Winter Impacts of Energy Efficiency In New England

April 2015

Investments in electric efficiency since 2000 reduced electric demand in New England by over 2 gigawatts.[1] These savings provide significant benefit during periods of peak demand, such as the winter of 2014. In this analysis the effects of electric efficiency are estimated by comparing actual demand and prices during January-March 2014 (defined as winter 2014 in this report) with a scenario where demonstrated savings from electric efficiency programs[2] are assumed not to exist. The resulting higher level of demand is then used to project what wholesale electricity prices and costs would be without energy efficiency.

The analysis demonstrates that without the demand reduction due to electric efficiency programs in New England, during the winter of 2014:

- Demand would have been 14% higher
- The price of wholesale electricity would have been 24% higher
- Overall costs for electricity would have been $1.5 billion higher

This relief during the winter of 2014 complements savings that electric efficiency programs deliver over the entire year, and reinforces the logic of investing in electric efficiency as the "first fuel" to meet the region's energy needs and reduce the risk of fuel price volatility. Saving electricity though measures such as LED lighting, building weatherization and incentives for efficient appliances costs about $0.04/kilowatt hour (kWh), which is **about a quarter of the regional average wholesale price** of $0.16/kWh during the winter of 2014. Efficiency savings are even more cost effective in comparison to the full retail electricity prices that consumers pay, which have recently been as high as $0.30/kWh in Massachusetts.[3]

As New England states work to meet the region's energy needs while controlling costs, policy makers should prioritize energy efficiency investments. Massachusetts and Rhode Island should continue to ramp up programs to procure all cost-effective efficiency, and other New England states should establish policy frameworks to invest in all energy savings that are cost-effective. Further, existing energy efficiency programs should continue to evolve to target savings during periods when they will deliver the most value.

Analysis Approach

This analysis uses linear regression to estimate the difference between actual hourly energy costs in the winter of 2014 and estimated hourly costs in the absence of electric efficiency investments made since 2000.[4] The analysis focuses on the winter of 2014 due to strong correlation between hourly temperature, demand, and wholesale electric price data. The analysis is limited to weekdays, when price spikes due to higher gas and electric demand were more frequent, and correlation between demand, temperature, and prices is highest. Potential effects of energy efficiency programs' demand reductions on the composition of the generating fleet in New England have not been included in this analysis. A more detailed description of the methodology, regression modeling and data sources is provided in appendices.

Impacts of Energy Efficiency

Comparisons of actual electric demand, wholesale prices, and costs to estimates without efficiency show the significant value that regional consumers accrued from efficiency savings during the winter of 2014 alone. Without savings from electric efficiency programs, region-wide demand would have been **13.7% higher**, wholesale electricity prices would have been **24% higher**, and electricity costs would have been **$1.46 billion higher**.

The following figures describe electric demand with and without efficiency in the analyzed winter months, and both the real time (RTLMP) and day-ahead (DALMP) wholesale prices.[5]

Table 1: Monthly Total Demand and Average Real Time and Day Ahead Locational Marginal Prices

Month	Demand with Efficiency (MWh)	Demand without Efficiency (MWh)	RTLMP with Efficiency ($/MWh)	RTLMP without Efficiency ($/MWh)	DALMP with Efficiency ($/MWh)	DALMP without Efficiency ($/MWh)
January	8,227,891	9,316,147	175	214	184	212
February	7,218,853	8,205,423	164	199	165	197
March	7,633,616	8,724,035	126	170	118	168

