ENBRIDGE INTERROGATORY #1

INTERROGATORY

Reference: Exhibit L.OEBStaff.1, general

Question:
Please provide the following information relevant to the Massachusetts energy market:

a. Number of utilities, divided by natural gas only, electricity only and dual-fuel
b. Total natural gas throughput in m3 in 2014
c. Total cost per m3 of natural gas to an average residential customer in 2014 (inclusive of commodity, distribution, transportation, storage, and any other costs borne by natural gas customers) stating any necessary assumptions
d. Statewide DSM budget specific to natural gas for each year from the inception of DSM in Massachusetts to 2020
e. Statewide DSM budget specific to electricity for each year from the inception of DSM in Massachusetts to 2020

RESPONSE

a. There are 8 investor owned gas utilities in Massachusetts: Bay State Gas Company, Blackstone Gas Company, Liberty Utilities, National Grid, Berkshire Gas Company, Eversource Energy, and Fitchburg Gas and Electric Light Company.[1]

   There are 4 investor owned electric utilities in Massachusetts: National Grid, NSTAR Electric and Western Massachusetts Electric Company (d/b/a Eversource Energy), and Fitchburg Gas and Electric Light Company.[2] Note that the Cape Light Compact is an electric energy efficiency program administrator.

   National Grid, Eversource, and Fitchburg provide both gas and electric services.

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[1] See http://www.mass.gov/eea/energy-utilities-clean-tech/natural-gas-utility/natural-gas-market-data/list-of-local-distribution-companies.html
[2] See http://www.mass.gov/eea/energy-utilities-clean-tech/electric-power/electric-power-division-responsibilities.html

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

b. According to the U.S. Energy Information Administration, natural gas delivered to customers in 2014 was 422,832 million cubic feet,[3] or 11,973 million m^3.

   For additional information, refer to the gas distribution companies' annual reports, found on the Massachusetts Department of Public Utilities website at, http://www.mass.gov/eea/energy-utilities-clean-tech/natural-gas-utility/natural-gas-tariffs/annual-reports.html.

c. According to the U.S. Energy Information Administration, the 2013 residential natural gas price ranged between $13.00 and $14.99 per thousand cubic feet.[4] Although EIA data for 2014 is not yet available, the 2014 price is likely within a similar range as the 2013 price range.

d. Energy efficiency programs have been in place in Massachusetts since the 1980s. Projections for energy efficiency programs in 2016 through 2018 are currently being developed, and are expected to be finalized in the spring of 2016. Actual and projected energy efficiency program budgets for gas and electric program administrators are available on the following website for 2010 through 2015: http://www.masssavedata.com/Public/PortfolioOverview.aspx.

e. See Exhibit M.Staff.EGDI.1, part d.

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[3] Source: http://www.eia.gov/dnav/ng/ng_sum_lsum_dcu_SMA_a.htm
[4] Source: http://www.eia.gov/energyexplained/index.cfm?page=natural_gas_prices

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

ENBRIDGE INTERROGATORY #2

INTERROGATORY

Reference: Exhibit L.OEBStaff.1, general

Question:
Please provide the most recent statewide and/or utility specific annual energy efficiency reports (outlining program details, highlights, spending, results, etc.) for the jurisdictions and utilities below.

a. Massachusetts
b. Vermont Gas
c. SoCal Gas
d. Nicor Gas

RESPONSE

a. Massachusetts: the Massachusetts electric and gas program administrator annual reports for 2010 through 2014 are available on the Massachusetts Energy Efficiency Advisory Council's website: http://ma-eeac.org/results-reporting/

b. Vermont Gas: the 2014 annual report is available at https://vermontgas.com/wp-content/uploads/2015/04/2014-Annual-Report.pdf

c. SoCal Gas: the 2014 annual energy efficiency report by SoCal Gas is available at eestats.cpuc.ca.gov/EEGA2010Files/SCG/AnnualReport/SCG.AnnualNarrative.2014.1.zip

d. Nicor Gas: Nicor Gas reports are available at http://www.ilsag.info/quarterly-reports.html.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

ENBRIDGE INTERROGATORY #3

INTERROGATORY

Reference: Exhibit L.OEBStaff.1, general

Question:
Please provide a list of key documents provided to SEE in order to complete its review of the gas utilities' DSM Plans.

RESPONSE

Please refer to the References section of the report, found at L.OEBStaff.1, pages 132-137. Specifically with regard to Ontario Energy Board documents, Synapse reviewed the following in preparing its report:

- Report of the Board, Demand Side Management Framework for Natural Gas Distributors (2015-2020), EB-2014-0134, December 22, 2014.
- Filing Guidelines to the Demand Side Management Framework for Natural Gas Distributors (2015-2020), EB-2014-0134, December 22, 2014.
- Staff Discussion Paper, On Revised Draft Demand Side Management Guidelines for Natural Gas Utilities. EB-2008-0346, January 21, 2011.
- Demand Side Management Guidelines for Natural Gas Utilities, EB-2008-0346, June 30, 2011.
- Decision and Order, EB-2014-0273, June 4, 2015.
- Ontario Power Authority, Conservation First 2015-2020 Evaluation, Measurement and Verification Protocols and Requirements V2.0, 2015.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

ENBRIDGE INTERROGATORY #4

INTERROGATORY

Reference: Exhibit L.OEBStaff.1, page 1

Preamble:
On page one and throughout this report, SEE discusses suggestions and recommendations for "improvements" to Enbridge's DSM Plan. The Company is curious as to what analytical work was done to assess the impact of undertaking those "improvements" to the budgets, metrics or targets of Enbridge's DSM Plan.

Question:

a. Please provide all work completed by SEE in advance of completing its report that estimates the impact on Enbridge's DSM annual and total budget from implementing each and all of the recommendations set out in the SEE report.
b. Please provide all work completed by SEE in advance of completing its report that evaluates the cost-effectiveness of any or all of the expanded or modified programs proposed.
c. Please confirm that SEE did not evaluate whether the implementation of its recommendations will lead to Enbridge exceeding the DSM budget guideline of a $2 per month impact on an average residential customer. If not confirmed, please provide details of the evaluation that was performed.

RESPONSE

Synapse was tasked with reviewing the proposed DSM programs and commenting on the program design elements that could be modified or improved. The Synapse recommendation referenced above is intended to provide general guidance and direction, and is not intended to indicate a specific quantitative outcome (see Exhibit L.OEBStaff.1, page 2). Therefore, we have not estimated the requested data in all three parts of this question as it is beyond the scope of our work.

