Low Demand Study Should factor in the EIA's Gross Over-optimism on Gas Production

Paul Lipke [plipke@roomtomaneuver.com]

Sent: Fri 10/31/2014 9:37 AM

To: Lowdemandstudy, (ENE)

Cc: bravanesi@hcwh.org; 'Nancy Goodman'; 'Shattuck Peter'; 'Cindy Lupi'; 'Jim O'Reilly'; 'Larry Chretien'; 'Marc Breslow'; 'George Bachrach'; 'Sonia Hamel'; 'Eugenia Gibbons'; 'Joel Wool'

Dear Synapse,
We urge very strongly that your low demand study should factor in this latest study that demonstrates the EIA is grossly over-optimistic in its forecasts of shale gas production nationally, and in the Marcellus region.

Respectfully,
Paul Lipke
Health Care Without Harm

"A few days ago, Post Carbon Institute released what is likely the most in-depth and conclusive study of shale gas and tight oil production ever conducted. Authored by PCI Fellow J. David Hughes, Drilling Deeper uses actual production data to show that the US Department of Energy's forecasts for tight oil and shale gas are likely highly over-optimistic. The EIA expects the so-called "shale revolution" to continue strong for at least the next 25 years, at stable and relatively low prices. Based on these optimistic forecasts, investments and policies are moving away from renewables and towards fracking. Our analysis shows that the "shale revolution" is much more likely to peak before the end of the decade and produce a small fraction of what the government forecasts for 2040."

From: http://www.postcarbon.org/publications/drillingdeeper/

Drilling Deeper

David Hughes
October 27, 2014

Abstract

Drilling Deeper reviews the twelve shale plays that account for 82% of the tight oil production and 88% of the shale gas production in the U.S. Department of Energyâ€™s Energy Information Administration (EIA) reference case forecasts through 2040. It utilizes all available production data for the plays analyzed, and assesses historical production, well- and field-decline rates, available drilling locations, and well-quality trends for each play, as well as counties within plays. Projections of future production rates are then made based on forecast drilling rates (and, by implication, capital expenditures). Tight oil (shale oil) and shale gas production is found to be unsustainable in the medium- and longer-term at the rates forecast by the EIA, which are extremely optimistic.

This report finds that tight oil production from major plays will peak before 2020. Barring major new discoveries on the scale of the Bakken or Eagle Ford, production will be far below the EIAâ€™s forecast by 2040. Tight oil production from the two top plays, the Bakken and Eagle

Ford, will underperform the EIAâ€™s reference case oil recovery by 28% from 2013 to 2040, and more of this production will be front-loaded than the EIA estimates. By 2040, production rates from the Bakken and Eagle Ford will be less than a tenth of that projected by the EIA. Tight oil production forecast by the EIA from plays other than the Bakken and Eagle Ford is in most cases highly optimistic and unlikely to be realized at the medium- and long-term rates projected.

Shale gas production from the top seven plays will also likely peak before 2020. Barring major new discoveries on the scale of the Marcellus, production will be far below the EIAâ€™s forecast by 2040. Shale gas production from the top seven plays will underperform the EIAâ€™s reference case forecast by 39% from 2014 to 2040, and more of this production will be front-loaded than the EIA estimates. By 2040, production rates from these plays will be about one-third that of the EIA forecast. Production from shale gas plays other than the top seven will need to be four times that estimated by the EIA in order to meet its reference case forecast.

Over the short term, U.S. production of both shale gas and tight oil is projected to be robust-but a thorough review of production data from the major plays indicates that this will not be sustainable in the long term. These findings have clear implications for medium and long term supply, and hence current domestic and foreign policy discussions, which generally assume decades of U.S. oil and gas abundance.

*********Here's a relevant excerpt, but there is tons more detail in the report*********

Figure 3-100 illustrates the EIAâ€™s projection for Marcellus production through 2040 compared to the â€œMost
Likely Rateâ€• scenario. The EIA projects recovery by 2040 of 129 Tcf to meet its reference case forecast,
which coincidentally is exactly the same quantity as projected in the â€œMost Likely Rateâ€• scenario. The shape
of the EIA production profile in its reference case, however, appears to underestimate past and current
productionÂeven compared to its own independent estimates (Natural Gas Weekly Update and Drilling
Productivity Report149)Âand overestimate production in later years, beyond 2024. The EIA projects a peak in
2024 at 13.8 Bcf/dÂlower than the 14.8 Bcf/d peak in 2018 in this reportÂand generally higher production
in the post-2022 timeframe.

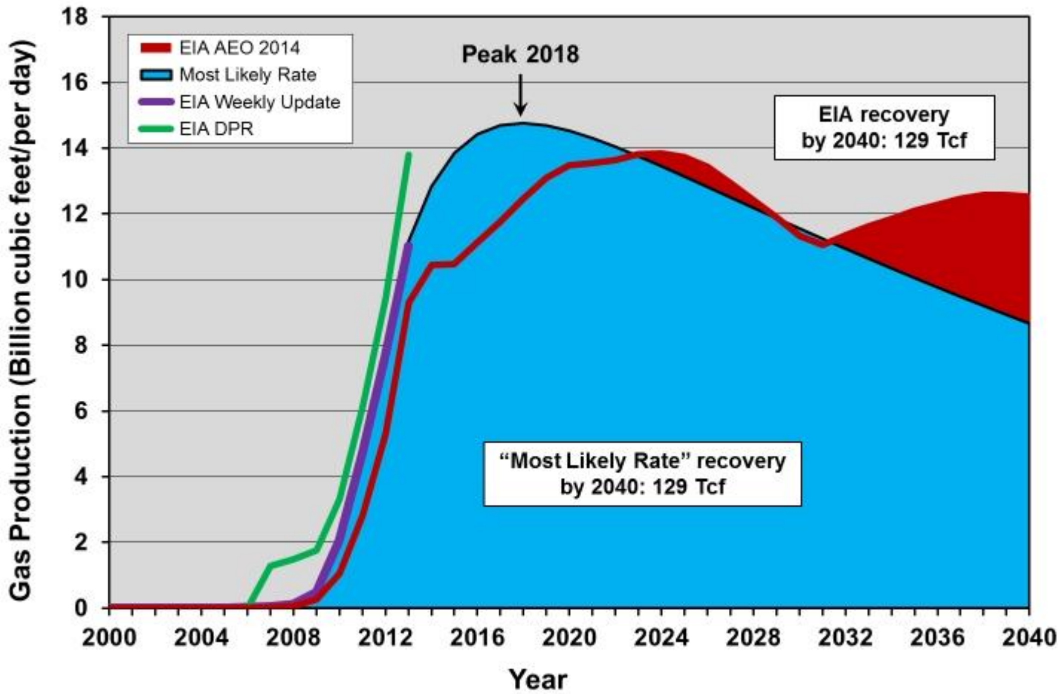

Figure 3-100. EIA reference case for Marcellus shale gas[150] vs. this report's "Most Likely Rate" scenario, 2000 to 2040.

The EIA underestimates past and current production compared to the "Most Likely Rate" scenario and its own independent estimates,[151] but overestimates production in later years. The EIA forecast is made on a "dry gas" basis, whereas the "Most Likely Rate" scenario forecast is made on a "raw gas" basis.

and

Several things are clear from this analysis:

1. Marcellus production is growing strongly and drilling rates are sufficient to see continued growth through 2018. There is a significant backlog of wells drilled but not connectedÂestimated at over 2,000 wellsÂwhich will serve to maintain productive well additions in the near term even if rig count and new well drilling declines.

2. High well- and field-decline rates mean a continued high rate of drilling is required to maintain, let alone increase, production. Current drilling rates of 1,320 wells per year are considerably above the roughly 1,000 wells per year required to offset field decline at current production rates. Offsetting field decline requires an investment of $6 billion per year for drilling (assuming $6 million per well), not including leasing, infrastructure and operating costs. Future production profiles are most dependent on drilling rate and to a lesser extent on the number of drilling locations (i.e., greatly increasing the number of drilling locations would not change the production profile nearly as much as changing the drilling rate). Although drilling in the sweet spots is certainly economic at current

prices, prices will have to increase to justify drilling in lower quality parts of the play when sweet spots are exhausted.

3. Production in the â€œMost Likely Rateâ€• scenario will rise to 15 Bcf/d at peak in the 2018 timeframe
followed by a gradual decline. The â€œHighâ€• drilling rate scenario would move this peak forward to
2019 at more than 15 Bcf/d. Drilling will continue in all scenarios until well beyond 2040.

4. The projected recovery of 129 Tcf by 2040 in the â€œMost Likely Rateâ€• scenario, is the same as the EIA
reference case. However, the EIA has underestimated near term production rates and overestimated
production rates in the longer term.

5. These projections are optimistic in that they assume the capital will be available for the drilling
treadmill that must be maintained to keep production up. This is not a sure thing as drilling in the
poorer quality parts of the play will require higher gas prices to make it economic. Failure to maintain
drilling rates will result in a lower production profile.

6. More than four times the current number of wells will need to be drilled by 2040 to meet production
projections.

7. The projections in this report assume that of the total number of wells that could be drilled if 100%
of the surface area was accessible for drilling at 4.3 wells per square mile, only 80% of the undrilled
locations will be available, owing to surface land use. Any additional restrictions on land use would
further limit the number of wells that could be drilled and result in lower production.

Paul Lipke
Senior Advisor, Energy & Buildings for ***Health Care Without Harm***
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Submission of Comments
Powers, Paul B. [ppowers@empireadvocates.com]
Sent: Fri 10/31/2014 3:50 PM
To: Lowdemandstudy, (ENE)

Dear Dr. Stanton and Colleagues,

I am a consultant in Albany that works with a client that might have an interest in submitting information for the MA Low Demand Study. I realized that they could further the record after reading some of the comments that were submitted after the October 20 stakeholder meeting. Is it possible to submit comments or information without heretofore having registered as a stakeholder or having attended a meeting? Since the comments have to do with some of the study assumptions, I would imagine we would need to get them in sooner than the next stakeholder meeting. Thanks in advance for your guidance.

Paul Powers

Paul B. Powers

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11022014 - Comments - Richard Crane - 95 Overlook Drive - Groton – MA
richcrane@savernac.com
Sent: Sun 11/2/2014 8:07 AM
To: Lowdemandstudy, (ENE)

I appreciate the efforts in developing a low demand natural gas study. Over the past year I have heard numerous issues with natural gas supply and demand. As a part of the study I think it is important to know the following:

1) It has been said that we do not have enough natural gas supply to meet demands for 30 peak days for one winter. This seems to be what is driving the need for a pipeline. What is the average number of peak days that we expect in the future? Is the extreme winter we saw a couple years ago a one time or rare occurrence? ... is it expected to be reoccurring?

2) During peak days it was said that oil needed to be purchased instead of natural gas. I have heard two conflicting stories on this. The first being that power companies were directly instructed to purchase oil over liquified natural gas as our backup fuel supply to drive up the price of electricity and create an artificial demand for natural gas. The second being that oil was actually cheaper during these peak times. We need to answer this question so that we can determine if additional natural gas infrastructure is actually needed.

3) If addressing peak demand is really all we are talking about, what alternative solutions other than natural gas can be used to address the peak demand problem? It seems to me that an entire pipeline just to address 30 days out of an entire year is extremely excessive.

4) Is there any negative impact to clean renewable energy solutions such as solar, wind, and geothermal by the introduction of additional natural gas? For example, I have three geothermal wells that are impacted with the current route proposed by Kinder Morgan.

Thanks,
Richard Crane

Stakeholder Comments upon 10/30 Power Point Presentation
Bruce W McKinnon [brucewmckinnon@gmail.com]
Sent: Fri 10/31/2014 10:06 AM
To: Lowdemandstudy, (ENE)

To whom it may concern:

I would like to comment upon certain data listed on slides 48 and 49;

I wonder how you can produce net energy annually from a pumped storage facility? It takes more electric energy to pump the water up the hill to the upper reservoir than is received from the generation occurring during the higher cost (or less fuel diverse) peak hours.

Similarly, I am assuming that the battery of slide 49 also consumes electricity at other hours to charge the battery to full power for use at time of need, resulting in net electric consumption at the end of the year, not MWhs of production.

Have you accounted for the needed electric energy by an alteration to the daily load forecast for dispatch purposes to supply the needed pumping and charging energy including losses caused by these cycles?

Bruce w. Mc Kinnon

Future investment in renewables
Stephen Wicks [swicks@eyeconography.net]
Sent: Fri 10/31/2014 8:48 PM
To: Lowdemandstudy, (ENE)

Hello,

One of the frequent questions many who are questioning the need for this pipeline project have frequently asked is:

How would the energy picture change if rather than paying a tariff to cover the "3 billion dollar " cost for the build out of the pipeline infrastructure - the 3Billion was invested in further development of wind, sold, bio - renewables?

Will that question be considered, addressed in this low demand study?

From: Peter Shattuck [mailto:pshattuck@acadiacenter.org]
Sent: Wednesday, November 05, 2014 9:57 AM
To: Lowdemandstudy, (ENE)
Subject: Air Source Heat Pump cost assumptions in LDS study

Dear DOER and Synapse,

With apologies for late submission, I am writing with information on assumed costs for Air Source Heat Pumps. Page 36 of the January 2014 *Northeast/Mid-Atlantic Air-Source Heat Pump Market Strategies Report* shows that costs of $2000-$4000 per ton would be more appropriate for ASHP than the $5800 figure based on the Commonwealth Accelerated Renewable Thermal Strategies report, which is already outdated due to advancements in technology.

Report at: http://www.neep.org/sites/default/files/resources/NortheastMid-Atlantic%20Air-Source%20Heat%20Pump%20Market%20Strategies%20Report_0.pdf

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www.acadiacenter.org

FW: National Grid comments from Oct. 30, 2014 meeting

Zaltman, Alexandra (ENV) on behalf of Lowdemandstudy, (ENE)

Sent: Tue 11/4/2014 2:38 PM

To: Aminpour, Farhad (ENE)

From: Stanzione, James [mailto:James.Stanzione@nationalgrid.com]
Sent: Tuesday, November 04, 2014 2:13 PM
To: Lowdemandstudy, (ENE)
Cc: Stanzione, James; Arangio, Elizabeth C. (Marketing); Brennan, Timothy J.; Vaughn, John V.; Holodak Jr, James G.

Subject: National Grid comments from Oct. 30, 2014 meeting

To all :

The following are comments from National Grid concerning the low demand analysis and discussions from the October 30, 2014 meeting :

As a general statement Ngrid believes a scenario which reflects the current status in New England indicating the existing pipeline constraints and its impacts to electric and gas prices for Power Generation be established to compare other scenarios from the low demand modeling. This will allow for the comparison of various modeling scenarios to the current infrastructure and price issues in New England.

Detailed comments :

- ***Natural Gas Price Assumptions and Modeling:***

  National Grid is concerned that the significant and extreme spikes in the basis differential seen in recent winters and expected in the event of any future deficiency of natural gas capacity to demand may not be modeled appropriately and lead to flawed analysis if only yearly or seasonal average gas prices differentials are assumed. Winter peak condition wholesale energy market prices from the simulation model could be significantly understated if the model does not appropriately capture the extreme natural gas price spikes likely to arise in any scarcity of pipeline capacity. This could significantly undervalue the benefits of additional pipeline capacity investments to relieve constraints and lead to questionable evaluation of the relative benefits of alternatives.

- ***Modeling of Reserves for Contingencies, including Non-Gas Contingencies:***

  ISO-NE has reported that during the coldest weather days, it is must carry reserves on gas-fired resources as protection against potential non-gas contingencies, which stresses the interstate pipelines. It is important for the model to appropriately capture such requirements, and analyze costs in the event of such contingencies, even if it is appears gas requirements have been reduced/imbalances eliminated by alternative resources in the security constrained economic dispatch for energy. Moreover, increasing us of intermittent resources will require even greater reserves to be carried by quick start, flexible, gas-fire resources; gas must be available for such reserve requirements. Only unconstrained pipeline capacity sufficient to cover the reserves carried by gas-fired resources can provide the reliability and economic relief needed, and thus must be valued properly.

- ***Incremental Canadian Transmission Sensitivity Assumptions:***

  The analysis of 2400 MW of Canadian hydro assumed to be available at 75 percent on average on a winter peak day and 100 percent in a winter peak hour should also include a simulation of the gas supply vs. demand imbalance and resulting wholesale market costs and reliability concerns in the case of the sudden loss of such capacity. The occurrence of such a non-gas contingency was experienced last winter on the evening of December 14th when New England suddenly experienced a generation capacity shortage event primarily driven by interchange curtailments experienced on the Hydro Quebec interfaces due to HQ suddenly requiring the energy for its own load.

- ***Avoided Costs:***

  The feasibility analysis appears to be using AESC 2013 data. With little time to consider such data, National Grid wishes to simply emphasize the importance of not overstating avoided costs resulting from such data. For example, it appears avoided capacity market costs are being included, and it is not clear how such costs will be avoided at all with some of the alternatives being considered given that the Forward Capacity Market is a marginal clearing price market that, with the recently approved downward sloping demand curve, is designed to produce the long-run cost of new entry on average, at $11.1/kW-month or approx. $4.4 billion/year in capacity market. If the analysis is assuming these alternatives will change this long run average price required to assure resource adequacy in the region, this should be explained. If this is not the expected result, then the use of avoided capacity costs as part of the economic feasibility analyses should be reconsidered, along with other avoided costs as appropriate.

- **Key Modeling Assumptions (Gas utility demand):**

Gas utility demand must incorporate the demand scenarios under which the respective gas local distribution companies must plan, including; design day, design season and cold-snap period. The forecasts should be the most recent forecasts as calculated by the companies. If this information is not utilized when compiling total gas demand, then there will be a disconnect on how the gas companies must plan and the results of the study, rendering the study, 'unrealistic' in this aspect.

- **Gas Pricing/Basis Assumptions**:

The forecast of basis pricing in New England will be critical to the study. Understanding from the last meeting, that this is still a 'work in progress', it is one of the most critical inputs to the study, and will clearly impact the results. The methodology will need to be clearly understood.

- **Role of LNG**:

It was discussed at the last meeting, that LNG was going to be considered as a supply source in the study. It is not clear at this point, if the study is going to consider the LNG behind the LDC gates, and if so, how are volumes and availability going to be determined?

Please let me know if you have any questions.

Thanks

Jim

James A. Stanzione
U.S. Regulation and Pricing
Director of Federal Gas Regulatory Policy
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One MetroTech Center
Brooklyn , NY, 11201
Tel: 929 324 4597
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Email: james.stanzione@us.ngrid.com

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Sent: Tuesday, November 04, 2014 2:13 PM
To: Lowdemandstudy, (ENE)
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Please let me know if you have any questions.

Thanks

Jim

James A. Stanzione
U.S. Regulation and Pricing
Director of Federal Gas Regulatory Policy
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Low Demand Study Feedback - Emera

BLACKMAN, ROGER [Roger.Blackman@emera.com]

Sent: Tue 11/4/2014 2:43 PM

To: Lowdemandstudy, (ENE)

Feedback based on material presented at the October 30th stakeholder meeting:

Assumptions for Incremental Canadian Transmission Sensitivity

As indicated in our comments submitted by email on October 17th, new transmission for electricity imports from Canada should be viewed as carrying a blend of both wind and hydroelectricity (i.e. onshore wind from Maine and/or the Maritime provinces balanced by hydro from Newfoundland & Labrador delivered through Atlantic Canada), with the transmission operated at between 80% and 90% capacity factor. As such, we recommend that the cost of transmission included in the levelized cost calculations for hydro and wind (slides 22 and 39-40) be prorated to reflect the shared transmission capacity.

Thank you for the opportunity to provide feedback and we look forward to the next stakeholder meeting on November 20th.

Regards,

Roger Blackman | Senior Business Development Director | **Emera Inc.**
T: 902-428-6008 | C: 902-229-1865 | F: 902-428-6101

E: roger.blackman@emera.com

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Comments #2 of the Massachusetts Sierra Club on Low Demand Analysis Study by Synapse

Woll, Jr., Edward [ewoll@sandw.com]

Sent: Tue 11/4/2014 2:49 PM
To: Lowdemandstudy, (ENE)
Attachments: Sierra Club Cmte Energy Low Demand Analysis Mass Sierra Club Submitted comments regarding low demand study FINAL 2014-11-04 (B1786760).PDF

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Massachusetts Sierra Club Comments #2
Massachusetts Low Demand Analysis

November 4, 2014

The Massachusetts Sierra Club is grateful for the opportunity to participate with many other stakeholders in the meeting on October 30, 2014 and to submit additional comments. The October 30, 2014 meeting was very informative, as was the "Feasibility Study for Low Gas Demand Analysis" distributed on Friday, October 31, 2014. We look forward to continue working constructively with you and all stakeholders in this effort.

The Massachusetts Sierra Club goals are the same as the Commonwealth's, i.e., to have a clean energy economy in the near future by avoiding policies that perpetuate and increase the excessive dependence on natural gas,[1] by developing a vibrant economy with clean energy jobs and by meeting the Global Warming Solutions Act's goal of reducing green house gasses.

The Massachusetts Sierra Club submits additional Points 7 through 18.[2]

[1] The Commonwealth's dependence on natural gas is trending to supply 60% of the Commonwealth's energy needs. The price of natural gas in Massachusetts has ranged from about $2.00 to as much as $6.00 per mBTU in the past 4 to 5 years. It has been about $4.50 to $5.50 per mBTU since this past winter. Therefore every $1.00 increase in the natural gas price increases the cost of energy for 60% of the Massachusetts economy by about 20%.

[2] The numbering starts at Point 7 because the Massachusetts Sierra Club submitted the still pertinent Points 1 through 6 on October 15, 2014. This submission refers to those Points and attaches them for convenient reference.

Points 7 and 8: Heat Pumps, an Overlooked Resource.

We believe that the potential of heat pumps, both ground source (commonly called geothermal or ground loop) and air source, is not well understood. We request that the report undertake or recommend undertaking an in depth analysis of the potential impact of ground source and air source heat pumps, or identify the lack of such a study as a potentially significant limitation. Heat pumps are incented by Alternative Energy Credits (AEC) by the 2014 passage of "An Act relative to credit for thermal energy generated with renewable fuels", at http://www.eesi.org/articles/view/massachusetts-bill-rewards-renewables-used-for-heating-and-cooling. We request that the report estimate both the effect of that recently passed bill and the likelihood it will accelerate development and installation of such heat pumps before any increased pipeline capacity can come on line. Omission of such an estimate should be noted as a limitation.

Point 7: **Ground Source Heat Pumps**:

Ground source heat pumps displace both electricity and natural gas usage. Ground source heat pumps both cool and heat. In cooling, they significantly reduce the use of electricity for air conditioning compared to conventional systems. The heating capability of ground source heat pumps displaces gas and oil entirely when compared to gas and oil fueled heating systems and displaces electricity use when compared to electric heat. Ground source heat pumps will require electricity to operate the pumps, compressors and fans. That relatively small amount of electricity can come from the grid and local solar panels. Electricity from the grid will increasingly be supplied from clean and renewable sources.

The potential impact is very large and likely significantly underestimated. One source of information on the effectiveness, market viability and benefits of ground source heat pumps is a Massachusetts company, EnergySmart Alternatives, LLC.[3] So far in 2014, EnergySmart has installed 30 units in 23 homes, and has installed many more in prior years. Approximately, 50% are retrofits and 50% are new construction. (Email correspondence). In summary, EnergySmart's 23 installations in 2014 supply an annual heating load of 1.825 million BTUs with 123 tons (1,476,000 Btuh) of geothermal heat pump equipment. These installations require in the aggregate modeled electricity use of 161,300 kWh per year to drive pumps, compressors and fans. See in Addendum A hereto EnergySmart letter and industry data on effect of different levels of market penetration. Based on those actual installed figures, the potential of geothermal heat pumps to replace thermal natural gas heating and cooling and electricity driven cooling and heating is enormous.

Also significant is that ground source heat pumps make more effective use of the electrical grid. They are 300 to 400% efficient: that is to say, for every unit of electricity consumed, 3 to 4 units of heat are transferred by the system into a home or other building.

Cost effectiveness. It has been mistakenly suggested that ground source heat pumps are too expensive compared with oil and gas heating. The credible study by the Rocky Mountain

3 EnergySmart Alternatives, LLC, Owner, Melanie Head, PhD, Mobile: 617-955-0063, Fax: 617-977-8982, www.EnergySmartAlternatives.com

Institute shows that heat pumps in New England, both ground source and air source, are far more economic than oil heating, "Heat Pumps: An alternative to oil heat in the northeast" at http://www.rmi.org/Knowledge-Center/Library/2013-05_HeatPumps The RMI report shows that the heat pump advantage extends also to natural gas heating, especially given the inevitable increase in gas price, and avoids the undesirable – and unacceptable - alternative of expanding natural gas pipeline infrastructure.

It is already well known that cost of energy from the capital investment of a heat pump amortized over its 30 year plus life, will be far less expensive than natural gas or oil driven heating and cooling over that period.

The "Feasibility Study for Low Gas Demand Analysis: distributed on Friday, October 31, 2014 relies on an NREL webinar entitled "Residential Geothermal Heat Pump Retrofits" ("Feasibility Study for Low Gas Demand Analysis" distributed on Friday, October 31, 2014 p. 23 fn 21). The economics are quite different for heat pumps installed not as retrofits but as part of new construction. For example, a major part of the installation cost of a ground source system for a ten unit subdivision, for example, would be absorbed in the cost of water, electricity, sewer, cable, road and driveway infrastructure.

Point 8: Air Source Heat Pumps.

Air source heat pumps displace both electricity and natural gas usage . Air source heat pumps were installed typically for cooling, thereby displacing not only the use of electricity to power room air conditioners but also gas powered air conditioning systems. The heating capability displaces both gas and oil fueled heating systems and electric heat as well.

Air source heat pumps also require electricity to run them, but that electricity may come from local solar panels supplemented by the grid, which will increasingly be supplied from clean and renewable sources.

The potential impact is very large and likely dramatically underestimated. A resource for information regarding savings of natural gas by installing and in the cost of, and the rate of installation of air source heat pumps in Massachusetts is NextStep Living. http://www.nextstepliving.com/. It has been conjectured that air source heat pumps are not 100% effective in very cold weather. We suggest that conjecture be tested by applying first energy efficiency technology and methodology.[4]

Cost effectiveness. It has also been suggested that air source heat pumps are too expensive compared with oil and gas heating. The factors affecting the cost effectiveness and competitive advantage of a ground source heat pump pertain to the air source heat pump.

Point 9: The impact of energy efficiency is likely underestimated.

NSTAR's Mass Save advertising of ENERGY STAR® certified LED bulbs says: "Lighting accounts for about 20% of the electric bill in the average U.S. home." See Addendum B.

[4] NextStep Living LLC alone has been installing on average 65 ductless mini-splits per month in Massachusetts, demonstrating market acceptability and data that is not likely being tracked publicly. Source: email correspondence.

Energy efficiency through replacement of incandescent lighting and use of LED lighting should not be underestimated. We request that the report estimate retail purchases as well as subsidized purchases or note the lack or inability to provide retail purchase estimates as a limitation.
One resource for information regarding the potential for reducing the need for natural gas through energy efficiency technology and practices and their application in Massachusetts is NextStep Living, http://www.nextstepliving.com/, which has conducted thousands of home energy audits.

Point 10: **The impact and degree of natural gas price sensitivity and potential to rise is likely underestimated**. We request that the report include the impact on the future price of natural gas in New England the upward price pressure due to the export of natural gas as LNG, which may start as early as the end of 2016. See http://www.eia.gov/analysis/requests/fe/ and **Point 3**, p. 5 of attached October 20, 2014 comments. A principal driver of choice of clean and renewable energy technology will be cost. The major competitor for clean and renewable energy resources is natural gas.
Natural gas for export as LNG is already being contracted for. See "Wall Street is seeing what some refuse to -- U.S. gas exports in big volumes" at
http://www.eenews.net/energywire/stories/1060006051/search?keyword=LNG+wall+street

Point 11: **Economic feasibility factors**. We request that the report consider in determining economic feasibility that the amortized cost of renewable energy facilities fixes the cost of energy over 25 year or greater lifetimes and is independent of the volatility of ever rising natural gas prices. For example, the capital investment in clean and renewable energy facilities amortized over their lifetime will be far less expensive than using natural gas on a pay-as-you-go basis for that period. We suggest that capital can be provided by low cost financing alternatives, and that the ultimate savings in energy cost will be ploughed back into the state's economy.
If the report does not take into account the amortized lifetime cost of clean and renewable energy resources as a favorable resource selection criteria, we request that omission be included in the list of the report's limitations.

Point 12: **Technological feasibility factors**. We request that the report take into account that policies that promote investment in natural gas infrastructure will undercut investment in clean and renewable energy sources and thus slow technological advances. Therefore we suggest that the report highlight the extent to which it is taking into account that effect, or note that it is not accounting for that effect and also note that increased technological feasibility of clean and renewable sources would likely occur earlier and accelerate if investment in natural gas infrastructure is deferred. See **Point 2** of attached October 20, 2014 comments.
If the report does not take into account the disincentive to investment in clean and renewable energy technology that will be created by policies favoring the expansion of natural gas infrastructure and use, we request that omission be included in the list of the report's limitations.

Point 13: **Economics of resource selection**. How economic and technological feasibility are determined will determine what resources alternative to natural gas will be "available" and when in the composition of the report.[5]

Point 14: **Natural gas storage facilities to buffer shortages**. We request that the report consider the economic feasibility and impact of constructing compressed gas storage tanks as reservoirs to buffer shortages and enhance deliverability at peak demand periods rather than constructing new, large gas pipeline infrastructure.[6] The storage tanks can be filled during low demand periods at a lower cost than at peak demand, thereby evening out and increasing the use of existing pipeline capacity.[7] Use of storage tanks will augment the current practice of line packing to store natural gas in existing pipelines.

Point 15: **The cost of solar pv is overestimated and growth underestimated**. The utilityscale, commercial and residential solar pv may be significantly underestimated in each of the 2015, 2020 and 2030 resource assessments. The state historically has underestimated the adoption of solar in the state as well as the market for SRECs. Moreover, the 2013 cost figures used are not current or applicable to the future. "Deutsche Bank: Solar to Reach 'Grid Parity' in Nearly All States by 2016" BNA, Inc. Daily Environment Report - Afternoon Briefing. *Posted October 27, 2014, 1:07 P.M. ET*
Residential prices are falling below $4 per watt.[8] Large scale utility solar is being installed for less than $2.00 per watt. And incrementally lower prices can be reasonably expected in the near future. See http://investors.solarcity.com/releasedetail.cfm?ReleaseID=871036

Point 16: **Limitation to be identified**. The report does not take into account changes in users' behavior or incentives to change usage of electricity during peak demand periods. Those changes are induced by the rising price of natural gas powered electricity generation and thermal heating can be stimulated by innovative retail marketing and demand side management incentives.

Point 17: **Limitation to be identified**. We request that the report identify as one of its limitations that has not been fully considered and factored into the report the impact of net zero carbon zoning codes. Cities such as Cambridge, Massachusetts have convened a task force study for developing net zero carbon zoning. See http://www.netzerocambridge.org/ and http://www.cambridgema.gov/cdd/projects/climate/~/media/D25E9C85B358488BBDC1D734D29F6E5E.ashx

[5] The Massachusetts Sierra Club assumes that coal and oil fired electricity generation will disappear and not remain in the energy mix. We also believe that oil fired heating systems will be replaced by clean and renewable facilities and that expansion of natural gas to areas not now served by natural gas is an unacceptable alternative or option both from a greenhouse gas standpoint as well as a non-viable long term economic alternative, especially for Massachusetts, and for New England as well. Massachusetts's excessive dependence on natural gas requires exporting dollars to buy fuel rather than investing those dollars in Massachusetts in clean and renewable energy.

[6] Such storage tanks are in addition to existing LNG storage.

[7] A 200 foot diameter, 60 foot high tank is equivalent in volume to 50 miles of a 36 inch natural gas pipeline.

[8] See Commonwealth Solar and Solarize Massachusetts results at http://www.masscec.com/content/commonwealthsolar-installers-costs-etc that 24% of (906 of 3777) 2014 applications

Somerville, MA has announced the goal of being carbon neutral by 2050.
https://unionsquaremain.org/blog/

Point 18: **Limitation to be identified**. We request that the report identify as one of its limitations that has not been fully considered and factored into the report the impact of the voluntary trend to green building demands of the marketplace.

The base case is a look at the status quo and therefore is a useful tool, a stepping stone, to achieve the desired goal for the Commonwealth to have its economy, public health and environment benefit from a 100% clean energy future. That goal will drive how energy policy and infrastructure is developed and built.

Feasible objectives are two fold. First: to develop and deploy sufficient peak shaving energy resources and policies incenting alternatives to natural gas over the time it will take to permit, construct and commence operating additional natural gas pipeline capacity and thereby assure and confirm that additional pipeline infrastructure is superfluous. Second: to deploy those resources in a manner to pave the way for energy and grid management programs and economic and technological improvement that will reduce over the long term the overall demand for energy sourced with natural gas.

We appreciate your considering these requests.

Respectfully

Edward Woll, Jr., Massachusetts Sierra Club
Vice-Chair, Chapter Energy Chair
ewoll@sierraclubmass.org
617-338-2859

ADDENDUM A

EnergySmart Alternatives, LLC
PO Box 304
Medford, MA 02155
Phone: 617-955-0063
Fax: 617-977-8982

October 31, 2014

Mr. Edward Woll
Sullivan & Worcester LLP
One Post Office Square
Boston, MA 02109
Via email: ewoll@sandw.com

Re: Geothermal Installations in Massachusetts

Dear Mr. Woll,

I am writing in response to your request for information about the number and capacity of ground source heat pump (geothermal) installations EnergySmart Alternatives, LLC will have completed during the 2014 calendar year. The following table summarizes our installations in 2014 based on contracts received to date:

Number of residences installed	23 homes
Number of geothermal heat pumps installed	30 units
Total capacity of systems installed	123 tons (1,476,000 Btuh)
Total annual heating load satisfied by geothermal heat pumps	1,825 Million Btu
Modeled electricity use for heating via geothermal	161,300 kWh per year

Please do not hesitate to call or email if you have any additional questions.

Sincerely,
EnergySmart Alternatives, LLC

M Head

Melanie Head, PhD
Owner

Potential Benefits of GHPs

Potential benefits of retrofitting existing U.S. single-family homes with GHP systems at various market penetration rates

Estimated National Benefit	Market Penetration Rate of GHP Retrofit				
	20%	40%	60%	80%	100%
Primary Energy Savings (Quadrillion BTU)	0.8	1.7	2.5	3.3	4.2
Percent Energy Savings (Quadrillion BTU)	9%	18%	27.1%	36.1%	45.1%
CO2 Emissions Reduction (MM Ton)	54.3	108.7	163.0	217.3	271.17
Percent Decrease in Carbon Emissions	9.1%	18.1%	27.2%	36.2%	45.3%
Summer Peak Electrical Demand Reduction (GW)	43.2	86.4	129.5	172.7	215.9
Percent Reduction in Summer Peak Electrical Demand	11.2%	22.4%	33.6%	44.9%	56.1%
Energy Expenditure Savings (Billion $)	10.4	20.9	31.3	41.7	52.2
Percent Reduction in Energy Expenditures	9.6%	19.3%	28.9%	38.5%	48.1%

Source: *Assessment of National Benefits from Retrofitting Existing Single-Family Homes with Ground Source Heat Pump Systems - Final Report* - Xiaobing Liu. Oak Ridge National Laboartory – 2010.

ADDENDUM B


EASY WAYS TO SAVE
WITH NSTAR THIS FALL
• Lighting accounts for about 20% of the electric bill in the average U.S. home. Switch to ENERGY STAR® certified LED bulbs to save energy and money!
• Electronic devices, such as DVD players and game consoles, use energy even when they are turned off. Cut this standby power loss with an Advanced Power Strip.
See reverse side for discounted pricing courtesy of NSTAR!
NSTAR
mass save

SIERRA CLUB
FOUNDED 1892
MASSACHUSETTS CHAPTER

Massachusetts Sierra Club
10 Milk Street, Suite 417
Boston MA 02103-4600

www.sierraclubmass.org
office@sierraclubmass.org
(617) 423-5775

Massachusetts Sierra Club Comments
Massachusetts Low Demand Analysis

October 20th, 2014

The Massachusetts Sierra Club is grateful for the opportunity to participate with many other stakeholders in the meeting on October 15, 2014 and to submit additional comments. We look forward to continue working constructively with you and all stakeholders in this effort.

The goals of the Massachusetts Sierra club are the same as those of the Commonwealth, i.e., to have a clean energy economy in the relatively near future by avoiding policies that perpetuate and increase the excessive dependence on natural gas, which is trending to supply 60% of the Commonwealth's energy needs, [9] by developing a vibrant economy with clean energy jobs and by meeting the Global Warming Solutions Act's goal of reducing green house gasses (GHG).

The Massachusetts Sierra Club has read and supports the comments submitted by the signatory stakeholders to ENE's (Environment Northeast) letter and submits the following requests.

Point 1: The goal of the Commonwealth is to have a clean energy economy. Therefore, we request that the study be written so that its results can be used to enable decisions to be made that advance that goal.

