STATE OF NEW HAMPSHIRE

BEFORE THE

PUBLIC UTILITIES COMMISSION

IR 15-124: INVESTIGATION INTO POTENTIAL APPROACHES TO MITIGATE WHOLESALE ELECTRICITY PRICES

OFFICE OF THE CONSUMER ADVOCATE'S

COMMENTS IN RESPONSE TO STAFF REQUEST FOR STAKEHOLDER INPUT

A. Introduction

The New Hampshire Public Utilities Commission (Commission) issued an Order of Notice on April 17, 2015 initiating an investigation into potential approaches to mitigate wholesale electricity prices. The Commission Staff met with interested stakeholders on May 12, 2015 and advised the assembled stakeholders that it would seek written input, no later than June 2, 2015. In a letter on May 14, 2015, Staff informed the commission that it is seeking input on solutions that address eight points. Staff letter, (May 14, 2015) at 2. The OCA appreciates this opportunity to share its views on such an important matter.

B. Root Cause of High Winter Wholesale Prices

Staff seeks input from interested stakeholders on the root cause of the high winter wholesale electricity prices. *Id.* While there are multiple reasons why winter wholesale electricity prices have lately been very high in New England (which translates into high retail prices), the primary cause is the transformed fuel-mix landscape that the region has witnessed since 2000.[1] New England predominantly relies on natural gas for its electricity generation (around 50 percent of the demand is met by gas-fired generators).

[1] See http://www.iso-ne.com/about/what-we-do/todays-challenges.

The dominance of natural gas benefits consumers significantly in summers as the electricity system in New England is summer peaking. From 2009 to 2012, lower natural gas prices helped the energy market value remain well below its high of $12 billion in 2008. *Id* at 2. In winters however, the non-electricity needs for gas (such as home heating) rely on the maximum amount of gas pipeline capacity in New England more often than before 2000 (especially during extreme cold events). The existing gas pipeline infrastructure was designed to meet the needs of traditional gas customers, generally served by local distribution companies (LDCs). The constrained pipeline capacity in New England is inadequate for meeting the capacity needs of gas-fired electric generators when total gas demand is close to or higher than the gas pipeline's design day capacity of regional pipeline infrastructure (such as during extremely cold winter days). The gas pipeline bottlenecks that New England currently experiences during extremely cold days do not allow gas generators to easily access low cost and abundant natural gas, for example, from Marcellus and Utica. Given that the lack of gas-availability affects generators for only a few days in the winter, the gas-fired generators do not find market-based long-term contracts for firm capacity with gas pipelines to be cost-effective.

Therefore, it is not surprising that other higher-cost fuels set the locational marginal prices during such events, causing New England's wholesale electricity prices to spike significantly during cold winter days. This is essentially a market phenomenon.

C. **Attributes of a Preferred Solution**

The OCA offers its views on a preferred solution to address high wholesale electricity prices by focusing on attributes that can be followed in adopting any potential solution going forward. As for specific solutions, whether they are gas-based, LNG-based or energy efficiency-based, the OCA would favor the most cost-effective and least market-disruptive options available. There is insufficient evidence that high wholesale electricity prices witnessed during recent winters is demonstratively due to wholesale electricity markets failure. For capital-intensive industries, market signals typically take some time to bear upon investment decisions. It is too early to presume that the wholesale electricity markets won't respond to the current realities. Such responses could lead to market solutions that will mitigate wholesale winter electricity prices in future years. For example, it may be that the Independent System Operator of New England's (ISO-NE's) pay-for-performance construct, which will begin in 2018, will not solve the problem, but it is too early to judge that. The market response to pay-for-performance will not take place until the forward market commitment periods, that are associated with the new construct, go into effect. Measured and careful consideration must be given to the threshold question as to whether any additional specific non-market/regulatory solution is needed exigently to influence wholesale electricity prices.