Specifically, Exhibit L.OEBStaff.1, page 2 states:

> Lastly, as Ontario's gas DSM programs are subject to a budget guideline maximum, as set out in the OEB's DSM framework, we recommend the utilities take a cautious and balanced approach when considering adopting our recommendations so that new changes would not push the utilities' programs over the current proposed budgets.[5]

[5] The utilities' proposed budgets are effectively at the budget guideline maximum.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

Some of our recommendations (such as improving program design and adding new measures) would increase program participation, which would result in an increase in incentive amounts and budget. On the other hand, other recommendations (such as reducing free-ridership, eliminating unnecessary measures, and providing financing) would decrease program budgets. In summary, both utilities should consider and balance potential improvements on participation rates, energy savings, cost-effectiveness, and a potential increase or decrease in budget from each recommendation, and determine which recommendations to adopt within their constraints.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

ENBRIDGE INTERROGATORY #5

INTERROGATORY

Reference: Exhibit L.OEBStaff.1– page 3

Question:
Please confirm that SEE reviewed the relative customer base characteristics, demographics and geographic zones for Enbridge and Union Gas respectively. What are the specific differences that Synapse noted?

RESPONSE

Please refer to section 3.2. Program Mix by Customer Sector of the report, found at L.OEBStaff.1, specifically pages 10-11, which provides the extent of the analysis that Synapse conducted on each utility's customer and sales.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

ENBRIDGE INTERROGATORY #6

INTERROGATORY

Reference: Exhibit L.OEBStaff.1, page 17

Preamble:
Page 17 of the SEE report states that "…Union provides detail on input assumptions for gross savings estimates for a number of its offerings, while Enbridge does not mention it at all in its evaluation plan…Enbridge should mention the use of input assumptions for specific offerings where appropriate."

Question:
Please confirm that page 4 of Enbridge's Evaluation Plan, filed as Exhibit B, Tab 2, Schedule 2, references Exhibit B, Tab 2, Schedule 6, as containing updated inputs and assumptions. Please further confirm that Exhibit B, Tab 2, Schedule 6 directs the reader to EB-2014-0354, the gas utilities' joint input assumptions filing, wherein the relevant input assumptions have been provided.

RESPONSE

Confirmed that Exhibit B, Tab 2, Schedule 2, page 4 references Exhibit B, Tab 2, Schedule 6 as containing updated inputs and assumptions. Confirmed that Exhibit B, Tab 2, Schedule 6 directs the reader to EB-2014-0354. Please note that Synapse's recommendation is that Enbridge should indicate the use of the input assumptions within the evaluation plan for any specific offerings where applicable.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

ENBRIDGE INTERROGATORY #7

INTERROGATORY

Reference: Exhibit L.OEBStaff.1, page 29

Preamble:
SEE identifies the multi-family market segment as "underserved."

Question:

a. Please indicate SEE's understanding of the multi-family building market segment in the Greater Toronto Area (Enbridge's largest franchise area). In particular, please indicate SEE's understanding of the size of this market (number of buildings and number of customers), the proportion of the market that has individual gas heating for each unit, and the age and energy efficiency of the housing stock in this market segment.
b. Did Synapse review Enbridge's historical DSM results to inform its conclusion that, relative to overall spending and savings in recent years, the multi-family market has been disproportionately underrepresented?

RESPONSE

a. Synapse was tasked with reviewing the proposed DSM programs and commenting on the program design elements that could be modified or improved. Synapse was not asked to evaluate energy efficiency potential for the multi-family building market segment. Therefore, the requested information is beyond the scope of our work.

   However, in the spirit of providing complete information, we offer the following.

   In our experience, the multi-family market segment is underserved by energy efficiency programs across North America. This is due to split incentives between renters and owners, financial barriers, and building owners facing limited time and technical ability when deciding to invest in energy efficiency resources. Our recommendations are based on our review of the proposed offering by the Ontario gas utilities and best practices in other jurisdictions to serve this underserved market segment. See a 2013 report by ACEEE titled "Apartment Hunters: Programs Searching for Energy Savings in Multifamily Buildings" for the characterization of the underserved multifamily market segment and best practices to overcome some of the barriers faced in this market segment, available at http://aceee.org/research-report/e13n.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

However, the most recent gas energy efficiency potential study for Enbridge's jurisdiction finds that the multi-family market segment has significant energy savings potential in Ontario (See Enbridge's Plan, Exhibit C, Tab 1, Schedule 1). This study reveals that the multi-family segment is the second largest customer segment in terms of potential savings, accounting for 17% to 18% of the total economic and achievable potential within the entire commercial sector (Exhibit C, Tab 1, Schedule 1, pages 78 and 114).

b. See Exhibit M.Staff.EGDI.7, part a.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

ENBRIDGE INTERROGATORY #8

INTERROGATORY

Reference: Exhibit L.OEBStaff.1, page 59

Preamble:
References and comparisons between Enbridge's program delivery, partners and incentives, have been made to weatherization programs such as WarmChoice and Massachusetts' Low Income Retrofit Program offered in US jurisdictions. The U.S. Department of Energy's Weatherization Assistance Program (WAP) is the foundation for these programs. The utilities that operate these programs act as program administrators.

WAP began in 1976 and is delivered by a network of community based agencies, as provided by federal law. In the state of Massachusetts, the network was formalized under Massachusetts law by the Restructuring Act of 1997 (effective March 1998). The Act specifically provided that "the low income residential demand-side management and education programs shall be implemented through the low-income weatherization and fuel assistance program network and shall be coordinated with all electric and gas distribution companies in the commonwealth with the objective of standardizing implementation".[6]

Question:
For the programs and utilities cited, please provide the following:

a. Program results, associated costs, and cost effectiveness ratios of these programs; and
b. Funding contributions of the utilities, state governments, and federal government respectively.