Point 2: We request that you take into account that increasing natural gas imports and pipeline infrastructure will reduce the incentive and slow the pace of investment in clean and renewable energy sources and energy efficiency and will impair the Commonwealth's goal of achieving a clean energy economy.

Point 3: We request that the report identify risk factors that may affect its conclusions so that decision makers and stakeholders may identify and develop policies that advance the goal of a clean energy economy. The following are some examples of specific risk factors:

[9] The price of natural gas in Massachusetts has ranged from about $2.00 to as much as $6.00 per mBTU in the past 4 to 5 years. It is about $4.50 to $5.50 per mBTU since after this past winter. Therefore every $1.00 increase in the natural gas price increases the cost of energy for 60% of the Massachusetts economy by about 20%.

- The effect of a revenue neutral carbon tax being adopted in Massachusetts. We would hope that you would also quantify that effect to the extent you are able in the time frame available. See "Modeling the Economic, Demographic, and Climate Impact of a Carbon Tax in Massachusetts" by REMI available at http://www.remi.com/carbon-tax-study

- The effect on the United States market price of natural gas of exporting United States produced natural gas as Liquid Natural Gas (LNG).

  There is a consensus that export of domestic gas as LNG will put upward pressure on domestic prices because of higher global market prices and reduced domestic supply.

  The global market price for LNG in recent years has ranged from about $10 per mBTU (or mmBTU depending on the convention one uses) in Europe and as high as $20 per mBTU in Asia compared to US market price ranges set out in footnote 1. See discussion of links between global natural gas and global oil market prices and price volatility and unpredictability at http://www.eia.gov/analysis/requests/fe/.

  An export terminal at Cove Point, MD may open as early as 2016, and there are applications pending for over 36 LNG export terminals in the United States. Massachusetts has at least three off shore conduits that could be used to export natural gas as LNG, and at least two LNG export terminals are being developed in the Canadian Maritimes, accessible by a pipeline (capacity: 833 mmcf/day) owned by Maritimes Northeast that currently flows to Dracut and Beverly, MA but could be reversed to export gas. There is limited ability to restrict gas export to Canada to those terminals.

  Dow Chemical uses natural gas domestically as industrial feedstock oppose exporting for price reasons and have most likely done thorough studies on the impact of exporting LNG on domestic natural gas prices and availability. See "Dow exec warns of policy-driven price spikes for homeowners" at http://www.eenews.net/energywire/2014/05/23/stories/1060000089

- The impact of the Environmental Protection Agency's new emission standards for fossil fueled electricity generation and the impact on both natural gas price and availability of reasonably foreseeable regulations for methane emissions now being considered by the Environmental Protection Agency.

- The possible regulation of methane under Massachusetts's Global Warming Solutions Act. Methane is a green house gas (GHG) that is measured in a relevant time frame as being 80 to 100 times more powerful a greenhouse gas than carbon dioxide, pound for pound.

Point 4(a): Given the dysfunctional separation between the thermal gas and electric power generation gas markets, thermal being supplied under long term contracts that tie up most of the pipeline capacity and electric power generation gas market being acquired under relatively shorter term contracts and on the spot market, we request that you consider changes in market policies that would better allocate natural gas in times of exceptional need, such as a very hot summer or a cold snap in winter.

Point 4(b): LDCs contract long term for pipeline capacity. We request that you examine the LDCs short and long projections to make sure they are properly discounted or adjusted downward to reflect the impact of each of the following alternative sources of thermal energy:

- Improvements in energy efficiency to reduce heating demand.

- Improvements in thermal energy conservation by insulation, smart thermostats, modern windows and doors, and other such devices and technologies. Massachusetts has led the nation for the past three consecutive years in energy efficiency improvements.

- Competition by both ductless, air source and ground loop heat pumps, which will reduce the demand for thermal energy sources. Please take into account the following:

  passage this year of "An Act relative to credit for thermal energy generated with renewable fuels", http://www.eesi.org/articles/view/massachusetts-bill-rewards-renewables-used-for-heating-and-cooling, and the likelihood of accelerated development and installation of such heat pumps during the period before a increased pipeline capacity comes on line. [10]

  such heat pump installations will most likely initially happen in areas served by oil heating and propane tanks, thereby reducing the future market for natural gas. See Addendum A.

- The eligibility for thermal renewable energy credits under the new legislation of certain CHIP facilities and the limited scope of eligibility of certain facilities powered by biomass.

- The effect of reducing gas leaks in order to comply with the recently passed Act Relative to Natural Gas Leaks. http://www.mass.gov/governor/pressoffice/pressreleases/2014/0707-governor-signs-gas-leaks-legislation-.html

- As the future demand for natural gas is reduced by the foregoing factors, please consider the likelihood that LDCs will end up with excess gas, with the only market being the export LNG market with higher prices and without strict resale price and volume controls for that excess. It would be to the LDCs advantage to over estimate their needs as a hedge and then sell any excess to electric power companies in the short term at higher prices. One method of over procurement is discussed in DPU Docket 14-111, Affidavit of Mellissa Whitten, ¶¶27-31.

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[10] A qualifying energy source under the act includes:

"(i) combined heat and power; (ii) flywheel energy storage; (iii) energy efficient steam technology; (iv) any facility that generates useful thermal energy using sunlight, biomass, biogas, including renewable natural gas that is introduced into the natural gas distribution system, liquid biofuel or naturally occurring temperature differences in ground, air or water, whereby 1 megawatt-hour of alternative energy credit shall be earned for every 3,412,000 British thermal units of net useful thermal energy produced and verified through an on-site utility grade meter or other means satisfactory to the department; provided, however, that facilities using biomass fuel shall be low emission, use efficient energy conversion technologies and fuel that is produced by means of sustainable forestry practices; or (v) any other alternative energy technology approved by the department under an administrative proceeding conducted under chapter 30A."

"The following technologies and fuels shall not be considered alternative energy supplies: (A) coal; (B) petroleum coke; (C) oil; (D) natural gas, except when used in combined heat and power or as a biogas generating useful thermal energy; (E) construction and demolition debris, including but not limited to chemically treated wood; and (F) nuclear power."

Point 4(c): We request that you consider and factor into your report the impact of the following on the need for electricity generated from natural gas:

- Improvements in energy efficiency to reduce electricity demand, including full conversion to efficient lighting.
- Increased generation of solar electric by solar, mainly photo voltaic and the increasing reduction in cost of solar facilities.
- Development of wind power, which, in combination with solar, increases the capacity factor of the solar and wind combination of as two intermittent sources, making it more reliable.
- Accelerating improving and upgrading the grid to accommodate intermittent and distributed electric energy sources and adding grid capacity so as to utilize fully existing energy resources, such as wind in Maine that is now being spilled.

Point 5: Consider as a likelihood that last summer's and last winter's shortfalls resulted from the electric power companies not adequately accounting for the contingencies of such very hot or very cold spells and that the issue is not pipeline capacity but a lack of adequate contingency planning. This involves considering how peak demand can be reduced or accommodated three or so years from now, i.e., at a time when more pipeline capacity may otherwise come online. For example, LNG should be considered as a means of accommodating possibly 5-20 peak days per year. The LDC's, we understand, may have as many as 46 peak-shaving storage facilities in New England, with others being planned, but it is difficult to determine what percentage of the 16 Bcf of storage can be or is currently used for electricity generation. And has the DistriGas (Everett) LNG terminal storage capability of 3.4 Bcf been underutilized (having received 60 Bcf/yr in 2013 versus 140 Bcf/yr in 2011) and been used to supply primarily the Mystic power station (1,550MW)?

Point 6: Wind, solar and geothermal are principally capital expenditures of long life (20 to 30 years) with relatively little variable cost so that energy costs over their life are fixed. We request that you take into account in determining what is economically feasible what is the appropriate price point to use over the next 20 to 25 years to assess economic feasibility of these long term capital investments in wind, solar and geothermal (heat pumps). Fossil fuel prices are volatile and trending up over the long term. See, for example, http://www.eia.gov/analysis/requests/fe/

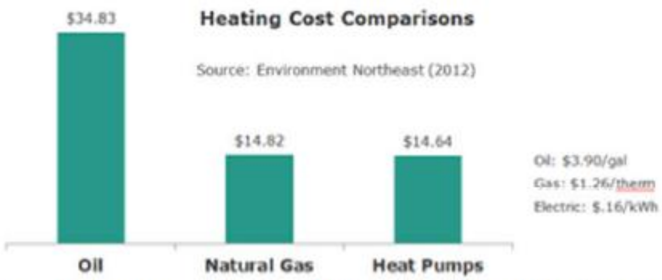
We appreciate your considering these requests.

Respectfully

Edward Woll, Jr., Massachusetts Sierra Club
Vice-Chair, Chapter Energy Chair
ewoll@sierraclubmass.org
617-338-2859

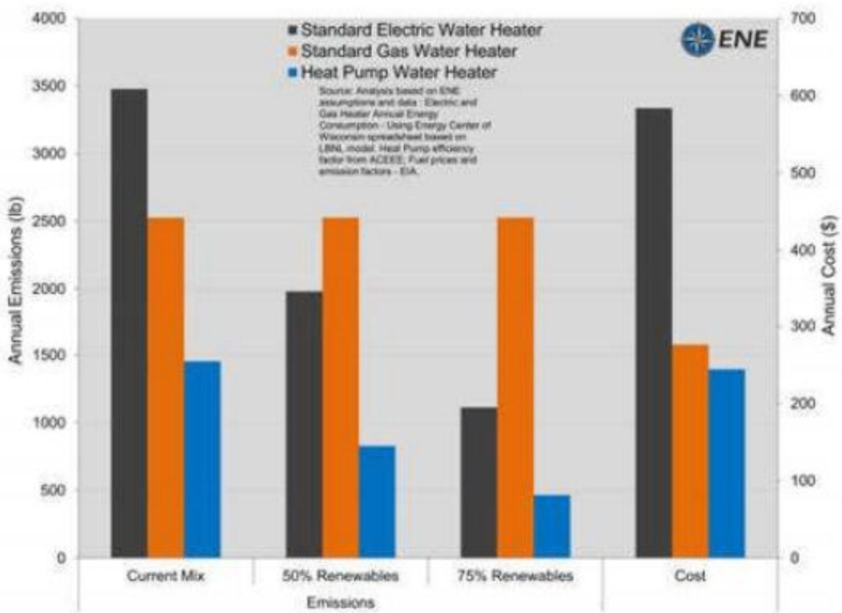
ADDENDUM A

See for example "Heat Pumps, and alternative to oil heat in the northeast" at http://www.rmi.org/Knowledge-Center/Library/2013-05_HeatPumps.
From a 2012 ENE study:



See also, among other available sources, the following from Environment Northeast regarding water heating: http://www.env-ne.org/public/resources/ENE_EnergyVision_Framework_FINAL.pdf

Cost and Emissions Savings from Heat Pump Water Heaters



Low Demand Study Comments

moloney [moloney@progress.com]

Extra line breaks in this message were removed.

Sent: Tue 11/4/2014 3:17 PM

To: Lowdemandstudy, (ENE)

Attachments: Low Demand Analysis Stakeholder Comments - DJM.docx

November 4, 2014

Massachusetts Department of Energy Resources (DOER)

Submitted Electronically to lowdemandstudy@state.ma.us

Low Demand Analysis – General Comments

The obvious must first be stated – that the Low Demand Study has not fed the proper metrics into its energy source analysis which is antithetical to its objectives. The inherent leakage of CH_4 from well head to burn (conservatively at about 5%) and methane's significant capacity to trap heat are neither factored into base case assumptions nor the true cost of forgoing MA RPS commitments under RGGI or its GWSA legal obligations because of it. The true cost of introducing new gas supply versus the cost of off-shore wind or solar are not being properly contrasted if methane emissions are absent from the comparative demand analysis for gas and its true price point.

Getting a good cement seal on wells is an unresolved engineering challenge that has avoided resolution for decades, now centuries, of drilling for oil and water. This fact is exacerbated by the higher challenge of now trying to contain gas supply over the next 30-100 years. From a Greenhouse Gas perspective, the inconvenient truth is that leaking methane places natural gas, as an alternative, on par with coal and oil. We should be considering these factors prior to the consideration of unprecedented investment in natural gas infrastructure that will create even greater energy security risk to New England for the longer term. Over-dependence on a single carbon-based fuel source would also come at the expense of carbon-free infrastructure investment and would act as an inhibitor to carbon-free supply curves over longer horizons, including 2020 and 2030.

Low Demand Analysis Recommendation

In reference to the above General Comments, it is essential that the base case and low demand projections include factorizations for methane leakage. But, more important, when the Low Demand Study begins to draw its final analysis, it is imperative that it super-impose atop of its projections the standard deviation of its chosen fuel supplies from RGGI and GWSA requirements which have already been committed over a longer term than the Low Demand Study. Each degree of deviance built into the final analysis represents a hidden cost to the future of energy sourcing for Massachusetts and New England. Since the Low Demand analysis is only factored out to the year 2030 and our carbon reduction commitments are factored up the year 2050, we need to have an understanding of how much it will cost us to recover tomorrow from compromises made today as a result of our energy planning.

Factoring in approvals of incremental gas proposed along existing rights of way

Point blank, we do NOT need new natural gas infrastructure to meet our low demand objectives. If all existing pipe to New England ran at full capacity for the whole year, there would still be significant availability of natural gas (for about 1/3 of the year) that could be stored as liquid natural gas (LNG) during low demand days that could be redistributed back into the supply chain during peak demand.

It should be acknowledged that more and more of the existing gas supply is being committed to long term DLC contracts and that this demand has placed a significant squeeze on fuel supply for gas-fired electrical production. However, it is also critical that the Low Demand Analysis consider the probable effects of the following new projects and their potential to change the gas infrastructure landscape in the near term. Using existing rights of way, the gas supply profile in Massachusetts and New England may soon change dramatically if the following subsequent capacities and their in-service dates are approved by the FERC:

1) *Tennessee CT Expansion (0.072 bcf) – Est. In-service Nov. 2016*
2) *Algonquin AIM (0.342 bcf) – Est. In-service Nov. 2016*
3) *Portland – C2C Expansion (up to 0.182 bcf) – Proposed Est. In-service Nov. 2016*
4) *4) Algonquin – Atlantic Bridge (up to 0.6 bcf) – Proposed Est. In-service Nov. 2017*

Near term solution to Winter Reliability

The 700 MW shortfall of power supply for which NESCOE's incremental gas initiative was originally proposed is theoretically solvable by the introduction of a single conventional LNG storage facility.

Given the accepted industry formula that 1 Mcf/d or 1 Dth/day of natural gas can produce 293 KWh's of electricity, 700 MWh's (the current shortfall) of electricity (700,000 KWh/293 KWh's) requires 2389 Mcf or 2.390 MMcf of gas.

A large conventional on-shore tank with 160,000 m^3 of LNG at NG compression rates of 600/1 can store 3.389 bcf of natural gas assuming a metric conversion of 1 m^3 = 35.3 ft^3. This is far more capacity than would be required to satisfy any electrical supply shortfall over the long term, far beyond the 700 MWh for which gas supply was originally proposed.

Conventional LNG tanks like the one specified above take approximately 34 months to construct at a cost of approximately $130M dollars, a considerable savings over the enormous costs of new pipeline capacity. A precast concrete alternative for LNG Storage, known as a Composite Concrete Cryogenic Tank (or C^3T) can now be built with a 10-15% capital cost reduction over conventional storage, can be built much larger than the 160,000 m^3 size limits of conventional tanks, are less labor intensive and can reduce construction time by upwards of 9 months.

The avoided costs associated with LNG are potentially tremendous. Assuming some existing or some new capacity can be dedicated to storage. However, there are two important feasibility measures that remain unstated but need to be factored into the realization of LNG storage:

1. Vaporization rates are limited. Improved infrastructure on existing tanks and infrastructure investment in new tanks would likely resolve the problem of vaporization and still at very significant cost reduction over additional pipeline capacity infrastructure.

2. All LNG production currently is commercial in nature which makes supply vulnerable to private speculation rather than public need. For decades, water has been recognized by municipalities as a valued community resource. Municipal water tanks have supplied potable water for human consumption, irrigation, fire suppression, etc. since the 19th century. The recognized value of water as a resource has necessitated public investment into the construction of municipal water tanks throughout the United States. It is time for our governments to make executive decisions regarding the need for LNG storage as a reliable means of resolving winter peak events without overbuilding natural gas capacity.

Public or public/private ventures to both construct and reserve LNG supply to the energy market is likely to pay for itself in most years as it would introduce supply into the wholesale market at advantageous times and at predictable rates while avoiding the volatilities of speculative supply demand in the commercial market. It should be noted that in some states, DLC's are already required by law to secure certain contracts with private LNG suppliers in order to lock in energy supply and rates that protect businesses and citizens. Extending the regulatory regime to include LNG supply makes sense for both our immediate and collective need in Massachusetts as well as our longer term energy project targets for New England as a whole.

Thank you for the opportunity to participate as we move forward in trying to chose wisely for our energy future.

For specific questions or additional information please contact David Moloney: moloney@progress.com, 781-280-4337.

Sincerely,

David J. Moloney,
nhpipelineawareness.org

Comments by Portland Natural Gas Transmission on Low Demand Study

From: Susan Rivo [mailto:Susan@raabassociates.org]
Sent: Tuesday, November 04, 2014 4:52 PM
To: Liz Stanton; Aminpour, Farhad (ENE); Lusardi, Meg (ENE); McBrien, Joanne (ENE); Jonathan Raab
Subject: FW: Comments by Portland Natural Gas Transmission on Low Demand Study

Just wanted to make sure you got this.

Susan Rivo

Raab Associates, Ltd.

118 South St., Suite 3A

Boston, MA 02111

tel 617-350-5544

fax 617-350-6655

susan@raabassociates.org

www.raabassociates.org

From: Cynthia Armstrong [cynthia_armstrong@transcanada.com]
Sent: Tuesday, November 04, 2014 4:33 PM
To: lowdemandstudy@state.ma.us; Susan Rivo
Cc: Keith Nelson; Richard Bralow
Subject: Comments by Portland Natural Gas Transmission on Low Demand Study

Ms. Meg Lusardi
Acting Commissioner
Massachusetts Department of Energy Resources
100 Cambridge Street, Suite 1020
Boston, MA 02114

November 4, 2014

Dear Acting Commissioner Lusardi:

Portland Natural Gas Transmission System ("PNGTS") commends the Massachusetts Department of Energy Resources ("DOER") for taking a comprehensive view of the State's energy portfolio needs and appreciates the opportunity to participate in the Low Demand Analysis. Massachusetts has been a national leader in energy efficiency and environmental protection, and the methodology of Synapse's Low Demand Analysis reflects this prioritization.

PNGTS's Continent to Coast ("C2C") Project offers Massachusetts the most environmentally sound, efficient and cost-effective solution to meet its necessary natural gas pipeline capacity requirements. C2C is essentially an energy efficiency project:

- The C2C expansion makes more efficient use of existing pipeline infrastructure – putting more gas through an existing line already in the ground.
    - This will result in greater utilization of the same infrastructure, with rates expected to decrease by over 31% from the currently filed recourse rates.
- NO construction is required on PNGTS.
    - Relatively minor expansion upstream on TransCanada Pipelines Limited ("TCPL") will push this extra gas to PNGTS, for delivery into PNGTS' existing pipeline infrastructure at Dracut, Haverhill and Methuen, MA.
    - There are no expected disruptions to Massachusetts landowners.
    - There are no construction/permitting delay issues on C2C that would increase costs and risks for Massachusetts energy consumers. Likewise, it is not expected that TCPL will experience such delays in its upstream expansion.
- C2C accesses Marcellus gas via TCPL at Northern and Western New York export points, as well as from land-based Western Canadian supplies in Alberta and British Columbia.
- C2C is right-sized: it is expandable by up to 167,000 MMBTU/day. It meets the reasonable expansion needs of the region without necessitating a massive overbuild.

The dramatic growth of North America shale gas has significantly reduced CO2 emissions and energy costs. Greater volumes of clean, cheap natural gas are supplying the backup requirements of intermittent renewable energy sources, as well as feeding the increased demands for electric generation, heating and industrial processes.

C2C, like other natural gas pipeline projects, requires long term commitments from creditworthy market participants. PNGTS would ask the DOER to support commitments by either LDCs or EDCs to commit to pipeline infrastructure expansions and to recommend the C2C Project as the first tranche to be fulfilled for the region.

Thank you,

Cynthia L. Armstrong
Director, Marketing and Business Development
Portland Natural Gas Transmission System
One Harbour Place, Suite 375
Portsmouth, NH 03801

Cc: Keith Nelson, President, PNGTS
Richard Bralow, Legal Counsel, PNGTS

nofracked gasinmass.org
Protect Our Common Wealth

Rosemary Wessel, Founder
nofrackegasinmass@gmail.com • 90 Trow Road, Cummington, MA 01026 • 413-634-5726

November 4, 2014

Synapse Energy Economics
485 Massachusetts Avenue, Suite 2 Cambridge,
MA 02139

Re: Massachusetts Low Demand Study

Dear Synapse,

In your price calculations regarding future prices of natural gas, please use the highest gas prices available for calculation. There are many factors that make this necessary, especially given the increased reliance on natural gas if additional pipeline capacity is considered. In a state already nearly 2/3 dependent on natural gas, increasing our reliance leaves us even more subject to market volatility, whether price swings are determined by competition with foreign markets through expected exports or from the increasingly-evidenced specter of a shale gas production bubble about to burst.

As recently reported by Bill Powers in Forbes magazine, the seeming stability of the natural gas market is likely to be short-lived: "America's shale gas resources and reserves have been grossly exaggerated and today's level of shale gas production is unsustainable. In fact, due the distortions of zero interest rates and other factors, an enormous shale gas bubble has developed. Like all bubbles, this one will pop sooner than expected and when it does, the aftermath will be very unpleasant. … the shale gas boom is rapidly maturing and we are quickly approaching a point where shale gas production heads into decline. In fact, the majority of shale gas basins in America are already exhibiting declining production."[1]

His assessment of the inaccuracies of the EIA's estimates of technically recoverable resources shows that their tendency is to grossly overestimate the availability of recoverable gas, mostly refuted by reports from the US Geological Survey. After taking the USGS studies into consideration the EIA's stated estimate of 750 tcf of shale was reduced to 481 tcf, which, at 2013 rates of production brings the total down to approximately a 19 year supply from the original estimates of up to 100 years' supply.[2]

As one shale play after another hits and early peak and decline, there is mounting evidence that EIA's methods of determining TRR need to come into question. A more accurate model for determining market prices would be one similar to that proposed by the Rocky Mountain Institute in it's July 2012 paper "Utility-Scale Wind and Natural Gas Volatility: Unovering the Hedge Value of Wind for Utilities and Their Customers" (attached). They suggest considering natural gas price volatility should be reflected as a risk premium added to the existing contract price.[3] This seems the only fair and accurate way to calculate the true cost of increasing long-term dependency on a finite and dwindling fuel source with a high potential for price spikes and global market volatility.

1 - Bill Powers, "The Popping of the Shale Gas Bubble", Forbes Magazine, September 3, 2014. http://www.forbes.com/sites/billpowers/2014/09/03/the-popping-of-the-shale-gas-bubble/

2 - ibid

3- p. 10, Lisa Huber, "Utility-Scale Wind and Natural Gas Volatility: Uncovering the Hedge Value of Wind for Utilites and Their Customers", Rocky Mountain Institute, July 2012 (attached)

From:	Shop_Angel
To:	Lowdemandstudy, (ENE)
Subject:	Copy of comment, including name & address
Date:	Tuesday, November 04, 2014 4:34:04 PM

In submitting this comment one minute ago, I failed to include my name & address:
Ariel Elan
P.O. Box 351
Montague, MA 01351

Dear Dr. Stanton and team, and Ms. Lusardi~
Thank you for the opportunity to comment on the low-demand energy study for Massachusetts that is currently underway. In consideration of Dr. Stanton's request at the Oct. 30 stakeholder meeting, I will submit my comments as much as possible as separate emails addressing individual aspects of the study.

Gas Exports and Future Prices
Among the many articles from the business and industry press that cross my desk almost daily, the unanimous consensus to date is that increasing exports of natural gas will inevitably raise domestic gas prices. Prices that gas suppliers can receive abroad are described as ranging from 2.2 to 6 times the prices suppliers can receive in the U.S., depending on the country where the buyers are located.

The most recent forecasting comes from the U.S. EIA--a source that must be viewed as neutral-to-conservative in its projections. The agency modeled 5 different export scenarios using different assumptions, and each scenario showed at least some increase in prices for U.S. consumers of natural gas.

http://www.eia.gov/analysis/requests/fe/
http://www.hellenicshippingnews.com/us-lng-exports-would-boost-economy-but-lead-to-higher-energy-prices-says-eia/

Simple arithmetic shows that the proposed Kinder Morgan gas pipeline with its 2.2bcf capacity will, of necessity, be used for exports, as the currently identified need for gas to supply electricity during winter peaks would absorb only .5 to .6bcf per day, for fewer than 20 to 30 days a year. The smaller proposed pipeline by Spectra/Northeast Utilities would supply 1bcf per day, also well in excess of this presumed need.

Additional Context: Recent claims of amplified need for gas are suspect
In the face of opposition to greenfields pipelines, industry lobbyists have teamed up with corporations whose local subsidiaries supply gas for heating, to create a manufactured crisis now hitting the headlines, in which these local suppliers claim they do not have enough pipeline capacity to accept any more of the customers that they have been aggressively pursuing to switch to gas for more than a decade.

I describe this as a manufactured crisis because there is not a hint of this potential problem in any press coverage during the past several years, whether in industry or mainstream press. There is no hint of a potential gas shortage, nor pipeline constraints, for heating fuel in any of the extensive and detailed studies and discussions of the gas and electricity markets during the past several years under the interconnected umbrellas of NESCOE, ISO-NE, and FERC.

There is also no sign that any of the newly complaining companies--Berkshire Gas and Columbia Gas among them--are rushing to repair the leaks in their systems that contribute to the annual loss of 1.725bcf of gas in the state:
http://www.clf.org/blog/clean-energy-climate-change/into-thin-air-time-to-replace-and-repair-leaking-natural-gas-pipelines/

In fact, NESCOE and ISO-NE officials have always stated that the gas LDCs are able to obtain all of the gas they need through their fixed contracts, but that electric generators are subject to higher prices because they buy on the spot market.

In this context, the sudden emergence of a shortage claim for gas heat can only be seen as a constructed phenomenon to push new pipeline construction, after many citizens and legislators used NESCOE's and ISO's own data, extensive stakeholder comments on the IGER reports, and other analyses to cast doubt on the nature and scope of gas constraints on electricity supply, as well as the practicality, cost, and externalities of filling whatever need exists by expanding gas infrastructure.

From:	Shop_Angel
To:	Lowdemandstudy, (ENE)
Subject:	stakeholder comment, METHANE
Date:	Tuesday, November 04, 2014 4:42:33 PM

I fully support the comments and citations of BEAT regarding the greenhouse-gas impact of methane from the full cycle of natural-gas production, transportation, distribution and use, which must be added to the GHG impact of CO-2 from natural gas in its entirety.

Regardless of whether laws and regulations take methane into account, the reality is that it is an extreme and powerful climate disruptor. We probably cannot put a "price tag" on it, as climate disruption changes every aspect of our environment, and the assumptions by which we live our lives, in ways that constantly escalate, and the escalation of all of these impacts is exponential and unpredictable.

At the very least, please emphasize that many stakeholders view natural gas an energy source whose increased use is not viable due its climate impact, and include the documentation that BEAT and others have provided.

Ariel Elan
P.O. Box 351
Montague, MA 01351

From:	Jenny Marusiak
To:	Lowdemandstudy, (ENE)
Subject:	Mothers Out Front comments from October 30
Date:	Tuesday, November 04, 2014 4:48:15 PM
Attachments:	Mothers Out Front LDS comment letter.pdf

Please find attached my comments from October 30 on behalf of Mothers Out Front. You can categorize them as 'Limitations of the study' if that helps you sort them.

I have copied the text below for convenience.

Thanks,

Jenny

--
Jenny Marusiak
(617) 583-0668

November 4, 2014

Massachusetts Department of Energy Resources (DOER)

Submitted Electronically to lowdemandstudy@state.ma.us

Re: Low Demand Analysis – Mothers Out Front on the limitations of the study

Thank you for the opportunity to comment on the Massachusetts Low Demand Analysis. I applaud you for undertaking the study and also for the enormous amount of work you have been able to accomplish in an extremely short time frame.

Ironically, Mothers Out Front agrees with the gas executive who asked during the October 30 stakeholder meeting: Will you calculate the cost of doing nothing? He calls not building a controversial gas pipeline 'doing nothing', but we call it 'taking the lead' on clean energy policy.

While the no new natural gas scenario may be outside the scope of the current study, it raises several questions about how DOER is prepared to deal with the environmental and generational costs that are external to the study's model. Mothers Out Front has signed a joint statement issued by the meeting's environmental break-out group that attempts to capture some of the evidence that fossil fuels and clean energy sources are still not on a level playing field. However, even if these factors were somehow addressed, we are not confident that the solutions provided by the study will result in the actions necessary to address climate change.

If Massachusetts is serious about complying with the Global Warming Solutions Act, and truly wants to show leadership on clean energy and energy efficiency, then DOER should recognize the limitations of the low demand analysis. The analysis may provide a useful comparison of alternative energy options, but it cannot quantify the lengths to which we must and will go to stop heaping future climate costs on our children's shoulders. It will give you numbers to define feasibility based on present and historic data. But it won't tell you the potential for citizens and groups like Mothers Out Front to change the dynamics when it really counts. Everyday hundreds of groups like Mothers Out Front are working to increase energy efficiency and support the development of renewable energy sources, and our numbers are only growing.

Natural gas is not the silver bullet for our current energy constraints. Any new pipelines would not appear overnight, but rather limp into existence over the next three to 10 years after drawn out conflicts over climate change and ecologically sensitive land. One way or another, Massachusetts residents will have to get through these next winters without additional piped gas.

One way we can get through them is while waiting for a new pipeline, which would hinder clean energy investments and undermine incentives for creative, long-term solutions to our energy constraints. This business-as-usual case would push us dangerously close to what our gas executive imagines as 'doing nothing'. We'd be sitting around bemoaning our energy problems and forking out preposterous sums of money to stay warm.

The other way is for Massachusetts to use these tough winters as a motivator and an opportunity to finally start moving away from our dependence on natural gas. We can tackle them, all-hands-on-deck, with determination and with clear pro-clean energy policies that send the right market signals for clean energy investment and innovation.

With bold leadership, we can alter economic feasibility, incentivize faster innovation, change consumer behavior and sway political will – all of which would require recognition that there exists an even lower energy demand scenario than the one currently in progress. What we cannot do is change the laws of nature that dictate the extent of climate change that our children will face.

Submitted by Jenny Marusiak

Member of Mothers Out Front and mother of two teenagers

From:	Ken Berthiaume
To:	Lowdemandstudy, (ENE)
Subject:	Follow-up Comments - October 30th Meeting/Workshop on the Low Demand Study
Date:	Tuesday, November 04, 2014 4:48:55 PM

As an attendee and active participant in the October 30th meeting I would offer the following comments:

- While it may have been discussed briefly, 'Repairing gas distribution leaks' was not mentioned in the October 31st Memorandum.
  1. It was mentioned in the October 15, 2014 First Stakeholder Meeting on slide 27 titled Feasibility Analysis.
  2. The amount cited by CLF[1] is between 8Bcf and 12Bcf annually. Based on U.S. EIA 2009 information[2], this equates to savings equal to the amount of annual gas consumption for an additional 93,000 to 140,000 homes.
  3. Is this information factored into the Base Scenario?

- In addition to the cost of the transmission pipeline, the cost of LDC's additional gas lines to new consumers (including street to homes/buildings) needs to be factored into the overall cost of NG.

- Page 20 of the October 31st Memorandum – CHP section, small combined heat and power lists the "Annual levelized costs **rise** from $103/MWh in 2015 to $118/MWh in 2030. (Net of avoided costs these values are -$15/MWh and -$22/MWh , respectively)". This -$22/MWh appears to be incorrect as the net of avoided costs should be increasing, not continuing to decrease.
  1. Same comment for the large combined heat and power, as the annualized costs **rise** in this case as well.

- Page 21 of the October 31st Memorandum – Energy Efficiency section, residential electric energy efficiency installations, "Annual levelized costs are constant over the study period at $109/MWh. What is the cause of the "net avoided costs" to rise from -$31/MWh in 2020 to $53/MWh in 2030?

- As mentioned at the October 30th meeting, the limitations encountered due to time-constraints and other factors should be listed within the summary report.

Thank you for the opportunity to participate in, and comment on, this critical Feasibility Study for Low Gas Demand analysis.

Sincerely,

Kenneth W. Berthiaume
52 Fryeville Road
Orange, MA

From:	Shop_Angel
To:	Lowdemandstudy, (ENE)
Subject:	stakeholder comment, Demand Reduction
Date:	Tuesday, November 04, 2014 4:52:32 PM

I support the comments of Sierra Club and other stakeholders who have commented that Synapse's sources and modeling parameters do not capture accurately the many, many different strategies and technologies that consumers and the providers of DR resources are already using. Each of dozens of resources should be examined as to their actual track record, and projected growth in Massachusetts, including projecting the costs and benefits of specific policies and incentives that would increase the adoption of each resource or strategy that is technically feasible or that realistically will be available soon.

Along these lines, I add my support to Sierra Club's citations on air-source and ground-source heat pumps, and submit this source as an answer to a question Ed Woll wishes to address:
Heat pumps--Becoming more effective & efficient during cold New England winters:
https://www.bostonglobe.com/business/2014/10/05/new-heat-pump-technology-can-warm-homes-even-cold-new-england-winters/JgABf7wNFqRcYI6YVN6nsI/story.html

Finally, I would urge the inclusion of each of these line items, among others that other stakeholders have suggested:

ALL new affordable-housing units shall be built as zero-net-energy or net-positive energy residences--achieving this standard functionally on site, not via carbon offsets or clean-energy credits. Here is one local builder who does this with single-family homes that sell at prices well within the overall real-estate market: http://www.berkshireeagle.com/business/ci_26666249/zero-energy-homes-are-available
--The economic benefits of a home or apartment that costs little to nothing to heat and power extend to a number of beneficiaries.
The representative from Metropolitan Area Planning Council who spoke at the first stakeholder session stated a new MAPC report calls for a massive increase in affordable housing units in Boston. A 100% commitment to zero-net-energy for these units would make the Commonwealth to a model for the nation in net-zero-energy affordable housing.
--A corollary benefit is that each low-to-middle-income household living in a zero-net-energy apartment or home is a household that is not competing for LiHEAP (fuel-assistance) subsidies and associated conservation and efficiency programs. Due to severe Congressional budget cuts for these programs, their resources fall drastically short of the needs. Providing low-income households with net-zero-energy housing will free up fuel-assistance funds to better serve other clients.

Going further, ALL new construction for any purpose in the state shall be as close to net-zero or net-positive for energy use as is feasible, given functional uses of the structures and the need to preserve freedom in esthetic choices.

SOLAR
In modeling solar energy's potential contributions, please consider:

--What if solar panels were installed on every sunny rooftop, and on every piece of land, where the installation is technically feasible, where a small number of panels would not obstruct any other use, and would not cause any negative health or environmental impact? What would our state's and our region's energy picture look like under such a scenario?
--Unrestricted deployment of neighborhood-shared and community-shared solar--free of any constraints except those stated above;
--The potential contributions of solar energy with NO net-metering cap or restriction, and without any type of restriction imposed by utility companies;
--The co-location of solar panels/solar "farms" with food production:
file:///C:/Users/Ariel/Desktop/GAS PIPELINE/Land use a balancing act _ The Recorder.htm
--Account for the reduction in demand from solar energy being produced and used off the grid, and projected increase in households that will continue to disconnect from the electric grid;
--Concentrated solar energy to produce heat:
http://www.gizmag.com/ibm-sunflower-hcpvt-pv-thermal-solar-concentrator/33989/
--Concentrated solar energy to produce steam:
http://news.yahoo.com/israeli-firm-looks-keep-solar-power-generators-running-110846637--finance.html
http://sciencealert.com.au/news/20140506-25618.html
--Rapidly developing advances in solar-energy storage: *see "israeli-firm" link above*;
http://www.nbcnews.com/science/science-news/worlds-first-solar-battery-captures-stores-suns-energy-n218091
--Comparative economic and technical efficiencies of distributed solar generation to electricity from solar "farms";
--Continuing technical advances that diversify the possibilities for on-site solar:
http://www.extremetech.com/extreme/188667-a-fully-transparent-solar-cell-that-could-make-every-window-and-screen-a-power-source
--The impact of innovative financing on the market for on-site solar:
http://thinkprogress.org/climate/2014/10/08/3577529/rooftop-solar-more-affordable/

--Larger solar developments becoming more competitive:
http://votesolar.org/2014/04/10/solar-gets-cheap-in-coal-country/

--Please account for the fast-increasing role of national and employer-based solar programs such as:
http://thinkprogress.org/climate/2014/10/22/3582763/cheap-solar-power-employee-benefit/

In evaluating the role of renewables with and without various incentives, please see coverage such as:
http://www.greencarreports.com/news/1094490_some-solar-wind-power-competes-with-natural-gas-without-incentives-study

Thank you for all of your hard work!