To the extent a non-market/regulatory solution is considered that directly targets wholesale electricity prices, the following principles should be followed:

1. **The Solution Should Not Unnecessarily Bind Ratepayers Into Long Term Commitments**

Based only on electricity prices experienced over the last two years, it would be unreasonable to promote any arrangement that binds customers into a ten-year or longer commitment. For example, a gas-pipeline arrangement for the next two or three years may be reasonable given the available evidence. However, New Hampshire's historical experience with stranded costs suggests that any solutions sought should at best be limited to a few years at a time, to avoid the risk of stranded costs. Ultimately, investment risks are better managed by market competitors, not ratepayers. A long term regulatory solution may unnecessarily expose ratepayers to investment risks, shifting risk from the market to residential ratepayers. Investment risk exposure is also a concern even in the case of short-term contracts, but the concern is mitigated compared to being captive to long-term contracts (contracts of more than 10 years).

2. **Any Solution in the Regulatory Sphere Should Remain Reasonably Resource-Neutral**

Ideally, if a regulatory solution is sought to lower wholesale electricity costs, the supply contract should be procured competitively for the intended periods, and the solicitation should be open to all resource types, including energy efficiency and demand response. The goal of minimizing the burden on ratepayers must be the guiding principle. Since the electricity market in New England is regional, it may be useful to have a regional procurement. However, the interests of New Hampshire ratepayers should not be compromised in the process. To the extent interests align, it can be helpful to pursue regional efforts that are multi-state, even if not all New England states join in.

3. **The Role of Energy Efficiency In Solving The High Electricity Prices In Winters**

There is significant potential in cost-effective energy efficiency measures for mitigating the high wholesale electricity prices in winter. Such measures avoid the future risk of high stranded costs which exist for example, with long-term gas-pipeline contracts. While market dynamics may accommodate significant savings through energy efficiency measures, the OCA is cognizant that the Commission is investigating means to introduce greater savings through energy efficiency both in electricity and gas sectors. To the extent the Commission pursues additional cost-effective energy-efficiency initiatives, such initiatives can mitigate wholesale electricity prices in winter by targeting the usage of both electric and gas customers. Research shows that in the winter of 2014, "[w]ithout 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."[2] A recent study conducted by the Analysis Group indicates significant potential for cost-effective energy efficiency in New Hampshire.[3]

4. **Avoid Duplication of Regulatory and Non-Market Solutions Across States**

The Commission should be wary of duplication of regulatory and non-market solutions across the New England region that diminish the effectiveness of existing measures to mitigate wholesale electricity prices and which do not increase reliability. As a case in point, the ISO-NE Winter Reliability Program addresses reliability with a comparatively modest price tag. This initiative combines regulatory and market solutions and may be sufficient in the near future to address short term reliability concerns.[4] To the extent high wholesale electricity prices remain a concern during extremely cold days, limited measures to mitigate volatility in retail prices will likely suffice at this point. Adding another wholesale electricity market oriented program increases the likelihood of unintended consequences for the market in the long-term. There is always a risk that a well-intentioned regulatory intervention will add costs, result in stranded costs, and perhaps turn out to have been unnecessary for purposes of reliability. This is particularly unreasonable if a regulatory intervention is not needed for reliability and comes at a high cost for ratepayers.

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[2] See the attached paper by Acadia Center, titled "Winter Impacts of Energy Efficiency in New England", April 2015.

[3] "Assessment of EPA's Clean Power Plan: Evaluation of Energy Efficiency Program Ramp Rates and Savings Rates", Paul J. Hibbard, Andrea M. Okie, and Katherine A. Franklin, Dec. 2014 (Analysis Group). See http://www.analysisgroup.com/uploadedfiles/content/insights/publishing/assessment_of_epa_clean_power_plan.pdf.

[4] See the attached NESCOE presentation, which was presented before the NEPOOL Markets Committee in May 2015.

