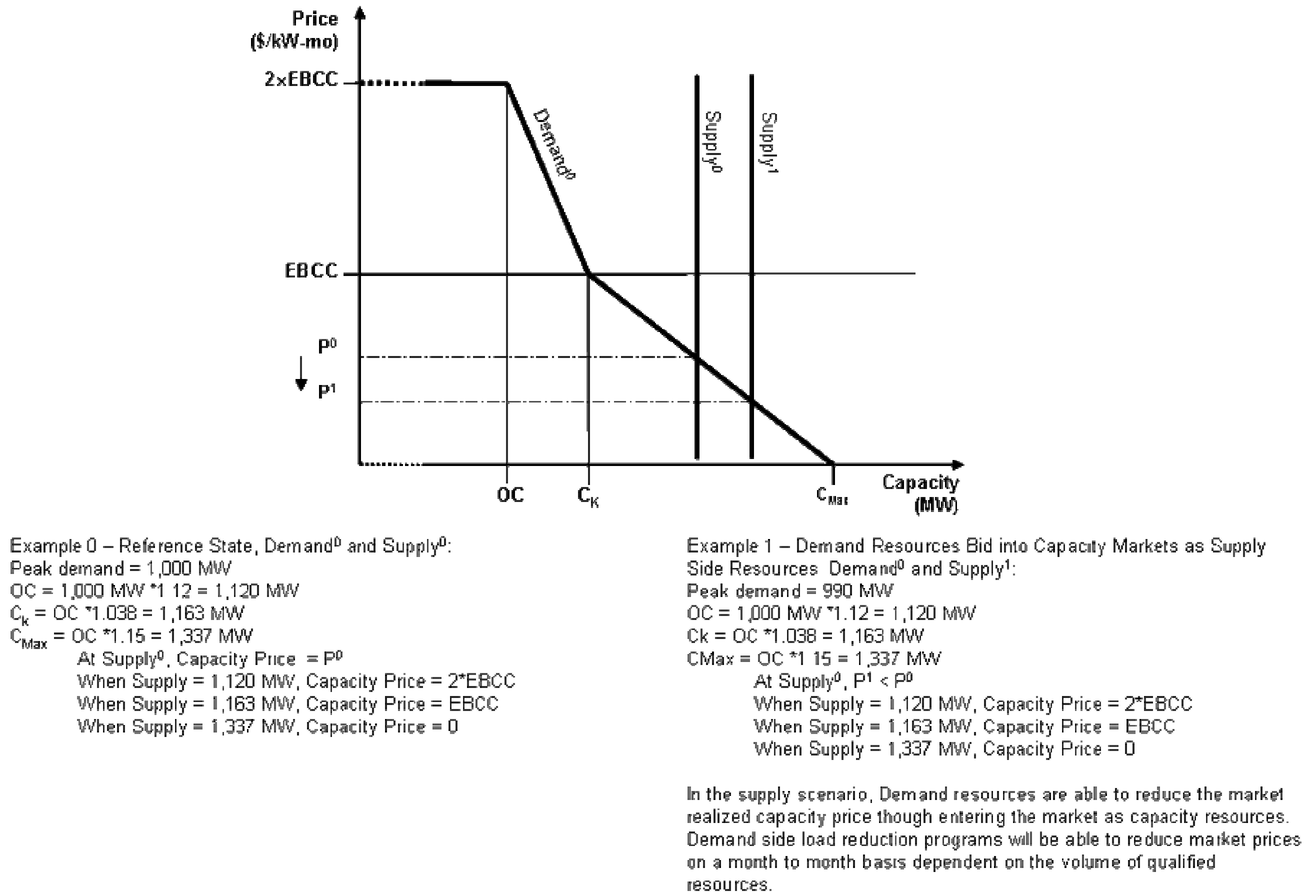


Exhibit A1-10 demonstrates the impact of a shift in supply side resources on capacity value, with all other assumptions held constant. In this case, an increase in supply will result in a decrease in capacity price (and hence the LSE total payments for capacity resources) from P^0 to P^1. Demand Reduction Resources are allowed to participate in the LICAP markets as resources to the extent they can be qualified in advance of the monthly clearing auctions. Through this mechanism, reductions in demand do result in price movement on a month to month basis and should be considered to have some value. Any customer that can respond within the timeframes required by the program (i.e., within 30 minutes or 2 hours during program hours -- i.e., 7 a.m. to 6 p.m. business days) are eligible to participate and receive a capacity credit. Eligible resources include reduced lighting, adjusting HVAC temps, adjusting refrigeration equip, turning off fan pumps. Further enhancements to the treatment of demand response resources in a day-ahead market (energy related) are being considered, However, given that these mechanisms are as of yet unknown or unclear, they are not considered in this analysis (neither for energy or capacity).

Given the design of the New England LICAP markets, the majority of capacity value will be recognized based on summer coincident peak conditions. However, value will still be recognized for load reductions in non-coincident peak hours. For example demand response resources may have value in non-peak periods. ICF recommends the use of two costing periods for capacity, 1) Summer Peak, for use in evaluating energy efficiency measures that may impact the summer peak; and 2) all else, for use in evaluating Load Response measures that may be effective at reducing demand in non-peak periods. Further discussion on the application of Summer Peak Energy Efficiency and Load Response values is found in Appendix 2.

Appendix Two: Detailed Electric Energy Avoided Cost Tables

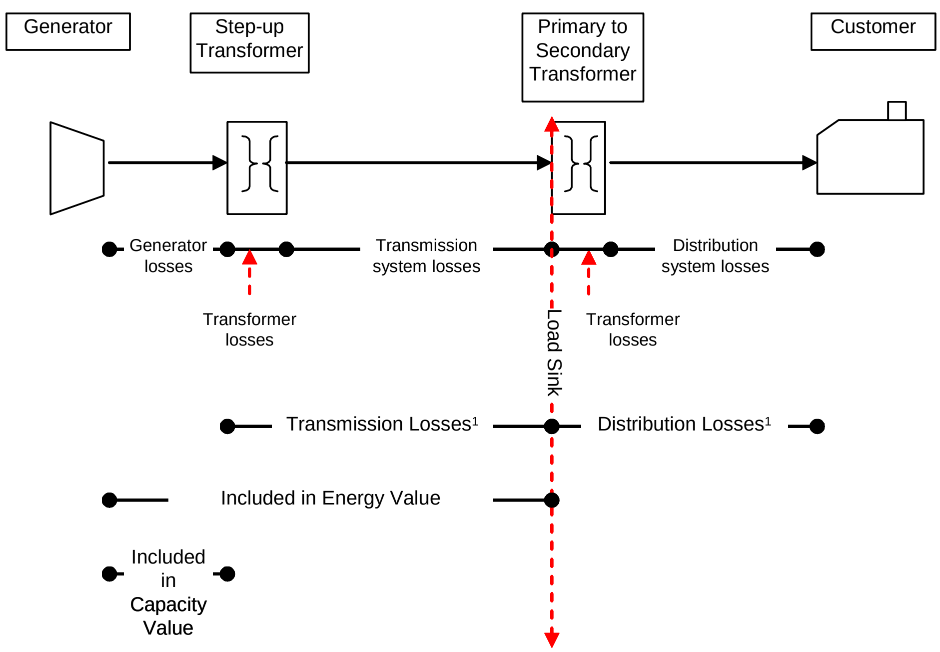
The electric energy avoided costs were provided at several levels of zonal aggregation for the use of the AESC study sponsors. Results were provided for AESC Screening Zone area, State, Pricing Zone, RTEP zone, and other requested zonal levels. The results for each of the areas were provided in spreadsheet format. This Appendix provides a description of the spreadsheet format as well as the results. All values are presented in this appendix are in real 2005$ unless otherwise noted.

Table Structure and Terminology

The Appendices' tables follow the same format structure. Values presented within each table for the avoided costs are dependent on the point at which the kilowatts are measured. The modeling analysis performed for this study of the wholesale energy and capacity markets reflect prices measured at the point prior to conversion from the primary transmission network to the distribution network for energy (referred to as load sink), and at the point at which generation capacity is delivered to the grid (prior to transformer losses) for capacity.

In contrast, in most cases, Program Administrators will measure potential demand savings from C&LM programs at the customer meter (end use). To apply the avoided costs reported in the tables to C&LM demand savings, the C&LM savings should be grossed up to reflect losses between the load sink or generator (for energy and capacity respectively) and the end user. Exhibit A2-1 provides a simplified illustration of losses on the transmission and distribution grids.

Exhibit A2-1. Illustration of Losses on the Transmission and Distribution Systems



1. Illustrative of terminology as commonly used in this report.

Total distribution losses as used herein indicate the losses that occur between the point of transmission voltage step-down to distribution voltage (including transformer losses) to the point of customer delivery. The forecast results presented in this report do not include distribution losses. A discussion on the estimation of losses consistent with the avoided costs is included in Chapter 3

Transmission losses as used herein reflect losses that occur from the point of generation power voltage step-up to transmission level voltage (including transformer losses), to the point of delivery to the load sink. Transmission losses are included in the energy forecasts provided herein (energy price forecasts are presented at the load sink); however, such losses are not included in the capacity forecasts.

Generator losses capture losses that occur between the generator and the step-up transformer to the transmission grid. Generator losses are included in both the energy and capacity forecasts (capacity price forecasts are provided at the generator level including generator losses).

The fields included are defined below in order of their appearance in the tables.

Winter Peak Energy ($/kWh): Values are avoided energy costs at the load sink. This represents the marginal cost of energy in the winter period peak hours defined as January, February, March, April, May, October, November and December, Monday through Friday 6am - 10pm (the 16 hour block beginning at 6am and ending at 9:59pm). To apply these values to CL&M savings measured at the customer meter, the savings should be grossed up for losses to the load sink level. To gross up kilowatt-hours savings measured at the customer meter, multiply the quantity (kWh) by the quantity one plus the distribution loss.

Winter Off-Peak Energy ($/kWh): Values are avoided energy costs at the load sink. This represents the marginal cost of energy in the winter period off-peak hours defined as January, February, March, April, May, October, November and December, 10:00pm – 5:59am Monday through Friday, and all day on Saturday and Sunday. When applying these values to C&LM savings measured at the customer meter, the savings should be grossed up for losses to the load sink level. To gross up kilowatt-hours savings measured at the customer meter, multiply the quantity (kWh) by the quantity one plus the distribution loss.

Summer Peak Energy ($/kWh): Values are avoided energy costs at the load sink. This represents the marginal cost of energy in the summer period peak hours defined as June, July, August and September, Monday through Friday 6:00am – 9:59pm. When applying these values to C&LM savings measured at the customer meter, the savings should be grossed up for losses to the load sink level. To gross up kilowatt-hours savings measured at the customer meter, multiply the quantity (kWh) by the quantity one plus the distribution loss.

Summer Off-Peak Energy ($/kWh): Values are avoided energy costs at the generator level. This represents the marginal cost of energy in the summer period off-peak hours defined as June, July, August and September, 10:00pm – 5:59am Monday through Friday, and all day Saturday and Sunday. When applying these values to C&LM savings measured at the customer meter, the savings should be grossed up for losses to the load sink level. To gross up kilowatt-hours savings measured at the customer meter, multiply the quantity (kWh) by the quantity one plus the distribution loss.

Annual Market Capacity Value ($/kW-yr): Reflects capacity price resulting from LICAP demand curve structure as modeled (beginning in 2006). The LICAP price is set by the LICAP demand curve and the capability bid into the market by each generator where generator losses are accounted for in the generator capability as modeled. This field provides the model results for capacity clearing value and does not include any incremental payments for out-of-market costs. The capacity price is measured at the generator level including generator losses. This value reflects the capacity value at summer coincident peak which is most likely to occur in the months of June, July or August between the hours of 3-5pm on a weekday[21]. In order to properly reflect the capacity avoided costs associated with LICAP purchases in the program screening tools, one should increase the megawatts as measured at the customer meter by the sum of the transmission and distribution losses. In addition, since each load serving entity has a target reserve margin above their peak obligation, the avoided megawatts (savings measured on the customer meter (MW) * [1 + (transmission loss (%) + distribution loss (%))] should also be increased by the reserve margin target of 12 percent. This field is provided as an information field given that the full capacity value would also include out-of-market expenses as described next.

Annual Out of Market Expense ($/kW-yr): Reflects the recovery of costs for RMR including continuing required payments after LICAP initiation considered avoidable due to load savings. This field provides the model results for fixed and operating expenses above the market payments for those units considered to be required to be on-line to ensure system reliability. The annual value is largely associated with peak system reliability and hence coincides with the timing of the annual market capacity value at summer coincident peak. This field is provided as an information field given that the full capacity value would also include the LICAP value as described above.

Total Annual Capacity Value ($/kW-yr): The sum of the Annual Out-of-Market Expense and the Annual Market Capacity Value. Given that the screening tools are designed to include a single capacity avoided cost value, the annual cost for the out of market expense and the LICAP price are summed together to reflect the total cost. This field is provided as an information field. Additional fields reflecting the avoided capacity costs are described next.

Capacity Value at Load Response (at any month $/kW-month): Avoided capacity cost applicable to kW savings contributing as supply side credit, i.e. load response recognized by ISO-NE. The

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[21] When applying these values to DSM or load conservation and management savings, the savings should be reasonably estimated to be those that occur at the summer coincident peak. The association of capacity value with summer coincident peak means that winter demand savings have no value.

Load Response category applies to programs that provide reliability, including ISO-NE's Real-Time Demand Response Program (including programs with 30-minute and 2 hour notice provisions) and the Real-Time Profiled Response Program. These resources are eligible to receive ICAP capacity credits and act as supply-side resources[22]. If the later, the This does not include programs designed to encourage load reduction in response to high real-time energy prices. The Load Response avoided costs should be treated as distinct from energy efficiency avoided costs which apply only for summer coincident peak savings. When applying these values to C&LM savings, the savings should be measured at the generator level (end use savings plus transmission losses (not including generator losses) + distribution losses) and should further include the reserve margin target for load serving entities (12 percent). These values represent the typical avoidable capacity market payments for a typical month (i.e. the average monthly value) and can be applied to load response savings that occur in any month. Seasonal values for summer and winter are provided in the following two fields.

Avoidable Capacity Payment for Load Response (Summer Season $/kW-season): Avoided capacity cost applicable to kW savings contributing as supply side credit, i.e. load response recognized by ISO-NE, in the summer season. The avoided load response $/kW has been determined on a seasonal basis as an expected value based on the probability of an OP4 event occurring in any given month. Over the course of the year, it is anticipated that roughly 93% of the Load Response events will occur over the June through August period with the remainder typically in the months of January and December. We have used a historical series from 1999 - 2004 to derive this likely distribution for OP4 events and applied it to determine what the seasonal value for this would be. For those parties who may have the data available on a monthly basis, we continue to provide the Load Response value in the $/kW-month estimate above. The Load Response category applies to programs that provide reliability including Real-Time Demand Response Program (including programs with 30-minute and 2 hour notice provisions) and the Real-Time Profiled Response Program. These resources are eligible to receive ICAP capacity credits and act as supply-side resources. This does not include programs designed to encourage load reduction in response to high real-time energy prices. The Load Response avoided costs should be treated as distinct from energy efficiency avoided costs which apply only for summer coincident peak savings. When applying these values to DSM savings, the savings should be measured at the generator level (end use savings plus transmission losses + distribution losses) and should further include the reserve margin target for load serving entities (12 percent). These values represent the average avoidable capacity market payments for the summer season (June through September).

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[22] In certain cases distributed generation (DG) resources may also qualify as supply-side credits. DG resources qualifying for other incentives may not qualify as a supply-side resource, or may only receive partial credit to net out other incentive payments it may receive. This analysis did not focus on DG resources. Additional analysis would be required to determine if the avoided costs presented here would be the same for DG resources.

Avoidable Capacity Payment for Load Response (Winter Season $/kW-season): Avoided capacity cost applicable to KW savings contributing as supply side credit, i.e. load response recognized by ISO-NE, in the winter season. The avoided load response $/kW has been determined on a seasonal basis as an expected value based on the probability of an OP4 event occurring in any given month. Over the course of the year, it is anticipated that roughly 93% of the Load Response events will occur over the June through August period with the remainder typically in the months of January and December. We have used a historical series from 1999 - 2004 to derive this likely distribution for OP4 events and applied it to determine what the seasonal value for this would be. For those parties who may have the data available on a monthly basis, we continue to provide the Load Response value in the $/kW-month estimate. The Load Response category applies to programs that provide reliability including Real-Time Demand Response Program (including programs with 30-minute and 2 hour notice provisions) and the Real-Time Profiled Response Program. These resources are eligible to receive ICAP capacity credits and act as supply-side resources. This does not include programs designed to encourage load reduction in response to high real-time energy prices. The Load Response avoided costs should be treated as distinct from energy efficiency avoided costs which apply only for summer coincident peak savings. When applying these values to DSM savings, the savings should be measured at the generator level (end use savings plus transmission losses + distribution losses) and should further include the reserve margin target for load serving entities (12 percent). These values represent the average avoidable capacity market payments for the winter season (January through May and October through December).

Avoidable Capacity Payment at Energy Efficiency at Summer Coincident Peak ($/kW-yr): Avoided Cost applicable to kW savings from C&LM programs at summer coincident peak. Based on a review of a long-term series of the timing of summer coincident peak, June, July and August are the months when peak is expected to occur. The peak hour is anticipated to be between 3pm and 5pm on a weekday in these months. Programs targeted to the peak hours will be able to contribute to capacity costs reductions. Savings from programs should be measured at the generator level when determining the total savings. To convert kilowatt reductions at the end use level to the generator level (after generator losses), the reserve margin credit and transmission and distribution losses should be applied to the actual load reduction. The value presented here for use in the screening models is the equivalent of the Annual Capacity Value described above.

Load Response (at any month $/kWh): This field provides the "*Capacity Value at Load Response*" for load response resources (see above for definition of load response resource) in $/kWh. The annual load response avoidable cost has been converted to $/kWh using a 100 percent load factor. This field is provided for information purposes to illustrate costs at the kWh level.

Energy Efficiency at Summer Coincident Peak ($/kWh): The *"Avoidable Capacity Payment at Energy Efficiency at Summer Coincident Peak"* is converted to $/kWh using a 100 percent load factor. This represents the average hourly avoided cost for all hours (8760 hours). This field is provided for information purposes to illustrate costs at the kWh level.

DRIPE 0.75% Capacity Price ($/kW-yr): The incremental avoided capacity payment related to price and supply responsiveness to an expected reduction in peak demand. The value represents the savings attributable to a 0.75 percent peak load reduction at summer coincident peak and is not applicable to energy savings. Further information on DRIPE can be found in Chapter 6.

DRIPE 0.75% Capacity Price ($/kWh): The annual avoided costs for DRIPE are converted to $/kWh at 100 percent load factor. This field represents the average savings for every hour (8760 hours). This value reflects only capacity savings and should not be applied to potential energy savings.

DRIPE Light 0.75% Capacity Price ($/kW-yr): The incremental avoided capacity payment related to price responsiveness to a demand reduction. The value represents the savings attributable to a 0.75percent peak load reduction at summer coincident peak and is not applicable to energy savings. Further information on DRIPE Light can be found in Chapter 6.

DRIPE Light 0.75% Capacity Price ($/kWh): The annual avoided costs for DRIPE Light are converted to $/kWh at 100 percent load factor. This field represents the average savings for every hour (8760 hours). This value reflects only capacity savings and should not be applied to potential energy savings.

Exhibit A2-2 presents the avoided electrical energy costs for AESC screening zones. Exhibit A2-3 presents avoided costs by State, Exhibit A2-4 by Pricing Zone, Exhibit A2-5 by RTEP zone and Exhibit A2-6 by additional zonal breakouts requested by the study group. A comparison of the zonal definitions can be found in Chapter 3 Exhibit 3-1.

The following notes apply to all tables contained in Exhibits A2-2, through A2-6:

1) Capacity value reflects value after peak energy rent (PER) payment

2) 2005 data for out of market transactions were estimated using ISO-NE current RMR payments as of July 27, 2005

3) Levelized using a 2.03 percent real discount rate

4) GDP Implicit Price Deflator for 2003 to 2004 is 2.11 percent, and 2004 to 2005 is 2.25 percent.

Exhibit A2-2. Electric Energy Avoided Costs by AESC Screening Zone

	Maine																
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value[1]	Annual Out of Market Expense	Total Annual Capacity Value	Capacity Value at Load Response (at any month)	Avoidable Capacity Payment at Load Response (Summer Season)	Avoidable Capacity Payment at Load Response (Winter Season)	Avoidable Capacity Payment at Energy Efficiency at Summer Coincident Peak	Load Response (at any month)	Energy Efficiency at Summer Coincident Peak	DRIPE 0.75% Capacity Price	DRIPE 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-month	$/kW-season	$/kW-season	$/kW-yr	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kW-yr	$/kWh
Comment 1:	Values are avoided costs at the generation plus transmission level. DSM savings should be measured at the generator plus transmission level. (Load plus + distribution losses)				Reflects Capacity Price resulting from LICAP beginning in 2006	Recovery of costs for RMR including continuing required payments after LICAP initiation		Avoided Cost applicable to KW savings contributing as supply side credit; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level			Avoided Cost applicable to KW savings at Summer Coincident Peak; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level	Avoided cost expressed in $/kWh at 100% load factor		Incremental to Avoided Cost at Summer Coincident Peak	Expressed in $/kWh at 100% load factor	DRIPE 0.75% measured assuming 10% of supply resources transact in spot market	Expressed in $/kWh at 100% load factor
Comment 2:					info	info	June/July/August	Average for 1 month savings	Average for Summer Season	Average for Winter Season	June / July / August			DRIPE measured at 0.75% peak savings are across all of New England.		DRIPE LIGHT measured at 0.75% peak savings are across all of New England.	
Period:							3-5 pm		June, July, August	Jan-May;Sept-Dec	3-5 pm						
2005 [2]	0.071	0.063	0.063	0.049	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.00	0.000	0.00	0.000
2006	0.080	0.071	0.070	0.057	23.304	0.000	23.304	1.942	5.465	1.084	23.304	0.003	0.003	1,115.39	0.127	90.57	0.010
2007	0.083	0.072	0.072	0.059	20.172	0.000	20.172	1.681	4.730	0.938	20.172	0.002	0.002	616.86	0.070	43.53	0.005
2008	0.070	0.059	0.060	0.048	19.462	0.000	19.462	1.622	4.564	0.905	19.462	0.002	0.002	23.10	0.003	6.00	0.001
2009	0.056	0.047	0.048	0.039	17.895	0.000	17.895	1.491	4.196	0.832	17.895	0.002	0.002	6.57	0.001	4.86	0.001
2010	0.049	0.041	0.043	0.034	27.761	0.000	27.761	2.313	6.510	1.291	27.761	0.003	0.003	9.00	0.001	7.86	0.001
2011	0.051	0.043	0.046	0.036	43.067	0.000	43.067	3.589	10.099	2.003	43.067	0.005	0.005	11.43	0.001	10.86	0.001
2012	0.054	0.044	0.049	0.038	66.810	0.000	66.810	5.568	15.667	3.107	66.810	0.008	0.008	13.86	0.002	13.86	0.002
2013	0.054	0.045	0.049	0.038	67.163	0.000	67.163	5.597	15.750	3.123	67.163	0.008	0.008	13.76	0.002	13.02	0.001
2014	0.054	0.046	0.049	0.039	67.517	0.000	67.517	5.626	15.833	3.140	67.517	0.008	0.008	13.66	0.002	12.18	0.001
2015	0.055	0.046	0.049	0.039	67.872	0.000	67.872	5.656	15.916	3.156	67.872	0.008	0.008	13.56	0.002	11.34	0.001
2016	0.055	0.047	0.049	0.039	68.230	0.000	68.230	5.686	16.000	3.173	68.230	0.008	0.008	13.46	0.002	10.51	0.001
2017	0.057	0.048	0.051	0.041	65.767	0.000	65.767	5.481	15.422	3.058	65.767	0.008	0.008	12.91	0.001	10.69	0.001
2018	0.059	0.050	0.053	0.043	63.392	0.000	63.392	5.283	14.865	2.948	63.392	0.007	0.007	12.36	0.001	10.88	0.001
2019	0.061	0.052	0.055	0.045	61.103	0.000	61.103	5.092	14.329	2.841	61.103	0.007	0.007	11.80	0.001	11.07	0.001
2020	0.063	0.054	0.057	0.047	58.896	0.000	58.896	4.908	13.811	2.739	58.896	0.007	0.007	11.25	0.001	11.25	0.001
2021	0.064	0.054	0.058	0.048	60.454	0.000	60.454	5.038	14.177	2.811	60.454	0.007	0.007	16.72	0.002	7.79	0.001
2022	0.064	0.055	0.059	0.048	62.053	0.000	62.053	5.171	14.552	2.885	62.053	0.007	0.007	22.18	0.003	4.32	0.000
2023	0.065	0.055	0.060	0.049	63.695	0.000	63.695	5.308	14.936	2.962	63.695	0.007	0.007	27.65	0.003	0.86	0.000
2024	0.065	0.056	0.061	0.050	65.380	0.000	65.380	5.448	15.332	3.040	65.380	0.007	0.007	33.12	0.004	(2.61)	(0.000)
2025	0.066	0.056	0.061	0.051	67.109	0.000	67.109	5.592	15.737	3.121	67.109	0.008	0.008	38.58	0.004	(6.07)	(0.001)
2026	0.067	0.057	0.062	0.051	68.885	0.000	68.885	5.740	16.153	3.203	68.885	0.008	0.008	44.05	0.005	(9.54)	(0.001)
2027	0.067	0.057	0.063	0.052	70.707	0.000	70.707	5.892	16.581	3.288	70.707	0.008	0.008	49.51	0.006	(13.00)	(0.001)
2028	0.068	0.058	0.064	0.053	72.577	0.000	72.577	6.048	17.019	3.375	72.577	0.008	0.008	54.98	0.006	(16.47)	(0.002)
2029	0.069	0.058	0.065	0.054	74.497	0.000	74.497	6.208	17.470	3.464	74.497	0.009	0.009	60.45	0.007	(19.93)	(0.002)
2030	0.069	0.059	0.066	0.054	76.468	0.000	76.468	6.372	17.932	3.556	76.468	0.009	0.009	65.91	0.008	(23.40)	(0.003)
2031	0.069	0.059	0.066	0.054	70.863	0.000	70.863	5.905	16.617	3.295	70.863	0.008	0.008	61.90	0.007	(22.31)	(0.003)
2032	0.070	0.059	0.066	0.054	65.669	0.000	65.669	5.472	15.399	3.054	65.669	0.007	0.007	57.88	0.007	(21.21)	(0.002)
2033	0.070	0.059	0.067	0.054	60.856	0.000	60.856	5.071	14.271	2.830	60.856	0.007	0.007	53.87	0.006	(20.12)	(0.002)
2034	0.070	0.059	0.067	0.054	56.395	0.000	56.395	4.700	13.225	2.622	56.395	0.006	0.006	49.85	0.006	(19.03)	(0.002)
2035	0.070	0.059	0.067	0.054	52.262	0.000	52.262	4.355	12.255	2.430	52.262	0.006	0.006	45.84	0.005	(17.94)	(0.002)
2036	0.070	0.059	0.068	0.054	48.431	0.000	48.431	4.036	11.357	2.252	48.431	0.006	0.006	41.82	0.005	(16.84)	(0.002)
2037	0.070	0.059	0.068	0.054	44.881	0.000	44.881	3.740	10.525	2.087	44.881	0.005	0.005	37.81	0.004	(15.75)	(0.002)
2038	0.070	0.059	0.068	0.054	41.591	0.000	41.591	3.466	9.753	1.934	41.591	0.005	0.005	33.79	0.004	(14.66)	(0.002)
2039	0.070	0.059	0.068	0.054	38.543	0.000	38.543	3.212	9.038	1.792	38.543	0.004	0.004	29.78	0.003	(13.57)	(0.002)
2040	0.070	0.059	0.069	0.053	35.718	0.000	35.718	2.976	8.376	1.661	35.718	0.004	0.004	25.76	0.003	6.15	0.001
Levelized[3]:																	
2005-2040	0.064	0.055	0.059	0.047	51.998	0.000	51.998	4.333	12.194	2.418	51.998	0.006	0.006	90.231	0.010	4.165	0.000
2006-2040	0.064	0.054	0.059	0.047	54.088	0.000	54.088	4.507	12.684	2.515	54.088	0.006	0.006	93.858	0.011	4.333	0.000
2006-2010	0.068	0.058	0.059	0.047	21.693	0.000	21.693	1.808	5.087	1.009	21.693	0.002	0.002	365.592	0.042	31.390	0.004
2006-2015	0.061	0.052	0.054	0.043	40.969	0.000	40.969	3.414	9.607	1.905	40.969	0.005	0.005	198.259	0.023	22.304	0.003
2006-2020	0.061	0.051	0.054	0.043	47.760	0.000	47.760	3.980	11.200	2.221	47.760	0.005	0.005	142.410	0.016	18.869	0.002

Exhibit A2-2. Electric Energy Avoided Costs by AESC Screening Zone (continued)

	Boston																			
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value[1]	Annual Out of Market Expense	Total Annual Capacity Value	Capacity Value at Load Response (at any month)	Avoidable Capacity Payment at Load Response (Summer Season)	Avoidable Capacity Payment at Load Response (Winter Season)	Avoidable Capacity Payment at Energy Efficiency at Summer Coincident Peak	Load Response (at any month)	Energy Efficiency at Summer Coincident Peak	DRIPE 0.75% Capacity Price	DRIPE 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-month	$/kW-season	$/kW-season	$/kW-yr	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kW-yr	$/kWh
Comment 1:	Values are avoided costs at the generation plus transmission level. DSM savings should be measured at the generator plus transmission level. (Load plus + distribution losses)				Reflects Capacity Price resulting from LICAP beginning in 2006	Recovery of costs for RMR including continuing required payments after LICAP initiation		Avoided Cost applicable to KW savings contributing as supply side credit; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level			Avoided Cost applicable to KW savings at Summer Coincident Peak; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level	Avoided cost expressed in $/kWh at 100% load factor		Incremental to Avoided Cost at Summer Coincident Peak	Expressed in $/kWh at 100% load factor	DRIPE 0.75% measured assuming 10% of supply resources transact in spot market	Expressed in $/kWh at 100% load factor
Comment 2:					info	info	June/July/August	Average for 1 month savings	Average for Summer Season	Average for Winter Season	June / July / August			DRIPE measured at 0.75% peak savings are across all of New England. Values are		DRIPE LIGHT measured at 0.75% peak savings are across all of New England.	
Period:							3-5 pm		June, July, August	Jan-May;Sept-Dec	3-5 pm						
2005[2]	0.074	0.064	0.069	0.051	5.387	4.835	10.222	0.449	1.263	0.251	10.222	0.001	0.001	0.00	0.000	0.00	0.000
2006	0.085	0.072	0.077	0.059	35.258	11.077	46.335	2.938	8.268	1.640	46.335	0.004	0.005	739.33	0.084	38.81	0.004
2007	0.087	0.074	0.081	0.062	39.936	9.630	49.566	3.328	9.365	1.857	49.566	0.005	0.006	978.41	0.112	54.89	0.006
2008	0.074	0.060	0.072	0.050	63.709	0.000	63.709	5.309	14.940	2.962	63.709	0.007	0.007	35.09	0.004	15.58	0.002
2009	0.060	0.049	0.056	0.040	68.126	0.000	68.126	5.677	15.976	3.168	68.126	0.008	0.008	436.08	0.050	41.82	0.005
2010	0.052	0.042	0.049	0.035	71.124	0.000	71.124	5.927	16.679	3.307	71.124	0.008	0.008	332.41	0.038	23.40	0.003
2011	0.055	0.044	0.051	0.037	74.254	0.000	74.254	6.188	17.413	3.453	74.254	0.008	0.008	228.74	0.026	4.97	0.001
2012	0.057	0.046	0.052	0.038	77.523	0.000	77.523	6.460	18.179	3.605	77.523	0.009	0.009	125.06	0.014	(13.45)	(0.002)
2013	0.057	0.046	0.053	0.039	79.296	0.000	79.296	6.608	18.595	3.687	79.296	0.009	0.009	142.39	0.016	(13.40)	(0.002)
2014	0.058	0.046	0.054	0.039	81.109	0.000	81.109	6.759	19.020	3.772	81.109	0.009	0.009	159.72	0.018	(13.35)	(0.002)
2015	0.058	0.047	0.054	0.040	82.965	0.000	82.965	6.914	19.455	3.858	82.965	0.009	0.009	177.04	0.020	(13.30)	(0.002)
2016	0.059	0.047	0.055	0.040	84.862	0.000	84.862	7.072	19.900	3.946	84.862	0.010	0.010	194.37	0.022	(13.25)	(0.002)
2017	0.060	0.049	0.057	0.042	84.012	0.000	84.012	7.001	19.701	3.907	84.012	0.010	0.010	218.99	0.025	(10.11)	(0.001)
2018	0.062	0.051	0.059	0.044	83.170	0.000	83.170	6.931	19.503	3.867	83.170	0.009	0.009	243.61	0.028	(6.97)	(0.001)
2019	0.064	0.053	0.061	0.045	82.336	0.000	82.336	6.861	19.308	3.829	82.336	0.009	0.009	268.23	0.031	(3.84)	(0.000)
2020	0.066	0.055	0.064	0.047	81.511	0.000	81.511	6.793	19.114	3.790	81.511	0.009	0.009	292.85	0.033	(0.70)	(0.000)
2021	0.066	0.055	0.065	0.048	81.400	0.000	81.400	6.783	19.088	3.785	81.400	0.009	0.009	277.03	0.032	(2.19)	(0.000)
2022	0.067	0.056	0.065	0.049	81.288	0.000	81.288	6.774	19.062	3.780	81.288	0.009	0.009	261.21	0.030	(3.68)	(0.000)
2023	0.068	0.056	0.066	0.049	81.177	0.000	81.177	6.765	19.036	3.775	81.177	0.009	0.009	245.39	0.028	(5.17)	(0.001)
2024	0.068	0.057	0.067	0.050	81.066	0.000	81.066	6.756	19.010	3.770	81.066	0.009	0.009	229.57	0.026	(6.66)	(0.001)
2025	0.069	0.057	0.068	0.051	80.956	0.000	80.956	6.746	18.984	3.764	80.956	0.009	0.009	213.75	0.024	(8.16)	(0.001)
2026	0.070	0.058	0.069	0.051	80.845	0.000	80.845	6.737	18.958	3.759	80.845	0.009	0.009	197.93	0.023	(9.65)	(0.001)
2027	0.070	0.059	0.069	0.052	80.735	0.000	80.735	6.728	18.932	3.754	80.735	0.009	0.009	182.10	0.021	(11.14)	(0.001)
2028	0.071	0.059	0.070	0.053	80.624	0.000	80.624	6.719	18.906	3.749	80.624	0.009	0.009	166.28	0.019	(12.63)	(0.001)
2029	0.072	0.060	0.071	0.054	80.514	0.000	80.514	6.710	18.881	3.744	80.514	0.009	0.009	150.46	0.017	(14.13)	(0.002)
2030	0.072	0.060	0.072	0.054	80.404	0.000	80.404	6.700	18.855	3.739	80.404	0.009	0.009	134.64	0.015	(15.62)	(0.002)
2031	0.072	0.060	0.072	0.054	74.442	0.000	74.442	6.203	17.457	3.462	74.442	0.008	0.008	123.74	0.014	(15.42)	(0.002)
2032	0.072	0.060	0.073	0.054	68.922	0.000	68.922	5.743	16.162	3.205	68.922	0.008	0.008	112.84	0.013	(15.22)	(0.002)
2033	0.072	0.060	0.073	0.054	63.811	0.000	63.811	5.318	14.964	2.967	63.811	0.007	0.007	101.95	0.012	(15.02)	(0.002)
2034	0.072	0.060	0.074	0.054	59.079	0.000	59.079	4.923	13.854	2.747	59.079	0.007	0.007	91.05	0.010	(14.82)	(0.002)
2035	0.072	0.059	0.074	0.053	54.698	0.000	54.698	4.558	12.827	2.543	54.698	0.006	0.006	80.15	0.009	(14.62)	(0.002)
2036	0.072	0.059	0.074	0.053	50.642	0.000	50.642	4.220	11.876	2.355	50.642	0.006	0.006	69.25	0.008	(14.42)	(0.002)
2037	0.072	0.059	0.075	0.053	46.887	0.000	46.887	3.907	10.995	2.180	46.887	0.005	0.005	58.36	0.007	(14.22)	(0.002)
2038	0.072	0.059	0.075	0.053	43.410	0.000	43.410	3.618	10.180	2.019	43.410	0.005	0.005	47.46	0.005	(14.02)	(0.002)
2039	0.072	0.059	0.076	0.053	40.191	0.000	40.191	3.349	9.425	1.869	40.191	0.005	0.005	36.56	0.004	(13.82)	(0.002)
2040	0.072	0.059	0.076	0.053	37.211	0.000	37.211	3.101	8.726	1.730	37.211	0.004	0.004	25.66	0.003	(13.62)	(0.002)
Levelized[3]:																	
2005-2040	0.067	0.056	0.065	0.048	67.827	0.964	68.790	5.652	15.905	3.154	68.790	0.008	0.008	225.800	0.026	-1.517	0.000
2006-2040	0.067	0.055	0.065	0.048	70.336	0.808	71.144	5.861	16.494	3.271	71.144	0.008	0.008	234.875	0.027	-1.578	0.000
2006-2010	0.072	0.060	0.067	0.050	55.228	4.270	59.498	4.602	12.951	2.568	59.498	0.006	0.007	509.740	0.058	35.078	0.004
2006-2015	0.065	0.053	0.060	0.044	66.491	2.242	68.733	5.541	15.592	3.092	68.733	0.008	0.008	346.913	0.040	13.879	0.002
2006-2020	0.064	0.052	0.060	0.044	71.515	1.568	73.083	5.960	16.770	3.325	73.083	0.008	0.008	315.578	0.036	7.576	0.001

Exhibit A2-2. Electric Energy Avoided Costs by AESC Screening Zone (continued)

	Boston																	
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value[1]	Annual Out of Market Expense	Total Annual Capacity Value	Capacity Value at Load Response (at any month)	Avoidable Capacity Payment at Load Response (Summer Season)	Avoidable Capacity Payment at Load Response (Winter Season)	Avoidable Capacity Payment at Energy Efficiency at Summer Coincident Peak	Load Response (at any month)	Energy Efficiency at Summer Coincident Peak	DRIPE 0.75% Capacity Price	DRIPE 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-month	$/kW-season	$/kW-season	$/kW-yr	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kW-yr	$/kWh
Comment 1:	Values are avoided costs at the generation plus transmission level. DSM savings should be measured at the generator plus transmission level. (Load plus + distribution losses)				Reflects Capacity Price resulting from LICAP beginning in 2006	Recovery of costs for RMR including continuing required payments after LICAP initiation		Avoided Cost applicable to KW savings contributing as supply side credit; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level			Avoided Cost applicable to KW savings at Summer Coincident Peak; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level	Avoided cost expressed in $/kWh at 100% load factor		Incremental to Avoided Cost at Summer Coincident Peak	Expressed in $/kWh at 100% load factor	DRIPE 0.75% measured assuming 10% of supply resources transact in spot market	Expressed in $/kWh at 100% load factor
Comment 2:					info	info	June/July/ August	Average for 1 month savings	Average for Summer Season	Average for Winter Season	June / July / August			DRIPE measured at 0.75% peak savings are across all of New England. Values are		DRIPE LIGHT measured at 0.75% peak savings are across all of New England.	
Period:							3-5 pm		June, July, August	Jan-May;Sept-Dec	3-5 pm						
2005[2]	0.074	0.064	0.069	0.051	5.387	4.835	10.222	0.449	1.263	0.251	10.222	0.001	0.001	0.00	0.000	0.00	0.000
2006	0.085	0.072	0.077	0.059	35.258	11.077	46.335	2.938	8.268	1.640	46.335	0.004	0.005	739.33	0.084	38.81	0.004
2007	0.087	0.074	0.081	0.062	39.936	9.630	49.566	3.328	9.365	1.857	49.566	0.005	0.006	978.41	0.112	54.89	0.006
2008	0.074	0.060	0.072	0.050	63.709	0.000	63.709	5.309	14.940	2.962	63.709	0.007	0.007	35.09	0.004	15.58	0.002
2009	0.060	0.049	0.056	0.040	68.126	0.000	68.126	5.677	15.976	3.168	68.126	0.008	0.008	436.08	0.050	41.82	0.005
2010	0.052	0.042	0.049	0.035	71.124	0.000	71.124	5.927	16.679	3.307	71.124	0.008	0.008	332.41	0.038	23.40	0.003
2011	0.055	0.044	0.051	0.037	74.254	0.000	74.254	6.188	17.413	3.453	74.254	0.008	0.008	228.74	0.026	4.97	0.001
2012	0.057	0.046	0.052	0.038	77.523	0.000	77.523	6.460	18.179	3.605	77.523	0.009	0.009	125.06	0.014	(13.45)	(0.002)
2013	0.057	0.046	0.053	0.039	79.296	0.000	79.296	6.608	18.595	3.687	79.296	0.009	0.009	142.39	0.016	(13.40)	(0.002)
2014	0.058	0.046	0.054	0.039	81.109	0.000	81.109	6.759	19.020	3.772	81.109	0.009	0.009	159.72	0.018	(13.35)	(0.002)
2015	0.058	0.047	0.054	0.040	82.965	0.000	82.965	6.914	19.455	3.858	82.965	0.009	0.009	177.04	0.020	(13.30)	(0.002)
2016	0.059	0.047	0.055	0.040	84.862	0.000	84.862	7.072	19.900	3.946	84.862	0.010	0.010	194.37	0.022	(13.25)	(0.002)
2017	0.060	0.049	0.057	0.042	84.012	0.000	84.012	7.001	19.701	3.907	84.012	0.010	0.010	218.99	0.025	(10.11)	(0.001)
2018	0.062	0.051	0.059	0.044	83.170	0.000	83.170	6.931	19.503	3.867	83.170	0.009	0.009	243.61	0.028	(6.97)	(0.001)
2019	0.064	0.053	0.061	0.045	82.336	0.000	82.336	6.861	19.308	3.829	82.336	0.009	0.009	268.23	0.031	(3.84)	(0.000)
2020	0.066	0.055	0.064	0.047	81.511	0.000	81.511	6.793	19.114	3.790	81.511	0.009	0.009	292.85	0.033	(0.70)	(0.000)
2021	0.066	0.055	0.065	0.048	81.400	0.000	81.400	6.783	19.088	3.785	81.400	0.009	0.009	277.03	0.032	(2.19)	(0.000)
2022	0.067	0.056	0.065	0.049	81.288	0.000	81.288	6.774	19.062	3.780	81.288	0.009	0.009	261.21	0.030	(3.68)	(0.000)
2023	0.068	0.056	0.066	0.049	81.177	0.000	81.177	6.765	19.036	3.775	81.177	0.009	0.009	245.39	0.028	(5.17)	(0.001)
2024	0.068	0.057	0.067	0.050	81.066	0.000	81.066	6.756	19.010	3.770	81.066	0.009	0.009	229.57	0.026	(6.66)	(0.001)
2025	0.069	0.057	0.068	0.051	80.956	0.000	80.956	6.746	18.984	3.764	80.956	0.009	0.009	213.75	0.024	(8.16)	(0.001)
2026	0.070	0.058	0.069	0.051	80.845	0.000	80.845	6.737	18.958	3.759	80.845	0.009	0.009	197.93	0.023	(9.65)	(0.001)
2027	0.070	0.059	0.069	0.052	80.735	0.000	80.735	6.728	18.932	3.754	80.735	0.009	0.009	182.10	0.021	(11.14)	(0.001)
2028	0.071	0.059	0.070	0.053	80.624	0.000	80.624	6.719	18.906	3.749	80.624	0.009	0.009	166.28	0.019	(12.63)	(0.001)
2029	0.072	0.060	0.071	0.054	80.514	0.000	80.514	6.710	18.881	3.744	80.514	0.009	0.009	150.46	0.017	(14.13)	(0.002)
2030	0.072	0.060	0.072	0.054	80.404	0.000	80.404	6.700	18.855	3.739	80.404	0.009	0.009	134.64	0.015	(15.62)	(0.002)
2031	0.072	0.060	0.072	0.054	74.442	0.000	74.442	6.203	17.457	3.462	74.442	0.008	0.008	123.74	0.014	(15.42)	(0.002)
2032	0.072	0.060	0.073	0.054	68.922	0.000	68.922	5.743	16.162	3.205	68.922	0.008	0.008	112.84	0.013	(15.22)	(0.002)
2033	0.072	0.060	0.073	0.054	63.811	0.000	63.811	5.318	14.964	2.967	63.811	0.007	0.007	101.95	0.012	(15.02)	(0.002)
2034	0.072	0.060	0.074	0.054	59.079	0.000	59.079	4.923	13.854	2.747	59.079	0.007	0.007	91.05	0.010	(14.82)	(0.002)
2035	0.072	0.059	0.074	0.053	54.698	0.000	54.698	4.558	12.827	2.543	54.698	0.006	0.006	80.15	0.009	(14.62)	(0.002)
2036	0.072	0.059	0.074	0.053	50.642	0.000	50.642	4.220	11.876	2.355	50.642	0.006	0.006	69.25	0.008	(14.42)	(0.002)
2037	0.072	0.059	0.075	0.053	46.887	0.000	46.887	3.907	10.995	2.180	46.887	0.005	0.005	58.36	0.007	(14.22)	(0.002)
2038	0.072	0.059	0.075	0.053	43.410	0.000	43.410	3.618	10.180	2.019	43.410	0.005	0.005	47.46	0.005	(14.02)	(0.002)
2039	0.072	0.059	0.076	0.053	40.191	0.000	40.191	3.349	9.425	1.869	40.191	0.005	0.005	36.56	0.004	(13.82)	(0.002)
2040	0.072	0.059	0.076	0.053	37.211	0.000	37.211	3.101	8.726	1.730	37.211	0.004	0.004	25.66	0.003	(13.62)	(0.002)
Levelized[3]:																	
2005-2040	0.067	0.056	0.065	0.048	67.827	0.964	68.790	5.652	15.905	3.154	68.790	0.008	0.008	225.800	0.026	-1.517	0.000
2006-2040	0.067	0.055	0.065	0.048	70.336	0.808	71.144	5.861	16.494	3.271	71.144	0.008	0.008	234.875	0.027	-1.578	0.000
2006-2010	0.072	0.060	0.067	0.050	55.228	4.270	59.498	4.602	12.951	2.568	59.498	0.006	0.007	509.740	0.058	35.078	0.004
2006-2015	0.065	0.053	0.060	0.044	66.491	2.242	68.733	5.541	15.592	3.092	68.733	0.008	0.008	346.913	0.040	13.879	0.002
2006-2020	0.064	0.052	0.060	0.044	71.515	1.568	73.083	5.960	16.770	3.325	73.083	0.008	0.008	315.578	0.036	7.576	0.001

Exhibit A2-2. Electric Energy Avoided Costs by AESC Screening Zone (continued)