RESPONSE

a. Please see pages 173-177 and 194-197 of Nowak, S., Kushler, M., Witte, P., & York, D. (2013). Leaders of the Pack: ACEEE's Third National Review of Exemplary Energy Efficiency Programs, available at http://aceee.org/research-report/u132.

b. Program-specific low income funding source data is not readily available in energy efficiency annual reports. For data on low income funding sources by state, please see tables 1, 3, and 7 in the *National Association for State Community Services Programs. 2014. Weatherization*

[6] Limited-Income Energy Efficiency Programs in Four States: Massachusetts, Arkansas, Ohio and Washington , ,Prepared for the Maryland Department of Housing and Community Development by Jerrold Oppenheim and Theo MacGregor, Democracy and Regulation, October 11, 2011.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

Assistance Program Funding Survey PY 2013, available at http://www.waptac.org/data/files/website_docs/reports/funding_survey/nascsp-2013-wap-summary_final_spread.pdf

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

ENBRIDGE INTERROGATORY #9

INTERROGATORY

Reference: Exhibit L.OEBStaff.1, page 64

Preamble:
Regarding the utilities' low income multi-family incentives, Synapse notes that "Enbridge's incentive for custom measures is $0.40/m3…while Union's is $0.10/m3."

Question:

a. Please identify whether each utility's incentive level is relevant to annual m3 savings or cumulative / lifetime m3 savings.
b. If different from each other, please provide a revised analysis wherein the incentive levels are comparable, stating any assumptions necessary.

RESPONSE

a. We now understand that Union's cost of saved energy is in terms of lifetime savings, while Enbridge's cost of saved energy is in terms of annual savings.

b. The cost of saved energy values indicated in the referenced section of the report were taken directly from the utilities plans, and Synapse did make any calculations to determine those values (see Enbridge Plan, Exh. B, Tab 2, Sch. 1, p. 34; and Union Plan, Exh. A, Tab 3, App. A, p. 84). In order to provide the data requested by this question, we used the data filed in the utilities' plans to calculate the cost of lifetime saved energy and the cost of annual saved energy.

   Please refer to the table below, which provides incentive costs, lifetime savings, annual savings, and the cost of both lifetime and annual saved energy for each utilities' 2016 Low Income Multi-Family offerings, including both custom and prescriptive measures. The data filed in the utilities' plans was not broken out by custom and prescriptive measures to be able to isolate for custom measures. Therefore, the cost of saved energy values in the table below cannot be directly compared to the referenced section of the report.

   We note that the table below confirms that there is a significant difference between Enbridge's cost of saved energy ($0.62 for annual savings) and Union's cost of saved energy ($2.63 for annual savings).

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

Metric	Enbridge	Union	Enbridge Source	Union Source
Incentive ($)	2,426,481	2,651,000	Exhibit I. T3. EGDI.EP.18	Exh. A, Tab 3, App. A p 87, Table 27
Lifetime Savings (m^3)	58,969,452	17,141,672	Exhibit I.T2.EGDI.STAFF.7	Exh. A, Tab 3, App. A p 89, Table 31
Annual Savings (m^3)	3,931,297	1,007,217	Exhibit I.T2.EGDI.STAFF.7	Exh. A, Tab 3, App. A p 89, Table 30
Incentive / Lifetime Savings ($\$/m^3$)	0.041	0.155	Calculation	Calculation
Incentive / Annual Savings ($\$/m^3$)	0.617	2.632	Calculation	Calculation

Please also see Exhibit M.Staff.UNION.9 and Exhibit M.Staff.EP.12.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

ENBRIDGE INTERROGATORY #10

INTERROGATORY

Reference: Exhibit L.OEBStaff.1, page 67

Preamble:
SEE recommends that Enbridge consider offering Union Gas's aboriginal program.

Question:
Please confirm that SEE reviewed Enbridge's geographic territory and understood that it does not currently contain any aboriginal communities.

RESPONSE

We now understand that Enbridge's geographic territory does not include any First Nations reserves, which is the target market for Union's Aboriginal Offering. We also assume, though it is not specified in the filings, that Aboriginal people who live throughout Enbridge and Union's service territory are eligible for energy efficiency upgrades through the Residential and Low Income offerings.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

ENBRIDGE INTERROGATORY #11

INTERROGATORY

Reference: Exhibit L.OEBStaff.1, page 87

Preamble:
Enbridge is concerned that SEE incorrectly believes the Company is using a "…ratepayer-funded energy efficiency program as a platform for increasing subscription to its presumable proprietary software (and increasing associated revenues)." Enbridge would like to clarify that this has not, and will not be the case.

Question:
Please provide the source for this presumption.

RESPONSE

The above referenced statement was intended to highlight the possibility that Enbridge could promote its energy management software through the free trail to be offered through the Run It Right offering, because Enbridge's description of the offerings was not clear on this point and on other points, as described further in Exhibit L.OEBStaff.1. Synapse appreciates this clarification.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

ENBRIDGE INTERROGATORY #12

INTERROGATORY

Reference: Exhibit L.OEBStaff.1, page 109

Preamble:
SEE has proposed that the gas utilities consider "…offering standard program design templates that electric utilities could select from."

Question:

a. Has SEE contacted any Ontario electric utility or the IESO to evaluate interest or workability of this approach?
b. Has SEE reviewed the Minister's Directive on Conservation and Demand Management issued on March 31, 2014 that provided LDCs control over the design and delivery of their programs?

RESPONSE

a. No, Synapse did not contact any Ontario electric utility or the IESO to evaluate interest or workability of this approach.

b. Synapse had not reviewed the March 31, 2014 Minister's Directive on Conservation and Demand Management ("Minister's Directive") prior to issuing the report (Exhibit L.OEBStaff.1). However, based on a review of the Minister's Directive at this time, the conclusions of the Synapse report would not be materially different had Synapse reviewed the directive previously.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

ENBRIDGE INTERROGATORY #13

INTERROGATORY

Reference: Exhibit L.OEBStaff.1, page 30 and pages 112-115

Preamble:
On page 30 of the report, SEE recommends that "Both utilities should provide customers with zero or low interest financing to address lack of funding".

Question:

a. With the above recommendation in mind, please discuss the appropriateness of the Ontario gas utilities offering ratepayer-funded financing, when there are currently private-sector parties offering loans for home improvement activities, and when some of those parties allow the loan to be included as a third-party charge on the Enbridge bill (through the Open Bill program).
b. Please also explain how Enbridge would be kept whole from the risk of a borrower defaulting on its loan and from the associated collection and enforcement costs.