Ariel Elan
P.O. Box 351

Montague, MA 01351

From: Ken Berthiaume
To: Lowdemandstudy, (ENE)
Subject: RE: Follow-up Comments - October 30th Meeting/Workshop on the Low Demand Study
Date: Tuesday, November 04, 2014 4:54:24 PM

References added.

As an attendee and active participant in the October 30th meeting I would offer the following comments:

- While it may have been discussed briefly, 'Repairing gas distribution leaks' was not mentioned in the October 31st Memorandum.

It was mentioned in the October 15, 2014 First Stakeholder Meeting on slide 27 titled Feasibility Analysis.

The amount cited by CLF[1] is between 8Bcf and 12Bcf annually. Based on U.S. EIA 2009 information[2], this equates to savings equal to the amount of annual gas consumption for an additional 93,000 to 140,000 homes.

Is this information factored into the Base Scenario?

In addition to the cost of the transmission pipeline, the cost of LDC's additional gas lines to new consumers (including street to homes/buildings) needs to be factored into the overall cost of NG.

Page 20 of the October 31st Memorandum – CHP section, small combined heat and power lists the "Annual levelized costs **rise** from $103/MWh in 2015 to $118/MWh in 2030. (Net of avoided costs these values are -$15/MWh

d -$22/MWh , respectively)". This -$22/MWh appears to be incorrect as the net of avoided costs should be increasing, not continuing to decrease.

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As mentioned at the October 30th meeting, the limitations encountered due to time-constraints and other factors should be listed within the summary report.

References:

[1] The Boston University Study's findings regarding the number of leaks in Boston are in line with reporting to the Department of Transportation and the Massachusetts Department of Public Utilities. *See* D.P.U. 12-38, Petition of Boston Gas Company and Colonial Gas Company d/b/a National Grid for Review and Approval of its Targeted Infrastructure Replacement Factor for 2011, NG-WFF-6 at 3 (Reporting 4,285 leaks on leakprone pipelines in 2011), available at http://www.env.state.ma.us/dpu/docs/gas/12-38/5112ngcmpex2.pdf; National Grid
orted 3,772 leaks on its Boston Gas Company mains to the Department of Transportation. Gas Distribution Annual Form 2011, PHMSA, Form F 7100.1-1.

[2]
http://www.eia.gov/pub/oil_gas/natural_gas/feature_articles/2010/ngtrendsresidcon/ngtrendsresidcon.pdf

Thank you for the opportunity to participate in, and comment on, this critical Feasibility Study for Low Gas Demand analysis.

Sincerely,
Kenneth W. Berthiaume
52 Fryeville Road
Orange, MA

From:	Skipworth, Norman D (Dodson)
To:	Lowdemandstudy, (ENE)
Subject:	DOER Low Demand Study - Comments of Tennessee Gas Pipeline Co. L.L.C. re: October 30, 2014 Meeting
Date:	Tuesday, November 04, 2014 4:54:26 PM
Attachments:	DOER Comments 11.04.2014.pdf

Good Afternoon:

Attached please find comments of Tennessee Gas Pipeline Co., L.L.C. regarding DOER's Low Demand Study October 30 stakeholder meeting.
Thank you for the opportunity to participate.

Sincerely,
Sital Mody
Vice President, Marketing & Business Development

Dodson Skipworth
Account Director, Northeast

Tennessee Gas Pipeline Co., L.L.C.

Utility-Scale Wind and Natural Gas Volatility

Uncovering the Hedge Value of Wind For Utilities and Their Customers

Lisa Huber | July 2012

ROCKY MOUNTAIN INSTITUTE | RMI.ORG

2317 Snowmass Creek Rd. Snowmass, CO 81654

Acknowledgements

Special thanks to Amory Lovins, Dan Seif and Jon Creyts of Rocky Mountain Institute, and the following individuals for their valuable insight:

Will Babler, First Capitol
Tom Beach and Patrick McGuire, Crossborder Energy
Mark Bolinger, Lawrence Berkeley National Lab
Tim Carter, Xcel Energy
Gary Demasi, Google
Michel DiCapua, Charles Blanchard, and Stefan Linder, Bloomberg New Energy Finance
Jenny Heeter, NREL
Dr. Taku Ide, Koveva
Buck Martinez and David Bates, Florida Power & Light
Edward May, US Renewables Group
Duncan McIntyre, Altenex
Will Shikani, Macquarie
Steven Taub, GE Capital
Kevin Walsh, GE Energy Financial Services

Also, considerable appreciation is extended to the Stanback Internship Program at Duke University's Nicholas School of the Environment for making this research project possible.

Table of Contents

EXECUTIVE SUMMARY

Prudent investors do not solely invest in junk bonds over treasury bonds; they do not purely chase yield without regard to risk. A portfolio approach applies not only to personal finances, but also to energy investments. While natural gas spot prices are low today, they remain volatile and present a number of risks[1]:

- Unreliable natural gas and electricity market forecasts
- Uncertain power generation costs for IPPs, utilities and regulators
- Unpredictable costs for large customers, especially publicly traded companies that must report to shareholders and industrial consumers who buy directly from the market
- Unexpected Fuel Cost Adjustments (FCA) for residential customers

This paper explores methods of quantifying natural gas volatility by examining theoretical models as well as case studies of utility hedging strategies. Including these volatility risk premiums in the price of natural gas establishes a basis for even comparison with utility-scale wind contracts, which enables smarter decision analysis by regulatory agencies, utilities, and ratepayers. This analysis shows that even without the Federal Production Tax Credit (PTC) and Renewable Portfolio Standards (RPS) power pricing support, wind becomes competitive with natural gas years sooner than is commonly believed, and in many cases is the economic choice for new build generation[2]. Wind competitiveness can be realized without increasing utility hedging budgets by redirecting current hedging cash flows from short-term option strategies into long-term wind Power Purchase Agreements (PPA). Using this methodology, hedging benefits can also be realized at the customer level by large organizations signing direct PPAs and residential customers participating in effective green power programs (GPP). This paper will demonstrate the hedging benefits of utility-scale wind and present practical solutions for utilities and ratepayers alike to decrease risk and encourage further domestic wind development.

---

[1] Roesser, Randy. "Natural Gas Price Volatility." Electricity Supply and Analysis Division, California Energy Commision, 2009.

[2] This paper underscores the importance of hedging against gas price volatility risk; however, short-term variability in wind must be acknowledged as an additional risk. PPA pricing models used in this analysis include an average $6/MWh cost to utilities for intermittency integration. A future analysis incorporating more specific costs and wind hedging instruments would be beneficial, as risks associated with wind variability and intermittency range widely by region.

BACKGROUND

Due to the recent, economically viable combination of two technologies - horizontal drilling and hydraulic fracturing – shale gas is expected to grow from 23% of total U.S. natural gas supply in 2010 to 49% in 2035[3]. In Pennsylvania, home of the Marcellus Shale and its 7,725 active wells managed by 67 operators, natural gas production more than quadrupled between 2009 and 2011[4]. Oversupply from Pennsylvania's drilling programs and other large shale plays such as Eagle Ford, Haynesville, Utica, and Barnett, have driven down the price of natural gas. Henry Hub spot prices have plummeted from over $14/mmBtu in 2008 to below $2/mmBtu in 2012[5]. Due to such low natural gas prices, drilling programs are starting to focus on more liquids-rich plays to improve margins[6]; however, many programs are caught continuing to market shale gas below the cost of production due to "use it or lose it" leases[7]. While both the EIA and NYMEX futures market project longer-term prices to settle around $6/mmBtu, natural gas projections often grossly underestimate prices (Figure 1).

> "Ben Franklin said there are two certainties in life: death and taxes. To that, I would add the price volatility of natural gas."
>
> - Jim Rogers, Duke Energy CEO

While all commodities bear volatility risk, natural gas, at twice the volatility of oil prices, is one of the riskiest commodities[8]. Prices of natural gas can be influenced by a number of factors[9]: development of LNG export facilities linking U.S. and overseas gas prices, depletion of conventional gas, offshore access to natural gas resources, seasonal and catastrophic weather, global warming and capital markets legislation, competition with coal prices for electricity generation, and deployment of natural gas vehicles, just to name a few.

---

[3] Energy Information Administration. "Annual Energy Outlook." 2012.
[4] Amico, Chris, Danny DeBelius, Scott Detrow, and Matt Stiles. *Shale Play: Natural Gas Fracking in Pennsylvania.* National Public Radio. 2011. http://stateimpact.npr.org/pennsylvania/drilling/ (accessed July 2012).
[5] CME Group. *Henry Hub Natural Gas.* 2012. http://www.cmegroup.com/trading/energy/natural-gas/natural-gas.html.
[6] Energy Information Administration. *Horizontal Drilling Boosts Pennsylvania's Natural Gas Production.* May 23, 2012. http://www.eia.gov/todayinenergy/detail.cfm?id=6390 (accessed July 2012).
[7] Blanchard, Thomas. "Cheap US Gas Won't Last Forever." Quarterly Gas Revew, Bloomberg New Energy Finance, 2011.
[8] Massachusetts Institute of Technology. "The Future of Natural Gas." MIT Energy Initiative, 2011.
[9] Costello, Ken. "Natural Gas Hedging: Should Utilities and Regulators Change Their Approach." National Regulatory Research Institute, 2011.

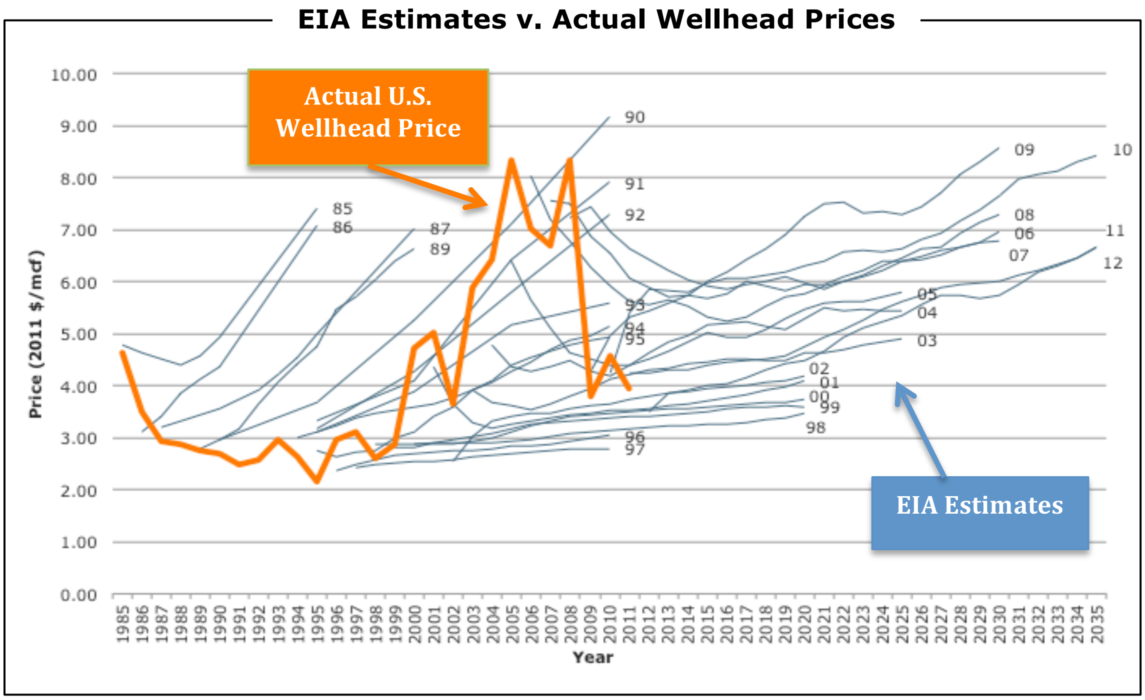

Figure 1: EIA estimates of natural gas prices v. actual, by Annual Energy Outlook publication date[10]

In order to properly compare natural gas with renewables, a volatility risk premium must be added to the price of natural gas. Wind, for example, is typically contracted over 20-30 years through a PPA that provides price certainty for both the producer and consumer. Adding an appropriate long-term risk premium to the price of natural gas would allow for apples-to-apples comparison of two very different cost structures and methods of power generation, thereby encouraging smarter resource planning by utilities and PUCs. Methods of quantifying such a risk premium are explored in this paper by examining both theoretical models and case studies. Despite the challenges posed to wind development – expiring PTC and dwindling RPS-enabled power purchase programs – a fair comparison to natural gas demonstrates the hedging potential of wind in a balanced energy portfolio.

WHAT IS VOLATILITY?

Volatility can be examined in two directions: forward-looking “implied volatility” and backward-looking “historical volatility”. Both calculations of volatility are expressed as percentages – historical volatility based on past prices, and implied volatility derived from option prices that expire in the future. Volatility, as it’s referred to in financial markets, is not simply a measure of daily or weekly relative

[10] Energy Information Administration. "Annual Energy Outlook." 1985-2012.

price changes, but rather the annualized standard deviation of daily or weekly logarithmic returns.

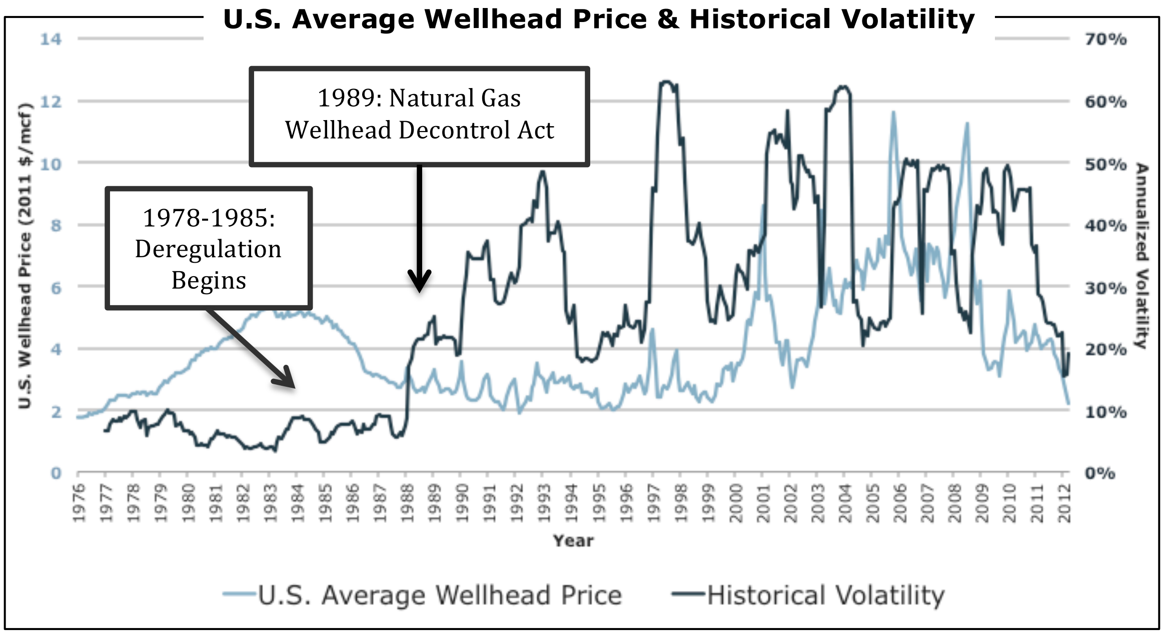

Figure 2: Historical volatility of natural gas prices. With spot prices and historical volatility levels at their lowest in over ten years, there is a current rare opportunity for utilities to lock in low prices at cheaper premiums. Many utilities, however, cannot participate in long-term strategies due to both regulatory restrictions and market liquidity constraints.

Historical Volatility

Historically speaking, natural gas tends to show volatility levels between 20% and 60% (Figure 2). While there has indeed been a period of sustained low prices and low volatility in the 1970s and 1980s, these prices and volatility levels were merely a result of regulation and wellhead price ceilings. The Natural Gas Policy Act of 1978 raised price ceilings and aimed to enable a national natural gas market. In 1985, significant deregulation began which fully removed price ceilings on natural gas at about 50% of U.S. wellheads[11]. In 1989, the Natural Gas Wellhead Decontrol Act eliminated price ceilings at the remaining regulated wellheads[10]. Since the natural gas industry has been deregulated, there has been a consistent trend of volatile natural gas prices.

Implied Volatility

Options on assets are priced by the "five greeks": delta, vega, theta, rho, and gamma. These factors, respectively, represent the sensitivity of the option value to changes

[11] NaturalGas.org. *The History of Regulation.* 2011. http://www.naturalgas.org/regulation/history.asp#wellhead (accessed June 2012).

in the underlying asset's price, volatility, time to expiration, and risk-free interest rate, and the sensitivity of delta to changes in the underlying asset price. Sensitivity to volatility, as measured by vega, is one of the most significant factors in pricing commodity options. In fact, implied volatility levels can be derived from listed option premiums to determine the magnitude of natural gas movements "priced-in" by the options market at a given future date (Figure 3). For example, options are currently pricing in a potential range of $1.18 to $13.80 per mmBtu at the 99% confidence interval by June 2015.

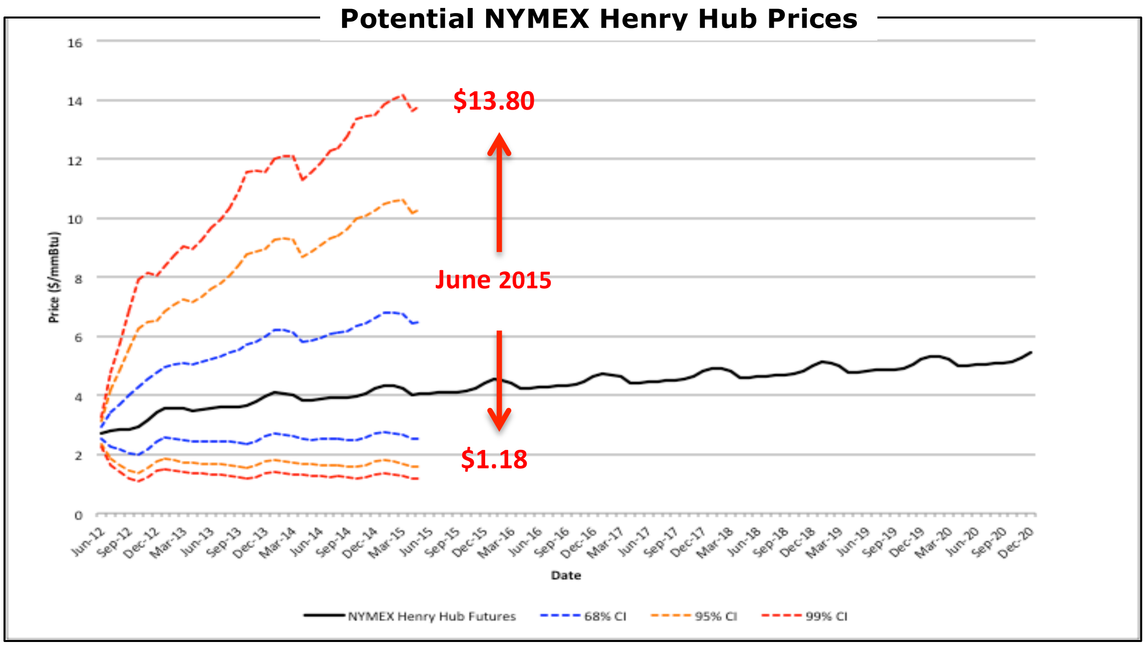

Figure 3: Using implied volatility levels and option premiums to determine future natural gas price ranges at 68%, 95%, and 99% confidence intervals

RISK DISTRIBUTION

Assets generally face two types of risk: risk associated strictly with the underlying asset (alpha), and risk correlated with the broader market (beta). A positive beta value represents a positive correlation with the broader market, whereas a negative beta value represents an inverse correlation. Calculating the beta value of natural gas has previously been attempted, but most studies conducting this analysis were published over 10 years ago (Table 1). It should be noted, however, that results have consistently shown negative beta values[12].

[12] Bolinger, M. and Wiser, R. LBNL 2002. "Quantifying the Value that Wind Power Provides as a Hedge Against Volatile Natural Gas Prices"

Study	Beta Value
Kahn & Stoft (1993)	-0.78
Awerbuch (1993)	-1.25 to -0.5
Talbot (1993)	-0.45
Bolinger & Wiser (2004)	-0.4 to -0.1

Table 1: Summary of findings of natural gas beta values

Because natural gas is believed to have an inverse relationship with the broader market, consumers of natural gas may have more of a reason to hedge than producers[13]. A producer will be naturally hedged to low prices with a rising market, whereas a consumer will be exposed to high natural gas prices in tandem with a down market (Figure 4). As consumers tend to be more exposed, in this sense, to natural gas price volatility, this paper will focus on hedging mechanisms and solutions for the consumer side: from utilities to industrial, commercial, and residential customers.

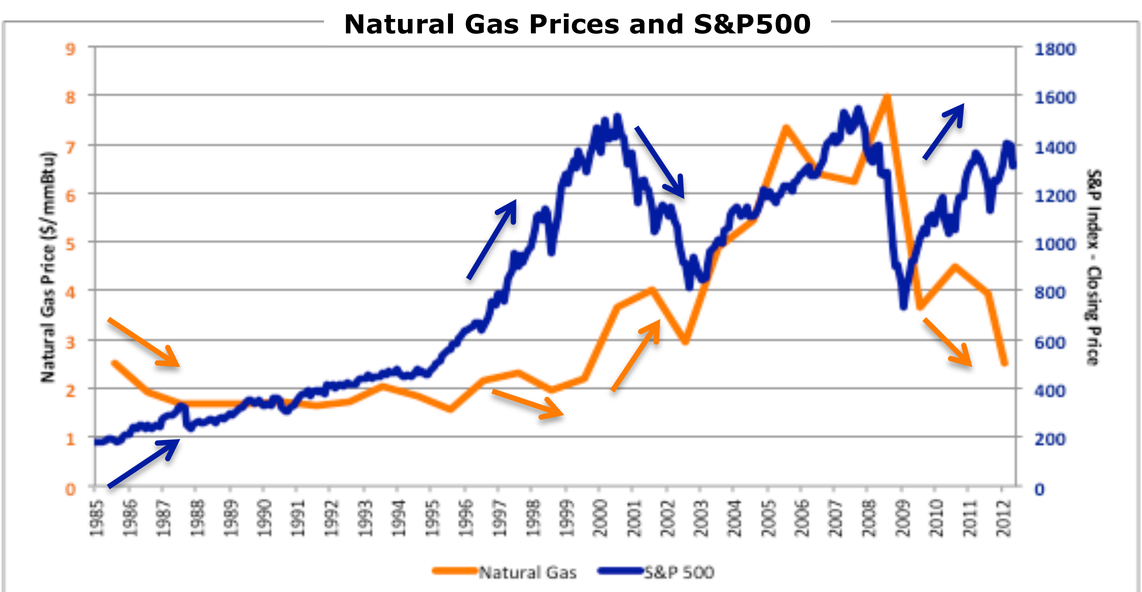

Figure 4: Natural gas prices and their relationship with the broader market: evidence of periods of significantly negative beta.

[13] Bolinger, M. and Wiser, R. LBNL 2002. "Quantifying the Value that Wind Power Provides as a Hedge Against Volatile Natural Gas Prices"

VOLATILITY PRICING

> "A variety of methods have been used to assess and sometimes quantify the benefits of fixed-price renewable energy contracts relative to variable-price fossil generation contracts, as well as the benefits of electricity supply diversity more generally. These methods have included risk-adjusted discount rates (e.g., Awerbuch 1993); Monte Carlo and decision analysis (e.g., Wiser and Bolinger 2006); portfolio theory (e.g., Bazilian and Roques 2008); market-based assessments of the cost of conventional fuel-price hedges (e.g., Bolinger et al. 2006); and various diversity indices (e.g., Stirling 1994, 2010). Many of these methods have proven controversial, and a single, standard approach to benefit quantification has not emerged."
>
> -NREL Renewable Electricity Futures Study, June 2012

The volatility inherent in natural gas prices should be reflected as a risk premium added to the price of the underlying contract to establish a risk-free price. Only then can one fairly compare natural gas to utility-scale wind, which is offered in fixed-price (read: volatility risk-free) long-term PPAs. While natural gas volatility is evident, quantifying the associated risk is often quite complicated, as noted in NREL's recent Renewable Electricity Futures Study.[14] Theoretical volatility pricing methods can provide a context for comparing fixed-price wind with natural gas, but rather than building on these models, this paper employs an empirical approach based on the knowledge that many regulated utilities already put a price on volatility via their annual hedging budgets. While these budgets may grossly over- or underestimate the true long-term price of volatility, they can provide insight into utility willingness-to-pay and PUC-determined prudence rather than pure valuation – concepts that are key to developing wind as a realistic hedge. Essentially, each utility has its own individual risk tolerance, regulated hedging constraints, and available amount of cash – three inputs that are necessary in determining a wind project's hedging benefit. Using this approach exposes value without requiring new policy or increased spending.

This same empirical analysis can be extended to apply to the retail power purchaser in deregulated markets, where green power programs (GPPs) are more likely to feature fixed green rates, serving as true hedges against the potential of escalating fuel prices (See Austin Energy Case Study, pg. 19).

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[14] NREL. "Renewable Electricity Futures Study." U.S. Department of Energy, 2012.

Theoretical Models

Theoretically, the price of a straddle contract – combined at-the-money call (right to buy) and put (right to sell) options (Figure 5) – should represent the price of volatility. Premiums on these contracts, which can effectively lock-in your future price, are not cheap. Buying straddles on the NYMEX curve just a couple years out costs about 20-25% of the underlying gas, even with current low historical volatility levels[15]. Adding the price of a straddle contract to the underlying gas purchase demonstrates a much higher actual price of natural gas that is less competitive than wind within 2 years (Figure 6).

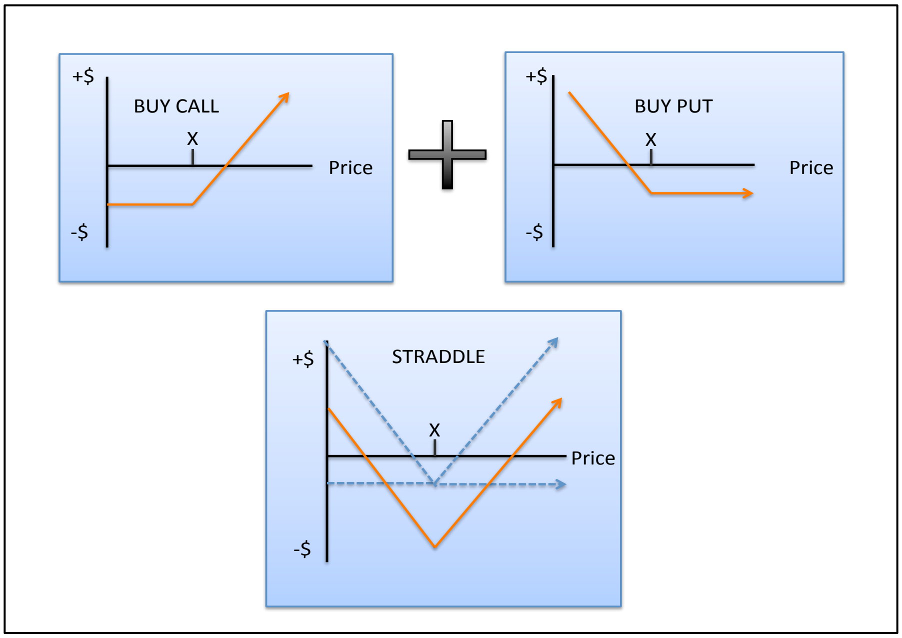

Figure 5: Straddle payoff diagram

[15] CME Group. *Henry Hub Natural Gas.* 2012. http://www.cmegroup.com/trading/energy/natural-gas/natural-gas.html.

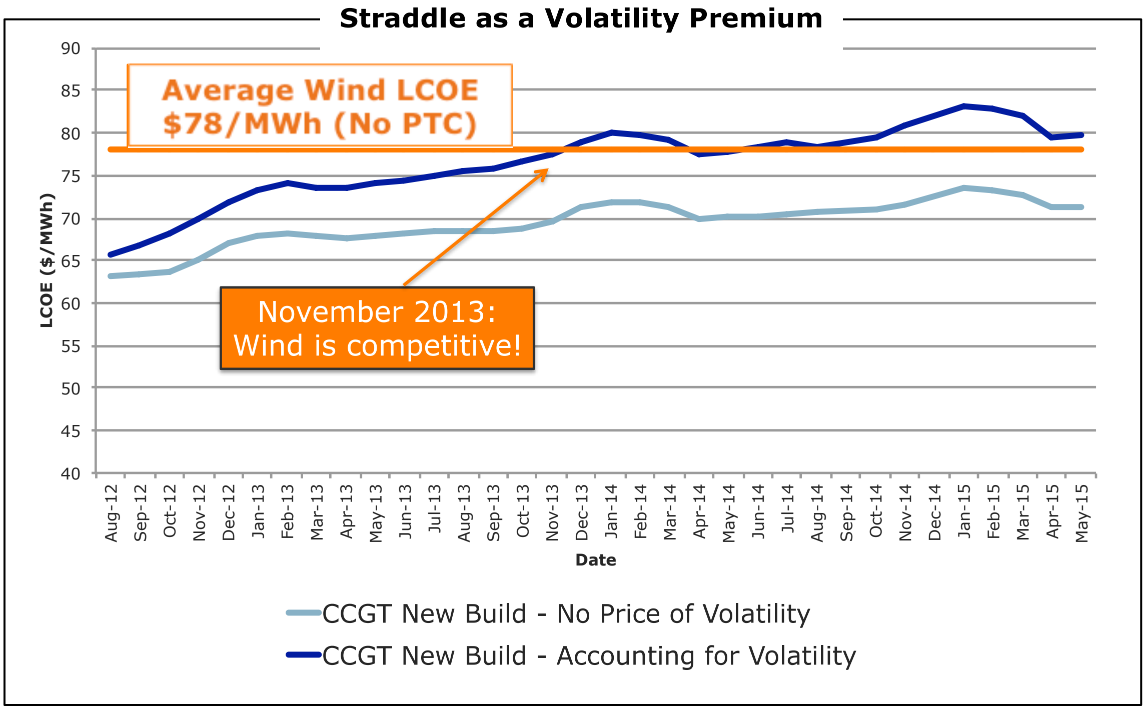

Figure 6: Comparing average wind and CCGT with volatility risk premiums as priced by straddle contracts. For LCOE assumptions, see Appendix.

Realistically, very few natural gas players would enter into a straddle contract. More often, straddles are employed by speculative traders to place bets on the direction of volatility. Consumers of natural gas generally have no incentive to pay an additional premium to protect against downward price movements just as suppliers of natural gas generally have no incentive to pay an additional premium to protect against upward price movements. In other words, the goal of most natural gas players is not to minimize overall volatility, but rather to mitigate one-directional risk. In order to accomplish this, a variety of less-expensive, short-term option strategies are employed as well as less common long-term physical delivery contracts.

Utility Hedging Strategies

Long-term

Because regulated utilities pass-through both the cost of fuel and hedging, risk mitigation plans must be presented and approved by the PUC[16]. Many PUCs restrict utilities to hedging gas volatility risk only three to five years out for three reasons: (1) Natural gas option markets lose significant liquidity after about one to two years which results in high transaction costs and unreliable pricing; (2) Losses on derivative investments could be devastating to both the utilities and ratepayers; (3)

[16] Bean, Patrick, Gregory C. Staple, and Geoff Bromaghim. "Power Switch: A No Regrets Guide to Expanding Natural Gas-Fired Electricity Generation." American Clean Skies Foundation, Washington, DC, 2012.

Margin calls on sold contracts can put utilities in low-cash positions. As examples of case (2), between 2007 and 2009, two California utilities lost a combined $97mm from bad hedges, and from 2006 to 2011, four Michigan utilities incurred a total of $1.6bn in losses from bad hedges[17]. To avoid hitting ratepayers with charges from imprudent derivative bets, PUCs can be quite strict in their approval process. Counter-intuitively, it is the volatile nature of gas prices that is driving the argument to *not* hedge in regulated markets – a phenomenon not seen in any other industry. By restricting hedging time horizons however, utilities are incentivized to maintain long-term risk exposure. Just as adjustable rate mortgages entice homebuyers to take on volatile long-term rates with low up-front costs, natural gas markets seem attractive in the short-run while posing huge risks only a few years out.

Even though participation in fixed-price, physical delivery natural gas contracts could offer medium-term (5-10 year) protection, these contracts are quite rare[18]. As an exceptional case, however, the Public Service Company of Colorado (PSCo) was approved by the Colorado PUC to sign a 10-year deal with Anadarko under the Clean Air Clean Jobs Act[19] (Figure 7). As Colorado sought to retire dirtier coal plants in favor of natural gas, PSCo agreed to obtain an undisclosed quantity of gas from Anadarko from 2011 to 2021 for an average premium of $1.38/mmBtu over EIA forecasts of Cheyenne Hub wellhead prices[20], assuming an $0.185 basis spread from Henry Hub[21]. While $1.38/mmBtu is a hefty premium in itself, PSCo also agreed to pay an additional dollar - named the “Volatility Mitigation Adder” - for any quantity of gas over the contracted amount, taking the all-in premium to $2.38/mmBtu[22]. These premiums reflect what one utility was willing to pay to offset price risk of natural gas over ten years. While these prices could offer a baseline for comparison to wind PPAs, they are still conservative numbers as the PSCo/Anadarko contract offers protection for less than half of the time horizon that a 25-year wind PPA would.

[17] Costello, Ken. NRRI 2011. “The Future of Natural Gas Hedging: Utilities, Consumer Advocates, and Regulators Weigh In”
[18] Massachusetts Institute of Technology. "The Future of Natural Gas." MIT Energy Initiative, 2011.
[19] Moore, Scott A. "Natural Gas Market Dynamics and Long Term Contracts." Marketing Department, Anadarko, Denver, CO, 2011.
[20] Energy Information Administration. "Annual Energy Outlook." 2012.
[21] Platts. "Gas Daily." 2011.
[22] Premiums calculated over EIA forecasts – Actual forecasts used as basis for this deal are undisclosed

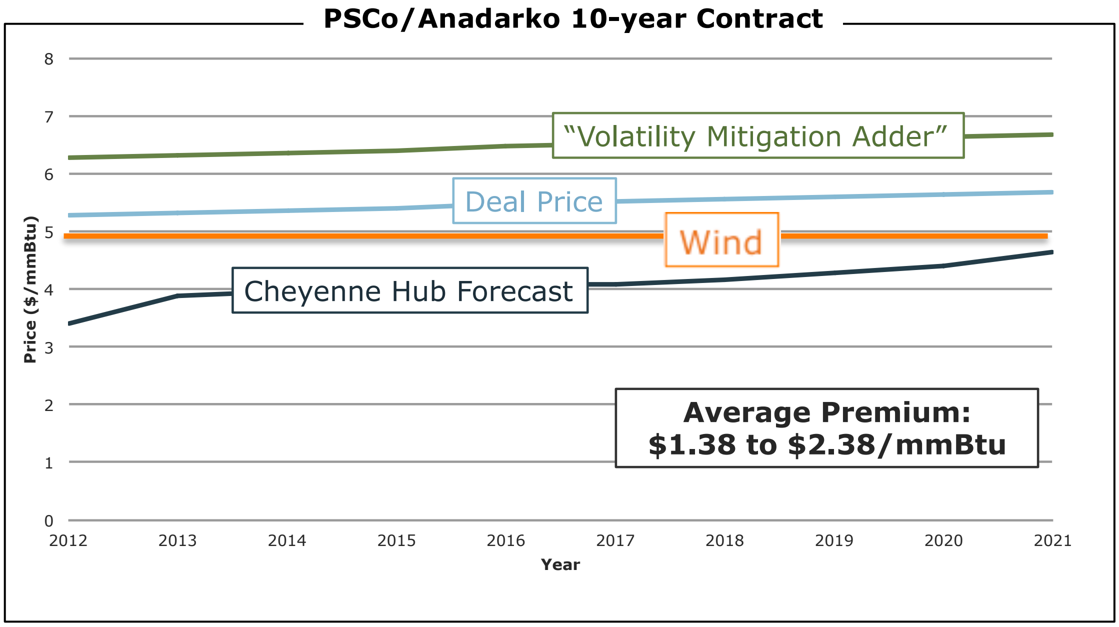

Figure 7: PSCo/Anadarko 10-year contract prices and volatility premiums at Cheyenne Wellhead

Short-term

While utilities are confined to hedging out only a few years in any significant way, they tend to weight their resources heavily in year one, slightly less in years two and three, and very little after that (Figure 8). Because hedging positions are constantly being managed and traded around, a utility following this pattern might be nearly 100% hedged, consistently, for the next 12 months, 50% hedged up to 24 months, 30% in year three, and 10-15% hedged in years four and five.