Figure 1: Daily Electricity Demand With and Without Efficiency

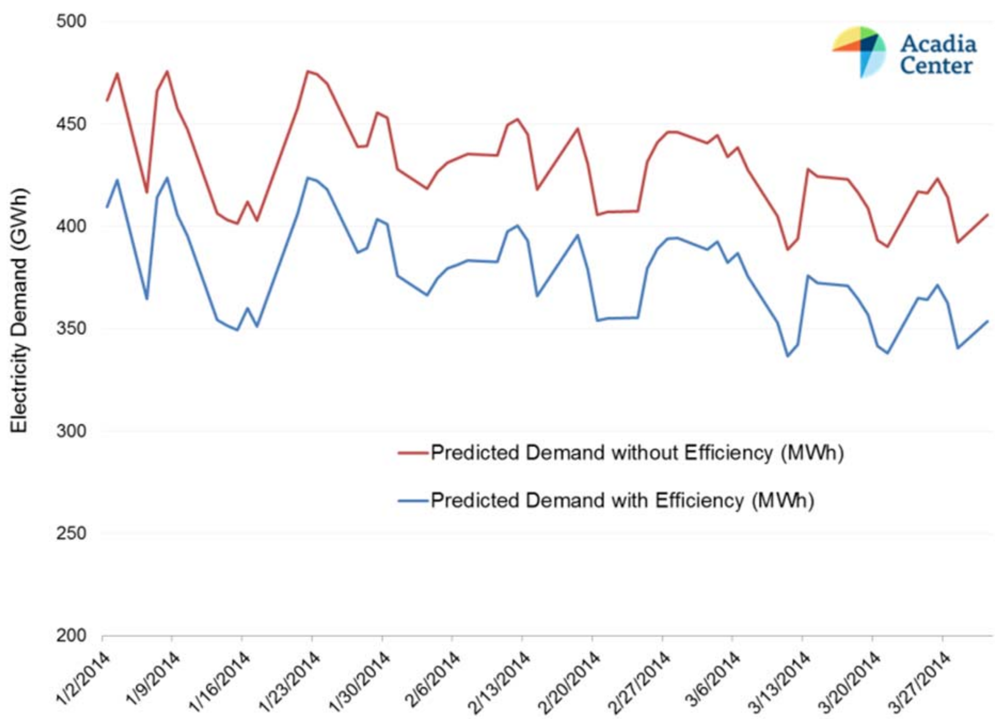


Figure 2: Daily Day Ahead Locational Marginal Prices With and Without Efficiency

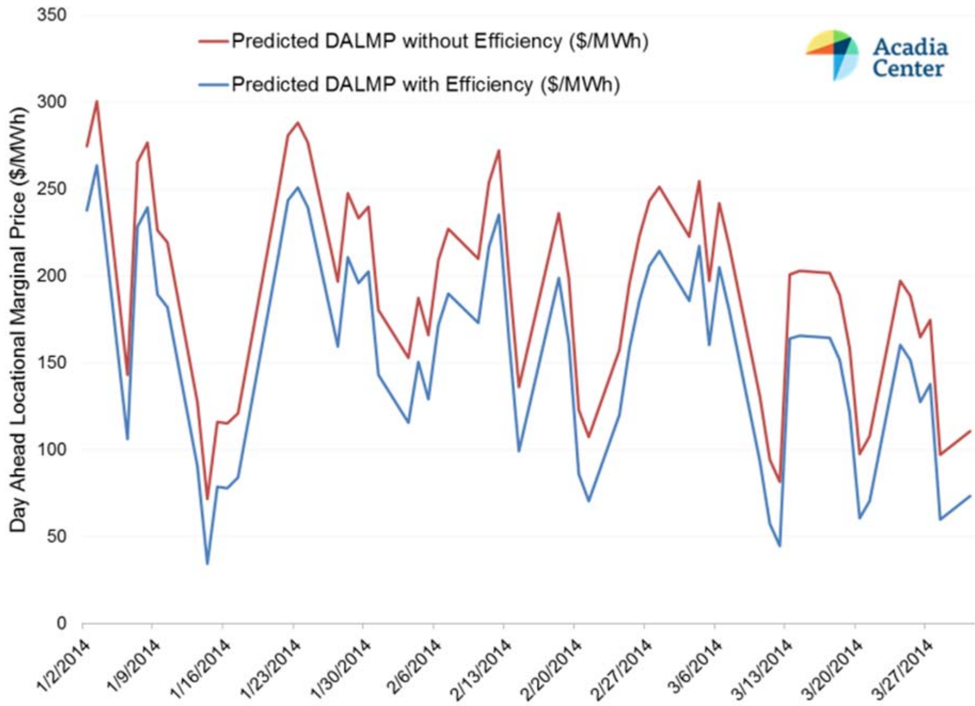
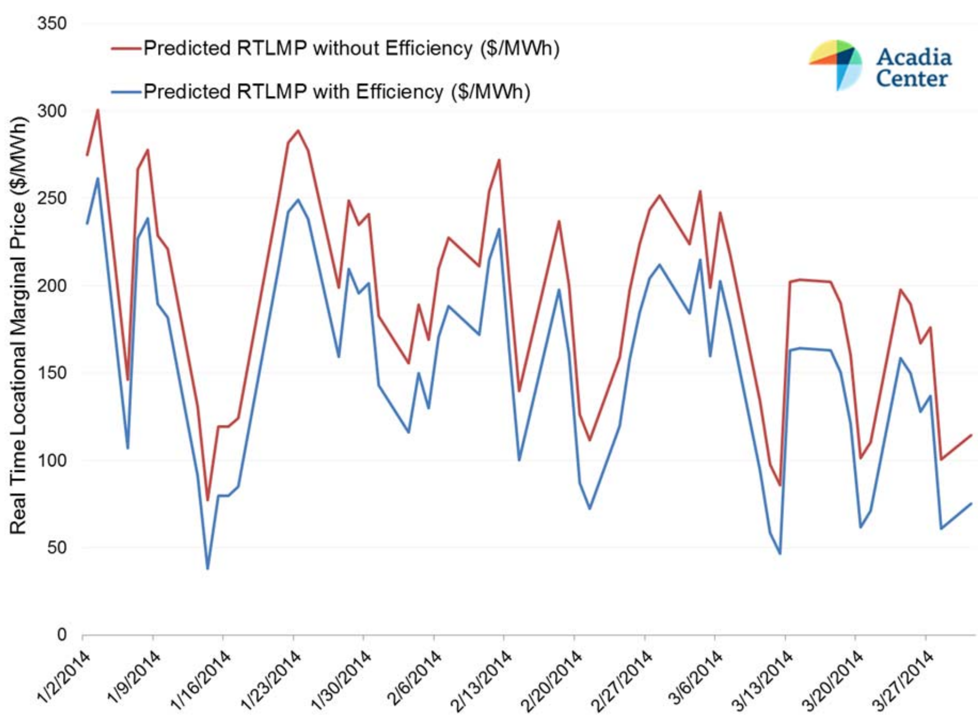