5. **The Key Problem for Ratepayers Is Spikes in Winter Retail Electricity Rates**

The real issue for ratepayers is that high wholesale electricity prices get reflected in retail energy rates during winters as spikes. This is a substantial irritant for residential ratepayers and small businesses, who seek rate stability. At the retail level the Commission can implement changes in energy procurement practices and rate setting mechanisms for default service residential customers to guard against volatility in wholesale electricity prices. The OCA shared such an approach in Docket IR 14-338, recommending that default service procurements using laddering and a rate-setting mechanism will mitigate volatility in retail prices, without intervening directly in wholesale markets. Such an approach is very useful in the short term, while wholesale electricity prices continue to spike during the winter. Efforts to address volatility in default service rates (especially for residential customers) may be more effective at this time than seeking alternatives which directly impact the market for wholesale electricity prices.

It is too early to tell whether regulatory interventions are necessary to influence the wholesale electricity markets at this time. The OCA, however, supports the Commission's initiative to conduct necessary conversations with stakeholders as a means of exploring avenues to specifically influence future wholesale electricity prices. This allows the Commission to be adequately prepared in the coming years if it is determined later that a more direct involvement in the electricity wholesale markets is imperative.

D. <u>OCA Concluding Remarks</u>

While wholesale electricity prices have been significantly higher in recent winters compared to two years ago, the jury is still out on whether the experience from 2013-14 necessitates exigent "non-market" measures to address the need for additional gas pipeline capacity. To the extent some intervention in the wholesale electricity markets may be necessary, the Commission is urged to ensure that ratepayers are not held captive to costs over a long-period of time, which may lead to stranded costs. Any short-term initiative to mitigate wholesale electricity prices should be resource-neutral, and should not lead to unnecessarily duplicative initiatives in the New England region. The OCA is aware that the Commission is investigating additional energy efficiency initiatives. To the extent cost-effective energy efficiency initiatives are undertaken by the Commission, they have the potential to substantially mitigate high prices in winter without creating stranded costs. Appropriate distributive generation policy can also provide necessary market support. It may be more effective at this point to indirectly address the problem of high wholesale electricity prices in winter through adjustments in the default-service solicitation processes for residential customers as well as concomitant default service rate-setting approaches.

The OCA thanks the Commission for the opportunity to present these comments and expresses appreciation for the Commission Staff's efforts in starting the conversation on the matter of how to mitigate high wholesale electricity prices in the winters.

Respectfully,

Wayne Fortner
Attorney for Office of the
Consumer Advocate

Dr. Pradip Chattopadhyay
Assistant Consumer Advocate
Rate and Market Policy Director

Winter Impacts of Energy Efficiency In New England

April 2015

Acadia Center

Advancing the Clean Energy Future

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.

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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