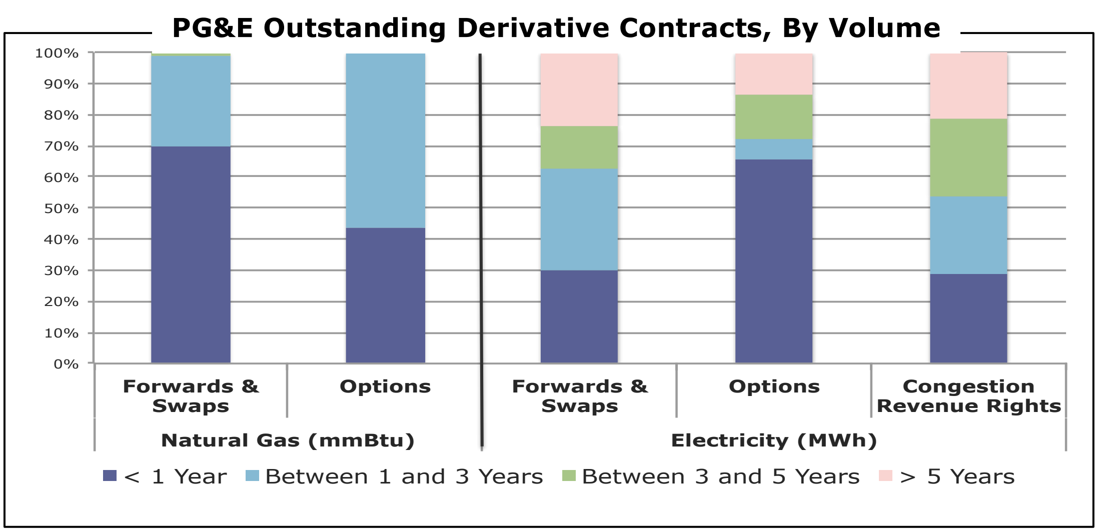

Figure 8: PG&E hedging strategy as documented in 2011 Annual Report[23]. Swaps are agreements between two parties in which the utility pays a pre-determined fixed price in exchange for a floating price. Congestion Revenue Rights are financial instruments that allow the utility to manage the daily cost of congestion based on locational marginal pricing

[23] Pacific Gas & Electric. "2011 Annual Report." 2011.

PG&E and other utilities with developed hedging programs will often buy gas-specific option products to partially de-risk natural gas price fluctuations. These could be vanilla call options, or more regularly, more complicated but less expensive strategies like costless collars, call spreads or three-ways (see Appendix). Each option or combination thereof comes at varying premiums and offers different levels of protection. Utilities with defined hedging budgets will often select which strategy to employ based on NYMEX futures and option premiums offered at the time of investment. PSCo, for example, has an explicit cap of $0.91/mmBtu to spend on short-term strategies for 55% of the gas requirements from November 2011 to March 2012[24] (see PSCo Case Study, pg. 17).

SOLUTIONS

Wind provides significant hedge value for buyers of power to take advantage of. Utilities can integrate a full assessment of long-term volatility in petitions to PUCs to gain approval for new wind investments that will serve as a hedge and protect ratepayers. Rather than building complex models to determine volatility premiums, utilities can simply demonstrate that redirecting a portion of their current hedging cash flows into wind PPA contracts can reduce volatility risk without increasing their annual hedging budget (see PSCo Case Study). If employed nationwide, this could have significant implications for the future of domestic wind development. Large commercial customers can also take advantage of wind's hedge value by signing direct PPAs and including such PPA contracts in their value-at-risk (VaR) calculations to realize a reduction in overall risk exposure. Google, for example, has already signed two wind PPAs with NextEra Energy for its data centers in Iowa and Oklahoma[25]. While residential customers cannot directly and individually sign onto wind PPAs, they can participate in GPPs that reduce their exposure to fluctuating fuel prices. Although many utilities offer programs allowing customers to pay "Green Premiums", only a small number are designed to utilize wind investments as a hedge by replacing the customer's fuel charge with a fixed renewable charge (a "Green Rate") that is not subject to Fuel Cost Adjustments (FCAs)[26]. While some of these programs are offered in regulated markets, there may be more of an opportunity to develop Green Rate programs in deregulated markets (See Appendix 4). One of the premier examples of a GPP Green Rate is Austin Energy's GreenChoice Program (see Austin Energy Case Study, pg. 19). Many other less effective programs offer the option for a customer to pay a set premium for renewables while their base rates are still subject to fluctuating fuel prices (Figure 9).

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[24] Public Service Company of Colorado. "Gas Price Volatility Mitigation Plan Approval Form: 2011-12 Gas Purchase Year." Gas Department.
[25] Google. "Google's Green PPAs: What, How, and Why." 2011.
[26] Bird, Lori A., Karlynn S. Cory, and Blair Swezey. "Renewable Energy Price-Stability Benefits in Utility Green Power Programs." National Renewable Energy Laboratory; Applied Materials, 2008.

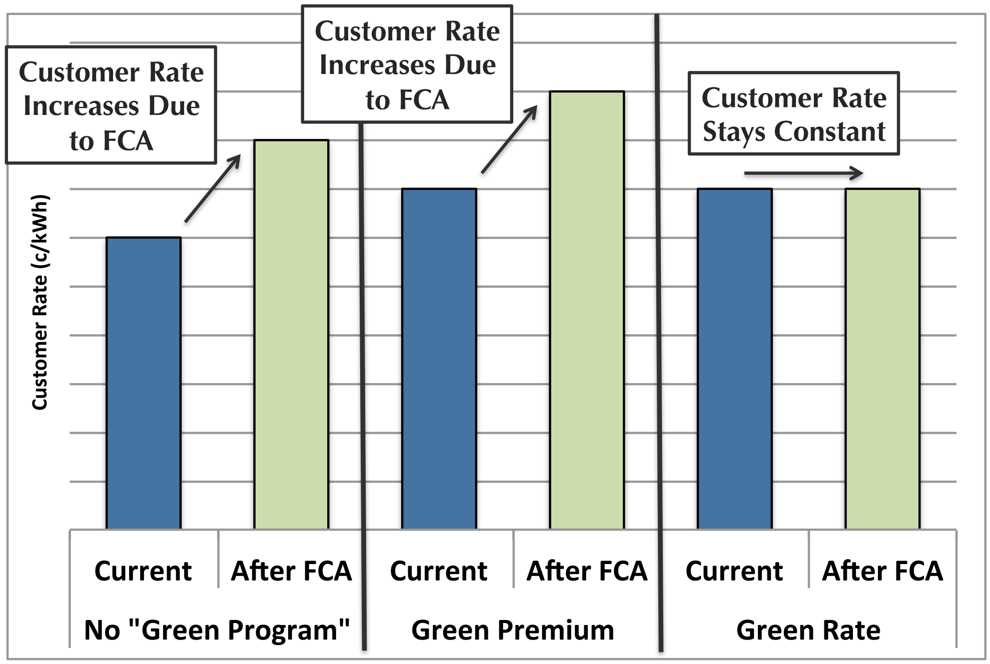

Figure 9: Examples of Green Power Purchase Programs. From left to right: standard customer payments, "Green Premium" programs subject to FCAs, and "Green Rate" programs exempt from FCAs. For a list of sample GPPs exhibiting best practices, see Appendix.

CASE STUDIES

Utility: Public Service Company of Colorado[27]

PSCo, a subsidiary of Xcel, submits annual Gas Price Volatility Mitigation Plans (GVPM) to the Colorado PUC for approval of their hedging strategies for natural gas exposure. For the purchase year of July 1, 2011 to June 30, 2012, PSCo applied and was approved to hedge a maximum of 75% of winter purchase requirements (November-March season). The planned 75% of hedged purchases break down into long-term and short-term strategies. The long-term strategy covers up to 25% of hedged purchases if gas can be acquired at a price below their set floor via storage. This price floor is established by averaging prices from the previous three heating seasons, which for the 2011-2012 plan resulted in a price floor of $5.00. The remaining 75% of hedged gas purchases are delegated to the short-term plan and use the same price floor with a per mmBtu budget of $0.91. Thus, for short-term hedges, up to 91 cents per mmBtu is spent on an option strategy or fixed-price swap. Option strategies targeted are first costless collars, followed by ATM call options, and finally OTM call options as a last resort.

For the 2011-2012 GVPM, PSCo projected a winter supply requirement of about 100 million mmBtus of which 22% was planned to come from storage as a physical hedge and 53% relied on financial hedges – totaling 75% of supply. Short-term hedges on the nearly 53 million mmBtus are determined as the markets move. If a fixed-price swap agreement or costless collar can be obtained for $5.91/mmBtu (price floor plus budget), PSCo will first choose one of these options. If, however, the fixed-price contracts come at a higher price, PSCo will look to buy ATM call options at or less than $0.91/mmBtu premiums. If PSCo cannot buy ATM call options within budget, they will purchase $0.91/mmBtu premium OTM call options with varying strike prices.

PSCo's GVPM for 2011-2012 essentially limits the company to spend no more than $0.91/mmBtu, for a total cap of $30 million on hedging expenses. If PSCo is consistently spending an additional $0.91/mmBtu on natural gas supply that currently costs around $3.00/mmBtu at the wellhead, they are paying a significant 30% premium. If option premiums rise as underlying prices and volatility rebound, PSCo will not even be protected at their floor of $5.00, but rather reliant on OTM call options with higher strike prices. Taking a $0.91/mmBtu premium into account, wind appears significantly more competitive years earlier than previously assumed – nearly breaking even with CCGT new build 2015-2018, and winning out after 2019 (Figure 10a).

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[27] Public Service Company of Colorado. "Gas Price Volatility Mitigation Plan Approval Form: 2011-12 Gas Purchase Year." Gas Department.

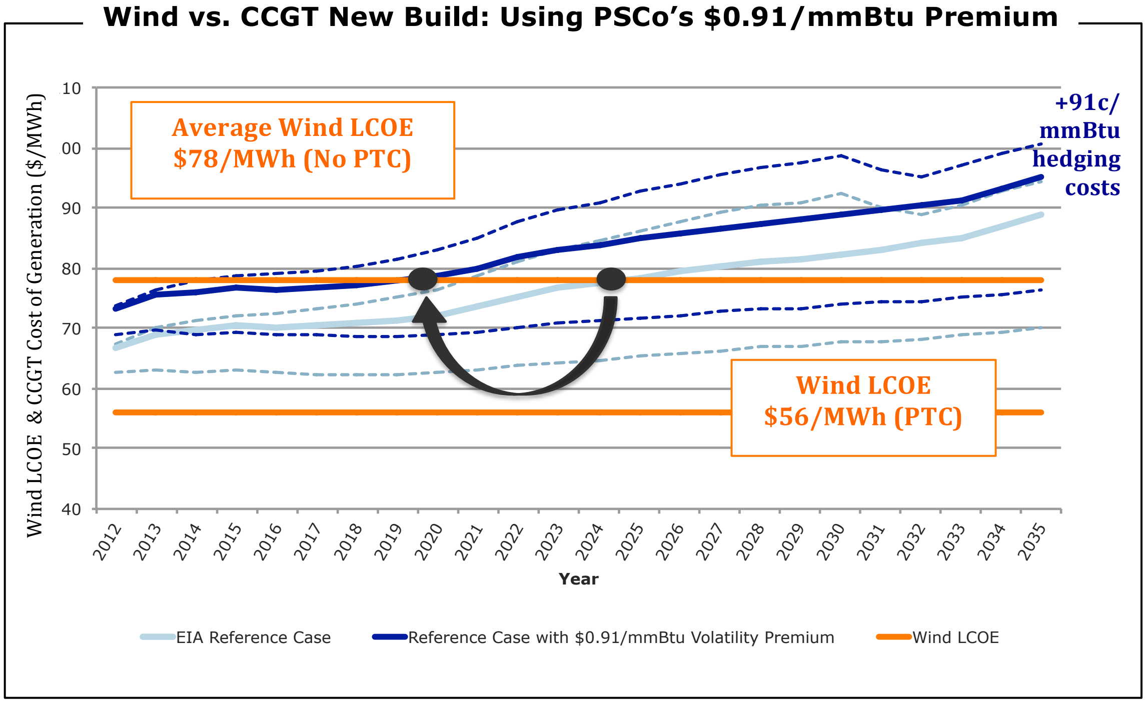

Figure 10a: Demonstration of wind competitiveness when accounting for volatility premiums. Adding PSCo's current $0.91 volatility premium shows wind and CCGT new build breaking even in 2019, as opposed to 2024 if not accounting for this premium. For wind LCOE and CCGT cost of generation assumptions, see Appendix.

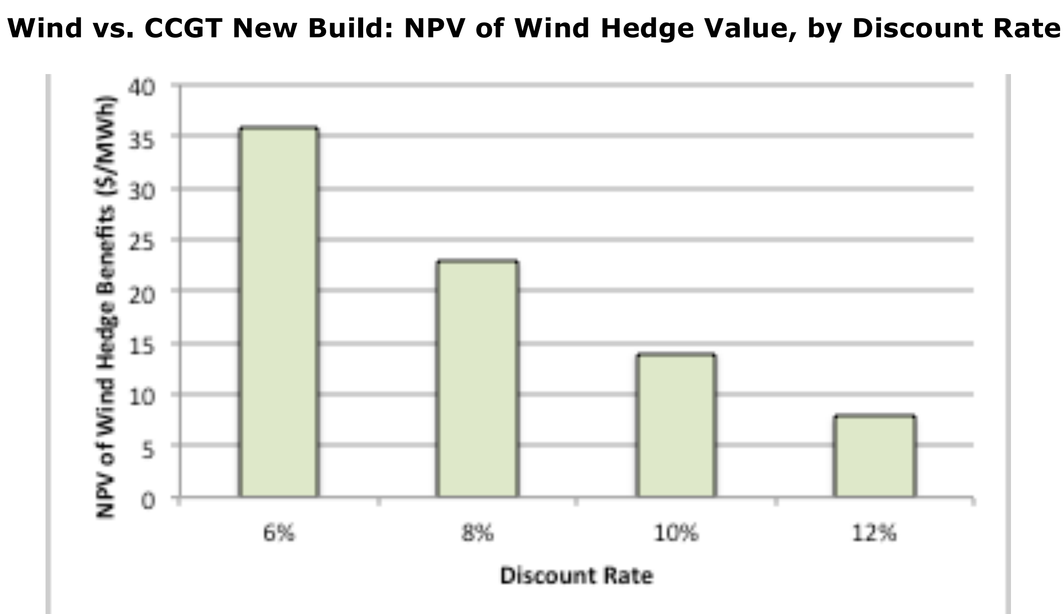

Figure 10b: Net present value of 23-year wind investment over CCGT investment

Industrial and Large Commercial Customers: Altenex Business Model[28]

Altenex takes an innovative approach to natural gas risk mitigation by serving as a "Match.com" of the power portfolio world. Altenex manages a database of renewable projects with its customers – large industrial and commercial organizations that have significant exposure to fluctuating fuel prices. Altenex uses a propriety model to analyze and compare its clients' risk profiles under varying power portfolio allocations that incorporate appropriately selected power purchases from renewable projects in their database. Altenex's model becomes more applicable the higher the dependence on natural gas. For example, large chemical companies that use natural gas as a feedstock and buy directly from the market, or massive data centers that require significant electricity consumption and are poised for further growth. These consumers can use Altenex's model to re-evaluate their value-at-risk under different natural gas and electricity market pricing scenarios.

Commercial and Residential Customers: Austin Energy GreenChoice[29]

Austin Energy's GreenChoice program is often touted as one of the most effective green purchasing programs in the country. Although not required to participate in the Texas RPS program, they offer long-term "batches" that residential and commercial customers can subscribe to in order to support renewables instead of fossil fuels. Each batch is offered for a set term and price that costumers pay in lieu of their traditional fuel charge. This means that GreenChoice subscribers are not subject to fluctuating fuel prices. After Austin Energy's first batch was oversubscribed at 1.7¢/kWh, they met continuing demand by offering a second batch at 2.85¢/kWh. These two batches both expired in March 2011 in the money. In fact, Austin Energy claims that "a batch 1 customer paying 1.7 cents per kWh and averaging 1,000 kWh per month will have saved about $1,300 [over the life of the subscription]"[30]. Batches 3, 4, 5, and 6 have been offered at 3.3¢/kWh, 3.5¢/kWh, 5.5¢/kWh, and 5.7¢/kWh, respectively, compared to a current fuel charge of 3.615¢/kWh. While the most recent batch will not expire until 2021, customers of Austin Energy's GreenChoice program have found the long-term hedge value of renewables to be significant.

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[28] For more information, visit www.altenex.com

[29] Austin Energy. *GreenChoice Energy Rider.* 2012. http://www.austinenergy.com/about%20us/rates/greenChoiceEnergyRider.htm.

[30] Austin News. "Austin Energy GreenChoice Customers: Your Rates May Go Up in March." *Austin Post.* October 26, 2010. http://www.austinpost.org/austin-news/austin-energy-greenchoice-customers-your-rates-may-go-march (accessed 2012).

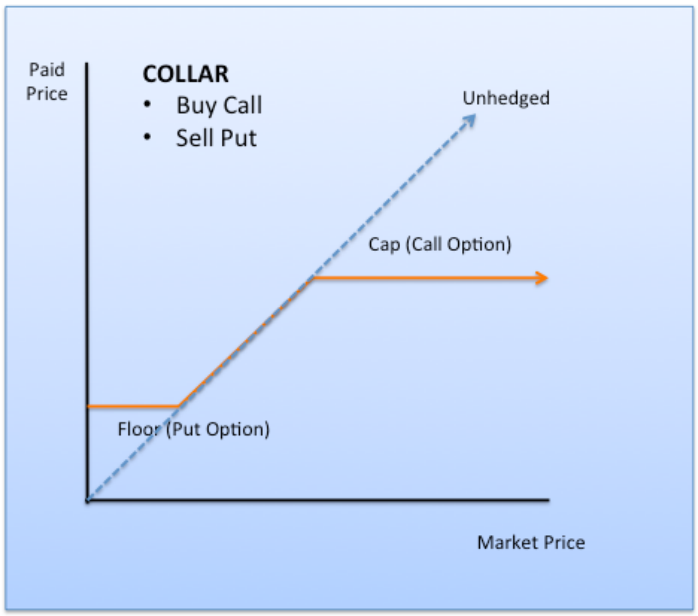
CONCLUSION

Although natural gas prices are depressed, the volatility inherent in the commodity remains and presents risks to consumers at all levels: utilities, industrial and commercial customers, as well as residential customers. Many utilities are already paying to hedge against the risk of an unexpected upward swing in prices in the near-term, but remain exposed in the long run. PUCs in regulated states tend to disapprove of long-term natural gas contracts. It is conceivable, however, they could be convinced to deem wind PPA contracts prudent as they provide a substantial hedge in the long-term, particularly if the PUCs adopt more risk-weighted "lowest cost" review criteria for PPAs or new plant rate-basing. Just as utilities can hedge with new wind project PPAs, large customers can sign direct PPAs as a hedge, and residential customers can participate in green power programs that exempt them from FCAs. These opportunities offer the chance for consumers of energy to both decrease their risk exposure to fluctuating fuel prices, as well as encourage the future development of domestic wind.

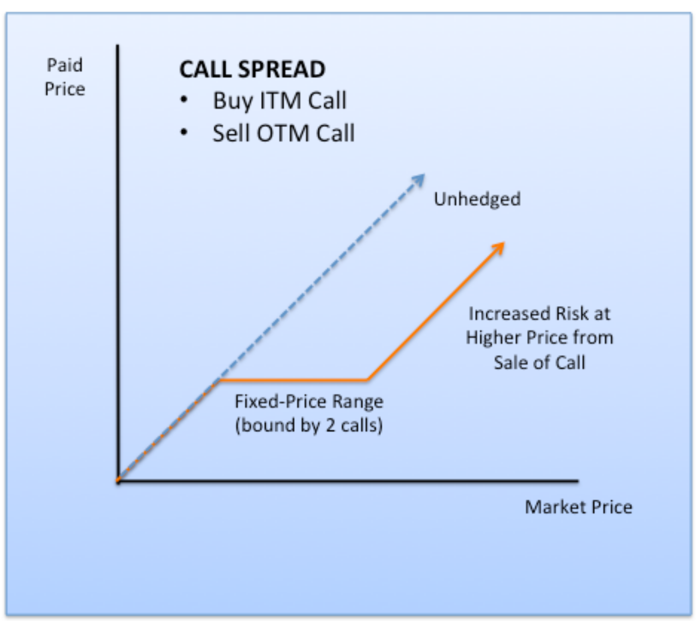
APPENDIX

1. Option Payoff Diagrams:

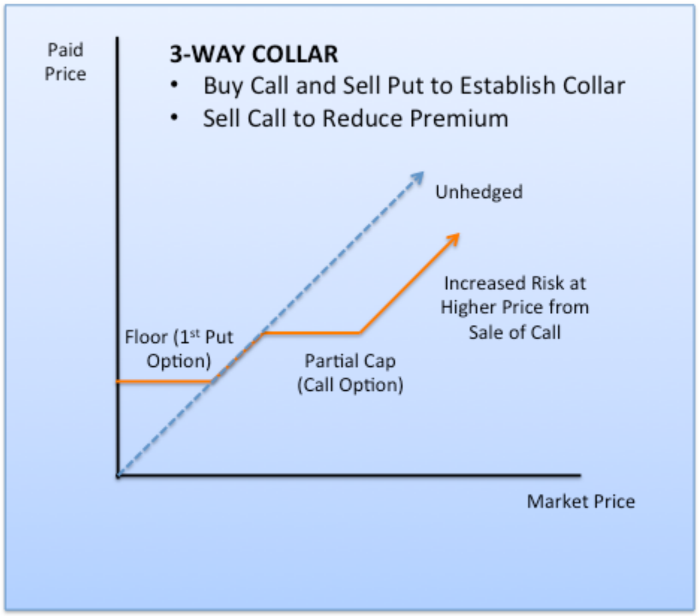
   1.1 Collar Strategy: Buy Call, Sell Put



   1.2 Call Spread Strategy: Buy ITM Call, Sell OTM Call



1.3 Three-Way Collar Strategy: Collar, Sell Additional OTM Put



Note: For all three option scenarios, it is possible to have a "costless" transaction. This means that there is no premium (but perhaps still a broker fee) to transact when the price of selling options is the same as the cost of buying other options within the same transaction (e.g. costless collar = proceeds from sale of put equals cost of purchase of call). To be clear, costless transactions can still eventually "cost" the transacting party if they are out-of-the-money or if they must post margin for future-dated sold contracts. All three transactions above a presented in a costless manner, but in most cases there is a transaction premium and that premium would offset the payoff (orange) line downwards uniformly across the market price axis.

2. LCOE (Wind) and Cost of Generation (CCGT) Assumptions[31]

Future Price of Natural Gas: EIA AEO 2012 Projections
Levelized Non-Fuel Costs of CCGT New Build: $43.5/MWh
Heat Rate of CCGT New Build: 7000 Btu/kWh
Wind LCOE*: $78/MWh without PTC (Includes $6/MWh Intermittency Integration Costs)
Production Tax Credit: $22/MWh

NOTE: While $78/MWh is used as Wind LCOE Assumption in this paper, wind projects with PTC assistance have been coming online around $30/MWh recently (not including utility wind integration costs, if any).

[31] Lazard. "Levelized Cost of Energy Analysis - Version 6.0." 2012.

3. Sample List of Utility Short-Term Hedging Budgets

Xcel/PSCo (Colorado): $0.55-$1.82/mmBtu, varies by department
Centerpoint Energy (Minnesota): $0.25/mmBtu
Portland General Electric (Oregon): about $0.01/mmBtu, calculated as ½ bid-ask spread (essentially a transaction cost)
Duke Energy Carolinas (North Carolina): $0/mmBtu

4. Sample List of GPPs offering at least partial FCA exemption[32]

Alliant Energy
Austin Energy
Clallam County PUD
Green Mountain Power
Holy Cross Energy
Madison Gas & Electric
Xcel Energy
We Energies

[32] Bird, Lori A., Karlynn S. Cory, and Blair Swezey. "Renewable Energy Price-Stability Benefits in Utility Green Power Programs." National Renewable Energy Laboratory; Applied Materials, 2008.

Comments on Low Demand Scenario Stakeholder's Meeting
Massachusetts Department fo Energy Resources &
Synapse Energy Economics, Inc.
October 30, 2014

By Dennis Eklof

Given the limited budget and tight schedule involved with this project, DOER and Synapse have done an amazing amount of work, and I commend the spirit of your endeavors and the importance you are attaching to the project.

Yet the New England's and Massachusetts' energy future may well depend on the results of this study, and there are several areas where the proposed study structure and processes seem to fall short of the importance of the study's outcomes.

General Comments on Study Shortcomings

Equating lower utility bills with the optimum energy strategy

With the exception of assuming that *Renewable Portfolio Standards* will be met and the imposition of modest carbon emissions penalties, the entire structure of the study seems to equate lower utility bills for consumers with the correct energy strategies and policies for Massachusetts and New England. The proposed methodologies for the *Low Demand Scenario* (LDS) are aimed at including alternatives to increasing gas pipeline capacity and gas generation only if those alternatives can compete on a long-term levalized cost basis with pipeline gas. Yet Massachusetts and many other states have rejected that purely financial criteria as evidenced by RPS, GWSA and RGGI. Synapse has stated in the last two meeting that it will not make policy recommendations, and the only non-financial considerations in its analysis will be the assumption that RPS now in place will be met and the modest RGGI CO2prices. While not influencing the results, CO2 emissions will be estimated, while methane emissions will be ignored.

One of the objections many have to huge increases in pipeline infrastructure such as the proposed Northeast Energy Direct project is its implications for increased rather than decreased reliance on fossil fuels and the detrimental impacts such a pipeline will have on GWSA achievements. Also ignored in the study will be any of the impacts and costs to society of destruction of farmlands, wetlands, and conservation lands implied by the Northeast Energy Direct project. Synapse excuses this shortcoming by stating that its study is agnostic on the source of new gas reserves, but for many this is the main point of objection to the ever-increasing use of fossil fuels.

Failure to adequately address volatility

The so-called natural gas price "crisis" in the winter of 2013/14 was the result of seasonality, the occurrence of the coldest winter in decades, and policy failures that restricted the use of readily available LNG infrastructure. It was not entirely about fundamental shortage of pipeline capacity on an annual basis. There were questions raised in Thursday's session about the evaluation of the impacts of gas price volatility on our increasing reliance on natural gas. These were dismissed by Synapse as being outside the scope of the study on the basis that enough resources would be added in both the base case and the LDS so that price volatility would be avoided and thus be irrelevant to the decision on the optimal mix of resources.

This is a major shortcoming in the analysis. While the extreme volatility experienced in the New England during the winter of 2013/14 would have been mitigated by greater pipeline capacity from the west (as well as by increased use of the LNG capacity that was and still is available without additional infrastructure), no matter how much is added in the way of resources, pipeline or other, gas prices will always be volatile. That volatility comes from weather variations, international oil price variations, timing of new domestic gas fields, and as the U.S. moves into the gas exporter role as seems likely, from volatility in international gas markets. All that adding resources in New England can do is volatility in the basis differential between New England and other US markets. Gas prices in absolute terms will remain volatile.

Why is this important? As we move to ever greater reliance on natural gas for power generation, our ability to mitigate the impacts of gas price volatility on electricity rates will be diminished. In a recent study on the subject, Cambridge Energy Research Associates (CERA, a subsidiary of IHS Energy)[1] estimated that moving the US installed gas generation capacity from the current 40 percent to 62 percent would result in:

- Total US power costs increasing by $93 billion per year
- US average household disposable income declining by $2,100 per year
- US GDP reduced by $200 billion
- US employment reduced by 1 million jobs.

Surely any recommendation to increase New England's dependence on natural gas should include these considerations, but no such analysis is included in the Synapse study.

No "Gas Bubble" considerations

The "conventional wisdom" prevailing in the US today is that because of the boom in shale gas production from Marcellus, Utica, and other plays, the US will enjoy decades of low-cost and abundant natural gas supplies. Yet, there are analysts who question this conventional wisdom and outline the risks associated with overbuilding of natural gas infrastructure.[2] [3] [4] Given the potentially costly overbuilding if New England bets the farm on low-cost natural gas, I think including a higher price case than the DOE Low Resource estimate is in order – at least a consideration of the high LNG exports/low resource price trajectory of the recent US DOE study on the price impacts of US LNG exports is in order.[5]

Avoided costs limitations?

Given the lack of detail in the resource calculations presented in this meeting, it is difficult to evaluate them in detail. However, one element is particularly unclear – how much avoided capital costs are included in the Annual Net Levalized Cost calculations. Take one example: Wind Offshore 2020 to 2030. Annual Net Levelized Cost is $66 per MWh or a cost of reported (see below on this topic) $788 per MMBtu of natural gas replaced. The potential is assessed at 1600MW. I have not found anywhere in your calculations a specification of what the offsetting reduction in capital costs or O&M costs for not building and operating the equivalent capacity in natural gas pipelines and generation. Surely it does not make sense to evaluate the long-term

[1] The Value of US Power Supply Diversity, IHS Energy, July 2014, http://www.ihs.com/info/0714/power-diversity-special-report.aspx,
[2] The Popping of the Shale Gas Bubble, Bill Power, Forbes Magazine, September 2014 http://www.forbes.com/sites/billpowers/2014/09/03/the-popping-of-the-shale-gas-bubble/
[3] Marcellus Shale: Through A Glass, Darkly, Moshe Ben-Reuvan, Seeking Alpha Investment Research, March, 2014, http://seekingalpha.com/article/2118153-marcellus-shale-through-a-glass-darkly
[4] The Fracked-up USA Shale Gas Bubble, F William Engdahl, nsnbcInternational, March 13, 2014, http://nsnbc.me/2014/03/13/fracked-usa-shale-gas-bubble/
[5] Effects of Increased Natural Gas Exports on Domestic Energy Markets, US DOE EIA, January, 2012, http://energy.gov/sites/prod/files/2013/04/f0/fe_eia_lng.pdf

addition of incremental wind capacity. Also, I could find nothing in the reference noted for this resource that bore any information behind the offshore wind numbers in your presentation.

Economic Threshold Calculations

My concerns on avoided cost calculations and economic thresholds apply to energy storage. To compare the cost of energy storage to the levelized cost of pipeline gas based on the levelized cost of a fully utilized pipeline seems to miss the point. If you cover peak requirements in a highly seasonal market by building additional pipeline capacity, that incremental capacity will be dramatically underutilized during non-peak periods, and thus the avoided cost associated with incremental energy storage will be much greater than $4 per MMBtu -- unless you assume that some other use of the spare capacity is extant. Certainly that was the role of power generation in the past through interruptible contracts. With more and more homes and businesses converting to natural gas, a seemingly ever increasing portion of our electricity to be generated by natural gas, and generators too seeking firm gas contracts, those days would appear to be over.

I am still scratching my head on the basis for the $18/MMBtu economic threshold calculation. In particular I do not see how it relates to the statements in the meeting that volatility was not to be addressed as it was assumed that sufficient resources would be added to avoid the winter price speaks of 2013/14. I assume that this might be the basis for evaluating energy storage, but that is not clear from any of the material presented to date.

Calculation of Net Levalized Cost per MMBtu of NG

I am afraid I cannot reconcile this calculation. Taking again the Wind: Offshore example, the net levelized cost for 2020 is $133 per MWh. If the assumed heat rate used is based on peak generation, i.e. 12,000 btu/kwh as stated in the meeting, the $0.133 ($133/MWh) spent on a kwh of offshore wind energy would displace a total of 12,000 btu or 0.012 MMBtu. That seems to me to be a lot closer to $11 per MMBtu displaced than $1,591 per MMBtu. What am I missing?

Submitted on Behalf of:
Acadia Center
Appalachian Mountain Club
Berkshire Environmental Action Team (BEAT)
Better Future Project
Clean Water Action
Climate X Change
Conservation Law Foundation
E2 (Environmental Entrepreneurs)
Environment Massachusetts
Environmental League of Massachusetts
Low-Income Weatherization and Fuel Assistance (Low-Income Network)
Mass Energy Consumers Alliance
Montague Resident
Mothers Out Front
Mount Grace Land Conservation Trust
Nashoba Conservation Trust
National Wildlife Federation
NHpipelineawareness.org
No Fracked Gas in Mass
Stop the Pipeline
StopNED

November 4, 2014

Massachusetts Department of Energy Resources (DOER)
Submitted Electronically to lowdemandstudy@state.ma.us

Re: Low Demand Analysis Stakeholder Comments

The undersigned represent environmental groups, business coalitions, low-income advocates, consumer advocacy organizations, citizen groups, and individuals. We thank you for the opportunity to actively participate in this process, to ask questions, and to provide comment in response to the presentation given by Synapse on October 30th. We urge you to consider the following as you proceed with your feasibility design and modeling.

Process Clarifications/Requests

1. Provide MW equivalent on ALL calculations provided in the final report (including supply curves), as this is what resonates most with legislators and other stakeholders.
2. Include in analysis thorough examination of solutions with potential to reduce capacity constraint between now and 2020 (e.g., air source heat pumps, CHP, more LNG, market reforms, commercial PACE program in CT, etc.).
3. To the extent possible, we ask that you share in advance the base case output(s) prior to the next stakeholder meeting.

Content Clarifications

1. **Assumptions:**
   a. Avoided Costs of Energy Efficiency
   Avoided costs for energy efficiency resource in the feasibility study are limited to (1) avoided energy, capacity, and T&D from the AESC 2013 base case; (2) avoided costs of GWSA compliance (DPU 14-86). However, the analysis should capture all other non-energy benefits starting with those already accounted for by the Department of Public Utilities. In addition, the AESC 2013 did not adequately monetize the impacts of winter prices spikes. The feasibility study should backcast to determine what the additional avoided costs of energy supply would have been had the winter price spikes been accounted for. The Rhode Island Public Utilities Commission estimated that AESC 2013 understated these costs by $200 million over a three-year period for Rhode Island alone. We would also like to see health benefits accounted for, which the DPU does not currently recognize but that are becoming increasingly easier to calculate. If the study excludes health benefits, we ask that the exclusion will be listed in the caveats.

   b. Potential for Energy Efficiency
   We believe that the currently modeled limit on energy and demand savings is arbitrary and insufficient given the great potential for avoiding costs. Given that Massachusetts energy efficiency programs have greatly expanded since 2009 without causing per unit costs to rise or BCRs to fall, we see the current amount of efficiency in the supply curve to be arbitrarily limited. We also know that the potential studies that could elucidate the availability of low-cost energy efficiency, specifically the amount of EE that would be allowable under the economic threshold,

are unavailable. We recommend modeling the energy demand savings associated with energy savings that would start at a significantly higher percentage of sales than in the base case. Although the following numbers are also not sufficient enough to capture all that is cost effective, at a minimum we recommend extrapolating from the CECP numbers for 2018: 2.9% reduction in annual electric sales due to efficiency measures installed during that year, 1.9% from natural gas efficiency, and an annual growth rate of 5% for efficiency savings related to fuel oil. Until more detailed potential studies are developed, this approach offers an appropriate means of reflecting the potential for greater efficiency savings in electricity and natural gas end use. Note also that the principal source for low-income energy efficiency projections actually combines residential and low-income energy efficiency without specifically addressing low-income.

c. High Natural Gas Prices/Price Volatility
The high natural gas price scenario should be utilized to evaluate consumer risk under a plausible scenario where a combination of forces causes gas prices to increase to the highest credible levels. Without evaluating such a scenario the study will fail to address the core challenge related to making long-lived investments in energy infrastructure; namely, how to support investments that create the greatest benefits and lowest costs across a range of future circumstances. The Energy Information Administration recently conducted analysis to evaluate how increased natural gas exports would impact prices in various scenarios related to availability of natural gas resources, economic growth levels, and electric sector gas consumption. This is particularly important as EIA's gas price forecasts in the 2014 AEO inadequately reflect the risk of increased natural gas exports driving a near-term price increase. EIA's base case assumes that the US becomes a net exporter in 2018, and net exports increase to approximately 5bcf by 2030.[1] However, the high gas price scenarios layered over this base case focus on high economic growth and low recoverability of oil and gas resources, and do not specifically evaluate the price impact of accelerated exports. Due to increasing political support for exports to support geopolitical objectives and the accelerated pace of approval for liquefied natural gas (LNG) export terminals, market-watchers have recently begun to assume a more rapid rate of increase in exports.[2] The most appropriate assumption for the high gas price scenario can be found in EIA's October 2014 *Effect of Increased Natural Gas Exports on Domestic Energy Markets*.[3] Of the scenarios explored in this analysis, the rapid increase in exports to a high level (20bcf/d by 2025), layered onto the low oil and gas resource case, is the scenario that best reflects the risk that gas production is more expensive than assumed, and that higher international market prices nonetheless drive a significant increase in exports. According to EIA, high exports and low recoverability leads to average natural gas prices of $9/Mcf in the Northeast over the study period of 2015-2040,[4] which 13% higher than EIA's base projection under the low oil and gas resource case.

d. Incremental Canadian Transmission Sensitivity
We support modeling a sensitivity to consider energy imports from Canada, but recommend that the assumptions related to such imports be modified to reflect the characteristics of

[1] See: http://www.eia.gov/forecasts/aeo/mt_naturalgas.cfm
[2] See: http://www.eenews.net/energywire/stories/1060006051/search?keyword=LNG+wall+street
[3] An update of a January, 2012 report with the same name, referenced in October 20th joint environmental comments. The updated EIA report is available at: http://www.eia.gov/analysis/requests/fe/pdf/lng.pdf
[4] Ibid, p. 32.

proposed projects that would carry wind in addition to hydroelectricity. Filling a large-scale transmission line with wind, and backstopping wind with hydroelectricity would enable cost-effective transportation of wind from Eastern Canada and northern New England, while providing firm supply to replace retiring in-region electric generation. A wind-hydro mix would likely have a higher annual capacity factor than the 67% assumed for both lines in the draft sensitivity. Given that developers are proposing projects to transport a mix of wind and hydro,[5] we believe the study would be remiss if it did not evaluate such an approach. In fact, analysis of two transmission projects provides a valuable opportunity to evaluate both types of imports by simply assuming that one line carries 30% wind generation and 70% imports from Canada. Additionally, we believe that it may be inappropriately conservative to assume that a second transmission line could not be brought online until 2022. Unless there is a concrete basis for this assumption, we recommend that the completion dates for transmission be based on developer projections, as will likely be the case for gas pipeline capacity.

e. Thermal Biomass

In the October 30th stakeholder meeting Synapse described an adjustment of the biomass thermal potential based on its apparent size. However, no additional explanation was provided, and we are concerned that the analysis may be undervaluing an important resource arbitrarily. If credible analyses have determined certain level of biomass thermal opportunity we recommend that findings of those analyses be incorporated in full. Without an explanation regarding the discounting of biomass thermal potential, an important resource for the Commonwealth to pursue could be unnecessarily set aside.