Figure 3: Daily Real Time Locational Marginal Prices With and Without Efficiency



Conclusion

Electric efficiency investments in New England made between 2000 and 2013 reduced region-wide electric demand by over 2 GW in the analyzed winter months of year 2014, and without these demand reductions modeled energy costs are significantly higher. Using verified electricity savings from states' efficiency programs and estimating the price of wholesale electricity without these savings, this analysis finds that energy prices would have been 24% higher during the winter of 2014, leading to an additional $1.5 billion in costs. Efficiency savings are achieved at an average of $0.04/kWh, which is about a quarter of the average winter 2014 wholesale electricity supply price of $0.16/KWh and even less in comparison to the full retail rates that consumers pay in many service territories.

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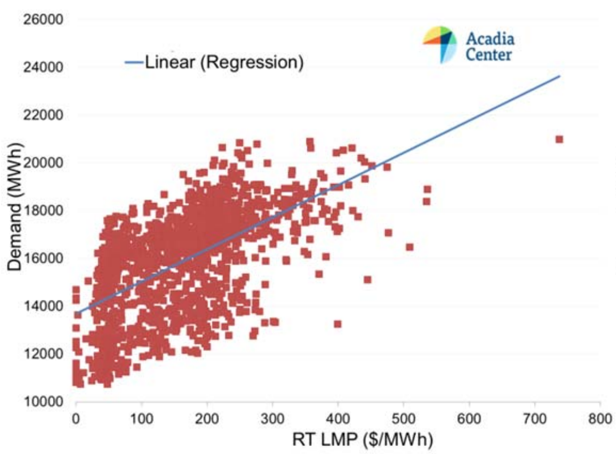
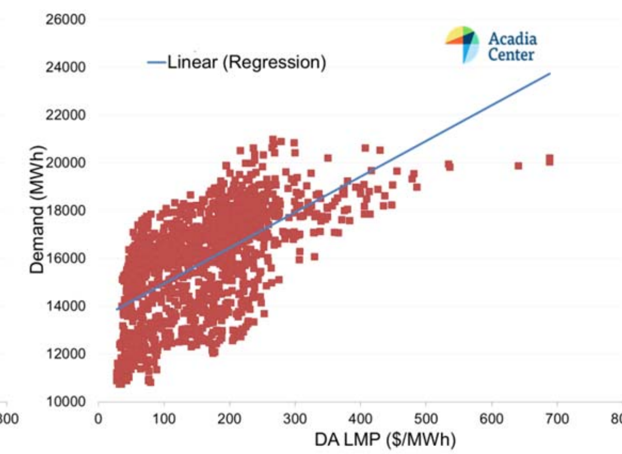
Appendix A