	Rest of Massachusetts - Southeast, Central and Western Massachusetts																
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value[1]	Annual Out of Market Expense	Total Annual Capacity Value	Capacity Value at Load Response (at any month)	Avoidable Capacity Payment at Load Response (Summer Season)	Avoidable Capacity Payment at Load Response (Winter Season)	Avoidable Capacity Payment at Energy Efficiency at Summer Coincident Peak	Load Response (at any month)	Energy Efficiency at Summer Coincident Peak	DRIPE 0.75% Capacity Price	DRIPE 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-month	$/kW-season	$/kW-season	$/kW-yr	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kW-yr	$/kWh
Comment 1:	Values are avoided costs at the generation plus transmission level. DSM savings should be measured at the generator plus transmission level. (Load plus + distribution losses)				Reflects Capacity Price resulting from LICAP beginning in 2006	Recovery of costs for RMR including continuing required payments after LICAP initiation		Avoided Cost applicable to KW savings contributing as supply side credit; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level			Avoided Cost applicable to KW savings at Summer Coincident Peak; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level	Avoided cost expressed in $/kWh at 100% load factor		Incremental to Avoided Cost at Summer Coincident Peak	Expressed in $/kWh at 100% load factor	DRIPE 0.75% measured assuming 10% of supply resources transact in spot market	Expressed in $/kWh at 100% load factor
Comment 2:					info	info	June/July/ August	Average for 1 month savings	Average for Summer Season	Average for Winter Season	June / July / August			DRIPE measured at 0.75% peak savings are across all of New England. Values are		DRIPE LIGHT measured at 0.75% peak savings are across all of New England.	
Period:							3-5 pm		June, July, August	Jan-May;Sept-Dec	3-5 pm						
2005[2]	0.074	0.064	0.069	0.051	2.662	0.954	3.616	0.222	0.624	0.124	3.616	0.000	0.000	0.00	0.000	0.00	0.000
2006	0.085	0.072	0.077	0.059	34.548	1.801	36.350	2.879	8.102	1.607	36.350	0.004	0.004	654.43	0.075	32.57	0.004
2007	0.087	0.074	0.081	0.062	39.132	2.151	41.283	3.261	9.176	1.820	41.283	0.004	0.005	906.91	0.104	88.60	0.010
2008	0.074	0.060	0.072	0.050	62.436	0.199	62.635	5.203	14.641	2.903	62.635	0.007	0.007	32.87	0.004	15.28	0.002
2009	0.060	0.049	0.056	0.040	66.758	0.204	66.962	5.563	15.655	3.104	66.962	0.008	0.008	357.68	0.041	9.62	0.001
2010	0.052	0.042	0.049	0.035	69.696	0.177	69.874	5.808	16.344	3.241	69.874	0.008	0.008	266.06	0.030	(6.87)	(0.001)
2011	0.055	0.044	0.051	0.037	72.764	0.154	72.918	6.064	17.063	3.384	72.918	0.008	0.008	174.43	0.020	(23.35)	(0.003)
2012	0.057	0.046	0.052	0.038	75.967	0.133	76.100	6.331	17.814	3.532	76.100	0.009	0.009	82.81	0.009	(39.84)	(0.005)
2013	0.057	0.046	0.053	0.039	76.270	0.000	76.270	6.356	17.885	3.547	76.270	0.009	0.009	119.16	0.014	(21.08)	(0.002)
2014	0.058	0.046	0.054	0.039	76.575	0.000	76.575	6.381	17.957	3.561	76.575	0.009	0.009	155.52	0.018	(2.33)	(0.000)
2015	0.058	0.047	0.054	0.040	76.881	0.000	76.881	6.407	18.029	3.575	76.881	0.009	0.009	191.87	0.022	16.43	0.002
2016	0.059	0.047	0.055	0.040	77.188	0.000	77.188	6.432	18.101	3.589	77.188	0.009	0.009	228.22	0.026	35.18	0.004
2017	0.060	0.049	0.057	0.042	76.704	0.000	76.704	6.392	17.987	3.567	76.704	0.009	0.009	258.99	0.030	36.72	0.004
2018	0.062	0.051	0.059	0.044	76.222	0.000	76.222	6.352	17.874	3.544	76.222	0.009	0.009	289.75	0.033	38.26	0.004
2019	0.064	0.053	0.061	0.045	75.743	0.000	75.743	6.312	17.762	3.522	75.743	0.009	0.009	320.52	0.037	39.80	0.005
2020	0.066	0.055	0.064	0.047	75.267	0.000	75.267	6.272	17.650	3.500	75.267	0.009	0.009	351.29	0.040	41.34	0.005
2021	0.066	0.055	0.065	0.048	75.613	0.000	75.613	6.301	17.731	3.516	75.613	0.009	0.009	328.09	0.037	35.34	0.004
2022	0.067	0.056	0.065	0.049	75.960	0.000	75.960	6.330	17.813	3.532	75.960	0.009	0.009	304.90	0.035	29.34	0.003
2023	0.068	0.056	0.066	0.049	76.309	0.000	76.309	6.359	17.894	3.548	76.309	0.009	0.009	281.70	0.032	23.34	0.003
2024	0.068	0.057	0.067	0.050	76.660	0.000	76.660	6.388	17.977	3.565	76.660	0.009	0.009	258.50	0.030	17.35	0.002
2025	0.069	0.057	0.068	0.051	77.012	0.000	77.012	6.418	18.059	3.581	77.012	0.009	0.009	235.31	0.027	11.35	0.001
2026	0.070	0.058	0.069	0.051	77.365	0.000	77.365	6.447	18.142	3.597	77.365	0.009	0.009	212.11	0.024	5.35	0.001
2027	0.070	0.059	0.069	0.052	77.721	0.000	77.721	6.477	18.225	3.614	77.721	0.009	0.009	188.91	0.022	(0.65)	(0.000)
2028	0.071	0.059	0.070	0.053	78.078	0.000	78.078	6.506	18.309	3.631	78.078	0.009	0.009	165.72	0.019	(6.65)	(0.001)
2029	0.072	0.060	0.071	0.054	78.436	0.000	78.436	6.536	18.393	3.647	78.436	0.009	0.009	142.52	0.016	(12.64)	(0.001)
2030	0.072	0.060	0.072	0.054	78.796	0.000	78.796	6.566	18.478	3.664	78.796	0.009	0.009	119.32	0.014	(18.64)	(0.002)
2031	0.072	0.060	0.072	0.054	72.952	0.000	72.952	6.079	17.107	3.392	72.952	0.008	0.008	109.42	0.012	(18.43)	(0.002)
2032	0.072	0.060	0.073	0.054	67.541	0.000	67.541	5.628	15.838	3.141	67.541	0.008	0.008	99.52	0.011	(18.22)	(0.002)
2033	0.072	0.060	0.073	0.054	62.531	0.000	62.531	5.211	14.664	2.908	62.531	0.007	0.007	89.62	0.010	(18.01)	(0.002)
2034	0.072	0.060	0.074	0.054	57.893	0.000	57.893	4.824	13.576	2.692	57.893	0.007	0.007	79.72	0.009	(17.80)	(0.002)
2035	0.072	0.059	0.074	0.053	53.599	0.000	53.599	4.467	12.569	2.492	53.599	0.006	0.006	69.82	0.008	(17.59)	(0.002)
2036	0.072	0.059	0.074	0.053	49.623	0.000	49.623	4.135	11.637	2.307	49.623	0.006	0.006	59.92	0.007	(17.38)	(0.002)
2037	0.072	0.059	0.075	0.053	45.943	0.000	45.943	3.829	10.774	2.136	45.943	0.005	0.005	50.02	0.006	(17.17)	(0.002)
2038	0.072	0.059	0.075	0.053	42.535	0.000	42.535	3.545	9.974	1.978	42.535	0.005	0.005	40.12	0.005	(16.96)	(0.002)
2039	0.072	0.059	0.076	0.053	39.380	0.000	39.380	3.282	9.235	1.831	39.380	0.004	0.004	30.22	0.003	(16.75)	(0.002)
2040	0.072	0.059	0.076	0.053	36.459	0.000	36.459	3.038	8.550	1.695	36.459	0.004	0.004	20.32	0.002	(16.54)	(0.002)
Levelized[3]:																	
2005-2040	0.067	0.056	0.065	0.048	64.742	0.215	64.957	5.395	15.182	3.010	64.957	0.007	0.007	220.657	0.025	7.200	0.001
2006-2040	0.067	0.055	0.065	0.048	67.237	0.186	67.422	5.603	15.767	3.127	67.422	0.008	0.008	229.525	0.026	7.489	0.001
2006-2010	0.072	0.060	0.067	0.050	54.120	0.927	55.047	4.510	12.691	2.517	55.047	0.006	0.006	448.938	0.051	28.472	0.003
2006-2015	0.065	0.053	0.060	0.044	64.347	0.515	64.862	5.362	15.089	2.992	64.862	0.007	0.007	304.283	0.035	8.063	0.001
2006-2020	0.064	0.052	0.060	0.044	67.922	0.360	68.282	5.660	15.928	3.158	68.282	0.008	0.008	299.546	0.034	17.117	0.002

Exhibit A2-2. Electric Energy Avoided Costs by AESC Screening Zone (continued)

	Boston & Southeast Massachusetts																
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value[1]	Annual Out of Market Expense	Total Annual Capacity Value	Capacity Value at Load Response (at any month)	Avoidable Capacity Payment at Load Response (Summer Season)	Avoidable Capacity Payment at Load Response (Winter Season)	Avoidable Capacity Payment at Energy Efficiency at Summer Coincident Peak	Load Response (at any month)	Energy Efficiency at Summer Coincident Peak	DRIPE 0.75% Capacity Price	DRIPE 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-month	$/kW-season	$/kW-season	$/kW-yr	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kW-yr	$/kWh
Comment 1:	Values are avoided costs at the generation plus transmission level. DSM savings should be measured at the generator plus transmission level. (Load plus + distribution losses)				Reflects Capacity Price resulting from LICAP beginning in 2006	Recovery of costs for RMR including continuing required payments after LICAP initiation		Avoided Cost applicable to KW savings contributing as supply side credit; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level			Avoided Cost applicable to KW savings at Summer Coincident Peak; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level	Avoided cost expressed in $/kWh at 100% load factor		Incremental to Avoided Cost at Summer Coincident Peak	Expressed in $/kWh at 100% load factor	DRIPE 0.75% measured assuming 10% of supply resources transact in spot market	Expressed in $/kWh at 100% load factor
Comment 2:					info	info	June/July/ August	Average for 1 month savings	Average for Summer Season	Average for Winter Season	June / July / August			DRIPE measured at 0.75% peak savings are across all of New England. Values are		DRIPE LIGHT measured at 0.75% peak savings are across all of New England.	
Period:							3-5 pm		June, July, August	Jan-May;Sept-Dec	3-5 pm						
2005[2]	0.074	0.064	0.069	0.051	4.489	3.555	8.045	0.374	1.053	0.209	8.045	0.001	0.001	0.00	0.000	0.00	0.000
2006	0.085	0.072	0.077	0.059	35.024	8.011	43.035	2.919	8.213	1.629	43.035	0.004	0.005	711.23	0.081	36.75	0.004
2007	0.087	0.074	0.081	0.062	39.670	7.154	46.824	3.306	9.303	1.845	46.824	0.005	0.005	954.69	0.109	66.07	0.008
2008	0.074	0.060	0.072	0.050	63.287	0.066	63.353	5.274	14.841	2.943	63.353	0.007	0.007	34.36	0.004	15.48	0.002
2009	0.060	0.049	0.056	0.040	67.672	0.068	67.740	5.639	15.869	3.147	67.740	0.008	0.008	409.99	0.047	31.11	0.004
2010	0.052	0.042	0.049	0.035	70.649	0.059	70.708	5.887	16.567	3.285	70.708	0.008	0.008	310.32	0.035	13.32	0.002
2011	0.055	0.044	0.051	0.037	73.758	0.051	73.809	6.147	17.296	3.430	73.809	0.008	0.008	210.65	0.024	(4.46)	(0.001)
2012	0.057	0.046	0.052	0.038	77.004	0.044	77.048	6.417	18.057	3.581	77.048	0.009	0.009	110.98	0.013	(22.25)	(0.003)
2013	0.057	0.046	0.053	0.039	78.292	0.000	78.292	6.524	18.360	3.641	78.292	0.009	0.009	134.66	0.015	(15.94)	(0.002)
2014	0.058	0.046	0.054	0.039	79.603	0.000	79.603	6.634	18.667	3.702	79.603	0.009	0.009	158.35	0.018	(9.63)	(0.001)
2015	0.058	0.047	0.054	0.040	80.935	0.000	80.935	6.745	18.979	3.763	80.935	0.009	0.009	182.04	0.021	(3.32)	(0.000)
2016	0.059	0.047	0.055	0.040	82.289	0.000	82.289	6.857	19.297	3.826	82.289	0.009	0.009	205.72	0.023	2.99	0.000
2017	0.060	0.049	0.057	0.042	81.558	0.000	81.558	6.797	19.125	3.792	81.558	0.009	0.009	232.44	0.027	5.62	0.001
2018	0.062	0.051	0.059	0.044	80.834	0.000	80.834	6.736	18.955	3.759	80.834	0.009	0.009	259.16	0.030	8.25	0.001
2019	0.064	0.053	0.061	0.045	80.116	0.000	80.116	6.676	18.787	3.725	80.116	0.009	0.009	285.88	0.033	10.88	0.001
2020	0.066	0.055	0.064	0.047	79.404	0.000	79.404	6.617	18.620	3.692	79.404	0.009	0.009	312.60	0.036	13.51	0.002
2021	0.066	0.055	0.065	0.048	79.449	0.000	79.449	6.621	18.631	3.694	79.449	0.009	0.009	294.28	0.034	10.49	0.001
2022	0.067	0.056	0.065	0.049	79.493	0.000	79.493	6.624	18.641	3.696	79.493	0.009	0.009	275.95	0.032	7.47	0.001
2023	0.068	0.056	0.066	0.049	79.538	0.000	79.538	6.628	18.652	3.699	79.538	0.009	0.009	257.63	0.029	4.46	0.001
2024	0.068	0.057	0.067	0.050	79.583	0.000	79.583	6.632	18.662	3.701	79.583	0.009	0.009	239.31	0.027	1.44	0.000
2025	0.069	0.057	0.068	0.051	79.628	0.000	79.628	6.636	18.673	3.703	79.628	0.009	0.009	220.99	0.025	(1.58)	(0.000)
2026	0.070	0.058	0.069	0.051	79.673	0.000	79.673	6.639	18.683	3.705	79.673	0.009	0.009	202.66	0.023	(4.59)	(0.001)
2027	0.070	0.059	0.069	0.052	79.718	0.000	79.718	6.643	18.694	3.707	79.718	0.009	0.009	184.34	0.021	(7.61)	(0.001)
2028	0.071	0.059	0.070	0.053	79.763	0.000	79.763	6.647	18.704	3.709	79.763	0.009	0.009	166.02	0.019	(10.63)	(0.001)
2029	0.072	0.060	0.071	0.054	79.808	0.000	79.808	6.651	18.715	3.711	79.808	0.009	0.009	147.70	0.017	(13.64)	(0.002)
2030	0.072	0.060	0.072	0.054	79.853	0.000	79.853	6.654	18.726	3.713	79.853	0.009	0.009	129.37	0.015	(16.66)	(0.002)
2031	0.072	0.060	0.072	0.054	73.930	0.000	73.930	6.161	17.337	3.438	73.930	0.008	0.008	118.82	0.014	(16.46)	(0.002)
2032	0.072	0.060	0.073	0.054	68.447	0.000	68.447	5.704	16.051	3.183	68.447	0.008	0.008	108.26	0.012	(16.25)	(0.002)
2033	0.072	0.060	0.073	0.054	63.370	0.000	63.370	5.281	14.860	2.947	63.370	0.007	0.007	97.70	0.011	(16.05)	(0.002)
2034	0.072	0.060	0.074	0.054	58.670	0.000	58.670	4.889	13.758	2.728	58.670	0.007	0.007	87.14	0.010	(15.85)	(0.002)
2035	0.072	0.059	0.074	0.053	54.318	0.000	54.318	4.527	12.738	2.526	54.318	0.006	0.006	76.58	0.009	(15.65)	(0.002)
2036	0.072	0.059	0.074	0.053	50.290	0.000	50.290	4.191	11.793	2.338	50.290	0.006	0.006	66.03	0.008	(15.45)	(0.002)
2037	0.072	0.059	0.075	0.053	46.560	0.000	46.560	3.880	10.918	2.165	46.560	0.005	0.005	55.47	0.006	(15.24)	(0.002)
2038	0.072	0.059	0.075	0.053	43.106	0.000	43.106	3.592	10.108	2.004	43.106	0.005	0.005	44.91	0.005	(15.04)	(0.002)
2039	0.072	0.059	0.076	0.053	39.909	0.000	39.909	3.326	9.359	1.856	39.909	0.005	0.005	34.35	0.004	(14.84)	(0.002)
2040	0.072	0.059	0.076	0.053	36.949	0.000	36.949	3.079	8.665	1.718	36.949	0.004	0.004	23.79	0.003	(14.64)	(0.002)
Levelized[3]:																	
2005-2040	0.067	0.056	0.065	0.048	66.790	0.716	67.506	5.566	15.662	3.106	67.506	0.008	0.008	224.114	0.026	1.425	0.000
2006-2040	0.067	0.055	0.065	0.048	69.294	0.602	69.896	5.774	16.249	3.222	69.896	0.008	0.008	233.121	0.027	1.482	0.000
2006-2010	0.072	0.060	0.067	0.050	54.861	3.164	58.025	4.572	12.865	2.551	58.025	0.006	0.007	489.553	0.056	32.873	0.004
2006-2015	0.065	0.053	0.060	0.044	65.778	1.671	67.449	5.482	15.425	3.059	67.449	0.008	0.008	332.756	0.038	11.953	0.001
2006-2020	0.064	0.052	0.060	0.044	70.312	1.169	71.481	5.859	16.488	3.270	71.481	0.008	0.008	310.322	0.035	10.809	0.001

Exhibit A2-2. Electric Energy Avoided Costs by AESC Screening Zone (continued)

	New Hampshire																
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value[1]	Annual Out of Market Expense	Total Annual Capacity Value	Capacity Value at Load Response (at any month)	Avoidable Capacity Payment at Load Response (Summer Season)	Avoidable Capacity Payment at Load Response (Winter Season)	Avoidable Capacity Payment at Energy Efficiency at Summer Coincident Peak	Load Response (at any month)	Energy Efficiency at Summer Coincident Peak	DRIPE 0.75% Capacity Price	DRIPE 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-month	$/kW-season	$/kW-season	$/kW-yr	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kW-yr	$/kWh
Comment 1:	Values are avoided costs at the generation plus transmission level. DSM savings should be measured at the generator plus transmission level. (Load plus + distribution losses)				Reflects Capacity Price resulting from LICAP beginning in 2006	Recovery of costs for RMR including continuing required payments after LICAP initiation		Avoided Cost applicable to KW savings contributing as supply side credit; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level			Avoided Cost applicable to KW savings at Summer Coincident Peak; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level	Avoided cost expressed in $/kWh at 100% load factor		Incremental to Avoided Cost at Summer Coincident Peak	Expressed in $/kWh at 100% load factor	DRIPE 0.75% measured assuming 10% of supply resources transact in spot market	Expressed in $/kWh at 100% load factor
Comment 2:					info	info	June/July/August	Average for 1 month savings	Average for Summer Season	Average for Winter Season	June / July / August			DRIPE measured at 0.75% peak savings are across all of New England. Values are		DRIPE LIGHT measured at 0.75% peak savings are across all of New England.	
Period:							3-5 pm		June, July, August	Jan-May;Sept-Dec	3-5 pm						
2005[2]	0.072	0.063	0.066	0.049	2.662	0.954	3.616	0.222	0.624	0.124	3.616	0.000	0.000	0.00	0.000	0.00	0.000
2006	0.082	0.070	0.074	0.058	34.548	1.801	36.350	2.879	8.102	1.607	36.350	0.004	0.004	654.43	0.075	32.57	0.004
2007	0.085	0.072	0.079	0.060	39.132	2.151	41.283	3.261	9.176	1.820	41.283	0.004	0.005	906.91	0.104	88.60	0.010
2008	0.072	0.059	0.070	0.050	62.436	0.199	62.635	5.203	14.641	2.903	62.635	0.007	0.007	32.87	0.004	15.28	0.002
2009	0.058	0.048	0.055	0.039	66.758	0.204	66.962	5.563	15.655	3.104	66.962	0.008	0.008	357.68	0.041	9.62	0.001
2010	0.051	0.041	0.048	0.034	69.696	0.177	69.874	5.808	16.344	3.241	69.874	0.008	0.008	266.06	0.030	(6.87)	(0.001)
2011	0.053	0.043	0.050	0.036	72.764	0.154	72.918	6.064	17.063	3.384	72.918	0.008	0.008	174.43	0.020	(23.35)	(0.003)
2012	0.056	0.045	0.051	0.038	75.967	0.133	76.100	6.331	17.814	3.532	76.100	0.009	0.009	82.81	0.009	(39.84)	(0.005)
2013	0.056	0.045	0.052	0.038	76.270	0.000	76.270	6.356	17.885	3.547	76.270	0.009	0.009	119.16	0.014	(21.08)	(0.002)
2014	0.057	0.046	0.053	0.039	76.575	0.000	76.575	6.381	17.957	3.561	76.575	0.009	0.009	155.52	0.018	(2.33)	(0.000)
2015	0.057	0.046	0.053	0.039	76.881	0.000	76.881	6.407	18.029	3.575	76.881	0.009	0.009	191.87	0.022	16.43	0.002
2016	0.058	0.047	0.054	0.039	77.188	0.000	77.188	6.432	18.101	3.589	77.188	0.009	0.009	228.22	0.026	35.18	0.004
2017	0.059	0.048	0.056	0.041	76.704	0.000	76.704	6.392	17.987	3.567	76.704	0.009	0.009	258.99	0.030	36.72	0.004
2018	0.061	0.050	0.058	0.043	76.222	0.000	76.222	6.352	17.874	3.544	76.222	0.009	0.009	289.75	0.033	38.26	0.004
2019	0.063	0.052	0.061	0.045	75.743	0.000	75.743	6.312	17.762	3.522	75.743	0.009	0.009	320.52	0.037	39.80	0.005
2020	0.065	0.054	0.063	0.047	75.267	0.000	75.267	6.272	17.650	3.500	75.267	0.009	0.009	351.29	0.040	41.34	0.005
2021	0.065	0.054	0.064	0.048	75.613	0.000	75.613	6.301	17.731	3.516	75.613	0.009	0.009	328.09	0.037	35.34	0.004
2022	0.066	0.055	0.065	0.048	75.960	0.000	75.960	6.330	17.813	3.532	75.960	0.009	0.009	304.90	0.035	29.34	0.003
2023	0.067	0.056	0.065	0.049	76.309	0.000	76.309	6.359	17.894	3.548	76.309	0.009	0.009	281.70	0.032	23.34	0.003
2024	0.067	0.056	0.066	0.050	76.660	0.000	76.660	6.388	17.977	3.565	76.660	0.009	0.009	258.50	0.030	17.35	0.002
2025	0.068	0.057	0.067	0.050	77.012	0.000	77.012	6.418	18.059	3.581	77.012	0.009	0.009	235.31	0.027	11.35	0.001
2026	0.069	0.057	0.068	0.051	77.365	0.000	77.365	6.447	18.142	3.597	77.365	0.009	0.009	212.11	0.024	5.35	0.001
2027	0.070	0.058	0.069	0.052	77.721	0.000	77.721	6.477	18.225	3.614	77.721	0.009	0.009	188.91	0.022	(0.65)	(0.000)
2028	0.070	0.058	0.070	0.053	78.078	0.000	78.078	6.506	18.309	3.631	78.078	0.009	0.009	165.72	0.019	(6.65)	(0.001)
2029	0.071	0.059	0.071	0.053	78.436	0.000	78.436	6.536	18.393	3.647	78.436	0.009	0.009	142.52	0.016	(12.64)	(0.001)
2030	0.072	0.060	0.071	0.054	78.796	0.000	78.796	6.566	18.478	3.664	78.796	0.009	0.009	119.32	0.014	(18.64)	(0.002)
2031	0.072	0.059	0.072	0.054	72.952	0.000	72.952	6.079	17.107	3.392	72.952	0.008	0.008	109.42	0.012	(18.43)	(0.002)
2032	0.072	0.059	0.072	0.054	67.541	0.000	67.541	5.628	15.838	3.141	67.541	0.008	0.008	99.52	0.011	(18.22)	(0.002)
2033	0.072	0.059	0.073	0.054	62.531	0.000	62.531	5.211	14.664	2.908	62.531	0.007	0.007	89.62	0.010	(18.01)	(0.002)
2034	0.072	0.059	0.073	0.053	57.893	0.000	57.893	4.824	13.576	2.692	57.893	0.007	0.007	79.72	0.009	(17.80)	(0.002)
2035	0.072	0.059	0.073	0.053	53.599	0.000	53.599	4.467	12.569	2.492	53.599	0.006	0.006	69.82	0.008	(17.59)	(0.002)
2036	0.072	0.059	0.074	0.053	49.623	0.000	49.623	4.135	11.637	2.307	49.623	0.006	0.006	59.92	0.007	(17.38)	(0.002)
2037	0.072	0.058	0.074	0.053	45.943	0.000	45.943	3.829	10.774	2.136	45.943	0.005	0.005	50.02	0.006	(17.17)	(0.002)
2038	0.071	0.058	0.075	0.053	42.535	0.000	42.535	3.545	9.974	1.978	42.535	0.005	0.005	40.12	0.005	(16.96)	(0.002)
2039	0.071	0.058	0.075	0.052	39.380	0.000	39.380	3.282	9.235	1.831	39.380	0.004	0.004	30.22	0.003	(16.75)	(0.002)
2040	0.071	0.058	0.075	0.052	36.459	0.000	36.459	3.038	8.550	1.695	36.459	0.004	0.004	20.32	0.002	(16.54)	(0.002)
Levelized[3]**:**																	
2005-2040	0.066	0.055	0.064	0.047	64.742	0.215	64.957	5.395	15.182	3.010	64.957	0.007	0.007	220.657	0.025	7.200	0.001
2006-2040	0.066	0.055	0.064	0.047	67.237	0.186	67.422	5.603	15.767	3.127	67.422	0.008	0.008	229.525	0.026	7.489	0.001
2006-2010	0.070	0.059	0.065	0.049	54.120	0.927	55.047	4.510	12.691	2.517	55.047	0.006	0.006	448.938	0.051	28.472	0.003
2006-2015	0.063	0.052	0.059	0.043	64.347	0.515	64.862	5.362	15.089	2.992	64.862	0.007	0.007	304.283	0.035	8.063	0.001
2006-2020	0.063	0.052	0.059	0.043	67.922	0.360	68.282	5.660	15.928	3.158	68.282	0.008	0.008	299.546	0.034	17.117	0.002

Exhibit A2-2. Electric Energy Avoided Costs by AESC Screening Zone (continued)

	Rhode Island																
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value[1]	Annual Out of Market Expense	Total Annual Capacity Value	Capacity Value at Load Response (at any month)	Avoidable Capacity Payment at Load Response (Summer Season)	Avoidable Capacity Payment at Load Response (Winter Season)	Avoidable Capacity Payment at Energy Efficiency at Summer Coincident Peak	Load Response (at any month)	Energy Efficiency at Summer Coincident Peak	DRIPE 0.75% Capacity Price	DRIPE 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-month	$/kW-season	$/kW-season	$/kW-yr	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kW-yr	$/kWh
Comment 1:	Values are avoided costs at the generation plus transmission level. DSM savings should be measured at the generator plus transmission level. (Load plus + distribution losses)				Reflects Capacity Price resulting from LICAP beginning in 2006	Recovery of costs for RMR including continuing required payments after LICAP initiation		Avoided Cost applicable to KW savings contributing as supply side credit; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level			Avoided Cost applicable to KW savings at Summer Coincident Peak; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level	Avoided cost expressed in $/kWh at 100% load factor		Incremental to Avoided Cost at Summer Coincident Peak	Expressed in $/kWh at 100% load factor	DRIPE 0.75% measured assuming 10% of supply resources transact in spot market	Expressed in $/kWh at 100% load factor
Comment 2:					info	info	June/July/ August	Average for 1 month savings	Average for Summer Season	Average for Winter Season	June / July / August			DRIPE measured at 0.75% peak savings are across all of New England. Values are		DRIPE LIGHT measured at 0.75% peak savings are across all of New England.	
Period:							3-5 pm		June, July, August	Jan-May;Sept-Dec	3-5 pm						
2005[2]	0.073	0.064	0.068	0.051	2.662	0.954	3.616	0.222	0.624	0.124	3.616	0.000	0.000	0.00	0.000	0.00	0.000
2006	0.084	0.072	0.077	0.060	34.548	1.801	36.350	2.879	8.102	1.607	36.350	0.004	0.004	654.43	0.075	32.57	0.004
2007	0.087	0.074	0.081	0.062	39.132	2.151	41.283	3.261	9.176	1.820	41.283	0.004	0.005	906.91	0.104	88.60	0.010
2008	0.074	0.060	0.071	0.051	62.436	0.199	62.635	5.203	14.641	2.903	62.635	0.007	0.007	32.87	0.004	15.28	0.002
2009	0.060	0.049	0.056	0.040	66.758	0.204	66.962	5.563	15.655	3.104	66.962	0.008	0.008	357.68	0.041	9.62	0.001
2010	0.052	0.042	0.048	0.035	69.696	0.177	69.874	5.808	16.344	3.241	69.874	0.008	0.008	266.06	0.030	(6.87)	(0.001)
2011	0.054	0.044	0.050	0.037	72.764	0.154	72.918	6.064	17.063	3.384	72.918	0.008	0.008	174.43	0.020	(23.35)	(0.003)
2012	0.057	0.045	0.052	0.038	75.967	0.133	76.100	6.331	17.814	3.532	76.100	0.009	0.009	82.81	0.009	(39.84)	(0.005)
2013	0.057	0.046	0.053	0.039	76.270	0.000	76.270	6.356	17.885	3.547	76.270	0.009	0.009	119.16	0.014	(21.08)	(0.002)
2014	0.057	0.046	0.053	0.039	76.575	0.000	76.575	6.381	17.957	3.561	76.575	0.009	0.009	155.52	0.018	(2.33)	(0.000)
2015	0.058	0.047	0.054	0.040	76.881	0.000	76.881	6.407	18.029	3.575	76.881	0.009	0.009	191.87	0.022	16.43	0.002
2016	0.058	0.047	0.054	0.040	77.188	0.000	77.188	6.432	18.101	3.589	77.188	0.009	0.009	228.22	0.026	35.18	0.004
2017	0.060	0.049	0.056	0.042	76.704	0.000	76.704	6.392	17.987	3.567	76.704	0.009	0.009	258.99	0.030	36.72	0.004
2018	0.062	0.050	0.059	0.044	76.222	0.000	76.222	6.352	17.874	3.544	76.222	0.009	0.009	289.75	0.033	38.26	0.004
2019	0.063	0.052	0.061	0.046	75.743	0.000	75.743	6.312	17.762	3.522	75.743	0.009	0.009	320.52	0.037	39.80	0.005
2020	0.065	0.054	0.063	0.048	75.267	0.000	75.267	6.272	17.650	3.500	75.267	0.009	0.009	351.29	0.040	41.34	0.005
2021	0.066	0.055	0.064	0.048	75.613	0.000	75.613	6.301	17.731	3.516	75.613	0.009	0.009	328.09	0.037	35.34	0.004
2022	0.067	0.055	0.065	0.049	75.960	0.000	75.960	6.330	17.813	3.532	75.960	0.009	0.009	304.90	0.035	29.34	0.003
2023	0.067	0.056	0.066	0.050	76.309	0.000	76.309	6.359	17.894	3.548	76.309	0.009	0.009	281.70	0.032	23.34	0.003
2024	0.068	0.057	0.067	0.050	76.660	0.000	76.660	6.388	17.977	3.565	76.660	0.009	0.009	258.50	0.030	17.35	0.002
2025	0.069	0.057	0.067	0.051	77.012	0.000	77.012	6.418	18.059	3.581	77.012	0.009	0.009	235.31	0.027	11.35	0.001
2026	0.069	0.058	0.068	0.052	77.365	0.000	77.365	6.447	18.142	3.597	77.365	0.009	0.009	212.11	0.024	5.35	0.001
2027	0.070	0.058	0.069	0.052	77.721	0.000	77.721	6.477	18.225	3.614	77.721	0.009	0.009	188.91	0.022	(0.65)	(0.000)
2028	0.071	0.059	0.070	0.053	78.078	0.000	78.078	6.506	18.309	3.631	78.078	0.009	0.009	165.72	0.019	(6.65)	(0.001)
2029	0.072	0.060	0.071	0.054	78.436	0.000	78.436	6.536	18.393	3.647	78.436	0.009	0.009	142.52	0.016	(12.64)	(0.001)
2030	0.072	0.060	0.072	0.054	78.796	0.000	78.796	6.566	18.478	3.664	78.796	0.009	0.009	119.32	0.014	(18.64)	(0.002)
2031	0.072	0.060	0.072	0.054	72.952	0.000	72.952	6.079	17.107	3.392	72.952	0.008	0.008	109.42	0.012	(18.43)	(0.002)
2032	0.072	0.060	0.072	0.054	67.541	0.000	67.541	5.628	15.838	3.141	67.541	0.008	0.008	99.52	0.011	(18.22)	(0.002)
2033	0.072	0.060	0.073	0.054	62.531	0.000	62.531	5.211	14.664	2.908	62.531	0.007	0.007	89.62	0.010	(18.01)	(0.002)
2034	0.072	0.060	0.073	0.054	57.893	0.000	57.893	4.824	13.576	2.692	57.893	0.007	0.007	79.72	0.009	(17.80)	(0.002)
2035	0.072	0.059	0.074	0.054	53.599	0.000	53.599	4.467	12.569	2.492	53.599	0.006	0.006	69.82	0.008	(17.59)	(0.002)
2036	0.072	0.059	0.074	0.053	49.623	0.000	49.623	4.135	11.637	2.307	49.623	0.006	0.006	59.92	0.007	(17.38)	(0.002)
2037	0.072	0.059	0.075	0.053	45.943	0.000	45.943	3.829	10.774	2.136	45.943	0.005	0.005	50.02	0.006	(17.17)	(0.002)
2038	0.072	0.059	0.075	0.053	42.535	0.000	42.535	3.545	9.974	1.978	42.535	0.005	0.005	40.12	0.005	(16.96)	(0.002)
2039	0.072	0.058	0.075	0.053	39.380	0.000	39.380	3.282	9.235	1.831	39.380	0.004	0.004	30.22	0.003	(16.75)	(0.002)
2040	0.072	0.058	0.076	0.053	36.459	0.000	36.459	3.038	8.550	1.695	36.459	0.004	0.004	20.32	0.002	(16.54)	(0.002)
Levelized[3]:																	
2005-2040	0.067	0.056	0.065	0.048	64.742	0.215	64.957	5.395	15.182	3.010	64.957	0.007	0.007	220.657	0.025	7.200	0.001
2006-2040	0.067	0.055	0.065	0.048	67.237	0.186	67.422	5.603	15.767	3.127	67.422	0.008	0.008	229.525	0.026	7.489	0.001
2006-2010	0.072	0.060	0.067	0.050	54.120	0.927	55.047	4.510	12.691	2.517	55.047	0.006	0.006	448.938	0.051	28.472	0.003
2006-2015	0.065	0.053	0.060	0.045	64.347	0.515	64.862	5.362	15.089	2.992	64.862	0.007	0.007	304.283	0.035	8.063	0.001
2006-2020	0.064	0.052	0.059	0.044	67.922	0.360	68.282	5.660	15.928	3.158	68.282	0.008	0.008	299.546	0.034	17.117	0.002

Exhibit A2-2. Electric Energy Avoided Costs by AESC Screening Zone (continued)

	Vermont																
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value[1]	Annual Out of Market Expense	Total Annual Capacity Value	Capacity Value at Load Response (at any month)	Avoidable Capacity Payment at Load Response (Summer Season)	Avoidable Capacity Payment at Load Response (Winter Season)	Avoidable Capacity Payment at Energy Efficiency at Summer Coincident Peak	Load Response (at any month)	Energy Efficiency at Summer Coincident Peak	DRIPE 0.75% Capacity Price	DRIPE 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-month	$/kW-season	$/kW-season	$/kW-yr	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kW-yr	$/kWh
Comment 1:	Values are avoided costs at the generation plus transmission level. DSM savings should be measured at the generator plus transmission level. (Load plus + distribution losses)				Reflects Capacity Price resulting from LICAP beginning in 2006	Recovery of costs for RMR including continuing required payments after LICAP initiation		Avoided Cost applicable to KW savings contributing as supply side credit; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level			Avoided Cost applicable to KW savings at Summer Coincident Peak; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level	Avoided cost expressed in $/kWh at 100% load factor		Incremental to Avoided Cost at Summer Coincident Peak	Expressed in $/kWh at 100% load factor	DRIPE 0.75% measured assuming 10% of supply resources transact in spot market	Expressed in $/kWh at 100% load factor
Comment 2:					info	info	June/July/ August	Average for 1 month savings	Average for Summer Season	Average for Winter Season	June / July / August			DRIPE measured at 0.75% peak savings are across all of New England. Values are		DRIPE LIGHT measured at 0.75% peak savings are across all of New England.	
Period:							3-5 pm		June, July, August	Jan-May;Sept-Dec	3-5 pm						
2005[2]	0.077	0.064	0.074	0.052	2.662	0.954	3.616	0.222	0.624	0.124	3.616	0.000	0.000	0.00	0.000	0.00	0.000
2006	0.088	0.072	0.081	0.061	34.548	1.801	36.350	2.879	8.102	1.607	36.350	0.004	0.001	654.43	0.075	32.57	0.004
2007	0.090	0.074	0.085	0.062	39.132	2.151	41.283	3.261	9.176	1.820	41.283	0.004	0.001	906.91	0.104	88.60	0.010
2008	0.076	0.060	0.073	0.051	62.436	0.199	62.635	5.203	14.641	2.903	62.635	0.007	0.002	32.87	0.004	15.28	0.002
2009	0.062	0.049	0.058	0.040	66.758	0.204	66.962	5.563	15.655	3.104	66.962	0.008	0.002	357.68	0.041	9.62	0.001
2010	0.053	0.042	0.050	0.035	69.696	0.177	69.874	5.808	16.344	3.241	69.874	0.008	0.002	266.06	0.030	(6.87)	(0.001)
2011	0.055	0.044	0.051	0.037	72.764	0.154	72.918	6.064	17.063	3.384	72.918	0.008	0.002	174.43	0.020	(23.35)	(0.003)
2012	0.056	0.046	0.052	0.038	75.967	0.133	76.100	6.331	17.814	3.532	76.100	0.009	0.002	82.81	0.009	(39.84)	(0.005)
2013	0.057	0.046	0.053	0.039	76.270	0.000	76.270	6.356	17.885	3.547	76.270	0.009	0.002	119.16	0.014	(21.08)	(0.002)
2014	0.057	0.047	0.053	0.039	76.575	0.000	76.575	6.381	17.957	3.561	76.575	0.009	0.002	155.52	0.018	(2.33)	(0.000)
2015	0.058	0.047	0.054	0.040	76.881	0.000	76.881	6.407	18.029	3.575	76.881	0.009	0.002	191.87	0.022	16.43	0.002
2016	0.058	0.048	0.055	0.040	77.188	0.000	77.188	6.432	18.101	3.589	77.188	0.009	0.002	228.22	0.026	35.18	0.004
2017	0.060	0.049	0.057	0.042	76.704	0.000	76.704	6.392	17.987	3.567	76.704	0.009	0.002	258.99	0.030	36.72	0.004
2018	0.062	0.051	0.059	0.044	76.222	0.000	76.222	6.352	17.874	3.544	76.222	0.009	0.002	289.75	0.033	38.26	0.004
2019	0.064	0.053	0.061	0.046	75.743	0.000	75.743	6.312	17.762	3.522	75.743	0.009	0.002	320.52	0.037	39.80	0.005
2020	0.065	0.055	0.064	0.048	75.267	0.000	75.267	6.272	17.650	3.500	75.267	0.009	0.002	351.29	0.040	41.34	0.005
2021	0.066	0.055	0.065	0.049	75.613	0.000	75.613	6.301	17.731	3.516	75.613	0.009	0.002	328.09	0.037	35.34	0.004
2022	0.067	0.056	0.066	0.049	75.960	0.000	75.960	6.330	17.813	3.532	75.960	0.009	0.002	304.90	0.035	29.34	0.003
2023	0.068	0.056	0.066	0.050	76.309	0.000	76.309	6.359	17.894	3.548	76.309	0.009	0.002	281.70	0.032	23.34	0.003
2024	0.068	0.057	0.067	0.051	76.660	0.000	76.660	6.388	17.977	3.565	76.660	0.009	0.002	258.50	0.030	17.35	0.002
2025	0.069	0.058	0.068	0.051	77.012	0.000	77.012	6.418	18.059	3.581	77.012	0.009	0.002	235.31	0.027	11.35	0.001
2026	0.070	0.058	0.069	0.052	77.365	0.000	77.365	6.447	18.142	3.597	77.365	0.009	0.002	212.11	0.024	5.35	0.001
2027	0.071	0.059	0.070	0.053	77.721	0.000	77.721	6.477	18.225	3.614	77.721	0.009	0.002	188.91	0.022	(0.65)	(0.000)
2028	0.071	0.059	0.071	0.054	78.078	0.000	78.078	6.506	18.309	3.631	78.078	0.009	0.002	165.72	0.019	(6.65)	(0.001)
2029	0.072	0.060	0.072	0.054	78.436	0.000	78.436	6.536	18.393	3.647	78.436	0.009	0.002	142.52	0.016	(12.64)	(0.001)
2030	0.073	0.061	0.073	0.055	78.796	0.000	78.796	6.566	18.478	3.664	78.796	0.009	0.002	119.32	0.014	(18.64)	(0.002)
2031	0.073	0.060	0.073	0.055	72.952	0.000	72.952	6.079	17.107	3.392	72.952	0.008	0.002	109.42	0.012	(18.43)	(0.002)
2032	0.073	0.060	0.073	0.055	67.541	0.000	67.541	5.628	15.838	3.141	67.541	0.008	0.002	99.52	0.011	(18.22)	(0.002)
2033	0.073	0.060	0.074	0.054	62.531	0.000	62.531	5.211	14.664	2.908	62.531	0.007	0.002	89.62	0.010	(18.01)	(0.002)
2034	0.073	0.060	0.074	0.054	57.893	0.000	57.893	4.824	13.576	2.692	57.893	0.007	0.002	79.72	0.009	(17.80)	(0.002)
2035	0.073	0.060	0.075	0.054	53.599	0.000	53.599	4.467	12.569	2.492	53.599	0.006	0.001	69.82	0.008	(17.59)	(0.002)
2036	0.073	0.060	0.075	0.054	49.623	0.000	49.623	4.135	11.637	2.307	49.623	0.006	0.001	59.92	0.007	(17.38)	(0.002)
2037	0.073	0.059	0.075	0.054	45.943	0.000	45.943	3.829	10.774	2.136	45.943	0.005	0.001	50.02	0.006	(17.17)	(0.002)
2038	0.073	0.059	0.076	0.053	42.535	0.000	42.535	3.545	9.974	1.978	42.535	0.005	0.001	40.12	0.005	(16.96)	(0.002)
2039	0.073	0.059	0.076	0.053	39.380	0.000	39.380	3.282	9.235	1.831	39.380	0.004	0.001	30.22	0.003	(16.75)	(0.002)
2040	0.073	0.059	0.076	0.053	36.459	0.000	36.459	3.038	8.550	1.695	36.459	0.004	0.001	20.32	0.002	(16.54)	(0.002)
Levelized[3]:																	
2005-2040	0.068	0.056	0.066	0.049	64.742	0.215	64.957	5.395	15.182	3.010	64.957	0.007	0.002	220.657	0.025	7.200	0.001
2006-2040	0.068	0.056	0.066	0.048	67.237	0.186	67.422	5.603	15.767	3.127	67.422	0.008	0.002	229.525	0.026	7.489	0.001
2006-2010	0.074	0.060	0.070	0.050	54.120	0.927	55.047	4.510	12.691	2.517	55.047	0.006	0.001	448.938	0.051	28.472	0.003
2006-2015	0.066	0.053	0.062	0.045	64.347	0.515	64.862	5.362	15.089	2.992	64.862	0.007	0.002	304.283	0.035	8.063	0.001
2006-2020	0.065	0.053	0.061	0.044	67.922	0.360	68.282	5.660	15.928	3.158	68.282	0.008	0.002	299.546	0.034	17.117	0.002

Exhibit A2-2. Electric Energy Avoided Costs by AESC Screening Zone (continued)

	Norwalk (RTEP)																
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value[1]	Annual Out of Market Expense	Total Annual Capacity Value	Capacity Value at Load Response (at any month)	Avoidable Capacity Payment at Load Response (Summer Season)	Avoidable Capacity Payment at Load Response (Winter Season)	Avoidable Capacity Payment at Energy Efficiency at Summer Coincident Peak	Load Response (at any month)	Energy Efficiency at Summer Coincident Peak	DRIPE 0.75% Capacity Price	DRIPE 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-month	$/kW-season	$/kW-season	$/kW-yr	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kW-yr	$/kWh
Comment 1:	Values are avoided costs at the generation plus transmission level. DSM savings should be measured at the generator plus transmission level. (Load plus + distribution losses)				Reflects Capacity Price resulting from LICAP beginning in 2006	Recovery of costs for RMR including continuing required payments after LICAP initiation		Avoided Cost applicable to KW savings contributing as supply side credit; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level			Avoided Cost applicable to KW savings at Summer Coincident Peak; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level	Avoided cost expressed in $/kWh at 100% load factor		Incremental to Avoided Cost at Summer Coincident Peak	Expressed in $/kWh at 100% load factor	DRIPE 0.75% measured assuming 10% of supply resources transact in spot market	Expressed in $/kWh at 100% load factor
Comment 2:					info	info	June/July/ August	Average for 1 month savings	Average for Summer Season	Average for Winter Season	June / July / August			DRIPE measured at 0.75% peak savings are across all of New England. Values are		DRIPE LIGHT measured at 0.75% peak savings are across all of New England.	
Period:							3-5 pm		June, July, August	Jan-May;Sept-Dec	3-5 pm						
2005[2]	0.083	0.068	0.085	0.056	16.785	10.071	26.856	1.399	3.936	0.781	26.856	0.002	0.003	0.00	0.000	0.00	0.000
2006	0.097	0.077	0.097	0.065	57.244	14.667	71.911	4.770	13.424	2.662	71.911	0.007	0.008	728.50	0.083	682.02	0.078
2007	0.102	0.079	0.099	0.067	55.163	14.312	69.475	4.597	12.936	2.565	69.475	0.006	0.008	675.20	0.077	675.20	0.077
2008	0.082	0.064	0.078	0.054	66.341	5.035	71.376	5.528	15.557	3.085	71.376	0.008	0.008	694.41	0.079	688.20	0.079
2009	0.067	0.052	0.062	0.043	70.934	4.889	75.824	5.911	16.634	3.298	75.824	0.008	0.009	775.44	0.089	690.24	0.079
2010	0.057	0.044	0.053	0.037	73.561	4.645	78.206	6.130	17.250	3.421	78.206	0.008	0.009	892.50	0.102	797.97	0.091
2011	0.058	0.045	0.054	0.038	76.285	4.412	80.697	6.357	17.889	3.547	80.697	0.009	0.009	1,009.57	0.115	905.70	0.103
2012	0.060	0.046	0.055	0.039	79.110	4.192	83.301	6.592	18.551	3.679	83.301	0.009	0.010	1,126.63	0.129	1,013.42	0.116
2013	0.060	0.046	0.055	0.039	79.424	0.000	79.424	6.619	18.625	3.693	79.424	0.009	0.009	994.56	0.114	857.38	0.098
2014	0.060	0.046	0.056	0.039	79.739	0.000	79.739	6.645	18.699	3.708	79.739	0.009	0.009	862.48	0.098	701.33	0.080
2015	0.060	0.046	0.056	0.039	80.055	0.000	80.055	6.671	18.773	3.723	80.055	0.009	0.009	730.41	0.083	545.28	0.062
2016	0.061	0.047	0.056	0.039	80.373	0.000	80.373	6.698	18.847	3.737	80.373	0.009	0.009	598.33	0.068	389.24	0.044
2017	0.062	0.048	0.058	0.041	79.557	0.000	79.557	6.630	18.656	3.699	79.557	0.009	0.009	518.84	0.059	319.39	0.036
2018	0.064	0.050	0.061	0.043	78.749	0.000	78.749	6.562	18.467	3.662	78.749	0.009	0.009	439.34	0.050	249.54	0.028
2019	0.066	0.052	0.063	0.045	77.949	0.000	77.949	6.496	18.279	3.625	77.949	0.009	0.009	359.84	0.041	179.69	0.021
2020	0.068	0.054	0.066	0.047	77.157	0.000	77.157	6.430	18.093	3.588	77.157	0.009	0.009	280.35	0.032	109.85	0.013
2021	0.068	0.054	0.066	0.047	77.319	0.000	77.319	6.443	18.131	3.595	77.319	0.009	0.009	278.00	0.032	112.75	0.013
2022	0.069	0.055	0.067	0.048	77.482	0.000	77.482	6.457	18.170	3.603	77.482	0.009	0.009	275.66	0.031	115.66	0.013
2023	0.069	0.056	0.068	0.049	77.645	0.000	77.645	6.470	18.208	3.611	77.645	0.009	0.009	273.32	0.031	118.57	0.014
2024	0.070	0.056	0.069	0.049	77.809	0.000	77.809	6.484	18.246	3.618	77.809	0.009	0.009	270.97	0.031	121.48	0.014
2025	0.070	0.057	0.069	0.050	77.972	0.000	77.972	6.498	18.285	3.626	77.972	0.009	0.009	268.63	0.031	124.39	0.014
2026	0.071	0.057	0.070	0.051	78.137	0.000	78.137	6.511	18.323	3.633	78.137	0.009	0.009	266.29	0.030	127.30	0.015
2027	0.072	0.058	0.071	0.051	78.301	0.000	78.301	6.525	18.362	3.641	78.301	0.009	0.009	263.94	0.030	130.21	0.015
2028	0.072	0.059	0.072	0.052	78.466	0.000	78.466	6.539	18.400	3.649	78.466	0.009	0.009	261.60	0.030	133.12	0.015
2029	0.073	0.059	0.072	0.053	78.631	0.000	78.631	6.553	18.439	3.656	78.631	0.009	0.009	259.26	0.030	136.03	0.016
2030	0.073	0.060	0.073	0.053	78.796	0.000	78.796	6.566	18.478	3.664	78.796	0.009	0.009	256.91	0.029	138.93	0.016
2031	0.074	0.060	0.074	0.053	72.952	0.000	72.952	6.079	17.107	3.392	72.952	0.008	0.008	239.38	0.027	130.11	0.015
2032	0.074	0.060	0.074	0.053	67.541	0.000	67.541	5.628	15.838	3.141	67.541	0.008	0.008	221.84	0.025	121.29	0.014
2033	0.074	0.060	0.075	0.053	62.531	0.000	62.531	5.211	14.664	2.908	62.531	0.007	0.007	204.31	0.023	112.47	0.013
2034	0.074	0.059	0.075	0.053	57.893	0.000	57.893	4.824	13.576	2.692	57.893	0.007	0.007	186.78	0.021	103.65	0.012
2035	0.074	0.059	0.076	0.053	53.599	0.000	53.599	4.467	12.569	2.492	53.599	0.006	0.006	169.24	0.019	94.83	0.011
2036	0.074	0.059	0.076	0.053	49.623	0.000	49.623	4.135	11.637	2.307	49.623	0.006	0.006	151.71	0.017	86.01	0.010
2037	0.074	0.059	0.077	0.053	45.943	0.000	45.943	3.829	10.774	2.136	45.943	0.005	0.005	134.17	0.015	77.19	0.009
2038	0.074	0.059	0.078	0.053	42.535	0.000	42.535	3.545	9.974	1.978	42.535	0.005	0.005	116.64	0.013	68.37	0.008
2039	0.074	0.059	0.078	0.053	39.380	0.000	39.380	3.282	9.235	1.831	39.380	0.004	0.004	99.11	0.011	59.54	0.007
2040	0.074	0.059	0.079	0.053	36.459	0.000	36.459	3.038	8.550	1.695	36.459	0.004	0.004	81.57	0.009	50.72	0.006
Levelized[3]:																	
2005-2040	0.071	0.056	0.069	0.049	68.307	2.287	70.595	5.692	16.018	3.176	70.595	0.008	0.008	461.530	0.053	350.465	0.040
2006-2040	0.070	0.056	0.069	0.048	70.378	1.975	72.353	5.865	16.504	3.273	72.353	0.008	0.008	480.080	0.055	364.550	0.042
2006-2010	0.081	0.064	0.078	0.054	64.454	8.828	73.283	5.371	15.115	2.997	73.283	0.007	0.008	751.504	0.086	705.744	0.081
2006-2015	0.071	0.055	0.067	0.047	71.309	5.478	76.787	5.942	16.722	3.316	76.787	0.008	0.009	844.828	0.096	754.662	0.086
2006-2020	0.069	0.054	0.065	0.045	73.557	3.832	77.389	6.130	17.249	3.420	77.389	0.008	0.009	723.957	0.083	603.740	0.069