2. Study Limitations: Methane Emissions

During the stakeholder meeting, we heard Dr. Stanton say that methane leakage would not be counted per direction of DOER because of limited time to analyze this question properly given the wide range of possibilities. As supporters of the Global Warming Solutions Act, we do not understand why the Commonwealth would carefully analyze its many energy options and to put a price on C02 up the stack without also putting a price on CH4 sent into the air.

We suggest a simplified approach that would be similar to approaches used in other parts of this Low Demand Analysis. That would be to utilize a conservative percent leakage as recently published in a report for US DOE.[6] In that report, the authors estimate a 1.2-1.6 percent methane leakage rate, conservatively, for Marcellus shale gas. (Please note this is a conservative estimate. We suggest a more appropriate rate would be 3-6%, but recognize that even higher estimates may be considered, too.[7]) It would seem reasonable to multiply the middle of that range, or 1.4% times the amount of natural gas that would be piped into Massachusetts to determine the quantity of leaked methane. Then multiply that number by 86[8] to derive a number that would be the number of tons of carbon dioxide equivalent.

[5] For example the Emera-National Grid Northeast Energy Link,

[6] http://energy.gov/sites/prod/files/2014/05/f16/Life%20Cycle%20GHG%20Perspective%20Report.pdf.

[7] See "A Bridge Too Far" page 7 for citations of rates between 1-9% including Harvard/NOAA. http://www.betterfutureproject.org/wp-content/uploads/2014/06/A-Bridge-Too-Far-Final.compressed.pdf

[8] IPCC, 2013: Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Stocker, T.F., D. Qin, G.-K. Plattner, M. Tignor, S.K. Allen, J. Boschung, A. Nauels, Y. Xia, V. Bex and P.M. Midgley eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, 1535 pp.

With respect to this issue of methane leakage, it is possible that new federal and state regulations will reduce the percent leakage from the unproven number that it is today. But that will come at a cost that is not built into the Base Case.

Next Steps/Final Report

1. **Score all 8 scenarios based on compliance with GWSA**
   We understand the purpose of this project is to consider solutions to MA energy demand in the near and long term and that these solutions will help DOER balance GHG emissions, economic costs and benefits, and system reliability. We also know that final report is not intended to offer policy recommendations. However, as groups committed to seeing MA meet the GWSA-mandated GHG emission reductions, we ask that as you model and then report each scenario, you make clear which scenarios ensure compliance with GWSA. This should be clearly indicated in the body of the report and not relegated to a footnote or endnote.

2. **Clearly flag ALL study limitations, as well as underlying assumptions in report, but also make note of "proposal for further inquiry" or "options for further inquiry."**
   We recognize that this low-demand scenario analysis is a situation model, not an optimization model. And for this reason, we also understand that certain analysis, for example factoring into the analysis of life-cycle accounting for methane emissions, is beyond the current scope of work. However, in addition to including in the final report a description of study limitations, we also urge the Administration to assign a follow on study that would model the clean energy future required to comply with GWSA. Assumptions that need explanation include the assumed costs of hydro and the assumed 100% availability of non-firm hydro at the peak hour.

Thank you again for providing this opportunity. We look forward to ongoing collaboration and engagement.

For specific questions or additional information please contact Eugenia Gibbons: eugenia@massenergy.org, 617-524-3950 x 141.

Sincerely,

Eugenia T. Gibbons, *Mass Energy Consumers Alliance*
Peter Shattuck, *Acadia Center*
Rosemary Wessel, *No Fracked Gas in Mass*
Jane Winn, *Berkshire Environmental Action Team (BEAT)*
Ben Hellerstein, *Environment Massachusetts*
Nancy Goodman, *Environmental League of Massachusetts*
Craig Altemose, *Better Future Project*
Joel Wool, *Clean Water Action*
David Moloney, *NHpipelineawareness.org*
Jerrold Oppenheim, *Low-Income Weatherization and Fuel Assistance (Low-Income Network)*
Cathy Kristofferson, *StopNED*
Ken Hartlege, *Nashoba Conservation Trust*
Leonard Johnson, *Mount Grace Land Conservation Trust*
Jenny Marusiak, *Mothers Out Front*
Shanna Cleveland, *Conservation Law Foundation*
Heather Clish, *Appalachian Mountain Club*
Ariel Elan, *Montague Resident*
Marc Breslow, *Climate X Change*
Peter Jeffrey, *member, Groton Stop the Pipeline Coordinating Committee*
Catherine Bowes, *National Wildlife Federation*
Rich Cowan, *Stop the Pipeline, Dracut and Eastern Middlesex*
Berl Hartman, *(E2) Environmental Entrepreneurs*

ENERGY CONSUMERS ALLIANCE OF NEW ENGLAND

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MASS ENERGY CONSUMERS ALLIANCE
A Non-Profit Organization

PEOPLE'S Power & Light

November 4, 2014

Massachusetts Department of Energy Resources (DOER)
Submitted Electronically to lowdemandstudy@state.ma.us

Re: Massachusetts Low Demand Analysis – Comments from Mass Energy Consumers Alliance

Thank you for the opportunity to ask questions and provide comments in response to the presentation given by Synapse during the stakeholder meeting on October 30, 2014. In addition to the joint comments submitted by a number of participants from the environmental/consumer advocacy/citizen group/individual stakeholder breakout group, Mass Energy asks you to consider and/or clarify the following as you move forward with your feasibility analysis and modeling.

Response to Slides Presented on October 30

It is unclear if, when Synapse refers to 2015, they mean the winter of 2014/2015, winter of 2015/2016, or calendar year 2015. Please clarify this.

Scenarios & Sensitivities

Slide 20 – Natural gas prices: To what extent has Synapse calculated the economic threshold considering the potential run-up in cost that could result from a substantial amount of natural gas exports?

Slide 21 - Hydro: Please explain why you model 1200 MW hydro in 2018 and then 1200 MW hydro in 2022, rather than 2400 MW in 2018 or otherwise sooner than 2022. Also, please explain why you did not model a higher amount of hydro by 2020.

Resource Assessments

Slide 40 - Hydro: Has Synapse considered whether the transmission facilities associated with 2400 MW of Canadian hydro could also support the transmission of wind power by 2018-2022? If not, could Synapse model that possibility, particularly given that the wind power would be incremental to the Base Case?

Slides 54-58 – Energy Efficiency Programs:

- Please model running each EE program out on the X-axis to the point at which each hits the economic threshold. We believe that the currently modeled limit on energy and demand savings is arbitrary and insufficient given the great potential for avoiding costs. Given that Massachusetts energy efficiency programs have greatly expanded since 2009 without causing per unit costs to rise or BCRs to fall, we see the current amount of efficiency in the supply curve to be arbitrarily limited. We also know that the potential studies that could elucidate the availability of low-cost energy efficiency, specifically the amount of EE that would be allowable under the economic threshold, are unavailable. We recommend modeling the energy demand savings associated with energy savings that would start at a significantly higher percentage of sales than in the base case.

- Please provide further detail on what interventions are responsible for the savings shown in these slides. In particular, please specify what is included regarding:
  - Spending by programs. We read the Lawrence Berkeley paper, *"The Future of Utility Customer-Funded Energy Efficiency Programs in the United States: Projected Spending and Savings to 2025"* and it seems to indicate cost-effective spending for Massachusetts by 2030 of 10 percent of retail electricity revenue[1]. That would be approximately double today's spending effort in Massachusetts. How does Synapse's modeling compare to LBNL's?
    - With respect to this piece, to what extent does the Base Case or efficiency as modeled in Slides 54-58 involve the participation of municipal utilities? Municipal utilities are responsible for about 15 percent of the state's load.
  - Combined Heat and Power. LBNL indicates that CHP could achieve 20% of electricity savings in Massachusetts by 2030. How does Synapse's modeling compare to LBL's?
  - Building Codes and Labeling. Our review of ACEEE's 2014 International Energy Scorecard indicates that several nations have more aggressive building codes and labeling policies in place and results in those countries have been positive[2]. LBNL indicates that building codes could achieve 16% of electricity savings in Massachusetts by 2030. How does Synapse's modeling compare to LBNL's?
  - Appliance Standards. LBNL indicates that building codes could achieve 2% of electricity savings in Massachusetts by 2030. How does Synapse's modeling compare to LBL's?

Slide 60 – Winter Reliability Program:

- Please explain why Synapse has assessed the feasibility of extending the Winter Reliability program to such a limited degree. Regarding the WRP, we also note that in 2020, you show annual production of 29.4 MMBtu, but zero MMBtu of peak hour gas savings. Please clarify why this is zero.
- Has Synapse and/or DOER considered running a WRP for Massachusetts alone, outside the WRP of ISO-NE?
- Could you model the benefits and costs, both financial and environmental, of running a Massachusetts-specific WRP that would include more:
  - LNG
  - Low-sulfur petroleum and biodiesel combusted in power plants with dual-fuel capability?

  Presumably these resources could be procured in advance for the winter of 2015/2016 and deployed during the hours, days, periods of greatest constraint.

[1] http://emp.lbl.gov/sites/all/files/lbnl-5803e.pdf
[2] http://aceee.org/research-report/e1402.

Other Comments/Study Limitations

Avoided Costs of Energy Efficiency:
Avoided costs for energy efficiency resource in the feasibility study are limited to (1) avoided energy, capacity, and T&D from the AESC 2013 base case; (2) avoided costs of GWSA compliance (DPU 14-86). However, the analysis should capture all other non-energy benefits starting with those already accounted for by the Department of Public Utilities. In addition, the AESC 2013 did not adequately monetize the impacts of winter prices spikes. The feasibility study should backcast to determine what the additional avoided costs of energy supply would have been had the winter price spikes been accounted for. Consultants for the Energy Efficiency Resource Management Council in Rhode Island explicitly recognized this in a recent review of energy efficiency program benefits and concluded that, had the winter price spikes been adequately accounted for in the Avoided Energy Supply Cost Study that guides regulators in evaluating the cost-effectiveness of programs, the Rhode Island analysis would have shown an additional $200 million in benefits. Given Massachusetts' much higher level of demand, the corresponding additional benefits from adequately valuing the winter price spikes would have been commensurately much higher as well. We have included a copy of the Winter Peak Implications graph that illustrates this. We would also like to see health benefits accounted for, which the DPU does not currently recognize but that are becoming increasingly easier to calculate. If the study excludes health benefits, we ask that the exclusion will be listed in the caveats.

Methane Emissions and Future Natural Gas Prices:
We heard Dr. Stanton state that methane leakage would not be counted per direction of DOER because of limited time to analyze this question properly given the wide range of possibilities. As supporters of the Global Warming Solutions Act, we do not understand why the Commonwealth would carefully analyze its many energy options and to put a price on C02 up the stack without also putting a price on CH4 sent into the air.

We suggest a simplified approach that would be similar to approaches used in other parts of this Low Demand Analysis. That would be to utilize a conservative percent leakage as recently published in a report for US DOE.[3] In that report, the authors estimate a 1.2-1.6 percent methane leakage rate, conservatively, for Marcellus shale gas. (Please note this is a conservative estimate. We suggest a more appropriate rate would be 3-6%, but recognize that even higher estimates may be considered, too.[4]) It would seem reasonable to multiply the middle of that range, or 1.4% times the amount of natural gas that would be piped into Massachusetts to determine the quantity of leaked methane. Then multiply that number by 86[5] to derive a number that would be the number of tons of carbon dioxide equivalent.

With respect to this issue of methane leakage, it is possible that new federal and state regulations will reduce the percent leakage from the unproven number that it is today. But that will come at a cost that is not built into the Base Case.

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[3] http://energy.gov/sites/prod/files/2014/05/f16/Life%20Cycle%20GHG%20Perspective%20Report.pdf.

[4] See "A Bridge Too Far" page 7 for citations of rates between 1-9% including Harvard/NOAA. http://www.betterfutureproject.org/wp-content/uploads/2014/06/A-Bridge-Too-Far-Final.compressed.pdf

[5] IPCC, 2013: Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Stocker, T.F., D. Qin, G.-K. Plattner, M. Tignor, S.K. Allen, J. Boschung, A. Nauels, Y. Xia, V. Bex and P.M. Midgley eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, 1535 pp.

Grid Modernization and Demand Response: Could you clarify whether the Base Case includes estimates for demand reduction associated with Time of Use rates, Advanced Meters, and other aspects of Grid Modernization?

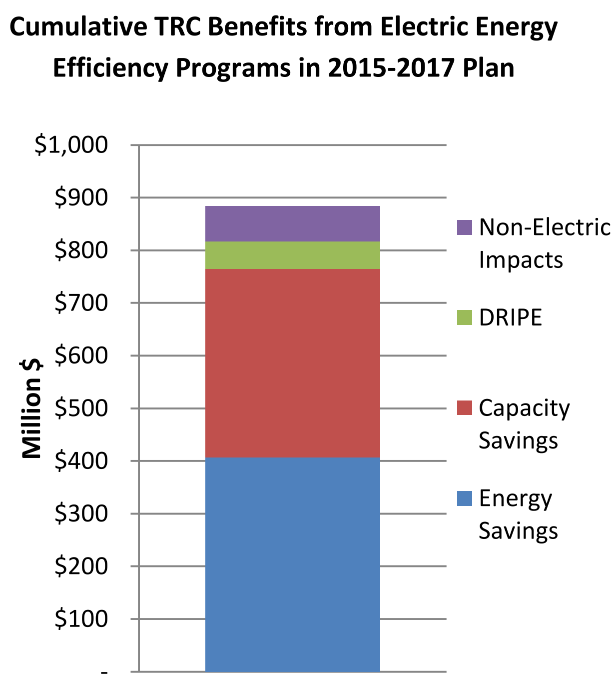
Timing of the Pipeline and a No Regrets Package of Alternatives:
It seems that we are comparing a very large natural gas pipeline expansion to a large number of alternative resources, each of which is relatively small compared to the pipeline in terms of meeting our energy needs. The pipeline question is just binary. It's built or not. But with almost all of the alternatives, we can envision a wide range of possibilities (i.e. with off-shore wind and energy efficiency, we could see any number of MW). Have you considered:

- Modeling construction of the pipeline, but with utilization rates that are significantly lower than assumed in the Base Case?
- Delaying construction of the pipeline in order to give alternative resources a chance to meet needs in 2015-2018? This scenario would be considered a "no regrets" policy insofar as that it would not preclude eventual construction of the pipeline and that it would be far more certain to meet requirements of the Global Warming Solutions Act.

For questions or additional information please contact Eugenia Gibbons: eugenia@massenergy.org, 617-524-3950 x 141.

Attachment B: Implications of Winter Gas constraint on Energy Efficiency Cost-Benefit Analysis

The figure below, reproduced from the report, shows how the benefits in the 2015-2017 Procurement Plan are built up from the individual components as defined by the Total Resource Cost test.



Benefits from energy savings account for the greatest share of the total benefits at 46%. They are calculated by multiplying the cumulative savings from the entire portfolio – which occur over a number of years in the future – against a forecast of avoided costs that roughly correspond to the wholesale price of power. The avoided costs used in the above calculation come from the 2013 Avoided Energy Supply Cost (AESC) study developed by Synapse.[1] Since the 2013 AESC study was published, the well-publicized winter gas constraint has driven wholesale prices up dramatically.[2] The table below shows the forecasted cost of energy for 2014 from the AESC report compared to an average of actual monthly wholesale prices reported by ISO-NE for the winter months.[3,4]

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[1] http://www.synapse-energy.com/Downloads/SynapseReport.2013-07.AESC.AESC-2013.13-029-Report.pdf
[2] http://isonewswire.com/updates/2014/5/13/first-quarter-markets-report-reviews-outcomes-during-january.html
[3] http://iso-ne.com/isoexpress/web/reports/load-and-demand/-/tree/monthly-wholesale-load-cost-report?loadZone=4005&periodicity=Monthly&detailLevel=ON&loadCostConcept=TC&startYear=2014&startMonth=01&endYear=2014&endMonth=12&type=
[4] Winter months are defined as December-March.

	Winter On-Peak	Winter Off-Peak
2013 AESC ($/kWh)	0.053	0.046
2014 ISO ($/kWh)	0.109	0.084
% Increase	**206%**	**181%**

Intuitively, higher avoided costs should lead to higher benefits since the state is avoiding a more expensive cost than initially anticipated. To test this idea we assumed the high costs would persist through 2019 before subsiding, and substituted the new forecast into the screening model. The resulting benefits are summarized in the table below.

	Total Electric Benefits ($M)
Original 2015-2017 Plan	$884
Plan with adjusted costs	$1,083
Difference	**$199**
% Difference	**22%**

Overall electric benefits increase by 22%, corresponding to roughly $200 million, when we substituted in revised avoided costs. This is significant. While the analysis is high-level, the results suggest Rhode Island is realizing even greater benefits than expected from its energy efficiency programs.

ENERGY CONSUMERS ALLIANCE OF NEW ENGLAND

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A Non-Profit Organization

PEOPLE'S Power & Light

October 20, 2014

Massachusetts Department of Energy Resources (DOER)
Submitted Electronically to lowdemandstudy@state.ma.us

Re: Massachusetts Low Demand Analysis – Comments from Mass Energy Consumers Alliance

Mass Energy Consumers Alliance commends the Administration for undertaking a low demand scenario analysis and thanks the Department of Energy Resources for moving forward with a study of alternative resources capable meeting heating and electricity demand. As a consumer advocacy organization committed to making energy affordable and sustainable, and to achieving 80% GHG emission reductions by 2050, Mass Energy supports this endeavor and steps taken to reduce our current over-reliance on natural gas. This over-reliance leaves ratepayers exposed and vulnerable to energy price volatility, particularly during extreme peak periods.

We appreciate the opportunity to provide initial comments in response to the presentation given during the stakeholder meeting held on October 15, 2014. We urge you to consider and/or clarify the following as you move forward with analysis design and modeling.

We recognize the challenge before DOER to explore solutions that meet energy demand while balancing reliability, cost, and environment, but proposed solutions must be consistent with the Global Warming Solutions Act. Outputs should be clearly labeled as to whether or not they would be compatible with reaching GWSA-required emissions reductions – specifically with regard to 2020 and 2050, but also 2030 (determined as a straight line interpolation between the 2020 and the 2050 targets). Any solution that cannot be reconciled to the GWSA should be considered irrelevant.

Related to GWSA compliance, the benefits of all resources analyzed must include a cost of carbon avoidance. At a minimum this should be consistent with the cost of carbon avoidance put forth in Dr. Elizabeth Stanton's own testimony for DPU docket 14-86 ($52/metric ton in 2020, and $59/metric ton in 2030). DPU 14-86 seeks to establish an adequate cost of carbon avoidance in evaluating the benefits and costs of utility-run efficiency programs so as to be able to capture all cost-effective energy efficiency required to comply with GWSA. Failure to screen resources in the low demand scenario analysis using this mechanism would be policy inconsistent. Using a lesser value to analyze alternative resources to meet demand puts in place an artificial limit on the amount of alternatives that may be less costly than expanding natural gas supply.

When assessing the benefits of alternative resources analysis should not be limited to only the benefits currently recognized by DPU. It is unclear how and to what extent this study will quantify and recognize other benefits associated with alternative resources (e.g., health benefits associated with reduced consumption of fossil fuels, or safety benefits associated with fixing gas leaks). It would be helpful to clarify this before or during the next stakeholder meeting.

With regard to assumptions about energy efficiency, it is important to note that presently the only energy savings goals that have been approved by the Department of Public Utilities are those pertaining to the Three-Year Plan for 2013-2015.The Three-Year Plan for 2016-2018 has not yet been approved and the first draft will not be submitted to the Energy Efficiency Advisory Council until April. The Green Communities Act and the Global Warming Solutions Act both dictate that all energy efficiency that costs less than supply ought to be captured. Therefore, in the case of the Low Demand Scenario Analysis, assumptions for 2016 and beyond should include capturing all cost-effective measures to reduce peak winter demand.

We know from evaluations that the BCR of the total energy efficiency program exceeds 3.0. We also know that the BCR for certain programs and measures are much higher than that. Massachusetts could greatly expand the efficiency program, with a renewed focus on reducing winter peak demand, and still maintain a BCR greater than 1.0. In fact, from 2010 through 2014, even as the efficiency programs have greatly expanded, the BCRs have not fallen. Therefore, we would reject an analysis that artificially limits demand savings to those at or near the savings that are currently being achieved in 2014.

We strongly urge you to evaluate a measure's merits throughout the year rather than during the few peak days alone. It was unclear at the October 15 stakeholder meeting if "alternative resources" such as those listed on slide 27 would be evaluated based upon merits during a winter peak day or merits throughout the year. Since resources are in place all year, evaluating them based on the full year more completely compares the Benefit Cost Ratios (BCR) associated with those resources compared to making a long-term financial commitment to fossil fuels. For example, installing an LED light bulb might cost more per peak watt than natural gas if the measurements are limited to, say January 2015. However, the LED bulb could provide a much better BCR over the life of the resource, especially as compared to the life of a new natural gas pipeline.

Finally, the BCR for alternative resources should be based upon the real values seen in 2013/2014 and those likely to be seen in 2014/2015, rather than the AESC for 2013. Consultants for the Energy Efficiency Resource Management Council in Rhode Island explicitly recognized this in a recent review of energy efficiency program benefits and concluded that, had the winter price spikes been adequately accounted for in the Avoided Energy Supply Cost Study that guides regulators in evaluating the cost-effectiveness of programs, the Rhode Island analysis would have shown an additional $200 million in benefits. Given Massachusetts' much higher level of demand, the corresponding additional benefits from adequately valuing the winter price spikes would have been commensurately much higher as well.

Thank you, again, for your time and consideration of these comments. We look forward to ongoing participation in this analysis and stakeholder process and welcome the opportunity to work collaboratively to advance energy resources that ensure reliability while also offering the greatest benefits to consumers and the environment.

For questions or additional information please contact Eugenia Gibbons: eugenia@massenergy.org, 617-524-3950 x 141.

From:	Shop_Angel
To:	Lowdemandstudy, (ENE)
Subject:	Stakeholder Comments due today
Date:	Tuesday, November 04, 2014 4:31:31 PM

Dear Dr. Stanton and team, and Ms. Lusardi~
Thank you for the opportunity to comment on the low-demand energy study for Massachusetts that is currently underway. In consideration of Dr. Stanton's request at the Oct. 30 stakeholder meeting, I will submit my comments as much as possible as separate emails addressing individual aspects of the study.

Gas Exports and Future Prices
Among the many articles from the business and industry press that cross my desk almost daily, the unanimous consensus to date is that increasing exports of natural gas will inevitably raise domestic gas prices. Prices that gas suppliers can receive abroad are described as ranging from 2.2 to 6 times the prices suppliers can receive in the U.S., depending on the country where the buyers are located.

The most recent forecasting comes from the U.S. EIA--a source that must be viewed as neutral-to-conservative in its projections. The agency modeled 5 different export scenarios using different assumptions, and each scenario showed at least some increase in prices for U.S. consumers of natural gas.

http://www.eia.gov/analysis/requests/fe/
http://www.hellenicshippingnews.com/us-lng-exports-would-boost-economy-but-lead-to-higher-energy-prices-says-eia/

Simple arithmetic shows that the proposed Kinder Morgan gas pipeline with its 2.2bcf capacity will, of necessity, be used for exports, as the currently identified need for gas to supply electricity during winter peaks would absorb only .5 to .6bcf per day, for fewer than 20 to 30 days a year. The smaller proposed pipeline by Spectra/Northeast Utilities would supply 1bcf per day, also well in excess of this presumed need.

Additional Context: Recent claims of amplified need for gas are suspect
In the face of opposition to greenfields pipelines, industry lobbyists have teamed up with corporations whose local subsidiaries supply gas for heating, to create a manufactured crisis now hitting the headlines, in which these local suppliers claim they do not have enough pipeline capacity to accept any more of the customers that they have been aggressively pursuing to switch to gas for more than a decade.

I describe this as a manufactured crisis because there is not a hint of this potential problem in any press coverage during the past several years, whether in industry or mainstream press. There is no hint of a potential gas shortage, nor pipeline constraints, for heating fuel in any of the extensive and detailed studies and discussions of the gas and electricity markets during the past several years under the interconnected umbrellas of NESCOE, ISO-NE, and FERC.

There is also no sign that any of the newly complaining companies--Berkshire Gas and Columbia Gas among them--are rushing to repair the leaks in their systems that contribute to the annual loss of 1.725bcf of gas in the state:
http://www.clf.org/blog/clean-energy-climate-change/into-thin-air-time-to-replace-and-repair-leaking-natural-gas-pipelines/

In fact, NESCOE and ISO-NE officials have always stated that the gas LDCs are able to obtain all of the gas they need through their fixed contracts, but that electric generators are subject to higher prices because they buy on the spot market.

In this context, the sudden emergence of a shortage claim for gas heat can only be seen as a constructed phenomenon to push new pipeline construction, after many citizens and legislators used NESCOE's and ISO's own data, extensive stakeholder comments on the IGER reports, and other analyses to cast doubt on the nature and scope of gas constraints on electricity supply, as well as the practicality, cost, and externalities of filling whatever need exists by expanding gas infrastructure.

From:	Cynthia Armstrong
To:	Lowdemandstudy, (ENE); Susan@RaabAssociates.org
Cc:	Keith Nelson; Richard Bralow
Subject:	Comments by Portland Natural Gas Transmission on Low Demand Study
Date:	Tuesday, November 04, 2014 4:33:52 PM

Ms. Meg Lusardi
Acting Commissioner
Massachusetts Department of Energy Resources
100 Cambridge Street, Suite 1020
Boston, MA 02114

November 4, 2014

Dear Acting Commissioner Lusardi:

Portland Natural Gas Transmission System ("PNGTS") commends the Massachusetts Department of Energy Resources ("DOER") for taking a comprehensive view of the State's energy portfolio needs and appreciates the opportunity to participate in the Low Demand Analysis. Massachusetts has been a national leader in energy efficiency and environmental protection, and the methodology of Synapse's Low Demand Analysis reflects this prioritization.

PNGTS's Continent to Coast ("C2C") Project offers Massachusetts the most environmentally sound, efficient and cost-effective solution to meet its necessary natural gas pipeline capacity requirements. C2C is essentially an energy efficiency project:

- The C2C expansion makes more efficient use of existing pipeline infrastructure – putting more gas through an existing line already in the ground.
    - This will result in greater utilization of the same infrastructure, with rates expected to decrease by over 31% from the currently filed recourse rates.
- NO construction is required on PNGTS.
    - Relatively minor expansion upstream on TransCanada Pipelines Limited ("TCPL") will push this extra gas to PNGTS, for delivery into PNGTS' existing pipeline infrastructure at Dracut, Haverhill and Methuen, MA.
    - There are no expected disruptions to Massachusetts landowners.
    - There are no construction/permitting delay issues on C2C that would increase costs and risks for Massachusetts energy consumers. Likewise, it is not expected that TCPL will experience such delays in its upstream expansion.
- C2C accesses Marcellus gas via TCPL at Northern and Western New York export points, as well as from land-based Western Canadian supplies in Alberta and British Columbia.
- C2C is right-sized: it is expandable by up to 167,000 MMBTU/day. It meets the reasonable expansion needs of the region without necessitating a massive overbuild.

The dramatic growth of North America shale gas has significantly reduced CO_2 emissions and energy costs. Greater volumes of clean, cheap natural gas are supplying the backup requirements of intermittent renewable energy sources, as well as feeding the increased demands for electric generation, heating and industrial processes.

C2C, like other natural gas pipeline projects, requires long term commitments from creditworthy market participants. PNGTS would ask the DOER to support commitments by either LDCs or EDCs to commit to pipeline infrastructure expansions and to recommend the C2C Project as the first tranche to be fulfilled for the region.

Thank you,

Cynthia L. Armstrong
Director, Marketing and Business Development
Portland Natural Gas Transmission System
One Harbour Place, Suite 375
Portsmouth, NH 03801

Cc: Keith Nelson, President, PNGTS
Richard Bralow, Legal Counsel, PNGTS

New England States
Committee on Electricity

To: Massachusetts DOER & Synapse Energy Economics, Inc.
From: NESCOE
Date: November 4, 2014
Subject: Comments on October 30 Low Demand Analysis presentation

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NESCOE appreciates the opportunity to provide some comments in connection with the Study discussed at the October 30, 2014 stakeholder session. In this context, NESCOE's views do not reflect the views of officials from the Commonwealth of Massachusetts.

The extent and quality of these comments are limited by the three days to review and consider eighty pages of material. The time constraint causes heightened concern because the revised slides had material errors that would fundamentally alter the Study outcome (for example, gas energy efficiency programs that overstated the potential for peak hour reduction by orders of magnitude and calculation errors regarding the peak hour availability of imported hydro). Time to carefully and closely review assumptions, sources and calculations is important so that major errors, or smaller errors that would in the aggregate result in erroneous conclusions, are identified in advance. NESCOE appreciates your attentiveness to feedback and looks forward to reviewing any changes made as a result. Given the expedited schedule for these comments, NESCOE expects to provide additional and potentially wider ranging comments.

These comments focus primarily on two areas: (1) the avoided-cost approach, and (2) certain proposed assumptions and analysis. Regarding the avoided-cost approach, as detailed below, there appears to be a major omission that will affect the Study's outcome. For the comparative resource that is the subject of the study, natural gas pipeline, the proposed analysis considers the costs but not the benefits of this resource. A comparison of cost-effectiveness cannot be achieved without this critical piece of missing information. Further consideration should be given to a number of assumptions: so-called economic hydro from Canada will be 100% available during the winter peak hour without any contractual commitment to do so; less efficient units called upon during the summer peak are an appropriate proxy for avoided gas consumption; and temporary winter emergency programs will continue for the next 15 years. These assumptions do not appear to have a reasonable connection to general experience or expectation. These assumptions should be revisited to ensure that they connect to general experience or expectations or, alternatively, the rationale for taking different paths that influence the study's outcome should be very clearly articulated for the reader.

Avoided Cost Approach and Feasibility Threshold – Considering Benefits as well as Costs

It appears that a Study objective is to enable a reader to understand the relative cost-effectiveness of alternative means to satisfy resource needs. To that end, the Study's Feasibility Threshold should consider the *benefits* – not just the *costs* - of the comparative resource, which the Study has in this case identified as a natural gas pipeline.

Study Description per Synapse: The Study will use a spreadsheet to evaluate the sufficiency of natural gas pipeline under winter peak conditions. Based on this infrastructure sufficiency evaluation, the Study will then "consider various solutions to address Massachusetts' short and long-term energy needs, taking into account greenhouse gas reductions, economic costs and benefits, and system reliability."[1] The means by which electric and gas supply- and demand-side resources will be tested for cost effectiveness, relative to a so-called "Feasibility Threshold," is based on an approach commonly used in the rate-regulated demand-side management realm.

Consistent with the concepts from the 1978 Public Utilities Regulatory Policy Act (PURPA), Synapse will determine which alternatives to pipeline investment are cost-effective by reference to an assumed "Avoided Cost". In the demand-side management context, the avoided cost is the amount that one would pay if they were to consume electricity. In the Study, Synapse assumes that the avoided cost is the amount that a consumer would save when an alternative resource is implemented. In other words, the Study assumes that avoided cost is a proxy for the benefits of each alternative resource. Combined with cost-of-service-based estimates of the costs of alternative resources, Synapse will compare assumed costs and benefits of each alternative resource ("Avoided Cost Approach").[2] This process will, in turn, establish a ranking of relative cost-effectiveness for each alternative resource, a spectrum that will range from highly cost-effective to relatively expensive ("Supply Curves"). Once the Supply Curve for cost-effective pipeline alternatives is developed, Synapse will then apply a Feasibility Threshold to determine the alternative measures and resources that will be incorporated into the Low Demand Scenario.

Comment: As structured, the benefits of the comparative resource identified in the Study, incremental pipeline investments, will not be considered in setting the Feasibility Threshold, only the costs.

At the October 30, 2014 stakeholder meeting, Synapse proposed to establish the Feasibility Threshold at a level equivalent to the annual costs of a representative lift-and-replace pipeline project, if those annual costs were recovered only during a portion of the winter season. In other words, the cost of a theoretical pipeline *is* the cost to avoid under the Avoided Cost Approach. This Feasibility Threshold, unlike all of the alternatives to which it would be compared, *only considers the theoretical pipeline's costs and not its benefits*.

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1 Massachusetts Low Demand Analysis, Second Stakeholder Meeting Slides (Revised) (Oct. 30, 2014), at 3, available at http://synapse-energy.com/project/massachusetts-low-

2 As described further below, Synapse has not yet disclosed the analysis or assumptions associated with converting estimated future costs and benefits to its Annual Net Levelized Cost values for each alternative resource.

It is foreseeable that the Study results will be misinterpreted as suggesting that alternative resources are more cost-effective than the reference resources identified in the Study, a pipeline investment. If the Feasibility Threshold does not consider the benefits of the measure comprising the threshold, then it would not be possible to determine the relative cost-effectiveness of all alternatives. To avoid this foreseeable misperception and misinterpretation, the Study should either 1) clearly explain this limitation, or 2) set the Feasibility Threshold at a level that includes its benefits, consistent with the cost-effective alternatives to which it is compared.

Certain Assumptions Should Have A Closer Connection To General Experience Or Expectations Or The Study Should Articulate Very Clearly Why Alternate Paths To An Outcome Were Chosen

Many important study assumptions are still pending with Synapse, including the potential adjustments to the electric load forecast. NESCOE offers its concerns on some of those released to date below.

> ***Imported Firm Hydro On the Coldest Days With No Associated Contract***: The Study includes two electric sector modeling runs to evaluate the sensitivity of power sector gas demand and emissions to an incremental 2400 MW of imported power, predominantly assumed to be hydroelectric. Despite experience to the contrary, the Study assumes that the so-called "Imported Hydro" power will have a winter peak day availability higher than its annual capacity factor.
>
> Further, and of greater concern, is that the Study assumes the Imported Hydro will be 100% available during the coincident design day winter peak hour.[3] At the October 30, 2014 stakeholder meeting, Synapse confirmed that the Study will assume no contract to assure hydro delivery during winter peak hours and that high electricity prices during the winter peak would naturally provide economic incentives for the assumed 100% availability. This assumption does not appear supported by experience.[4] For example, on a particularly cold day last winter, December 14, 2013, Hydro-Quebec "reduced its imports into New England in order to maintain Hydro-Quebec's own operating reserve requirement."[5] Analysis of power system interface flows shows similar trends on January 20-25, 2014.[6] The Imported Hydro sensitivities should: (i) accurately

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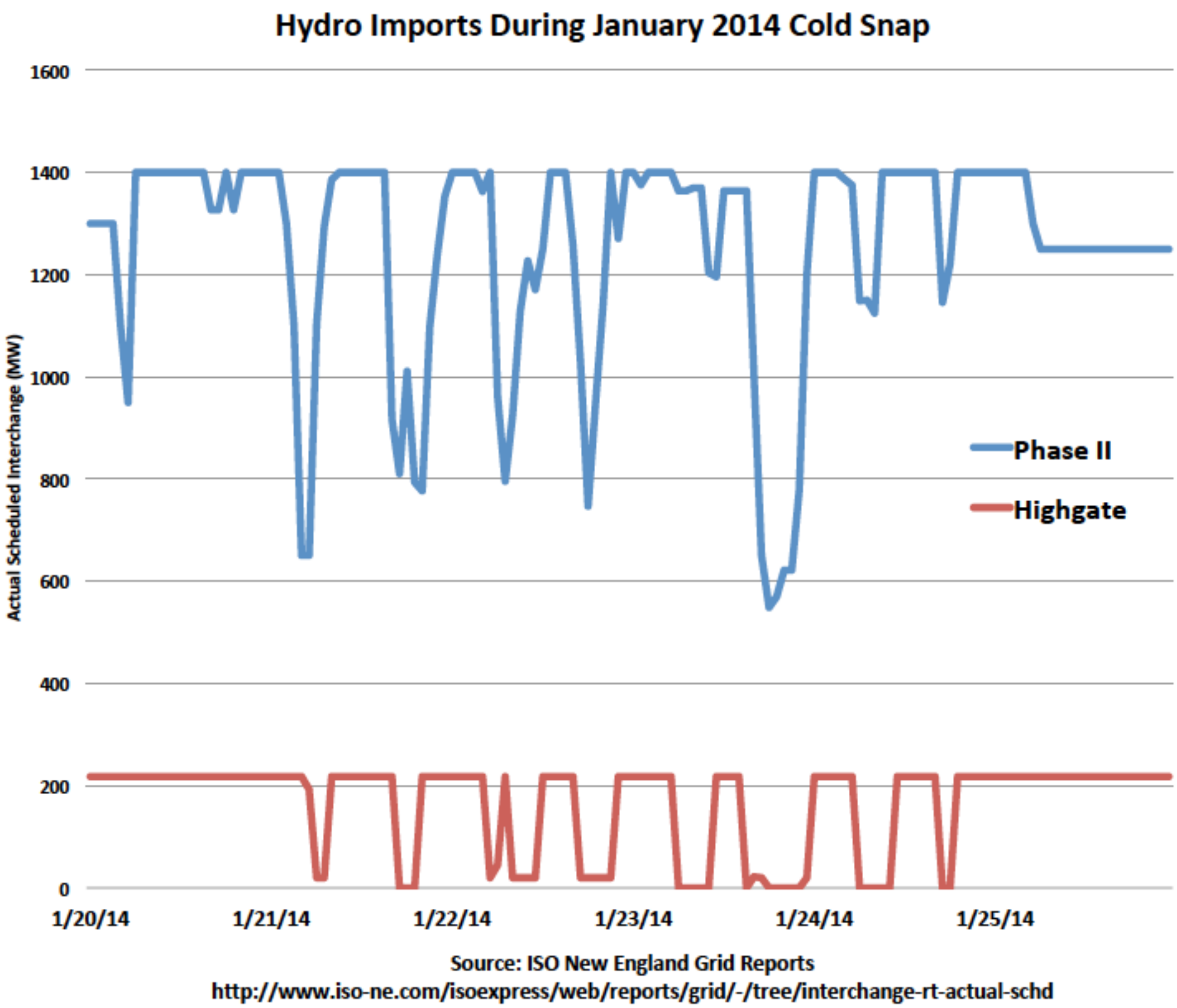
3 Second Stakeholder Meeting Slides, at 21.