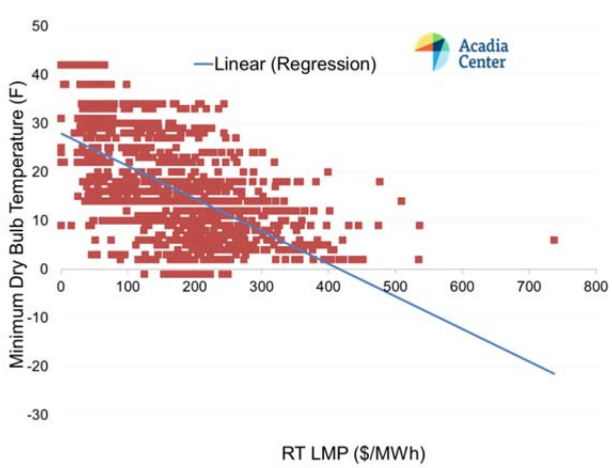
Methodology

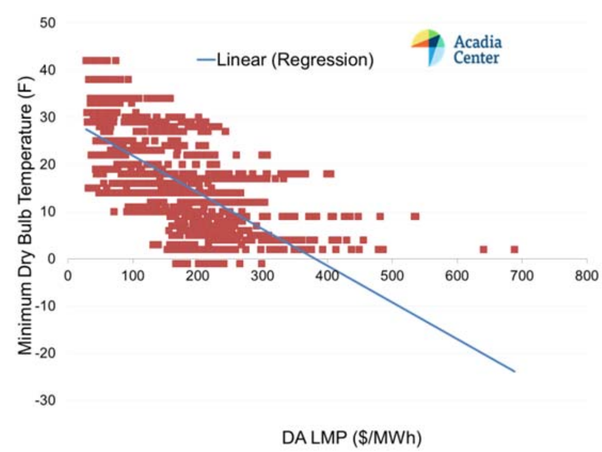
This analysis relies on regression modeling in R (statistical language) to compare actual demand and prices seen in the winter months of January through March, 2014 with a scenario including estimated energy demand and prices that would have occurred in the *absence* of energy efficiency investments from 2004-2013. This is accomplished by establishing a linear regression between electricity, locational marginal prices (RT LMPs & DALMPs) and demand for January -March of 2014 for the entire ISO NE region. Dependent variables are Real Time Locational Marginal Price (RT LMP) and Day Ahead Locational Marginal Price (DALMP). Independent or predictor variables are minimum temperature and electricity demand. Demand is used as a predictor directly correlated with prices, as increased electricity demand can cause dispatch of more expensive generation resources and increased congestion, both of which increase wholesale prices. Minimum temperature per day is used as a co-variable or control variable to represent the effects of natural gas supply constraints and temperature on LMPs. This is based on the premise that a lower daily minimum temperature will lead to higher heating demand, which can cause natural gas supply changes and lead to higher wholesale prices for natural gas, and natural gas generation, which frequently sets the price of power in New England. Lack of strong correlation between minimum temperature and electricity demand also reduces possibility of multi-collinearity. [6]

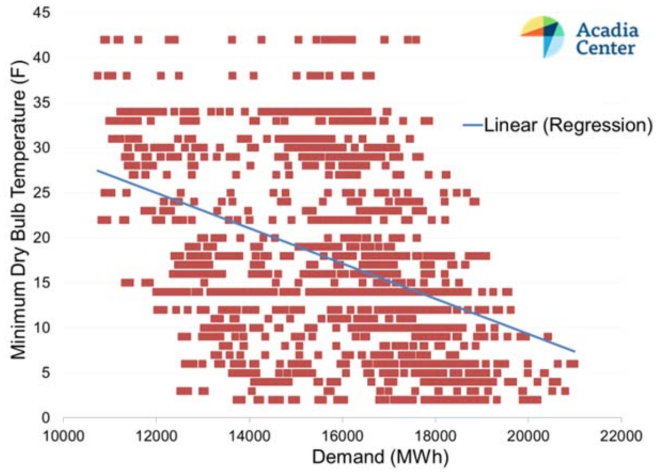
The figures below show correlations between the above mentioned variables, and demonstrate that demand and temperature are strongly correlated to price, while temperature is poorly correlated with demand:











The regression developed is described below:

$$LMP/_{hour} = B_0 + B_1 Demand/_{hour} + B_2 Min\_Temperature/_{hour} + \varepsilon$$

LMP $/_{hour}$ – Locational Marginal Prices Per Hour (Real Time)