Exhibit A2-2. Electric Energy Avoided Costs by AESC Screening Zone (continued)

	Southwest Connecticut (RTEP)																
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value[1]	Annual Out of Market Expense	Total Annual Capacity Value	Capacity Value at Load Response (at any month)	Avoidable Capacity Payment at Load Response (Summer Season)	Avoidable Capacity Payment at Load Response (Winter Season)	Avoidable Capacity Payment at Energy Efficiency at Summer Coincident Peak	Load Response (at any month)	Energy Efficiency at Summer Coincident Peak	DRIPE 0.75% Capacity Price	DRIPE 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-month	$/kW-season	$/kW-season	$/kW-yr	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kW-yr	$/kWh
Comment 1:	Values are avoided costs at the generation plus transmission level. DSM savings should be measured at the generator plus transmission level. (Load plus + distribution losses)				Reflects Capacity Price resulting from LICAP beginning in 2006	Recovery of costs for RMR including continuing required payments after LICAP initiation		Avoided Cost applicable to KW savings contributing as supply side credit; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level			Avoided Cost applicable to KW savings at Summer Coincident Peak; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level	Avoided cost expressed in $/kWh at 100% load factor		Incremental to Avoided Cost at Summer Coincident Peak	Expressed in $/kWh at 100% load factor	DRIPE 0.75% measured assuming 10% of supply resources transact in spot market	Expressed in $/kWh at 100% load factor
Comment 2:					info	info	June/July/ August	Average for 1 month savings	Average for Summer Season	Average for Winter Season	June / July / August			DRIPE measured at 0.75% peak savings are across all of New England. Values are		DRIPE LIGHT measured at 0.75% peak savings are across all of New England.	
Period:							3-5 pm		June, July, August	Jan-May;Sept-Dec	3-5 pm						
2005[2]	0.081	0.066	0.083	0.055	3.351	23.505	26.856	0.279	0.786	0.156	26.856	0.000	0.003	0.00	0.000	0.00	0.000
2006	0.095	0.076	0.095	0.064	44.207	3.733	47.940	3.684	10.367	2.056	47.940	0.005	0.005	273.51	0.037	(14.21)	(0.002)
2007	0.100	0.078	0.097	0.065	50.237	1.226	51.463	4.186	11.781	2.336	51.463	0.006	0.006	(2.77)	0.006	(2.77)	(0.000)
2008	0.080	0.063	0.077	0.053	66.341	0.000	66.341	5.528	15.557	3.085	66.341	0.008	0.008	(34.01)	0.004	(63.11)	(0.007)
2009	0.065	0.051	0.061	0.042	70.934	0.000	70.934	5.911	16.634	3.298	70.934	0.008	0.008	337.05	0.047	(30.14)	(0.003)
2010	0.056	0.044	0.052	0.036	73.561	0.000	73.561	6.130	17.250	3.421	73.561	0.008	0.008	156.01	0.026	(141.89)	(0.016)
2011	0.057	0.045	0.053	0.038	76.285	0.000	76.285	6.357	17.889	3.547	76.285	0.009	0.009	(25.03)	0.006	(253.65)	(0.029)
2012	0.059	0.046	0.054	0.039	79.110	0.000	79.110	6.592	18.551	3.679	79.110	0.009	0.009	(206.08)	(0.014)	(365.40)	(0.042)
2013	0.059	0.047	0.054	0.039	79.424	0.000	79.424	6.619	18.625	3.693	79.424	0.009	0.009	(145.52)	(0.008)	(321.89)	(0.037)
2014	0.059	0.047	0.055	0.040	79.739	0.000	79.739	6.645	18.699	3.708	79.739	0.009	0.009	(84.97)	(0.001)	(278.38)	(0.032)
2015	0.060	0.047	0.055	0.040	80.055	0.000	80.055	6.671	18.773	3.723	80.055	0.009	0.009	(24.42)	0.006	(234.87)	(0.027)
2016	0.060	0.047	0.056	0.040	80.373	0.000	80.373	6.698	18.847	3.737	80.373	0.009	0.009	36.13	0.013	(191.36)	(0.022)
2017	0.061	0.049	0.058	0.042	79.557	0.000	79.557	6.630	18.656	3.699	79.557	0.009	0.009	73.89	0.018	(154.61)	(0.018)
2018	0.063	0.051	0.060	0.044	78.749	0.000	78.749	6.562	18.467	3.662	78.749	0.009	0.009	111.65	0.022	(117.86)	(0.013)
2019	0.065	0.053	0.063	0.046	77.949	0.000	77.949	6.496	18.279	3.625	77.949	0.009	0.009	149.42	0.026	(81.11)	(0.009)
2020	0.067	0.055	0.065	0.048	77.157	0.000	77.157	6.430	18.093	3.588	77.157	0.009	0.009	187.18	0.030	(44.36)	(0.005)
2021	0.067	0.055	0.066	0.048	77.319	0.000	77.319	6.443	18.131	3.595	77.319	0.009	0.009	170.53	0.028	(54.49)	(0.006)
2022	0.068	0.056	0.066	0.049	77.482	0.000	77.482	6.457	18.170	3.603	77.482	0.009	0.009	153.88	0.026	(64.62)	(0.007)
2023	0.069	0.056	0.067	0.049	77.645	0.000	77.645	6.470	18.208	3.611	77.645	0.009	0.009	137.23	0.025	(74.75)	(0.009)
2024	0.069	0.057	0.068	0.050	77.809	0.000	77.809	6.484	18.246	3.618	77.809	0.009	0.009	120.57	0.023	(84.88)	(0.010)
2025	0.070	0.057	0.069	0.051	77.972	0.000	77.972	6.498	18.285	3.626	77.972	0.009	0.009	103.92	0.021	(95.01)	(0.011)
2026	0.070	0.058	0.069	0.051	78.137	0.000	78.137	6.511	18.323	3.633	78.137	0.009	0.009	87.27	0.019	(105.14)	(0.012)
2027	0.071	0.059	0.070	0.052	78.301	0.000	78.301	6.525	18.362	3.641	78.301	0.009	0.009	70.62	0.017	(115.27)	(0.013)
2028	0.072	0.059	0.071	0.052	78.466	0.000	78.466	6.539	18.400	3.649	78.466	0.009	0.009	53.97	0.015	(125.41)	(0.014)
2029	0.072	0.060	0.072	0.053	78.631	0.000	78.631	6.553	18.439	3.656	78.631	0.009	0.009	37.31	0.013	(135.54)	(0.015)
2030	0.073	0.060	0.072	0.054	78.796	0.000	78.796	6.566	18.478	3.664	78.796	0.009	0.009	20.66	0.011	(145.67)	(0.017)
2031	0.073	0.060	0.073	0.054	72.952	0.000	72.952	6.079	17.107	3.392	72.952	0.008	0.008	16.27	0.010	(137.72)	(0.016)
2032	0.073	0.060	0.073	0.054	67.541	0.000	67.541	5.628	15.838	3.141	67.541	0.008	0.008	11.88	0.009	(129.78)	(0.015)
2033	0.073	0.060	0.074	0.054	62.531	0.000	62.531	5.211	14.664	2.908	62.531	0.007	0.007	7.50	0.008	(121.83)	(0.014)
2034	0.073	0.060	0.075	0.054	57.893	0.000	57.893	4.824	13.576	2.692	57.893	0.007	0.007	3.11	0.007	(113.88)	(0.013)
2035	0.073	0.060	0.075	0.054	53.599	0.000	53.599	4.467	12.569	2.492	53.599	0.006	0.006	(1.28)	0.006	(105.94)	(0.012)
2036	0.073	0.060	0.076	0.053	49.623	0.000	49.623	4.135	11.637	2.307	49.623	0.006	0.006	(5.67)	0.005	(97.99)	(0.011)
2037	0.074	0.059	0.076	0.053	45.943	0.000	45.943	3.829	10.774	2.136	45.943	0.005	0.005	(10.06)	0.004	(90.05)	(0.010)
2038	0.074	0.059	0.077	0.053	42.535	0.000	42.535	3.545	9.974	1.978	42.535	0.005	0.005	(14.45)	0.003	(82.10)	(0.009)
2039	0.074	0.059	0.077	0.053	39.380	0.000	39.380	3.282	9.235	1.831	39.380	0.004	0.004	(18.84)	0.002	(74.15)	(0.008)
2040	0.074	0.059	0.078	0.053	36.459	0.000	36.459	3.038	8.550	1.695	36.459	0.004	0.004	(23.23)	0.002	(66.21)	(0.008)
Levelized[3]:																	
2005-2040	0.070	0.056	0.069	0.049	67.112	1.095	68.207	5.593	15.738	3.121	68.207	0.008	0.008	51.439	0.014	-121.550	-0.014
2006-2040	0.070	0.056	0.068	0.049	69.674	0.194	69.869	5.806	16.339	3.240	69.869	0.008	0.008	53.507	0.014	-126.435	-0.014
2006-2010	0.079	0.063	0.077	0.053	60.736	1.027	61.763	5.061	14.243	2.824	61.763	0.007	0.007	145.560	0.024	-49.293	-0.006
2006-2015	0.070	0.055	0.066	0.046	69.357	0.539	69.896	5.780	16.264	3.225	69.896	0.008	0.008	30.046	0.011	-164.235	-0.019
2006-2020	0.068	0.054	0.064	0.045	72.191	0.377	72.568	6.016	16.929	3.357	72.568	0.008	0.008	54.110	0.014	-150.744	-0.017

Exhibit A2-2. Electric Energy Avoided Costs by AESC Screening Zone (continued)

	Rest of Connecticut																
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value[1]	Annual Out of Market Expense	Total Annual Capacity Value	Capacity Value at Load Response (at any month)	Avoidable Capacity Payment at Load Response (Summer Season)	Avoidable Capacity Payment at Load Response (Winter Season)	Avoidable Capacity Payment at Energy Efficiency at Summer Coincident Peak	Load Response (at any month)	Energy Efficiency at Summer Coincident Peak	DRIPE 0.75% Capacity Price	DRIPE 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-month	$/kW-season	$/kW-season	$/kW-yr	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kW-yr	$/kWh
Comment 1:	Values are avoided costs at the generation plus transmission level. DSM savings should be measured at the generator plus transmission level. (Load plus + distribution losses)				Reflects Capacity Price resulting from LICAP beginning in 2006	Recovery of costs for RMR including continuing required payments after LICAP initiation		Avoided Cost applicable to KW savings contributing as supply side credit; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level			Avoided Cost applicable to KW savings at Summer Coincident Peak; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level	Avoided cost expressed in $/kWh at 100% load factor		Incremental to Avoided Cost at Summer Coincident Peak	Expressed in $/kWh at 100% load factor	DRIPE 0.75% measured assuming 10% of supply resources transact in spot market	Expressed in $/kWh at 100% load factor
Comment 2:					info	info	June/July/ August	Average for 1 month savings	Average for Summer Season	Average for Winter Season	June / July / August			DRIPE measured at 0.75% peak savings are across all of New England. Values are		DRIPE LIGHT measured at 0.75% peak savings are across all of New England.	
Period:							3-5 pm		June, July, August	Jan-May;Sept-Dec	3-5 pm						
2005[2]	0.080	0.065	0.081	0.054	5.377	8.265	13.642	0.448	1.261	0.250	13.642	0.001	0.002	0.00	0.000	0.00	0.000
2006	0.093	0.074	0.093	0.063	47.881	0.000	47.881	3.990	11.228	2.226	47.881	0.005	0.005	171.25	0.025	234.47	0.027
2007	0.098	0.076	0.095	0.064	50.951	0.000	50.951	4.246	11.948	2.369	50.951	0.006	0.006	12.61	0.007	239.13	0.027
2008	0.078	0.062	0.075	0.052	63.709	0.000	63.709	5.309	14.940	2.962	63.709	0.007	0.007	(5.29)	0.007	204.86	0.023
2009	0.064	0.050	0.060	0.041	68.126	0.000	68.126	5.677	15.976	3.168	68.126	0.008	0.008	408.59	0.054	226.52	0.026
2010	0.055	0.043	0.051	0.036	71.124	0.000	71.124	5.927	16.679	3.307	71.124	0.008	0.008	328.38	0.046	192.60	0.022
2011	0.056	0.044	0.052	0.037	74.254	0.000	74.254	6.188	17.413	3.453	74.254	0.008	0.008	248.18	0.037	158.68	0.018
2012	0.058	0.046	0.053	0.039	77.523	0.000	77.523	6.460	18.179	3.605	77.523	0.009	0.009	167.97	0.028	124.76	0.014
2013	0.058	0.046	0.054	0.039	77.831	0.000	77.831	6.486	18.251	3.619	77.831	0.009	0.009	190.34	0.031	97.20	0.011
2014	0.058	0.046	0.054	0.039	78.141	0.000	78.141	6.512	18.324	3.634	78.141	0.009	0.009	212.71	0.033	69.65	0.008
2015	0.059	0.047	0.055	0.040	78.453	0.000	78.453	6.538	18.397	3.648	78.453	0.009	0.009	235.08	0.036	42.09	0.005
2016	0.059	0.047	0.055	0.040	78.765	0.000	78.765	6.564	18.470	3.663	78.765	0.009	0.009	257.45	0.038	14.53	0.002
2017	0.061	0.049	0.057	0.042	77.965	0.000	77.965	6.497	18.283	3.625	77.965	0.009	0.009	252.98	0.038	13.44	0.002
2018	0.063	0.050	0.060	0.044	77.172	0.000	77.172	6.431	18.097	3.589	77.172	0.009	0.009	248.52	0.037	12.35	0.001
2019	0.064	0.052	0.062	0.045	76.388	0.000	76.388	6.366	17.913	3.552	76.388	0.009	0.009	244.05	0.037	11.26	0.001
2020	0.066	0.054	0.064	0.047	75.612	0.000	75.612	6.301	17.731	3.516	75.612	0.009	0.009	239.59	0.036	10.18	0.001
2021	0.067	0.055	0.065	0.048	75.771	0.000	75.771	6.314	17.768	3.523	75.771	0.009	0.009	233.15	0.035	4.58	0.001
2022	0.068	0.055	0.066	0.049	75.931	0.000	75.931	6.328	17.806	3.531	75.931	0.009	0.009	226.71	0.035	(1.02)	(0.000)
2023	0.068	0.056	0.067	0.049	76.091	0.000	76.091	6.341	17.843	3.538	76.091	0.009	0.009	220.28	0.034	(6.61)	(0.001)
2024	0.069	0.056	0.068	0.050	76.251	0.000	76.251	6.354	17.881	3.546	76.251	0.009	0.009	213.84	0.033	(12.21)	(0.001)
2025	0.070	0.057	0.068	0.050	76.412	0.000	76.412	6.368	17.919	3.553	76.412	0.009	0.009	207.40	0.032	(17.81)	(0.002)
2026	0.070	0.057	0.069	0.051	76.573	0.000	76.573	6.381	17.956	3.561	76.573	0.009	0.009	200.97	0.032	(23.40)	(0.003)
2027	0.071	0.058	0.070	0.052	76.734	0.000	76.734	6.394	17.994	3.568	76.734	0.009	0.009	194.53	0.031	(29.00)	(0.003)
2028	0.072	0.058	0.071	0.052	76.895	0.000	76.895	6.408	18.032	3.576	76.895	0.009	0.009	188.09	0.030	(34.59)	(0.004)
2029	0.072	0.059	0.072	0.053	77.057	0.000	77.057	6.421	18.070	3.583	77.057	0.009	0.009	181.66	0.030	(40.19)	(0.005)
2030	0.073	0.059	0.072	0.054	77.220	0.000	77.220	6.435	18.108	3.591	77.220	0.009	0.009	175.22	0.029	(45.79)	(0.005)
2031	0.073	0.059	0.073	0.053	71.490	0.000	71.490	5.957	16.764	3.324	71.490	0.008	0.008	162.05	0.027	(43.76)	(0.005)
2032	0.073	0.059	0.073	0.053	66.185	0.000	66.185	5.515	15.520	3.078	66.185	0.008	0.008	148.87	0.025	(41.73)	(0.005)
2033	0.073	0.059	0.074	0.053	61.274	0.000	61.274	5.106	14.369	2.849	61.274	0.007	0.007	135.70	0.023	(39.70)	(0.005)
2034	0.073	0.059	0.074	0.053	56.727	0.000	56.727	4.727	13.303	2.638	56.727	0.006	0.006	122.52	0.021	(37.67)	(0.004)
2035	0.073	0.059	0.074	0.053	52.518	0.000	52.518	4.376	12.315	2.442	52.518	0.006	0.006	109.35	0.019	(35.64)	(0.004)
2036	0.073	0.058	0.075	0.053	48.621	0.000	48.621	4.052	11.402	2.261	48.621	0.006	0.006	96.18	0.017	(33.61)	(0.004)
2037	0.073	0.058	0.075	0.053	45.013	0.000	45.013	3.751	10.556	2.093	45.013	0.005	0.005	83.00	0.015	(31.58)	(0.004)
2038	0.073	0.058	0.076	0.052	41.673	0.000	41.673	3.473	9.772	1.938	41.673	0.005	0.005	69.83	0.013	(29.55)	(0.003)
2039	0.073	0.058	0.076	0.052	38.581	0.000	38.581	3.215	9.047	1.794	38.581	0.004	0.004	56.66	0.011	(27.52)	(0.003)
2040	0.072	0.058	0.076	0.052	35.718	0.000	35.718	2.976	8.376	1.661	35.718	0.004	0.004	43.48	0.009	(25.49)	(0.003)
Levelized[3]:																	
2005-2040	0.069	0.056	0.068	0.048	65.936	0.319	66.255	5.495	15.462	3.066	66.255	0.008	0.008	179.123	0.028	45.882	0.005
2006-2040	0.069	0.055	0.067	0.048	68.370	0.000	68.370	5.698	16.033	3.179	68.370	0.008	0.008	186.322	0.029	47.726	0.005
2006-2010	0.078	0.061	0.075	0.051	60.102	0.000	60.102	5.009	14.094	2.795	60.102	0.007	0.007	180.277	0.027	219.903	0.025
2006-2015	0.068	0.054	0.065	0.046	68.224	0.000	68.224	5.685	15.998	3.172	68.224	0.008	0.008	194.768	0.030	162.788	0.019
2006-2020	0.067	0.053	0.063	0.045	70.924	0.000	70.924	5.910	16.632	3.298	70.924	0.008	0.008	210.970	0.032	117.602	0.013

Exhibit A2-3. Electric Energy Avoided Costs by State

	Maine																
	Winter Peak Energy	**Winter Off-Peak Energy**	**Summer Peak Energy**	**Summer Off-Peak Energy**	**Annual Market Capacity Value[1]**	**Annual Out of Market Expense**	**Total Annual Capacity Value**	**Capacity Value at Load Response (at any month)**	**Avoidable Capacity Payment at Load Response (Summer Season)**	**Avoidable Capacity Payment at Load Response (Winter Season)**	**Avoidable Capacity Payment at Energy Efficiency at Summer Coincident Peak**	**Load Response (at any month)**	**Energy Efficiency at Summer Coincident Peak**	**DRIPE 0.75% Capacity Price**	**DRIPE 0.75% Capacity Price**	**DRIPE LIGHT 0.75% Capacity Price**	**DRIPE LIGHT 0.75% Capacity Price**
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-month	$/kW-season	$/kW-season	$/kW-yr	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kW-yr	$/kWh
Comment 1:	Values are avoided costs at the generation plus transmission level. DSM savings should be measured at the generator plus transmission level. (Load plus + distribution losses)				Reflects Capacity Price resulting from LICAP beginning in 2006	Recovery of costs for RMR including continuing required payments after LICAP initiation		Avoided Cost applicable to KW savings contributing as supply side credit; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level			Avoided Cost applicable to KW savings at Summer Coincident Peak; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level	Avoided cost expressed in $/kWh at 100% load factor		Incremental to Avoided Cost at Summer Coincident Peak	Expressed in $/kWh at 100% load factor	DRIPE 0.75% measured assuming 10% of supply resources transact in spot market	Expressed in $/kWh at 100% load factor
Comment 2:					info	info	June/July/August	Average for 1 month savings	Average for Summer Season	Average for Winter Season	June / July / August			DRIPE measured at 0.75% peak savings are across all of New England.		DRIPE LIGHT measured at 0.75% peak savings are across all of New England.	
Period:							3-5 pm		June, July, August	Jan-May;Sept-Dec	3-5 pm						
2005[2]	0.071	0.063	0.063	0.049	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.00	0.000	0.00	0.000
2006	0.080	0.071	0.070	0.057	23.304	0.000	23.304	1.942	5.465	1.084	23.304	0.003	0.003	1,115.39	0.127	90.57	0.010
2007	0.083	0.072	0.072	0.059	20.172	0.000	20.172	1.681	4.730	0.938	20.172	0.002	0.002	616.86	0.070	43.53	0.005
2008	0.070	0.059	0.060	0.048	19.462	0.000	19.462	1.622	4.564	0.905	19.462	0.002	0.002	23.10	0.003	6.00	0.001
2009	0.056	0.047	0.048	0.039	17.895	0.000	17.895	1.491	4.196	0.832	17.895	0.002	0.002	6.57	0.001	4.86	0.001
2010	0.049	0.041	0.043	0.034	27.761	0.000	27.761	2.313	6.510	1.291	27.761	0.003	0.003	9.00	0.001	7.86	0.001
2011	0.051	0.043	0.046	0.036	43.067	0.000	43.067	3.589	10.099	2.003	43.067	0.005	0.005	11.43	0.001	10.86	0.001
2012	0.054	0.044	0.049	0.038	66.810	0.000	66.810	5.568	15.667	3.107	66.810	0.008	0.008	13.86	0.002	13.86	0.002
2013	0.054	0.045	0.049	0.038	67.163	0.000	67.163	5.597	15.750	3.123	67.163	0.008	0.008	13.76	0.002	13.02	0.001
2014	0.054	0.046	0.049	0.039	67.517	0.000	67.517	5.626	15.833	3.140	67.517	0.008	0.008	13.66	0.002	12.18	0.001
2015	0.055	0.046	0.049	0.039	67.872	0.000	67.872	5.656	15.916	3.156	67.872	0.008	0.008	13.56	0.002	11.34	0.001
2016	0.055	0.047	0.049	0.039	68.230	0.000	68.230	5.686	16.000	3.173	68.230	0.008	0.008	13.46	0.002	10.51	0.001
2017	0.057	0.048	0.051	0.041	65.767	0.000	65.767	5.481	15.422	3.058	65.767	0.008	0.008	12.91	0.001	10.69	0.001
2018	0.059	0.050	0.053	0.043	63.392	0.000	63.392	5.283	14.865	2.948	63.392	0.007	0.007	12.36	0.001	10.88	0.001
2019	0.061	0.052	0.055	0.045	61.103	0.000	61.103	5.092	14.329	2.841	61.103	0.007	0.007	11.80	0.001	11.07	0.001
2020	0.063	0.054	0.057	0.047	58.896	0.000	58.896	4.908	13.811	2.739	58.896	0.007	0.007	11.25	0.001	11.25	0.001
2021	0.064	0.054	0.058	0.048	60.454	0.000	60.454	5.038	14.177	2.811	60.454	0.007	0.007	16.72	0.002	7.79	0.001
2022	0.064	0.055	0.059	0.048	62.053	0.000	62.053	5.171	14.552	2.885	62.053	0.007	0.007	22.18	0.003	4.32	0.000
2023	0.065	0.055	0.060	0.049	63.695	0.000	63.695	5.308	14.936	2.962	63.695	0.007	0.007	27.65	0.003	0.86	0.000
2024	0.065	0.056	0.061	0.050	65.380	0.000	65.380	5.448	15.332	3.040	65.380	0.007	0.007	33.12	0.004	(2.61)	(0.000)
2025	0.066	0.056	0.061	0.051	67.109	0.000	67.109	5.592	15.737	3.121	67.109	0.008	0.008	38.58	0.004	(6.07)	(0.001)
2026	0.067	0.057	0.062	0.051	68.885	0.000	68.885	5.740	16.153	3.203	68.885	0.008	0.008	44.05	0.005	(9.54)	(0.001)
2027	0.067	0.057	0.063	0.052	70.707	0.000	70.707	5.892	16.581	3.288	70.707	0.008	0.008	49.51	0.006	(13.00)	(0.001)
2028	0.068	0.058	0.064	0.053	72.577	0.000	72.577	6.048	17.019	3.375	72.577	0.008	0.008	54.98	0.006	(16.47)	(0.002)
2029	0.069	0.058	0.065	0.054	74.497	0.000	74.497	6.208	17.470	3.464	74.497	0.009	0.009	60.45	0.007	(19.93)	(0.002)
2030	0.069	0.059	0.066	0.054	76.468	0.000	76.468	6.372	17.932	3.556	76.468	0.009	0.009	65.91	0.008	(23.40)	(0.003)
2031	0.069	0.059	0.066	0.054	70.863	0.000	70.863	5.905	16.617	3.295	70.863	0.008	0.008	61.90	0.007	(22.31)	(0.003)
2032	0.070	0.059	0.066	0.054	65.669	0.000	65.669	5.472	15.399	3.054	65.669	0.007	0.007	57.88	0.007	(21.21)	(0.002)
2033	0.070	0.059	0.067	0.054	60.856	0.000	60.856	5.071	14.271	2.830	60.856	0.007	0.007	53.87	0.006	(20.12)	(0.002)
2034	0.070	0.059	0.067	0.054	56.395	0.000	56.395	4.700	13.225	2.622	56.395	0.006	0.006	49.85	0.006	(19.03)	(0.002)
2035	0.070	0.059	0.067	0.054	52.262	0.000	52.262	4.355	12.255	2.430	52.262	0.006	0.006	45.84	0.005	(17.94)	(0.002)
2036	0.070	0.059	0.068	0.054	48.431	0.000	48.431	4.036	11.357	2.252	48.431	0.006	0.006	41.82	0.005	(16.84)	(0.002)
2037	0.070	0.059	0.068	0.054	44.881	0.000	44.881	3.740	10.525	2.087	44.881	0.005	0.005	37.81	0.004	(15.75)	(0.002)
2038	0.070	0.059	0.068	0.054	41.591	0.000	41.591	3.466	9.753	1.934	41.591	0.005	0.005	33.79	0.004	(14.66)	(0.002)
2039	0.070	0.059	0.068	0.054	38.543	0.000	38.543	3.212	9.038	1.792	38.543	0.004	0.004	29.78	0.003	(13.57)	(0.002)
2040	0.070	0.059	0.069	0.053	35.718	0.000	35.718	2.976	8.376	1.661	35.718	0.004	0.004	25.76	0.003	6.15	0.001
Levelized[3]:																	
2005-2040	0.064	0.055	0.059	0.047	51.998	0.000	51.998	4.333	12.194	2.418	51.998	0.006	0.006	90.231	0.010	4.165	0.000
2006-2040	0.064	0.054	0.059	0.047	54.088	0.000	54.088	4.507	12.684	2.515	54.088	0.006	0.006	93.858	0.011	4.333	0.000
2006-2010	0.068	0.058	0.059	0.047	21.693	0.000	21.693	1.808	5.087	1.009	21.693	0.002	0.002	365.592	0.042	31.390	0.004
2006-2015	0.061	0.052	0.054	0.043	40.969	0.000	40.969	3.414	9.607	1.905	40.969	0.005	0.005	198.259	0.023	22.304	0.003
2006-2020	0.061	0.051	0.054	0.043	47.760	0.000	47.760	3.980	11.200	2.221	47.760	0.005	0.005	142.410	0.016	18.869	0.002

Exhibit A2-3. Electric Energy Avoided Costs by State (continued)

	Massachusetts																
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value[1]	Annual Out of Market Expense	Total Annual Capacity Value	Capacity Value of Load Response (at any month)	Avoidable Capacity Payment of Load Response (Summer Season)	Avoidable Capacity Payment of Load Response (Winter Season)	Avoidable Capacity Payment of Energy Efficiency at Summer Coincident Peak	Load Response (at any month)	Energy Efficiency at Summer Coincident Peak	DRIPE 0.75% Capacity Price	DRIPE 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-month	$/kW-season	$/kW-season	$/kW-yr	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kW-yr	$/kWh
Comment 1:	Values are avoided costs at the generation plus transmission level. DSM savings should be measured at the generator plus transmission level. (Load plus + distribution losses)				Reflects Capacity Price resulting from LICAP beginning in 2006	Recovery of costs for RMR including continuing required payments after LICAP initiation		Avoided Cost applicable to KW savings contributing as supply side credit; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level			Avoided Cost applicable to KW savings at Summer Coincident Peak; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level	Avoided cost expressed in $/kWh at 100% load factor		Incremental to Avoided Cost at Summer Coincident Peak	Expressed in $/kWh at 100% load factor	DRIPE 0.75% measured assuming 10% of supply resources transact in spot market	Expressed in $/kWh at 100% load factor
Comment 2:					info	info	June/July/ August	Average for 1 month savings	Average for Summer Season	Average for Winter Season	June / July / August			DRIPE measured at 0.75% peak savings are across all of New England. Values		DRIPE LIGHT measured at 0.75% peak savings are across all of New England.	
Period:							3-5 pm		June, July, August	Jan-May;Sept-Dec	3-5 pm						
2005[2]	0.074	0.064	0.069	0.051	3.908	2.728	6.637	0.326	0.917	0.182	6.637	0.000	0.001	0.00	0.000	0.00	0.000
2006	0.085	0.072	0.077	0.059	34.873	6.047	40.920	2.906	8.178	1.622	40.920	0.004	0.005	693.25	0.079	35.43	0.004
2007	0.087	0.074	0.081	0.062	39.500	5.576	45.076	3.292	9.263	1.837	45.076	0.005	0.005	939.61	0.107	73.18	0.008
2008	0.074	0.060	0.072	0.050	63.019	0.108	63.127	5.252	14.778	2.930	63.127	0.007	0.007	33.89	0.004	15.42	0.002
2009	0.060	0.049	0.056	0.040	67.385	0.111	67.496	5.615	15.802	3.133	67.496	0.008	0.008	393.57	0.045	24.36	0.003
2010	0.052	0.042	0.049	0.035	70.352	0.096	70.447	5.863	16.497	3.271	70.447	0.008	0.008	296.45	0.034	7.00	0.001
2011	0.055	0.044	0.051	0.037	73.448	0.083	73.531	6.121	17.224	3.415	73.531	0.008	0.008	199.34	0.023	(10.36)	(0.001)
2012	0.057	0.046	0.052	0.038	76.681	0.072	76.753	6.390	17.982	3.566	76.753	0.009	0.009	102.22	0.012	(27.72)	(0.003)
2013	0.057	0.046	0.053	0.039	77.672	0.000	77.672	6.473	18.214	3.612	77.672	0.009	0.009	129.83	0.015	(17.56)	(0.002)
2014	0.058	0.046	0.054	0.039	78.675	0.000	78.675	6.556	18.449	3.658	78.675	0.009	0.009	157.43	0.018	(7.41)	(0.001)
2015	0.058	0.047	0.054	0.040	79.691	0.000	79.691	6.641	18.688	3.706	79.691	0.009	0.009	185.04	0.021	2.74	0.000
2016	0.059	0.047	0.055	0.040	80.721	0.000	80.721	6.727	18.929	3.754	80.721	0.009	0.009	212.64	0.024	12.89	0.001
2017	0.060	0.049	0.057	0.042	80.070	0.000	80.070	6.672	18.776	3.723	80.070	0.009	0.009	240.57	0.027	15.16	0.002
2018	0.062	0.051	0.059	0.044	79.424	0.000	79.424	6.619	18.625	3.693	79.424	0.009	0.009	268.50	0.031	17.43	0.002
2019	0.064	0.053	0.061	0.045	78.783	0.000	78.783	6.565	18.475	3.663	78.783	0.009	0.009	296.43	0.034	19.70	0.002
2020	0.066	0.055	0.064	0.047	78.148	0.000	78.148	6.512	18.326	3.634	78.148	0.009	0.009	324.36	0.037	21.96	0.003
2021	0.066	0.055	0.065	0.048	78.286	0.000	78.286	6.524	18.358	3.640	78.286	0.009	0.009	304.56	0.035	18.04	0.002
2022	0.067	0.056	0.065	0.049	78.425	0.000	78.425	6.535	18.391	3.647	78.425	0.009	0.009	284.77	0.033	14.12	0.002
2023	0.068	0.056	0.066	0.049	78.564	0.000	78.564	6.547	18.423	3.653	78.564	0.009	0.009	264.97	0.030	10.20	0.001
2024	0.068	0.057	0.067	0.050	78.703	0.000	78.703	6.559	18.456	3.660	78.703	0.009	0.009	245.18	0.028	6.28	0.001
2025	0.069	0.057	0.068	0.051	78.842	0.000	78.842	6.570	18.488	3.666	78.842	0.009	0.009	225.38	0.026	2.36	0.000
2026	0.070	0.058	0.069	0.051	78.981	0.000	78.981	6.582	18.521	3.673	78.981	0.009	0.009	205.59	0.023	(1.56)	(0.000)
2027	0.070	0.059	0.069	0.052	79.121	0.000	79.121	6.593	18.554	3.679	79.121	0.009	0.009	185.79	0.021	(5.48)	(0.001)
2028	0.071	0.059	0.070	0.053	79.261	0.000	79.261	6.605	18.587	3.686	79.261	0.009	0.009	166.00	0.019	(9.40)	(0.001)
2029	0.072	0.060	0.071	0.054	79.402	0.000	79.402	6.617	18.620	3.692	79.402	0.009	0.009	146.21	0.017	(13.32)	(0.002)
2030	0.072	0.060	0.072	0.054	79.542	0.000	79.542	6.629	18.653	3.699	79.542	0.009	0.009	126.41	0.014	(17.24)	(0.002)
2031	0.072	0.060	0.072	0.054	73.643	0.000	73.643	6.137	17.269	3.424	73.643	0.008	0.008	116.05	0.013	(17.04)	(0.002)
2032	0.072	0.060	0.073	0.054	68.182	0.000	68.182	5.682	15.989	3.170	68.182	0.008	0.008	105.69	0.012	(16.83)	(0.002)
2033	0.072	0.060	0.073	0.054	63.126	0.000	63.126	5.260	14.803	2.935	63.126	0.007	0.007	95.33	0.011	(16.62)	(0.002)
2034	0.072	0.060	0.074	0.054	58.444	0.000	58.444	4.870	13.705	2.718	58.444	0.007	0.007	84.97	0.010	(16.42)	(0.002)
2035	0.072	0.059	0.074	0.053	54.110	0.000	54.110	4.509	12.689	2.516	54.110	0.006	0.006	74.61	0.009	(16.21)	(0.002)
2036	0.072	0.059	0.074	0.053	50.097	0.000	50.097	4.175	11.748	2.330	50.097	0.006	0.006	64.24	0.007	(16.01)	(0.002)
2037	0.072	0.059	0.075	0.053	46.382	0.000	46.382	3.865	10.877	2.157	46.382	0.005	0.005	53.88	0.006	(15.80)	(0.002)
2038	0.072	0.059	0.075	0.053	42.942	0.000	42.942	3.579	10.070	1.997	42.942	0.005	0.005	43.52	0.005	(15.59)	(0.002)
2039	0.072	0.059	0.076	0.053	39.758	0.000	39.758	3.313	9.323	1.849	39.758	0.005	0.005	33.16	0.004	(15.39)	(0.002)
2040	0.072	0.059	0.076	0.053	36.809	0.000	36.809	3.067	8.632	1.712	36.809	0.004	0.004	22.80	0.003	(15.18)	(0.002)
Levelized[3]:																	
2005-2040	0.067	0.056	0.065	0.048	66.167	0.558	66.725	5.514	15.516	3.077	66.725	0.008	0.008	222.99	0.025	3.18	0.000
2006-2040	0.067	0.055	0.065	0.048	68.669	0.471	69.139	5.722	16.103	3.193	69.139	0.008	0.008	231.955	0.026	3.309	0.000
2006-2010	0.072	0.060	0.067	0.050	54.628	2.458	57.085	4.552	12.810	2.540	57.085	0.006	0.007	476.761	0.054	31.501	0.004
2006-2015	0.065	0.053	0.060	0.044	65.336	1.306	66.641	5.445	15.321	3.038	66.641	0.007	0.008	323.802	0.037	10.725	0.001
2006-2020	0.064	0.052	0.060	0.044	69.578	0.913	70.491	5.798	16.316	3.235	70.491	0.008	0.008	306.849	0.035	12.712	0.001

Exhibit A2-3. Electric Energy Avoided Costs by State (continued)

	New Hampshire															
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value[1]	Annual Out of Market Expense	Total Annual Capacity Value	Capacity Value at Load Response (at any month)	Avoidable Capacity Payment at Load Response (Summer Season)	Avoidable Capacity Payment at Load Response (Winter Season)	Avoidable Capacity Payment at Energy Efficiency at Summer Coincident Peak	Load Response (at any month)	Energy Efficiency at Summer Coincident Peak	DRIPE 0.75% Capacity Price	DRIPE 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-month	$/kW-season	$/kW-season	$/kW-yr	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kW-yr	$/kWh
Comment 1:	Values are avoided costs at the generation plus transmission level. DSM savings should be measured at the generator plus transmission level. (Load plus + distribution losses)				Reflects Capacity Price resulting from LICAP beginning in 2006	Recovery of costs for RMR including continuing required payments after LICAP initiation		Avoided Cost applicable to KW savings contributing as supply side credit; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level			Avoided Cost applicable to KW savings at Summer Coincident Peak; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level	Avoided cost expressed in $/kWh at 100% load factor		Incremental to Avoided Cost at Summer Coincident Peak	Expressed in $/kWh at 100% load factor	DRIPE 0.75% measured assuming 10% of supply resources transact in spot market	Expressed in $/kWh at 100% load factor
Comment 2:					info	info	June/July/August	Average for 1 month savings	Average for Summer Season	Average for Winter Season	June / July / August			DRIPE measured at 0.75% peak savings are across all of New England. Values are		DRIPE LIGHT measured at 0.75% peak savings are across all of New England.	
Period:							3-5 pm		June, July, August	Jan-May;Sept-Dec	3-5 pm						
2005[2]	0.072	0.063	0.066	0.049	2.662	0.954	3.616	0.222	0.624	0.124	3.616	0.000	0.000	0.00	0.000	0.00	0.000
2006	0.082	0.070	0.074	0.058	34.548	1.801	36.350	2.879	8.102	1.607	36.350	0.004	0.004	654.43	0.075	32.57	0.004
2007	0.085	0.072	0.079	0.060	39.132	2.151	41.283	3.261	9.176	1.820	41.283	0.004	0.005	906.91	0.104	88.60	0.010
2008	0.072	0.059	0.070	0.050	62.436	0.199	62.635	5.203	14.641	2.903	62.635	0.007	0.007	32.87	0.004	15.28	0.002
2009	0.058	0.048	0.055	0.039	66.758	0.204	66.962	5.563	15.655	3.104	66.962	0.008	0.008	357.68	0.041	9.62	0.001
2010	0.051	0.041	0.048	0.034	69.696	0.177	69.874	5.808	16.344	3.241	69.874	0.008	0.008	266.06	0.030	(6.87)	(0.001)
2011	0.053	0.043	0.050	0.036	72.764	0.154	72.918	6.064	17.063	3.384	72.918	0.008	0.008	174.43	0.020	(23.35)	(0.003)
2012	0.056	0.045	0.051	0.038	75.967	0.133	76.100	6.331	17.814	3.532	76.100	0.009	0.009	82.81	0.009	(39.84)	(0.005)
2013	0.056	0.045	0.052	0.038	76.270	0.000	76.270	6.356	17.885	3.547	76.270	0.009	0.009	119.16	0.014	(21.08)	(0.002)
2014	0.057	0.046	0.053	0.039	76.575	0.000	76.575	6.381	17.957	3.561	76.575	0.009	0.009	155.52	0.018	(2.33)	(0.000)
2015	0.057	0.046	0.053	0.039	76.881	0.000	76.881	6.407	18.029	3.575	76.881	0.009	0.009	191.87	0.022	16.43	0.002
2016	0.058	0.047	0.054	0.039	77.188	0.000	77.188	6.432	18.101	3.589	77.188	0.009	0.009	228.22	0.026	35.18	0.004
2017	0.059	0.048	0.056	0.041	76.704	0.000	76.704	6.392	17.987	3.567	76.704	0.009	0.009	258.99	0.030	36.72	0.004
2018	0.061	0.050	0.058	0.043	76.222	0.000	76.222	6.352	17.874	3.544	76.222	0.009	0.009	289.75	0.033	38.26	0.004
2019	0.063	0.052	0.061	0.045	75.743	0.000	75.743	6.312	17.762	3.522	75.743	0.009	0.009	320.52	0.037	39.80	0.005
2020	0.065	0.054	0.063	0.047	75.267	0.000	75.267	6.272	17.650	3.500	75.267	0.009	0.009	351.29	0.040	41.34	0.005
2021	0.065	0.054	0.064	0.048	75.613	0.000	75.613	6.301	17.731	3.516	75.613	0.009	0.009	328.09	0.037	35.34	0.004
2022	0.066	0.055	0.065	0.048	75.960	0.000	75.960	6.330	17.813	3.532	75.960	0.009	0.009	304.90	0.035	29.34	0.003
2023	0.067	0.056	0.065	0.049	76.309	0.000	76.309	6.359	17.894	3.548	76.309	0.009	0.009	281.70	0.032	23.34	0.003
2024	0.067	0.056	0.066	0.050	76.660	0.000	76.660	6.388	17.977	3.565	76.660	0.009	0.009	258.50	0.030	17.35	0.002
2025	0.068	0.057	0.067	0.050	77.012	0.000	77.012	6.418	18.059	3.581	77.012	0.009	0.009	235.31	0.027	11.35	0.001
2026	0.069	0.057	0.068	0.051	77.365	0.000	77.365	6.447	18.142	3.597	77.365	0.009	0.009	212.11	0.024	5.35	0.001
2027	0.070	0.058	0.069	0.052	77.721	0.000	77.721	6.477	18.225	3.614	77.721	0.009	0.009	188.91	0.022	(0.65)	(0.000)
2028	0.070	0.058	0.070	0.053	78.078	0.000	78.078	6.506	18.309	3.631	78.078	0.009	0.009	165.72	0.019	(6.65)	(0.001)
2029	0.071	0.059	0.071	0.053	78.436	0.000	78.436	6.536	18.393	3.647	78.436	0.009	0.009	142.52	0.016	(12.64)	(0.001)
2030	0.072	0.060	0.071	0.054	78.796	0.000	78.796	6.566	18.478	3.664	78.796	0.009	0.009	119.32	0.014	(18.64)	(0.002)
2031	0.072	0.059	0.072	0.054	72.952	0.000	72.952	6.079	17.107	3.392	72.952	0.008	0.008	109.42	0.012	(18.43)	(0.002)
2032	0.072	0.059	0.072	0.054	67.541	0.000	67.541	5.628	15.838	3.141	67.541	0.008	0.008	99.52	0.011	(18.22)	(0.002)
2033	0.072	0.059	0.073	0.054	62.531	0.000	62.531	5.211	14.664	2.908	62.531	0.007	0.007	89.62	0.010	(18.01)	(0.002)
2034	0.072	0.059	0.073	0.053	57.893	0.000	57.893	4.824	13.576	2.692	57.893	0.007	0.007	79.72	0.009	(17.80)	(0.002)
2035	0.072	0.059	0.073	0.053	53.599	0.000	53.599	4.467	12.569	2.492	53.599	0.006	0.006	69.82	0.008	(17.59)	(0.002)
2036	0.072	0.059	0.074	0.053	49.623	0.000	49.623	4.135	11.637	2.307	49.623	0.006	0.006	59.92	0.007	(17.38)	(0.002)
2037	0.072	0.058	0.074	0.053	45.943	0.000	45.943	3.829	10.774	2.136	45.943	0.005	0.005	50.02	0.006	(17.17)	(0.002)
2038	0.071	0.058	0.075	0.053	42.535	0.000	42.535	3.545	9.974	1.978	42.535	0.005	0.005	40.12	0.005	(16.96)	(0.002)
2039	0.071	0.058	0.075	0.052	39.380	0.000	39.380	3.282	9.235	1.831	39.380	0.004	0.004	30.22	0.003	(16.75)	(0.002)
2040	0.071	0.058	0.075	0.052	36.459	0.000	36.459	3.038	8.550	1.695	36.459	0.004	0.004	20.32	0.002	(16.54)	(0.002)
Levelized[3]:																	
2005-2040	0.066	0.055	0.064	0.047	64.742	0.215	64.957	5.395	15.182	3.010	64.957	0.007	0.007	220.657	0.025	7.200	0.001
2006-2040	0.066	0.055	0.064	0.047	67.237	0.186	67.422	5.603	15.767	3.127	67.422	0.008	0.008	229.525	0.026	7.489	0.001
2006-2010	0.070	0.059	0.065	0.049	54.120	0.927	55.047	4.510	12.691	2.517	55.047	0.006	0.006	448.938	0.051	28.472	0.003
2006-2015	0.063	0.052	0.059	0.043	64.347	0.515	64.862	5.362	15.089	2.992	64.862	0.007	0.007	304.283	0.035	8.063	0.001
2006-2020	0.063	0.052	0.059	0.043	67.922	0.360	68.282	5.660	15.928	3.158	68.282	0.008	0.008	299.546	0.034	17.117	0.002

Exhibit A2-3. Electric Energy Avoided Costs by State (continued)