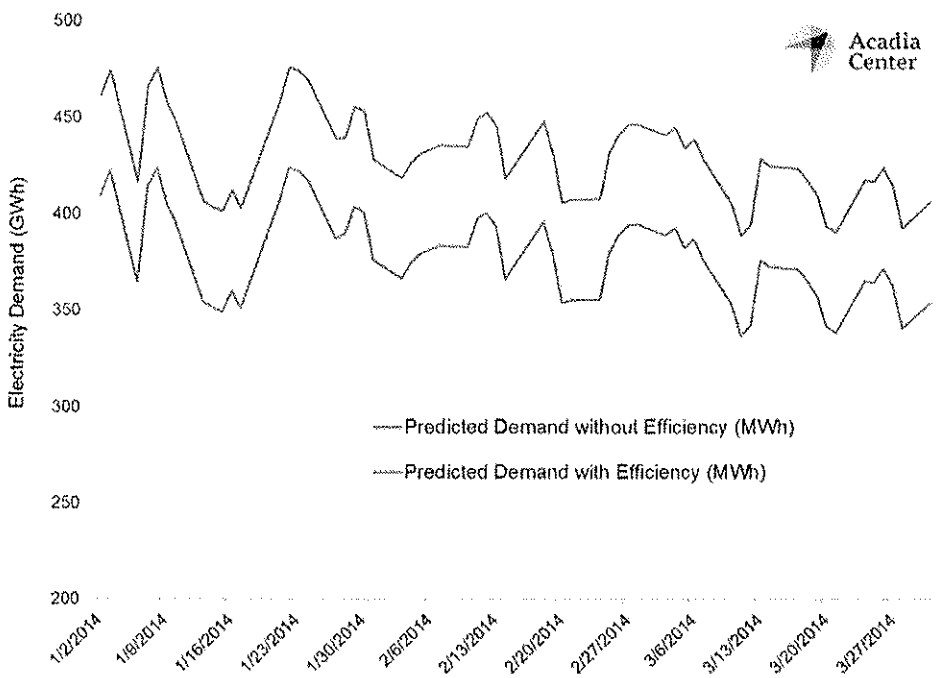


Figure 2: Daily Day Ahead Locational Marginal Prices With and Without Efficiency

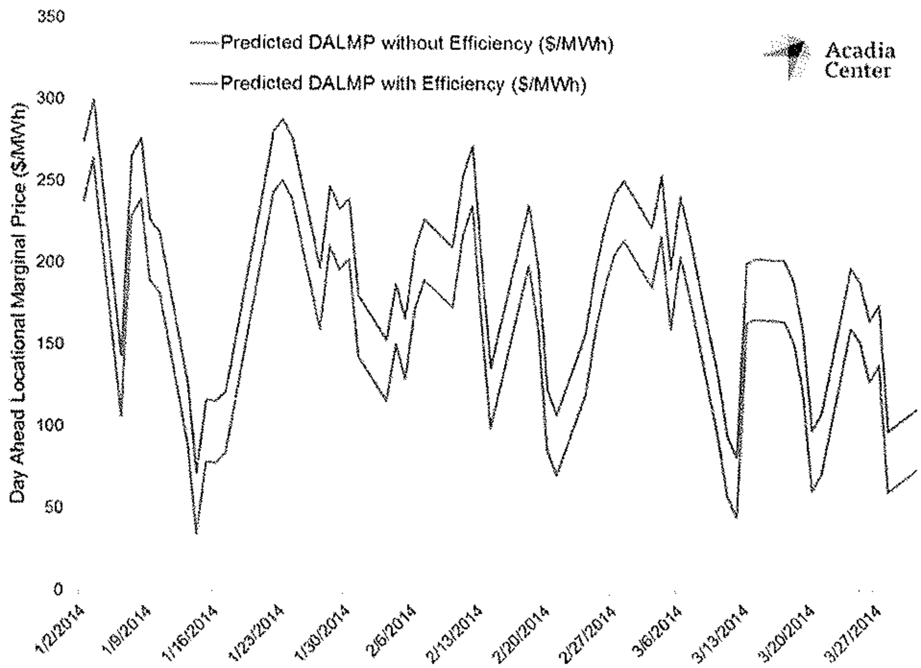
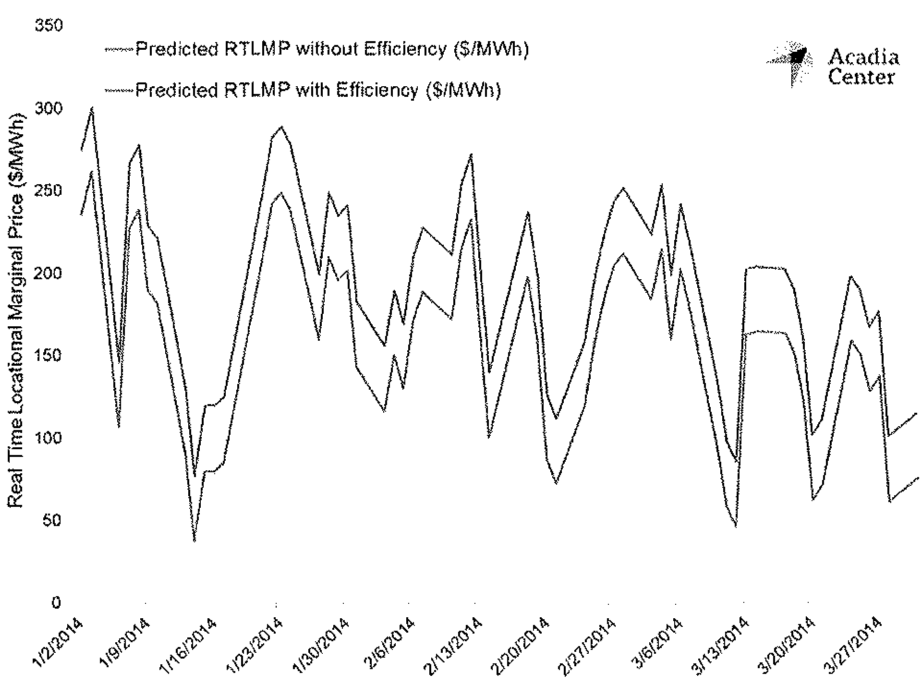