B_0 –Intercept

B_1 – Coefficient of Demand Per Hour

B_2 – Coefficient of Minimum Temperature Per Hour

ε – Error

Total cumulative winter savings from electric efficiency programs is calculated using annual incremental winter savings and energy efficiency measure life data for the New England states. These demand savings of 2,164 MW are added to actual day-ahead demand to estimate modeled day-ahead hourly demand without efficiency.[7] The model coefficients are then used to estimate new hourly RT LMPs and DALMPs for the new demand levels without efficiency.[8] These new LMPs and demand for each hour are then used to determine a new wholesale load cost in the scenario without efficiency. Existing wholesale load cost is calculated using actual demand and LMPs for each hour. The difference between costs between the scenario without efficiency and actual costs is the basis of savings due to efficiency investments. [6]

The data used in the analysis include hourly wholesale electric prices (both real time locational marginal prices and day ahead locational marginal prices), hourly dry bulb temperature, and electric demand for the entire ISO New England (ISO NE) region for January-March 2014.[9] 1463 observations were analyzed in the model. One data point was excluded as it was causing significant influence on the statistical significance of parameter estimates. This unusually high RTLMP price event occurred as generator units failed to start in a tight capacity situation and other market conditions.[10] Incremental annual winter energy efficiency savings data for New England states are based on energy efficiency programs administrators' annual legislative reports.

Appendix B

Regression Model Results

Regression model results are presented in the table below:[6]

RTLMP Model Parameter Estimates						
Variable	Label	DF	Parameter Estimates	Standard Error	t Value	Pr > |t|
Intercept	Intercept	1	-62.53249	15.51958	-4.03	<.0001
Temperature	Minimum Dry Bulb	1	-3.94295	0.18064	-21.83	<.0001
DEMAND	DEMAND	1	0.01817	0.0008788	20.67	<.0001
Adj R-Sq	0.5082					

DALMP Model Parameter Estimates						
Variable	Label	DF	Parameter Estimates	Standard Error	t Value	Pr > |t|
Intercept	Intercept	1	-42.1962	13.48969	-3.13	0.0018
Temperature	Minimum Dry Bulb	1	-4.14085	0.15701	-26.37	<.0001
DEMAND	DEMAND	1	0.01713	0.0007639	22.43	<.0001
Adj R-Sq	0.5774					

The parameter estimates for the predictors are statistically significant and make intuitive sense. The negative coefficient for temperature suggests that lower minimum temperature leads to higher prices. The positive coefficient of demand suggests that increased demand leads to increased prices.

Endnotes

[1] The 2,164MW of cumulative savings is equivalent to the combined output (2,237MW) of Pilgrim Nuclear (680MW) and Brayton Point (1,557 MW) power plants in Massachusetts.

[2] Total cumulative winter savings from electric efficiency programs were calculated using annual incremental winter savings and energy efficiency measure life data from New England states, as compiled through program administrator's energy efficiency annual reports, plans and regulatory filings. Average year-round peak savings for CT were used based on available Program Administrator reports. Average year-round MW savings for ME and NH were calculated by dividing MWh savings by 8760 hours.

[3] A National Grid customer on the Residential Basic Service variable rate plan paid 22.067 cents/kWh for the energy portion of electric supply in January 2015 (https://www.nationalgridus.com/masselectric/non_html/MA_Residential_Table.pdf) and 7.827 cents/kWh for electric distribution (https://www.nationalgridus.com/masselectric/home/rates/4_res.asp) for a total of 29.894 cents per kWh.

[4] For MA and NH, data included is from 2003 and for ME data included is from 2004 based on availability.

[5] Real time locational marginal prices (RTLMP) reflect the price of power purchased during the time period that it is consumed, and day-ahead locational marginal prices reflect the price of power bid into the market one day ahead of time. On average 98% of power is purchased on the day-ahead market, but real-time prices are also analyzed in this report as prices on the real-time market can be more volatile during peak periods.

[6] Please note that the modeling is assuming an effect for the energy efficiency programs and simulating the consequences for prices and cost. The parameter estimates for temperature and demand do not represent the precise impact they may have on prices as there might be omitted variable bias due to variation by location, over time or due to other factors not evaluated in this study.

[7] Real time demand stays the same in both scenarios.

[8] In the scenario without efficiency savings the potential effects of new generation that might have entered the market due to higher electric demand have not been considered.

[9] ISO New England ISO-NE Market Zonal Data - http://www.iso-ne.com/isoexpress/web/reports/pricing/-/tree/zone-info

[10] ISO-NE determined that this unique event took place during a tight capacity period with binding reserve constraints over the morning pickup, with failed unit starts and loads slightly over the forecast, and price separation due to heavy North-South flows. See: http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/prtcpnts/mtrls/2014/feb72014/npc_20140207_add1.pdf