RESPONSE

a. It may be appropriate for the Ontario gas utilities to offer ratepayer-funded financing. For example, utilities can offer financing to some customers who may not be eligible for private-sector financing. Further, the Ontario gas utilities could buy down interest rates from both private-sector loans and utility-offered loans.

b. Experience to date suggests that default risks associated with energy efficiency programs are very low. Please see SEEAction's 2014 Report entitled Financing Energy Improvements on Utility Bills: Market Updates and Key Program Design Considerations for Policymakers and Administrators, available at: https://www4.eere.energy.gov/seeaction/system/files/documents/onbill_financing.pdf. Table ES - 1 titled Summary Statistics for Surveyed On-Bill Programs on page xi summarizes the default rates.

   Loan loss reserves can be established using public funds to keep the utility whole in the event of defaults. With regard to funding such a loan loss reserve, as noted at Exhibit L.OEBStaff.1, page 2 and in Exhibit M.Staff.EGDI.4, the utilities should consider and balance potential improvements on participation rates, energy savings, cost-effectiveness from improved financing opportunities with a potential increase or decrease in budgets, and determine how to proceed within their constraints.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

ENBRIDGE INTERROGATORY #14

INTERROGATORY

Reference: Exhibit L.OEBStaff.1, page 116

Question:
In defining “Net Savings”, please clarify the meaning and/or what is included in “energy efficiency standards” within this definition.

RESPONSE

The net savings definition was adopted from the Northeast Energy Efficiency Partnerships’ “Glossary of Terms, Version 2.1,” issued in July 2011 (see pages 23-24). That report does not define nor clarify the meaning of “energy efficiency standards.”

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

ENBRIDGE INTERROGATORY #15

INTERROGATORY

Reference: Exhibit L.OEBStaff.1, page 128

Question:
Please provide the report by Neme & Grevatt relating to the deferral of utility infrastructure through targeted DSM.

RESPONSE

Please refer to Exhibit M.Staff.EGDI.15, Attachment 1. This report is listed in the Reference section of the report,[7] and can be accessed here: http://www.neep.org/energy-efficiency-transmission-and-distribution-resource-using-geotargeting-report-0

[7] See Neme, C., & Grevatt, J. (2015). *Energy Efficiency as a Transmission and Distribution Resource: Lessons from Recent U.S. Efforts to Use Geographically Targeted Efficiency Programs to Defer T&D Investments.*

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

Northeast Energy Efficiency Partnerships

Energy Efficiency as a T&D Resource:

Lessons from Recent U.S. Efforts to Use Geographically Targeted Efficiency Programs to Defer T&D Investments

January 9, 2015

Chris Neme & Jim Grevatt, Energy Futures Group

ENERGY FUTURES GROUP

About NEEP & the Regional EM&V Forum

REGIONAL EVALUATION,
MEASUREMENT & VERIFICATION FORUM

NEEP was founded in 1996 as a non-profit whose mission is to serve the Northeast and Mid-Atlantic to accelerate energy efficiency in the building sector through public policy, program strategies and education. Our vision is that the region will fully embrace energy efficiency as a cornerstone of sustainable energy policy to help achieve a cleaner environment and a more reliable and affordable energy system.

The Regional Evaluation, Measurement and Verification Forum (EM&V Forum or Forum) is a project facilitated by Northeast Energy Efficiency Partnerships, Inc. (NEEP). The Forum's purpose is to provide a framework for the development and use of common and/or consistent protocols to measure, verify, track, and report energy efficiency and other demand resource savings, costs, and emission impacts to support the role and credibility of these resources in current and emerging energy and environmental policies and markets in the Northeast, New York, and the Mid-Atlantic region.

About Energy Futures Group

ENERGY FUTURES GROUP

EFG is a consulting firm that provides clients with specialized expertise on energy efficiency markets, programs and policies, with an emphasis on cutting-edge approaches. EFG has worked with a wide range of clients – consumer advocates, government agencies, environmental groups, other consultants and utilities – in more than 25 states and provinces.

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This report benefitted from the contributions of the many professionals who are designing, implementing, testing, and regulating the use of energy efficiency and other non-wires approaches as alternatives to traditional T&D construction. We especially thank the following for giving us their assistance:

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- Chuck Cohen & colleagues, Maine Public Utilities Commission;
- Beth Nagusky, formerly Environment Northeast;
- Dan Blais, GridSolar;
- Ian Barnes, Efficiency Maine;
- Jeff Schlegel, Schlegel & Associates;
- Marco Padula, NY Public Service Commission;
- Nita Zimmerman and colleagues, Bonneville Power Administration
- Eric Winkler, ISO New England
- Sharon Daly, MA Department of Public Utilities

The generous contributions of time and knowledge from those listed above made the report possible, but any fault for errors or mischaracterizations that it may contain lies with the authors alone.

[1] See: http://www.neep.org/sites/default/files/EMV-Forum_Geotargeting_Subcommittee-List_12-5-14.pdf.

I. Introduction

Improvements in the efficiency of energy use in homes and businesses can provide substantial benefits to the consumers who own, live in and work in the buildings. They can also reduce the need for capital investments in electric and gas utility systems – benefits that accrue to all consumers whether or not they participate in the efficiency programs. This report focuses on the role efficiency can play in deferring utility transmission and distribution (T&D) system investments. In particular, it addresses the role that intentional targeting of efficiency programs to specific constrained geographies – either by itself or in concert with demand response, distributed generation and/or other "non-wires alternatives" (NWAs)[2] – can play in deferring such investments. The report focuses primarily on electric T&D deferral, since that is where efforts in this area have focused to date. However, the concepts should be equally applicable to natural gas delivery infrastructure.

The report builds on a report published by the Regulatory Assistance Project (RAP) nearly three years ago.[3] Selected portions of the text of the RAP report – particularly for older case studies for which no update was necessary – have been re-used here. Several of the case studies highlighted in the RAP report have evolved considerably in the intervening years. There are also new case studies on which to report. This report documents these experiences and highlights some important new developments in the field that the recent experience has brought to light. In addition, to address the interests of the Regional EM&V Forum project funders, this report also includes an explicit set of policy recommendations or "guidelines".

The remainder of the report is organized as follows:

> **Section II: Efficiency as a T&D Resource** – summarizes the magnitude and drivers of T&D investment in the U.S., and provides an introduction to the concept of geo-targeting efficiency programs to defer some such investments.
>
> **Section III: Summaries of Examples** – provides high level summaries of about a dozen examples across the U.S. in which geographically targeted efficiency has been employed and/or is in the process of being employed, either alone or in combination with other NWAs, in order to defer more traditional T&D investments.