Figure 3: Daily Real Time Locational Marginal Prices With and Without Efficiency



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.

Acknowledgments

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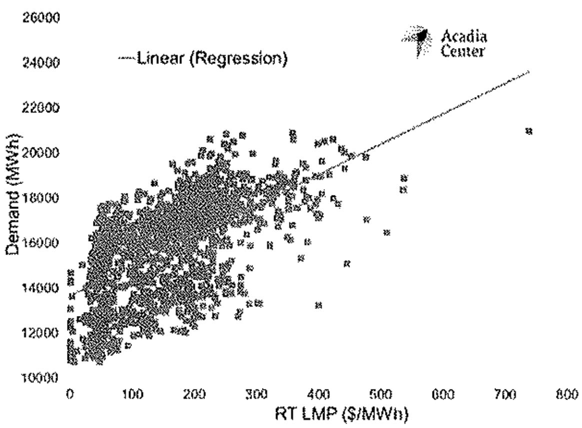
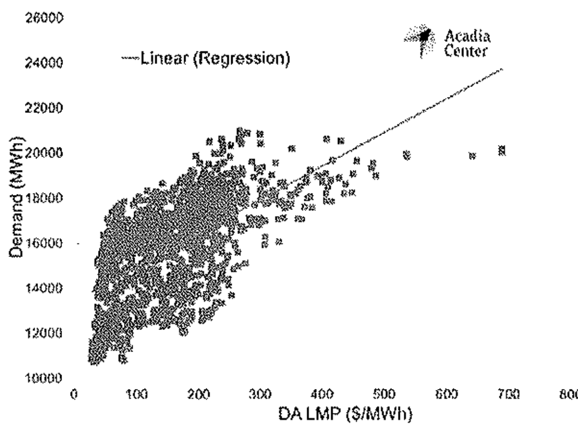
Appendix A