4 In addition, given legislative proposals in Massachusetts regarding long-term contracting authority by electric distribution companies for large-scale hydropower resources, the assumption could suggest, perhaps erroneously, that long-term contracts for hydropower resources may be unnecessary. Further clarity on this assumption would be helpful to the reader.

5 ISO New England, Quarterly Market Report, 4th Quarter 2013, at 8, available at http://www.iso-ne.com/markets/mkt_anlys_rpts/qtrly_mktops_rpts/2013/q4_2013_qmr.pdf.

6 ISO New England Grid Reports, Real-Time Actual Scheduled Interchange data, available at http://www.iso-ne.com/isoexpress/web/reports/grid/-/tree/interchange-rt-actual-schd.

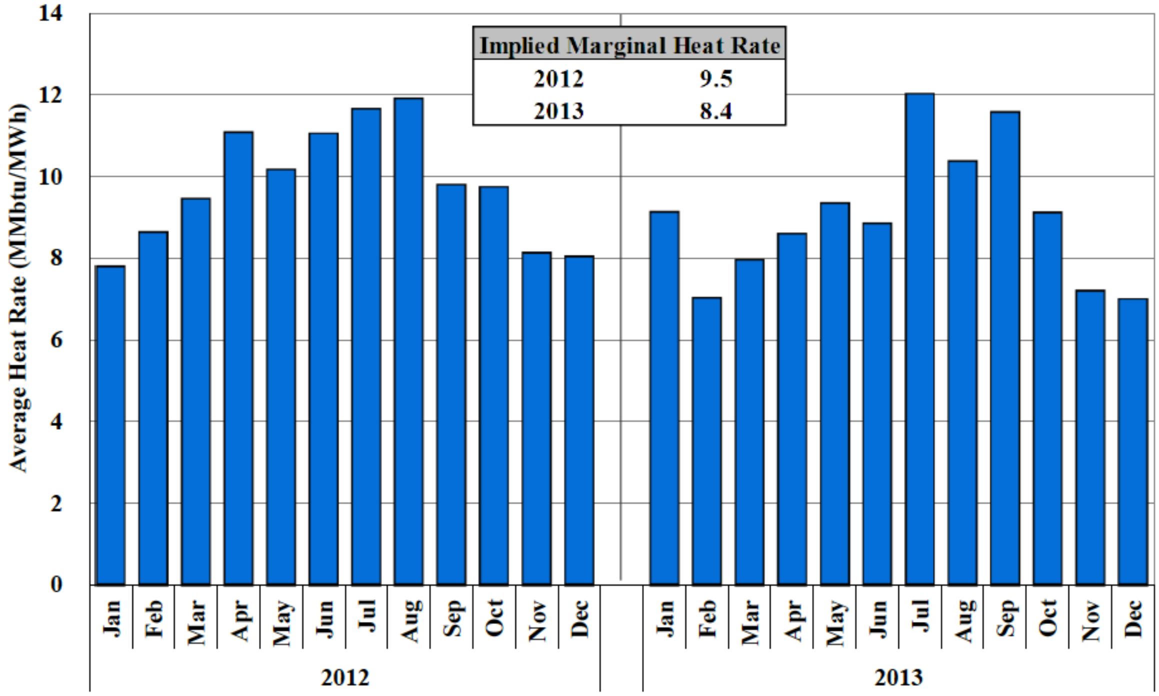
reflect peak day and peak hour availability for economically-based power imports, and/or (ii) accurately reflect the costs associated with firm power delivery during the peak hour. Assuming power will flow on the coldest common winter day by and between Canada and New England with no contractual obligation will likely understate the cost of that power source.



Heat Rate Conversion Assumption: To enable comparison between electric and gas supply- and demand-side resource alternatives, it is necessary to establish a conversion ratio between electricity and natural gas. This is typically achieved by reference to a hypothetical gas-fired electric generator with a specific fuel-to-power conversion ratio, a so-called "Heat Rate." For a study based on the avoided costs of gas-fired electric generation on the Winter Peak Day, the Heat Rate assumption should reflect the resources it is likely to displace. The preliminary assumption for this value is 12 MMBtu/MWh, consistent with the monthly average value of the peak month in 2013. However, the peak month in New England is during the summer and a winter-time marginal heat rate is much lower than the preliminary 12 MMBtu/MWh assumption.

The chart below is from Synapse's data source, the External Market Monitor's annual report.[7]

Figure 2: Monthly Average Implied Marginal Heat Rate
Based on Day-Ahead Prices at New England Hub, 2012 – 2013



As shown in the chart, the marginal heat rate during the winter season rarely exceeds the annual average. In order to accurately reflect the hypothetically displaced electric sector gas demand, the Heat Rate assumption should reflect winter conditions rather than the annual maximum value.

This past winter, pipeline network constraints resulted in delivered natural gas prices that were higher than fuel oil. This caused distillate (and sometimes residual) oil-burning units to run in economic merit. Under these circumstances, the marginal heat rate may be more than the monthly average. However, if these are the conditions upon which the Study would base its electric to gas conversion ratio, this assumption should be made very clear and its implications explained.

ISO-NE Winter Program Continuation through 2030: While it is unclear whether this assumption is likely to have a material effect on the Study results, it is unclear why Synapse would assume the ISO New England (ISO-NE) Winter Program will continue through 2030. These programs, in which consumers invest primarily in incremental fuel

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7 Potomac Economics, *2013 Assessment of the ISO New England Electricity Market* (June 2014), at 44, available at http://www.iso-ne.com/static-assets/documents/markets/mktmonmit/rpts/ind_mkt_advsr/isone_2013_emm_report_final_6_25_2014.pdf.

oil to ensure reliability, are generally considered to be costly and dirty, and specifically intended by ISO-NE to be temporary, emergency fuel security measures.

In sum, assuming so-called economic hydro from Canada will be 100% available during a design day winter peak hour without any contractual commitment to do so, that less efficient units called upon during the summer peak are an appropriate proxy for avoided gas consumption, and that temporary emergency programs will continue for the next 15 years does not appear to be designed to result in outcomes that have a reasonable connection to experience.

Resource Assessment Assumptions and Analysis Remain Pending

The materials for the October 30, 2014 stakeholder meeting included the results for thirty (30) different resource assessments. However, the assumptions and analytical approach used to develop the Total Potential Capacity, Annual Net Levelized Costs, and associated Peak Hour Gas Savings for the 30 alternative resources were not provided. Rather than a cursory data source description, the Study should make available the assumptions, their associated data sources, and the analysis used to develop the aforementioned metrics. In particular, two aspects of the Study should be further explained and supported.

Annual Net Levelized Costs: Annual Net Levelized Costs are understood to be costs, net of benefits (avoided costs). For most resource assessments, the values assumed for each resource's capital costs, annual carrying charge rates and values, discount rate(s), and annual performance characteristics are unknown. The benefits (avoided costs) of these measures are referenced to Synapse's 2013 Avoided Energy Supply Cost study and testimony in a current Department of Public Utilities (DPU) proceeding regarding the Global Warming Solutions Act (GWSA), DPU 14-86. The annual net costs are then apportioned to annual resource output to arrive at a unit cost. The values and calculations used in developing the annual net costs per unit of output should be made available for each resource assessment.

Infrastructure Sufficiency - Information Pending: To establish the amount of alternative resources included in the Low Demand Scenario, Synapse will estimate the sufficiency of the New England natural gas infrastructure. The spreadsheet model has not yet been released. Nor have the assumptions associated with the gas demand forecast, available pipeline capacity, peak-shaving and imported liquefied natural gas (LNG) send out rates, and local gas distribution company (LDC) long-term growth rates.

Conclusion

NESCOE appreciates the opportunity to share its views and looks forward to reviewing other forthcoming assumptions including the electric and gas load forecasts, generator retirements and additions, pipeline additions and flows, imported and peak shaving LNG send-out rates, alternative resource technical and economic potential, alternative resource capital and carrying cost assumptions, and fuel prices. NESCOE has previously expressed caution about drawing conclusions about solutions to gas supply constraints from a study that focuses on a single winter peak hour under a single generator retirement scenario. NESCOE similarly urges caution about drawing conclusions from a study that appears to be highly sensitive to the analytical approach pursued. New England is fortunate to have many relevant studies conducted by a range of entities with diverse interests to help provide context and comparisons on this critically important issue.[8]

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[8] See, generally:

North American Electric Reliability Corporation (NERC),
Phase I (Primer, December 2011):
http://www.nerc.com/files/gas_electric_interdependencies_phase_i.pdf.
Phase II (Vulnerability and Scenario Assessment, May 2013):
http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_PhaseII_FINAL.pdf.

ICF International (ICF) for ISO New England,
Phase I (Deterministic Scenarios, June 2012): http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2012/gas_study_public.pdf.
Phase II (Scenarios with Duration, December 2013): http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2013/dec182013/a3_draft_icf_phase_2_gas_study_report_without_appendices.pdf.
Post Winter Assessment (Benchmarking, April 2014): http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2014/apr292014/a3_icf_benchmarking_study.pdf.

Black & Veatch for NESCOE,
Phase I (Literature Review, December 2012): http://www.nescoe.com/uploads/Phase_I_Report_12-17-2012_Final.pdf.
Phase II (Duration and Scenario Design, April 2013):
http://www.nescoe.com/uploads/Phase_II_Report_FINAL_04-16-2013.pdf.
Phase III (Scenarios and Economic Analysis, September 2013):
http://www.nescoe.com/uploads/Phase_III_Gas-Elec_Report_Sept._2013.pdf.

ICF for GDF Suez NA,
Post-Winter Review (Updated Analysis, May 2014): http://www.nescoe.com/uploads/GDF-SUEZ_CommenstonIGER_30May2014.pdf

ICF for the Eastern Interconnection States Planning Council (EISPC),
Long Term Study (Scenarios, Duration, and Economic Analysis, pending publication), webinar providing results available at
http://naruc.org/Grants/EISPC/2014-09-04_14_01_Webina_Final_EISPC_report-Long-Term_Electric_and_Natural_Gas_Study_by_ICF.wmv

Levitan & Associates for the Eastern Interconnection Planning Collaborative (EIPC),
Multi-Targeted Analysis (Scenarios, Duration, Hydraulics, Dual Fuel Economics, pending publication), drafts available at http://www.eipconline.com/Gas-Electric_Documents.html.

Attached, please find NU's comments on the Low Demand Study.

James

James G. Daly, Vice President Energy Supply, Northeast Utilities
One NSTAR Way, Westwood MA 02090

Office: 781 441 8258, Mobile: 339 987 7884

Northeast Utilities

Northeast Utilities Service Company
One NSTAR Way, NE 210
Westwood, MA 02090

November 3, 2014

Mr. Farhad Aminpour
Director Energy Markets Division
Department of Energy Resources
100 Cambridge Street
Boston, MA 02114

Re: Study on Low Gas Demand

Dear Sir:

Thank you for the opportunity to address the DOER commissioned "Low Demand" study on gas being conducted by Synapse.

Gas and Power Market in New England:

The DOER is studying a low demand scenario during a time when the MA Local Distribution Companies (LDC's) are engaged with the MA Department of Public Utilities on ways in which the LDC's can meet increased demand from customers who are experiencing extremely high prices due to a shortage of gas transportation. Included are large customers who have not taken supplies from their LDC's since the market was deregulated. This situation is likely to continue until additional gas transportation is made available in the region. LDC's have contracted for new capacity with interstate pipelines but this capacity has not yet been constructed.

Added to the LDC demand, is the increase in demand from power generators. Last winter electricity prices increased by over $3Bn in the period December through March due to gas shortages. See attached chart which uses ISO NE data on the wholesale cost of electricity over the past 4 winters. Unlike gas LDC companies, power generators are not contracting for additional transportation capacity. None of the contracting parties on the Algonquin Incremental Market (AIM) project were power generators.

The New England Governors' Initiative which would add both gas transportation and increased hydro power/renewable imports offer a promising solution but will take many years to implement assuming we can agree on ways to fund these large infrastructure developments.

Modeling Gas Demand:

By regulation in MA, LDC's are required to design their supply portfolio using a "Design Season" and "Design Peak" standard based on historical weather conditions. For NSTAR Gas the standard is one season in 33 years and one day in 50 years respectively. Other MA LDC's have similar standards. Synapse should study LDC demand using similar standards rather than attempt to determine some other untested standard.

Some of the MA LDC's have provided Synapse with updated demand forecasts as a result of an increase in customer conversions and customers returning to LDC supply. NSTAR has also updated its forecast, a copy of which is attached to aid Synapse in its studies.

Other increases in demand should be assumed from the power generation sector as nuclear, coal and oil units are scheduled to retire.

Contingency Analysis:

Synapse is attempting to construct an alternative portfolio using non gas fired resources to meet electric demand. The cost and reliability of these alternative resources should be transparent and equivalent in reliability to gas fired generation with firm transportation.

Since this is also a peak day reliability study the portfolio should be tested against the loss of a large base load unit during peak demand days such as a nuclear or other non gas base load unit.

I hope you find these comments constructive and are able to incorporate them into your study.

Sincerely,

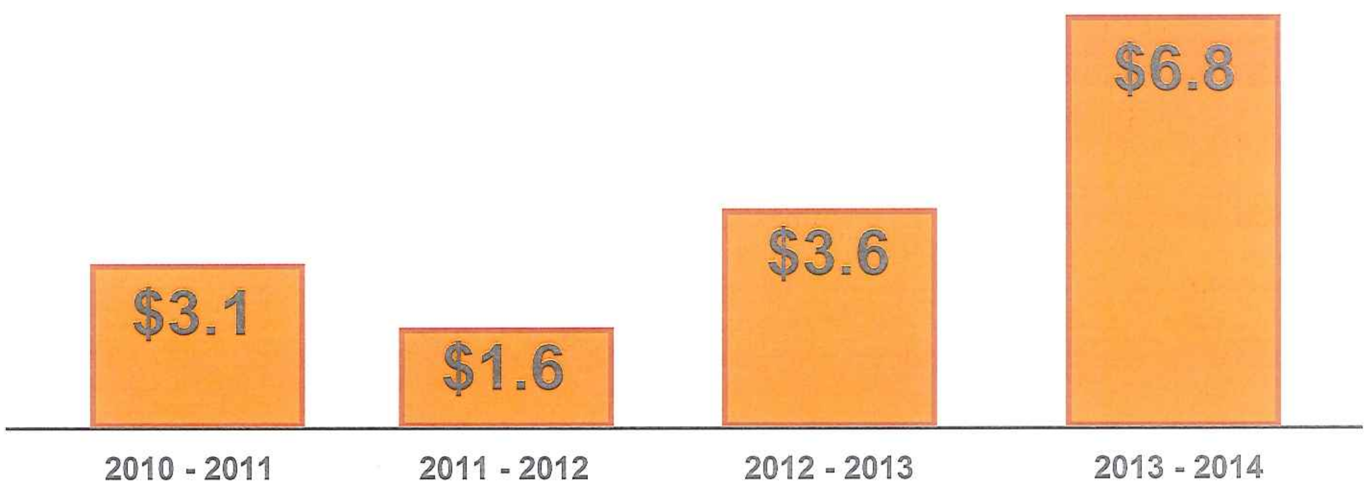
James G. Daly
VP, Energy Supply
Northeast Utilities

Energy Prices Are Escalating

Northeast Utilities

- Gas pipeline constraints have added over $3 billion to our electric bills this past winter

Winter Season Wholesale Electricity Costs
December – March
($Billions, ISO-NE Region)



NSTAR Firm Load Requirements 1/

		2014/15	2015/16	2016/17	2017/18	2018/19	CAGR
Alternative Case Annual (Bbtu)	Normal Gas Year	42,887	44,466	46,261	49,264	50,332	4.1%
	Design Gas Year	47,208	49,185	50,785	53,999	55,183	4.0%
	Design Day (Bbtu)	479	501	515	541	546	3.3%

1/Per NSTAR 2014 IRP Filing - includes Capacity Exempt Customers Returning. Includes entire planning load, Firm Sales and Capacity Eligible FT

Susan Van Dolsen [svandolsen@gmail.com] Mon 11/3/2014 4:46 PM
Lowdemandstudy, (ENE)
Comment about Stakeholder meeting - request for stakeholder meeting in CT or NY

The stakeholder meetings have raised many important issues about energy policy and the need to truly evaluate all alternatives to "natural" gas. I am sorry that I am not able to travel to Boston to attend these meetings.

I have two comments:

1) I would like to request that a stakeholder meeting be held in New York because I believe that Synapse should factor in the impacts of expanded gas infrastructure on the state that will be the conduit for the gas to New England and beyond. New York State will bear the brunt of the expanded pipelines and associated gas infrastructure.

2) I concerned that the Synapse study does not examine the "natural" gas exports to Canada and overseas. The gas companies have stated publicly on their websites that they are expanding their infrastructure in order to ship gas overseas. The price of gas in Europe and Asia is significantly higher than domestic prices. Meanwhile, the "natural" gas pipeline companies are encouraging the approval of more gas infrastructure based on the premise that the gas is cheap and the companies are encouraging elected officials to support long-term commitments of the use of "natural" gas for electric generation in New England. The domestic consumers will feel the impact of higher prices when the gas is exported, therefore I feel that the Synapse study cannot be done properly without factoring in exports.

Best,
Susan Van Dolsen
29 Highland Rd.
Rye, NY 10580
914-525-8886

Comments on DOER Low Gas Demand Analysis

Submitted by Leonard Johnson, Vice President, Mount Grace Land Conservation Trust

On behalf of the Mount Grace Land Conservation Trust thank you for the opportunity to provide comments on scenarios employed for the Massachusetts DOER Low Gas Demand Analysis. Mount Grace is a regional land trust located in north central Massachusetts that has assisted in the protection of nearly 29,000 acres since 1986. Increasingly, energy infrastructure often has the potential to directly impact conserved land. The comments below address the consistency of study scenarios with regard to compliance with the Massachusetts Global Warming Solutions Act (GWSA).

The requirements of the GWSA call for reductions in greenhouse gas (GHG) emissions relative to 1990 levels of at least 25% by 2020 and 80% by 2050. Policies designed to comply with GWSA requirements are described in the Massachusetts Clean Energy and Climate Plan for 2020 (CECP). The CECP calls for GHG emission level limits in 2020 by sector, and specifically calls for large reductions in the Buildings and Electric Supply sectors. Further significant reductions will be necessary by 2030 to be on track to meet 2050 mandates. In Massachusetts, both of these sectors are currently highly reliant on natural gas.

Given the substantial reductions in GHG emissions called for by 2020, and with further reductions in 2030, we urge that all study scenarios be scored relative to compliance with the GWSA. Specifically, comparing GHG emission levels on an annualized basis for each scenario with the respective 2020 and 2030 GWSA targets will provide valuable guidance for assessing the suitability of expanding natural gas infrastructure. Furthermore, at a minimum, the Low Energy Demand scenarios should be consistent with meeting GWSA mandates. Recognizing that the study is designed to place emphasis on the “winter peak” event, it is reasonable to expect that many of the actions that will be required to achieve timely compliance with GWSA will also result in reduction of natural gas demand during the winter peak.

Thank you for your consideration of this comment. We look forward to the opportunity to review the results of the study.

Elisa Grammer [elisa.grammer@perennialmotion.com]

Ladies and Gentlemen:

Many thanks to all of you for your commitment, insights, and hard work on the Massachusetts Low Gas Demand Analysis. 47 Coffin Street Ratepayer Advocates (those of us living at 47 Coffin St., West Newbury, MA in National Grid's NEMA/Boston load zone) very much appreciate the opportunity to submit the attached comments, which address overlooked opportunities/inevitabilities of additional demand response:

> 47 Coffin is concerned that the analysis to date fails to capture readily available and/or inevitable demand response (DR) opportunities to reduce winter peak electric demand. Specifically, the October 31 Feasibility Study relies on New England Independent System Operator (ISO-NE) forecasts to determine winter peak, and predicts only a potential DR capacity addition of 400 MW by 2015, with no further growth whatsoever through 2030, all at an annualized levelized cost of \$500/MWh and net avoided cost of \$373/MWh.[1] As discussed below, this analysis apparently disregards the proven potential for thousands of MW in capacity additions and peak shaving available through
>
> 1) **retail direct load control** in response to automatic utility dispatch (reported to have a potential as high as 2,620 MW in Florida alone[2] and **currently in use by National Grid in the UK for the express purpose of meeting this winter's peak power demands**[3]);
>
> 2) **voluntary load reduction** (used successfully in California to **shave some 700 MW in Southern California alone during cold weather winter**

[1] Synapse Energy Economics, Inc., *Feasibility Study for Low Gas Demand* at 5, 21-22 (Oct. 31, 2014), *available at* http://synapse-energy.com/sites/default/files/Feasibility%20Study%20for%20Low%20Gas%20Demand%20Analysis.pdf [hereinafter Feasibility Study].
[2] Federal Energy Regulatory Comm'n (FERC) Staff, *2012 Assessment of Demand Response and Advanced Metering* at 28 (Dec. 2012), *available at* http://www.ferc.gov/legal/staff-reports/12-20-12-demand-response.pdf [hereinafter 2012 DR Assessment].
[3] Flexicitricity News Release, *Companies win contracts for reducing power demand: National Grid has contracted 319 MW of Demand Side Balancing Reserve (DSBR) across 431 individual sites, to be available this winter* (Sept. 23, 2014), *available at* http://www.flexitricity.com/news.php?section=10&newsid=126 ("Demand Side Balancing Reserve will enable large energy users to reduce their demand or run other sources of generation during peak periods in return for a payment. The service will be available for short periods between 1600hrs and 2000hrs on weekday evenings between November and February.")

electric peaks when natural gas supply constraints impacted power generation[4]); and

3) **self-directed demand destruction and peak shaving** attributable to soaring power prices in the face of flat or falling overall demand. [5]

Please let me know if you would like additional information or have any questions.

Elisa J. Grammer
703-855-5406

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[4] Caroline Aoyagi-Stom, Southern California Edison Co., *SCE Customers Help Save Almost 700 MW During Recent Flex Alert and Warning Triggered by CAISO* (Feb. 14, 2014), available at http://newsroom.edison.com/stories/sce-customers-help-save-almost-700-mw-during-recent-flex-alert-and-warning-triggered-by-caiso ("The Flex Alert and subsequent warning on Feb. 6 were called because of extreme cold weather in much of the United States and Canada impacting fuel supplies to power plants in Southern California, resulting in a reduction of electricity generation. As a result, SCE immediately asked all interruptible power use be suspended (mostly business customers, who have signed up for programs designed to temporarily suspend some of their electricity use).")

[5] *See, e.g.,* eCURV, *There is a better way* (accessed Nov. 1, 2014), *available at* http://www.ecurv.com/ (novel digital network that avoids coincident peak usage via patented queuing algorithms to optimize the runtime of commercial/industrial appliances like HVAC systems, pumps, motors, battery chargers, heating and refrigeration equipment).

47 Coffin Street Ratepayer Advocates
47 Coffin Street
West Newbury, Massachusetts 01985
November 4, 2014

Ms. Meg Lusardi Acting Commissioner Massachusetts Department of Energy Resources	Dr. Elizabeth Stanton Senior Economist Synapse Energy Economics, Inc.

By email

Re: Massachusetts DOER Low Gas Demand Analysis (RFR-ENE-2015-012)

Dear Acting Commissioner Lusardi, Dr. Stanton, *et al.,*

47 Coffin Street Ratepayer Advocates (47 Coffin)[1] commends the Department of Energy Resources (DOER) for engaging in the Low Gas Demand Analysis (Analysis), appreciates the work of Synapse Energy Economics in making this analysis happen in a very short time frame, and thanks them both for this opportunity to submit the following comments.

Briefly, 47 Coffin is concerned that the analysis to date fails to capture readily available and/or inevitable demand response (DR) opportunities to reduce winter peak electric demand. Specifically, the October 31 Feasibility Study relies on New England Independent System Operator (ISO-NE) forecasts to determine winter peak, and predicts only a potential DR capacity addition of 400 MW by 2015, with no further growth whatsoever through 2030, all at an annualized levelized cost of $500/MWh and net avoided cost of $373/MWh.[2] As discussed below, this analysis apparently disregards the proven potential for thousands of MW in capacity additions and peak shaving available through

> 1) **retail direct load control** in response to automatic utility dispatch (reported to have a potential as high as 2,620 MW in Florida alone[3] and **currently in use by National Grid in the UK for the express purpose of meeting this winter's peak power demands**[4]);

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[1] 47 Coffin comprises senior citizen, mostly retired, retail National Grid zone NEMA/Boston electric ratepayers residing at 47 Coffin Street, West Newbury, MA, which at the moment is .5 miles from the Merrimack River, about 10 miles from the Atlantic, and roughly 50 feet above sea level.

[2] Synapse Energy Economics, Inc., *Feasibility Study for Low Gas Demand* at 5, 21-22 (Oct. 31, 2014), *available at* http://synapse-energy.com/sites/default/files/Feasibility%20Study%20for%20Low%20Gas%20Demand%20Analysis.pdf [hereinafter Feasibility Study].

[3] Federal Energy Regulatory Comm'n (FERC) Staff, *2012 Assessment of Demand Response and Advanced Metering* at 28 (Dec. 2012), *available at* http://www.ferc.gov/legal/staff-reports/12-20-12-demand-response.pdf [hereinafter 2012 DR Assessment].

[4] Flexicitricity News Release, *Companies win contracts for reducing power demand: National Grid has contracted 319 MW of Demand Side Balancing Reserve (DSBR) across 431 individual sites, to be available this winter* (Sept. 23, 2014), *available at* http://www.flexitricity.com/news.php?section=10&newsid=126 ("Demand Side Balancing Reserve will enable large

Footnote continued

2) **voluntary load reduction** (used successfully in California to **shave some 700 MW in Southern California alone during cold weather winter electric peaks when natural gas supply constraints impacted power generation**[5]); and

3) **self-directed demand destruction and peak shaving** attributable to soaring power prices in the face of flat or falling overall demand. [6]

With respect, 47 Coffin disputes the Feasibility Study's assertion that DR is best assessed through the lens of wholesale centralized forward capacity markets (FCM) as opposed to retail demand side management (DSM),[7] voluntary load reduction and self-directed DR. New England's wholesale DR "markets" would be problematic even if they were not under continuous legal attack from energy suppliers,[8] if major wholesale demand-side players like Enernoc had not quit,[9] if the command-and-control FCM were not overtly non-competitive,[10] and if the critical DR "baseline"[11] were not an invitation to

Footnote continued
energy users to reduce their demand or run other sources of generation during peak periods in return for a payment. The service will be available for short periods between 1600hrs and 2000hrs on weekday evenings between November and February.")

5 Caroline Aoyagi-Stom, Southern California Edison Co., *SCE Customers Help Save Almost 700 MW During Recent Flex Alert and Warning Triggered by CAISO* (Feb. 14, 2014), available at http://newsroom.edison.com/stories/sce-customers-help-save-almost-700-mw-during-recent-flex-alert-and-warning-triggered-by-caiso ("The Flex Alert and subsequent warning on Feb. 6 were called because of extreme cold weather in much of the United States and Canada impacting fuel supplies to power plants in Southern California, resulting in a reduction of electricity generation. As a result, SCE immediately asked all interruptible power use be suspended (mostly business customers, who have signed up for programs designed to temporarily suspend some of their electricity use).")

6 *See, e.g.,* eCURV, *There is a better way* (accessed Nov. 1, 2014), *available at* http://www.ecurv.com/ (novel digital network that avoids coincident peak usage via patented queuing algorithms to optimize the runtime of commercial/industrial appliances like HVAC systems, pumps, motors, battery chargers, heating and refrigeration equipment).

7 *Cf.* Synapse Energy Economics Inc., *Modeling Demand Response and Air Emissions in New England* at 6 (rev. Sept. 4, 2003) http://www.synapse-energy.com/sites/default/files/SynapseReport.2003-09.US-EPA.NE-DR-and-AE-Modeling.03-01.pdf ("We modeled . . . an economic DR program, one in which DR resources bid into the day-ahead [wholesale] energy market along with other supply-side resources and are dispatched based on their bids, just like supply-side resources. . . . . Under a reliability-based DR program, DR resources are dispatched based on a measure of system reliability or available reserves. . . . We chose to investigate . . . economic DR rather than emergency DR, because the impacts of economic DR are much more controversial and potentially much larger than those of emergency DR.")

8 *Electric Power Supply Ass'n v. FERC*, 753 F.3d 216 (D.C. Cir. 2014), *mandate stayed,* No. 11-1486 (D.C. Cir. Oct. 20, 2014) (per curiam); *FirstEnergy Service Co. v. PJM,* FERC Docket No. EL14-55, Formal Complaint of FirstEnergy (May 23, 2014), *available at* http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=13554068, *amended,* Amended Complaint (Sept. 22, 2014), *available at* http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=13641870.

9 Andrew Price, Competitive Energy Services Sr. VP, CES Energy Blog, *Enernoc Exits ISO New England Demand Response Program* (Mar. 29, 2013), *available at* http://www.competitive-energy.com/blog/energy-strategy/enernoc-exits-iso-new-england-demand-response-program

10 *ISO New England Inc.,* FERC Docket No. ER14-1409, Explanatory Statement of FERC Chairman LeFleur (Sept. 16, 2014), *available at* http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=13638080 ("FCA 8 results in the NEMA/Boston capacity zone were 'non-competitive,' indicating that the level of participation in the auction was inadequate to satisfy the Installed Capacity Requirement….")

overconsume and thus depict a false demand reduction.[12] Centralized markets are by definition one-size-fits-all, generation-oriented constructs that preclude highly valuable, environmentally benign, low cost and readily available individualized DR services.[13] In California alone, a single user's 2,000+ MW of dispatchable synchronous water pumping loads—which prior to electric restructuring could contractually provide such sophisticated grid services as load following through complementary morning and evening ramping, voltage support, underfrequency load shedding and a Remedial Action System to address contingencies such forced outages of nuclear generation or major transmission—have no ISO "market."[14]

The Analysis' use of ISO-NE's CELT forecast[15] to determine winter peak electric demand, as well as its view of future DR potential, disregard or understate significant non-market, retail DR. 47 Coffin cannot follow the Feasibility Study's explanation, "There are many MW of demand response that occur outside of the markets that is triggered by expected monthly peak load hours which act as triggers for large cost allocations such as transmission costs and demand charges." [16] It is confident that whatever this refers to fails to include projected MW of DSM capacity. Reported DSM is currently virtually non-existent in New England[17] and thus would not have been, per the Feasibility Study, "already occurring on its own"

Footnote continued

[11] Synapse Energy Economics Inc., *Demand Response as a Power System Resource Program Designs, Performance, and Lessons Learned in the United States*, at 8 (May 2013) http://www.synapse-energy.com/sites/default/files/SynapseReport.2013-03.RAP_.US-Demand-Response.12-080.pdf ("Without feasible, trustworthy baselines, demand response will not succeed.")

[12] *E.g., Competitive Energy Services LLC,* 144 FERC ¶ 61,163 at Para. 3 (Aug. 2013) (imposing civil penalties relating to "a fraudulent scheme in connection with [ISO-New England's DR program], so that CES and Rumford would artificially inflate Rumford's customer baseline to enable Rumford and CES to receive compensation for demand response without Rumford intending to provide the service or actually having to reduce load.")

[13] *E.g., Cal. Indep. Sys. Operator Corp.*, 94 F.E.R.C. ¶ 61,266, at 61,926-27 (2001) ("DWR protests for the fourth time the ISO's continued failure to establish permanent rules that recognize that large dispatchable loads, such as DWR's, cannot be turned on and off every ten minutes. . . . DWR's continued request . . . is . . . a collateral attack on the Commission's previous order. . . .").

[14] *E.g., Cal. Indep. Sys. Operator Corp.*, FERC Docket No. ER02-1656, Comments and Protest of the California Department of Water Resources State Water Project (Nov. 12, 2002), *available at* http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=9591689.

[15] Time constraints proscribe a detailed discussion of CELT methodology here. Suffice it to say that ISO-NE stakeholders who understandably welcome transmission expansion as a means of increasing rate base, may be expected to question or discount the value of customer action to reduce peak usage, *E.g.,* ICF International on behalf of Northeast Utilities, *Comments on ISONE's Draft Final Energy Efficiency Forecasts of Peak Demand Savings* (March 2012) *available at* http://www.iso-ne.com/committees/comm_wkgrps/othr/enrgy_effncy_frcst/mtrls/nu_icf_comments_ee_forecast.pdf

[16] Feasibility Study at 22.

[17] 2012 DR Assessment at 32, 99-101. National Grid's version of demand management in Massachusetts evidently focuses on non-dispatchable load control by the customer. *E.g.,* Metering International, *US utility National Grid has*

Footnote continued

and accordingly "captured in the current forecast of winter peak demand."[18] It would be a serious mistake for the Analysis to dismiss this kind of DR as a quaint artifact of the days of vertically integrated utilities.[19]

1) Tried and true, verifiable retail DSM DR should be included in the Analysis.

Retail DSM programs, in which an end-user receives a reduced rate in exchange for permitting its utility to remotely dispatch load adjustments by, for instance, cycling hot water heaters, electric heating and/or air conditioning,[20] provides substantial, proven advantages while avoiding all of the problems noted above with DR in wholesale markets. They can be integrated into ISO systems by, among other things, including them in the responsible utility's Demand Bids and load forecasting. Indeed, Connecticut Light & Power has recently proven it possible to implement such a DSM program with Walgreen's Distribution Center, representing over 1.7 MW within the confines of the ISO-NE system.[21] In 2013, this program was recognized for its operational success.[22]

Footnote continued

deployed a CEIVA Energy home energy management system (HEMs) as part of its Smart Energy Solutions Programme (Aug. 13, 2014), *available at* http://www.metering.com/national-grid-rolls-out-ceiva-solution-for-home-energy-management/ *See also* National Grid, *EMS- Existing Facility/Retrofit* (visited Nov. 1, 2014) *available at* https://www1.nationalgridus.com/MAEMSExisting ("Systems can be programmed to reflect occupancy levels, shift schedules, type of work performed, and other variables that affect the need for heating and cooling. EMS technology can be used to relax temperature set points when a building is unoccupied by alternating use of heating and air conditioning rather than turning the systems off completely.")

18 Feasibility Study at 22.

19 Synapse Energy Economics, *Demand Response as a Power System Resource Program Designs, Performance, and Lessons Learned in the United States*, at 9 (May 2013), *available at* http://www.synapse-energy.com/sites/default/files/SynapseReport.2013-03.RAP_.US-Demand-Response.12-080.pdf (describing DSM load control programs as "popular during the 1980s and 1990s," but rarely called upon, poorly dispatched and superseded by restructured wholesale markets).

20 An example of Baltimore Gas & Electric's retail tariff for this dispatched load interruption may be found at https://www.bge.com/myaccount/billsrates/ratestariffs/electricservice/electric%20services%20rates%20and%20tariffs/rdr_15.pdf. *See also* FERC Staff, Demand Response and Advanced Metering at 25 (Oct. 2013), *available at* http://www.ferc.gov/legal/staff-reports/2013/oct-demand-response.pdf ("Utilities in Maryland have a goal of delivering 200 MW of demand response from dynamic pricing programs, in addition to approximately 700 MW from direct load control programs.")