	Rhode Island																
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value[1]	Annual Out of Market Expense	Total Annual Capacity Value	Capacity Value at Load Response (at any month)	Avoidable Capacity Payment at Load Response (Summer Season)	Avoidable Capacity Payment at Load Response (Winter Season)	Avoidable Capacity Payment at Energy Efficiency at Summer Coincident Peak	Load Response (at any month)	Energy Efficiency at Summer Coincident Peak	DRIPE 0.75% Capacity Price	DRIPE 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-month	$/kW-season	$/kW-season	$/kW-yr	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kW-yr	$/kWh
Comment 1:	Values are avoided costs at the generation plus transmission level. DSM savings should be measured at the generator plus transmission level. (Load plus + distribution losses)				Reflects Capacity Price resulting from LICAP beginning in 2006	Recovery of costs for RMR including continuing required payments after LICAP initiation		Avoided Cost applicable to KW savings contributing as supply side credit; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level			Avoided Cost applicable to KW savings at Summer Coincident Peak; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level	Avoided cost expressed in $/kWh at 100% load factor		Incremental to Avoided Cost at Summer Coincident Peak	Expressed in $/kWh at 100% load factor	DRIPE 0.75% measured assuming 10% of supply resources transact in spot market	Expressed in $/kWh at 100% load factor
Comment 2:					info	info	June/July/ August	Average for 1 month savings	Average for Summer Season	Average for Winter Season	June / July / August			DRIPE measured at 0.75% peak savings are across all of New England. Values are		DRIPE LIGHT measured at 0.75% peak savings are across all of New England.	
Period:							3-5 pm		June, July, August	Jan-May;Sept-Dec	3-5 pm						
2005[2]	0.073	0.064	0.068	0.051	2.662	0.954	3.616	0.222	0.624	0.124	3.616	0.000	0.000	0.00	0.000	0.00	0.000
2006	0.084	0.072	0.077	0.060	34.548	1.801	36.350	2.879	8.102	1.607	36.350	0.004	0.004	654.43	0.075	32.57	0.004
2007	0.087	0.074	0.081	0.062	39.132	2.151	41.283	3.261	9.176	1.820	41.283	0.004	0.005	906.91	0.104	88.60	0.010
2008	0.074	0.060	0.071	0.051	62.436	0.199	62.635	5.203	14.641	2.903	62.635	0.007	0.007	32.87	0.004	15.28	0.002
2009	0.060	0.049	0.056	0.040	66.758	0.204	66.962	5.563	15.655	3.104	66.962	0.008	0.008	357.68	0.041	9.62	0.001
2010	0.052	0.042	0.048	0.035	69.696	0.177	69.874	5.808	16.344	3.241	69.874	0.008	0.008	266.06	0.030	(6.87)	(0.001)
2011	0.054	0.044	0.050	0.037	72.764	0.154	72.918	6.064	17.063	3.384	72.918	0.008	0.008	174.43	0.020	(23.35)	(0.003)
2012	0.057	0.045	0.052	0.038	75.967	0.133	76.100	6.331	17.814	3.532	76.100	0.009	0.009	82.81	0.009	(39.84)	(0.005)
2013	0.057	0.046	0.053	0.039	76.270	0.000	76.270	6.356	17.885	3.547	76.270	0.009	0.009	119.16	0.014	(21.08)	(0.002)
2014	0.057	0.046	0.053	0.039	76.575	0.000	76.575	6.381	17.957	3.561	76.575	0.009	0.009	155.52	0.018	(2.33)	(0.000)
2015	0.058	0.047	0.054	0.040	76.881	0.000	76.881	6.407	18.029	3.575	76.881	0.009	0.009	191.87	0.022	16.43	0.002
2016	0.058	0.047	0.054	0.040	77.188	0.000	77.188	6.432	18.101	3.589	77.188	0.009	0.009	228.22	0.026	35.18	0.004
2017	0.060	0.049	0.056	0.042	76.704	0.000	76.704	6.392	17.987	3.567	76.704	0.009	0.009	258.99	0.030	36.72	0.004
2018	0.062	0.050	0.059	0.044	76.222	0.000	76.222	6.352	17.874	3.544	76.222	0.009	0.009	289.75	0.033	38.26	0.004
2019	0.063	0.052	0.061	0.046	75.743	0.000	75.743	6.312	17.762	3.522	75.743	0.009	0.009	320.52	0.037	39.80	0.005
2020	0.065	0.054	0.063	0.048	75.267	0.000	75.267	6.272	17.650	3.500	75.267	0.009	0.009	351.29	0.040	41.34	0.005
2021	0.066	0.055	0.064	0.048	75.613	0.000	75.613	6.301	17.731	3.516	75.613	0.009	0.009	328.09	0.037	35.34	0.004
2022	0.067	0.055	0.065	0.049	75.960	0.000	75.960	6.330	17.813	3.532	75.960	0.009	0.009	304.90	0.035	29.34	0.003
2023	0.067	0.056	0.066	0.050	76.309	0.000	76.309	6.359	17.894	3.548	76.309	0.009	0.009	281.70	0.032	23.34	0.003
2024	0.068	0.057	0.067	0.050	76.660	0.000	76.660	6.388	17.977	3.565	76.660	0.009	0.009	258.50	0.030	17.35	0.002
2025	0.069	0.057	0.067	0.051	77.012	0.000	77.012	6.418	18.059	3.581	77.012	0.009	0.009	235.31	0.027	11.35	0.001
2026	0.069	0.058	0.068	0.052	77.365	0.000	77.365	6.447	18.142	3.597	77.365	0.009	0.009	212.11	0.024	5.35	0.001
2027	0.070	0.058	0.069	0.052	77.721	0.000	77.721	6.477	18.225	3.614	77.721	0.009	0.009	188.91	0.022	(0.65)	(0.000)
2028	0.071	0.059	0.070	0.053	78.078	0.000	78.078	6.506	18.309	3.631	78.078	0.009	0.009	165.72	0.019	(6.65)	(0.001)
2029	0.072	0.060	0.071	0.054	78.436	0.000	78.436	6.536	18.393	3.647	78.436	0.009	0.009	142.52	0.016	(12.64)	(0.001)
2030	0.072	0.060	0.072	0.054	78.796	0.000	78.796	6.566	18.478	3.664	78.796	0.009	0.009	119.32	0.014	(18.64)	(0.002)
2031	0.072	0.060	0.072	0.054	72.952	0.000	72.952	6.079	17.107	3.392	72.952	0.008	0.008	109.42	0.012	(18.43)	(0.002)
2032	0.072	0.060	0.072	0.054	67.541	0.000	67.541	5.628	15.838	3.141	67.541	0.008	0.008	99.52	0.011	(18.22)	(0.002)
2033	0.072	0.060	0.073	0.054	62.531	0.000	62.531	5.211	14.664	2.908	62.531	0.007	0.007	89.62	0.010	(18.01)	(0.002)
2034	0.072	0.060	0.073	0.054	57.893	0.000	57.893	4.824	13.576	2.692	57.893	0.007	0.007	79.72	0.009	(17.80)	(0.002)
2035	0.072	0.059	0.074	0.054	53.599	0.000	53.599	4.467	12.569	2.492	53.599	0.006	0.006	69.82	0.008	(17.59)	(0.002)
2036	0.072	0.059	0.074	0.053	49.623	0.000	49.623	4.135	11.637	2.307	49.623	0.006	0.006	59.92	0.007	(17.38)	(0.002)
2037	0.072	0.059	0.075	0.053	45.943	0.000	45.943	3.829	10.774	2.136	45.943	0.005	0.005	50.02	0.006	(17.17)	(0.002)
2038	0.072	0.059	0.075	0.053	42.535	0.000	42.535	3.545	9.974	1.978	42.535	0.005	0.005	40.12	0.005	(16.96)	(0.002)
2039	0.072	0.058	0.075	0.053	39.380	0.000	39.380	3.282	9.235	1.831	39.380	0.004	0.004	30.22	0.003	(16.75)	(0.002)
2040	0.072	0.058	0.076	0.053	36.459	0.000	36.459	3.038	8.550	1.695	36.459	0.004	0.004	20.32	0.002	(16.54)	(0.002)
Levelized[3]:																	
2005-2040	0.067	0.056	0.065	0.048	64.742	0.215	64.957	5.395	15.182	3.010	64.957	0.007	0.007	220.657	0.025	7.200	0.001
2006-2040	0.067	0.055	0.065	0.048	67.237	0.186	67.422	5.603	15.767	3.127	67.422	0.008	0.008	229.525	0.026	7.489	0.001
2006-2010	0.072	0.060	0.067	0.050	54.120	0.927	55.047	4.510	12.691	2.517	55.047	0.006	0.006	448.938	0.051	28.472	0.003
2006-2015	0.065	0.053	0.060	0.045	64.347	0.515	64.862	5.362	15.089	2.992	64.862	0.007	0.007	304.283	0.035	8.063	0.001
2006-2020	0.064	0.052	0.059	0.044	67.922	0.360	68.282	5.660	15.928	3.158	68.282	0.008	0.008	299.546	0.034	17.117	0.002

Exhibit A2-3. Electric Energy Avoided Costs by State (continued)

	Vermont																	
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value[1]	Annual Out of Market Expense	Total Annual Capacity Value	Capacity Value at Load Response (at any month)	Avoidable Capacity Payment at Load Response (Summer Season)	Avoidable Capacity Payment at Load Response (Winter Season)	Avoidable Capacity Payment at Energy Efficiency at Summer Coincident Peak	Load Response (at any month)	Energy Efficiency at Summer Coincident Peak	DRIPE 0.75% Capacity Price	DRIPE 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price
Units:	**$/kWh**	**$/kWh**	**$/kWh**	**$/kWh**	**$/kW-yr**	**$/kW-yr**	**$/kW-yr**	**$/kW-month**	**$/kW-season**	**$/kW-season**	**$/kW-yr**	**$/kWh**	**$/kWh**	**$/kW-yr**	**$/kWh**	**$/kW-yr**	**$/kWh**
Comment 1:	Values are avoided costs at the generation plus transmission level. DSM savings should be measured at the generator plus transmission level. (Load plus + distribution losses)				Reflects Capacity Price resulting from LICAP beginning in 2006	Recovery of costs for RMR including continuing required payments after LICAP initiation		Avoided Cost applicable to KW savings contributing as supply side credit; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level			Avoided Cost applicable to KW savings at Summer Coincident Peak; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level	Avoided cost expressed in $/kWh at 100% load factor		Incremental to Avoided Cost at Summer Coincident Peak	Expressed in $/kWh at 100% load factor	DRIPE 0.75% measured assuming 10% of supply resources transact in spot market	Expressed in $/kWh at 100% load factor
Comment 2:					info	info	June/July/ August	Average for 1 month savings	Average for Summer Season	Average for Winter Season	June / July / August			DRIPE measured at 0.75% peak savings are across all of New England. Values are		DRIPE LIGHT measured at 0.75% peak savings are across all of New England.	
Period:							3-5 pm		June, July, August	Jan-May;Sept-Dec	3-5 pm						
2005[2]	0.077	0.064	0.074	0.052	2.662	0.954	3.616	0.222	0.624	0.124	3.616	0.000	0.000	0.00	0.000	0.00	0.000
2006	0.088	0.072	0.081	0.061	34.548	1.801	36.350	2.879	8.102	1.607	36.350	0.004	0.001	654.43	0.075	32.57	0.004
2007	0.090	0.074	0.085	0.062	39.132	2.151	41.283	3.261	9.176	1.820	41.283	0.004	0.001	906.91	0.104	88.60	0.010
2008	0.076	0.060	0.073	0.051	62.436	0.199	62.635	5.203	14.641	2.903	62.635	0.007	0.002	32.87	0.004	15.28	0.002
2009	0.062	0.049	0.058	0.040	66.758	0.204	66.962	5.563	15.655	3.104	66.962	0.008	0.002	357.68	0.041	9.62	0.001
2010	0.053	0.042	0.050	0.035	69.696	0.177	69.874	5.808	16.344	3.241	69.874	0.008	0.002	266.06	0.030	(6.87)	(0.001)
2011	0.055	0.044	0.051	0.037	72.764	0.154	72.918	6.064	17.063	3.384	72.918	0.008	0.002	174.43	0.020	(23.35)	(0.003)
2012	0.056	0.046	0.052	0.038	75.967	0.133	76.100	6.331	17.814	3.532	76.100	0.009	0.002	82.81	0.009	(39.84)	(0.005)
2013	0.057	0.046	0.053	0.039	76.270	0.000	76.270	6.356	17.885	3.547	76.270	0.009	0.002	119.16	0.014	(21.08)	(0.002)
2014	0.057	0.047	0.053	0.039	76.575	0.000	76.575	6.381	17.957	3.561	76.575	0.009	0.002	155.52	0.018	(2.33)	(0.000)
2015	0.058	0.047	0.054	0.040	76.881	0.000	76.881	6.407	18.029	3.575	76.881	0.009	0.002	191.87	0.022	16.43	0.002
2016	0.058	0.048	0.055	0.040	77.188	0.000	77.188	6.432	18.101	3.589	77.188	0.009	0.002	228.22	0.026	35.18	0.004
2017	0.060	0.049	0.057	0.042	76.704	0.000	76.704	6.392	17.987	3.567	76.704	0.009	0.002	258.99	0.030	36.72	0.004
2018	0.062	0.051	0.059	0.044	76.222	0.000	76.222	6.352	17.874	3.544	76.222	0.009	0.002	289.75	0.033	38.26	0.004
2019	0.064	0.053	0.061	0.046	75.743	0.000	75.743	6.312	17.762	3.522	75.743	0.009	0.002	320.52	0.037	39.80	0.005
2020	0.065	0.055	0.064	0.048	75.267	0.000	75.267	6.272	17.650	3.500	75.267	0.009	0.002	351.29	0.040	41.34	0.005
2021	0.066	0.055	0.065	0.049	75.613	0.000	75.613	6.301	17.731	3.516	75.613	0.009	0.002	328.09	0.037	35.34	0.004
2022	0.067	0.056	0.066	0.049	75.960	0.000	75.960	6.330	17.813	3.532	75.960	0.009	0.002	304.90	0.035	29.34	0.003
2023	0.068	0.056	0.066	0.050	76.309	0.000	76.309	6.359	17.894	3.548	76.309	0.009	0.002	281.70	0.032	23.34	0.003
2024	0.068	0.057	0.067	0.051	76.660	0.000	76.660	6.388	17.977	3.565	76.660	0.009	0.002	258.50	0.030	17.35	0.002
2025	0.069	0.058	0.068	0.051	77.012	0.000	77.012	6.418	18.059	3.581	77.012	0.009	0.002	235.31	0.027	11.35	0.001
2026	0.070	0.058	0.069	0.052	77.365	0.000	77.365	6.447	18.142	3.597	77.365	0.009	0.002	212.11	0.024	5.35	0.001
2027	0.071	0.059	0.070	0.053	77.721	0.000	77.721	6.477	18.225	3.614	77.721	0.009	0.002	188.91	0.022	(0.65)	(0.000)
2028	0.071	0.059	0.071	0.054	78.078	0.000	78.078	6.506	18.309	3.631	78.078	0.009	0.002	165.72	0.019	(6.65)	(0.001)
2029	0.072	0.060	0.072	0.054	78.436	0.000	78.436	6.536	18.393	3.647	78.436	0.009	0.002	142.52	0.016	(12.64)	(0.001)
2030	0.073	0.061	0.073	0.055	78.796	0.000	78.796	6.566	18.478	3.664	78.796	0.009	0.002	119.32	0.014	(18.64)	(0.002)
2031	0.073	0.060	0.073	0.055	72.952	0.000	72.952	6.079	17.107	3.392	72.952	0.008	0.002	109.42	0.012	(18.43)	(0.002)
2032	0.073	0.060	0.073	0.055	67.541	0.000	67.541	5.628	15.838	3.141	67.541	0.008	0.002	99.52	0.011	(18.22)	(0.002)
2033	0.073	0.060	0.074	0.054	62.531	0.000	62.531	5.211	14.664	2.908	62.531	0.007	0.002	89.62	0.010	(18.01)	(0.002)
2034	0.073	0.060	0.074	0.054	57.893	0.000	57.893	4.824	13.576	2.692	57.893	0.007	0.002	79.72	0.009	(17.80)	(0.002)
2035	0.073	0.060	0.075	0.054	53.599	0.000	53.599	4.467	12.569	2.492	53.599	0.006	0.001	69.82	0.008	(17.59)	(0.002)
2036	0.073	0.060	0.075	0.054	49.623	0.000	49.623	4.135	11.637	2.307	49.623	0.006	0.001	59.92	0.007	(17.38)	(0.002)
2037	0.073	0.059	0.075	0.054	45.943	0.000	45.943	3.829	10.774	2.136	45.943	0.005	0.001	50.02	0.006	(17.17)	(0.002)
2038	0.073	0.059	0.076	0.053	42.535	0.000	42.535	3.545	9.974	1.978	42.535	0.005	0.001	40.12	0.005	(16.96)	(0.002)
2039	0.073	0.059	0.076	0.053	39.380	0.000	39.380	3.282	9.235	1.831	39.380	0.004	0.001	30.22	0.003	(16.75)	(0.002)
2040	0.073	0.059	0.076	0.053	36.459	0.000	36.459	3.038	8.550	1.695	36.459	0.004	0.001	20.32	0.002	(16.54)	(0.002)
Levelized[3]:																	
2005-2040	0.068	0.056	0.066	0.049	64.742	0.215	64.957	5.395	15.182	3.010	64.957	0.007	0.002	220.657	0.025	7.200	0.001
2006-2040	0.068	0.056	0.066	0.048	67.237	0.186	67.422	5.603	15.767	3.127	67.422	0.008	0.002	229.525	0.026	7.489	0.001
2006-2010	0.074	0.060	0.070	0.050	54.120	0.927	55.047	4.510	12.691	2.517	55.047	0.006	0.001	448.938	0.051	28.472	0.003
2006-2015	0.066	0.053	0.062	0.045	64.347	0.515	64.862	5.362	15.089	2.992	64.862	0.007	0.002	304.283	0.035	8.063	0.001
2006-2020	0.065	0.053	0.061	0.044	67.922	0.360	68.282	5.660	15.928	3.158	68.282	0.008	0.002	299.546	0.034	17.117	0.002

Exhibit A2-3. Electric Energy Avoided Costs by State (continued)

	Connecticut																
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value[1]	Annual Out of Market Expense	Total Annual Capacity Value	Capacity Value of Load Response (at any month)	Avoidable Capacity Payment of Load Response (Summer Season)	Avoidable Capacity Payment of Load Response (Winter Season)	Avoidable Capacity Payment of Energy Efficiency at Summer Coincident Peak	Load Response (at any month)	Energy Efficiency at Summer Coincident Peak	DRIPE 0.75% Capacity Price	DRIPE 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-month	$/kW-season	$/kW-season	$/kW-yr	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kW-yr	$/kWh
Comment 1:	Values are avoided costs at the generation plus transmission level. DSM savings should be measured at the generator plus transmission level. (Load plus + distribution losses)				Reflects Capacity Price resulting from LICAP beginning in 2006	Recovery of costs for RMR including continuing required payments after LICAP initiation		Avoided Cost applicable to KW savings contributing as supply side credit; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level			Avoided Cost applicable to KW savings at Summer Coincident Peak; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level	Avoided cost expressed in $/kWh at 100% load factor		Incremental to Avoided Cost at Summer Coincident Peak	Expressed in $/kWh at 100% load factor	DRIPE 0.75% measured assuming 10% of supply resources transact in spot market	Expressed in $/kWh at 100% load factor
Comment 2:					info	info	June/July/ August	Average for 1 month savings	Average for Summer Season	Average for Winter Season	June / July / August			DRIPE measured at 0.75% peak savings are across all of New England. Values		DRIPE LIGHT measured at 0.75% peak savings are across all of New England.	
Period:							3-5 pm		June, July, August	Jan-May;Sept-Dec	3-5 pm						
2005[2]	0.081	0.066	0.082	0.055	6.783	13.549	20.332	0.565	1.591	0.315	20.332	0.001	0.002	0.00	0.000	0.00	0.000
2006	0.094	0.075	0.095	0.064	48.378	3.865	52.243	4.031	11.345	2.250	52.243	0.006	0.006	305.26	0.035	156.87	0.018
2007	0.099	0.077	0.096	0.065	51.479	2.983	54.462	4.290	12.072	2.394	54.462	0.006	0.006	127.23	0.015	181.29	0.021
2008	0.080	0.063	0.076	0.053	65.040	0.908	65.949	5.420	15.252	3.024	65.949	0.007	0.008	111.60	0.013	157.35	0.018
2009	0.065	0.051	0.060	0.042	69.546	0.881	70.427	5.796	16.309	3.234	70.427	0.008	0.008	451.40	0.052	192.54	0.022
2010	0.056	0.043	0.052	0.036	72.357	0.836	73.194	6.030	16.968	3.365	73.194	0.008	0.008	373.73	0.043	180.60	0.021
2011	0.057	0.045	0.053	0.038	75.282	0.794	76.076	6.273	17.654	3.501	76.076	0.009	0.009	296.05	0.034	168.65	0.019
2012	0.058	0.046	0.054	0.039	78.325	0.753	79.078	6.527	18.367	3.642	79.078	0.009	0.009	218.38	0.025	156.71	0.018
2013	0.059	0.046	0.054	0.039	78.636	0.000	78.636	6.553	18.440	3.657	78.636	0.009	0.009	225.37	0.026	144.31	0.016
2014	0.059	0.047	0.055	0.039	78.948	0.000	78.948	6.579	18.513	3.671	78.948	0.009	0.009	232.37	0.027	131.91	0.015
2015	0.059	0.047	0.055	0.040	79.262	0.000	79.262	6.605	18.587	3.686	79.262	0.009	0.009	239.36	0.027	119.51	0.014
2016	0.060	0.047	0.055	0.040	79.577	0.000	79.577	6.631	18.661	3.700	79.577	0.009	0.009	246.36	0.028	107.11	0.012
2017	0.061	0.049	0.058	0.042	78.769	0.000	78.769	6.564	18.471	3.663	78.769	0.009	0.009	242.21	0.028	104.93	0.012
2018	0.063	0.051	0.060	0.043	77.968	0.000	77.968	6.497	18.284	3.626	77.968	0.009	0.009	238.06	0.027	102.74	0.012
2019	0.065	0.052	0.062	0.045	77.176	0.000	77.176	6.431	18.098	3.589	77.176	0.009	0.009	233.91	0.027	100.55	0.011
2020	0.067	0.054	0.065	0.047	76.392	0.000	76.392	6.366	17.914	3.552	76.392	0.009	0.009	229.77	0.026	98.36	0.011
2021	0.067	0.055	0.066	0.048	76.552	0.000	76.552	6.379	17.952	3.560	76.552	0.009	0.009	220.70	0.025	95.45	0.011
2022	0.068	0.055	0.066	0.049	76.713	0.000	76.713	6.393	17.989	3.567	76.713	0.009	0.009	211.64	0.024	92.54	0.011
2023	0.068	0.056	0.067	0.049	76.875	0.000	76.875	6.406	18.027	3.575	76.875	0.009	0.009	202.58	0.023	89.63	0.010
2024	0.069	0.056	0.068	0.050	77.036	0.000	77.036	6.420	18.065	3.582	77.036	0.009	0.009	193.51	0.022	86.72	0.010
2025	0.070	0.057	0.069	0.050	77.199	0.000	77.199	6.433	18.103	3.590	77.199	0.009	0.009	184.45	0.021	83.81	0.010
2026	0.070	0.058	0.069	0.051	77.361	0.000	77.361	6.447	18.141	3.597	77.361	0.009	0.009	175.39	0.020	80.90	0.009
2027	0.071	0.058	0.070	0.052	77.524	0.000	77.524	6.460	18.179	3.605	77.524	0.009	0.009	166.32	0.019	77.99	0.009
2028	0.072	0.059	0.071	0.052	77.687	0.000	77.687	6.474	18.218	3.612	77.687	0.009	0.009	157.26	0.018	75.08	0.009
2029	0.072	0.059	0.072	0.053	77.850	0.000	77.850	6.488	18.256	3.620	77.850	0.009	0.009	148.20	0.017	72.17	0.008
2030	0.073	0.060	0.073	0.054	78.014	0.000	78.014	6.501	18.294	3.628	78.014	0.009	0.009	139.13	0.016	69.26	0.008
2031	0.073	0.060	0.073	0.053	72.226	0.000	72.226	6.019	16.937	3.359	72.226	0.008	0.008	128.05	0.015	64.91	0.007
2032	0.073	0.060	0.073	0.053	66.868	0.000	66.868	5.572	15.680	3.109	66.868	0.008	0.008	116.96	0.013	60.55	0.007
2033	0.073	0.059	0.074	0.053	61.907	0.000	61.907	5.159	14.517	2.879	61.907	0.007	0.007	105.88	0.012	56.19	0.006
2034	0.073	0.059	0.074	0.053	57.314	0.000	57.314	4.776	13.440	2.665	57.314	0.007	0.007	94.80	0.011	51.84	0.006
2035	0.073	0.059	0.075	0.053	53.062	0.000	53.062	4.422	12.443	2.467	53.062	0.006	0.006	83.71	0.010	47.48	0.005
2036	0.073	0.059	0.075	0.053	49.125	0.000	49.125	4.094	11.520	2.284	49.125	0.006	0.006	72.63	0.008	43.13	0.005
2037	0.073	0.059	0.076	0.053	45.481	0.000	45.481	3.790	10.665	2.115	45.481	0.005	0.005	61.55	0.007	38.77	0.004
2038	0.073	0.059	0.076	0.053	42.106	0.000	42.106	3.509	9.874	1.958	42.106	0.005	0.005	50.46	0.006	34.42	0.004
2039	0.073	0.059	0.077	0.053	38.982	0.000	38.982	3.249	9.141	1.813	38.982	0.004	0.004	39.38	0.004	30.06	0.003
2040	0.073	0.058	0.077	0.053	36.090	0.000	36.090	3.008	8.463	1.678	36.090	0.004	0.004	28.30	0.003	25.70	0.003
Levelized[3]:																	
2005-2040	0.070	0.056	0.068	0.049	66.745	0.927	67.672	5.562	15.652	3.104	67.672	0.008	0.008	188.17	0.021	101.57	0.012
2006-2040	0.069	0.056	0.068	0.048	69.155	0.419	69.575	5.763	16.217	3.216	69.575	0.008	0.008	195.735	0.022	105.654	0.012
2006-2010	0.079	0.062	0.076	0.052	61.095	1.928	63.022	5.091	14.327	2.841	63.022	0.007	0.007	272.011	0.031	173.493	0.020
2006-2015	0.069	0.054	0.066	0.046	69.150	1.164	70.313	5.762	16.216	3.215	70.313	0.008	0.008	258.097	0.029	159.825	0.018
2006-2020	0.067	0.053	0.064	0.045	71.811	0.814	72.625	5.984	16.840	3.339	72.625	0.008	0.008	252.128	0.029	142.700	0.016

Exhibit A2-4. Electric Energy Avoided Costs by Pricing Zone

	Maine																
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value[1]	Annual Out of Market Expense	Total Annual Capacity Value	Capacity Value at Load Response (at any month)	Avoidable Capacity Payment at Load Response (Summer Season)	Avoidable Capacity Payment at Load Response (Winter Season)	Avoidable Capacity Payment at Energy Efficiency at Summer Coincident Peak	Load Response (at any month)	Energy Efficiency at Summer Coincident Peak	DRIPE 0.75% Capacity Price	DRIPE 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price
Units:	**$/kWh**	**$/kWh**	**$/kWh**	**$/kWh**	**$/kW-yr**	**$/kW-yr**	**$/kW-yr**	**$/kW-month**	**$/kW-season**	**$/kW-season**	**$/kW-yr**	**$/kWh**	**$/kWh**	**$/kW-yr**	**$/kWh**	**$/kW-yr**	**$/kWh**
Comment 1:	Values are avoided costs at the generation plus transmission level. DSM savings should be measured at the generator plus transmission level. (Load plus + distribution losses)				Reflects Capacity Price resulting from LICAP beginning in 2006	Recovery of costs for RMR including continuing required payments after LICAP initiation		Avoided Cost applicable to KW savings contributing as supply side credit; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level			Avoided Cost applicable to KW savings at Summer Coincident Peak; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level	Avoided cost expressed in $/kWh at 100% load factor		Incremental to Avoided Cost at Summer Coincident Peak	Expressed in $/kWh at 100% load factor	DRIPE 0.75% measured assuming 10% of supply resources transact in spot market	Expressed in $/kWh at 100% load factor
Comment 2:					info	info	June/July/August	Average for 1 month savings	Average for Summer Season	Average for Winter Season	June / July / August			DRIPE measured at 0.75% peak savings are across all of New England.		DRIPE LIGHT measured at 0.75% peak savings are across all of New England.	
Period:							3-5 pm		June, July, August	Jan-May;Sept-Dec	3-5 pm						
2005[2]	0.071	0.063	0.063	0.049	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.00	0.000	0.00	0.000
2006	0.080	0.071	0.070	0.057	23.304	0.000	23.304	1.942	5.465	1.084	23.304	0.003	0.003	1,115.39	0.127	90.57	0.010
2007	0.083	0.072	0.072	0.059	20.172	0.000	20.172	1.681	4.730	0.938	20.172	0.002	0.002	616.86	0.070	43.53	0.005
2008	0.070	0.059	0.060	0.048	19.462	0.000	19.462	1.622	4.564	0.905	19.462	0.002	0.002	23.10	0.003	6.00	0.001
2009	0.056	0.047	0.048	0.039	17.895	0.000	17.895	1.491	4.196	0.832	17.895	0.002	0.002	6.57	0.001	4.86	0.001
2010	0.049	0.041	0.043	0.034	27.761	0.000	27.761	2.313	6.510	1.291	27.761	0.003	0.003	9.00	0.001	7.86	0.001
2011	0.051	0.043	0.046	0.036	43.067	0.000	43.067	3.589	10.099	2.003	43.067	0.005	0.005	11.43	0.001	10.86	0.001
2012	0.054	0.044	0.049	0.038	66.810	0.000	66.810	5.568	15.667	3.107	66.810	0.008	0.008	13.86	0.002	13.86	0.002
2013	0.054	0.045	0.049	0.038	67.163	0.000	67.163	5.597	15.750	3.123	67.163	0.008	0.008	13.76	0.002	13.02	0.001
2014	0.054	0.046	0.049	0.039	67.517	0.000	67.517	5.626	15.833	3.140	67.517	0.008	0.008	13.66	0.002	12.18	0.001
2015	0.055	0.046	0.049	0.039	67.872	0.000	67.872	5.656	15.916	3.156	67.872	0.008	0.008	13.56	0.002	11.34	0.001
2016	0.055	0.047	0.049	0.039	68.230	0.000	68.230	5.686	16.000	3.173	68.230	0.008	0.008	13.46	0.002	10.51	0.001
2017	0.057	0.048	0.051	0.041	65.767	0.000	65.767	5.481	15.422	3.058	65.767	0.008	0.008	12.91	0.001	10.69	0.001
2018	0.059	0.050	0.053	0.043	63.392	0.000	63.392	5.283	14.865	2.948	63.392	0.007	0.007	12.36	0.001	10.88	0.001
2019	0.061	0.052	0.055	0.045	61.103	0.000	61.103	5.092	14.329	2.841	61.103	0.007	0.007	11.80	0.001	11.07	0.001
2020	0.063	0.054	0.057	0.047	58.896	0.000	58.896	4.908	13.811	2.739	58.896	0.007	0.007	11.25	0.001	11.25	0.001
2021	0.064	0.054	0.058	0.048	60.454	0.000	60.454	5.038	14.177	2.811	60.454	0.007	0.007	16.72	0.002	7.79	0.001
2022	0.064	0.055	0.059	0.048	62.053	0.000	62.053	5.171	14.552	2.885	62.053	0.007	0.007	22.18	0.003	4.32	0.000
2023	0.065	0.055	0.060	0.049	63.695	0.000	63.695	5.308	14.936	2.962	63.695	0.007	0.007	27.65	0.003	0.86	0.000
2024	0.065	0.056	0.061	0.050	65.380	0.000	65.380	5.448	15.332	3.040	65.380	0.007	0.007	33.12	0.004	(2.61)	(0.000)
2025	0.066	0.056	0.061	0.051	67.109	0.000	67.109	5.592	15.737	3.121	67.109	0.008	0.008	38.58	0.004	(6.07)	(0.001)
2026	0.067	0.057	0.062	0.051	68.885	0.000	68.885	5.740	16.153	3.203	68.885	0.008	0.008	44.05	0.005	(9.54)	(0.001)
2027	0.067	0.057	0.063	0.052	70.707	0.000	70.707	5.892	16.581	3.288	70.707	0.008	0.008	49.51	0.006	(13.00)	(0.001)
2028	0.068	0.058	0.064	0.053	72.577	0.000	72.577	6.048	17.019	3.375	72.577	0.008	0.008	54.98	0.006	(16.47)	(0.002)
2029	0.069	0.058	0.065	0.054	74.497	0.000	74.497	6.208	17.470	3.464	74.497	0.009	0.009	60.45	0.007	(19.93)	(0.002)
2030	0.069	0.059	0.066	0.054	76.468	0.000	76.468	6.372	17.932	3.556	76.468	0.009	0.009	65.91	0.008	(23.40)	(0.003)
2031	0.069	0.059	0.066	0.054	70.863	0.000	70.863	5.905	16.617	3.295	70.863	0.008	0.008	61.90	0.007	(22.31)	(0.003)
2032	0.070	0.059	0.066	0.054	65.669	0.000	65.669	5.472	15.399	3.054	65.669	0.007	0.007	57.88	0.007	(21.21)	(0.002)
2033	0.070	0.059	0.067	0.054	60.856	0.000	60.856	5.071	14.271	2.830	60.856	0.007	0.007	53.87	0.006	(20.12)	(0.002)
2034	0.070	0.059	0.067	0.054	56.395	0.000	56.395	4.700	13.225	2.622	56.395	0.006	0.006	49.85	0.006	(19.03)	(0.002)
2035	0.070	0.059	0.067	0.054	52.262	0.000	52.262	4.355	12.255	2.430	52.262	0.006	0.006	45.84	0.005	(17.94)	(0.002)
2036	0.070	0.059	0.068	0.054	48.431	0.000	48.431	4.036	11.357	2.252	48.431	0.006	0.006	41.82	0.005	(16.84)	(0.002)
2037	0.070	0.059	0.068	0.054	44.881	0.000	44.881	3.740	10.525	2.087	44.881	0.005	0.005	37.81	0.004	(15.75)	(0.002)
2038	0.070	0.059	0.068	0.054	41.591	0.000	41.591	3.466	9.753	1.934	41.591	0.005	0.005	33.79	0.004	(14.66)	(0.002)
2039	0.070	0.059	0.068	0.054	38.543	0.000	38.543	3.212	9.038	1.792	38.543	0.004	0.004	29.78	0.003	(13.57)	(0.002)
2040	0.070	0.059	0.069	0.053	35.718	0.000	35.718	2.976	8.376	1.661	35.718	0.004	0.004	25.76	0.003	6.15	0.001
Levelized[3]:																	
2005-2040	0.064	0.055	0.059	0.047	51.998	0.000	51.998	4.333	12.194	2.418	51.998	0.006	0.006	90.231	0.010	4.165	0.000
2006-2040	0.064	0.054	0.059	0.047	54.088	0.000	54.088	4.507	12.684	2.515	54.088	0.006	0.006	93.858	0.011	4.333	0.000
2006-2010	0.068	0.058	0.059	0.047	21.693	0.000	21.693	1.808	5.087	1.009	21.693	0.002	0.002	365.592	0.042	31.390	0.004
2006-2015	0.061	0.052	0.054	0.043	40.969	0.000	40.969	3.414	9.607	1.905	40.969	0.005	0.005	198.259	0.023	22.304	0.003
2006-2020	0.061	0.051	0.054	0.043	47.760	0.000	47.760	3.980	11.200	2.221	47.760	0.005	0.005	142.410	0.016	18.869	0.002

Exhibit A2-4. Electric Energy Avoided Costs by Pricing Zone (continued)

	Nema-Boston																
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value[1]	Annual Out of Market Expense	Total Annual Capacity Value	Capacity Value at Load Response (at any month)	Avoidable Capacity Payment at Load Response (Summer Season)	Avoidable Capacity Payment at Load Response (Winter Season)	Avoidable Capacity Payment at Energy Efficiency at Summer Coincident Peak	Load Response (at any month)	Energy Efficiency at Summer Coincident Peak	DRIPE 0.75% Capacity Price	DRIPE 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-month	$/kW-season	$/kW-season	$/kW-yr	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kW-yr	$/kWh
Comment 1:	Values are avoided costs at the generation plus transmission level. DSM savings should be measured at the generator plus transmission level. (Load plus + distribution losses)				Reflects Capacity Price resulting from LICAP beginning in 2006	Recovery of costs for RMR including continuing required payments after LICAP initiation		Avoided Cost applicable to KW savings contributing as supply side credit; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level			Avoided Cost applicable to KW savings at Summer Coincident Peak; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level	Avoided cost expressed in $/kWh at 100% load factor		Incremental to Avoided Cost at Summer Coincident Peak	Expressed in $/kWh at 100% load factor	DRIPE 0.75% measured assuming 10% of supply resources transact in spot market	Expressed in $/kWh at 100% load factor
Comment 2:					info	info	June/July/August	Average for 1 month savings	Average for Summer Season	Average for Winter Season	June / July / August			DRIPE measured at 0.75% peak savings are across all of New England. Values		DRIPE LIGHT measured at 0.75% peak savings are across all of New England.	
Period:							3-5 pm		June, July, August	Jan-May;Sept-Dec	3-5 pm						
2005[2]	0.074	0.064	0.069	0.051	5.387	4.835	10.222	0.449	1.263	0.251	10.222	0.001	0.001	0.00	0.000	0.00	0.000
2006	0.085	0.072	0.077	0.059	35.258	11.077	46.335	2.938	8.268	1.640	46.335	0.004	0.005	739.33	0.084	38.81	0.004
2007	0.087	0.074	0.081	0.062	39.936	9.630	49.566	3.328	9.365	1.857	49.566	0.005	0.006	978.41	0.112	54.89	0.006
2008	0.074	0.060	0.072	0.050	63.709	0.000	63.709	5.309	14.940	2.962	63.709	0.007	0.007	35.09	0.004	15.58	0.002
2009	0.060	0.049	0.056	0.040	68.126	0.000	68.126	5.677	15.976	3.168	68.126	0.008	0.008	436.08	0.050	41.82	0.005
2010	0.052	0.042	0.049	0.035	71.124	0.000	71.124	5.927	16.679	3.307	71.124	0.008	0.008	332.41	0.038	23.40	0.003
2011	0.055	0.044	0.051	0.037	74.254	0.000	74.254	6.188	17.413	3.453	74.254	0.008	0.008	228.74	0.026	4.97	0.001
2012	0.057	0.046	0.052	0.038	77.523	0.000	77.523	6.460	18.179	3.605	77.523	0.009	0.009	125.06	0.014	(13.45)	(0.002)
2013	0.057	0.046	0.053	0.039	79.296	0.000	79.296	6.608	18.595	3.687	79.296	0.009	0.009	142.39	0.016	(13.40)	(0.002)
2014	0.058	0.046	0.054	0.039	81.109	0.000	81.109	6.759	19.020	3.772	81.109	0.009	0.009	159.72	0.018	(13.35)	(0.002)
2015	0.058	0.047	0.054	0.040	82.965	0.000	82.965	6.914	19.455	3.858	82.965	0.009	0.009	177.04	0.020	(13.30)	(0.002)
2016	0.059	0.047	0.055	0.040	84.862	0.000	84.862	7.072	19.900	3.946	84.862	0.010	0.010	194.37	0.022	(13.25)	(0.002)
2017	0.060	0.049	0.057	0.042	84.012	0.000	84.012	7.001	19.701	3.907	84.012	0.010	0.010	218.99	0.025	(10.11)	(0.001)
2018	0.062	0.051	0.059	0.044	83.170	0.000	83.170	6.931	19.503	3.867	83.170	0.009	0.009	243.61	0.028	(6.97)	(0.001)
2019	0.064	0.053	0.061	0.045	82.336	0.000	82.336	6.861	19.308	3.829	82.336	0.009	0.009	268.23	0.031	(3.84)	(0.000)
2020	0.066	0.055	0.064	0.047	81.511	0.000	81.511	6.793	19.114	3.790	81.511	0.009	0.009	292.85	0.033	(0.70)	(0.000)
2021	0.066	0.055	0.065	0.048	81.400	0.000	81.400	6.783	19.088	3.785	81.400	0.009	0.009	277.03	0.032	(2.19)	(0.000)
2022	0.067	0.056	0.065	0.049	81.288	0.000	81.288	6.774	19.062	3.780	81.288	0.009	0.009	261.21	0.030	(3.68)	(0.000)
2023	0.068	0.056	0.066	0.049	81.177	0.000	81.177	6.765	19.036	3.775	81.177	0.009	0.009	245.39	0.028	(5.17)	(0.001)
2024	0.068	0.057	0.067	0.050	81.066	0.000	81.066	6.756	19.010	3.770	81.066	0.009	0.009	229.57	0.026	(6.66)	(0.001)
2025	0.069	0.057	0.068	0.051	80.956	0.000	80.956	6.746	18.984	3.764	80.956	0.009	0.009	213.75	0.024	(8.16)	(0.001)
2026	0.070	0.058	0.069	0.051	80.845	0.000	80.845	6.737	18.958	3.759	80.845	0.009	0.009	197.93	0.023	(9.65)	(0.001)
2027	0.070	0.059	0.069	0.052	80.735	0.000	80.735	6.728	18.932	3.754	80.735	0.009	0.009	182.10	0.021	(11.14)	(0.001)
2028	0.071	0.059	0.070	0.053	80.624	0.000	80.624	6.719	18.906	3.749	80.624	0.009	0.009	166.28	0.019	(12.63)	(0.001)
2029	0.072	0.060	0.071	0.054	80.514	0.000	80.514	6.710	18.881	3.744	80.514	0.009	0.009	150.46	0.017	(14.13)	(0.002)
2030	0.072	0.060	0.072	0.054	80.404	0.000	80.404	6.700	18.855	3.739	80.404	0.009	0.009	134.64	0.015	(15.62)	(0.002)
2031	0.072	0.060	0.072	0.054	74.442	0.000	74.442	6.203	17.457	3.462	74.442	0.008	0.008	123.74	0.014	(15.42)	(0.002)
2032	0.072	0.060	0.073	0.054	68.922	0.000	68.922	5.743	16.162	3.205	68.922	0.008	0.008	112.84	0.013	(15.22)	(0.002)
2033	0.072	0.060	0.073	0.054	63.811	0.000	63.811	5.318	14.964	2.967	63.811	0.007	0.007	101.95	0.012	(15.02)	(0.002)
2034	0.072	0.060	0.074	0.054	59.079	0.000	59.079	4.923	13.854	2.747	59.079	0.007	0.007	91.05	0.010	(14.82)	(0.002)
2035	0.072	0.059	0.074	0.053	54.698	0.000	54.698	4.558	12.827	2.543	54.698	0.006	0.006	80.15	0.009	(14.62)	(0.002)
2036	0.072	0.059	0.074	0.053	50.642	0.000	50.642	4.220	11.876	2.355	50.642	0.006	0.006	69.25	0.008	(14.42)	(0.002)
2037	0.072	0.059	0.075	0.053	46.887	0.000	46.887	3.907	10.995	2.180	46.887	0.005	0.005	58.36	0.007	(14.22)	(0.002)
2038	0.072	0.059	0.075	0.053	43.410	0.000	43.410	3.618	10.180	2.019	43.410	0.005	0.005	47.46	0.005	(14.02)	(0.002)
2039	0.072	0.059	0.076	0.053	40.191	0.000	40.191	3.349	9.425	1.869	40.191	0.005	0.005	36.56	0.004	(13.82)	(0.002)
2040	0.072	0.059	0.076	0.053	37.211	0.000	37.211	3.101	8.726	1.730	37.211	0.004	0.004	25.66	0.003	(13.62)	(0.002)
Levelized[3]:																	
2005-2040	0.067	0.056	0.065	0.048	67.827	0.964	68.790	5.652	15.905	3.154	68.790	0.008	0.008	225.80	0.026	(1.52)	(0.000)
2006-2040	0.067	0.055	0.065	0.048	70.336	0.808	71.144	5.861	16.494	3.271	71.144	0.008	0.008	234.875	0.027	-1.578	0.000
2006-2010	0.072	0.060	0.067	0.050	55.228	4.270	59.498	4.602	12.951	2.568	59.498	0.006	0.007	509.740	0.058	35.078	0.004
2006-2015	0.065	0.053	0.060	0.044	66.491	2.242	68.733	5.541	15.592	3.092	68.733	0.008	0.008	346.913	0.040	13.879	0.002
2006-2020	0.064	0.052	0.060	0.044	71.515	1.568	73.083	5.960	16.770	3.325	73.083	0.008	0.008	315.578	0.036	7.576	0.001

Exhibit A2-4. Electric Energy Avoided Costs by Pricing Zone (continued)