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[2] We use the term "non-wires alternatives" (NWAs) throughout this paper when referring to a range of alternatives to investment in the T&D system. That term is synonymous with "non-wires solutions", "non-transmission alternatives" (when referring to just the transmission portion of T&D), "grid reliability resources", "distributed energy resources", and other terms sometimes used by other parties. It should be noted that "non-wires" is an imperfect, "shorthand" term that is intended to refer to alternatives to a wide range of traditional T&D infrastructure investments, many of which – e.g. substations and/or transformers – are not really "wires".

[3] Neme, Chris and Rich Sedano, *"U.S. Experience with Efficiency as a Transmission and Distribution System Resource"*, Regulatory Assistance Project, February 2012.

Section IV: Detailed Case Studies – provides more detailed discussions of four of those examples which offer unique insights.

Section V: Cross-Cutting Observations and Lessons Learned – summarizes key conclusions the authors have drawn from the case studies examined in the report.

Section VI: Policy Recommendations – presents four policies that state governments should consider pursuing if they would like to effectively advance consideration of non-wires alternatives to traditional T&D investments.

Section VII: Bibliography – provides a list of all of the documents referenced in the report.

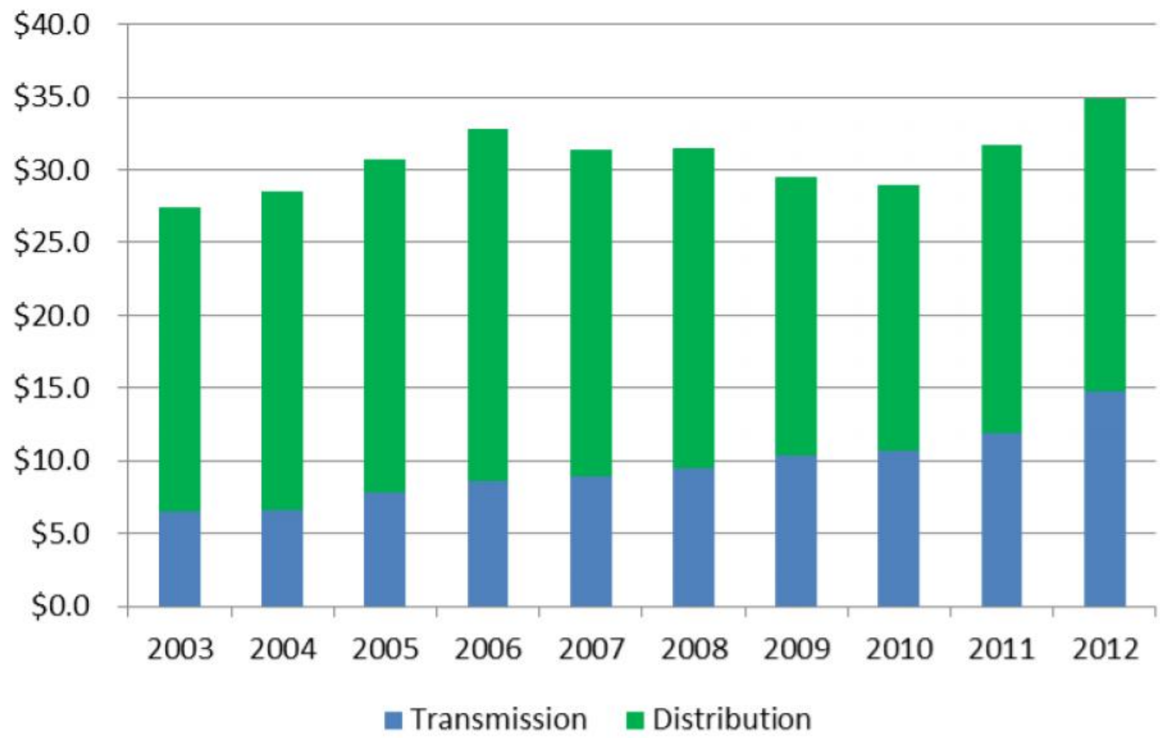
Appendices – contain excerpts from legislation in Vermont, Maine and California; regulatory standards for Rhode Island; and screening forms for Vermont that underpin those states' current requirements to consider and, where appropriate, promote non-wires alternatives.

II. Energy Efficiency as a T&D Resource

Context – Historic and Future Electric Utility T&D Investments

As Figure 1 shows, T&D investments by investor-owned electric utilities, which collectively account for approximately two-thirds of electricity sales in the U.S., have averaged a little more than $30 billion a year over the past decade. If public utilities[4] were investing at a comparable rate, total national investment would have been on the order of $45 billion per year.

Figure 1: T&D Investment by U.S. Investor-Owned Utilities (Billions of 2012 Dollars)[5]



That level of investment is expected to continue or increase in the future, with studies suggesting that the industry will spend an average of roughly $45 billion per year over the next two decades.[6,7] That would represent approximately 60% of forecasted utility capital investment.[8]

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[4] Public utilities include municipal utilities, rural electric cooperatives and the Tennessee Valley Authority.
[5] Edison Electric Institute, Statistical Yearbook of the Electric Power Industry 2012 Data, Table 9.1.
[6] Chupka, Marc et al. (The Brattle Group), *Transforming America's Power Industry: The Investment Challenge 2010-2030*, prepared for the Edison Foundation, November 2008. Harris Williams & Co., *Transmission and Distribution Infrastructure*, a Harris Williams & Co. White Paper, Summer 2014 (http://www.harriswilliams.com/sites/default/files/industry_reports/ep_td_white_paper_06_10_14_final.pdf?cm_mid=3575875&cm_crmid=e5418e44-29ef-e211-9e7f-00505695730e&cm_medium=email)
[7] Note that the ultimate cost to electric ratepayers may be significantly greater, since ratepayers will pay a rate of return on all investments made by regulated utilities.
[8] Chupka, Marc et al. (The Brattle Group), *Transforming America's Power Industry: The Investment Challenge 2010-2030*, prepared for the Edison Foundation, November 2008.

As discussed below, only a portion of T&D investment could potentially be deferred through deployment of energy efficiency and/or other non-wires alternatives. Data on the portion of U.S. T&D investment that might be deferrable are not currently available.

When Efficiency Programs Can Affect T&D Investments

T&D investments are driven by a number of different factors. Among these are:

- The need to replace aging T&D infrastructure;
- The need to address unexpected equipment failures;
- The need to connect new generation – this is particularly important for renewable electric generation that is often sited in somewhat remote locations, but can also be true for other types of electric generation;
- A desire to provide access to more economic sources of energy and peak capacity; and
- The need to address load growth.