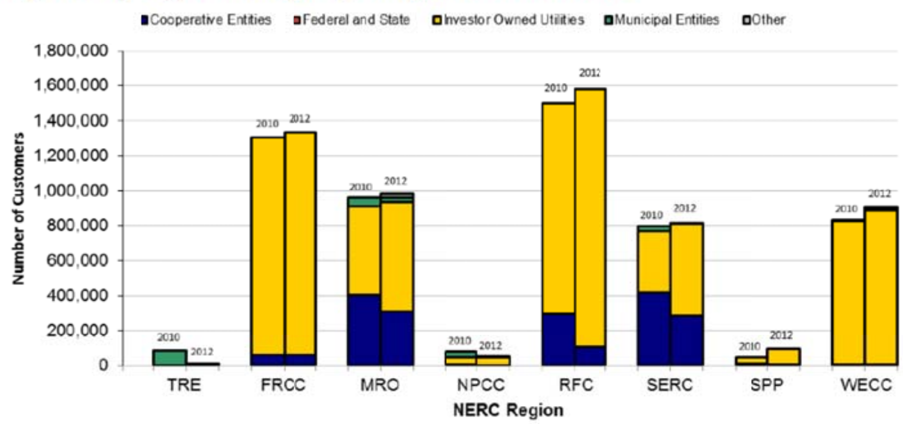
21 Energize Connecticut, *Automated Demand Response Energy Efficiency Case Study: Walgreens Distribution Center, Windsor, CT*, *available at* http://www.cl-p.com/downloads/Walgreens.pdf?id=4294989252&dl=t ("Working with the Burton Energy Group and Conservation Resource Solutions (CRS), one of the ISO New England permitted data collection vendors . . . , CL&P program administrators developed the Automated Demand Response pilot for the largest per square foot building in Connecticut. . . . When ISO New England calls an event, a signal is sent to the Walgreens Distribution Center by CRS through the interface. Energy use at the Walgreens facility is monitored and heating, cooling, lighting systems and more are adjusted according to preprogrammed settings. When the event ends, a second signal is sent restoring the pre-event settings.")

22 Christina Griffin, Windsor, CT, Patch, *Walgreens Distribution Center Wins Award for Energy Efficiency* (May 6, 2013), *available at* http://patch.com/connecticut/windsor/walgreens-distribution-center-wins-award-for-energy-efficiency.

a) New England should be able to quickly develop DSM participation levels at least comparable to Maryland (822 MW) or Minnesota (994 MW).

Across the country, DSM, also known as direct load control or DLC, is by far the most favored new demand response program planned by those responding to the Federal Energy Regulatory Commission's 2012 DR survey.[23] Florida alone reported over 2,500 MW of direct load potential peak reduction.[24] As early as 2004, Florida Power & Light's load management system used over 816,000 load-control transponders connecting more than 712,000 users, permitting sophisticated load shaping/peak management *and* providing a cost-effective alternative to additional gas-fired generation.[25] **In 2012, all New England states together reported 0 MW of DLC.**[26] New England—which with northeastern Canada is in the NPCC reliability region saved from last place only by Texas—has abundant room for growth in capturing this emission-free, low cost, peak shaving and load shaping. [27]

Figure 3-11. Reported number of customers enrolled in direct load control programs by region and type of entity in 2010 and 2012



	TRE	FRCC	MRO	NPCC	RFC	SERC	SPP	WECC	Other
Percent of total estimated customers in the region in a direct load control program	0.11%	14.54%	12.15%	0.25%	4.39%	2.28%	1.43%	3.09%	4.59%

If Massachusetts were to pursue DSM with the zeal that made the Commonwealth first in the nation in energy efficiency, the Analysis would need to include over 2,500 MW of this form of DR. More conservatively, it would appear reasonable for the Analysis to project that New England could within a

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[23] 2012 DR Assessment at 32.
[24] 2012 DR Assessment at at 28.
[25] Michael Andreolas, FPL, Transmission & Distribution World, Mega Load Management System Pays Dividends (Feb. 1, 2004), *available at* http://tdworld.com/distribution-management-systems/mega-load-management-system-pays-dividends ("From the operational point of view, FPL's load-management experience has been positive. The load-management program is an effective and reliable tool to reduce peak demand.")
[26] 2012 DR Assessment at 32, 99-101.
[27] *Id.* at 34.

short timeframe achieve at least comparable direct control DSM as that reported in 2012 by Maryland (822 MW) or Minnesota (994 MW).[28]

b) With appropriate mandates and guidance from the Commonwealth, National Grid should be able to draw on its experience in the UK to put into place a vibrant and highly effective DSM program.

Without question, consumer-owned municipal and cooperative utilities, whose interests in cost savings, peak shaving, and efficiency align directly with those of their customers, have shown leadership in DSM programs.[29] In Massachusetts, National Grid presents a more complex picture, simultaneously urging customers to take advantage of its incentive to switch to natural gas heating ("It's not often that you have the opportunity to improve productivity, while saving money. But clean, efficient natural gas does just that, and more!")[30] while blaming this winter's electric rate increase on natural gas insufficiencies ("[W]ith about half of New England's electricity generation now fueled by natural gas, electric commodity prices have risen due to continued constraints on the natural gas pipelines serving the region.")[31] In such circumstances, mandates and /or guidance from retail regulatory bodies and policy makers may be required to help align interests in cost savings, peak shaving, and overall energy efficiency.

With guidance from the Commonwealth placing emphasis on selling DSM in addition to natural gas heating, National Grid should be readily able to import its enthusiasm and expertise in DSM from England to New England. National Grid has also long used UK behind the meter standby generation and DSM as grid management resources.[32] In September in the UK, National Grid was quoted as "keen to promote and stimulate demand side services and will continue to talk to the industry to make the [winter peak shaving Demand

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[28] *Id.* at 28.

[29] A cursory collection of electric cooperative DSM programs can be found at:
http://www.piercepepin.com/content/load-management-0;
http://www.greatriverenergy.com/savingelectricity/loadmanagement/loadmanagementprograms.html ;
http://www.wildriceelectric.com/msp-load.html ;
http://central.coopwebbuilder2.com/sites/centralcentral/files/images/load-managment-programupdated-6-2013.pdf ;
http://www.riverlandenergy.com/content/load-management-program.

[30] National Grid US/MA, *Convert to Natural Gas: Boost Your Bottom Line with Natural Gas* (visited Nov. 1, 2014), *available at* https://www1.nationalgridus.com/ConvertToNaturalGas ("Our generous incentives make it easy to switch to natural gas heating.")

[31] National Grid US/MA, *Update on Winter Electric Supply Rates* (pop-up viewed Nov. 1, 21014), *available at* https://www1.nationalgridus.com/BilsAndPayments.

[32] David Andrews, Senior Technical Consultant, Biwater Energy, *National Grid's use of Emergency Diesel Standby Generator's in Dealing with Grid Intermittency and Variability Potential Contribution in Assisting Renewables* at 7-8 (Jan. 24, 2006), *available at* http://www.claverton-energy.com/wordpress/wp-content/files/ou-idgte-talk-load-managment-diesels.pdf

Side Balancing Reserve] DSBR product mutually beneficial."[33] Within the past week or so, National Grid described a DR program to meet winter peak demands notwithstanding serious contingency events concerning forced outages of key generators in the UK.[34]

c) Costs of retail DSM have been below costs for new generation capacity and have recently been estimated at between $51-$164/kW-year.

Costs, controversies, and delays associated with developing a Smart Grid have not impeded successful DSM programs throughout the nation. Florida Power & Light, a leader in this area with efforts beginning in the 1980s, determined that "that the economic costs of building and operating [new base-load power-generating equipment, such as combined cycle units] are at least 20% to 30% higher than the cost of installing and operating the DMS program."[35] This is not rocket science. The municipal power system in the Town of Apex, NC, provides load management switches on all new and remodeled home construction of $10,000 or more. It explains, "Load management switch devices allow the Town, via radio control, to temporarily turn off water heaters, electric heat strips, and air conditioning compressors on an intermittent basis. In doing so, the Town reduces the peak demand all across its service area. The more switches the Town has in place, the greater the impact of this peak-shaving program."[36]

While 47 Coffin is not in a position to price DSM in New England, such a program is likely to compare favorably with ISO-NE's FCM outcomes. Additional information about costs of direct load control is available from the many utilities and utility commissions throughout the nation and the world that have adopted it. Further, PacifiCorp, whose DMS penetration and experience is extensive (potentially increasing marginal costs of DSM additions), recently commissioned a detailed integrated resource study looking forward to 2032, which estimated DSM costs as follows:

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[33] Flexicitricity News Release, *Companies win contracts for reducing power demand: National Grid has contracted 319 MW of Demand Side Balancing Reserve (DSBR) across 431 individual sites, to be available this winter* (Sept. 23, 2014), *available at* http://www.flexitricity.com/news.php?section=10&newsid=126 (quoting National Grid's Peter Bingham).

[34] Nena Chestney, Reuters, *Fire closes UK power generation unit, squeezing electricity supply* (Oct. 20, 2014), *available at* http://uk.reuters.com/article/2014/10/20/uk-britain-fire-idUKKCN0I80VH20141020 ("Grid operator National Grid has announced precautionary measures to keep the lights on, including a scheme to encourage utilities to make idle capacity available and paying offices and factories for reducing electricity use to ensure supply to households.")

[35] Michael Andreolas, FPL, Transmission & Distribution World, Mega Load Management System Pays Dividends (Feb. 1, 2004), *available at* http://tdworld.com/distribution-management-systems/mega-load-management-system-pays-dividends.

[36] Town of Apex, NC, Load Management Program: *Want to save money on your Electric bill? Try Load Management!* (accessed Nov. 1, 2014), *available at* http://www.apexnc.org/services/public-works/electric-utilities-division/load-management-program.

> The irrigation DLC program is expected to be the least expensive program option, with levelized costs ranging from $51/kW-year to $64/kW-year. Per-unit resource costs for the nonresidential load curtailment program are estimated at $69/kW-year for both service territories (as events are assumed to be called on a system-wide basis). The residential DLC AC program exhibits levelized costs ranging from $72/kW-year in Utah to $164/kW-year in Idaho. The assumed per-switch kW impact drives this variation in cost, with these impacts highest in Utah (1 kW) and the lowest in Idaho (0.43 kW).[37]

2) Voluntary demand response of the sort California has achieved with the FlexAlert program should be included in the Analysis.

Another significant source of potential additional DR is a range of retail voluntary load curtailment programs currently in place throughout the country, but weakly represented, if at all, in New England. 47 Coffin cannot determine from the Feasibility Study whether ISO-NE's Operating Procedure No. 4 has been factored into the winter peak at the publicly noted 200-300 MW demand reduction in response to an ISO-NE Power Warning, or whether other values or additional non-market DR resources have been considered.[38] Opportunities for MW growth in the OP 4 program, which provides no public service announcements and "almost no outreach to increase awareness of these conservation appeals outside of the appeals themselves"[39] may be significant.

A model to consider is California's FlexAlert program. FlexAlert has been proven, in the nearly decade and a half since its inception during the Energy Crisis, to be a highly effective means of managing extreme peak demands, often providing 1,000 MW of peak shaving and at times more.[40] California's utilities, in coordination with the ISO and state agencies, operate FlexAlert, casting wide public awareness

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[37] The Cadmus Group, *Assessment of Long-Term, System-Wide Potential for Demand-Side and Other Supplemental Resources, 2013-2032* at 31(Mar. 2013) http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Demand_Side_Management/DSM_Potential_Study/PacifiCorp_DSMPotential_FINAL_Vol%20I.pdf .

[38] Research into Action, *Final Report: Process Evaluation of the 2013 Statewide Flex Alert Program* at 49 (May 2, 2014), *available at* http://www3.sce.com/sscc/law/dis/dbattach5e.nsf/0/74BA2E806FE19D4788257CED005C010C/$FILE/A1208007%20et%20al%20Statewide%20MEO%20Apps%20-%20SCE%20Flex%20Alert%20Final%20Report.pdf [hereinafter 2013 FlexAlert Evaluation].

[39] *Id.*

[40] Energy Upgrade California, *See the Impact of Flex Alert* (visited Nov. 1, 2014), *available at* https://www.energyupgradeca.org/en/save-energy/home/see-the-impact/see-the-impact-of-flex-alert ("History has shown that Californians respond when called to action and often generate savings of 1,000 megawatts — enough electricity to power 1 million households. In fact, July 1st and 2nd, 2013, a Flex Alert was called and many businesses, residents, local governments and organizations responded quickly, dropping their energy demand by thousands of megawatts.")

campaigns.[41] FlexAlert has mitigated not only summer peaks, but also peaking associated with cold weather winter demand when natural gas becomes constrained, adversely impacting gas-fired generation. In the Southern California Edison service area alone, FlexAlert provided nearly 700 MW in February, 2014.[42] Many industrial and commercial users are enthusiastic participants in FlexAlert, including Kinder Morgan Energy Partners, which was quoted as follows:

> "The incentives are very significant in managing electrical costs at Kinder Morgan, which also ultimately benefits all customers of refined petroleum products," says Joel Hvidsten, energy forecaster at the energy transport company.
>
> Kinder Morgan, like many other demand response participants, also takes pride in helping California avoid a repeat of the devastating energy crisis of 2000-2001. "Kinder Morgan understands it could not effectively operate its pipelines without reliable electrical power," Hvidsten observes. "Additionally, since many Kinder Morgan employees are residents of California, the power grid's reliability impacts both business and personal life."[43]

Indeed, National Grid already has implemented a voluntary, incentive-based load drop program for commercial/industrial entities with behind the meter generation in New York. This program is "used when the NYISO declares a system emergency. Companies enrolled in this program will receive a financial incentive if they can curtail at least 100 kW of electricity one hour after notification. Incentive payments will only be made to program participants if power use is actually curtailed."[44]

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[41] *See generally* 2013 FlexAlert Evaluation.

[42] Caroline Aoyagi-Stom, Southern California Edison Co., *SCE Customers Help Save Almost 700 MW During Recent Flex Alert and Warning Triggered by CAISO* (Feb. 14, 2014), available at http://newsroom.edison.com/stories/sce-customers-help-save-almost-700-mw-during-recent-flex-alert-and-warning-triggered-by-caiso ("Something happened recently that we don't normally see in Southern California during the colder, winter months: the California Independent System Operator issued a statewide Flex Alert asking consumers to immediately start conserving energy. . . . The warning . . . during the afternoon of Feb. 6, triggered Southern California Edison (SCE)'s demand response programs and enrolled customers to respond immediately. Their response made a critical contribution, helping to reduce energy usage by almost 700 megawatts, enough power to provide electricity to more than 35,000 homes.")

[43] Jonathan Marshall, Pacific Gas & Electric Co. Currents, *PG&E Customers Heed the Call to Conserve* (Aug. 17, 2012), *available at* http://www.pgecurrents.com/2012/08/17/pge-customers-heed-the-call-to-conserve/ ("Some 4,100 large business customers also cut back that day, chopping peak demand by 475 MW, equal to the output of a major natural gas-fired generator. One such customer is Kinder Morgan Energy Partners, which transports refined petroleum products over pipelines throughout California. It alone shed more than 10 MW of load on both August 9 and 10, by turning off large electric motors used to drive centrifugal pumps.")

[44] National Grid, *Energy Demand* (visited Nov. 1, 2014), *available at* http://www.nationalgridus.com/niagaramohawk/business/programs/4_emergency.asp.

Expansion of these programs into New England should be incorporated in the Analysis. Although recent research indicates even greater potential for this kind of voluntary demand response,[45] the Analysis can and should conservatively develop MW and cost projections from existing successful programs, including FlexAlert and other voluntary DR programs.

3) The Analysis should examine peak shaving and demand destruction attributable to steadily skyrocketing power costs.

Among the indisputable benefits of wholesale power market restructuring is the new-found opportunity to examine electric demand price elasticity in the face of relentless rate shock. Long term decreasing cost trends vexed such inquiries,[46] but ISO-NE wholesale markets are rapidly rectifying this problem. As of September 2014, National Grid residential rates, driven by wholesale market outcomes, had increased by almost 12% as compared to the same 2013 time period.[47] On November 1, 2014, residential rates increased 37% as compared to the same 2013 time period—and other customer classes are experiencing significantly higher increases.[48] Customers can count on continued price escalation in years ahead. ISO-NE's non-competitive FCM has produced capacity costs for 2017-18 that will almost *triple* 2013 levels, increasing to $3.05 billion.[49] According to consumer interests, New England customers look forward to an additional $180 million costs in the capacity commitment period beginning in June 2017,

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[45] Robert Walton, Utility Dive, *If you want customers to decrease energy consumption, just ask* (Oct. 27, 2014) *available at* http://www.utilitydive.com/news/if-you-want-customers-to-decrease-energy-consumption-just-ask/325736/.

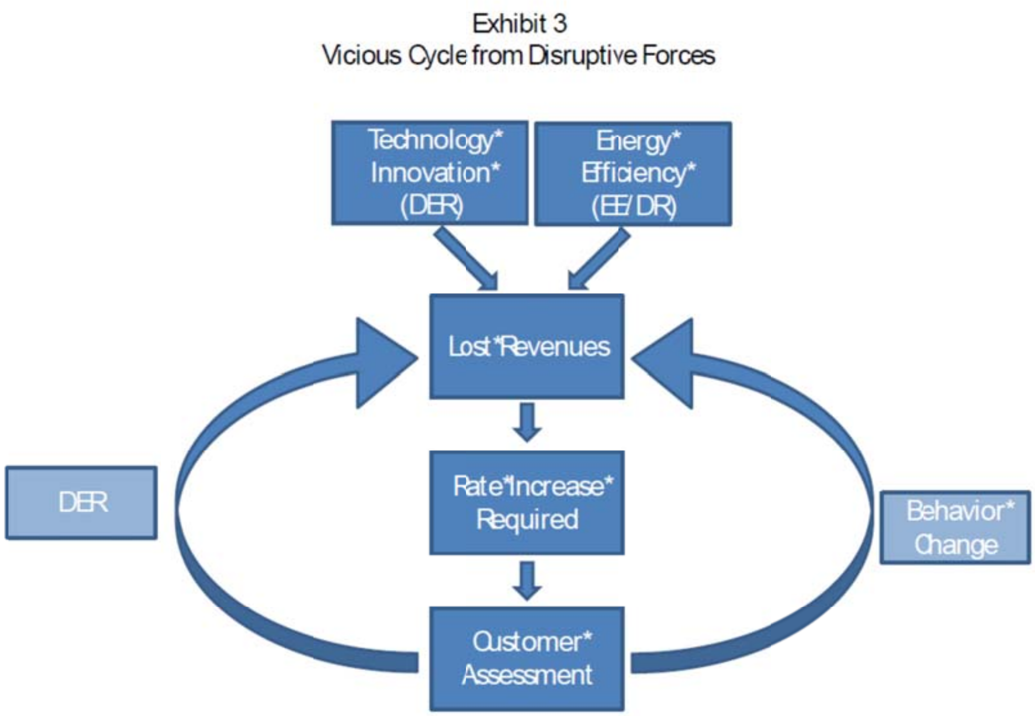
[46] *E.g.,* Mark A. Bernstein, James Griffin, Rand Infrastructure, Safety and Environment, *Regional Differences in the Price-Elasticity of Demand for Energy* (2005), *available at* http://www.rand.org/content/dam/rand/pubs/technical_reports/2005/RAND_TR292.pdf (Findings for prior periods showing price inelasticity "might imply that there are few options available to the consumer in response to changes in the price of energy, and that price does not respond much to changes in demand. On the other hand, because prices were declining in real terms over most of the period we studied, the inelasticity of demand may be more of an artifact of the lack of price increases.")

[47] US Dept of Energy, Energy Information Agency, *Residential Electricity Prices Are Rising* (Sept. 2, 2014), *available at* http://www.eia.gov/todayinenergy/detail.cfm?id=17791. ("The primary driver of the recent increase in New England retail rates was the sharp rise in wholesale power prices. For the first six months of 2014, the day-ahead wholesale power price in the ISO-New England control area averaged $93 per megawatthour, 45% higher than the average wholesale price during the same period last year. The increased cost of producing electricity in New England is evident in the 21% increase in the energy-only component of restructured retail suppliers' rates.")

[48] Robert Walton, Utility Dive, *National Grid customers to see 37% higher rates this winter* (Sept. 29, 2014), *available at* http://www.utilitydive.com/news/national-grid-customers-to-see-37-higher-rates-this-winter/314414/

[49] ISO New England Press Release, *Finalized Auction Results Confirm Slight Power System Resource Shortfall in 2017–2018* at 2 (Feb. 28, 2014), *available at* http://www.iso-ne.com/nwsiss/pr/2014/fca8_final_results_final_02282014.pdf.

with customers in the Northeastern MA/Boston zone bearing the greatest burden.[50] In a short time, New England power markets have produced incomparable motivation for high levels of self-help DR.[51]



Importantly, the Edison Electric Institute (EEI) posits that electric demand is remarkably price-sensitive. Expressed in terms of culprits comprising DR, DSM, and distributed energy resources (DER) the conclusion (diagrammed left) of a recent EEI-commissioned report is that demand reduction increases per unit rates as costs are shifted to fewer remaining customers, which then provokes spiraling demand reduction, spurring a "vicious cycle" (aka death spiral) of increasing demand destruction and ultimately stranded utility costs. [52] The same reasoning must logically apply when the rate increase triggering EEI's "Customer Assessment" that results in more DER or its DSM/DR "Behavior Change" is the utility industry's own kamikaze electric price increases in the face of flat or falling demand. 47 Coffin has found no evidence that this phenomenon has been included in ISO-NE's CELT forecasts, however.

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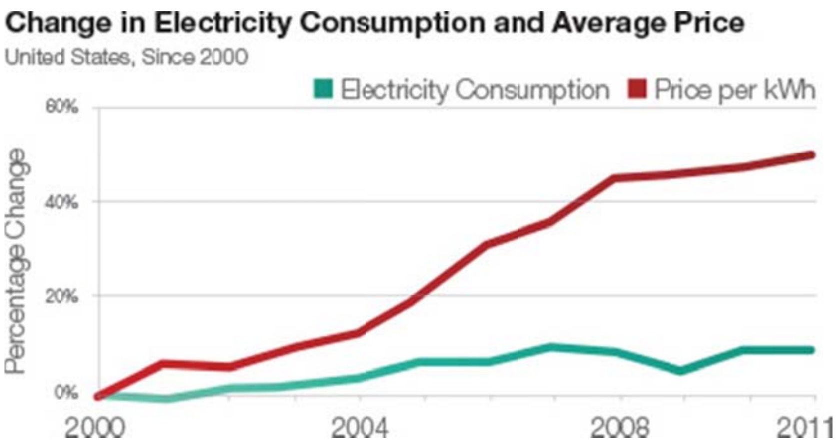
[50] *ISO New England Inc.,* FERC Docket No. ER14-1409, Joint Motion to Intervene, Motion Requesting Waiver, and Objection of Massachusetts Electric Co. *et al.* at 10 (Apr. 14, 2014), *available at* http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=13514034.

[51] By comparison, California's 2000-01 price fly up was unanticipated and contemporaneously paid for not by electric ratepayers but rather with state funds recouped through a $11.2 billion bond, whose repayment has been spread out in electric bills over many years. *See* Oscar Hidalgo, Cal. Dept. Water Res., DWR News, *DWR Keeps Power Flowing* (2006), *available at* http://www.cers.water.ca.gov/pdf_files/about_us/cers_history.pdf.

[52] Peter Kind, Energy Infrastructure Advocates, *Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Electric Business* (Jan. 2013), *available at* http://www.eei.org/ourissues/finance/documents/disruptivechallenges.pdf.

Commercial and industrial end users who do not relocate must be expected to undertake increasingly cost-effective self-help measures to mitigate ever-escalating New England rate hikes. SolarCity,



for example, uses the chart at left to advertise its DemandLogic program. DemandLogic supplements solar installations with battery resources that enable a commercial/ industrial user to avoid consumption in evening peak periods. As of 2014, this program became available in the Connecticut Power & Light and NStar service areas.[53] eCURV, a Boston start-up, offers sophisticated network systems computing to provide self-driven load control that reduces demand charges by avoiding coincident peak usage.[54]

Over and above current ratepayer-funded energy efficiency and stretch building codes that appear to form the basis of the Feasibility Study's energy efficiency analysis,[55] New England's spectacular electric rate increases, known to continue through at least 2018 *even without the additional burden of natural gas pipeline costs*, are highly likely to promote load shifting, demand reduction, and ultimately the demand destruction cycle EEI describes. Spiraling load reduction and particularly load shifting in response to stunning, ongoing price spikes in New England electricity costs should also be considered in the Analysis. This kind of peak shaving may be "invisible" insofar as it may be neither utility- nor government-sponsored but rather self-driven and involve no subsidies. But it has very significant potential and can occur quite swiftly as power rates go up…and up. The Analysis could estimate MW potential and costs simply through calls to providers such as eCURV and SolarCity.

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[53] SolarCity, DemandLogic, *Start saving right away* (accessed Nov. 1. 2014), *available at* http://www.solarcity.com/commercial/demandlogic.
[54] eCURV, *There is a better way* (accessed Nov. 1, 2014), *available at* http://www.ecurv.com/ (describing a digital network that seamlessly applies patented queuing algorithms to optimize the runtime of commercial/industrial appliances like HVAC systems, pumps, motors, battery chargers, heating and refrigeration equipment).
[55] Feasibility Study at 22. It would also appear that expansion of the innovations in peak shaving only recently offered by eCURV and SolarCity also cannot be "already occurring on its own" and thus "captured in the current forecast of winter peak demand." *Id.*

In summary, a review of established, successful electric DR outside of New England—and outside of centralized ISO wholesale markets—reveals thousands of MW of untapped retail DR potential that should be taken into account in the Low Gas Demand Analysis. 47 Coffin thanks DOER and Synapse for their work, appreciates the opportunity to provide these comments, and would be happy to answer questions or provide additional information.

Respectfully submitted,

Elisa J Grammer

Elisa J. Grammer

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Email: Elisa.Grammer@PerennialMotion.com

Berkshire Environmental Action Team
Protecting the Environment for Wildlife

November 4, 2014

Synapse Energy Economics
485 Massachusetts Avenue, Suite 2
Cambridge, MA 02139

Re: Massachusetts Low Demand Study

Dear Synapse,

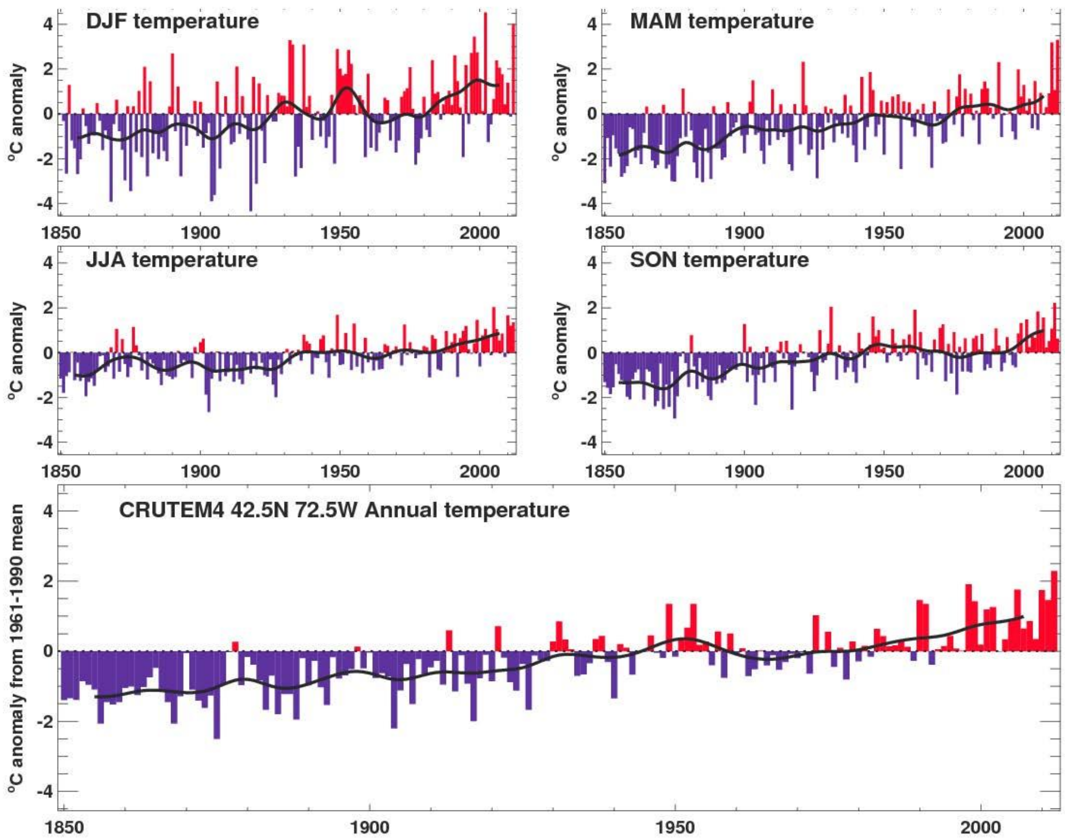
Please accept the following comments from Berkshire Environmental Action Team, Inc. (BEAT). Our mission is to work with you to protect the environment for wildlife in support of the natural world that supports us all.

Our comments on the following pages will focus on:

- The definition of a **Winter Peak Event** taking into consideration not only historical data, but also the trend seen in that data.
- The **Price** and **Risk** of increasing our reliance on natural gas. Natural gas is a finite resource and may not be nearly as available as the gas industry would like us to believe. The potential lack of availability of natural gas coupled with the plans to export the gas that could come into New England, lead us to believe that the estimates for future price of gas is very low.
- We ask that throughout the final document, Synapse make very clear how each scenario relates to the **Global Warming Solutions Act** statutory goals.
- We ask that the final report make very clear that **methane leakage** at the hydrofracking fields is not being taken into account, even though recent non-industry studies are showing the methane leakage to be substantial – more than enough to make natural gas worse from a climate change standpoint, than diesel and even coal.

(continued next page)

Winter peak event – The winter peak event should be based on not just historical temperature data, but the trend in that data. And please keep in mind that our winters are showing even more of a warming trend than our summers.



Temperature data for CRUTEM dataset North 42.5 West -72.5 (New England area), maintained by the climatic research unit, funding provided by the US Dept of Energy. The Climate Research Unit at the University of East Anglia. (DJF=December, January, February. MAM=March, April, May. JJA=June, July, August. SON=September, October, November.)

Price and Risk of increasing our reliance on natural gas –

BEAT believes that between a finite resource and the probability of export, the price of natural gas will rise dramatically. We would suggest some credible sources presenting the viewpoint that the Energy Information Administration may not be accurate in their predictions of future natural gas price or availability: 1) article in Forbes Magazine, 2) market analysis from Seeking Alpha, 3) report from geoscientist David Hughes 4) report from Deborah Rogers of the Energy Policy Forum, and 5) evidence of three export terminals planning on using gas from the Maritimes and Northeast Pipeline.

1. **Article in Forbes Magazine: The Popping of the Shale Gas Bubble, by Bill Powers. September 3, 2014.**
   http://www.forbes.com/sites/billpowers/2014/09/03/the-popping-of-the-shale-gas-bubble

From the end of the article:

"There is a large and growing body of empirical evidence to support the notion that the importance of shale gas has been overstated and that today's level of shale gas production is woefully unsustainable. Unfortunately, in today's nonlinear world, the bursting of the shale gas bubble will not lead to a gradual increase in prices, but rather a violent spike that will be very difficult to mitigate. As we lurch closer to the inflection point where Marcellus production growth plateaus and can no longer make for declines in nearly every other field in America, everything will change."

Bill Powers brief bio: "I am an independent analyst, author, contrarian and private investor. I am the former editor of the Powers Energy Investor, the Canadian Energy Viewpoint and the US Energy Investor. I have published investment research on the oil and gas industry since 2002 and sit on the Board of Directors of Arsenal Energy. As a true contrarian, I use independent and verifiable sources to come to conclusions that may not be the conventional wisdom of the day. For example, I was one of the first analysts to identify the fallacy of the 100-year natural gas supply myth. I hold a B.S. in Business Administration with a concentration in Finance from Georgetown University."

2. **Market Analysis: Marcellus Shale: Through a glass darkly by Moshe Ben-Reuven. March 31, 2014.**
   http://seekingalpha.com/article/2118153-marcellus-shale-through-a-glass-darkly

   > "Marcellus proved reserves, along with production rate, allow projection of life span, which is shown far less than the 100 years, closer to 10 years."

   Moshe Ben-Reuven brief bio: "Formerly in Aerospace/Defence propulsion area, I made a transition to energy/environment in 1995 to work on renewable energy. Specifically, biomass thermochemical processing into standard drop-in transportation fuels, like high-octane gasoline. I have founded Transmediair, Inc (later renamed Primus Green Energy, Inc) in New Jersey. I am the architect of Primus' proprietary technology, specifically, catalytic biomass gasification and other patents, including a modified version of the Mobil (1972) methanol to gasoline or MTG process. I am currently the President of Verdant Aerospace, LLC, developing technologies for renewable fuels, advanced micro turbines, and non-fracking shale-gas extraction. I have a BSc from the Technion, Haifa, and a PhD from Princeton University, both in aerospace and mechanical engineering."

3. **Report: Drilling Deeper: A reality check on U.S. government forecasts for a lasting tight oil & shale gas boom, by David Hughes. October 2014.**
   http://www.postcarbon.org/publications/drillingdeeper/
   "In late 2013 he [David Hughes] authored Drilling California: A Reality Check on the Monterey Shale, which critically examined the U.S. Energy Information

Administration's (EIA) estimates of technically recoverable tight oil in the Monterey Shale, which the EIA claimed constituted two-thirds of U.S. tight oil; the EIA subsequently wrote down its resource estimate for the Monterey by 96%."

David Hughes brief biography: "a geoscientist who has studied the energy resources of Canada for nearly four decades, including 32 years with the Geological Survey of Canada as a scientist and research manager."

Below from Page 300 of the report:

Figure 3-116 illustrates the EIA's reference case forecast for shale gas compared to the projections in this report for the seven plays analyzed. This comparison is made on a "dry" basis, given that the EIA forecast is for dry gas. 176 As can be seen, actual production of shale gas from these plays is higher in the near term than the EIA forecast and higher yet for the EIA's own independent estimate (from its Natural Gas Weekly Update) of actual shale gas production through August 2014. In the longer term, however, the EIA forecast overestimates production from the plays in this report's "Most Likely Rate" scenario through 2040 by 147.4 Tcf, or 64%. The EIA further estimates that in 2040, production from the plays analyzed in this report with be 182% higher (nearly 3 times) than estimated herein, and that by 2040, another 49.6 Tcf will have been recovered from other plays not analyzed in this report. Indeed, if the analysis in this report is correct, in order to meet the EIA reference case forecast other plays will have to recover an additional 198.2 Tcf—nearly 4 times the EIA's own estimate for other plays.

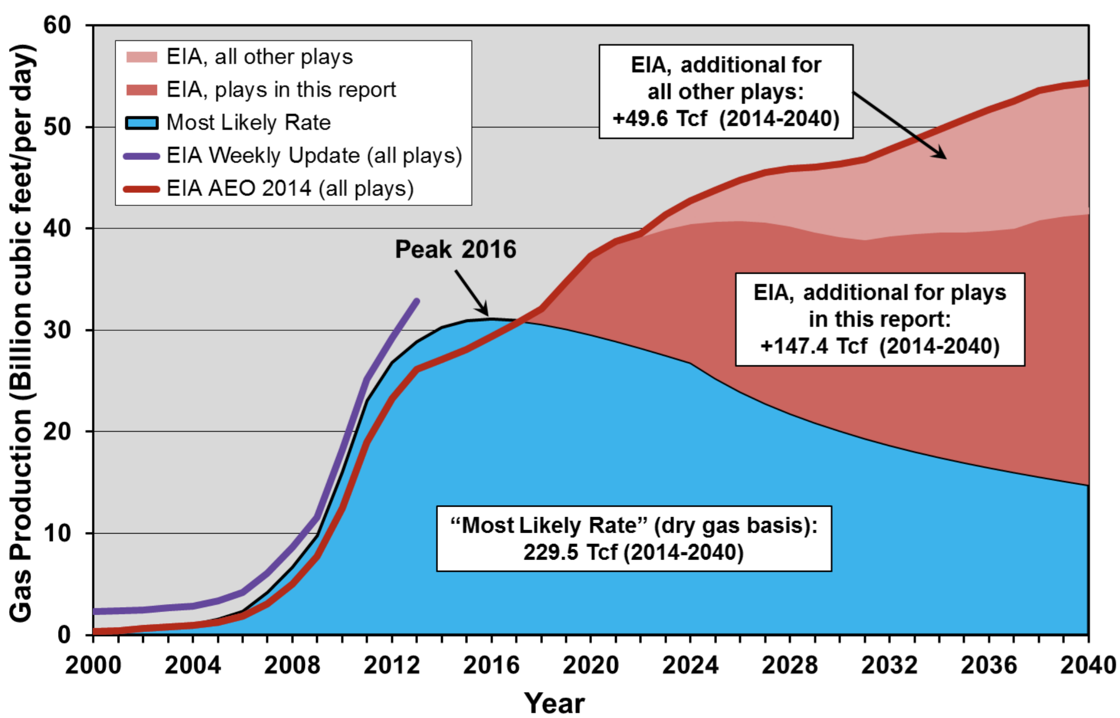


Figure 3-116. Totaled "Most Likely Rate" scenarios for the seven shale gas plays analyzed in this report, compared to the EIA's reference case forecast for these plays and for all plays.[177,178]

The "Most Likely Rate" scenario projections here are made on a "dry gas" basis. Also shown are the EIA's gas production statistics from its Natural Gas Weekly Update,[179] which contradict the early years of its AEO 2014 forecast.