	Southeast Massachusetts																
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value[1]	Annual Out of Market Expense	Total Annual Capacity Value	Capacity Value at Load Response (at any month)	Avoidable Capacity Payment at Load Response (Summer Season)	Avoidable Capacity Payment at Load Response (Winter Season)	Avoidable Capacity Payment of Energy Efficiency at Summer Coincident Peak	Load Response (at any month)	Energy Efficiency at Summer Coincident Peak	DRIPE 0.75% Capacity Price	DRIPE 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-month	$/kW-season	$/kW-season	$/kW-yr	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kW-yr	$/kWh
Comment 1:	Values are avoided costs at the generation plus transmission level. DSM savings should be measured at the generator plus transmission level. (Load plus + distribution losses)				Reflects Capacity Price resulting from LICAP beginning in 2006	Recovery of costs for RMR including continuing required payments after LICAP initiation		Avoided Cost applicable to KW savings contributing as supply side credit; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level			Avoided Cost applicable to KW savings at Summer Coincident Peak; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level	Avoided cost expressed in $/kWh at 100% load factor		Incremental to Avoided Cost at Summer Coincident Peak	Expressed in $/kWh at 100% load factor	DRIPE 0.75% measured assuming 10% of supply resources transact in spot market	Expressed in $/kWh at 100% load factor
Comment 2:					info	info	June/July/ August	Average for 1 month savings	Average for Summer Season	Average for Winter Season	June / July / August			DRIPE measured at 0.75% peak savings are across all of New England. Values		DRIPE LIGHT measured at 0.75% peak savings are across all of New England.	
Period:							3-5 pm		June, July, August	Jan-May;Sept-Dec	3-5 pm						
2005[2]	0.074	0.064	0.069	0.051	2.662	0.954	3.616	0.222	0.624	0.124	3.616	0.000	0.000	0.00	0.000	0.00	0.000
2006	0.085	0.072	0.077	0.059	34.548	1.801	36.350	2.879	8.102	1.607	36.350	0.004	0.004	654.43	0.075	32.57	0.004
2007	0.087	0.074	0.081	0.062	39.132	2.151	41.283	3.261	9.176	1.820	41.283	0.004	0.005	906.91	0.104	88.60	0.010
2008	0.074	0.060	0.072	0.050	62.436	0.199	62.635	5.203	14.641	2.903	62.635	0.007	0.007	32.87	0.004	15.28	0.002
2009	0.060	0.049	0.056	0.040	66.758	0.204	66.962	5.563	15.655	3.104	66.962	0.008	0.008	357.68	0.041	9.62	0.001
2010	0.052	0.042	0.049	0.035	69.696	0.177	69.874	5.808	16.344	3.241	69.874	0.008	0.008	266.06	0.030	(6.87)	(0.001)
2011	0.055	0.044	0.051	0.037	72.764	0.154	72.918	6.064	17.063	3.384	72.918	0.008	0.008	174.43	0.020	(23.35)	(0.003)
2012	0.057	0.046	0.052	0.038	75.967	0.133	76.100	6.331	17.814	3.532	76.100	0.009	0.009	82.81	0.009	(39.84)	(0.005)
2013	0.057	0.046	0.053	0.039	76.270	0.000	76.270	6.356	17.885	3.547	76.270	0.009	0.009	119.16	0.014	(21.08)	(0.002)
2014	0.058	0.046	0.054	0.039	76.575	0.000	76.575	6.381	17.957	3.561	76.575	0.009	0.009	155.52	0.018	(2.33)	(0.000)
2015	0.058	0.047	0.054	0.040	76.881	0.000	76.881	6.407	18.029	3.575	76.881	0.009	0.009	191.87	0.022	16.43	0.002
2016	0.059	0.047	0.055	0.040	77.188	0.000	77.188	6.432	18.101	3.589	77.188	0.009	0.009	228.22	0.026	35.18	0.004
2017	0.060	0.049	0.057	0.042	76.704	0.000	76.704	6.392	17.987	3.567	76.704	0.009	0.009	258.99	0.030	36.72	0.004
2018	0.062	0.051	0.059	0.044	76.222	0.000	76.222	6.352	17.874	3.544	76.222	0.009	0.009	289.75	0.033	38.26	0.004
2019	0.064	0.053	0.061	0.045	75.743	0.000	75.743	6.312	17.762	3.522	75.743	0.009	0.009	320.52	0.037	39.80	0.005
2020	0.066	0.055	0.064	0.047	75.267	0.000	75.267	6.272	17.650	3.500	75.267	0.009	0.009	351.29	0.040	41.34	0.005
2021	0.066	0.055	0.065	0.048	75.613	0.000	75.613	6.301	17.731	3.516	75.613	0.009	0.009	328.09	0.037	35.34	0.004
2022	0.067	0.056	0.065	0.049	75.960	0.000	75.960	6.330	17.813	3.532	75.960	0.009	0.009	304.90	0.035	29.34	0.003
2023	0.068	0.056	0.066	0.049	76.309	0.000	76.309	6.359	17.894	3.548	76.309	0.009	0.009	281.70	0.032	23.34	0.003
2024	0.068	0.057	0.067	0.050	76.660	0.000	76.660	6.388	17.977	3.565	76.660	0.009	0.009	258.50	0.030	17.35	0.002
2025	0.069	0.057	0.068	0.051	77.012	0.000	77.012	6.418	18.059	3.581	77.012	0.009	0.009	235.31	0.027	11.35	0.001
2026	0.070	0.058	0.069	0.051	77.365	0.000	77.365	6.447	18.142	3.597	77.365	0.009	0.009	212.11	0.024	5.35	0.001
2027	0.070	0.059	0.069	0.052	77.721	0.000	77.721	6.477	18.225	3.614	77.721	0.009	0.009	188.91	0.022	(0.65)	(0.000)
2028	0.071	0.059	0.070	0.053	78.078	0.000	78.078	6.506	18.309	3.631	78.078	0.009	0.009	165.72	0.019	(6.65)	(0.001)
2029	0.072	0.060	0.071	0.054	78.436	0.000	78.436	6.536	18.393	3.647	78.436	0.009	0.009	142.52	0.016	(12.64)	(0.001)
2030	0.072	0.060	0.072	0.054	78.796	0.000	78.796	6.566	18.478	3.664	78.796	0.009	0.009	119.32	0.014	(18.64)	(0.002)
2031	0.072	0.060	0.072	0.054	72.952	0.000	72.952	6.079	17.107	3.392	72.952	0.008	0.008	109.42	0.012	(18.43)	(0.002)
2032	0.072	0.060	0.073	0.054	67.541	0.000	67.541	5.628	15.838	3.141	67.541	0.008	0.008	99.52	0.011	(18.22)	(0.002)
2033	0.072	0.060	0.073	0.054	62.531	0.000	62.531	5.211	14.664	2.908	62.531	0.007	0.007	89.62	0.010	(18.01)	(0.002)
2034	0.072	0.060	0.074	0.054	57.893	0.000	57.893	4.824	13.576	2.692	57.893	0.007	0.007	79.72	0.009	(17.80)	(0.002)
2035	0.072	0.059	0.074	0.053	53.599	0.000	53.599	4.467	12.569	2.492	53.599	0.006	0.006	69.82	0.008	(17.59)	(0.002)
2036	0.072	0.059	0.074	0.053	49.623	0.000	49.623	4.135	11.637	2.307	49.623	0.006	0.006	59.92	0.007	(17.38)	(0.002)
2037	0.072	0.059	0.075	0.053	45.943	0.000	45.943	3.829	10.774	2.136	45.943	0.005	0.005	50.02	0.006	(17.17)	(0.002)
2038	0.072	0.059	0.075	0.053	42.535	0.000	42.535	3.545	9.974	1.978	42.535	0.005	0.005	40.12	0.005	(16.96)	(0.002)
2039	0.072	0.059	0.076	0.053	39.380	0.000	39.380	3.282	9.235	1.831	39.380	0.004	0.004	30.22	0.003	(16.75)	(0.002)
2040	0.072	0.059	0.076	0.053	36.459	0.000	36.459	3.038	8.550	1.695	36.459	0.004	0.004	20.32	0.002	(16.54)	(0.002)
Levelized[3]**:**																	
2005-2040	0.067	0.056	0.065	0.048	64.742	0.215	64.957	5.395	15.182	3.010	64.957	0.007	0.007	220.66	0.025	7.20	0.001
2006-2040	0.067	0.055	0.065	0.048	67.237	0.186	67.422	5.603	15.767	3.127	67.422	0.008	0.008	229.525	0.026	7.489	0.001
2006-2010	0.072	0.060	0.067	0.050	54.120	0.927	55.047	4.510	12.691	2.517	55.047	0.006	0.006	448.938	0.051	28.472	0.003
2006-2015	0.065	0.053	0.060	0.044	64.347	0.515	64.862	5.362	15.089	2.992	64.862	0.007	0.007	304.283	0.035	8.063	0.001
2006-2020	0.064	0.052	0.060	0.044	67.922	0.360	68.282	5.660	15.928	3.158	68.282	0.008	0.008	299.546	0.034	17.117	0.002

Exhibit A2-4. Electric Energy Avoided Costs by Pricing Zone (continued)

	Central & Western Massachusetts																
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value[1]	Annual Out of Market Expense	Total Annual Capacity Value	Capacity Value at Load Response (at any month)	Avoidable Capacity Payment at Load Response (Summer Season)	Avoidable Capacity Payment at Load Response (Winter Season)	Avoidable Capacity Payment of Energy Efficiency at Summer Coincident Peak	Load Response (at any month)	Energy Efficiency at Summer Coincident Peak	DRIPE 0.75% Capacity Price	DRIPE 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-month	$/kW-season	$/kW-season	$/kW-yr	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kW-yr	$/kWh
Comment 1:	Values are avoided costs at the generation plus transmission level. DSM savings should be measured at the generator plus transmission level. (Load plus + distribution losses)				Reflects Capacity Price resulting from LICAP beginning in 2006	Recovery of costs for RMR including continuing required payments after LICAP initiation		Avoided Cost applicable to KW savings contributing as supply side credit; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level			Avoided Cost applicable to KW savings at Summer Coincident Peak; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level	Avoided cost expressed in $/kWh at 100% load factor		Incremental to Avoided Cost at Summer Coincident Peak	Expressed in $/kWh at 100% load factor	DRIPE 0.75% measured assuming 10% of supply resources transact in spot market	Expressed in $/kWh at 100% load factor
Comment 2:					info	info	June/July/ August	Average for 1 month savings	Average for Summer Season	Average for Winter Season	June / July / August			DRIPE measured at 0.75% peak savings are across all of New England. Values		DRIPE LIGHT measured at 0.75% peak savings are across all of New England.	
Period:							3-5 pm		June, July, August	Jan-May;Sept-Dec	3-5 pm						
2005[2]	0.074	0.064	0.069	0.051	2.662	0.954	3.616	0.222	0.624	0.124	3.616	0.000	0.000	0.00	0.000	0.00	0.000
2006	0.085	0.072	0.077	0.059	34.548	1.801	36.350	2.879	8.102	1.607	36.350	0.004	0.004	654.43	0.075	32.57	0.004
2007	0.087	0.074	0.081	0.062	39.132	2.151	41.283	3.261	9.176	1.820	41.283	0.004	0.005	906.91	0.104	88.60	0.010
2008	0.074	0.060	0.072	0.050	62.436	0.199	62.635	5.203	14.641	2.903	62.635	0.007	0.007	32.87	0.004	15.28	0.002
2009	0.060	0.049	0.056	0.040	66.758	0.204	66.962	5.563	15.655	3.104	66.962	0.008	0.008	357.68	0.041	9.62	0.001
2010	0.052	0.042	0.049	0.035	69.696	0.177	69.874	5.808	16.344	3.241	69.874	0.008	0.008	266.06	0.030	(6.87)	(0.001)
2011	0.055	0.044	0.051	0.037	72.764	0.154	72.918	6.064	17.063	3.384	72.918	0.008	0.008	174.43	0.020	(23.35)	(0.003)
2012	0.057	0.046	0.052	0.038	75.967	0.133	76.100	6.331	17.814	3.532	76.100	0.009	0.009	82.81	0.009	(39.84)	(0.005)
2013	0.057	0.046	0.053	0.039	76.270	0.000	76.270	6.356	17.885	3.547	76.270	0.009	0.009	119.16	0.014	(21.08)	(0.002)
2014	0.058	0.046	0.054	0.039	76.575	0.000	76.575	6.381	17.957	3.561	76.575	0.009	0.009	155.52	0.018	(2.33)	(0.000)
2015	0.058	0.047	0.054	0.040	76.881	0.000	76.881	6.407	18.029	3.575	76.881	0.009	0.009	191.87	0.022	16.43	0.002
2016	0.059	0.047	0.055	0.040	77.188	0.000	77.188	6.432	18.101	3.589	77.188	0.009	0.009	228.22	0.026	35.18	0.004
2017	0.060	0.049	0.057	0.042	76.704	0.000	76.704	6.392	17.987	3.567	76.704	0.009	0.009	258.99	0.030	36.72	0.004
2018	0.062	0.051	0.059	0.044	76.222	0.000	76.222	6.352	17.874	3.544	76.222	0.009	0.009	289.75	0.033	38.26	0.004
2019	0.064	0.053	0.061	0.045	75.743	0.000	75.743	6.312	17.762	3.522	75.743	0.009	0.009	320.52	0.037	39.80	0.005
2020	0.066	0.055	0.064	0.047	75.267	0.000	75.267	6.272	17.650	3.500	75.267	0.009	0.009	351.29	0.040	41.34	0.005
2021	0.066	0.055	0.065	0.048	75.613	0.000	75.613	6.301	17.731	3.516	75.613	0.009	0.009	328.09	0.037	35.34	0.004
2022	0.067	0.056	0.065	0.049	75.960	0.000	75.960	6.330	17.813	3.532	75.960	0.009	0.009	304.90	0.035	29.34	0.003
2023	0.068	0.056	0.066	0.049	76.309	0.000	76.309	6.359	17.894	3.548	76.309	0.009	0.009	281.70	0.032	23.34	0.003
2024	0.068	0.057	0.067	0.050	76.660	0.000	76.660	6.388	17.977	3.565	76.660	0.009	0.009	258.50	0.030	17.35	0.002
2025	0.069	0.057	0.068	0.051	77.012	0.000	77.012	6.418	18.059	3.581	77.012	0.009	0.009	235.31	0.027	11.35	0.001
2026	0.070	0.058	0.069	0.051	77.365	0.000	77.365	6.447	18.142	3.597	77.365	0.009	0.009	212.11	0.024	5.35	0.001
2027	0.070	0.059	0.069	0.052	77.721	0.000	77.721	6.477	18.225	3.614	77.721	0.009	0.009	188.91	0.022	(0.65)	(0.000)
2028	0.071	0.059	0.070	0.053	78.078	0.000	78.078	6.506	18.309	3.631	78.078	0.009	0.009	165.72	0.019	(6.65)	(0.001)
2029	0.072	0.060	0.071	0.054	78.436	0.000	78.436	6.536	18.393	3.647	78.436	0.009	0.009	142.52	0.016	(12.64)	(0.001)
2030	0.072	0.060	0.072	0.054	78.796	0.000	78.796	6.566	18.478	3.664	78.796	0.009	0.009	119.32	0.014	(18.64)	(0.002)
2031	0.072	0.060	0.072	0.054	72.952	0.000	72.952	6.079	17.107	3.392	72.952	0.008	0.008	109.42	0.012	(18.43)	(0.002)
2032	0.072	0.060	0.073	0.054	67.541	0.000	67.541	5.628	15.838	3.141	67.541	0.008	0.008	99.52	0.011	(18.22)	(0.002)
2033	0.072	0.060	0.073	0.054	62.531	0.000	62.531	5.211	14.664	2.908	62.531	0.007	0.007	89.62	0.010	(18.01)	(0.002)
2034	0.072	0.060	0.074	0.054	57.893	0.000	57.893	4.824	13.576	2.692	57.893	0.007	0.007	79.72	0.009	(17.80)	(0.002)
2035	0.072	0.059	0.074	0.053	53.599	0.000	53.599	4.467	12.569	2.492	53.599	0.006	0.006	69.82	0.008	(17.59)	(0.002)
2036	0.072	0.059	0.074	0.053	49.623	0.000	49.623	4.135	11.637	2.307	49.623	0.006	0.006	59.92	0.007	(17.38)	(0.002)
2037	0.072	0.059	0.075	0.053	45.943	0.000	45.943	3.829	10.774	2.136	45.943	0.005	0.005	50.02	0.006	(17.17)	(0.002)
2038	0.072	0.059	0.075	0.053	42.535	0.000	42.535	3.545	9.974	1.978	42.535	0.005	0.005	40.12	0.005	(16.96)	(0.002)
2039	0.072	0.059	0.076	0.053	39.380	0.000	39.380	3.282	9.235	1.831	39.380	0.004	0.004	30.22	0.003	(16.75)	(0.002)
2040	0.072	0.059	0.076	0.053	36.459	0.000	36.459	3.038	8.550	1.695	36.459	0.004	0.004	20.32	0.002	(16.54)	(0.002)
Levelized[3]:																	
2005-2040	0.067	0.056	0.065	0.048	64.742	0.215	64.957	5.395	15.182	3.010	64.957	0.007	0.007	220.66	0.025	7.20	0.001
2006-2040	0.067	0.055	0.065	0.048	67.237	0.186	67.422	5.603	15.767	3.127	67.422	0.008	0.008	229.525	0.026	7.489	0.001
2006-2010	0.072	0.060	0.067	0.050	54.120	0.927	55.047	4.510	12.691	2.517	55.047	0.006	0.006	448.938	0.051	28.472	0.003
2006-2015	0.065	0.053	0.060	0.044	64.347	0.515	64.862	5.362	15.089	2.992	64.862	0.007	0.007	304.283	0.035	8.063	0.001
2006-2020	0.064	0.052	0.060	0.044	67.922	0.360	68.282	5.660	15.928	3.158	68.282	0.008	0.008	299.546	0.034	17.117	0.002

Exhibit A2-4. Electric Energy Avoided Costs by Pricing Zone (continued)

	New Hampshire																
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value[1]	Annual Out of Market Expense	Total Annual Capacity Value	Capacity Value at Load Response (at any month)	Avoidable Capacity Payment at Load Response (Summer Season)	Avoidable Capacity Payment at Load Response (Winter Season)	Avoidable Capacity Payment at Energy Efficiency of Summer Coincident Peak	Load Response (at any month)	Energy Efficiency at Summer Coincident Peak	DRIPE 0.75% Capacity Price	DRIPE 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-month	$/kW-season	$/kW-season	$/kW-yr	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kW-yr	$/kWh
Comment 1:	Values are avoided costs at the generation plus transmission level. DSM savings should be measured at the generator plus transmission level. (Load plus + distribution losses)				Reflects Capacity Price resulting from LICAP beginning in 2006	Recovery of costs for RMR including continuing required payments after LICAP initiation		Avoided Cost applicable to KW savings contributing as supply side credit; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level			Avoided Cost applicable to KW savings at Summer Coincident Peak; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level	Avoided cost expressed in $/kWh at 100% load factor		Incremental to Avoided Cost at Summer Coincident Peak	Expressed in $/kWh at 100% load factor	DRIPE 0.75% measured assuming 10% of supply resources transact in spot market	Expressed in $/kWh at 100% load factor
Comment 2:					info	info	June/July/August	Average for 1 month savings	Average for Summer Season	Average for Winter Season	June / July / August			DRIPE measured at 0.75% peak savings are across all of New England. Values are		DRIPE LIGHT measured at 0.75% peak savings are across all of New England.	
Period:							3-5 pm		June, July, August	Jan-May;Sept-Dec	3-5 pm						
2005 [2]	0.072	0.063	0.066	0.049	2.662	0.954	3.616	0.222	0.624	0.124	3.616	0.000	0.000	0.00	0.000	0.00	0.000
2006	0.082	0.070	0.074	0.058	34.548	1.801	36.350	2.879	8.102	1.607	36.350	0.004	0.004	654.43	0.075	32.57	0.004
2007	0.085	0.072	0.079	0.060	39.132	2.151	41.283	3.261	9.176	1.820	41.283	0.004	0.005	906.91	0.104	88.60	0.010
2008	0.072	0.059	0.070	0.050	62.436	0.199	62.635	5.203	14.641	2.903	62.635	0.007	0.007	32.87	0.004	15.28	0.002
2009	0.058	0.048	0.055	0.039	66.758	0.204	66.962	5.563	15.655	3.104	66.962	0.008	0.008	357.68	0.041	9.62	0.001
2010	0.051	0.041	0.048	0.034	69.696	0.177	69.874	5.808	16.344	3.241	69.874	0.008	0.008	266.06	0.030	(6.87)	(0.001)
2011	0.053	0.043	0.050	0.036	72.764	0.154	72.918	6.064	17.063	3.384	72.918	0.008	0.008	174.43	0.020	(23.35)	(0.003)
2012	0.056	0.045	0.051	0.038	75.967	0.133	76.100	6.331	17.814	3.532	76.100	0.009	0.009	82.81	0.009	(39.84)	(0.005)
2013	0.056	0.045	0.052	0.038	76.270	0.000	76.270	6.356	17.885	3.547	76.270	0.009	0.009	119.16	0.014	(21.08)	(0.002)
2014	0.057	0.046	0.053	0.039	76.575	0.000	76.575	6.381	17.957	3.561	76.575	0.009	0.009	155.52	0.018	(2.33)	(0.000)
2015	0.057	0.046	0.053	0.039	76.881	0.000	76.881	6.407	18.029	3.575	76.881	0.009	0.009	191.87	0.022	16.43	0.002
2016	0.058	0.047	0.054	0.039	77.188	0.000	77.188	6.432	18.101	3.589	77.188	0.009	0.009	228.22	0.026	35.18	0.004
2017	0.059	0.048	0.056	0.041	76.704	0.000	76.704	6.392	17.987	3.567	76.704	0.009	0.009	258.99	0.030	36.72	0.004
2018	0.061	0.050	0.058	0.043	76.222	0.000	76.222	6.352	17.874	3.544	76.222	0.009	0.009	289.75	0.033	38.26	0.004
2019	0.063	0.052	0.061	0.045	75.743	0.000	75.743	6.312	17.762	3.522	75.743	0.009	0.009	320.52	0.037	39.80	0.005
2020	0.065	0.054	0.063	0.047	75.267	0.000	75.267	6.272	17.650	3.500	75.267	0.009	0.009	351.29	0.040	41.34	0.005
2021	0.065	0.054	0.064	0.048	75.613	0.000	75.613	6.301	17.731	3.516	75.613	0.009	0.009	328.09	0.037	35.34	0.004
2022	0.066	0.055	0.065	0.048	75.960	0.000	75.960	6.330	17.813	3.532	75.960	0.009	0.009	304.90	0.035	29.34	0.003
2023	0.067	0.056	0.065	0.049	76.309	0.000	76.309	6.359	17.894	3.548	76.309	0.009	0.009	281.70	0.032	23.34	0.003
2024	0.067	0.056	0.066	0.050	76.660	0.000	76.660	6.388	17.977	3.565	76.660	0.009	0.009	258.50	0.030	17.35	0.002
2025	0.068	0.057	0.067	0.050	77.012	0.000	77.012	6.418	18.059	3.581	77.012	0.009	0.009	235.31	0.027	11.35	0.001
2026	0.069	0.057	0.068	0.051	77.365	0.000	77.365	6.447	18.142	3.597	77.365	0.009	0.009	212.11	0.024	5.35	0.001
2027	0.070	0.058	0.069	0.052	77.721	0.000	77.721	6.477	18.225	3.614	77.721	0.009	0.009	188.91	0.022	(0.65)	(0.000)
2028	0.070	0.058	0.070	0.053	78.078	0.000	78.078	6.506	18.309	3.631	78.078	0.009	0.009	165.72	0.019	(6.65)	(0.001)
2029	0.071	0.059	0.071	0.053	78.436	0.000	78.436	6.536	18.393	3.647	78.436	0.009	0.009	142.52	0.016	(12.64)	(0.001)
2030	0.072	0.060	0.071	0.054	78.796	0.000	78.796	6.566	18.478	3.664	78.796	0.009	0.009	119.32	0.014	(18.64)	(0.002)
2031	0.072	0.059	0.072	0.054	72.952	0.000	72.952	6.079	17.107	3.392	72.952	0.008	0.008	109.42	0.012	(18.43)	(0.002)
2032	0.072	0.059	0.072	0.054	67.541	0.000	67.541	5.628	15.838	3.141	67.541	0.008	0.008	99.52	0.011	(18.22)	(0.002)
2033	0.072	0.059	0.073	0.054	62.531	0.000	62.531	5.211	14.664	2.908	62.531	0.007	0.007	89.62	0.010	(18.01)	(0.002)
2034	0.072	0.059	0.073	0.053	57.893	0.000	57.893	4.824	13.576	2.692	57.893	0.007	0.007	79.72	0.009	(17.80)	(0.002)
2035	0.072	0.059	0.073	0.053	53.599	0.000	53.599	4.467	12.569	2.492	53.599	0.006	0.006	69.82	0.008	(17.59)	(0.002)
2036	0.072	0.059	0.074	0.053	49.623	0.000	49.623	4.135	11.637	2.307	49.623	0.006	0.006	59.92	0.007	(17.38)	(0.002)
2037	0.072	0.058	0.074	0.053	45.943	0.000	45.943	3.829	10.774	2.136	45.943	0.005	0.005	50.02	0.006	(17.17)	(0.002)
2038	0.071	0.058	0.075	0.053	42.535	0.000	42.535	3.545	9.974	1.978	42.535	0.005	0.005	40.12	0.005	(16.96)	(0.002)
2039	0.071	0.058	0.075	0.052	39.380	0.000	39.380	3.282	9.235	1.831	39.380	0.004	0.004	30.22	0.003	(16.75)	(0.002)
2040	0.071	0.058	0.075	0.052	36.459	0.000	36.459	3.038	8.550	1.695	36.459	0.004	0.004	20.32	0.002	(16.54)	(0.002)
Levelized[3]:																	
2005-2040	0.066	0.055	0.064	0.047	64.742	0.215	64.957	5.395	15.182	3.010	64.957	0.007	0.007	220.657	0.025	7.200	0.001
2006-2040	0.066	0.055	0.064	0.047	67.237	0.186	67.422	5.603	15.767	3.127	67.422	0.008	0.008	229.525	0.026	7.489	0.001
2006-2010	0.070	0.059	0.065	0.049	54.120	0.927	55.047	4.510	12.691	2.517	55.047	0.006	0.006	448.938	0.051	28.472	0.003
2006-2015	0.063	0.052	0.059	0.043	64.347	0.515	64.862	5.362	15.089	2.992	64.862	0.007	0.007	304.283	0.035	8.063	0.001
2006-2020	0.063	0.052	0.059	0.043	67.922	0.360	68.282	5.660	15.928	3.158	68.282	0.008	0.008	299.546	0.034	17.117	0.002

Exhibit A2-4. Electric Energy Avoided Costs by Pricing Zone (continued)

	Rhode Island																
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value[1]	Annual Out of Market Expense	Total Annual Capacity Value	Capacity Value at Load Response (at any month)	Avoidable Capacity Payment at Load Response (Summer Season)	Avoidable Capacity Payment at Load Response (Winter Season)	Avoidable Capacity Payment of Energy Efficiency at Summer Coincident Peak	Load Response (at any month)	Energy Efficiency at Summer Coincident Peak	DRIPE 0.75% Capacity Price	DRIPE 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price
Units:	**$/kWh**	**$/kWh**	**$/kWh**	**$/kWh**	**$/kW-yr**	**$/kW-yr**	**$/kW-yr**	**$/kW-month**	**$/kW-season**	**$/kW-season**	**$/kW-yr**	**$/kWh**	**$/kWh**	**$/kW-yr**	**$/kWh**	**$/kW-yr**	**$/kWh**
Comment 1:	Values are avoided costs at the generation plus transmission level. DSM savings should be measured at the generator plus transmission level. (Load plus + distribution losses)				Reflects Capacity Price resulting from LICAP beginning in 2006	Recovery of costs for RMR including continuing required payments after LICAP initiation		Avoided Cost applicable to KW savings contributing as supply side credit; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level			Avoided Cost applicable to KW savings at Summer Coincident Peak; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level	Avoided cost expressed in $/kWh at 100% load factor		Incremental to Avoided Cost at Summer Coincident Peak	Expressed in $/kWh at 100% load factor	DRIPE 0.75% measured assuming 10% of supply resources transact in spot market	Expressed in $/kWh at 100% load factor
Comment 2:					info	info	June/July/ August	Average for 1 month savings	Average for Summer Season	Average for Winter Season	June / July / August			DRIPE measured at 0.75% peak savings are across all of New England. Values are		DRIPE LIGHT measured at 0.75% peak savings are across all of New England.	
Period:							3-5 pm		June, July, August	Jan-May;Sept-Dec	3-5 pm						
2005[2]	0.073	0.064	0.068	0.051	2.662	0.954	3.616	0.222	0.624	0.124	3.616	0.000	0.000	0.00	0.000	0.00	0.000
2006	0.084	0.072	0.077	0.060	34.548	1.801	36.350	2.879	8.102	1.607	36.350	0.004	0.004	654.43	0.075	32.57	0.004
2007	0.087	0.074	0.081	0.062	39.132	2.151	41.283	3.261	9.176	1.820	41.283	0.004	0.005	906.91	0.104	88.60	0.010
2008	0.074	0.060	0.071	0.051	62.436	0.199	62.635	5.203	14.641	2.903	62.635	0.007	0.007	32.87	0.004	15.28	0.002
2009	0.060	0.049	0.056	0.040	66.758	0.204	66.962	5.563	15.655	3.104	66.962	0.008	0.008	357.68	0.041	9.62	0.001
2010	0.052	0.042	0.048	0.035	69.696	0.177	69.874	5.808	16.344	3.241	69.874	0.008	0.008	266.06	0.030	(6.87)	(0.001)
2011	0.054	0.044	0.050	0.037	72.764	0.154	72.918	6.064	17.063	3.384	72.918	0.008	0.008	174.43	0.020	(23.35)	(0.003)
2012	0.057	0.045	0.052	0.038	75.967	0.133	76.100	6.331	17.814	3.532	76.100	0.009	0.009	82.81	0.009	(39.84)	(0.005)
2013	0.057	0.046	0.053	0.039	76.270	0.000	76.270	6.356	17.885	3.547	76.270	0.009	0.009	119.16	0.014	(21.08)	(0.002)
2014	0.057	0.046	0.053	0.039	76.575	0.000	76.575	6.381	17.957	3.561	76.575	0.009	0.009	155.52	0.018	(2.33)	(0.000)
2015	0.058	0.047	0.054	0.040	76.881	0.000	76.881	6.407	18.029	3.575	76.881	0.009	0.009	191.87	0.022	16.43	0.002
2016	0.058	0.047	0.054	0.040	77.188	0.000	77.188	6.432	18.101	3.589	77.188	0.009	0.009	228.22	0.026	35.18	0.004
2017	0.060	0.049	0.056	0.042	76.704	0.000	76.704	6.392	17.987	3.567	76.704	0.009	0.009	258.99	0.030	36.72	0.004
2018	0.062	0.050	0.059	0.044	76.222	0.000	76.222	6.352	17.874	3.544	76.222	0.009	0.009	289.75	0.033	38.26	0.004
2019	0.063	0.052	0.061	0.046	75.743	0.000	75.743	6.312	17.762	3.522	75.743	0.009	0.009	320.52	0.037	39.80	0.005
2020	0.065	0.054	0.063	0.048	75.267	0.000	75.267	6.272	17.650	3.500	75.267	0.009	0.009	351.29	0.040	41.34	0.005
2021	0.066	0.055	0.064	0.048	75.613	0.000	75.613	6.301	17.731	3.516	75.613	0.009	0.009	328.09	0.037	35.34	0.004
2022	0.067	0.055	0.065	0.049	75.960	0.000	75.960	6.330	17.813	3.532	75.960	0.009	0.009	304.90	0.035	29.34	0.003
2023	0.067	0.056	0.066	0.050	76.309	0.000	76.309	6.359	17.894	3.548	76.309	0.009	0.009	281.70	0.032	23.34	0.003
2024	0.068	0.057	0.067	0.050	76.660	0.000	76.660	6.388	17.977	3.565	76.660	0.009	0.009	258.50	0.030	17.35	0.002
2025	0.069	0.057	0.067	0.051	77.012	0.000	77.012	6.418	18.059	3.581	77.012	0.009	0.009	235.31	0.027	11.35	0.001
2026	0.069	0.058	0.068	0.052	77.365	0.000	77.365	6.447	18.142	3.597	77.365	0.009	0.009	212.11	0.024	5.35	0.001
2027	0.070	0.058	0.069	0.052	77.721	0.000	77.721	6.477	18.225	3.614	77.721	0.009	0.009	188.91	0.022	(0.65)	(0.000)
2028	0.071	0.059	0.070	0.053	78.078	0.000	78.078	6.506	18.309	3.631	78.078	0.009	0.009	165.72	0.019	(6.65)	(0.001)
2029	0.072	0.060	0.071	0.054	78.436	0.000	78.436	6.536	18.393	3.647	78.436	0.009	0.009	142.52	0.016	(12.64)	(0.001)
2030	0.072	0.060	0.072	0.054	78.796	0.000	78.796	6.566	18.478	3.664	78.796	0.009	0.009	119.32	0.014	(18.64)	(0.002)
2031	0.072	0.060	0.072	0.054	72.952	0.000	72.952	6.079	17.107	3.392	72.952	0.008	0.008	109.42	0.012	(18.43)	(0.002)
2032	0.072	0.060	0.072	0.054	67.541	0.000	67.541	5.628	15.838	3.141	67.541	0.008	0.008	99.52	0.011	(18.22)	(0.002)
2033	0.072	0.060	0.073	0.054	62.531	0.000	62.531	5.211	14.664	2.908	62.531	0.007	0.007	89.62	0.010	(18.01)	(0.002)
2034	0.072	0.060	0.073	0.054	57.893	0.000	57.893	4.824	13.576	2.692	57.893	0.007	0.007	79.72	0.009	(17.80)	(0.002)
2035	0.072	0.059	0.074	0.054	53.599	0.000	53.599	4.467	12.569	2.492	53.599	0.006	0.006	69.82	0.008	(17.59)	(0.002)
2036	0.072	0.059	0.074	0.053	49.623	0.000	49.623	4.135	11.637	2.307	49.623	0.006	0.006	59.92	0.007	(17.38)	(0.002)
2037	0.072	0.059	0.075	0.053	45.943	0.000	45.943	3.829	10.774	2.136	45.943	0.005	0.005	50.02	0.006	(17.17)	(0.002)
2038	0.072	0.059	0.075	0.053	42.535	0.000	42.535	3.545	9.974	1.978	42.535	0.005	0.005	40.12	0.005	(16.96)	(0.002)
2039	0.072	0.058	0.075	0.053	39.380	0.000	39.380	3.282	9.235	1.831	39.380	0.004	0.004	30.22	0.003	(16.75)	(0.002)
2040	0.072	0.058	0.076	0.053	36.459	0.000	36.459	3.038	8.550	1.695	36.459	0.004	0.004	20.32	0.002	(16.54)	(0.002)
Levelized[3]:																	
2005-2040	0.067	0.056	0.065	0.048	64.742	0.215	64.957	5.395	15.182	3.010	64.957	0.007	0.007	220.657	0.025	7.200	0.001
2006-2040	0.067	0.055	0.065	0.048	67.237	0.186	67.422	5.603	15.767	3.127	67.422	0.008	0.008	229.525	0.026	7.489	0.001
2006-2010	0.072	0.060	0.067	0.050	54.120	0.927	55.047	4.510	12.691	2.517	55.047	0.006	0.006	448.938	0.051	28.472	0.003
2006-2015	0.065	0.053	0.060	0.045	64.347	0.515	64.862	5.362	15.089	2.992	64.862	0.007	0.007	304.283	0.035	8.063	0.001
2006-2020	0.064	0.052	0.059	0.044	67.922	0.360	68.282	5.660	15.928	3.158	68.282	0.008	0.008	299.546	0.034	17.117	0.002

Exhibit A2-4. Electric Energy Avoided Costs by Pricing Zone (continued)

	Vermont																		
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value[1]	Annual Out of Market Expense	Total Annual Capacity Value	Capacity Value at Load Response (at any month)	Avoidable Capacity Payment at Load Response (Summer Season)	Avoidable Capacity Payment at Load Response (Winter Season)	Avoidable Capacity Payment of Energy Efficiency at Summer Coincident Peak	Load Response (at any month)	Energy Efficiency at Summer Coincident Peak	DRIPE 0.75% Capacity Price	DRIPE 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-month	$/kW-season	$/kW-season	$/kW-yr	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kW-yr	$/kWh
Comment 1:	Values are avoided costs at the generation plus transmission level. DSM savings should be measured at the generator plus transmission level. (Load plus + distribution losses)				Reflects Capacity Price resulting from LICAP beginning in 2006	Recovery of costs for RMR including continuing required payments after LICAP initiation		Avoided Cost applicable to KW savings contributing as supply side credit; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level			Avoided Cost applicable to KW savings at Summer Coincident Peak; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level	Avoided cost expressed in $/kWh at 100% load factor		Incremental to Avoided Cost at Summer Coincident Peak	Expressed in $/kWh at 100% load factor	DRIPE 0.75% measured assuming 10% of supply resources transact in spot market	Expressed in $/kWh at 100% load factor
Comment 2:					info	info	June/July/ August	Average for 1 month savings	Average for Summer Season	Average for Winter Season	June / July / August			DRIPE measured at 0.75% peak savings are across all of New England. Values are		DRIPE LIGHT measured at 0.75% peak savings are across all of New England.	
Period:							3-5 pm		June, July, August	Jan-May;Sept-Dec	3-5 pm						
2005[2]	0.077	0.064	0.074	0.052	2.662	0.954	3.616	0.222	0.624	0.124	3.616	0.000	0.000	0.00	0.000	0.00	0.000
2006	0.088	0.072	0.081	0.061	34.548	1.801	36.350	2.879	8.102	1.607	36.350	0.004	0.001	654.43	0.075	32.57	0.004
2007	0.090	0.074	0.085	0.062	39.132	2.151	41.283	3.261	9.176	1.820	41.283	0.004	0.001	906.91	0.104	88.60	0.010
2008	0.076	0.060	0.073	0.051	62.436	0.199	62.635	5.203	14.641	2.903	62.635	0.007	0.002	32.87	0.004	15.28	0.002
2009	0.062	0.049	0.058	0.040	66.758	0.204	66.962	5.563	15.655	3.104	66.962	0.008	0.002	357.68	0.041	9.62	0.001
2010	0.053	0.042	0.050	0.035	69.696	0.177	69.874	5.808	16.344	3.241	69.874	0.008	0.002	266.06	0.030	(6.87)	(0.001)
2011	0.055	0.044	0.051	0.037	72.764	0.154	72.918	6.064	17.063	3.384	72.918	0.008	0.002	174.43	0.020	(23.35)	(0.003)
2012	0.056	0.046	0.052	0.038	75.967	0.133	76.100	6.331	17.814	3.532	76.100	0.009	0.002	82.81	0.009	(39.84)	(0.005)
2013	0.057	0.046	0.053	0.039	76.270	0.000	76.270	6.356	17.885	3.547	76.270	0.009	0.002	119.16	0.014	(21.08)	(0.002)
2014	0.057	0.047	0.053	0.039	76.575	0.000	76.575	6.381	17.957	3.561	76.575	0.009	0.002	155.52	0.018	(2.33)	(0.000)
2015	0.058	0.047	0.054	0.040	76.881	0.000	76.881	6.407	18.029	3.575	76.881	0.009	0.002	191.87	0.022	16.43	0.002
2016	0.058	0.048	0.055	0.040	77.188	0.000	77.188	6.432	18.101	3.589	77.188	0.009	0.002	228.22	0.026	35.18	0.004
2017	0.060	0.049	0.057	0.042	76.704	0.000	76.704	6.392	17.987	3.567	76.704	0.009	0.002	258.99	0.030	36.72	0.004
2018	0.062	0.051	0.059	0.044	76.222	0.000	76.222	6.352	17.874	3.544	76.222	0.009	0.002	289.75	0.033	38.26	0.004
2019	0.064	0.053	0.061	0.046	75.743	0.000	75.743	6.312	17.762	3.522	75.743	0.009	0.002	320.52	0.037	39.80	0.005
2020	0.065	0.055	0.064	0.048	75.267	0.000	75.267	6.272	17.650	3.500	75.267	0.009	0.002	351.29	0.040	41.34	0.005
2021	0.066	0.055	0.065	0.049	75.613	0.000	75.613	6.301	17.731	3.516	75.613	0.009	0.002	328.09	0.037	35.34	0.004
2022	0.067	0.056	0.066	0.049	75.960	0.000	75.960	6.330	17.813	3.532	75.960	0.009	0.002	304.90	0.035	29.34	0.003
2023	0.068	0.056	0.066	0.050	76.309	0.000	76.309	6.359	17.894	3.548	76.309	0.009	0.002	281.70	0.032	23.34	0.003
2024	0.068	0.057	0.067	0.051	76.660	0.000	76.660	6.388	17.977	3.565	76.660	0.009	0.002	258.50	0.030	17.35	0.002
2025	0.069	0.058	0.068	0.051	77.012	0.000	77.012	6.418	18.059	3.581	77.012	0.009	0.002	235.31	0.027	11.35	0.001
2026	0.070	0.058	0.069	0.052	77.365	0.000	77.365	6.447	18.142	3.597	77.365	0.009	0.002	212.11	0.024	5.35	0.001
2027	0.071	0.059	0.070	0.053	77.721	0.000	77.721	6.477	18.225	3.614	77.721	0.009	0.002	188.91	0.022	(0.65)	(0.000)
2028	0.071	0.059	0.071	0.054	78.078	0.000	78.078	6.506	18.309	3.631	78.078	0.009	0.002	165.72	0.019	(6.65)	(0.001)
2029	0.072	0.060	0.072	0.054	78.436	0.000	78.436	6.536	18.393	3.647	78.436	0.009	0.002	142.52	0.016	(12.64)	(0.001)
2030	0.073	0.061	0.073	0.055	78.796	0.000	78.796	6.566	18.478	3.664	78.796	0.009	0.002	119.32	0.014	(18.64)	(0.002)
2031	0.073	0.060	0.073	0.055	72.952	0.000	72.952	6.079	17.107	3.392	72.952	0.008	0.002	109.42	0.012	(18.43)	(0.002)
2032	0.073	0.060	0.073	0.055	67.541	0.000	67.541	5.628	15.838	3.141	67.541	0.008	0.002	99.52	0.011	(18.22)	(0.002)
2033	0.073	0.060	0.074	0.054	62.531	0.000	62.531	5.211	14.664	2.908	62.531	0.007	0.002	89.62	0.010	(18.01)	(0.002)
2034	0.073	0.060	0.074	0.054	57.893	0.000	57.893	4.824	13.576	2.692	57.893	0.007	0.002	79.72	0.009	(17.80)	(0.002)
2035	0.073	0.060	0.075	0.054	53.599	0.000	53.599	4.467	12.569	2.492	53.599	0.006	0.001	69.82	0.008	(17.59)	(0.002)
2036	0.073	0.060	0.075	0.054	49.623	0.000	49.623	4.135	11.637	2.307	49.623	0.006	0.001	59.92	0.007	(17.38)	(0.002)
2037	0.073	0.059	0.075	0.054	45.943	0.000	45.943	3.829	10.774	2.136	45.943	0.005	0.001	50.02	0.006	(17.17)	(0.002)
2038	0.073	0.059	0.076	0.053	42.535	0.000	42.535	3.545	9.974	1.978	42.535	0.005	0.001	40.12	0.005	(16.96)	(0.002)
2039	0.073	0.059	0.076	0.053	39.380	0.000	39.380	3.282	9.235	1.831	39.380	0.004	0.001	30.22	0.003	(16.75)	(0.002)
2040	0.073	0.059	0.076	0.053	36.459	0.000	36.459	3.038	8.550	1.695	36.459	0.004	0.001	20.32	0.002	(16.54)	(0.002)
Levelized[3]:																	
2005-2040	0.068	0.056	0.066	0.049	64.742	0.215	64.957	5.395	15.182	3.010	64.957	0.007	0.002	220.657	0.025	7.200	0.001
2006-2040	0.068	0.056	0.066	0.048	67.237	0.186	67.422	5.603	15.767	3.127	67.422	0.008	0.002	229.525	0.026	7.489	0.001
2006-2010	0.074	0.060	0.070	0.050	54.120	0.927	55.047	4.510	12.691	2.517	55.047	0.006	0.001	448.938	0.051	28.472	0.003
2006-2015	0.066	0.053	0.062	0.045	64.347	0.515	64.862	5.362	15.089	2.992	64.862	0.007	0.002	304.283	0.035	8.063	0.001
2006-2020	0.065	0.053	0.061	0.044	67.922	0.360	68.282	5.660	15.928	3.158	68.282	0.008	0.002	299.546	0.034	17.117	0.002

Exhibit A2-4. Electric Energy Avoided Costs by Pricing Zone (continued)

	Rest of Connecticut (LICAP)																
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value[1]	Annual Out of Market Expense	Total Annual Capacity Value	Capacity Value at Load Response (at any month)	Avoidable Capacity Payment at Load Response (Summer Season)	Avoidable Capacity Payment at Load Response (Winter Season)	Avoidable Capacity Payment at Energy Efficiency of Summer Coincident Peak	Load Response (at any month)	Energy Efficiency at Summer Coincident Peak	DRIPE 0.75% Capacity Price	DRIPE 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-month	$/kW-season	$/kW-season	$/kW-yr	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kW-yr	$/kWh
Comment 1:	Values are avoided costs at the generation plus transmission level. DSM savings should be measured at the generator plus transmission level. (Load plus + distribution losses)				Reflects Capacity Price resulting from LICAP beginning in 2006	Recovery of costs for RMR including continuing required payments after LICAP initiation		Avoided Cost applicable to KW savings contributing as supply side credit; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level			Avoided Cost applicable to KW savings at Summer Coincident Peak; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level	Avoided cost expressed in $/kWh at 100% load factor		Incremental to Avoided Cost at Summer Coincident Peak	Expressed in $/kWh at 100% load factor	DRIPE 0.75% measured assuming 10% of supply resources transact in spot market	Expressed in $/kWh at 100% load factor
Comment 2:					info	info	June/July/ August	Average for 1 month savings	Average for Summer Season	Average for Winter Season	June / July / August			DRIPE measured at 0.75% peak savings are across all of New England. Values are		DRIPE LIGHT measured at 0.75% peak savings are across all of New England.	
Period:							3-5 pm		June, July, August	Jan-May;Sept-Dec	3-5 pm						
2005[2]	0.080	0.065	0.081	0.054	5.377	8.265	13.642	0.448	1.261	0.250	13.642	0.001	0.002	0.00	0.000	0.00	0.000
2006	0.093	0.074	0.093	0.063	47.881	0.000	47.881	3.990	11.228	2.226	47.881	0.005	0.005	171.25	0.025	234.47	0.027
2007	0.098	0.076	0.095	0.064	50.951	0.000	50.951	4.246	11.948	2.369	50.951	0.006	0.006	12.61	0.007	239.13	0.027
2008	0.078	0.062	0.075	0.052	63.709	0.000	63.709	5.309	14.940	2.962	63.709	0.007	0.007	(5.29)	0.007	204.86	0.023
2009	0.064	0.050	0.060	0.041	68.126	0.000	68.126	5.677	15.976	3.168	68.126	0.008	0.008	408.59	0.054	226.52	0.026
2010	0.055	0.043	0.051	0.036	71.124	0.000	71.124	5.927	16.679	3.307	71.124	0.008	0.008	328.38	0.046	192.60	0.022
2011	0.056	0.044	0.052	0.037	74.254	0.000	74.254	6.188	17.413	3.453	74.254	0.008	0.008	248.18	0.037	158.68	0.018
2012	0.058	0.046	0.053	0.039	77.523	0.000	77.523	6.460	18.179	3.605	77.523	0.009	0.009	167.97	0.028	124.76	0.014
2013	0.058	0.046	0.054	0.039	77.831	0.000	77.831	6.486	18.251	3.619	77.831	0.009	0.009	190.34	0.031	97.20	0.011
2014	0.058	0.046	0.054	0.039	78.141	0.000	78.141	6.512	18.324	3.634	78.141	0.009	0.009	212.71	0.033	69.65	0.008
2015	0.059	0.047	0.055	0.040	78.453	0.000	78.453	6.538	18.397	3.648	78.453	0.009	0.009	235.08	0.036	42.09	0.005
2016	0.059	0.047	0.055	0.040	78.765	0.000	78.765	6.564	18.470	3.663	78.765	0.009	0.009	257.45	0.038	14.53	0.002
2017	0.061	0.049	0.057	0.042	77.965	0.000	77.965	6.497	18.283	3.625	77.965	0.009	0.009	252.98	0.038	13.44	0.002
2018	0.063	0.050	0.060	0.044	77.172	0.000	77.172	6.431	18.097	3.589	77.172	0.009	0.009	248.52	0.037	12.35	0.001
2019	0.064	0.052	0.062	0.045	76.388	0.000	76.388	6.366	17.913	3.552	76.388	0.009	0.009	244.05	0.037	11.26	0.001
2020	0.066	0.054	0.064	0.047	75.612	0.000	75.612	6.301	17.731	3.516	75.612	0.009	0.009	239.59	0.036	10.18	0.001
2021	0.067	0.055	0.065	0.048	75.771	0.000	75.771	6.314	17.768	3.523	75.771	0.009	0.009	233.15	0.035	4.58	0.001
2022	0.068	0.055	0.066	0.049	75.931	0.000	75.931	6.328	17.806	3.531	75.931	0.009	0.009	226.71	0.035	(1.02)	(0.000)
2023	0.068	0.056	0.067	0.049	76.091	0.000	76.091	6.341	17.843	3.538	76.091	0.009	0.009	220.28	0.034	(6.61)	(0.001)
2024	0.069	0.056	0.068	0.050	76.251	0.000	76.251	6.354	17.881	3.546	76.251	0.009	0.009	213.84	0.033	(12.21)	(0.001)
2025	0.070	0.057	0.068	0.050	76.412	0.000	76.412	6.368	17.919	3.553	76.412	0.009	0.009	207.40	0.032	(17.81)	(0.002)
2026	0.070	0.057	0.069	0.051	76.573	0.000	76.573	6.381	17.956	3.561	76.573	0.009	0.009	200.97	0.032	(23.40)	(0.003)
2027	0.071	0.058	0.070	0.052	76.734	0.000	76.734	6.394	17.994	3.568	76.734	0.009	0.009	194.53	0.031	(29.00)	(0.003)
2028	0.072	0.058	0.071	0.052	76.895	0.000	76.895	6.408	18.032	3.576	76.895	0.009	0.009	188.09	0.030	(34.59)	(0.004)
2029	0.072	0.059	0.072	0.053	77.057	0.000	77.057	6.421	18.070	3.583	77.057	0.009	0.009	181.66	0.030	(40.19)	(0.005)
2030	0.073	0.059	0.072	0.054	77.220	0.000	77.220	6.435	18.108	3.591	77.220	0.009	0.009	175.22	0.029	(45.79)	(0.005)
2031	0.073	0.059	0.073	0.053	71.490	0.000	71.490	5.957	16.764	3.324	71.490	0.008	0.008	162.05	0.027	(43.76)	(0.005)
2032	0.073	0.059	0.073	0.053	66.185	0.000	66.185	5.515	15.520	3.078	66.185	0.008	0.008	148.87	0.025	(41.73)	(0.005)
2033	0.073	0.059	0.074	0.053	61.274	0.000	61.274	5.106	14.369	2.849	61.274	0.007	0.007	135.70	0.023	(39.70)	(0.005)
2034	0.073	0.059	0.074	0.053	56.727	0.000	56.727	4.727	13.303	2.638	56.727	0.006	0.006	122.52	0.021	(37.67)	(0.004)
2035	0.073	0.059	0.074	0.053	52.518	0.000	52.518	4.376	12.315	2.442	52.518	0.006	0.006	109.35	0.019	(35.64)	(0.004)
2036	0.073	0.058	0.075	0.053	48.621	0.000	48.621	4.052	11.402	2.261	48.621	0.006	0.006	96.18	0.017	(33.61)	(0.004)
2037	0.073	0.058	0.075	0.053	45.013	0.000	45.013	3.751	10.556	2.093	45.013	0.005	0.005	83.00	0.015	(31.58)	(0.004)
2038	0.073	0.058	0.076	0.052	41.673	0.000	41.673	3.473	9.772	1.938	41.673	0.005	0.005	69.83	0.013	(29.55)	(0.003)
2039	0.073	0.058	0.076	0.052	38.581	0.000	38.581	3.215	9.047	1.794	38.581	0.004	0.004	56.66	0.011	(27.52)	(0.003)
2040	0.072	0.058	0.076	0.052	35.718	0.000	35.718	2.976	8.376	1.661	35.718	0.004	0.004	43.48	0.009	(25.49)	(0.003)
Levelized[3]**:**																	
2005-2040	0.069	0.056	0.068	0.048	65.936	0.319	66.255	5.495	15.462	3.066	66.255	0.008	0.008	179.123	0.028	45.882	0.005
2006-2040	0.069	0.055	0.067	0.048	68.370	0.000	68.370	5.698	16.033	3.179	68.370	0.008	0.008	186.322	0.029	47.726	0.005
2006-2010	0.078	0.061	0.075	0.051	60.102	0.000	60.102	5.009	14.094	2.795	60.102	0.007	0.007	180.277	0.027	219.903	0.025
2006-2015	0.068	0.054	0.065	0.046	68.224	0.000	68.224	5.685	15.998	3.172	68.224	0.008	0.008	194.768	0.030	162.788	0.019
2006-2020	0.067	0.053	0.063	0.045	70.924	0.000	70.924	5.910	16.632	3.298	70.924	0.008	0.008	210.970	0.032	117.602	0.013