Needless to say, some of these needs would not be significantly affected by the customer investments in energy efficiency or the programs that promote such investments. In particular, investments related to the condition of a T&D asset – whether equipment has failed due to a defect or natural disaster or whether it is just too old and/or has become insufficiently reliable – are largely unaffected by the level of end use efficiency. In that context, it is worth noting that one of the reasons some are predicting national investment in electric T&D infrastructure to be substantial in the coming years is that much of the existing infrastructure is old. For example, it is estimated that approximately 70% of transformers are over 25 years old (relative to a useful life of 25 years), 60% of circuit breakers are over 30 years old (relative to a useful life of 20 years), 70% of transmission lines are 25 years old or older ("approaching the end of their useful life"), and more than 60% of distribution poles were installed 40 to 70 years ago (i.e. are approaching or have surpassed expected useful life of 50 years).[9] All told, the electric utility industry has estimated that between 35% and 48% of T&D assets either currently or will soon need to be replaced simply because of their age and/or condition.[10]

On the other hand, energy efficiency programs can defer T&D investments whose need is driven, at least in part, by economic conditions and/or growing peak loads. In that context, it is important to note that even if total electricity sales are not growing, peak load may be. Also, even if peak loads in a region are not growing *in aggregate*, they may be growing in a portion of the region to the point where they may be putting stress on the system.

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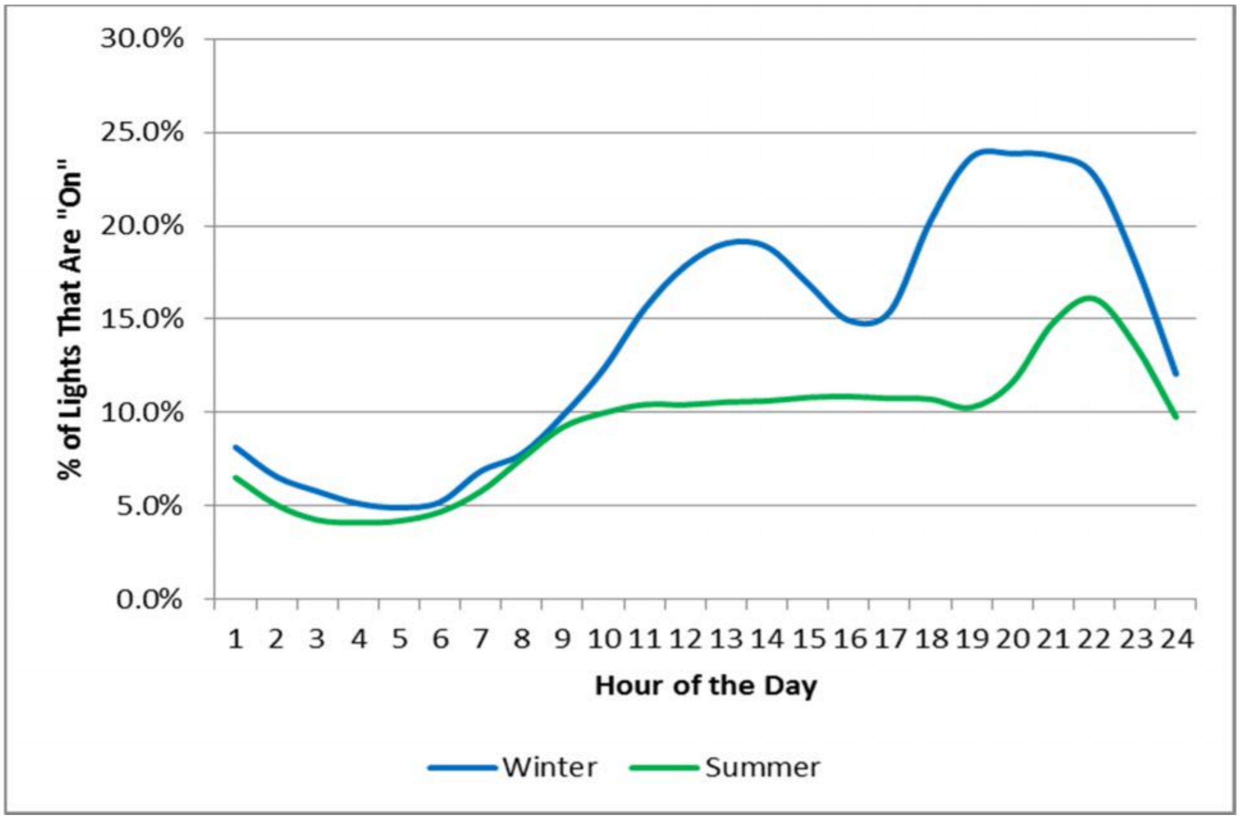
[9] Harris Williams & Co., *Transmission and Distribution Infrastructure*, a Harris Williams & Co. White Paper, Summer 2014 (http://www.harriswilliams.com/sites/default/files/industry_reports/ep_td_white_paper_06_10_14_final.pdf?cm_mid=3575875&cm_crmid=e5418e44-29ef-e211-9e7f-00505695730e&cm_medium=email).
[10] Ibid.

How Efficiency Programs Can Affect T&D Investments

Different elements of the T&D system can experience peak demand at different times of day and even in different seasons. Thus, the extent to which an efficiency program can help defer a T&D investment will depend on the hour and season of peak and the hourly and seasonal profile of the efficiency program's savings. For example, as shown in Figure 2, a program to promote the sale and purchase of compact fluorescent light bulbs (CFLs) provides some energy savings during every hour of the day (when sales are spread across many thousands of customers), but greater savings in winter than in summer and more savings in the evening than during the day.

Figure 2: Average Hourly CFL Usage Patterns[11]



Because different programs provide different levels of savings at different times and in different seasons, the *mix* of efficiency programs also matters. For example, as Table 1 illustrates, the same hypothetical mix of efficiency programs would have different impacts on three hypothetical electric substations which experience peak demands in different seasons and during different times of day because of the different mixes of customers that they serve. However, it is also worth noting that the differences across the portfolio of programs is not as great as across

[11] Nexus Market Research, *Residential Lighting Markdown Impact Evaluation*, submitted to Markdown and Buydown Program Sponsors in Connecticut, Massachusetts, Rhode Island and Vermont, January 20, 2009 (from Figures 5-1 and 5-2).

any individual program. This is the result of diversification, as the lower impact from one program is offset by a higher impact from another at the time of a given substation peak.