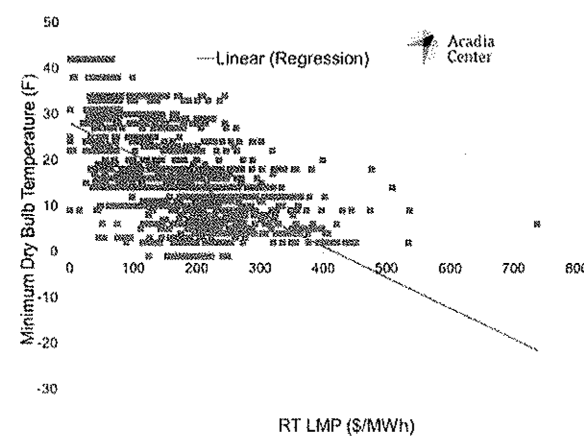
Methodology

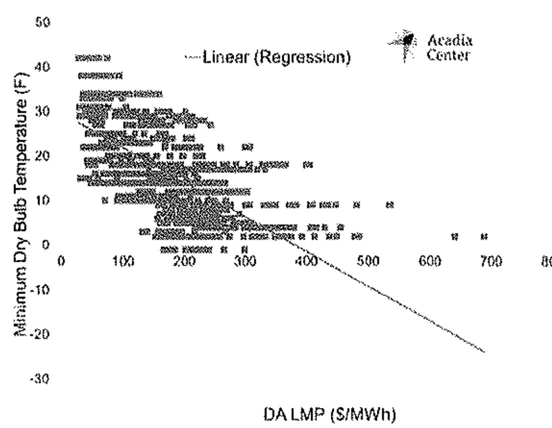
This analysis relies on regression modeling in R (statistical language) to compare actual demand and prices seen in the winter months of January through March, 2014 with a scenario including estimated energy demand and prices that would have occurred in the *absence* of energy efficiency investments 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]

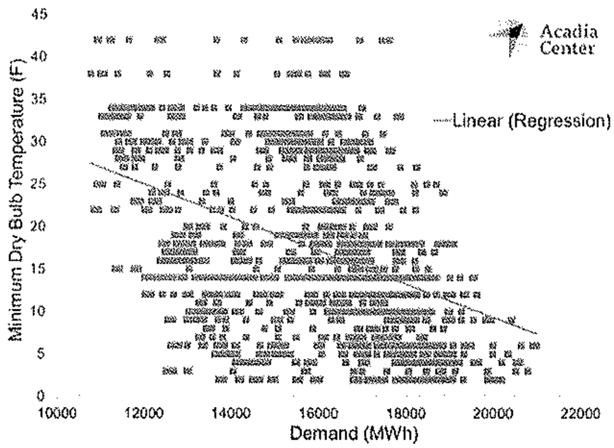
The figures below show correlations between the above mentioned variables, and demonstrate that demand and temperature are strongly correlated to price, while temperature is poorly correlated with demand:











The regression developed is described below:

$LMP/_{hour} = B_0 + B_1Demand/_{hour} + B_2Min\_Temperature/_{hour} + \varepsilon$

$LMP/_{hour}$ – 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

Winter Program:
New England States' Preferred Approach

New England States Committee on Electricity

NEPOOL Markets Committee

May 2015

Outline of Presentation

1. NESCOE's proposed winter program description
2. Alternative proposal advantages
3. Cost Considerations
4. Next Steps

Proposal: Similar to 2014/15 Winter Program with some Adjustments

Same as Prior Year

- Maintains same type of participation, including the eligible categories of:
  - Fuel oil (barrels)
  - Liquefied Natural Gas (Bcf)
  - Demand Response (MW)
- Fuel survey participation
- End of season inventory compensation mechanism

Change From Prior Year

- Winter seasons 2015-16, 2016-17 and 2017-18, with Appendix K expiring on March 15, 2018
- Update payment rates and other participation requirements to be consistent with the current ISO-NE program proposal
- Replenishment: Change in section III.K.2 to exclude inventory added after February 1 instead of March 1

Other changes could develop as a result of continued stakeholder feedback both on this proposal and the ISO-NE expanded proposal

Advantages of an Alternative Proposal

Compared to the other proposals, the NESCOE proposal:

- Continues a proven, effective and efficient program touted by ISO-NE as successfully providing the necessary level of incremental reliability to New England
  - Found by FERC to be a just and reasonable and not unduly discriminatory means of providing *additional* reliability services until a long-term market-based solution is implemented
- Maintains a known and reasonable program cost estimate for the benefits provided to consumers in return for their investment
- The other proposals to date are non-starters
  - An expected cost of two, three or four times more that provides ***at best*** the same level of verifiable fuel assurance is unjust and unreasonable
  - The "Markets-No-Matter-The-Cost" approach puts the objective of sustainable competitive markets to serve New England consumers at risk
    - The point of markets is to drive efficiency, not inefficiencies that drive costs up
  - Neither of the other proposals provide incremental fuel assurance reliability benefits beyond the existing program

A proven interim program at a proven cost provides the optimal course of action as a stop-gap measure in advance of long-term market design changes

Cost Comparison

At Prior Year $18 Rate				In millions Max Cost Exposure			2014/2015
	Total MW*	Equiv BBL*	Payment rate	ISO-NE	NESCOE	EE&N	Actual
Nuclear	4041	1.62	$18	$29.16	$0.00	$0.00	$0.00
Coal	2002	0.8	$18	$14.40	$0.00	$0.00	$0.00
BioMass	577	0.23	$18	$4.14	$0.00	$0.00	$0.00
Hydro	2941	0.05	$18	$0.90	$0.00	$0.00	$0.00
Other	1500	0.6	$18	$10.80	$0.00	$0.00	$0.00
Oil	10778	4.1	$18	$73.80	$73.80	$0.00	$45.90
LNG	6 (BCF)	1	$18	$18.00	$18.00	$0.00	$1.50
DR**	-	-	-	$0.00	$0.11	$0.00	$0.08
EE&N Proposal	24000	-	$3	$0.00	$0.00	$216.00	$0.00
	Max Cost Exposure			**$151.20**	**$91.91**	**$216.00**	**$47.48**

At Estimated $14 Rate				In millions Max Cost Exposure			2014/15
	Total MW*	Equiv BBL*	Payment rate	ISO-NE	NESCOE	EE&N	Actual
Nuclear	4041	1.62	$14	$22.68	$0.00	$0.00	$0.00
Coal	2002	0.8	$14	$11.20	$0.00	$0.00	$0.00
BioMass	577	0.23	$14	$3.22	$0.00	$0.00	$0.00
Hydro	2941	0.05	$14	$0.70	$0.00	$0.00	$0.00
Other	1500	0.6	$14	$8.40	$0.00	$0.00	$0.00
Oil	10778	4.1	$14	$57.40	$57.40	$0.00	$45.90
LNG	6 (BCF)	1	$14	$14.00	$14.00	$0.00	$1.50
DR**	-	-	-	$0.00	$0.11	$0.00	$0.08
EE&N Proposal	24,000MW	-	$3	$0.00	$0.00	$216.00	$0.00
	Max Cost Exposure			**$117.60**	**$71.51**	**$216.00**	**$47.48**

* Values per ISO-NE April MC slide presentation slide 14

** DR price exposure based on highest cost to date.

At the $14 rate 2014/15 cost would have been ~$37M

Conclusion

- ISO-NE's expansion of a program should result in increased efficiency and more competition driving costs lower not higher
- NESCOE's proposal benefits consumers by providing a reasonably priced interim solution
- It is targeted at what the ISO-NE expressed as its immediate need leading up to the implementation of the Pay-for-Performance design
- Costs to consumers must always be a strong consideration
    - Especially true when the short-term need is driven because of a market design failure
- An out of market, non-fuel neutral program is admittedly imperfect; however, in this circumstance where New England consumers are forced to fill a hole to ensure power system reliability during a transition to a market-based program, a non-fuel neutral stop-gap program that is the most economically efficient option is the only reasonable way forward
- Proposals that result in increased cost with no incremental reliability benefit are unjust and unreasonable. As an interim solution, the optimal course of action is to continue with the existing proven program

Next Steps

- Continue to evaluate ISO-NE and other proposals
- Solicit feedback from stakeholders on NESCOE proposal
- Identify sponsors for the NESCOE proposal
- Move forward with a vote next month on the proposal

Thank You

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