Exhibit A2-4. Electric Energy Avoided Costs by Pricing Zone (continued)

	Southwest Connecticut (NOR RTEP + SWCT RTEP)																
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value[1]	Annual Out of Market Expense	Total Annual Capacity Value	Capacity Value at Load Response (at any month)	Avoidable Capacity Payment at Load Response (Summer Season)	Avoidable Capacity Payment at Load Response (Winter Season)	Avoidable Capacity Payment of Energy Efficiency at Summer Coincident Peak	Load Response (at any month)	Energy Efficiency at Summer Coincident Peak	DRIPE 0.75% Capacity Price	DRIPE 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-month	$/kW-season	$/kW-season	$/kW-yr	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kW-yr	$/kWh
Comment 1:	Values are avoided costs at the generation plus transmission level. DSM savings should be measured at the generator plus transmission level. (Load plus + distribution losses)				Reflects Capacity Price resulting from LICAP beginning in 2006	Recovery of costs for RMR including continuing required payments after LICAP initiation		Avoided Cost applicable to KW savings contributing as supply side credit; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level			Avoided Cost applicable to KW savings at Summer Coincident Peak; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level	Avoided cost expressed in $/kWh at 100% load factor		Incremental to Avoided Cost at Summer Coincident Peak	Expressed in $/kWh at 100% load factor	DRIPE 0.75% measured assuming 10% of supply resources transact in spot market	Expressed in $/kWh at 100% load factor
Comment 2:					info	info	June/July/ August	Average for 1 month savings	Average for Summer Season	Average for Winter Season	June / July / August			DRIPE measured at 0.75% peak savings are across all of New England. Values		DRIPE LIGHT measured at 0.75% peak savings are across all of New England.	
Period:							3-5 pm		June, July, August	Jan-May;Sept-Dec	3-5 pm						
2005[2]	0.082	0.067	0.083	0.055	8.154	18.702	26.856	0.680	1.912	0.379	26.856	0.001	0.003	0.00	0.000	0.00	0.000
2006	0.095	0.076	0.096	0.065	48.863	7.638	56.500	4.072	11.458	2.272	56.500	0.006	0.006	436.02	0.050	234.47	0.027
2007	0.100	0.078	0.097	0.066	51.995	5.896	57.891	4.333	12.193	2.418	57.891	0.006	0.007	239.13	0.027	239.13	0.027
2008	0.081	0.064	0.077	0.053	66.341	1.795	68.136	5.528	15.557	3.085	68.136	0.008	0.008	225.80	0.026	204.86	0.023
2009	0.066	0.051	0.061	0.042	70.934	1.742	72.676	5.911	16.634	3.298	72.676	0.008	0.008	493.24	0.056	226.52	0.026
2010	0.056	0.044	0.052	0.037	73.561	1.654	75.215	6.130	17.250	3.421	75.215	0.008	0.009	418.06	0.048	192.60	0.022
2011	0.058	0.045	0.053	0.038	76.285	1.570	77.855	6.357	17.889	3.547	77.855	0.009	0.009	342.88	0.039	158.68	0.018
2012	0.059	0.046	0.054	0.039	79.110	1.491	80.600	6.592	18.551	3.679	80.600	0.009	0.009	267.70	0.031	124.76	0.014
2013	0.059	0.046	0.055	0.039	79.424	0.000	79.424	6.619	18.625	3.693	79.424	0.009	0.009	259.64	0.030	97.20	0.011
2014	0.060	0.047	0.055	0.039	79.739	0.000	79.739	6.645	18.699	3.708	79.739	0.009	0.009	251.59	0.029	69.65	0.008
2015	0.060	0.047	0.056	0.040	80.055	0.000	80.055	6.671	18.773	3.723	80.055	0.009	0.009	243.54	0.028	42.09	0.005
2016	0.060	0.047	0.056	0.040	80.373	0.000	80.373	6.698	18.847	3.737	80.373	0.009	0.009	235.49	0.027	14.53	0.002
2017	0.062	0.049	0.058	0.041	79.557	0.000	79.557	6.630	18.656	3.699	79.557	0.009	0.009	231.65	0.026	13.44	0.002
2018	0.063	0.051	0.060	0.043	78.749	0.000	78.749	6.562	18.467	3.662	78.749	0.009	0.009	227.81	0.026	12.35	0.001
2019	0.065	0.052	0.063	0.045	77.949	0.000	77.949	6.496	18.279	3.625	77.949	0.009	0.009	223.97	0.026	11.26	0.001
2020	0.067	0.054	0.065	0.047	77.157	0.000	77.157	6.430	18.093	3.588	77.157	0.009	0.009	220.13	0.025	10.18	0.001
2021	0.068	0.055	0.066	0.048	77.319	0.000	77.319	6.443	18.131	3.595	77.319	0.009	0.009	208.47	0.024	4.58	0.001
2022	0.068	0.056	0.067	0.049	77.482	0.000	77.482	6.457	18.170	3.603	77.482	0.009	0.009	196.82	0.022	(1.02)	(0.000)
2023	0.069	0.056	0.067	0.049	77.645	0.000	77.645	6.470	18.208	3.611	77.645	0.009	0.009	185.16	0.021	(6.61)	(0.001)
2024	0.069	0.057	0.068	0.050	77.809	0.000	77.809	6.484	18.246	3.618	77.809	0.009	0.009	173.51	0.020	(12.21)	(0.001)
2025	0.070	0.057	0.069	0.050	77.972	0.000	77.972	6.498	18.285	3.626	77.972	0.009	0.009	161.85	0.018	(17.81)	(0.002)
2026	0.071	0.058	0.070	0.051	78.137	0.000	78.137	6.511	18.323	3.633	78.137	0.009	0.009	150.20	0.017	(23.40)	(0.003)
2027	0.071	0.058	0.070	0.052	78.301	0.000	78.301	6.525	18.362	3.641	78.301	0.009	0.009	138.54	0.016	(29.00)	(0.003)
2028	0.072	0.059	0.071	0.052	78.466	0.000	78.466	6.539	18.400	3.649	78.466	0.009	0.009	126.89	0.014	(34.59)	(0.004)
2029	0.073	0.060	0.072	0.053	78.631	0.000	78.631	6.553	18.439	3.656	78.631	0.009	0.009	115.23	0.013	(40.19)	(0.005)
2030	0.073	0.060	0.073	0.054	78.796	0.000	78.796	6.566	18.478	3.664	78.796	0.009	0.009	103.57	0.012	(45.79)	(0.005)
2031	0.073	0.060	0.073	0.054	72.952	0.000	72.952	6.079	17.107	3.392	72.952	0.008	0.008	94.54	0.011	(43.76)	(0.005)
2032	0.073	0.060	0.074	0.054	67.541	0.000	67.541	5.628	15.838	3.141	67.541	0.008	0.008	85.51	0.010	(41.73)	(0.005)
2033	0.073	0.060	0.074	0.053	62.531	0.000	62.531	5.211	14.664	2.908	62.531	0.007	0.007	76.48	0.009	(39.70)	(0.005)
2034	0.073	0.060	0.075	0.053	57.893	0.000	57.893	4.824	13.576	2.692	57.893	0.007	0.007	67.45	0.008	(37.67)	(0.004)
2035	0.074	0.060	0.075	0.053	53.599	0.000	53.599	4.467	12.569	2.492	53.599	0.006	0.006	58.42	0.007	(35.64)	(0.004)
2036	0.074	0.059	0.076	0.053	49.623	0.000	49.623	4.135	11.637	2.307	49.623	0.006	0.006	49.39	0.006	(33.61)	(0.004)
2037	0.074	0.059	0.076	0.053	45.943	0.000	45.943	3.829	10.774	2.136	45.943	0.005	0.005	40.36	0.005	(31.58)	(0.004)
2038	0.074	0.059	0.077	0.053	42.535	0.000	42.535	3.545	9.974	1.978	42.535	0.005	0.005	31.33	0.004	(29.55)	(0.003)
2039	0.074	0.059	0.077	0.053	39.380	0.000	39.380	3.282	9.235	1.831	39.380	0.004	0.004	22.30	0.003	(27.52)	(0.003)
2040	0.074	0.059	0.078	0.053	36.459	0.000	36.459	3.038	8.550	1.695	36.459	0.004	0.004	13.27	0.002	(25.49)	(0.003)
Levelized[3]:																	
2005-2040	0.070	0.056	0.069	0.049	67.539	1.520	69.059	5.628	15.838	3.141	69.059	0.008	0.008	196.91	0.022	45.88	0.005
2006-2040	0.070	0.056	0.068	0.049	69.926	0.829	70.755	5.827	16.398	3.252	70.755	0.008	0.008	204.825	0.023	47.726	0.005
2006-2010	0.080	0.063	0.077	0.053	62.064	3.810	65.874	5.172	14.554	2.886	65.874	0.007	0.008	361.593	0.041	219.903	0.025
2006-2015	0.070	0.055	0.067	0.046	70.054	2.300	72.354	5.838	16.428	3.258	72.354	0.008	0.008	319.966	0.037	162.788	0.019
2006-2020	0.068	0.054	0.065	0.045	72.679	1.609	74.288	6.057	17.043	3.380	74.288	0.008	0.008	292.324	0.033	117.602	0.013

Exhibit A2-5. Electric Energy Avoided Costs by RTEP Zone

	Bangor Hydro																
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value[1]	Annual Out of Market Expense	Total Annual Capacity Value	Capacity Value Load Response (at any month)	Avoidable Capacity Payment Load Response (Summer Season)	Avoidable Capacity Payment Load Response (Winter Season)	Avoidable Capacity Payment of Energy Efficiency at Summer Coincident Peak	Load Response (at any month)	Energy Efficiency at Summer Coincident Peak	DRIPE 0.75% Capacity Price	DRIPE 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-month	$/kW-season	$/kW-season	$/kW-yr	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kW-yr	$/kWh
Comment 1:	Values are avoided costs at the generation plus transmission level. DSM savings should be measured at the generator plus transmission level. (Load plus + distribution losses)				Reflects Capacity Price resulting from LICAP beginning in 2006	Recovery of costs for RMR including continuing required payments after LICAP initiation		Avoided Cost applicable to KW savings contributing as supply side credit; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level			Avoided Cost applicable to KW savings at Summer Coincident Peak; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level	Avoided cost expressed in $/kWh at 100% load factor		Incremental to Avoided Cost at Summer Coincident Peak	Expressed in $/kWh at 100% load factor	DRIPE 0.75% measured assuming 10% of supply resources transact in spot market	Expressed in $/kWh at 100% load factor
Comment 2:					info	info	June/July/August	Average for 1 month savings	Average for Summer Season	Average for Winter Season	June / July / August			DRIPE measured at 0.75% peak savings are across all of New England. Values		DRIPE LIGHT measured at 0.75% peak savings are across all of New England.	
Period:							3-5 pm		June, July, August	Jan-May;Sept-Dec	3-5 pm						
2005 [2]	0.070	0.062	0.059	0.048	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.00	0.000	0.00	0.000
2006	0.079	0.070	0.067	0.056	23.304	0.000	23.304	1.942	5.465	1.084	23.304	0.003	0.003	1,138.69	0.130	113.87	0.013
2007	0.081	0.071	0.068	0.058	20.172	0.000	20.172	1.681	4.730	0.938	20.172	0.002	0.002	637.03	0.073	63.70	0.007
2008	0.068	0.058	0.055	0.047	19.462	0.000	19.462	1.622	4.564	0.905	19.462	0.002	0.002	42.57	0.005	4.26	0.000
2009	0.055	0.046	0.044	0.038	17.895	0.000	17.895	1.491	4.196	0.832	17.895	0.002	0.002	24.47	0.003	2.45	0.000
2010	0.048	0.041	0.040	0.033	27.761	0.000	27.761	2.313	6.510	1.291	27.761	0.003	0.003	43.20	0.005	4.32	0.000
2011	0.050	0.042	0.044	0.035	43.067	0.000	43.067	3.589	10.099	2.003	43.067	0.005	0.005	61.94	0.007	6.19	0.001
2012	0.052	0.044	0.048	0.037	66.810	0.000	66.810	5.568	15.667	3.107	66.810	0.008	0.008	80.67	0.009	8.07	0.001
2013	0.053	0.045	0.047	0.038	67.163	0.000	67.163	5.597	15.750	3.123	67.163	0.008	0.008	80.92	0.009	8.09	0.001
2014	0.053	0.045	0.047	0.038	67.517	0.000	67.517	5.626	15.833	3.140	67.517	0.008	0.008	81.18	0.009	8.12	0.001
2015	0.054	0.046	0.046	0.039	67.872	0.000	67.872	5.656	15.916	3.156	67.872	0.008	0.008	81.43	0.009	8.14	0.001
2016	0.054	0.047	0.046	0.039	68.230	0.000	68.230	5.686	16.000	3.173	68.230	0.008	0.008	81.69	0.009	8.17	0.001
2017	0.056	0.048	0.048	0.041	65.767	0.000	65.767	5.481	15.422	3.058	65.767	0.008	0.008	78.80	0.009	7.88	0.001
2018	0.058	0.050	0.050	0.043	63.392	0.000	63.392	5.283	14.865	2.948	63.392	0.007	0.007	75.92	0.009	7.59	0.001
2019	0.060	0.052	0.052	0.045	61.103	0.000	61.103	5.092	14.329	2.841	61.103	0.007	0.007	73.03	0.008	7.30	0.001
2020	0.062	0.054	0.054	0.047	58.896	0.000	58.896	4.908	13.811	2.739	58.896	0.007	0.007	70.15	0.008	7.01	0.001
2021	0.063	0.054	0.055	0.048	60.454	0.000	60.454	5.038	14.177	2.811	60.454	0.007	0.007	77.37	0.009	7.74	0.001
2022	0.063	0.055	0.056	0.049	62.053	0.000	62.053	5.171	14.552	2.885	62.053	0.007	0.007	84.60	0.010	8.46	0.001
2023	0.064	0.056	0.057	0.049	63.695	0.000	63.695	5.308	14.936	2.962	63.695	0.007	0.007	91.82	0.010	9.18	0.001
2024	0.065	0.056	0.059	0.050	65.380	0.000	65.380	5.448	15.332	3.040	65.380	0.007	0.007	99.04	0.011	9.90	0.001
2025	0.065	0.057	0.060	0.051	67.109	0.000	67.109	5.592	15.737	3.121	67.109	0.008	0.008	106.26	0.012	10.63	0.001
2026	0.066	0.057	0.061	0.052	68.885	0.000	68.885	5.740	16.153	3.203	68.885	0.008	0.008	113.49	0.013	11.35	0.001
2027	0.067	0.058	0.062	0.053	70.707	0.000	70.707	5.892	16.581	3.288	70.707	0.008	0.008	120.71	0.014	12.07	0.001
2028	0.067	0.058	0.063	0.054	72.577	0.000	72.577	6.048	17.019	3.375	72.577	0.008	0.008	127.93	0.015	12.79	0.001
2029	0.068	0.059	0.064	0.054	74.497	0.000	74.497	6.208	17.470	3.464	74.497	0.009	0.009	135.16	0.015	13.52	0.002
2030	0.069	0.060	0.065	0.055	76.468	0.000	76.468	6.372	17.932	3.556	76.468	0.009	0.009	142.38	0.016	14.24	0.002
2031	0.069	0.060	0.065	0.055	70.863	0.000	70.863	5.905	16.617	3.295	70.863	0.008	0.008	134.29	0.015	13.43	0.002
2032	0.069	0.060	0.066	0.055	65.669	0.000	65.669	5.472	15.399	3.054	65.669	0.007	0.007	126.20	0.014	12.62	0.001
2033	0.069	0.060	0.066	0.055	60.856	0.000	60.856	5.071	14.271	2.830	60.856	0.007	0.007	118.11	0.013	11.81	0.001
2034	0.070	0.060	0.066	0.055	56.395	0.000	56.395	4.700	13.225	2.622	56.395	0.006	0.006	110.02	0.013	11.00	0.001
2035	0.070	0.060	0.066	0.055	52.262	0.000	52.262	4.355	12.255	2.430	52.262	0.006	0.006	101.93	0.012	10.19	0.001
2036	0.070	0.060	0.066	0.055	48.431	0.000	48.431	4.036	11.357	2.252	48.431	0.006	0.006	93.84	0.011	9.38	0.001
2037	0.070	0.060	0.066	0.055	44.881	0.000	44.881	3.740	10.525	2.087	44.881	0.005	0.005	85.75	0.010	8.58	0.001
2038	0.070	0.060	0.066	0.055	41.591	0.000	41.591	3.466	9.753	1.934	41.591	0.005	0.005	77.66	0.009	7.77	0.001
2039	0.070	0.060	0.066	0.054	38.543	0.000	38.543	3.212	9.038	1.792	38.543	0.004	0.004	69.57	0.008	6.96	0.001
2040	0.071	0.060	0.066	0.054	35.718	0.000	35.718	2.976	8.376	1.661	35.718	0.004	0.004	61.48	0.007	6.15	0.001
Levelized[3]:																	
2005-2040	0.063	0.055	0.057	0.047	51.998	0.000	51.998	4.333	12.194	2.418	51.998	0.006	0.006	143.358	0.016	14.336	0.002
2006-2040	0.063	0.054	0.056	0.047	54.088	0.000	54.088	4.507	12.684	2.515	54.088	0.006	0.006	149.119	0.017	14.912	0.002
2006-2010	0.066	0.057	0.055	0.046	21.693	0.000	21.693	1.808	5.087	1.009	21.693	0.002	0.002	388.522	0.044	38.852	0.004
2006-2015	0.060	0.051	0.051	0.042	40.969	0.000	40.969	3.414	9.607	1.905	40.969	0.005	0.005	240.613	0.027	24.061	0.003
2006-2020	0.059	0.051	0.051	0.042	47.760	0.000	47.760	3.980	11.200	2.221	47.760	0.005	0.005	191.165	0.022	19.116	0.002

Exhibit A2-5. Electric Energy Avoided Costs by RTEP Zone (continued)

	Central Maine																
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value[1]	Annual Out of Market Expense	Total Annual Capacity Value	Capacity Value Load Response (at any month)	Avoidable Capacity Payment Load Response (Summer Season)	Avoidable Capacity Payment Load Response (Winter Season)	Avoidable Capacity Payment of Energy Efficiency at Summer Coincident Peak	Load Response (at any month)	Energy Efficiency at Summer Coincident Peak	DRIPE 0.75% Capacity Price	DRIPE 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-month	$/kW-season	$/kW-season	$/kW-yr	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kW-yr	$/kWh
Comment 1:	Values are avoided costs at the generation plus transmission level. DSM savings should be measured at the generator plus transmission level. (Load plus + distribution losses)				Reflects Capacity Price resulting from LICAP beginning in 2006	Recovery of costs for RMR including continuing required payments after LICAP initiation		Avoided Cost applicable to KW savings contributing as supply side credit; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level			Avoided Cost applicable to KW savings at Summer Coincident Peak; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level	Avoided cost expressed in $/kWh at 100% load factor		Incremental to Avoided Cost at Summer Coincident Peak	Expressed in $/kWh at 100% load factor	DRIPE 0.75% measured assuming 10% of supply resources transact in spot market	Expressed in $/kWh at 100% load factor
Comment 2:					info	info	June/July/August	Average for 1 month savings	Average for Summer Season	Average for Winter Season	June / July / August			DRIPE measured at 0.75% peak savings are across all of New England. Values		DRIPE LIGHT measured at 0.75% peak savings are across all of New England.	
Period:							3-5 pm		June, July, August	Jan-May;Sept-Dec	3-5 pm						
2005[2]	0.071	0.063	0.063	0.049	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.00	0.000	0.00	0.000
2006	0.080	0.071	0.068	0.057	23.304	0.000	23.304	1.942	5.465	1.084	23.304	0.003	0.003	1,138.69	0.130	113.87	0.013
2007	0.082	0.072	0.070	0.059	20.172	0.000	20.172	1.681	4.730	0.938	20.172	0.002	0.002	637.03	0.073	63.70	0.007
2008	0.069	0.059	0.056	0.048	19.462	0.000	19.462	1.622	4.564	0.905	19.462	0.002	0.002	42.57	0.005	4.26	0.000
2009	0.056	0.047	0.045	0.038	17.895	0.000	17.895	1.491	4.196	0.832	17.895	0.002	0.002	24.47	0.003	2.45	0.000
2010	0.049	0.041	0.041	0.034	27.761	0.000	27.761	2.313	6.510	1.291	27.761	0.003	0.003	43.20	0.005	4.32	0.000
2011	0.051	0.043	0.045	0.036	43.067	0.000	43.067	3.589	10.099	2.003	43.067	0.005	0.005	61.94	0.007	6.19	0.001
2012	0.053	0.044	0.048	0.038	66.810	0.000	66.810	5.568	15.667	3.107	66.810	0.008	0.008	80.67	0.009	8.07	0.001
2013	0.054	0.045	0.048	0.038	67.163	0.000	67.163	5.597	15.750	3.123	67.163	0.008	0.008	80.92	0.009	8.09	0.001
2014	0.054	0.045	0.047	0.039	67.517	0.000	67.517	5.626	15.833	3.140	67.517	0.008	0.008	81.18	0.009	8.12	0.001
2015	0.055	0.046	0.047	0.039	67.872	0.000	67.872	5.656	15.916	3.156	67.872	0.008	0.008	81.43	0.009	8.14	0.001
2016	0.055	0.046	0.046	0.039	68.230	0.000	68.230	5.686	16.000	3.173	68.230	0.008	0.008	81.69	0.009	8.17	0.001
2017	0.057	0.048	0.048	0.041	65.767	0.000	65.767	5.481	15.422	3.058	65.767	0.008	0.008	78.80	0.009	7.88	0.001
2018	0.059	0.050	0.050	0.043	63.392	0.000	63.392	5.283	14.865	2.948	63.392	0.007	0.007	75.92	0.009	7.59	0.001
2019	0.061	0.052	0.053	0.045	61.103	0.000	61.103	5.092	14.329	2.841	61.103	0.007	0.007	73.03	0.008	7.30	0.001
2020	0.063	0.053	0.055	0.047	58.896	0.000	58.896	4.908	13.811	2.739	58.896	0.007	0.007	70.15	0.008	7.01	0.001
2021	0.063	0.054	0.056	0.047	60.454	0.000	60.454	5.038	14.177	2.811	60.454	0.007	0.007	77.37	0.009	7.74	0.001
2022	0.064	0.054	0.057	0.048	62.053	0.000	62.053	5.171	14.552	2.885	62.053	0.007	0.007	84.60	0.010	8.46	0.001
2023	0.064	0.055	0.058	0.049	63.695	0.000	63.695	5.308	14.936	2.962	63.695	0.007	0.007	91.82	0.010	9.18	0.001
2024	0.065	0.055	0.059	0.050	65.380	0.000	65.380	5.448	15.332	3.040	65.380	0.007	0.007	99.04	0.011	9.90	0.001
2025	0.066	0.056	0.060	0.050	67.109	0.000	67.109	5.592	15.737	3.121	67.109	0.008	0.008	106.26	0.012	10.63	0.001
2026	0.066	0.056	0.061	0.051	68.885	0.000	68.885	5.740	16.153	3.203	68.885	0.008	0.008	113.49	0.013	11.35	0.001
2027	0.067	0.057	0.062	0.052	70.707	0.000	70.707	5.892	16.581	3.288	70.707	0.008	0.008	120.71	0.014	12.07	0.001
2028	0.068	0.058	0.063	0.053	72.577	0.000	72.577	6.048	17.019	3.375	72.577	0.008	0.008	127.93	0.015	12.79	0.001
2029	0.068	0.058	0.064	0.054	74.497	0.000	74.497	6.208	17.470	3.464	74.497	0.009	0.009	135.16	0.015	13.52	0.002
2030	0.069	0.059	0.066	0.054	76.468	0.000	76.468	6.372	17.932	3.556	76.468	0.009	0.009	142.38	0.016	14.24	0.002
2031	0.069	0.059	0.066	0.054	70.863	0.000	70.863	5.905	16.617	3.295	70.863	0.008	0.008	134.29	0.015	13.43	0.002
2032	0.069	0.059	0.066	0.054	65.669	0.000	65.669	5.472	15.399	3.054	65.669	0.007	0.007	126.20	0.014	12.62	0.001
2033	0.069	0.059	0.066	0.054	60.856	0.000	60.856	5.071	14.271	2.830	60.856	0.007	0.007	118.11	0.013	11.81	0.001
2034	0.069	0.059	0.066	0.054	56.395	0.000	56.395	4.700	13.225	2.622	56.395	0.006	0.006	110.02	0.013	11.00	0.001
2035	0.069	0.059	0.066	0.054	52.262	0.000	52.262	4.355	12.255	2.430	52.262	0.006	0.006	101.93	0.012	10.19	0.001
2036	0.070	0.059	0.066	0.054	48.431	0.000	48.431	4.036	11.357	2.252	48.431	0.006	0.006	93.84	0.011	9.38	0.001
2037	0.070	0.059	0.066	0.054	44.881	0.000	44.881	3.740	10.525	2.087	44.881	0.005	0.005	85.75	0.010	8.58	0.001
2038	0.070	0.059	0.066	0.054	41.591	0.000	41.591	3.466	9.753	1.934	41.591	0.005	0.005	77.66	0.009	7.77	0.001
2039	0.070	0.059	0.066	0.053	38.543	0.000	38.543	3.212	9.038	1.792	38.543	0.004	0.004	69.57	0.008	6.96	0.001
2040	0.070	0.059	0.066	0.053	35.718	0.000	35.718	2.976	8.376	1.661	35.718	0.004	0.004	61.48	0.007	6.15	0.001
Levelized[3]:																	
2005-2040	0.064	0.054	0.057	0.047	51.998	0.000	51.998	4.333	12.194	2.418	51.998	0.006	0.006	143.358	0.016	14.336	0.002
2006-2040	0.064	0.054	0.057	0.047	54.088	0.000	54.088	4.507	12.684	2.515	54.088	0.006	0.006	149.119	0.017	14.912	0.002
2006-2010	0.068	0.058	0.056	0.047	21.693	0.000	21.693	1.808	5.087	1.009	21.693	0.002	0.002	388.522	0.044	38.852	0.004
2006-2015	0.061	0.052	0.052	0.043	40.969	0.000	40.969	3.414	9.607	1.905	40.969	0.005	0.005	240.613	0.027	24.061	0.003
2006-2020	0.060	0.051	0.052	0.043	47.760	0.000	47.760	3.980	11.200	2.221	47.760	0.005	0.005	191.165	0.022	19.116	0.002

Exhibit A2-5. Electric Energy Avoided Costs by RTEP Zone (continued)

	Southern Maine																
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value[1]	Annual Out of Market Expense	Total Annual Capacity Value	Capacity Value Load Response (at any month)	Avoidable Capacity Payment Load Response (Summer Season)	Avoidable Capacity Payment Load Response (Winter Season)	Avoidable Capacity Payment of Energy Efficiency at Summer Coincident Peak	Load Response (at any month)	Energy Efficiency at Summer Coincident Peak	DRIPE 0.75% Capacity Price	DRIPE 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-month	$/kW-season	$/kW-season	$/kW-yr	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kW-yr	$/kWh
Comment 1:	Values are avoided costs at the generation plus transmission level. DSM savings should be measured at the generator plus transmission level. (Load plus + distribution losses)				Reflects Capacity Price resulting from LICAP beginning in 2006	Recovery of costs for RMR including continuing required payments after LICAP initiation		Avoided Cost applicable to KW savings contributing as supply side credit; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level			Avoided Cost applicable to KW savings at Summer Coincident Peak; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level	Avoided cost expressed in $/kWh at 100% load factor		Incremental to Avoided Cost at Summer Coincident Peak	Expressed in $/kWh at 100% load factor	DRIPE 0.75% measured assuming 10% of supply resources transact in spot market	Expressed in $/kWh at 100% load factor
Comment 2:					info	info	June/July/August	Average for 1 month savings	Average for Summer Season	Average for Winter Season	June / July / August			DRIPE measured at 0.75% peak savings are across all of New England. Values		DRIPE LIGHT measured at 0.75% peak savings are across all of New England.	
Period:							3-5 pm		June, July, August	Jan-May;Sept-Dec	3-5 pm						
2005[2]	0.072	0.064	0.066	0.049	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.00	0.000	0.00	0.000
2006	0.081	0.072	0.074	0.058	23.304	0.000	23.304	1.942	5.465	1.084	23.304	0.003	0.003	1,138.69	0.130	113.87	0.013
2007	0.084	0.073	0.078	0.060	20.172	0.000	20.172	1.681	4.730	0.938	20.172	0.002	0.002	637.03	0.073	63.70	0.007
2008	0.071	0.060	0.069	0.049	19.462	0.000	19.462	1.622	4.564	0.905	19.462	0.002	0.002	42.57	0.005	4.26	0.000
2009	0.057	0.048	0.054	0.039	17.895	0.000	17.895	1.491	4.196	0.832	17.895	0.002	0.002	24.47	0.003	2.45	0.000
2010	0.050	0.042	0.047	0.034	27.761	0.000	27.761	2.313	6.510	1.291	27.761	0.003	0.003	43.20	0.005	4.32	0.000
2011	0.052	0.043	0.049	0.036	43.067	0.000	43.067	3.589	10.099	2.003	43.067	0.005	0.005	61.94	0.007	6.19	0.001
2012	0.055	0.045	0.051	0.038	66.810	0.000	66.810	5.568	15.667	3.107	66.810	0.008	0.008	80.67	0.009	8.07	0.001
2013	0.055	0.046	0.051	0.038	67.163	0.000	67.163	5.597	15.750	3.123	67.163	0.008	0.008	80.92	0.009	8.09	0.001
2014	0.055	0.046	0.052	0.039	67.517	0.000	67.517	5.626	15.833	3.140	67.517	0.008	0.008	81.18	0.009	8.12	0.001
2015	0.056	0.047	0.052	0.039	67.872	0.000	67.872	5.656	15.916	3.156	67.872	0.008	0.008	81.43	0.009	8.14	0.001
2016	0.056	0.047	0.053	0.040	68.230	0.000	68.230	5.686	16.000	3.173	68.230	0.008	0.008	81.69	0.009	8.17	0.001
2017	0.058	0.049	0.055	0.041	65.767	0.000	65.767	5.481	15.422	3.058	65.767	0.008	0.008	78.80	0.009	7.88	0.001
2018	0.060	0.051	0.058	0.043	63.392	0.000	63.392	5.283	14.865	2.948	63.392	0.007	0.007	75.92	0.009	7.59	0.001
2019	0.062	0.053	0.060	0.045	61.103	0.000	61.103	5.092	14.329	2.841	61.103	0.007	0.007	73.03	0.008	7.30	0.001
2020	0.064	0.055	0.063	0.047	58.896	0.000	58.896	4.908	13.811	2.739	58.896	0.007	0.007	70.15	0.008	7.01	0.001
2021	0.064	0.055	0.063	0.048	60.454	0.000	60.454	5.038	14.177	2.811	60.454	0.007	0.007	77.37	0.009	7.74	0.001
2022	0.065	0.055	0.063	0.049	62.053	0.000	62.053	5.171	14.552	2.885	62.053	0.007	0.007	84.60	0.010	8.46	0.001
2023	0.066	0.056	0.064	0.049	63.695	0.000	63.695	5.308	14.936	2.962	63.695	0.007	0.007	91.82	0.010	9.18	0.001
2024	0.066	0.056	0.064	0.050	65.380	0.000	65.380	5.448	15.332	3.040	65.380	0.007	0.007	99.04	0.011	9.90	0.001
2025	0.067	0.057	0.065	0.051	67.109	0.000	67.109	5.592	15.737	3.121	67.109	0.008	0.008	106.26	0.012	10.63	0.001
2026	0.068	0.057	0.065	0.051	68.885	0.000	68.885	5.740	16.153	3.203	68.885	0.008	0.008	113.49	0.013	11.35	0.001
2027	0.068	0.058	0.065	0.052	70.707	0.000	70.707	5.892	16.581	3.288	70.707	0.008	0.008	120.71	0.014	12.07	0.001
2028	0.069	0.058	0.066	0.053	72.577	0.000	72.577	6.048	17.019	3.375	72.577	0.008	0.008	127.93	0.015	12.79	0.001
2029	0.070	0.059	0.066	0.053	74.497	0.000	74.497	6.208	17.470	3.464	74.497	0.009	0.009	135.16	0.015	13.52	0.002
2030	0.070	0.059	0.067	0.054	76.468	0.000	76.468	6.372	17.932	3.556	76.468	0.009	0.009	142.38	0.016	14.24	0.002
2031	0.070	0.059	0.067	0.054	70.863	0.000	70.863	5.905	16.617	3.295	70.863	0.008	0.008	134.29	0.015	13.43	0.002
2032	0.070	0.059	0.068	0.054	65.669	0.000	65.669	5.472	15.399	3.054	65.669	0.007	0.007	126.20	0.014	12.62	0.001
2033	0.070	0.059	0.069	0.054	60.856	0.000	60.856	5.071	14.271	2.830	60.856	0.007	0.007	118.11	0.013	11.81	0.001
2034	0.071	0.059	0.069	0.054	56.395	0.000	56.395	4.700	13.225	2.622	56.395	0.006	0.006	110.02	0.013	11.00	0.001
2035	0.071	0.059	0.070	0.054	52.262	0.000	52.262	4.355	12.255	2.430	52.262	0.006	0.006	101.93	0.012	10.19	0.001
2036	0.071	0.059	0.071	0.053	48.431	0.000	48.431	4.036	11.357	2.252	48.431	0.006	0.006	93.84	0.011	9.38	0.001
2037	0.071	0.059	0.071	0.053	44.881	0.000	44.881	3.740	10.525	2.087	44.881	0.005	0.005	85.75	0.010	8.58	0.001
2038	0.071	0.059	0.072	0.053	41.591	0.000	41.591	3.466	9.753	1.934	41.591	0.005	0.005	77.66	0.009	7.77	0.001
2039	0.071	0.059	0.073	0.053	38.543	0.000	38.543	3.212	9.038	1.792	38.543	0.004	0.004	69.57	0.008	6.96	0.001
2040	0.071	0.059	0.073	0.053	35.718	0.000	35.718	2.976	8.376	1.661	35.718	0.004	0.004	61.48	0.007	6.15	0.001
Levelized[3]:																	
2005-2040	0.065	0.055	0.063	0.048	51.998	0.000	51.998	4.333	12.194	2.418	51.998	0.006	0.006	143.358	0.016	14.336	0.002
2006-2040	0.065	0.055	0.062	0.048	54.088	0.000	54.088	4.507	12.684	2.515	54.088	0.006	0.006	149.119	0.017	14.912	0.002
2006-2010	0.069	0.059	0.065	0.048	21.693	0.000	21.693	1.808	5.087	1.009	21.693	0.002	0.002	388.522	0.044	38.852	0.004
2006-2015	0.062	0.053	0.058	0.043	40.969	0.000	40.969	3.414	9.607	1.905	40.969	0.005	0.005	240.613	0.027	24.061	0.003
2006-2020	0.061	0.052	0.058	0.043	47.760	0.000	47.760	3.980	11.200	2.221	47.760	0.005	0.005	191.165	0.022	19.116	0.002

Exhibit A2-5. Electric Energy Avoided Costs by RTEP Zone (continued)

	Boston																	
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value[1]	Annual Out of Market Expense	Total Annual Capacity Value	Capacity Value Load Response (at any month)	Avoidable Capacity Payment Load Response (Summer Season)	Avoidable Capacity Payment Load Response (Winter Season)	Avoidable Capacity Payment of Energy Efficiency at Summer Coincident Peak	Load Response (at any month)	Energy Efficiency at Summer Coincident Peak	DRIPE 0.75% Capacity Price	DRIPE 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-month	$/kW-season	$/kW-season	$/kW-yr	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kW-yr	$/kWh
Comment 1:	Values are avoided costs at the generation plus transmission level. DSM savings should be measured at the generator plus transmission level. (Load plus + distribution losses)				Reflects Capacity Price resulting from LICAP beginning in 2006	Recovery of costs for RMR including continuing required payments after LICAP initiation		Avoided Cost applicable to KW savings contributing as supply side credit; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level			Avoided Cost applicable to KW savings at Summer Coincident Peak; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level	Avoided cost expressed in $/kWh at 100% load factor		Incremental to Avoided Cost at Summer Coincident Peak	Expressed in $/kWh at 100% load factor	DRIPE 0.75% measured assuming 10% of supply resources transact in spot market	Expressed in $/kWh at 100% load factor
Comment 2:					info	info	June/July/August	Average for 1 month savings	Average for Summer Season	Average for Winter Season	June / July / August			DRIPE measured at 0.75% peak savings are across all of New England. Values		DRIPE LIGHT measured at 0.75% peak savings are across all of New England.	
Period:							3-5 pm		June, July, August	Jan-May;Sept-Dec	3-5 pm						
2005[2]	0.074	0.064	0.069	0.051	5.387	4.835	10.222	0.449	1.263	0.251	10.222	0.001	0.001	0.00	0.000	0.00	0.000
2006	0.085	0.072	0.077	0.059	35.258	11.077	46.335	2.938	8.268	1.640	46.335	0.004	0.005	739.33	0.084	38.81	0.004
2007	0.087	0.074	0.081	0.062	39.936	9.630	49.566	3.328	9.365	1.857	49.566	0.005	0.006	978.41	0.112	54.89	0.006
2008	0.074	0.060	0.072	0.050	63.709	0.000	63.709	5.309	14.940	2.962	63.709	0.007	0.007	35.09	0.004	15.58	0.002
2009	0.060	0.049	0.056	0.040	68.126	0.000	68.126	5.677	15.976	3.168	68.126	0.008	0.008	436.08	0.050	41.82	0.005
2010	0.052	0.042	0.049	0.035	71.124	0.000	71.124	5.927	16.679	3.307	71.124	0.008	0.008	332.41	0.038	23.40	0.003
2011	0.055	0.044	0.051	0.037	74.254	0.000	74.254	6.188	17.413	3.453	74.254	0.008	0.008	228.74	0.026	4.97	0.001
2012	0.057	0.046	0.052	0.038	77.523	0.000	77.523	6.460	18.179	3.605	77.523	0.009	0.009	125.06	0.014	(13.45)	(0.002)
2013	0.057	0.046	0.053	0.039	79.296	0.000	79.296	6.608	18.595	3.687	79.296	0.009	0.009	142.39	0.016	(13.40)	(0.002)
2014	0.058	0.046	0.054	0.039	81.109	0.000	81.109	6.759	19.020	3.772	81.109	0.009	0.009	159.72	0.018	(13.35)	(0.002)
2015	0.058	0.047	0.054	0.040	82.965	0.000	82.965	6.914	19.455	3.858	82.965	0.009	0.009	177.04	0.020	(13.30)	(0.002)
2016	0.059	0.047	0.055	0.040	84.862	0.000	84.862	7.072	19.900	3.946	84.862	0.010	0.010	194.37	0.022	(13.25)	(0.002)
2017	0.060	0.049	0.057	0.042	84.012	0.000	84.012	7.001	19.701	3.907	84.012	0.010	0.010	218.99	0.025	(10.11)	(0.001)
2018	0.062	0.051	0.059	0.044	83.170	0.000	83.170	6.931	19.503	3.867	83.170	0.009	0.009	243.61	0.028	(6.97)	(0.001)
2019	0.064	0.053	0.061	0.045	82.336	0.000	82.336	6.861	19.308	3.829	82.336	0.009	0.009	268.23	0.031	(3.84)	(0.000)
2020	0.066	0.055	0.064	0.047	81.511	0.000	81.511	6.793	19.114	3.790	81.511	0.009	0.009	292.85	0.033	(0.70)	(0.000)
2021	0.066	0.055	0.065	0.048	81.400	0.000	81.400	6.783	19.088	3.785	81.400	0.009	0.009	277.03	0.032	(2.19)	(0.000)
2022	0.067	0.056	0.065	0.049	81.288	0.000	81.288	6.774	19.062	3.780	81.288	0.009	0.009	261.21	0.030	(3.68)	(0.000)
2023	0.068	0.056	0.066	0.049	81.177	0.000	81.177	6.765	19.036	3.775	81.177	0.009	0.009	245.39	0.028	(5.17)	(0.001)
2024	0.068	0.057	0.067	0.050	81.066	0.000	81.066	6.756	19.010	3.770	81.066	0.009	0.009	229.57	0.026	(6.66)	(0.001)
2025	0.069	0.057	0.068	0.051	80.956	0.000	80.956	6.746	18.984	3.764	80.956	0.009	0.009	213.75	0.024	(8.16)	(0.001)
2026	0.070	0.058	0.069	0.051	80.845	0.000	80.845	6.737	18.958	3.759	80.845	0.009	0.009	197.93	0.023	(9.65)	(0.001)
2027	0.070	0.059	0.069	0.052	80.735	0.000	80.735	6.728	18.932	3.754	80.735	0.009	0.009	182.10	0.021	(11.14)	(0.001)
2028	0.071	0.059	0.070	0.053	80.624	0.000	80.624	6.719	18.906	3.749	80.624	0.009	0.009	166.28	0.019	(12.63)	(0.001)
2029	0.072	0.060	0.071	0.054	80.514	0.000	80.514	6.710	18.881	3.744	80.514	0.009	0.009	150.46	0.017	(14.13)	(0.002)
2030	0.072	0.060	0.072	0.054	80.404	0.000	80.404	6.700	18.855	3.739	80.404	0.009	0.009	134.64	0.015	(15.62)	(0.002)
2031	0.072	0.060	0.072	0.054	74.442	0.000	74.442	6.203	17.457	3.462	74.442	0.008	0.008	123.74	0.014	(15.42)	(0.002)
2032	0.072	0.060	0.073	0.054	68.922	0.000	68.922	5.743	16.162	3.205	68.922	0.008	0.008	112.84	0.013	(15.22)	(0.002)
2033	0.072	0.060	0.073	0.054	63.811	0.000	63.811	5.318	14.964	2.967	63.811	0.007	0.007	101.95	0.012	(15.02)	(0.002)
2034	0.072	0.060	0.074	0.054	59.079	0.000	59.079	4.923	13.854	2.747	59.079	0.007	0.007	91.05	0.010	(14.82)	(0.002)
2035	0.072	0.059	0.074	0.053	54.698	0.000	54.698	4.558	12.827	2.543	54.698	0.006	0.006	80.15	0.009	(14.62)	(0.002)
2036	0.072	0.059	0.074	0.053	50.642	0.000	50.642	4.220	11.876	2.355	50.642	0.006	0.006	69.25	0.008	(14.42)	(0.002)
2037	0.072	0.059	0.075	0.053	46.887	0.000	46.887	3.907	10.995	2.180	46.887	0.005	0.005	58.36	0.007	(14.22)	(0.002)
2038	0.072	0.059	0.075	0.053	43.410	0.000	43.410	3.618	10.180	2.019	43.410	0.005	0.005	47.46	0.005	(14.02)	(0.002)
2039	0.072	0.059	0.076	0.053	40.191	0.000	40.191	3.349	9.425	1.869	40.191	0.005	0.005	36.56	0.004	(13.82)	(0.002)
2040	0.072	0.059	0.076	0.053	37.211	0.000	37.211	3.101	8.726	1.730	37.211	0.004	0.004	25.66	0.003	(13.62)	(0.002)
Levelized[3]:																	
2005-2040	0.067	0.056	0.065	0.048	67.827	0.964	68.790	5.652	15.905	3.154	68.790	0.008	0.008	225.800	0.026	-1.517	0.000
2006-2040	0.067	0.055	0.065	0.048	70.336	0.808	71.144	5.861	16.494	3.271	71.144	0.008	0.008	234.875	0.027	-1.578	0.000
2006-2010	0.072	0.060	0.067	0.050	55.228	4.270	59.498	4.602	12.951	2.568	59.498	0.006	0.007	509.740	0.058	35.078	0.004
2006-2015	0.065	0.053	0.060	0.044	66.491	2.242	68.733	5.541	15.592	3.092	68.733	0.008	0.008	346.913	0.040	13.879	0.002
2006-2020	0.064	0.052	0.060	0.044	71.515	1.568	73.083	5.960	16.770	3.325	73.083	0.008	0.008	315.578	0.036	7.576	0.001

Exhibit A2-5. Electric Energy Avoided Costs by RTEP Zone (continued)