Table 1: Hypothetical Efficiency Program Portfolio Impacts on Different Substation Peaks

Substation	Customer Mix	Peak Season	Peak Hour	Annual Peak MW Savings by Program			
				Residential CFLs	Residential A/C	Commercial Lighting Retrofits	Total
A	Primarily Business	Summer	3:00 PM	0.4	0.9	0.7	2.0
B	Primarily Residential	Summer	7:00 PM	0.4	1.4	0.3	2.1
C	Primarily Residential w/Electric Heat	Winter	7:00 PM	1.0	0.0	0.4	1.4

Finally, the level of savings that the mix of programs provides also has important implications for whether any T&D investment deferral is possible and, if it is, how long a deferral the efficiency programs will provide. This is illustrated in the hypothetical example depicted in Table 2. In this example, the existing electric substation load is 90 MW and its maximum capacity is 100 MW, so capacity will need to be added by the year load is projected to exceed that level. The first scenario depicted is one in which there are no efficiency programs offered to customers served by the substation (i.e. a “business as usual” scenario). It assumes 3% annual growth in substation peak load. The other three scenarios depict different levels of efficiency program savings, presented in increments of 0.5 percentage point reductions in annual peak load growth relative to the “business as usual” or “no efficiency” scenario. In this example, the substation capacity would need to be upgraded in four years (2018) in the business as usual scenario. The degree to which the efficiency programs defer the need for the upgrade varies with the level of savings achieved, ranging from a one year deferral (to 2019) for savings sufficient to reduce the peak growth rate by 0.5% each year (i.e. from 3.0% to 2.5%) to an eight year deferral (to 2026) for savings sufficient to reduce the peak growth rate by 2.0% annually (i.e. from 3.0% to 1.0%). Clearly, if savings were greater than 2.0% per year, the need for the substation upgrade would be deferred beyond the time horizon depicted in the table.

Table 2: Illustrative Impact of Savings Level (MW) on Deferral of Substation Upgrade

Level of Savings	Net Growth Rate	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
No EE programs	3.0%	90	93	95	98	101	104	107	111	114	117	121	125	128
0.5% savings/year	2.5%	90	92	95	97	99	102	104	107	110	112	115	118	121
1.0% savings/year	2.0%	90	92	94	96	97	99	101	103	105	108	110	112	114
1.5% savings/year	1.5%	90	91	93	94	96	97	98	100	101	103	104	106	108
2.0% savings/year	1.0%	90	91	92	93	94	95	96	96	97	98	99	100	101

Passive Deferrals vs. Active Deferrals

Energy efficiency programs can lead to deferrals of T&D investments in two ways: passive deferral and active deferral. We define those two concepts as follows:

> **Passive deferral**: when system-wide efficiency programs, implemented for broad-based economic and/or other reasons rather than with an intent to defer specific T&D projects, nevertheless produce enough impact to defer specific T&D investments.
>
> **Active deferral**: when geographically-targeted efforts to promote efficiency – *intentionally designed to defer specific T&D projects* – meet their objectives.

Passive deferrals, almost by definition, will occur to some degree in any jurisdiction that has system-wide efficiency programs of any significance. However, as noted above, the degree and value of passive deferral will obviously be heavily dependent on the scale and longevity of the programs. The benefits may be modest, deferring a small number of planned investments a year or two. They can be also quite substantial. For example, Consolidated Edison (Con Ed), the electric utility serving New York City and neighboring Westchester County, recently estimated that including the effects of its system-wide efficiency programs in its 10-year forecast reduced capital expenditures by more than $1 billion.[12] Similarly, since it began integrating long-term forecasts of energy efficiency savings into its transmission planning in 2012, the New England ISO has identified over $400 million in previously planned transmission investments in New Hampshire and Vermont that it is now deferring beyond its 10 year planning horizon.[13]

The benefits of such passive deferrals are sometimes reflected in average statewide or utility service territory-wide avoided T&D costs. Such avoided costs – along with avoided costs of energy and system peak capacity – are commonly used to assess whether efficiency programs are cost-effective (usually a regulatory requirement for funding approval). At the most general level,

[12] Gazze, Chris and Madlen Massarlian, "Planning for Efficiency: Forecasting the Geographic Distribution of Demand Reductions", in *Public Utilities Fortnightly*, August 2011, pp. 36-41.
[13] The initial March 2012 estimate was $265.4 million in deferred projects. In June 2013 an additional $157 million in projects was deferred (Personal communication from Eric Wilkinson, ISO New England, 11/6/14. Also see: George, Anne and Stephen J. Rourke (ISO New England), "ISO on Background: Energy Efficiency Forecast", December 12, 2012; and ISO New England, 2013 Regional System Plan, November 7, 2013).

estimates of avoided T&D costs are typically developed by dividing the portion of forecast T&D capital investments that are associated with load growth (i.e., excluding the portion that is associated with replacement due to time-related deterioration or other factors that are independent of load), by the forecast growth in system load. Such estimates can vary considerably, often as a function of the utilities' assumptions regarding how much investment is deferrable. For example, in New England, utility estimates of avoided T&D costs currently range from about $30 per kW-year (CL&P) to about $200 per kW-year (National Grid – Massachusetts).[14]

Like passive deferrals, the benefits of active deferrals are a function of the value of each year of deferral and the length of the deferral. However, because the deferral of a specific T&D investment is the primary objective rather than by-product of the efficiency programs, benefits are always very project-specific. Examples of such benefits are provided in the following sections of this report.

It is important to recognize that deferred T&D investments – whether passive or active – are a subset of the benefits of the efficiency programs that produced the deferral. Efficiency programs always also provide energy savings to participating customers, reductions in line losses, and environmental emission reductions. They also typically provide system peak capacity savings, reduced risk of exposure to fuel price volatility and, particularly in jurisdictions with competitive energy and/or capacity markets, price suppression benefits.

Applicability to Natural Gas Infrastructure

Though this report focuses primarily on the role that efficiency programs can play in actively deferring *electric* T&D investments, the concepts are just as applicable to gas T&D infrastructure investments. That is, natural gas efficiency programs are likely to be passively deferring some gas T&D investments and, under the right circumstances – e.g. for load-related T&D needs, with enough lead time, etc. – should be viable options for deferring some gas T&D investments.