177 – EIA, *Annual Energy Outlook* 2014, unpublished tables from AEO 2014, provided by EIA
178 – EIA, *Annual Energy Outlook* 2014, reference case forecast Table 14, oil and gas supply
179 – EIA, *Natural Gas Weekly Update,* retrieved October 2014

4. **Report: Shale and Wall Street: Was the Decline of Natural Gas Prices Orchestrated? By Deborah Rogers. February 2013.**
   http://energypolicyforum.org/portfolio/was-the-decline-in-natural-gas-prices-orchestrated/

   "Exportation is being pursued for the differential between the domestic and international prices in an effort to shore up ailing balance sheets invested in shale assets"

   Deborah Rogers brief bio: "Deborah Rogers began her financial career in London working in investment banking. Upon her return to the U.S., she worked as a financial consultant for several major Wall Street firms, including Merrill Lynch and Smith Barney. Ms. Rogers was appointed as a primary member to the U.S. Extractive Industries Transparency Initiative (USEITI), an advisory committee within the Department of Interior, in 2013 for a three year term. She also served on the Advisory Council for the Federal Reserve Bank of Dallas from 2008-2011. She was appointed in 2011 by the Texas Commission on Environmental Quality (TCEQ) to a task force reviewing placement of air monitors in the Barnett Shale region in light of air quality concerns brought about by the natural gas operations in North Texas.

   "Ms. Rogers is a Member of the Board of Earthworks/OGAP (Oil and Gas Accountability Project). She is also the founder of Energy Policy Forum, a consultancy and educational forum dedicated to policy and financial issues regarding shale gas and renewable energy. She lectures on shale gas economics throughout the U.S. and abroad and has appeared on MSNBC and NPR. She has also been featured in articles discussing the financial anomalies of shale gas in the New York Times (June 2011), Rolling Stone (March 2012) and the Village Voice (September 2012)."

   Article: "Energy Policy Forum's work corroborated". August 12, 2014.
   http://energypolicyforum.org/2014/08/12/eia-corroborates-the-work-of-energy-policy-forum/

5. **The evidence that this gas would be exported is clear. There are at least three companies planning export terminals, all planning on gas from the Maritimes & Northeast Pipeline:**

1) Goldboro, Nova Scotia –

Pieridae Energy has a signed long-term sales agreement to export 5 million tons per annum (MTPA), and plans to export an additional 5 MTPA for a total of 10 MTPA.

"Pieridae Energy signs E.ON as long-term Goldboro LNG customer

http://goldborolng.com/2013/06/pieridae-energy-signs-e-on-as-long-term-goldboro-lng-customer/

June 3, 2013
HALIFAX, NOVA SCOTIA June 3, 2013 – Pieridae Energy (Canada) Ltd. (Pieridae) today announced that it has entered into a long-term sales agreement with E.ON Global Commodities SE, a subsidiary of E.ON SE, one of the world's largest investor-owned power and gas companies, for the purchase of liquefied natural gas (LNG) from the Goldboro LNG project in Nova Scotia, Canada.
Under the agreement, Pieridae will deliver approximately 5 million tons per annum (MTPA) of LNG to E.ON for 20 years into a number of locations in Western Europe."

2) Bear Head –
ASX/MEDIA RELEASE - 27 August 2014
LIQUEFIED NATURAL GAS LIMITED FINALISES ACQUISITION OF BEAR HEAD LNG PROJECT IN CANADA AHEAD OF SCHEDULE
http://www.lnglimited.com.au/IRM/Company/ShowPage.aspx/PDFs/2093-82675202/LNGLFinalisesAcquisitionofBearHeadLNGProject

Highlights
• LNGL has finalised the acquisition of Bear Head LNG Corporation whose assets include a 255 acre (land and water) industrial-zoned site in Richmond County, Nova Scotia, Canada with all project rights, approvals, LNG tank foundations and significant civil works
• LNGL proposes to develop the site for initial 4 mtpa LNG export project with potential for future expansion

3) Canaport

"No immediate plans, but provides 'flexibility' to seek higher selling prices worldwide, official says
CBC News Posted: Nov 26, 2013 6:33 PM Last Updated: Nov 26, 2013 6:33 PM AT
http://www.cbc.ca/news/canada/new-brunswick/canaport-lng-given-permission-to-export-via-tankers-1.2441102
Saint John's Canaport liquefied natural gas terminal has been given permission by the provincial Department of Environment to export natural gas
using tankers.
The approved application will give Canaport LNG the ability to look for better markets for its product worldwide, said company spokesperson Kate Shannon."

Global Warming Solutions Act

Please clearly state throughout the document when different scenarios meet, or do not meet, Massachusetts statutory obligation to meet our Global Warming Solutions Act goals. BEAT believes that we should eliminate any scenario that would not allow us to meet these goals.

Methane Leakage

Not accounting for methane leakage should be clearly stated throughout the document. BEAT sees this as a huge abdication of responsibility on the part of Massachusetts. If we are using the energy, we should take responsibility for the full life-cycle greenhouse gas emissions in this case from well-head to burner-tip. The methane leakage in distribution lines is beginning to be addressed – at least for leaks that pose a threat of explosion.

However, the leaks at the hydraulic fracturing fields are just beginning to be independently studied and are showing leakage rates far in excess of the EPA estimates. If Massachusetts included all the CO2equivilant emissions from our fracked gas use, we would need to dramatically reduce our gas use in order to meet our Global Warming Solutions Act statutory goals.

Article from Al Jazeera America referring to many studies indicating the EPA estimate of methane leakage at the fracking fields is well below reality.
http://america.aljazeera.com/articles/2014/10/22/how-much-methaneisleakingfromfrackinginfrastructure.html

> "But a growing list of studies — most of them using top-down approaches, in which monitoring equipment measures emissions over a wide area — throw the EPA's estimates into question."
>
> "Consistently, studies show [methane leaks] are between 4 and 17 percent," said Seth B.C. Shonkoff, a visiting scholar at the University of California at Berkeley and the executive director at science policy think tank PSE Healthy Energy. "The most authoritative say the EPA underestimates methane emissions by about 50 percent. It seems the EPA is forgetting this big field of independent science."
>
> "A scientific review led by Adam Brandt, an assistant professor of energy resources engineering at Stanford University, also found that most studies on the topic estimate natural gas methane leakage to be significantly higher than the EPA's estimates."

And one of the most recent studies that the Al Jazeera article refers to:

Remote sensing of fugitive methane emissions from oil and gas production in North American tight geologic formations

1. Oliver Schneising[1,*],
2. John P. Burrows[1,2,3],
3. Russell R. Dickerson[2],
4. Michael Buchwitz[1],
5. Maximilian Reuter[1] and
6. Heinrich Bovensmann[1]

Article first published online: 6 OCT 2014
http://onlinelibrary.wiley.com/doi/10.1002/2014EF000265/full

Abstract: In the past decade, there has been a massive growth in the horizontal drilling and hydraulic fracturing of shale gas and tight oil reservoirs to exploit formerly inaccessible or unprofitable energy resources in rock formations with low permeability. In North America, these unconventional domestic sources of natural gas and oil provide an opportunity to achieve energy self-sufficiency and to reduce greenhouse gas emissions when displacing coal as a source of energy in power plants. However, fugitive methane emissions in the production process may counter the benefit over coal with respect to climate change and therefore need to be well quantified. Here we demonstrate that positive methane anomalies associated with the oil and gas industries can be detected from space and that corresponding regional emissions can be constrained using satellite observations. On the basis of a mass-balance approach, we estimate that methane emissions for two of the fastest growing production regions in the United States, the Bakken and Eagle Ford formations, have increased by 990 ± 650 ktCH_4 yr^{-1} and 530 ± 330 ktCH_4 yr^{-1} between the periods 2006–2008 and 2009–2011. Relative to the respective increases in oil and gas production, these emission estimates correspond to **leakages of 10.1% ± 7.3% and 9.1% ± 6.2% in terms of energy content**, calling immediate climate benefit into question and indicating that current inventories likely underestimate the fugitive emissions from Bakken and Eagle Ford. [**emphasis added**]

Thank you for considering our comments. We look forward to the next meeting.

Sincerely,

Jane Winn, Executive Director

Katy Eiseman [katyeiseman@gmail.com]

I am writing to ask that the study in some way account for the likelihood of gas prices being pushed up by the anticipated export of LNG, as explained in this recent EIA report: http://www.eia.gov/analysis/requests/fe/

Senator Markey also pointed out this summer: "Since May of 2011, DOE approved seven licenses to export liquefied natural gas at six export facilities and has for years approved exports through pipelines to Canada and Mexico. **The total amount approved by DOE through these terminals and pipelines has now far exceeded the level that DOE's own study said would increase domestic natural gas prices by more than 50 percent.**"
(http://www.markey.senate.gov/news/press-releases/markey-natural-gas-export-approvals-may-be-unlawful)

Thank you,
Katy Eiseman
--
Kathryn R. Eiseman, Director
Massachusetts PipeLine Awareness Network
MassPLAN.org
(413) 320-0747

November 3, 2014

Meg Lusardi
Department of Energy Resources
100 Cambridge Street, Suite 1020
Boston, MA 02114

lowdemandstudy@state.ma.us

Re: Comment Letter Synapse Energy Economics
Low Demand Study, October 30

Dear Ms. Lusardi:

Within this period of reinvestment in energy infrastructure in the northeast, there exists a momentary deficiency in the determination of what kind of generation will fill the forecasted retirement of "8,300 MW" of oil and coal generation assets. If nothing is done to declare the expansion of a state-sponsored renewable energy program, the requirements of reliability will quickly fill the void with dual fuel, combined cycle and combined heat and power fossil fuel generators; as well as out of state wind resources requiring long-term contracts. Given the billions of dollars that long-term contracts are going to require in pipelines and out-of-state transmission commitments, the Low Demand Study should examine installing 1,000 MW per year of solar within the Commonwealth with and without battery storage.

ISO-NE established a criterion that was determinant in forecasting the retirement of "8,300 MW" of coal and oil generation facilities by 2020.[1] ISO-NE also recognizes over "8,300 MW" of replacement assets in the interconnection queue[2] and yet acknowledges that only six of those fifty-seven projects totaling 85 MW have a high degree of probability of going into service[3]. ISO-NE and FERC are both waiting to see the outcome of how the states are going to respond to renewable energy and how the states are going to provide fuel for replacement assets and fast-start balancing resources. There is a gap, an opportunity now, for the Commonwealth to lead the other New England states to give notice to the market that state-sponsored, in-state, installed capacity of solar and other distributed energy resources are going to replace the retiring coal and oil generating assets now and in the future.

ISO-NE, in 2014 has 31,000 MW of generation capacity that is not expected to grow significantly. If solar and other distributed energy resources do not obtain installed capacity from retiring assets, where is the capacity to be obtained? Generators bid into the capacity market according to the economics of available load. Market signals need to be given now if distributed energy resources are to contribute to more significantly. If state-sponsored renewable energy programs are announced now, fast-start assets and

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[1] ISO New England's Strategic Transmission Analysis, Generation Retirement Study& 2020 Resource Options, Stephen Rourke, VP System Planning June 14, 2014
[2] NEPOOL Participants Committee Report, August 2014, Vamsi Chadalavada, EVP & CEO, Page 45
[3] NEPOOL Participants Committee Report, August 2014, Vamsi Chadalavada, EVP & CEO, Page 48

PO Box 290835, 42, Eighth Street, Suite 4413, Boston, MA 02129
1-617-337-0199, doug.pope@popeenergy.com www.PopeEnergy.com

base load requirements can be forecasted as well as the fuel required for dependable operations.

Performance based incentives should specifically encourage residential, medium and large scale solar with batteries and wind generation. As a base case, Synapse should use the existing $285 per MW as the performance based, paid for value payments for transition to solar. This would include both payments for value and virtual net metering.

Synapse needs to review the ISO-NE 2014 New England Regional System Plan, draft, released for review. Only in-state, distributed energy resources with in conjunction with energy storage technologies are going to alleviate the large deficiencies anticipated through 2020. ISO-NE anticipates change relative to distributed generation, but is using current legislation as a base case in their forecast, which undervalues the potential of solar PV and other distributed energy resources.

Synapse throughout their investigation, needs to include an avoided cost of carbon calculation as their low demand study report models scenarios and sensitivity combinations.

The UN, Intergovernmental Panel on Climate Change just published on November 1, the Climate Change 2014 Synthesis Report. Summarizing the report, the AP reported that "the report warned that failure to reduce emissions could lock the world on a trajectory with "irreversible" impacts and that greenhouse gas emissions need to be reduced to zero within this century. Global Climate Change, a NASA website, says 97 percent of climate scientist agree that warming trends over the past century are very likely due to human activity.

DOER should contract with Synapse Energy to finish the many "caveats" that are going to apparently exist within the December deadline report. Within that engagement, Synapse should study the economic multiplier of solar and distributed energy resources developed within the Commonwealth.

The opportunity to replace the rolling retirement of fossil fuel assets with renewable generation created within the state is now and represents a 25% installed capacity of solar, wind and other renewables.

The policy questions are: will the Commonwealth take ambitious steps to move significantly towards solar and distributed energy resources and will we continue to export our energy dollars out of state or do we recirculate those economics benefits within the Commonwealth.

Thank you for your consideration.

Best Regards,

Doug Pope
President

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[1] ISO New England's Strategic Transmission Analysis, Generation Retirement Study & 2020Resource Options, Stephen Rourke, VP System Planning June 14, 2014

Capacity Resources Assumed to be at Risk of Retirement (from 2010 Economic Study)

Unit	Unit Type	MW Maximum Assumed	In-service Date	Age in 2020	Unit	Unit Type	MW Maximum Assumed	In-service Date	Age in 2020
BRAYTON POINT 1	Coal	261	01-Aug-63	57	MONTVILLE 6	Oil	418	01-Jul-71	49
BRAYTON POINT 2	Coal	258	01-Jul-64	56	MOUNT TOM 1	Coal	159	01-Jun-60	60
BRAYTON POINT 3	Coal	643	01-Jul-69	51	MYSTIC 7 GT	Oil	615	01-Jun-75	45
BRAYTON POINT 4	Oil	458	01-Dec-74	46	NEW HAVEN HBR	Oil	483	01-Aug-75	45
BRIDGEPORT HBR 2	Oil	190	01-Aug-61	59	NEWINGTON 1	Oil	424	01-Jun-74	46
BRIDGEPORT HBR 3	Coal	401	01-Aug-68	52	NORWALK HBR 1	Oil	173	01-Jan-60	60
CANAL 1	Oil	597	01-Jul-68	52	NORWALK HBR 2	Oil	179	01-Jan-63	57
CANAL 2	Oil	599	01-Feb-76	44	SCHILLER 4	Coal	51	01-Apr-52	68
MERRIMACK 1	Coal	121	01-Dec-60	60	SCHILLER 6	Coal	51	01-Jul-57	63
MERRIMACK 2	Coal	343	30-Apr-68	52	W. SPRINGFIELD 3	Oil	111	01-Jan-57	63
MIDDLETOWN 2	Oil	123	01-Jan-58	62	YARMOUTH 1	Oil	56	01-Jan-57	63
MIDDLETOWN 3	Oil	248	01-Jan-64	56	YARMOUTH 2	Oil	56	01-Jan-58	62
MIDDLETOWN 4	Oil	415	01-Jun-73	47	YARMOUTH 3	Oil	122	01-Jul-65	55
MONTVILLE 5	Oil	85	01-Jan-54	66	YARMOUTH 4	Oil	632	01-Dec-78	42

TOTAL 8,281 MW

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[1] NEPOOL Participants Committee Report, August 2014, Vamsi Chadalavada, EVP & CEO, Page 45

New Generation Update

Based on 7/23/14 Interim Queue Update

- Five new projects, with a total rating of 1,335 MW, have applied for interconnection study since the last update
  - The new projects consist of three combined cycle uprates to existing plants/projects, and two wind facilities with expected in-service dates of 2019 and 2020
- Three projects withdrew from the Queue, two projects went commercial, and the capacity of one existing project was increased, resulting in a net increase in new generation projects of 1,390 MW
- In total, 57 generation projects are currently being tracked by the ISO, totaling 8,300 MW

45

New Generation Projection

By Fuel Type

Fuel Type	Total		Green		Yellow	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	2	70	0	0	2	70
Hydro	5	35	0	0	5	35
Landfill Gas	0	0	0	0	0	0
Natural Gas	7	1,902	0	0	7	1,902
Natural Gas/Oil	10	2,577	0	0	10	2,577
Oil	0	0	0	0	0	0
Solar	3	16	2	10	1	6
Wind	30	3,699	4	75	26	3,624
Total	57	8,299	6	85	51	8,214

- Projects in the Natural Gas/Oil category may have either gas or oil as the primary fuel
- Green denotes projects with a high probability of going into service
- Yellow denotes projects with a lower probability of going into service or new applications

48

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SREC Cost Per 200 MW At Floor $285 = $0.00134 per kWh

- A. Solar Installed and Billable to Ratepayers 200 MW
- B. Average PV Solar Capacity Factor 13.21%
- C. Hours per year 8760 hrs/yr
- D. Annual Solar PV Energy Production 231,439 MWh/yr (D=A*B*C)
- E. **Cost of SRECs (priced at Floor) $285 per MWh**
- F**. Annual Cost of SREC Program $65,960,172 per year** (F=D/E)
- G. **Annual System Load 49,386,169 MWh/yr (DOER RPS 2011 Compliance Filing)**
- H**. SREC Charge per unit Enegy Consumed $1.34 per MWh** (H=F/G)
- I. kWhs per MWh 1000 kWh/MWh
- J. **Unit SREC Charge in Customer Bills $0.00134 per kWh** (J=H/I)
- K. Average NSTAR Residential Customer Energy Consumption 500 kWh/Mo (see: http://www.nstar.com/residential/customer_information/nstar_green/nstar_green.asp)
- L. Average NSTAR Residential Monthly Cost of SREC Program $0.67 per month (L=J*K)
- M. Months per Year 12 mo/yr
- N. Average NSTAR Residential Annual Cost of SREC Program $8.01 per year (N=L*M)
- [Renewable Energy .00050 per kWh, Energy Conservation 0.00250, Transition 0.00783
- Distribution: 0.05847]

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Northeast GAS ASSOCIATION

November 4, 2014

Mr. Farhad Aminpour
Director, Energy Markets Division
Massachusetts Department of Energy Resources
100 Cambridge Street, Suite 1020
Boston, MA 02114

Re: DOER's Low-Demand Gas Study

Dear Mr. Aminpour:

The Northeast Gas Association (NGA) appreciates the opportunity to provide comments on the modeling design developed by Synapse Economics, Inc. for the Massachusetts Department of Energy Resource's (DOER's) low demand analysis.

The feasibility analysis as presented by Synapse in its presentation on October 30 and its summary paper is extensive. It presents a suite of energy supply and demand resource opportunities to be assessed as Synapse seeks to identify the Commonwealth's energy needs over the coming fifteen years and its possible options, measured against price and environmental impacts.

Modeling Gas Demand:
Natural gas is currently the leading fuel for both home heating and power generation in the Commonwealth, and its potential for further growth is considerable. As NGA noted in its letter of October 20, we hope that the DOER analysis will reflect the natural gas demand that the Commonwealth's natural gas utilities (LDCs) are currently experiencing, especially in light of the high demand recorded last winter. Furthermore, customer growth on the LDC systems is anticipated to grow strongly, in response to the positive price situation of natural gas compared to other home heating fuels and to the Commonwealth's support for further natural gas expansion, as witnessed by H. 4164.

On page 4 of its feasibility analysis paper, Synapse notes that the "LDCs' five-year design day forecast will be applied to the January of the split year and remain unadjusted from their most recent filing as provided to DOER." The 2013-14 winter as noted above saw very high demand on all the utility systems. It is our understanding that the three largest gas utilities in the Commonwealth – Columbia Gas of MA, National Grid and NSTAR/NU – have already submitted updated demand forecasts to DOER reflecting this recent historical experience. These three companies collectively serve about 90% of the Commonwealth's utility customer base. The Commonwealth's LDCs are also planning to provide for a portion of "capacity exempt" customers starting this winter, under the guidance of the Department of Public Utilities. Thus, we urge DOER and Synapse to adjust the LDCs' demand forecast in line with actual available data and market conditions that are both timely and realistic.

We concur with the comments of James Daly of NU in his letter of November 3 regarding contingency analysis, and that Synapse should study LDC demand using the standards for "design season" and "design peak" as utilized by utilities in Massachusetts, "rather than attempt to determine some other untested standard."

Thank you for the consideration of our comments.

Sincerely,

Stephen Leahy
Vice President, Policy

Tuesday, November 4, 2014

To DOER and Synapse Energy Consulting:

Thank you for the opportunity to provide additional comments on the Massachusetts Low Demand Analysis study. I write representing members of Stop the Pipeline in Dracut, MA and in Eastern Middlesex County

Our concerns are as follows:

1. The existing list of alternative resources fails to explicitly mention Heat Pump Water Heaters. These water heaters have the potential to reduce electricity cost and Federal standards on 55+ gallon units go into effect almost immediately, in 2015:
http://www1.eere.energy.gov/buildings/appliance_standards/product.aspx/productid/27

Furthermore, NEEP anticipates that heat pump technology will become a mandate for water heaters during the time of the study. Thus, the study should be explicit in separating out Heat Pump Water Heaters from the other air-sourced heat pump that are for space heating. This technology has a huge potential according to NEEP:
http://www.neep.org/sites/default/files/resources/HPWH_One_Pager_Final_0.pdf

and thus should be modeled separately.

2. The Study should model improvements in efficiency of lighting which have been substantial and are continuing to occur as less efficient halogen and incandescent and CFL bulbs are replaced by LEDs. Existing studies significantly understate this impact.

For example, see page 29 of the NEEP residential lighting study update at:
http://www.neep.org/northeast-residential-lighting-strategy-2013-2014-update
This document shows that the price of LED bulbs as of May 2013 is $10.17. That price is expected to reach $5 in mid-2016, according to page 35. In reality, the “street” price of a 10.0 watt LED bulb -- a bulb more efficient than the bulbs distributed this fall by MassSave, has reached $4.99 as of October 6 at a Market Basket store in Lowell, the attached photo shows. Further price and wattage reductions are expected by 2018.

3. The list of alternative resources fails to include not only the potential of time-varying electric rates, but also the possibility of a public education campaign in Massachusetts similar to Connecticut's "wait til 8" program.

The idea is to encourage dishwasher and dryer usage after 8 or 9pm to help manage peak demand. Details are readily available from the State of Connecticut:
http://nuwnotes1.nu.com/apps/mediarelease/clp-pr.nsf/0/E86E61978913CDD6852573060050998D?OpenDocument

4. Municipalities and utilities can be a partner in energy reduction measures affecting peak demand, through expanded incentives to encourage municipal adoption of LED lighting.

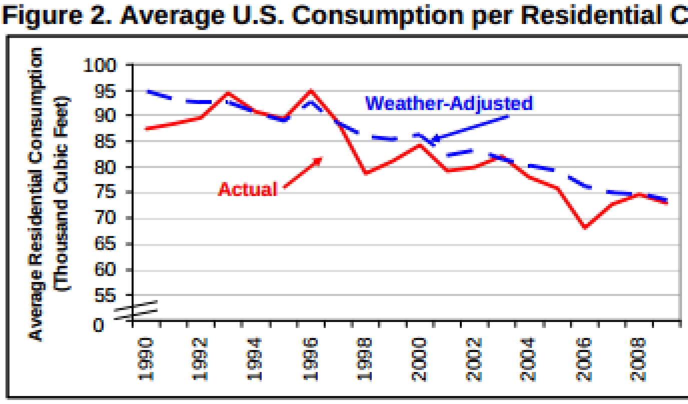
Currently many municipalities depend on lighting that is owned by the electric utilities. A statewide mandate to convert all municipal lighting to LED by 2018 or 2020 would offer immense energy savings during the period of greatest peak demand. Towns that have been able to convert their own street lights have found that the cost of retrofits pays for itself and can be finance through loans, achieving immediate budgetary savings. There is no reason that an LED conversion "mandate" should not be considered as a major alternative resource, all on its own. Current energy efficiency calculations embedded in the CELT report do not assume universal adoption of LED lighting which leeds to an overestimate of the required generation capacity.

5. The 2014 ISO CELT report (dated May 16, 2014) does not include many other technological improvements in its calculations of projected energy demand. For example, it does not include any assumptions on the adoption of heat pump electric clothes dryers. It does not assume that additional states will adopt the IECC 2012 building code, as Massachusetts has done.

Given this concerns, the data in the CELT report on these non-fossil fuel energy sources should not be relied on to form "base case" assumptions for total generation capacity in 2016 to 2023. Furthermore, the 2014 report of the American Gas Association, *Promise Delivered*, shows a strong downward trajectory in per capita customer usage of gas, from 1975 to 2013. See page 3 of the section on Energy Efficiency and the Customer Experience:
http://www.aga.org/Kc/winterheatingseason/Documents/Promise%20Delivered%20-%20Full%20Report.pdf

The base case scenario for all New England states should assume continued improvement in per-household gas usage of 1 to 2 percent per year, regardless of state policy, as homes and appliances designed for an era when fossil fuels were less expensive and regulations were less stringent continue to be retired or renovated. This base case rate of improvement can be set by incorporating EIA data; for example, the chart below appears in EIA's Natural Gas Monthly (March 2010).

Figure 2. Average U.S. Consumption per Residential Customer, 1990-2009



Source: Residential consumption: Energy Information Administration, *Natural Gas Monthly* (March 2010).
Weather data: National Oceanic and Atmospheric Administration.

6. The study should include solar energy backed by batteries as a separate alternative resource.

It does not really make sense for the study to include batteries as a generation category as batteries do not create energy. Instead, the study should include a major category for “battery-backed, decentralized solar energy” and assume significant market penetration of this technology beginning in 2016 or 2017.

The Institute for Local Self Reliance, Rocky Mountain Institute, Deutsche Bank, and Morgan Stanley have all released reports showing that "grid parity" for battery backed solar is likely to be achieved in the next 2 to 5 years in much of the US, including New England. Due to the paradigm shifting potential of this technology, the study team should assume that new capacity in that timeframe will be renewables, based on favorable economics.
See:
http://www.ilsr.org/projects/solarparitymap/
http://oilprice.com/Latest-Energy-News/World-News/Report-Off-Grid-May-Soon-Reach-Tipping-Point.html

Regarding the cost of decentralized battery tech, Synaps should not assume that everyone who gets solar will do so for economic reasons. It is reasonable to assume that many will get solar backed by batteries even while it is still more expensive in the short term, because a) "it is cool" and b) it is likely to be cheaper in the long term, and c) battery backed solar will replace generators as an emergency power source during blackouts.

Please note that Google bought the NEST thermostat company and wants the grid operators to allow them to participate in Demand Responses, and to allow solar backed by batteries to also be permitted where currently it is not.
http://www.greentechmedia.com/articles/read/solarcity-nest-to-energy-regulators-open-the-grid

These intelligent home energy systems that store up power and release it to the grid at peak time are not some futuristic dream. The products are coming out now and even without any tech advances, many people will buy them at the initial high cost, a cost expected to drop by a factor of more than 50% in the next 4 years. Here are just 5 such products, I am sure you have seen others:

Juicebox
http://cleantechnica.com/2014/09/30/solar-energy-storage-system-homes-businesses-unveiled/
Enphase
http://www.renewableenergyworld.com/rea/blog/post/2014/10/solar-technology-to-take-quantum-leap-with-latest-enphase-product-unveiling
Solar City
http://cleantechnica.com/2014/11/03/solarcity-tesla-storage-system-cost/
Cumulus
http://www.businessweek.com/videos/2014-10-06/battery-power-builds-low-cost-clean-energy-storage
Stem
http://cleantechnica.com/2014/10/20/kyocera-solar-offer-stem-intelligent-energy-storage-system/
even GE is getting into the market
bttp://**geenergystorage**.com

7. The list of alternative resources to be considered should be robust.

The attachment to this letter provides a longer list of policy changes including many that Synapse did not include. These include the demand reduction programs of Concord Power and Light and Sunamp of the UK, two heat storage technologies that directly address winter peak demand and do not require any advanced battery technology..

We look forward to participating further as this process moves forward.

Sincerely,

Richard A. Cowan
Stop the Pipeline - Dracut, MA

email: richcowan@gmail.com
twitter: @GreenDracut
phone: (617) 642-3379

List of Possible Alternative Resources for the Massachusetts Low Demand Scenario

A. Energy reduction mandates

1. Requirement for landlords to provide primary LED lighting to new tenants by 2018
   Further improvement in energy usage; as LED light bulbs are expected to consume 6-7 watts or less compared to 9.5 watts for 60W equivalent now.
   see: http://earthled.com/collections/new-led-light-bulbs

2. Ban on consumer sales of 43 watt incandescent light bulbs and some halogens, 2015
   Reduction of 10 million bulbs, used 3 hours/day in the winter could save 10M * 40 = ~400MW during hours that are usually part of peak demand.
   see:
http://neep.org/Assets/uploads/files/market-strategies/lighting/2013-ResLighting-Workshop/October%202013%20RLS%20Update_FINAL.pdf

3. Prohibit municipal street lighting that is not high efficiency (i.e. LED or better) in new england
   (State treasurer could provide a path to financing.)
   see: http://www.capelightcompact.org/ee/business/ledstreetlights/

4. Require landlords to remedy basic issues like lack of attic insulation in rental units.
   see:
https://www.burlingtonelectric.com/sites/default/files/Documents/Energy_Eff/time-of-sale-energy-ordinance.pdf
   Passage of such an ordinance could be one of the ways a town could qualifiy for green community status.

B. Energy reduction incentives

1. Installation of cold climate heat pumps instead of anticipated gas conversion from oil
   Installation of cold climate heat pumps instead of anticipated gas furnace upgrade
   Installation of cold climate heat pumps that replace electric resistance heating
   see: http://www2.buildinggreen.com/blogs/7-tips-get-more-mini-split-heat-pumps-colder-climates

2. Installation of electric heat pumps for hot water and drying (would displace power generation, or oil, or gas)
   see: http://energy.gov/sites/prod/files/2014/01/f7/case_study_hpwh_northeast.pdf
http://www.neep.org/broadcast/neep-expert-heralds-lg-ecohybrid-heat-pump-dryer-2014-energy-star%C2%AE-emerging-technology

3. Installation of solar hot water systems (would displace power generation, or oil, or gas)
   see: http://neshw.com/residential/new-england-drainback-appliance/

4. Augment energy efficiency programs to provide greater assistance with pre-weatherization issues
   see: http://clud6.prometheuslabor.com/sites/clud6.prometheuslabor.com/files/pre-weatherization_brief.pdf

5. Approval of IECC 2012 building code in 4 NE states who have not adopted it yet -- and do not allow building code adoption to displace other efficiency requirements
   see: https://www.energycodes.gov/status-state-energy-code-adoption

(continued)

6. Adopt enhanced massachusetts "stretch code," encourage adoption elsewhere.
   see: http://www.neep.org/sites/default/files/resources/VT_2015_IECC_LOS.pdf

7. Impact of time-varying electricity rates
   see: http://www.mass.gov/eea/docs/dpu/orders/d-p-u-14-04-b-order-6-12-14.pdf

8. Public campaign to encourage use of appliances during non-peak hours, i.e. the "wait til 8" in ct
   see:
http://nuwnotes1.nu.com/apps/mediarelease/clp-pr.nsf/0/E86E61978913CDD6852573060050998D?OpenDocument

9. Better implementation of "cash for clunkers" type programs -- identify high energy using appliances and give a coupon for replacement. These programs -- including those for lighting -- should insure that the old appliances (and old light bulbs) are thrown away and not reused. As of 2014 this is not always the case in Massachusetts.
   see: http://ei.haas.berkeley.edu/pdf/working_papers/WP230.pdf

C. Replacing Energy Generation to Reduce Gas Usage

1.. Grid scale batteries to provide peak power
   see: http://energystorage.org/news/esa-news/arizona-poised-open-new-market-energy-storage
   http://www.pv-tech.org/news/japanese_energy_companies_test_80mwh_of_large_scale_battery_storage_systems

2. Distributed solar backed by battery
   see: http://cleantechnica.com/2014/09/22/every-solarcity-customer-will-get-battery-backup-within-5-10-years/
   http://goo.gl/y5W8jh -- Morgan Stanley report

3. Distributed wind backed by compressed air storage
   see: http://spectrum.ieee.org/energy/renewables/hydrostor-wants-to-stash-energy-in-underwater-bags

4. Honda micro CHP units (not currently sold in the US):
   see: https://www.puc.state.pa.us/electric/pdf/dsr/DSR_Present-MicroCHP_Pilot.pdf

5. “Heat Batteries” -- thermal bricks paired with heat pump heat, designed to offset peak demand:
   see: http://sunamp.co.uk/products/sunampstack/
   Note: this company’s product is similar to the Concord, MA municipal light electric thermal storage option (http://**concord**ma.gov/pages/**Concord**MA_LightPlant/**ets** **)**, but based on newer technology.

Note: I focused on the newer technologies coming online, assuming that larger CHP and wind turbine systems would already be included in a low demand study.

D. Replacing Pipeline Capacity from the West with Atlantic Canada Storage

1. Alton salt caverns, in Nova Scotia, is a project expected to feed the Maritimes Northeast Pipeline in winter of 2015-6. This cavern could be filled with gas from a low cost supply region. Capacity can be expanded to 20 BCF.
see: http://altagas.ca/gas/energy_services/natural_gas_storage

compiled by Rich Cowan, Dracut MA. For questions: email richcowan@gmail.com

Tennessee Gas Pipeline
Company, L.L.C.
a Kinder Morgan company

November 4, 2014

Ms. Meg Lusardi
Acting Commissioner
Massachusetts Department of Energy Resources
100 Cambridge Street, Suite 1020
Boston, MA 02114

Submitted via email: lowdemandstudy@state.ma.us

RE: Comments of Tennessee Gas Pipeline Company L.L.C.
Low Demand Analysis Project – Stakeholder Meeting October 30, 2014

Dear Acting Commissioner Lusardi:

Tennessee Gas Pipeline Company, L.L.C. ("TGP") hereby submits the following comments regarding the above-referenced meeting.

Winter Peak Event

As TGP understands from the October 30, 2014 stakeholder meeting, Synapse's Low Demand Scenario Analysis will model eight scenarios, with different combinations of resources, in which natural gas pipeline capacity will be "sufficient," i.e., gas demand needs and supply will be in equilibrium. If this model structure is to be employed, TGP urges Synapse to reconsider the definition of "sufficiency". As currently proposed, Synapse will test such sufficiency based on a "winter peak event," which is described as:

- Capacity and demand in the peak hour of an expected future "design day";
- Gas requirements for electric generation representing the coincident peak with LDCs' design day: for each year, the highest gas requirement for a January day from 6 to 7 pm;
- Sufficiency of natural gas capacity taking into account the effects of a cold snap of 12 days.

Such a definition inadequately defines the problem facing New England. For example, this past winter gas prices were higher than oil prices 57% of days, not just for one hour during a hypothetical design day within a twelve day cold snap. Sustained periods of high natural gas prices reflect a demand for natural gas that regularly outstrips supply. Further, as noted by comments of other stakeholders involved in this process, LDCs are obligated to ensure service for a design season and design day. If the Low Demand Scenario Analysis does not consider similar design standards it will likely understate the demand for natural gas and how LDCs plan to serve that demand.

Base Case Scenario

For the Base Case Scenario, Synapse plans to model electric and gas load using "existing, well-recognized projections and appropriate adjustments to these forecasts based on well-known critiques." When pressed by multiple stakeholders on the need for and nature of such adjustments, Synapse was unable to provide clear examples or reasoning. TGP suggests that "well-known critiques" be identified up front, as should clear underlying reasons for the apparent need to adjust "existing, well-recognized projections."

Canadian Natural Gas Supply, Demand and Exports

Since an important source of natural gas for New England has been gas flows from Atlantic Canada south into the region, it is very important that any study of natural gas supply and demand in New England consider forecasts of gas production volumes out of Sable Island and Deep Panuke as well as natural gas demand for heating, industrial processes, and electric generation in New Brunswick and Nova Scotia. It is not clear that the scope of the Synapse study extends to include our Canadian neighbors. All assumptions about these parameters and values should be explicitly stated to ensure their transparency.

Do Nothing Option

As yet more studies and proceedings are being undertaken across New England to identify the exact nature of the energy problem plaguing the region, consensus has been reached on a few facts: the problem is costing the region billions of dollars annually and it will not be solved in the near term. As time drags on and stakeholders continue to argue as to effect and solution, a Do Nothing scenario grows ever more self-fulfilling. As such, TGP urges the DOER to consider the effect of not reaching equilibrium between gas needs and infrastructure, as this appears to be one possible outcome.

Sincerely,

Sital Mody
Vice President, Marketing & Business Development