	Central Massachusetts																		
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value[1]	Annual Out of Market Expense	Total Annual Capacity Value	Capacity Value Load Response (at any month)	Avoidable Capacity Payment Load Response (Summer Season)	Avoidable Capacity Payment Load Response (Winter Season)	Avoidable Capacity Payment of Energy Efficiency at Summer Coincident Peak	Load Response (at any month)	Energy Efficiency at Summer Coincident Peak	DRIPE 0.75% Capacity Price	DRIPE 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-month	$/kW-season	$/kW-season	$/kW-yr	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kW-yr	$/kWh
Comment 1:	Values are avoided costs at the generation plus transmission level. DSM savings should be measured at the generator plus transmission level. (Load plus + distribution losses)				Reflects Capacity Price resulting from LICAP beginning in 2006	Recovery of costs for RMR including continuing required payments after LICAP initiation		Avoided Cost applicable to KW savings contributing as supply side credit; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level			Avoided Cost applicable to KW savings at Summer Coincident Peak; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level	Avoided cost expressed in $/kWh at 100% load factor		Incremental to Avoided Cost at Summer Coincident Peak	Expressed in $/kWh at 100% load factor	DRIPE 0.75% measured assuming 10% of supply resources transact in spot market	Expressed in $/kWh at 100% load factor
Comment 2:					info	info	June/July/August	Average for 1 month savings	Average for Summer Season	Average for Winter Season	June / July / August			DRIPE measured at 0.75% peak savings are across all of New England. Values		DRIPE LIGHT measured at 0.75% peak savings are across all of New England.	
Period:							3-5 pm		June, July, August	Jan-May;Sept-Dec	3-5 pm						
2005 [2]	0.074	0.064	0.069	0.051	2.662	0.954	3.616	0.222	0.624	0.124	3.616	0.000	0.000	0.00	0.000	0.00	0.000
2006	0.085	0.072	0.077	0.059	34.548	1.801	36.350	2.879	8.102	1.607	36.350	0.004	0.004	654.43	0.075	32.57	0.004
2007	0.087	0.074	0.081	0.062	39.132	2.151	41.283	3.261	9.176	1.820	41.283	0.004	0.005	906.91	0.104	88.60	0.010
2008	0.074	0.060	0.072	0.050	62.436	0.199	62.635	5.203	14.641	2.903	62.635	0.007	0.007	32.87	0.004	15.28	0.002
2009	0.060	0.049	0.056	0.040	66.758	0.204	66.962	5.563	15.655	3.104	66.962	0.008	0.008	357.68	0.041	9.62	0.001
2010	0.052	0.042	0.049	0.035	69.696	0.177	69.874	5.808	16.344	3.241	69.874	0.008	0.008	266.06	0.030	(6.87)	(0.001)
2011	0.055	0.044	0.051	0.037	72.764	0.154	72.918	6.064	17.063	3.384	72.918	0.008	0.008	174.43	0.020	(23.35)	(0.003)
2012	0.057	0.046	0.052	0.038	75.967	0.133	76.100	6.331	17.814	3.532	76.100	0.009	0.009	82.81	0.009	(39.84)	(0.005)
2013	0.057	0.046	0.053	0.039	76.270	0.000	76.270	6.356	17.885	3.547	76.270	0.009	0.009	119.16	0.014	(21.08)	(0.002)
2014	0.058	0.046	0.054	0.039	76.575	0.000	76.575	6.381	17.957	3.561	76.575	0.009	0.009	155.52	0.018	(2.33)	(0.000)
2015	0.058	0.047	0.054	0.040	76.881	0.000	76.881	6.407	18.029	3.575	76.881	0.009	0.009	191.87	0.022	16.43	0.002
2016	0.059	0.047	0.055	0.040	77.188	0.000	77.188	6.432	18.101	3.589	77.188	0.009	0.009	228.22	0.026	35.18	0.004
2017	0.060	0.049	0.057	0.042	76.704	0.000	76.704	6.392	17.987	3.567	76.704	0.009	0.009	258.99	0.030	36.72	0.004
2018	0.062	0.051	0.059	0.044	76.222	0.000	76.222	6.352	17.874	3.544	76.222	0.009	0.009	289.75	0.033	38.26	0.004
2019	0.064	0.053	0.061	0.045	75.743	0.000	75.743	6.312	17.762	3.522	75.743	0.009	0.009	320.52	0.037	39.80	0.005
2020	0.066	0.055	0.064	0.047	75.267	0.000	75.267	6.272	17.650	3.500	75.267	0.009	0.009	351.29	0.040	41.34	0.005
2021	0.066	0.055	0.065	0.048	75.613	0.000	75.613	6.301	17.731	3.516	75.613	0.009	0.009	328.09	0.037	35.34	0.004
2022	0.067	0.056	0.065	0.049	75.960	0.000	75.960	6.330	17.813	3.532	75.960	0.009	0.009	304.90	0.035	29.34	0.003
2023	0.068	0.056	0.066	0.049	76.309	0.000	76.309	6.359	17.894	3.548	76.309	0.009	0.009	281.70	0.032	23.34	0.003
2024	0.068	0.057	0.067	0.050	76.660	0.000	76.660	6.388	17.977	3.565	76.660	0.009	0.009	258.50	0.030	17.35	0.002
2025	0.069	0.057	0.068	0.051	77.012	0.000	77.012	6.418	18.059	3.581	77.012	0.009	0.009	235.31	0.027	11.35	0.001
2026	0.070	0.058	0.069	0.051	77.365	0.000	77.365	6.447	18.142	3.597	77.365	0.009	0.009	212.11	0.024	5.35	0.001
2027	0.070	0.059	0.069	0.052	77.721	0.000	77.721	6.477	18.225	3.614	77.721	0.009	0.009	188.91	0.022	(0.65)	(0.000)
2028	0.071	0.059	0.070	0.053	78.078	0.000	78.078	6.506	18.309	3.631	78.078	0.009	0.009	165.72	0.019	(6.65)	(0.001)
2029	0.072	0.060	0.071	0.054	78.436	0.000	78.436	6.536	18.393	3.647	78.436	0.009	0.009	142.52	0.016	(12.64)	(0.001)
2030	0.072	0.060	0.072	0.054	78.796	0.000	78.796	6.566	18.478	3.664	78.796	0.009	0.009	119.32	0.014	(18.64)	(0.002)
2031	0.072	0.060	0.072	0.054	72.952	0.000	72.952	6.079	17.107	3.392	72.952	0.008	0.008	109.42	0.012	(18.43)	(0.002)
2032	0.072	0.060	0.073	0.054	67.541	0.000	67.541	5.628	15.838	3.141	67.541	0.008	0.008	99.52	0.011	(18.22)	(0.002)
2033	0.072	0.060	0.073	0.054	62.531	0.000	62.531	5.211	14.664	2.908	62.531	0.007	0.007	89.62	0.010	(18.01)	(0.002)
2034	0.072	0.060	0.074	0.054	57.893	0.000	57.893	4.824	13.576	2.692	57.893	0.007	0.007	79.72	0.009	(17.80)	(0.002)
2035	0.072	0.059	0.074	0.053	53.599	0.000	53.599	4.467	12.569	2.492	53.599	0.006	0.006	69.82	0.008	(17.59)	(0.002)
2036	0.072	0.059	0.074	0.053	49.623	0.000	49.623	4.135	11.637	2.307	49.623	0.006	0.006	59.92	0.007	(17.38)	(0.002)
2037	0.072	0.059	0.075	0.053	45.943	0.000	45.943	3.829	10.774	2.136	45.943	0.005	0.005	50.02	0.006	(17.17)	(0.002)
2038	0.072	0.059	0.075	0.053	42.535	0.000	42.535	3.545	9.974	1.978	42.535	0.005	0.005	40.12	0.005	(16.96)	(0.002)
2039	0.072	0.059	0.076	0.053	39.380	0.000	39.380	3.282	9.235	1.831	39.380	0.004	0.004	30.22	0.003	(16.75)	(0.002)
2040	0.072	0.059	0.076	0.053	36.459	0.000	36.459	3.038	8.550	1.695	36.459	0.004	0.004	20.32	0.002	(16.54)	(0.002)
Levelized [3]**:**																	
2005-2040	0.067	0.056	0.065	0.048	64.742	0.215	64.957	5.395	15.182	3.010	64.957	0.007	0.007	220.657	0.025	7.200	0.001
2006-2040	0.067	0.055	0.065	0.048	67.237	0.186	67.422	5.603	15.767	3.127	67.422	0.008	0.008	229.525	0.026	7.489	0.001
2006-2010	0.072	0.060	0.067	0.050	54.120	0.927	55.047	4.510	12.691	2.517	55.047	0.006	0.006	448.938	0.051	28.472	0.003
2006-2015	0.065	0.053	0.060	0.044	64.347	0.515	64.862	5.362	15.089	2.992	64.862	0.007	0.007	304.283	0.035	8.063	0.001
2006-2020	0.064	0.052	0.060	0.044	67.922	0.360	68.282	5.660	15.928	3.158	68.282	0.008	0.008	299.546	0.034	17.117	0.002

Exhibit A2-5. Electric Energy Avoided Costs by RTEP Zone (continued)

	Southeast Massachusetts																
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value[1]	Annual Out of Market Expense	Total Annual Capacity Value	Capacity Value Load Response (at any month)	Avoidable Capacity Payment Load Response (Summer Season)	Avoidable Capacity Payment Load Response (Winter Season)	Avoidable Capacity Payment of Energy Efficiency at Summer Coincident Peak	Load Response (at any month)	Energy Efficiency at Summer Coincident Peak	DRIPE 0.75% Capacity Price	DRIPE 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-month	$/kW-season	$/kW-season	$/kW-yr	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kW-yr	$/kWh
Comment 1:	Values are avoided costs at the generation plus transmission level. DSM savings should be measured at the generator plus transmission level. (Load plus + distribution losses)				Reflects Capacity Price resulting from LICAP beginning in 2006	Recovery of costs for RMR including continuing required payments after LICAP initiation		Avoided Cost applicable to KW savings contributing as supply side credit; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level			Avoided Cost applicable to KW savings at Summer Coincident Peak; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level	Avoided cost expressed in $/kWh at 100% load factor		Incremental to Avoided Cost at Summer Coincident Peak	Expressed in $/kWh at 100% load factor	DRIPE 0.75% measured assuming 10% of supply resources transact in spot market	Expressed in $/kWh at 100% load factor
Comment 2:					info	info	June/July/August	Average for 1 month savings	Average for Summer Season	Average for Winter Season	June / July / August			DRIPE measured at 0.75% peak savings are across all of New England. Values		DRIPE LIGHT measured at 0.75% peak savings are across all of New England.	
Period:							3-5 pm		June, July, August	Jan-May;Sept-Dec	3-5 pm						
2005[2]	0.074	0.064	0.069	0.051	2.662	0.954	3.616	0.222	0.624	0.124	3.616	0.000	0.000	0.00	0.000	0.00	0.000
2006	0.085	0.072	0.077	0.059	34.548	1.801	36.350	2.879	8.102	1.607	36.350	0.004	0.004	654.43	0.075	32.57	0.004
2007	0.087	0.074	0.081	0.062	39.132	2.151	41.283	3.261	9.176	1.820	41.283	0.004	0.005	906.91	0.104	88.60	0.010
2008	0.074	0.060	0.072	0.050	62.436	0.199	62.635	5.203	14.641	2.903	62.635	0.007	0.007	32.87	0.004	15.28	0.002
2009	0.060	0.049	0.056	0.040	66.758	0.204	66.962	5.563	15.655	3.104	66.962	0.008	0.008	357.68	0.041	9.62	0.001
2010	0.052	0.042	0.049	0.035	69.696	0.177	69.874	5.808	16.344	3.241	69.874	0.008	0.008	266.06	0.030	(6.87)	(0.001)
2011	0.055	0.044	0.051	0.037	72.764	0.154	72.918	6.064	17.063	3.384	72.918	0.008	0.008	174.43	0.020	(23.35)	(0.003)
2012	0.057	0.046	0.052	0.038	75.967	0.133	76.100	6.331	17.814	3.532	76.100	0.009	0.009	82.81	0.009	(39.84)	(0.005)
2013	0.057	0.046	0.053	0.039	76.270	0.000	76.270	6.356	17.885	3.547	76.270	0.009	0.009	119.16	0.014	(21.08)	(0.002)
2014	0.058	0.046	0.054	0.039	76.575	0.000	76.575	6.381	17.957	3.561	76.575	0.009	0.009	155.52	0.018	(2.33)	(0.000)
2015	0.058	0.047	0.054	0.040	76.881	0.000	76.881	6.407	18.029	3.575	76.881	0.009	0.009	191.87	0.022	16.43	0.002
2016	0.059	0.047	0.055	0.040	77.188	0.000	77.188	6.432	18.101	3.589	77.188	0.009	0.009	228.22	0.026	35.18	0.004
2017	0.060	0.049	0.057	0.042	76.704	0.000	76.704	6.392	17.987	3.567	76.704	0.009	0.009	258.99	0.030	36.72	0.004
2018	0.062	0.051	0.059	0.044	76.222	0.000	76.222	6.352	17.874	3.544	76.222	0.009	0.009	289.75	0.033	38.26	0.004
2019	0.064	0.053	0.061	0.045	75.743	0.000	75.743	6.312	17.762	3.522	75.743	0.009	0.009	320.52	0.037	39.80	0.005
2020	0.066	0.055	0.064	0.047	75.267	0.000	75.267	6.272	17.650	3.500	75.267	0.009	0.009	351.29	0.040	41.34	0.005
2021	0.066	0.055	0.065	0.048	75.613	0.000	75.613	6.301	17.731	3.516	75.613	0.009	0.009	328.09	0.037	35.34	0.004
2022	0.067	0.056	0.065	0.049	75.960	0.000	75.960	6.330	17.813	3.532	75.960	0.009	0.009	304.90	0.035	29.34	0.003
2023	0.068	0.056	0.066	0.049	76.309	0.000	76.309	6.359	17.894	3.548	76.309	0.009	0.009	281.70	0.032	23.34	0.003
2024	0.068	0.057	0.067	0.050	76.660	0.000	76.660	6.388	17.977	3.565	76.660	0.009	0.009	258.50	0.030	17.35	0.002
2025	0.069	0.057	0.068	0.051	77.012	0.000	77.012	6.418	18.059	3.581	77.012	0.009	0.009	235.31	0.027	11.35	0.001
2026	0.070	0.058	0.069	0.051	77.365	0.000	77.365	6.447	18.142	3.597	77.365	0.009	0.009	212.11	0.024	5.35	0.001
2027	0.070	0.059	0.069	0.052	77.721	0.000	77.721	6.477	18.225	3.614	77.721	0.009	0.009	188.91	0.022	(0.65)	(0.000)
2028	0.071	0.059	0.070	0.053	78.078	0.000	78.078	6.506	18.309	3.631	78.078	0.009	0.009	165.72	0.019	(6.65)	(0.001)
2029	0.072	0.060	0.071	0.054	78.436	0.000	78.436	6.536	18.393	3.647	78.436	0.009	0.009	142.52	0.016	(12.64)	(0.001)
2030	0.072	0.060	0.072	0.054	78.796	0.000	78.796	6.566	18.478	3.664	78.796	0.009	0.009	119.32	0.014	(18.64)	(0.002)
2031	0.072	0.060	0.072	0.054	72.952	0.000	72.952	6.079	17.107	3.392	72.952	0.008	0.008	109.42	0.012	(18.43)	(0.002)
2032	0.072	0.060	0.073	0.054	67.541	0.000	67.541	5.628	15.838	3.141	67.541	0.008	0.008	99.52	0.011	(18.22)	(0.002)
2033	0.072	0.060	0.073	0.054	62.531	0.000	62.531	5.211	14.664	2.908	62.531	0.007	0.007	89.62	0.010	(18.01)	(0.002)
2034	0.072	0.060	0.074	0.054	57.893	0.000	57.893	4.824	13.576	2.692	57.893	0.007	0.007	79.72	0.009	(17.80)	(0.002)
2035	0.072	0.059	0.074	0.053	53.599	0.000	53.599	4.467	12.569	2.492	53.599	0.006	0.006	69.82	0.008	(17.59)	(0.002)
2036	0.072	0.059	0.074	0.053	49.623	0.000	49.623	4.135	11.637	2.307	49.623	0.006	0.006	59.92	0.007	(17.38)	(0.002)
2037	0.072	0.059	0.075	0.053	45.943	0.000	45.943	3.829	10.774	2.136	45.943	0.005	0.005	50.02	0.006	(17.17)	(0.002)
2038	0.072	0.059	0.075	0.053	42.535	0.000	42.535	3.545	9.974	1.978	42.535	0.005	0.005	40.12	0.005	(16.96)	(0.002)
2039	0.072	0.059	0.076	0.053	39.380	0.000	39.380	3.282	9.235	1.831	39.380	0.004	0.004	30.22	0.003	(16.75)	(0.002)
2040	0.072	0.059	0.076	0.053	36.459	0.000	36.459	3.038	8.550	1.695	36.459	0.004	0.004	20.32	0.002	(16.54)	(0.002)
Levelized[3]:																	
2005-2040	0.067	0.056	0.065	0.048	64.742	0.215	64.957	5.395	15.182	3.010	64.957	0.007	0.007	220.657	0.025	7.200	0.001
2006-2040	0.067	0.055	0.065	0.048	67.237	0.186	67.422	5.603	15.767	3.127	67.422	0.008	0.008	229.525	0.026	7.489	0.001
2006-2010	0.072	0.060	0.067	0.050	54.120	0.927	55.047	4.510	12.691	2.517	55.047	0.006	0.006	448.938	0.051	28.472	0.003
2006-2015	0.065	0.053	0.060	0.044	64.347	0.515	64.862	5.362	15.089	2.992	64.862	0.007	0.007	304.283	0.035	8.063	0.001
2006-2020	0.064	0.052	0.060	0.044	67.922	0.360	68.282	5.660	15.928	3.158	68.282	0.008	0.008	299.546	0.034	17.117	0.002

Exhibit A2-5. Electric Energy Avoided Costs by RTEP Zone (continued)

	Western Massachusetts																
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value[1]	Annual Out of Market Expense	Total Annual Capacity Value	Capacity Value Load Response (at any month)	Avoidable Capacity Payment Load Response (Summer Season)	Avoidable Capacity Payment Load Response (Winter Season)	Avoidable Capacity Payment of Energy Efficiency at Summer Coincident Peak	Load Response (at any month)	Energy Efficiency at Summer Coincident Peak	DRIPE 0.75% Capacity Price	DRIPE 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-month	$/kW-season	$/kW-season	$/kW-yr	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kW-yr	$/kWh
Comment 1:	Values are avoided costs at the generation plus transmission level. DSM savings should be measured at the generator plus transmission level. (Load plus + distribution losses)				Reflects Capacity Price resulting from LICAP beginning in 2006	Recovery of costs for RMR including continuing required payments after LICAP initiation		Avoided Cost applicable to KW savings contributing as supply side credit; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level			Avoided Cost applicable to KW savings at Summer Coincident Peak; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level	Avoided cost expressed in $/kWh at 100% load factor		Incremental to Avoided Cost at Summer Coincident Peak	Expressed in $/kWh at 100% load factor	DRIPE 0.75% measured assuming 10% of supply resources transact in spot market	Expressed in $/kWh at 100% load factor
Comment 2:					info	info	June/July/August	Average for 1 month savings	Average for Summer Season	Average for Winter Season	June / July / August			DRIPE measured at 0.75% peak savings are across all of New England. Values		DRIPE LIGHT measured at 0.75% peak savings are across all of New England.	
Period:							3-5 pm		June, July, August	Jan-May;Sept-Dec	3-5 pm						
2005[2]	0.074	0.064	0.069	0.051	2.662	0.954	3.616	0.222	0.624	0.124	3.616	0.000	0.000	0.00	0.000	0.00	0.000
2006	0.085	0.072	0.077	0.059	34.548	1.801	36.350	2.879	8.102	1.607	36.350	0.004	0.004	654.43	0.075	32.57	0.004
2007	0.087	0.074	0.081	0.062	39.132	2.151	41.283	3.261	9.176	1.820	41.283	0.004	0.005	906.91	0.104	88.60	0.010
2008	0.074	0.060	0.072	0.050	62.436	0.199	62.635	5.203	14.641	2.903	62.635	0.007	0.007	32.87	0.004	15.28	0.002
2009	0.060	0.049	0.056	0.040	66.758	0.204	66.962	5.563	15.655	3.104	66.962	0.008	0.008	357.68	0.041	9.62	0.001
2010	0.052	0.042	0.049	0.035	69.696	0.177	69.874	5.808	16.344	3.241	69.874	0.008	0.008	266.06	0.030	(6.87)	(0.001)
2011	0.055	0.044	0.051	0.037	72.764	0.154	72.918	6.064	17.063	3.384	72.918	0.008	0.008	174.43	0.020	(23.35)	(0.003)
2012	0.057	0.046	0.052	0.038	75.967	0.133	76.100	6.331	17.814	3.532	76.100	0.009	0.009	82.81	0.009	(39.84)	(0.005)
2013	0.057	0.046	0.053	0.039	76.270	0.000	76.270	6.356	17.885	3.547	76.270	0.009	0.009	119.16	0.014	(21.08)	(0.002)
2014	0.058	0.046	0.054	0.039	76.575	0.000	76.575	6.381	17.957	3.561	76.575	0.009	0.009	155.52	0.018	(2.33)	(0.000)
2015	0.058	0.047	0.054	0.040	76.881	0.000	76.881	6.407	18.029	3.575	76.881	0.009	0.009	191.87	0.022	16.43	0.002
2016	0.059	0.047	0.055	0.040	77.188	0.000	77.188	6.432	18.101	3.589	77.188	0.009	0.009	228.22	0.026	35.18	0.004
2017	0.060	0.049	0.057	0.042	76.704	0.000	76.704	6.392	17.987	3.567	76.704	0.009	0.009	258.99	0.030	36.72	0.004
2018	0.062	0.051	0.059	0.044	76.222	0.000	76.222	6.352	17.874	3.544	76.222	0.009	0.009	289.75	0.033	38.26	0.004
2019	0.064	0.053	0.061	0.045	75.743	0.000	75.743	6.312	17.762	3.522	75.743	0.009	0.009	320.52	0.037	39.80	0.005
2020	0.066	0.055	0.064	0.047	75.267	0.000	75.267	6.272	17.650	3.500	75.267	0.009	0.009	351.29	0.040	41.34	0.005
2021	0.066	0.055	0.065	0.048	75.613	0.000	75.613	6.301	17.731	3.516	75.613	0.009	0.009	328.09	0.037	35.34	0.004
2022	0.067	0.056	0.065	0.049	75.960	0.000	75.960	6.330	17.813	3.532	75.960	0.009	0.009	304.90	0.035	29.34	0.003
2023	0.068	0.056	0.066	0.049	76.309	0.000	76.309	6.359	17.894	3.548	76.309	0.009	0.009	281.70	0.032	23.34	0.003
2024	0.068	0.057	0.067	0.050	76.660	0.000	76.660	6.388	17.977	3.565	76.660	0.009	0.009	258.50	0.030	17.35	0.002
2025	0.069	0.057	0.068	0.051	77.012	0.000	77.012	6.418	18.059	3.581	77.012	0.009	0.009	235.31	0.027	11.35	0.001
2026	0.070	0.058	0.069	0.051	77.365	0.000	77.365	6.447	18.142	3.597	77.365	0.009	0.009	212.11	0.024	5.35	0.001
2027	0.070	0.059	0.069	0.052	77.721	0.000	77.721	6.477	18.225	3.614	77.721	0.009	0.009	188.91	0.022	(0.65)	(0.000)
2028	0.071	0.059	0.070	0.053	78.078	0.000	78.078	6.506	18.309	3.631	78.078	0.009	0.009	165.72	0.019	(6.65)	(0.001)
2029	0.072	0.060	0.071	0.054	78.436	0.000	78.436	6.536	18.393	3.647	78.436	0.009	0.009	142.52	0.016	(12.64)	(0.001)
2030	0.072	0.060	0.072	0.054	78.796	0.000	78.796	6.566	18.478	3.664	78.796	0.009	0.009	119.32	0.014	(18.64)	(0.002)
2031	0.072	0.060	0.072	0.054	72.952	0.000	72.952	6.079	17.107	3.392	72.952	0.008	0.008	109.42	0.012	(18.43)	(0.002)
2032	0.072	0.060	0.073	0.054	67.541	0.000	67.541	5.628	15.838	3.141	67.541	0.008	0.008	99.52	0.011	(18.22)	(0.002)
2033	0.072	0.060	0.073	0.054	62.531	0.000	62.531	5.211	14.664	2.908	62.531	0.007	0.007	89.62	0.010	(18.01)	(0.002)
2034	0.072	0.060	0.074	0.054	57.893	0.000	57.893	4.824	13.576	2.692	57.893	0.007	0.007	79.72	0.009	(17.80)	(0.002)
2035	0.072	0.059	0.074	0.053	53.599	0.000	53.599	4.467	12.569	2.492	53.599	0.006	0.006	69.82	0.008	(17.59)	(0.002)
2036	0.072	0.059	0.074	0.053	49.623	0.000	49.623	4.135	11.637	2.307	49.623	0.006	0.006	59.92	0.007	(17.38)	(0.002)
2037	0.072	0.059	0.075	0.053	45.943	0.000	45.943	3.829	10.774	2.136	45.943	0.005	0.005	50.02	0.006	(17.17)	(0.002)
2038	0.072	0.059	0.075	0.053	42.535	0.000	42.535	3.545	9.974	1.978	42.535	0.005	0.005	40.12	0.005	(16.96)	(0.002)
2039	0.072	0.059	0.076	0.053	39.380	0.000	39.380	3.282	9.235	1.831	39.380	0.004	0.004	30.22	0.003	(16.75)	(0.002)
2040	0.072	0.059	0.076	0.053	36.459	0.000	36.459	3.038	8.550	1.695	36.459	0.004	0.004	20.32	0.002	(16.54)	(0.002)
Levelized[3]:																	
2005-2040	0.067	0.056	0.065	0.048	64.742	0.215	64.957	5.395	15.182	3.010	64.957	0.007	0.007	220.657	0.025	7.200	0.001
2006-2040	0.067	0.055	0.065	0.048	67.237	0.186	67.422	5.603	15.767	3.127	67.422	0.008	0.008	229.525	0.026	7.489	0.001
2006-2010	0.072	0.060	0.067	0.050	54.120	0.927	55.047	4.510	12.691	2.517	55.047	0.006	0.006	448.938	0.051	28.472	0.003
2006-2015	0.065	0.053	0.060	0.044	64.347	0.515	64.862	5.362	15.089	2.992	64.862	0.007	0.007	304.283	0.035	8.063	0.001
2006-2020	0.064	0.052	0.060	0.044	67.922	0.360	68.282	5.660	15.928	3.158	68.282	0.008	0.008	299.546	0.034	17.117	0.002

Exhibit A2-5. Electric Energy Avoided Costs by RTEP Zone (continued)

	New Hampshire																
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value[1]	Annual Out of Market Expense	Total Annual Capacity Value	Capacity Value Load Response (at any month)	Avoidable Capacity Payment Load Response (Summer Season)	Avoidable Capacity Payment Load Response (Winter Season)	Avoidable Capacity Payment of Energy Efficiency at Summer Coincident Peak	Load Response (at any month)	Energy Efficiency at Summer Coincident Peak	DRIPE 0.75% Capacity Price	DRIPE 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price
Units:	**$/kWh**	**$/kWh**	**$/kWh**	**$/kWh**	**$/kW-yr**	**$/kW-yr**	**$/kW-yr**	**$/kW-month**	**$/kW-season**	**$/kW-season**	**$/kW-yr**	**$/kWh**	**$/kWh**	**$/kW-yr**	**$/kWh**	**$/kW-yr**	**$/kWh**
Comment 1:	Values are avoided costs at the generation plus transmission level. DSM savings should be measured at the generator plus transmission level. (Load plus + distribution losses)				Reflects Capacity Price resulting from LICAP beginning in 2006	Recovery of costs for RMR including continuing required payments after LICAP initiation		Avoided Cost applicable to KW savings contributing as supply side credit; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level			Avoided Cost applicable to KW savings at Summer Coincident Peak; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level	Avoided cost expressed in $/kWh at 100% load factor		Incremental to Avoided Cost at Summer Coincident Peak	Expressed in $/kWh at 100% load factor	DRIPE 0.75% measured assuming 10% of supply resources transact in spot market	Expressed in $/kWh at 100% load factor
Comment 2:					info	info	June/July/August	Average for 1 month savings	Average for Summer Season	Average for Winter Season	June / July / August			DRIPE measured at 0.75% peak savings are across all of New England. Values		DRIPE LIGHT measured at 0.75% peak savings are across all of New England.	
Period:							3-5 pm		June, July, August	Jan-May;Sept-Dec	3-5 pm						
2005[2]	0.072	0.063	0.066	0.049	2.662	0.954	3.616	0.222	0.624	0.124	3.616	0.000	0.000	0.00	0.000	0.00	0.000
2006	0.082	0.070	0.074	0.058	34.548	1.801	36.350	2.879	8.102	1.607	36.350	0.004	0.004	654.43	0.083	682.02	0.078
2007	0.085	0.072	0.079	0.060	39.132	2.151	41.283	3.261	9.176	1.820	41.283	0.004	0.005	906.91	0.077	675.20	0.077
2008	0.072	0.059	0.070	0.050	62.436	0.199	62.635	5.203	14.641	2.903	62.635	0.007	0.007	32.87	0.079	688.20	0.079
2009	0.058	0.048	0.055	0.039	66.758	0.204	66.962	5.563	15.655	3.104	66.962	0.008	0.008	357.68	0.089	690.24	0.079
2010	0.051	0.041	0.048	0.034	69.696	0.177	69.874	5.808	16.344	3.241	69.874	0.008	0.008	266.06	0.102	797.97	0.091
2011	0.053	0.043	0.050	0.036	72.764	0.154	72.918	6.064	17.063	3.384	72.918	0.008	0.008	174.43	0.115	905.70	0.103
2012	0.056	0.045	0.051	0.038	75.967	0.133	76.100	6.331	17.814	3.532	76.100	0.009	0.009	82.81	0.129	1,013.42	0.116
2013	0.056	0.045	0.052	0.038	76.270	0.000	76.270	6.356	17.885	3.547	76.270	0.009	0.009	119.16	0.114	857.38	0.098
2014	0.057	0.046	0.053	0.039	76.575	0.000	76.575	6.381	17.957	3.561	76.575	0.009	0.009	155.52	0.098	701.33	0.080
2015	0.057	0.046	0.053	0.039	76.881	0.000	76.881	6.407	18.029	3.575	76.881	0.009	0.009	191.87	0.083	545.28	0.062
2016	0.058	0.047	0.054	0.039	77.188	0.000	77.188	6.432	18.101	3.589	77.188	0.009	0.009	228.22	0.068	389.24	0.044
2017	0.059	0.048	0.056	0.041	76.704	0.000	76.704	6.392	17.987	3.567	76.704	0.009	0.009	258.99	0.059	319.39	0.036
2018	0.061	0.050	0.058	0.043	76.222	0.000	76.222	6.352	17.874	3.544	76.222	0.009	0.009	289.75	0.050	249.54	0.028
2019	0.063	0.052	0.061	0.045	75.743	0.000	75.743	6.312	17.762	3.522	75.743	0.009	0.009	320.52	0.041	179.69	0.021
2020	0.065	0.054	0.063	0.047	75.267	0.000	75.267	6.272	17.650	3.500	75.267	0.009	0.009	351.29	0.032	109.85	0.013
2021	0.065	0.054	0.064	0.048	75.613	0.000	75.613	6.301	17.731	3.516	75.613	0.009	0.009	328.09	0.032	112.75	0.013
2022	0.066	0.055	0.065	0.048	75.960	0.000	75.960	6.330	17.813	3.532	75.960	0.009	0.009	304.90	0.031	115.66	0.013
2023	0.067	0.056	0.065	0.049	76.309	0.000	76.309	6.359	17.894	3.548	76.309	0.009	0.009	281.70	0.031	118.57	0.014
2024	0.067	0.056	0.066	0.050	76.660	0.000	76.660	6.388	17.977	3.565	76.660	0.009	0.009	258.50	0.031	121.48	0.014
2025	0.068	0.057	0.067	0.050	77.012	0.000	77.012	6.418	18.059	3.581	77.012	0.009	0.009	235.31	0.031	124.39	0.014
2026	0.069	0.057	0.068	0.051	77.365	0.000	77.365	6.447	18.142	3.597	77.365	0.009	0.009	212.11	0.030	127.30	0.015
2027	0.070	0.058	0.069	0.052	77.721	0.000	77.721	6.477	18.225	3.614	77.721	0.009	0.009	188.91	0.030	130.21	0.015
2028	0.070	0.058	0.070	0.053	78.078	0.000	78.078	6.506	18.309	3.631	78.078	0.009	0.009	165.72	0.030	133.12	0.015
2029	0.071	0.059	0.071	0.053	78.436	0.000	78.436	6.536	18.393	3.647	78.436	0.009	0.009	142.52	0.030	136.03	0.016
2030	0.072	0.060	0.071	0.054	78.796	0.000	78.796	6.566	18.478	3.664	78.796	0.009	0.009	119.32	0.029	138.93	0.016
2031	0.072	0.059	0.072	0.054	72.952	0.000	72.952	6.079	17.107	3.392	72.952	0.008	0.008	109.42	0.027	130.11	0.015
2032	0.072	0.059	0.072	0.054	67.541	0.000	67.541	5.628	15.838	3.141	67.541	0.008	0.008	99.52	0.025	121.29	0.014
2033	0.072	0.059	0.073	0.054	62.531	0.000	62.531	5.211	14.664	2.908	62.531	0.007	0.007	89.62	0.023	112.47	0.013
2034	0.072	0.059	0.073	0.053	57.893	0.000	57.893	4.824	13.576	2.692	57.893	0.007	0.007	79.72	0.021	103.65	0.012
2035	0.072	0.059	0.073	0.053	53.599	0.000	53.599	4.467	12.569	2.492	53.599	0.006	0.006	69.82	0.019	94.83	0.011
2036	0.072	0.059	0.074	0.053	49.623	0.000	49.623	4.135	11.637	2.307	49.623	0.006	0.006	59.92	0.017	86.01	0.010
2037	0.072	0.058	0.074	0.053	45.943	0.000	45.943	3.829	10.774	2.136	45.943	0.005	0.005	50.02	0.015	77.19	0.009
2038	0.071	0.058	0.075	0.053	42.535	0.000	42.535	3.545	9.974	1.978	42.535	0.005	0.005	40.12	0.013	68.37	0.008
2039	0.071	0.058	0.075	0.052	39.380	0.000	39.380	3.282	9.235	1.831	39.380	0.004	0.004	30.22	0.011	59.54	0.007
2040	0.071	0.058	0.075	0.052	36.459	0.000	36.459	3.038	8.550	1.695	36.459	0.004	0.004	20.32	0.009	50.72	0.006
Levelized[3]:																	
2005-2040	0.066	0.055	0.064	0.047	64.742	0.215	64.957	5.395	15.182	3.010	64.957	0.007	0.007	220.657	0.053	350.465	0.040
2006-2040	0.066	0.055	0.064	0.047	67.237	0.186	67.422	5.603	15.767	3.127	67.422	0.008	0.008	229.525	0.055	364.550	0.042
2006-2010	0.070	0.059	0.065	0.049	54.120	0.927	55.047	4.510	12.691	2.517	55.047	0.006	0.006	448.938	0.086	705.744	0.081
2006-2015	0.063	0.052	0.059	0.043	64.347	0.515	64.862	5.362	15.089	2.992	64.862	0.007	0.007	304.283	0.096	754.662	0.086
2006-2020	0.063	0.052	0.059	0.043	67.922	0.360	68.282	5.660	15.928	3.158	68.282	0.008	0.008	299.546	0.083	603.740	0.069

Exhibit A2-5. Electric Energy Avoided Costs by RTEP Zone (continued)

	Rhode Island																
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value[1]	Annual Out of Market Expense	Total Annual Capacity Value	Capacity Value Load Response (at any month)	Avoidable Capacity Payment Load Response (Summer Season)	Avoidable Capacity Payment Load Response (Winter Season)	Avoidable Capacity Payment of Energy Efficiency at Summer Coincident Peak	Load Response (at any month)	Energy Efficiency at Summer Coincident Peak	DRIPE 0.75% Capacity Price	DRIPE 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price
Units:	**$/kWh**	**$/kWh**	**$/kWh**	**$/kWh**	**$/kW-yr**	**$/kW-yr**	**$/kW-yr**	**$/kW-month**	**$/kW-season**	**$/kW-season**	**$/kW-yr**	**$/kWh**	**$/kWh**	**$/kW-yr**	**$/kWh**	**$/kW-yr**	**$/kWh**
Comment 1:	Values are avoided costs at the generation plus transmission level. DSM savings should be measured at the generator plus transmission level. (Load plus + distribution losses)				Reflects Capacity Price resulting from LICAP beginning in 2006	Recovery of costs for RMR including continuing required payments after LICAP initiation		Avoided Cost applicable to KW savings contributing as supply side credit; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level			Avoided Cost applicable to KW savings at Summer Coincident Peak; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level	Avoided cost expressed in $/kWh at 100% load factor		Incremental to Avoided Cost at Summer Coincident Peak	Expressed in $/kWh at 100% load factor	DRIPE 0.75% measured assuming 10% of supply resources transact in spot market	Expressed in $/kWh at 100% load factor
Comment 2:					info	info	June/July/August	Average for 1 month savings	Average for Summer Season	Average for Winter Season	June / July / August			DRIPE measured at 0.75% peak savings are across all of New England. Values		DRIPE LIGHT measured at 0.75% peak savings are across all of New England.	
Period:							3-5 pm		June, July, August	Jan-May;Sept-Dec	3-5 pm						
2005[2]	0.073	0.064	0.068	0.051	2.662	0.954	3.616	0.222	0.624	0.124	3.616	0.000	0.000	0.00	0.000	0.00	0.000
2006	0.084	0.072	0.077	0.060	34.548	1.801	36.350	2.879	8.102	1.607	36.350	0.004	0.004	654.43	0.075	32.57	0.004
2007	0.087	0.074	0.081	0.062	39.132	2.151	41.283	3.261	9.176	1.820	41.283	0.004	0.005	906.91	0.104	88.60	0.010
2008	0.074	0.060	0.071	0.051	62.436	0.199	62.635	5.203	14.641	2.903	62.635	0.007	0.007	32.87	0.004	15.28	0.002
2009	0.060	0.049	0.056	0.040	66.758	0.204	66.962	5.563	15.655	3.104	66.962	0.008	0.008	357.68	0.041	9.62	0.001
2010	0.052	0.042	0.048	0.035	69.696	0.177	69.874	5.808	16.344	3.241	69.874	0.008	0.008	266.06	0.030	(6.87)	(0.001)
2011	0.054	0.044	0.050	0.037	72.764	0.154	72.918	6.064	17.063	3.384	72.918	0.008	0.008	174.43	0.020	(23.35)	(0.003)
2012	0.057	0.045	0.052	0.038	75.967	0.133	76.100	6.331	17.814	3.532	76.100	0.009	0.009	82.81	0.009	(39.84)	(0.005)
2013	0.057	0.046	0.053	0.039	76.270	0.000	76.270	6.356	17.885	3.547	76.270	0.009	0.009	119.16	0.014	(21.08)	(0.002)
2014	0.057	0.046	0.053	0.039	76.575	0.000	76.575	6.381	17.957	3.561	76.575	0.009	0.009	155.52	0.018	(2.33)	(0.000)
2015	0.058	0.047	0.054	0.040	76.881	0.000	76.881	6.407	18.029	3.575	76.881	0.009	0.009	191.87	0.022	16.43	0.002
2016	0.058	0.047	0.054	0.040	77.188	0.000	77.188	6.432	18.101	3.589	77.188	0.009	0.009	228.22	0.026	35.18	0.004
2017	0.060	0.049	0.056	0.042	76.704	0.000	76.704	6.392	17.987	3.567	76.704	0.009	0.009	258.99	0.030	36.72	0.004
2018	0.062	0.050	0.059	0.044	76.222	0.000	76.222	6.352	17.874	3.544	76.222	0.009	0.009	289.75	0.033	38.26	0.004
2019	0.063	0.052	0.061	0.046	75.743	0.000	75.743	6.312	17.762	3.522	75.743	0.009	0.009	320.52	0.037	39.80	0.005
2020	0.065	0.054	0.063	0.048	75.267	0.000	75.267	6.272	17.650	3.500	75.267	0.009	0.009	351.29	0.040	41.34	0.005
2021	0.066	0.055	0.064	0.048	75.613	0.000	75.613	6.301	17.731	3.516	75.613	0.009	0.009	328.09	0.037	35.34	0.004
2022	0.067	0.055	0.065	0.049	75.960	0.000	75.960	6.330	17.813	3.532	75.960	0.009	0.009	304.90	0.035	29.34	0.003
2023	0.067	0.056	0.066	0.050	76.309	0.000	76.309	6.359	17.894	3.548	76.309	0.009	0.009	281.70	0.032	23.34	0.003
2024	0.068	0.057	0.067	0.050	76.660	0.000	76.660	6.388	17.977	3.565	76.660	0.009	0.009	258.50	0.030	17.35	0.002
2025	0.069	0.057	0.067	0.051	77.012	0.000	77.012	6.418	18.059	3.581	77.012	0.009	0.009	235.31	0.027	11.35	0.001
2026	0.069	0.058	0.068	0.052	77.365	0.000	77.365	6.447	18.142	3.597	77.365	0.009	0.009	212.11	0.024	5.35	0.001
2027	0.070	0.058	0.069	0.052	77.721	0.000	77.721	6.477	18.225	3.614	77.721	0.009	0.009	188.91	0.022	(0.65)	(0.000)
2028	0.071	0.059	0.070	0.053	78.078	0.000	78.078	6.506	18.309	3.631	78.078	0.009	0.009	165.72	0.019	(6.65)	(0.001)
2029	0.072	0.060	0.071	0.054	78.436	0.000	78.436	6.536	18.393	3.647	78.436	0.009	0.009	142.52	0.016	(12.64)	(0.001)
2030	0.072	0.060	0.072	0.054	78.796	0.000	78.796	6.566	18.478	3.664	78.796	0.009	0.009	119.32	0.014	(18.64)	(0.002)
2031	0.072	0.060	0.072	0.054	72.952	0.000	72.952	6.079	17.107	3.392	72.952	0.008	0.008	109.42	0.012	(18.43)	(0.002)
2032	0.072	0.060	0.072	0.054	67.541	0.000	67.541	5.628	15.838	3.141	67.541	0.008	0.008	99.52	0.011	(18.22)	(0.002)
2033	0.072	0.060	0.073	0.054	62.531	0.000	62.531	5.211	14.664	2.908	62.531	0.007	0.007	89.62	0.010	(18.01)	(0.002)
2034	0.072	0.060	0.073	0.054	57.893	0.000	57.893	4.824	13.576	2.692	57.893	0.007	0.007	79.72	0.009	(17.80)	(0.002)
2035	0.072	0.059	0.074	0.054	53.599	0.000	53.599	4.467	12.569	2.492	53.599	0.006	0.006	69.82	0.008	(17.59)	(0.002)
2036	0.072	0.059	0.074	0.053	49.623	0.000	49.623	4.135	11.637	2.307	49.623	0.006	0.006	59.92	0.007	(17.38)	(0.002)
2037	0.072	0.059	0.075	0.053	45.943	0.000	45.943	3.829	10.774	2.136	45.943	0.005	0.005	50.02	0.006	(17.17)	(0.002)
2038	0.072	0.059	0.075	0.053	42.535	0.000	42.535	3.545	9.974	1.978	42.535	0.005	0.005	40.12	0.005	(16.96)	(0.002)
2039	0.072	0.058	0.075	0.053	39.380	0.000	39.380	3.282	9.235	1.831	39.380	0.004	0.004	30.22	0.003	(16.75)	(0.002)
2040	0.072	0.058	0.076	0.053	36.459	0.000	36.459	3.038	8.550	1.695	36.459	0.004	0.004	20.32	0.002	(16.54)	(0.002)
Levelized[3]:																	
2005-2040	0.067	0.056	0.065	0.048	64.742	0.215	64.957	5.395	15.182	3.010	64.957	0.007	0.007	220.657	0.025	7.200	0.001
2006-2040	0.067	0.055	0.065	0.048	67.237	0.186	67.422	5.603	15.767	3.127	67.422	0.008	0.008	229.525	0.026	7.489	0.001
2006-2010	0.072	0.060	0.067	0.050	54.120	0.927	55.047	4.510	12.691	2.517	55.047	0.006	0.006	448.938	0.051	28.472	0.003
2006-2015	0.065	0.053	0.060	0.045	64.347	0.515	64.862	5.362	15.089	2.992	64.862	0.007	0.007	304.283	0.035	8.063	0.001
2006-2020	0.064	0.052	0.059	0.044	67.922	0.360	68.282	5.660	15.928	3.158	68.282	0.008	0.008	299.546	0.034	17.117	0.002

Exhibit A2-5. Electric Energy Avoided Costs by RTEP Zone (continued)

	Vermont																
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value[1]	Annual Out of Market Expense	Total Annual Capacity Value	Capacity Value Load Response (at any month)	Avoidable Capacity Payment Load Response (Summer Season)	Avoidable Capacity Payment Load Response (Winter Season)	Avoidable Capacity Payment of Energy Efficiency at Summer Coincident Peak	Load Response (at any month)	Energy Efficiency at Summer Coincident Peak	DRIPE 0.75% Capacity Price	DRIPE 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price
Units:	**$/kWh**	**$/kWh**	**$/kWh**	**$/kWh**	**$/kW-yr**	**$/kW-yr**	**$/kW-yr**	**$/kW-month**	**$/kW-season**	**$/kW-season**	**$/kW-yr**	**$/kWh**	**$/kWh**	**$/kW-yr**	**$/kWh**	**$/kW-yr**	**$/kWh**
Comment 1:	Values are avoided costs at the generation plus transmission level. DSM savings should be measured at the generator plus transmission level. (Load plus + distribution losses)				Reflects Capacity Price resulting from LICAP beginning in 2006	Recovery of costs for RMR including continuing required payments after LICAP initiation		Avoided Cost applicable to KW savings contributing as supply side credit; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level			Avoided Cost applicable to KW savings at Summer Coincident Peak; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level	Avoided cost expressed in $/kWh at 100% load factor		Incremental to Avoided Cost at Summer Coincident Peak	Expressed in $/kWh at 100% load factor	DRIPE 0.75% measured assuming 10% of supply resources transact in spot market	Expressed in $/kWh at 100% load factor
Comment 2:					info	info	June/July/August	Average for 1 month savings	Average for Summer Season	Average for Winter Season	June / July / August			DRIPE measured at 0.75% peak savings are across all of New England. Values		DRIPE LIGHT measured at 0.75% peak savings are across all of New England.	
Period:							3-5 pm		June, July, August	Jan-May;Sept-Dec	3-5 pm						
2005 [2]	0.077	0.064	0.074	0.052	2.662	0.954	3.616	0.222	0.624	0.124	3.616	0.000	0.000	0.00	0.000	0.00	0.000
2006	0.088	0.072	0.081	0.061	34.548	1.801	36.350	2.879	8.102	1.607	36.350	0.004	0.004	654.43	0.075	32.57	0.004
2007	0.090	0.074	0.085	0.062	39.132	2.151	41.283	3.261	9.176	1.820	41.283	0.004	0.005	906.91	0.104	88.60	0.010
2008	0.076	0.060	0.073	0.051	62.436	0.199	62.635	5.203	14.641	2.903	62.635	0.007	0.007	32.87	0.004	15.28	0.002
2009	0.062	0.049	0.058	0.040	66.758	0.204	66.962	5.563	15.655	3.104	66.962	0.008	0.008	357.68	0.041	9.62	0.001
2010	0.053	0.042	0.050	0.035	69.696	0.177	69.874	5.808	16.344	3.241	69.874	0.008	0.008	266.06	0.030	(6.87)	(0.001)
2011	0.055	0.044	0.051	0.037	72.764	0.154	72.918	6.064	17.063	3.384	72.918	0.008	0.008	174.43	0.020	(23.35)	(0.003)
2012	0.056	0.046	0.052	0.038	75.967	0.133	76.100	6.331	17.814	3.532	76.100	0.009	0.009	82.81	0.009	(39.84)	(0.005)
2013	0.057	0.046	0.053	0.039	76.270	0.000	76.270	6.356	17.885	3.547	76.270	0.009	0.009	119.16	0.014	(21.08)	(0.002)
2014	0.057	0.047	0.053	0.039	76.575	0.000	76.575	6.381	17.957	3.561	76.575	0.009	0.009	155.52	0.018	(2.33)	(0.000)
2015	0.058	0.047	0.054	0.040	76.881	0.000	76.881	6.407	18.029	3.575	76.881	0.009	0.009	191.87	0.022	16.43	0.002
2016	0.058	0.048	0.055	0.040	77.188	0.000	77.188	6.432	18.101	3.589	77.188	0.009	0.009	228.22	0.026	35.18	0.004
2017	0.060	0.049	0.057	0.042	76.704	0.000	76.704	6.392	17.987	3.567	76.704	0.009	0.009	258.99	0.030	36.72	0.004
2018	0.062	0.051	0.059	0.044	76.222	0.000	76.222	6.352	17.874	3.544	76.222	0.009	0.009	289.75	0.033	38.26	0.004
2019	0.064	0.053	0.061	0.046	75.743	0.000	75.743	6.312	17.762	3.522	75.743	0.009	0.009	320.52	0.037	39.80	0.005
2020	0.065	0.055	0.064	0.048	75.267	0.000	75.267	6.272	17.650	3.500	75.267	0.009	0.009	351.29	0.040	41.34	0.005
2021	0.066	0.055	0.065	0.049	75.613	0.000	75.613	6.301	17.731	3.516	75.613	0.009	0.009	328.09	0.037	35.34	0.004
2022	0.067	0.056	0.066	0.049	75.960	0.000	75.960	6.330	17.813	3.532	75.960	0.009	0.009	304.90	0.035	29.34	0.003
2023	0.068	0.056	0.066	0.050	76.309	0.000	76.309	6.359	17.894	3.548	76.309	0.009	0.009	281.70	0.032	23.34	0.003
2024	0.068	0.057	0.067	0.051	76.660	0.000	76.660	6.388	17.977	3.565	76.660	0.009	0.009	258.50	0.030	17.35	0.002
2025	0.069	0.058	0.068	0.051	77.012	0.000	77.012	6.418	18.059	3.581	77.012	0.009	0.009	235.31	0.027	11.35	0.001
2026	0.070	0.058	0.069	0.052	77.365	0.000	77.365	6.447	18.142	3.597	77.365	0.009	0.009	212.11	0.024	5.35	0.001
2027	0.071	0.059	0.070	0.053	77.721	0.000	77.721	6.477	18.225	3.614	77.721	0.009	0.009	188.91	0.022	(0.65)	(0.000)
2028	0.071	0.059	0.071	0.054	78.078	0.000	78.078	6.506	18.309	3.631	78.078	0.009	0.009	165.72	0.019	(6.65)	(0.001)
2029	0.072	0.060	0.072	0.054	78.436	0.000	78.436	6.536	18.393	3.647	78.436	0.009	0.009	142.52	0.016	(12.64)	(0.001)
2030	0.073	0.061	0.073	0.055	78.796	0.000	78.796	6.566	18.478	3.664	78.796	0.009	0.009	119.32	0.014	(18.64)	(0.002)
2031	0.073	0.060	0.073	0.055	72.952	0.000	72.952	6.079	17.107	3.392	72.952	0.008	0.008	109.42	0.012	(18.43)	(0.002)
2032	0.073	0.060	0.073	0.055	67.541	0.000	67.541	5.628	15.838	3.141	67.541	0.008	0.008	99.52	0.011	(18.22)	(0.002)
2033	0.073	0.060	0.074	0.054	62.531	0.000	62.531	5.211	14.664	2.908	62.531	0.007	0.007	89.62	0.010	(18.01)	(0.002)
2034	0.073	0.060	0.074	0.054	57.893	0.000	57.893	4.824	13.576	2.692	57.893	0.007	0.007	79.72	0.009	(17.80)	(0.002)
2035	0.073	0.060	0.075	0.054	53.599	0.000	53.599	4.467	12.569	2.492	53.599	0.006	0.006	69.82	0.008	(17.59)	(0.002)
2036	0.073	0.060	0.075	0.054	49.623	0.000	49.623	4.135	11.637	2.307	49.623	0.006	0.006	59.92	0.007	(17.38)	(0.002)
2037	0.073	0.059	0.075	0.054	45.943	0.000	45.943	3.829	10.774	2.136	45.943	0.005	0.005	50.02	0.006	(17.17)	(0.002)
2038	0.073	0.059	0.076	0.053	42.535	0.000	42.535	3.545	9.974	1.978	42.535	0.005	0.005	40.12	0.005	(16.96)	(0.002)
2039	0.073	0.059	0.076	0.053	39.380	0.000	39.380	3.282	9.235	1.831	39.380	0.004	0.004	30.22	0.003	(16.75)	(0.002)
2040	0.073	0.059	0.076	0.053	36.459	0.000	36.459	3.038	8.550	1.695	36.459	0.004	0.004	20.32	0.002	(16.54)	(0.002)
Levelized[3]:																	
2005-2040	0.068	0.056	0.066	0.049	64.742	0.215	64.957	5.395	15.182	3.010	64.957	0.007	0.007	220.657	0.025	7.200	0.001
2006-2040	0.068	0.056	0.066	0.048	67.237	0.186	67.422	5.603	15.767	3.127	67.422	0.008	0.008	229.525	0.026	7.489	0.001
2006-2010	0.074	0.060	0.070	0.050	54.120	0.927	55.047	4.510	12.691	2.517	55.047	0.006	0.006	448.938	0.051	28.472	0.003
2006-2015	0.066	0.053	0.062	0.045	64.347	0.515	64.862	5.362	15.089	2.992	64.862	0.007	0.007	304.283	0.035	8.063	0.001
2006-2020	0.065	0.053	0.061	0.044	67.922	0.360	68.282	5.660	15.928	3.158	68.282	0.008	0.008	299.546	0.034	17.117	0.002

Exhibit A2-5. Electric Energy Avoided Costs by RTEP Zone (continued)

	Rest of Connecticut (RTEP / LICAP)																
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value[1]	Annual Out of Market Expense	Total Annual Capacity Value	Capacity Value Load Response (at any month)	Avoidable Capacity Payment Load Response (Summer Season)	Avoidable Capacity Payment Load Response (Winter Season)	Avoidable Capacity Payment of Energy Efficiency at Summer Coincident Peak	Load Response (at any month)	Energy Efficiency at Summer Coincident Peak	DRIPE 0.75% Capacity Price	DRIPE 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price
Units:	**$/kWh**	**$/kWh**	**$/kWh**	**$/kWh**	**$/kW-yr**	**$/kW-yr**	**$/kW-yr**	**$/kW-month**	**$/kW-season**	**$/kW-season**	**$/kW-yr**	**$/kWh**	**$/kWh**	**$/kW-yr**	**$/kWh**	**$/kW-yr**	**$/kWh**
Comment 1:	Values are avoided costs at the generation plus transmission level. DSM savings should be measured at the generator plus transmission level. (Load plus + distribution losses)				Reflects Capacity Price resulting from LICAP beginning in 2006	Recovery of costs for RMR including continuing required payments after LICAP initiation		Avoided Cost applicable to KW savings contributing as supply side credit; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level			Avoided Cost applicable to KW savings at Summer Coincident Peak; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level	Avoided cost expressed in $/kWh at 100% load factor		Incremental to Avoided Cost at Summer Coincident Peak	Expressed in $/kWh at 100% load factor	DRIPE 0.75% measured assuming 10% of supply resources transact in spot market	Expressed in $/kWh at 100% load factor
Comment 2:					info	info	June/July/August	Average for 1 month savings	Average for Summer Season	Average for Winter Season	June / July / August			DRIPE measured at 0.75% peak savings are across all of New England. Values are		DRIPE LIGHT measured at 0.75% peak savings are across all of New England.	
Period:							3-5 pm		June, July, August	Jan-May;Sept-Dec	3-5 pm						
2005[2]	0.080	0.065	0.081	0.054	5.377	8.265	13.642	0.448	1.261	0.250	13.642	0.001	0.002	0.00	0.000	0.00	0.000
2006	0.093	0.074	0.093	0.063	47.881	0.000	47.881	3.990	11.228	2.226	47.881	0.005	0.005	171.25	0.025	234.47	0.027
2007	0.098	0.076	0.095	0.064	50.951	0.000	50.951	4.246	11.948	2.369	50.951	0.006	0.006	12.61	0.007	239.13	0.027
2008	0.078	0.062	0.075	0.052	63.709	0.000	63.709	5.309	14.940	2.962	63.709	0.007	0.007	(5.29)	0.007	204.86	0.023
2009	0.064	0.050	0.060	0.041	68.126	0.000	68.126	5.677	15.976	3.168	68.126	0.008	0.008	408.59	0.054	226.52	0.026
2010	0.055	0.043	0.051	0.036	71.124	0.000	71.124	5.927	16.679	3.307	71.124	0.008	0.008	328.38	0.046	192.60	0.022
2011	0.056	0.044	0.052	0.037	74.254	0.000	74.254	6.188	17.413	3.453	74.254	0.008	0.008	248.18	0.037	158.68	0.018
2012	0.058	0.046	0.053	0.039	77.523	0.000	77.523	6.460	18.179	3.605	77.523	0.009	0.009	167.97	0.028	124.76	0.014
2013	0.058	0.046	0.054	0.039	77.831	0.000	77.831	6.486	18.251	3.619	77.831	0.009	0.009	190.34	0.031	97.20	0.011
2014	0.058	0.046	0.054	0.039	78.141	0.000	78.141	6.512	18.324	3.634	78.141	0.009	0.009	212.71	0.033	69.65	0.008
2015	0.059	0.047	0.055	0.040	78.453	0.000	78.453	6.538	18.397	3.648	78.453	0.009	0.009	235.08	0.036	42.09	0.005
2016	0.059	0.047	0.055	0.040	78.765	0.000	78.765	6.564	18.470	3.663	78.765	0.009	0.009	257.45	0.038	14.53	0.002
2017	0.061	0.049	0.057	0.042	77.965	0.000	77.965	6.497	18.283	3.625	77.965	0.009	0.009	252.98	0.038	13.44	0.002
2018	0.063	0.050	0.060	0.044	77.172	0.000	77.172	6.431	18.097	3.589	77.172	0.009	0.009	248.52	0.037	12.35	0.001
2019	0.064	0.052	0.062	0.045	76.388	0.000	76.388	6.366	17.913	3.552	76.388	0.009	0.009	244.05	0.037	11.26	0.001
2020	0.066	0.054	0.064	0.047	75.612	0.000	75.612	6.301	17.731	3.516	75.612	0.009	0.009	239.59	0.036	10.18	0.001
2021	0.067	0.055	0.065	0.048	75.771	0.000	75.771	6.314	17.768	3.523	75.771	0.009	0.009	233.15	0.035	4.58	0.001
2022	0.068	0.055	0.066	0.049	75.931	0.000	75.931	6.328	17.806	3.531	75.931	0.009	0.009	226.71	0.035	(1.02)	(0.000)
2023	0.068	0.056	0.067	0.049	76.091	0.000	76.091	6.341	17.843	3.538	76.091	0.009	0.009	220.28	0.034	(6.61)	(0.001)
2024	0.069	0.056	0.068	0.050	76.251	0.000	76.251	6.354	17.881	3.546	76.251	0.009	0.009	213.84	0.033	(12.21)	(0.001)
2025	0.070	0.057	0.068	0.050	76.412	0.000	76.412	6.368	17.919	3.553	76.412	0.009	0.009	207.40	0.032	(17.81)	(0.002)
2026	0.070	0.057	0.069	0.051	76.573	0.000	76.573	6.381	17.956	3.561	76.573	0.009	0.009	200.97	0.032	(23.40)	(0.003)
2027	0.071	0.058	0.070	0.052	76.734	0.000	76.734	6.394	17.994	3.568	76.734	0.009	0.009	194.53	0.031	(29.00)	(0.003)
2028	0.072	0.058	0.071	0.052	76.895	0.000	76.895	6.408	18.032	3.576	76.895	0.009	0.009	188.09	0.030	(34.59)	(0.004)
2029	0.072	0.059	0.072	0.053	77.057	0.000	77.057	6.421	18.070	3.583	77.057	0.009	0.009	181.66	0.030	(40.19)	(0.005)
2030	0.073	0.059	0.072	0.054	77.220	0.000	77.220	6.435	18.108	3.591	77.220	0.009	0.009	175.22	0.029	(45.79)	(0.005)
2031	0.073	0.059	0.073	0.053	71.490	0.000	71.490	5.957	16.764	3.324	71.490	0.008	0.008	162.05	0.027	(43.76)	(0.005)
2032	0.073	0.059	0.073	0.053	66.185	0.000	66.185	5.515	15.520	3.078	66.185	0.008	0.008	148.87	0.025	(41.73)	(0.005)
2033	0.073	0.059	0.074	0.053	61.274	0.000	61.274	5.106	14.369	2.849	61.274	0.007	0.007	135.70	0.023	(39.70)	(0.005)
2034	0.073	0.059	0.074	0.053	56.727	0.000	56.727	4.727	13.303	2.638	56.727	0.006	0.006	122.52	0.021	(37.67)	(0.004)
2035	0.073	0.059	0.074	0.053	52.518	0.000	52.518	4.376	12.315	2.442	52.518	0.006	0.006	109.35	0.019	(35.64)	(0.004)
2036	0.073	0.058	0.075	0.053	48.621	0.000	48.621	4.052	11.402	2.261	48.621	0.006	0.006	96.18	0.017	(33.61)	(0.004)
2037	0.073	0.058	0.075	0.053	45.013	0.000	45.013	3.751	10.556	2.093	45.013	0.005	0.005	83.00	0.015	(31.58)	(0.004)
2038	0.073	0.058	0.076	0.052	41.673	0.000	41.673	3.473	9.772	1.938	41.673	0.005	0.005	69.83	0.013	(29.55)	(0.003)
2039	0.073	0.058	0.076	0.052	38.581	0.000	38.581	3.215	9.047	1.794	38.581	0.004	0.004	56.66	0.011	(27.52)	(0.003)
2040	0.072	0.058	0.076	0.052	35.718	0.000	35.718	2.976	8.376	1.661	35.718	0.004	0.004	43.48	0.009	(25.49)	(0.003)
Levelized[3]:																	
2005-2040	0.069	0.056	0.068	0.048	65.936	0.319	66.255	5.495	15.462	3.066	66.255	0.008	0.008	179.123	0.028	45.882	0.005
2006-2040	0.069	0.055	0.067	0.048	68.370	0.000	68.370	5.698	16.033	3.179	68.370	0.008	0.008	186.322	0.029	47.726	0.005
2006-2010	0.078	0.061	0.075	0.051	60.102	0.000	60.102	5.009	14.094	2.795	60.102	0.007	0.007	180.277	0.027	219.903	0.025
2006-2015	0.068	0.054	0.065	0.046	68.224	0.000	68.224	5.685	15.998	3.172	68.224	0.008	0.008	194.768	0.030	162.788	0.019
2006-2020	0.067	0.053	0.063	0.045	70.924	0.000	70.924	5.910	16.632	3.298	70.924	0.008	0.008	210.970	0.032	117.602	0.013

Exhibit A2-5. Electric Energy Avoided Costs by RTEP Zone (continued)

	Southwest Connecticut																
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value[1]	Annual Out of Market Expense	Total Annual Capacity Value	Capacity Value Load Response (at any month)	Avoidable Capacity Payment Load Response (Summer Season)	Avoidable Capacity Payment Load Response (Winter Season)	Avoidable Capacity Payment of Energy Efficiency at Summer Coincident Peak	Load Response (at any month)	Energy Efficiency at Summer Coincident Peak	DRIPE 0.75% Capacity Price	DRIPE 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price
Units:	**$/kWh**	**$/kWh**	**$/kWh**	**$/kWh**	**$/kW-yr**	**$/kW-yr**	**$/kW-yr**	**$/kW-month**	**$/kW-season**	**$/kW-season**	**$/kW-yr**	**$/kWh**	**$/kWh**	**$/kW-yr**	**$/kWh**	**$/kW-yr**	**$/kWh**
Comment 1:	Values are avoided costs at the generation plus transmission level. DSM savings should be measured at the generator plus transmission level. (Load plus + distribution losses)				Reflects Capacity Price resulting from LICAP beginning in 2006	Recovery of costs for RMR including continuing required payments after LICAP initiation		Avoided Cost applicable to KW savings contributing as supply side credit; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level			Avoided Cost applicable to KW savings at Summer Coincident Peak; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level	Avoided cost expressed in $/kWh at 100% load factor		Incremental to Avoided Cost at Summer Coincident Peak	Expressed in $/kWh at 100% load factor	DRIPE 0.75% measured assuming 10% of supply resources transact in spot market	Expressed in $/kWh at 100% load factor
Comment 2:					info	info	June/July/August	Average for 1 month savings	Average for Summer Season	Average for Winter Season	June / July / August			DRIPE measured at 0.75% peak savings are across all of New England. Values are		DRIPE LIGHT measured at 0.75% peak savings are across all of New England.	
Period:							3-5 pm		June, July, August	Jan-May;Sept-Dec	3-5 pm						
2005[2]	0.081	0.066	0.083	0.055	3.351	23.505	26.856	0.279	0.786	0.156	26.856	0.000	0.003	0.00	0.000	0.00	0.000
2006	0.095	0.076	0.095	0.064	44.207	3.733	47.940	3.684	10.367	2.056	47.940	0.005	0.005	273.51	0.037	(14.21)	(0.002)
2007	0.100	0.078	0.097	0.065	50.237	1.226	51.463	4.186	11.781	2.336	51.463	0.006	0.006	(2.77)	0.006	(2.77)	(0.000)
2008	0.080	0.063	0.077	0.053	66.341	0.000	66.341	5.528	15.557	3.085	66.341	0.008	0.008	(34.01)	0.004	(63.11)	(0.007)
2009	0.065	0.051	0.061	0.042	70.934	0.000	70.934	5.911	16.634	3.298	70.934	0.008	0.008	337.05	0.047	(30.14)	(0.003)
2010	0.056	0.044	0.052	0.036	73.561	0.000	73.561	6.130	17.250	3.421	73.561	0.008	0.008	156.01	0.026	(141.89)	(0.016)
2011	0.057	0.045	0.053	0.038	76.285	0.000	76.285	6.357	17.889	3.547	76.285	0.009	0.009	(25.03)	0.006	(253.65)	(0.029)
2012	0.059	0.046	0.054	0.039	79.110	0.000	79.110	6.592	18.551	3.679	79.110	0.009	0.009	(206.08)	(0.014)	(365.40)	(0.042)
2013	0.059	0.047	0.054	0.039	79.424	0.000	79.424	6.619	18.625	3.693	79.424	0.009	0.009	(145.52)	(0.008)	(321.89)	(0.037)
2014	0.059	0.047	0.055	0.040	79.739	0.000	79.739	6.645	18.699	3.708	79.739	0.009	0.009	(84.97)	(0.001)	(278.38)	(0.032)
2015	0.060	0.047	0.055	0.040	80.055	0.000	80.055	6.671	18.773	3.723	80.055	0.009	0.009	(24.42)	0.006	(234.87)	(0.027)
2016	0.060	0.047	0.056	0.040	80.373	0.000	80.373	6.698	18.847	3.737	80.373	0.009	0.009	36.13	0.013	(191.36)	(0.022)
2017	0.061	0.049	0.058	0.042	79.557	0.000	79.557	6.630	18.656	3.699	79.557	0.009	0.009	73.89	0.018	(154.61)	(0.018)
2018	0.063	0.051	0.060	0.044	78.749	0.000	78.749	6.562	18.467	3.662	78.749	0.009	0.009	111.65	0.022	(117.86)	(0.013)
2019	0.065	0.053	0.063	0.046	77.949	0.000	77.949	6.496	18.279	3.625	77.949	0.009	0.009	149.42	0.026	(81.11)	(0.009)
2020	0.067	0.055	0.065	0.048	77.157	0.000	77.157	6.430	18.093	3.588	77.157	0.009	0.009	187.18	0.030	(44.36)	(0.005)
2021	0.067	0.055	0.066	0.048	77.319	0.000	77.319	6.443	18.131	3.595	77.319	0.009	0.009	170.53	0.028	(54.49)	(0.006)
2022	0.068	0.056	0.066	0.049	77.482	0.000	77.482	6.457	18.170	3.603	77.482	0.009	0.009	153.88	0.026	(64.62)	(0.007)
2023	0.069	0.056	0.067	0.049	77.645	0.000	77.645	6.470	18.208	3.611	77.645	0.009	0.009	137.23	0.025	(74.75)	(0.009)
2024	0.069	0.057	0.068	0.050	77.809	0.000	77.809	6.484	18.246	3.618	77.809	0.009	0.009	120.57	0.023	(84.88)	(0.010)
2025	0.070	0.057	0.069	0.051	77.972	0.000	77.972	6.498	18.285	3.626	77.972	0.009	0.009	103.92	0.021	(95.01)	(0.011)
2026	0.070	0.058	0.069	0.051	78.137	0.000	78.137	6.511	18.323	3.633	78.137	0.009	0.009	87.27	0.019	(105.14)	(0.012)
2027	0.071	0.059	0.070	0.052	78.301	0.000	78.301	6.525	18.362	3.641	78.301	0.009	0.009	70.62	0.017	(115.27)	(0.013)
2028	0.072	0.059	0.071	0.052	78.466	0.000	78.466	6.539	18.400	3.649	78.466	0.009	0.009	53.97	0.015	(125.41)	(0.014)
2029	0.072	0.060	0.072	0.053	78.631	0.000	78.631	6.553	18.439	3.656	78.631	0.009	0.009	37.31	0.013	(135.54)	(0.015)
2030	0.073	0.060	0.072	0.054	78.796	0.000	78.796	6.566	18.478	3.664	78.796	0.009	0.009	20.66	0.011	(145.67)	(0.017)
2031	0.073	0.060	0.073	0.054	72.952	0.000	72.952	6.079	17.107	3.392	72.952	0.008	0.008	16.27	0.010	(137.72)	(0.016)
2032	0.073	0.060	0.073	0.054	67.541	0.000	67.541	5.628	15.838	3.141	67.541	0.008	0.008	11.88	0.009	(129.78)	(0.015)
2033	0.073	0.060	0.074	0.054	62.531	0.000	62.531	5.211	14.664	2.908	62.531	0.007	0.007	7.50	0.008	(121.83)	(0.014)
2034	0.073	0.060	0.075	0.054	57.893	0.000	57.893	4.824	13.576	2.692	57.893	0.007	0.007	3.11	0.007	(113.88)	(0.013)
2035	0.073	0.060	0.075	0.054	53.599	0.000	53.599	4.467	12.569	2.492	53.599	0.006	0.006	(1.28)	0.006	(105.94)	(0.012)
2036	0.073	0.060	0.076	0.053	49.623	0.000	49.623	4.135	11.637	2.307	49.623	0.006	0.006	(5.67)	0.005	(97.99)	(0.011)
2037	0.074	0.059	0.076	0.053	45.943	0.000	45.943	3.829	10.774	2.136	45.943	0.005	0.005	(10.06)	0.004	(90.05)	(0.010)
2038	0.074	0.059	0.077	0.053	42.535	0.000	42.535	3.545	9.974	1.978	42.535	0.005	0.005	(14.45)	0.003	(82.10)	(0.009)
2039	0.074	0.059	0.077	0.053	39.380	0.000	39.380	3.282	9.235	1.831	39.380	0.004	0.004	(18.84)	0.002	(74.15)	(0.008)
2040	0.074	0.059	0.078	0.053	36.459	0.000	36.459	3.038	8.550	1.695	36.459	0.004	0.004	(23.23)	0.002	(66.21)	(0.008)
Levelized[3]**:**																	
2005-2040	0.070	0.056	0.069	0.049	67.112	1.095	68.207	5.593	15.738	3.121	68.207	0.008	0.008	51.439	0.014	-121.550	-0.014
2006-2040	0.070	0.056	0.068	0.049	69.674	0.194	69.869	5.806	16.339	3.240	69.869	0.008	0.008	53.507	0.014	-126.435	-0.014
2006-2010	0.079	0.063	0.077	0.053	60.736	1.027	61.763	5.061	14.243	2.824	61.763	0.007	0.007	145.560	0.024	-49.293	-0.006
2006-2015	0.070	0.055	0.066	0.046	69.357	0.539	69.896	5.780	16.264	3.225	69.896	0.008	0.008	30.046	0.011	-164.235	-0.019
2006-2020	0.068	0.054	0.064	0.045	72.191	0.377	72.568	6.016	16.929	3.357	72.568	0.008	0.008	54.110	0.014	-150.744	-0.017

Exhibit A2-5. Electric Energy Avoided Costs by RTEP Zone (continued)

	Norwalk (RTEP)																
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value[1]	Annual Out of Market Expense	Total Annual Capacity Value	Capacity Value Load Response (at any month)	Avoidable Capacity Payment Load Response (Summer Season)	Avoidable Capacity Payment Load Response (Winter Season)	Avoidable Capacity Payment of Energy Efficiency at Summer Coincident Peak	Load Response (at any month)	Energy Efficiency at Summer Coincident Peak	DRIPE 0.75% Capacity Price	DRIPE 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-month	$/kW-season	$/kW-season	$/kW-yr	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kW-yr	$/kWh
Comment 1:	Values are avoided costs at the generation plus transmission level. DSM savings should be measured at the generator plus transmission level. (Load plus + distribution losses)				Reflects Capacity Price resulting from LICAP beginning in 2006	Recovery of costs for RMR including continuing required payments after LICAP initiation		Avoided Cost applicable to KW savings contributing as supply side credit; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level			Avoided Cost applicable to KW savings at Summer Coincident Peak; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level	Avoided cost expressed in $/kWh at 100% load factor		Incremental to Avoided Cost at Summer Coincident Peak	Expressed in $/kWh at 100% load factor	DRIPE 0.75% measured assuming 10% of supply resources transact in spot market	Expressed in $/kWh at 100% load factor
Comment 2:					info	info	June/July/August	Average for 1 month savings	Average for Summer Season	Average for Winter Season	June / July / August			DRIPE measured at 0.75% peak savings are across all of New England. Values are		DRIPE LIGHT measured at 0.75% peak savings are across all of New England.	
Period:							3-5 pm		June, July, August	Jan-May;Sept-Dec	3-5 pm						
2005[2]	0.083	0.068	0.085	0.056	16.785	10.071	26.856	1.399	3.936	0.781	26.856	0.002	0.003	0.00	0.000	0.00	0.000
2006	0.097	0.077	0.097	0.065	57.244	14.667	71.911	4.770	13.424	2.662	71.911	0.007	0.008	728.50	0.083	682.02	0.078
2007	0.102	0.079	0.099	0.067	55.163	14.312	69.475	4.597	12.936	2.565	69.475	0.006	0.008	675.20	0.077	675.20	0.077
2008	0.082	0.064	0.078	0.054	66.341	5.035	71.376	5.528	15.557	3.085	71.376	0.008	0.008	694.41	0.079	688.20	0.079
2009	0.067	0.052	0.062	0.043	70.934	4.889	75.824	5.911	16.634	3.298	75.824	0.008	0.009	775.44	0.089	690.24	0.079
2010	0.057	0.044	0.053	0.037	73.561	4.645	78.206	6.130	17.250	3.421	78.206	0.008	0.009	892.50	0.102	797.97	0.091
2011	0.058	0.045	0.054	0.038	76.285	4.412	80.697	6.357	17.889	3.547	80.697	0.009	0.009	1,009.57	0.115	905.70	0.103
2012	0.060	0.046	0.055	0.039	79.110	4.192	83.301	6.592	18.551	3.679	83.301	0.009	0.010	1,126.63	0.129	1,013.42	0.116
2013	0.060	0.046	0.055	0.039	79.424	0.000	79.424	6.619	18.625	3.693	79.424	0.009	0.009	994.56	0.114	857.38	0.098
2014	0.060	0.046	0.056	0.039	79.739	0.000	79.739	6.645	18.699	3.708	79.739	0.009	0.009	862.48	0.098	701.33	0.080
2015	0.060	0.046	0.056	0.039	80.055	0.000	80.055	6.671	18.773	3.723	80.055	0.009	0.009	730.41	0.083	545.28	0.062
2016	0.061	0.047	0.056	0.039	80.373	0.000	80.373	6.698	18.847	3.737	80.373	0.009	0.009	598.33	0.068	389.24	0.044
2017	0.062	0.048	0.058	0.041	79.557	0.000	79.557	6.630	18.656	3.699	79.557	0.009	0.009	518.84	0.059	319.39	0.036
2018	0.064	0.050	0.061	0.043	78.749	0.000	78.749	6.562	18.467	3.662	78.749	0.009	0.009	439.34	0.050	249.54	0.028
2019	0.066	0.052	0.063	0.045	77.949	0.000	77.949	6.496	18.279	3.625	77.949	0.009	0.009	359.84	0.041	179.69	0.021
2020	0.068	0.054	0.066	0.047	77.157	0.000	77.157	6.430	18.093	3.588	77.157	0.009	0.009	280.35	0.032	109.85	0.013
2021	0.068	0.054	0.066	0.047	77.319	0.000	77.319	6.443	18.131	3.595	77.319	0.009	0.009	278.00	0.032	112.75	0.013
2022	0.069	0.055	0.067	0.048	77.482	0.000	77.482	6.457	18.170	3.603	77.482	0.009	0.009	275.66	0.031	115.66	0.013
2023	0.069	0.056	0.068	0.049	77.645	0.000	77.645	6.470	18.208	3.611	77.645	0.009	0.009	273.32	0.031	118.57	0.014
2024	0.070	0.056	0.069	0.049	77.809	0.000	77.809	6.484	18.246	3.618	77.809	0.009	0.009	270.97	0.031	121.48	0.014
2025	0.070	0.057	0.069	0.050	77.972	0.000	77.972	6.498	18.285	3.626	77.972	0.009	0.009	268.63	0.031	124.39	0.014
2026	0.071	0.057	0.070	0.051	78.137	0.000	78.137	6.511	18.323	3.633	78.137	0.009	0.009	266.29	0.030	127.30	0.015
2027	0.072	0.058	0.071	0.051	78.301	0.000	78.301	6.525	18.362	3.641	78.301	0.009	0.009	263.94	0.030	130.21	0.015
2028	0.072	0.059	0.072	0.052	78.466	0.000	78.466	6.539	18.400	3.649	78.466	0.009	0.009	261.60	0.030	133.12	0.015
2029	0.073	0.059	0.072	0.053	78.631	0.000	78.631	6.553	18.439	3.656	78.631	0.009	0.009	259.26	0.030	136.03	0.016
2030	0.073	0.060	0.073	0.053	78.796	0.000	78.796	6.566	18.478	3.664	78.796	0.009	0.009	256.91	0.029	138.93	0.016
2031	0.074	0.060	0.074	0.053	72.952	0.000	72.952	6.079	17.107	3.392	72.952	0.008	0.008	239.38	0.027	130.11	0.015
2032	0.074	0.060	0.074	0.053	67.541	0.000	67.541	5.628	15.838	3.141	67.541	0.008	0.008	221.84	0.025	121.29	0.014
2033	0.074	0.060	0.075	0.053	62.531	0.000	62.531	5.211	14.664	2.908	62.531	0.007	0.007	204.31	0.023	112.47	0.013
2034	0.074	0.059	0.075	0.053	57.893	0.000	57.893	4.824	13.576	2.692	57.893	0.007	0.007	186.78	0.021	103.65	0.012
2035	0.074	0.059	0.076	0.053	53.599	0.000	53.599	4.467	12.569	2.492	53.599	0.006	0.006	169.24	0.019	94.83	0.011
2036	0.074	0.059	0.076	0.053	49.623	0.000	49.623	4.135	11.637	2.307	49.623	0.006	0.006	151.71	0.017	86.01	0.010
2037	0.074	0.059	0.077	0.053	45.943	0.000	45.943	3.829	10.774	2.136	45.943	0.005	0.005	134.17	0.015	77.19	0.009
2038	0.074	0.059	0.078	0.053	42.535	0.000	42.535	3.545	9.974	1.978	42.535	0.005	0.005	116.64	0.013	68.37	0.008
2039	0.074	0.059	0.078	0.053	39.380	0.000	39.380	3.282	9.235	1.831	39.380	0.004	0.004	99.11	0.011	59.54	0.007
2040	0.074	0.059	0.079	0.053	36.459	0.000	36.459	3.038	8.550	1.695	36.459	0.004	0.004	81.57	0.009	50.72	0.006
Levelized[3]:																	
2005-2040	0.071	0.056	0.069	0.049	68.307	2.287	70.595	5.692	16.018	3.176	70.595	0.008	0.008	461.530	0.053	350.465	0.040
2006-2040	0.070	0.056	0.069	0.048	70.378	1.975	72.353	5.865	16.504	3.273	72.353	0.008	0.008	480.080	0.055	364.550	0.042
2006-2010	0.081	0.064	0.078	0.054	64.454	8.828	73.283	5.371	15.115	2.997	73.283	0.007	0.008	751.504	0.086	705.744	0.081
2006-2015	0.071	0.055	0.067	0.047	71.309	5.478	76.787	5.942	16.722	3.316	76.787	0.008	0.009	844.828	0.096	754.662	0.086
2006-2020	0.069	0.054	0.065	0.045	73.557	3.832	77.389	6.130	17.249	3.420	77.389	0.008	0.009	723.957	0.083	603.740	0.069

Exhibit A2-6. Electric Energy Avoided Costs by Other Zones

	Rest of Connecticut (includes SWCT and ROC RTEP zones)																
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value[1]	Annual Out of Market Expense	Total Annual Capacity Value	Capacity Value at Load Response (at any month)	Avoidable Capacity Payment at Load Response (Summer Season)	Avoidable Capacity Payment at Load Response (Winter Season)	Avoidable Capacity Payment at Energy Efficiency at Summer Coincident Peak	Load Response (at any month)	Energy Efficiency at Summer Coincident Peak	DRIPE 0.75% Capacity Price	DRIPE 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-month	$/kW-season	$/kW-season	$/kW-yr	$/kWh	$/kWh	$/kW	$/kWh	$/kW	$/kWh
Comment 1:	Values are avoided costs at the generation plus transmission level. DSM savings should be measured at the generator plus transmission level. (Load plus + distribution losses)				Reflects Capacity Price resulting from LICAP beginning in 2006	Recovery of costs for RMR including continuing required payments after LICAP initiation		Avoided Cost applicable to KW savings contributing as supply side credit; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level			Avoided Cost applicable to KW savings at Summer Coincident Peak; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level	Avoided cost expressed in $/kWh at 100% load factor		Incremental to Avoided Cost at Summer Coincident Peak	Expressed in $/kWh at 100% load factor	Incremental to Avoided Cost at Summer Coincident Peak; Assumes 10% of supply resources transact in spot market	Expressed in $/kWh at 100% load factor
Comment 2:					info	info	June / July / August	Average for 1 month savings	Average for Summer Season	Average for Winter Season	June / July / August			DRIPE measured at 0.75% peak savings are across all of New England. Values		DRIPE LIGHT measured at 0.75% peak savings are across all of New England.	
Period:							3-5 pm		June, July, August	Jan-May;Sept-Dec	3-5 pm						
2005[2]	0.081	0.066	0.082	0.054	4.572	14.317	18.889	0.381	1.072	0.213	18.889	0.001	0.002	0.00	0.000	0.00	0.000
2006	0.094	0.075	0.094	0.063	46.422	1.483	47.905	3.869	10.886	2.159	47.905	0.005	0.005	211.86	0.024	(21.30)	(0.002)
2007	0.098	0.077	0.096	0.065	50.667	0.487	51.154	4.222	11.882	2.356	51.154	0.006	0.006	6.50	0.001	6.50	0.001
2008	0.079	0.062	0.076	0.052	64.754	0.000	64.754	5.396	15.185	3.011	64.754	0.007	0.007	(16.69)	(0.002)	(39.97)	(0.005)
2009	0.064	0.050	0.060	0.042	69.241	0.000	69.241	5.770	16.237	3.220	69.241	0.008	0.008	380.18	0.043	(2.76)	(0.000)
2010	0.055	0.043	0.051	0.036	72.093	0.000	72.093	6.008	16.906	3.352	72.093	0.008	0.008	259.93	0.030	(44.29)	(0.005)
2011	0.057	0.045	0.052	0.038	75.062	0.000	75.062	6.255	17.602	3.490	75.062	0.009	0.009	139.68	0.016	(85.82)	(0.010)
2012	0.058	0.046	0.053	0.039	78.153	0.000	78.153	6.513	18.327	3.634	78.153	0.009	0.009	19.43	0.002	(127.35)	(0.015)
2013	0.058	0.046	0.054	0.039	78.464	0.000	78.464	6.539	18.400	3.649	78.464	0.009	0.009	56.96	0.007	(108.36)	(0.012)
2014	0.059	0.047	0.054	0.040	78.776	0.000	78.776	6.565	18.473	3.663	78.776	0.009	0.009	94.49	0.011	(89.37)	(0.010)
2015	0.059	0.047	0.055	0.040	79.089	0.000	79.089	6.591	18.546	3.678	79.089	0.009	0.009	132.02	0.015	(70.38)	(0.008)
2016	0.059	0.047	0.055	0.040	79.404	0.000	79.404	6.617	18.620	3.692	79.404	0.009	0.009	169.55	0.019	(51.39)	(0.006)
2017	0.061	0.049	0.058	0.042	78.597	0.000	78.597	6.550	18.431	3.655	78.597	0.009	0.009	181.86	0.021	(37.82)	(0.004)
2018	0.063	0.051	0.060	0.044	77.798	0.000	77.798	6.483	18.244	3.618	77.798	0.009	0.009	194.16	0.022	(24.26)	(0.003)
2019	0.065	0.052	0.062	0.045	77.008	0.000	77.008	6.417	18.058	3.581	77.008	0.009	0.009	206.47	0.024	(10.69)	(0.001)
2020	0.066	0.054	0.065	0.047	76.226	0.000	76.226	6.352	17.875	3.544	76.226	0.009	0.009	218.77	0.025	2.88	0.000
2021	0.067	0.055	0.065	0.048	76.386	0.000	76.386	6.366	17.913	3.552	76.386	0.009	0.009	208.28	0.024	(1.46)	(0.000)
2022	0.068	0.055	0.066	0.049	76.547	0.000	76.547	6.379	17.950	3.559	76.547	0.009	0.009	197.79	0.023	(5.79)	(0.001)
2023	0.068	0.056	0.067	0.049	76.708	0.000	76.708	6.392	17.988	3.567	76.708	0.009	0.009	187.29	0.021	(10.13)	(0.001)
2024	0.069	0.056	0.068	0.050	76.870	0.000	76.870	6.406	18.026	3.574	76.870	0.009	0.009	176.80	0.020	(14.46)	(0.002)
2025	0.070	0.057	0.068	0.050	77.031	0.000	77.031	6.419	18.064	3.582	77.031	0.009	0.009	166.31	0.019	(18.79)	(0.002)
2026	0.070	0.058	0.069	0.051	77.194	0.000	77.194	6.433	18.102	3.590	77.194	0.009	0.009	155.81	0.018	(23.13)	(0.003)
2027	0.071	0.058	0.070	0.052	77.356	0.000	77.356	6.446	18.140	3.597	77.356	0.009	0.009	145.32	0.017	(27.46)	(0.003)
2028	0.072	0.059	0.071	0.052	77.519	0.000	77.519	6.460	18.178	3.605	77.519	0.009	0.009	134.83	0.015	(31.80)	(0.004)
2029	0.072	0.059	0.072	0.053	77.682	0.000	77.682	6.474	18.216	3.612	77.682	0.009	0.009	124.33	0.014	(36.13)	(0.004)
2030	0.073	0.060	0.072	0.054	77.846	0.000	77.846	6.487	18.255	3.620	77.846	0.009	0.009	113.84	0.013	(40.46)	(0.005)
2031	0.073	0.060	0.073	0.054	72.070	0.000	72.070	6.006	16.901	3.351	72.070	0.008	0.008	104.16	0.012	(38.75)	(0.004)
2032	0.073	0.060	0.073	0.053	66.723	0.000	66.723	5.560	15.647	3.103	66.723	0.008	0.008	94.47	0.011	(37.04)	(0.004)
2033	0.073	0.059	0.074	0.053	61.773	0.000	61.773	5.148	14.486	2.872	61.773	0.007	0.007	84.79	0.010	(35.33)	(0.004)
2034	0.073	0.059	0.074	0.053	57.190	0.000	57.190	4.766	13.411	2.659	57.190	0.007	0.007	75.10	0.009	(33.62)	(0.004)
2035	0.073	0.059	0.075	0.053	52.947	0.000	52.947	4.412	12.416	2.462	52.947	0.006	0.006	65.42	0.007	(31.91)	(0.004)
2036	0.073	0.059	0.075	0.053	49.019	0.000	49.019	4.085	11.495	2.279	49.019	0.006	0.006	55.73	0.006	(30.20)	(0.003)
2037	0.073	0.059	0.076	0.053	45.382	0.000	45.382	3.782	10.642	2.110	45.382	0.005	0.005	46.04	0.005	(28.49)	(0.003)
2038	0.073	0.059	0.076	0.053	42.015	0.000	42.015	3.501	9.853	1.954	42.015	0.005	0.005	36.36	0.004	(26.78)	(0.003)
2039	0.073	0.058	0.077	0.053	38.898	0.000	38.898	3.242	9.122	1.809	38.898	0.004	0.004	26.67	0.003	(25.07)	(0.003)
2040	0.073	0.058	0.077	0.053	36.012	0.000	36.012	3.001	8.445	1.675	36.012	0.004	0.004	16.99	0.002	(23.35)	(0.003)
Levelized[3]:																	
2005-2040	0.070	0.056	0.068	0.049	66.403	0.627	67.031	5.534	15.572	3.088	67.031	0.008	0.008	128.416	0.015	-35.002	-0.004
2006-2040	0.069	0.056	0.067	0.048	68.888	0.077	68.965	5.741	16.154	3.203	68.965	0.008	0.008	133.577	0.015	-36.409	-0.004
2006-2010	0.079	0.062	0.076	0.052	60.354	0.408	60.762	5.030	14.153	2.806	60.762	0.007	0.007	166.491	0.019	-20.145	-0.002
2006-2015	0.069	0.054	0.065	0.046	68.674	0.214	68.888	5.723	16.104	3.193	68.888	0.008	0.008	129.352	0.015	-56.420	-0.006
2006-2020	0.067	0.053	0.064	0.045	71.427	0.150	71.577	5.952	16.750	3.321	71.577	0.008	0.008	148.676	0.017	-46.921	-0.005

Exhibit A2-6. Electric Energy Avoided Costs by Other Zones

	Central & Western Massachusetts																
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value[1]	Annual Out of Market Expense	Total Annual Capacity Value	Capacity Value at Load Response (at any month)	Avoidable Capacity Payment at Load Response (Summer Season)	Avoidable Capacity Payment at Load Response (Winter Season)	Avoidable Capacity Payment at Energy Efficiency at Summer Coincident Peak	Load Response (at any month)	Energy Efficiency at Summer Coincident Peak	DRIPE 0.75% Capacity Price	DRIPE 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-month	$/kW-season	$/kW-season	$/kW-yr	$/kWh	$/kWh	$/kW	$/kWh	$/kW	$/kWh
Comment 1:	Values are avoided costs at the generation plus transmission level. DSM savings should be measured at the generator plus transmission level. (Load plus + distribution losses)				Reflects Capacity Price resulting from LICAP beginning in 2006	Recovery of costs for RMR including continuing required payments after LICAP initiation		Avoided Cost applicable to KW savings contributing as supply side credit; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level			Avoided Cost applicable to KW savings at Summer Coincident Peak; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level	Avoided cost expressed in $/kWh at 100% load factor		Incremental to Avoided Cost at Summer Coincident Peak	Expressed in $/kWh at 100% load factor	Incremental to Avoided Cost at Summer Coincident Peak; Assumes 10% of supply resources transact in spot market	Expressed in $/kWh at 100% load factor
Comment 2:					info	info	June / July / August	Average for 1 month savings	Average for Summer Season	Average for Winter Season	June / July / August			DRIPE measured at 0.75% peak savings are across all of New England. Values		DRIPE LIGHT measured at 0.75% peak savings are across all of New England.	
Period:							3-5 pm		June, July, August	Jan-May;Sept-Dec	3-5 pm						
2005[2]	0.074	0.064	0.069	0.051	2.662	0.954	3.616	0.222	0.624	0.124	3.616	0.000	0.000	0.00	0.000	0.00	0.000
2006	0.085	0.072	0.077	0.059	34.548	1.801	36.350	2.879	8.102	1.607	36.350	0.004	0.004	654.43	0.075	32.57	0.004
2007	0.087	0.074	0.081	0.062	39.132	2.151	41.283	3.261	9.176	1.820	41.283	0.004	0.005	906.91	0.104	88.60	0.010
2008	0.074	0.060	0.072	0.050	62.436	0.199	62.635	5.203	14.641	2.903	62.635	0.007	0.007	32.87	0.004	15.28	0.002
2009	0.060	0.049	0.056	0.040	66.758	0.204	66.962	5.563	15.655	3.104	66.962	0.008	0.008	357.68	0.041	9.62	0.001
2010	0.052	0.042	0.049	0.035	69.696	0.177	69.874	5.808	16.344	3.241	69.874	0.008	0.008	266.06	0.030	(6.87)	(0.001)
2011	0.055	0.044	0.051	0.037	72.764	0.154	72.918	6.064	17.063	3.384	72.918	0.008	0.008	174.43	0.020	(23.35)	(0.003)
2012	0.057	0.046	0.052	0.038	75.967	0.133	76.100	6.331	17.814	3.532	76.100	0.009	0.009	82.81	0.009	(39.84)	(0.005)
2013	0.057	0.046	0.053	0.039	76.270	0.000	76.270	6.356	17.885	3.547	76.270	0.009	0.009	119.16	0.014	(21.08)	(0.002)
2014	0.058	0.046	0.054	0.039	76.575	0.000	76.575	6.381	17.957	3.561	76.575	0.009	0.009	155.52	0.018	(2.33)	(0.000)
2015	0.058	0.047	0.054	0.040	76.881	0.000	76.881	6.407	18.029	3.575	76.881	0.009	0.009	191.87	0.022	16.43	0.002
2016	0.059	0.047	0.055	0.040	77.188	0.000	77.188	6.432	18.101	3.589	77.188	0.009	0.009	228.22	0.026	35.18	0.004
2017	0.060	0.049	0.057	0.042	76.704	0.000	76.704	6.392	17.987	3.567	76.704	0.009	0.009	258.99	0.030	36.72	0.004
2018	0.062	0.051	0.059	0.044	76.222	0.000	76.222	6.352	17.874	3.544	76.222	0.009	0.009	289.75	0.033	38.26	0.004
2019	0.064	0.053	0.061	0.045	75.743	0.000	75.743	6.312	17.762	3.522	75.743	0.009	0.009	320.52	0.037	39.80	0.005
2020	0.066	0.055	0.064	0.047	75.267	0.000	75.267	6.272	17.650	3.500	75.267	0.009	0.009	351.29	0.040	41.34	0.005
2021	0.066	0.055	0.065	0.048	75.613	0.000	75.613	6.301	17.731	3.516	75.613	0.009	0.009	328.09	0.037	35.34	0.004
2022	0.067	0.056	0.065	0.049	75.960	0.000	75.960	6.330	17.813	3.532	75.960	0.009	0.009	304.90	0.035	29.34	0.003
2023	0.068	0.056	0.066	0.049	76.309	0.000	76.309	6.359	17.894	3.548	76.309	0.009	0.009	281.70	0.032	23.34	0.003
2024	0.068	0.057	0.067	0.050	76.660	0.000	76.660	6.388	17.977	3.565	76.660	0.009	0.009	258.50	0.030	17.35	0.002
2025	0.069	0.057	0.068	0.051	77.012	0.000	77.012	6.418	18.059	3.581	77.012	0.009	0.009	235.31	0.027	11.35	0.001
2026	0.070	0.058	0.069	0.051	77.365	0.000	77.365	6.447	18.142	3.597	77.365	0.009	0.009	212.11	0.024	5.35	0.001
2027	0.070	0.059	0.069	0.052	77.721	0.000	77.721	6.477	18.225	3.614	77.721	0.009	0.009	188.91	0.022	(0.65)	(0.000)
2028	0.071	0.059	0.070	0.053	78.078	0.000	78.078	6.506	18.309	3.631	78.078	0.009	0.009	165.72	0.019	(6.65)	(0.001)
2029	0.072	0.060	0.071	0.054	78.436	0.000	78.436	6.536	18.393	3.647	78.436	0.009	0.009	142.52	0.016	(12.64)	(0.001)
2030	0.072	0.060	0.072	0.054	78.796	0.000	78.796	6.566	18.478	3.664	78.796	0.009	0.009	119.32	0.014	(18.64)	(0.002)
2031	0.072	0.060	0.072	0.054	72.952	0.000	72.952	6.079	17.107	3.392	72.952	0.008	0.008	109.42	0.012	(18.43)	(0.002)
2032	0.072	0.060	0.073	0.054	67.541	0.000	67.541	5.628	15.838	3.141	67.541	0.008	0.008	99.52	0.011	(18.22)	(0.002)
2033	0.072	0.060	0.073	0.054	62.531	0.000	62.531	5.211	14.664	2.908	62.531	0.007	0.007	89.62	0.010	(18.01)	(0.002)
2034	0.072	0.060	0.074	0.054	57.893	0.000	57.893	4.824	13.576	2.692	57.893	0.007	0.007	79.72	0.009	(17.80)	(0.002)
2035	0.072	0.059	0.074	0.053	53.599	0.000	53.599	4.467	12.569	2.492	53.599	0.006	0.006	69.82	0.008	(17.59)	(0.002)
2036	0.072	0.059	0.074	0.053	49.623	0.000	49.623	4.135	11.637	2.307	49.623	0.006	0.006	59.92	0.007	(17.38)	(0.002)
2037	0.072	0.059	0.075	0.053	45.943	0.000	45.943	3.829	10.774	2.136	45.943	0.005	0.005	50.02	0.006	(17.17)	(0.002)
2038	0.072	0.059	0.075	0.053	42.535	0.000	42.535	3.545	9.974	1.978	42.535	0.005	0.005	40.12	0.005	(16.96)	(0.002)
2039	0.072	0.059	0.076	0.053	39.380	0.000	39.380	3.282	9.235	1.831	39.380	0.004	0.004	30.22	0.003	(16.75)	(0.002)
2040	0.072	0.059	0.076	0.053	36.459	0.000	36.459	3.038	8.550	1.695	36.459	0.004	0.004	20.32	0.002	(16.54)	(0.002)
Levelized[3]:																	
2005-2040	0.067	0.056	0.065	0.048	64.742	0.215	64.957	5.395	15.182	3.010	64.957	0.007	0.007	220.657	0.025	7.200	0.001
2006-2040	0.067	0.055	0.065	0.048	67.237	0.186	67.422	5.603	15.767	3.127	67.422	0.008	0.008	229.525	0.026	7.489	0.001
2006-2010	0.072	0.060	0.067	0.050	54.120	0.927	55.047	4.510	12.691	2.517	55.047	0.006	0.006	448.938	0.051	28.472	0.003
2006-2015	0.065	0.053	0.060	0.044	64.347	0.515	64.862	5.362	15.089	2.992	64.862	0.007	0.007	304.283	0.035	8.063	0.001
2006-2020	0.064	0.052	0.060	0.044	67.922	0.360	68.282	5.660	15.928	3.158	68.282	0.008	0.008	299.546	0.034	17.117	0.002

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