The passive deferral benefits of gas efficiency programs have either not been widely studied or not been widely publicized. However, there are at least a couple of examples worth noting. First, Vermont Gas Systems (VGS) routinely includes the impacts of its efficiency programs in its integrated resource planning (IRP). As noted in its revised 2012 IRP, efficiency programs are forecast to not only reduce gas purchases, but also contribute to "delayed transmission investment during the term of (the) plan."[15] In its 2001 plan, VGS was even more explicit, concluding that its efficiency programs would produce sufficient peak day savings to delay implementation of at least one transmission system looping project by one year.[16]

[14] Hornby, Rick et al. (Synapse Energy Economics), *Avoided Energy Supply Costs in New England: 2013 Report*, prepared for the Avoided Energy Supply Component (AESC) Study Group, July 12, 2013.
[15] Vermont Gas Systems, Inc., *REVISED Integrated Resource Plan*, 2012.
[16] Vermont Gas Systems, Inc., *Integrated Resource Plan*, 2001.

We are not aware of any publicly available documentation of examples in which a gas utility has used geographically-targeted efficiency programs to *actively defer* a T&D investment. However, there may be growing interest in this topic. For example, following a hotly contested proceeding on a very large gas pipeline project, the Ontario Energy Board recently concluded that geographically-targeted efficiency and demand response programs might have been able to mitigate the need for a portion of the project designed to meet growing loads in downtown Toronto, but "significant uncertainties", mostly related to time limitations and to Enbridge Gas' (the local gas utility's) lack of information on and experience with assessing peak demand impacts of its efficiency programs, led it to approve the project as proposed. However, the Board also stated that "further examination of integrated resource planning" is warranted and that it "expects applicants to provide more rigorous examination of demand side alternatives" in all future proposals for significant T&D investments.[17] In a very different context, some parties have suggested that geographic targeting of gas efficiency programs to areas near gas-fired electric generating stations could help alleviate pipeline congestion that is driving up the winter cost of electricity in parts of New England.[18] It is conceivable that such efforts might also help defer the need for some gas T&D investments.

NEEP will be undertaking a 2015 scoping project to document what gas system planners would need to assess the potential viability of demand-side alternatives to gas T&D investments.

[17] Ontario Energy Board, *Decision and Order*, EB-2012-0451, in the matter of an application by Enbridge Gas Distribution, Inc. Leave to Construct the GTA Project, January 30, 2014.
[18] Schlegel, Jeff, "Winter Energy Prices and Reliability: What Can EE Do to Help Mitigate the Causes and Effects on Customers", June 11, 2014.

III. Summaries of Examples

Though far from widespread, a number of jurisdictions have tested and/or are in the process of testing the role that geographically-targeted efficiency programs could play in cost-effectively deferring electric T&D investments. In this section of the report we briefly summarize examples of such efforts from ten different jurisdictions. More detailed discussion of some of these examples follows in the next section.

Bonneville Power Administration (under consideration in 2014)

The Bonneville Power Administration (BPA) has periodically considered energy efficiency and other non-wires alternatives to transmission projects over the past two decades. One notable example was in the early 1990s. At the time the Puget Sound area received more than three-quarters of its peak energy (i.e., during times of high demand for electric heat) via high voltage transmission lines that crossed the Cascade mountain range. BPA studies concluded the region could experience a voltage collapse – or blackout or brownout – if one of the lines failed during a cold snap.[19] The level of risk "violated transmission planning standards."[20] The traditional option for addressing this reliability concern would have been to build additional high voltage transmission lines over the Cascades into the Puget Sound area. However, BPA and the local utilities chose instead to pursue a lower cost path that included adding voltage support to the transmission system (e.g., "series capacitors to avoid building additional transmission corridors over the Cascades") and more intensive deployment of energy efficiency programs that focused on loads that would help avoid voltage collapse. The voltage support was by far the most important of these elements.[21] The project, known as the Puget Sound Area electric Reliability Plan, ended up delaying construction of expensive new high voltage transmission lines for at least a decade.[22] Indeed, no new cross-Cascade transmission lines have been built to date.[23]

Several years later, BPA invested in a substantial demand response initiative in the San Juan Islands to address reliability concerns after the newest of three underwater cables bringing power to the islands was accidentally severed. The initiative ran for five years and succeeded in keeping loads on the remaining cables at appropriate levels until a new cable was added.

[19] U.S. Department of Energy, Bonneville Power Administration, Public Utility District Number 1 of Snohomish County, Puget Sound Power & Light, Seattle City Light and Tacoma City Light, "Puget Sound Reinforcement Project: Planning for Peak Power Needs", Scoping report, Part A, Summary of Public Comments, July 1990.
[20] Bonneville Power Administration Non-Construction Alternatives Roundtable, "Who Funds? Who Implements?" Subcommitee, "Non-Construction Alternatives – A Cost-Effective Way to Avoid, Defer or Reduce Transmission System Investments", March 2004.
[21] Indeed, though the plan included additional investments in efficiency, the additional capacitors, coupled with the addition of some local combustion turbines, were likely enough to defer the transmission lines even without the additional efficiency investments (personal communication with Frank Brown, BPA, 11/7/11).
[22] Bonneville Power Administration, "Non-Wires Solutions Questions & Answers" fact sheet.
[23] The system has been significantly altered over the past two decades as a result of substantial fuel-switching from electric heat to gas heat, the addition of significant wind generating capacity (much of it for sale to California) and other factors. Thus, today, BPA has more "North-South issues" than "East-West issues" (personal communication with Frank Brown, BPA, 11/7/11).

Although BPA has since commissioned several studies to assess non-wires alternatives to traditional transmission projects, it has not yet pursued any additional now-wires projects. BPA is currently in the process of rebooting and revamping their corporate approach to non-wires alternatives. That has included a restructuring of where this function is situated within the organization. Prior to 2012 the non-wires team at BPA was part of the Energy Efficiency team, but in early 2013 it became a corporate level function in an attempt to better integrate strategic planning for non-wires approaches across the organization by bridging the energy efficiency and resource planning functions.

BPA is also re-assessing the threshold criteria used to determine whether a project might be a good candidate for a non-wires approach. In the past, projects needed to be planned to be at least eight years in the future, and have a cost of at least $5M to be considered for a non-wires alternative. Currently the BPA team feels that an eight-year lead time is too long, because it allows too much time for projects to change in significant ways before they would be implemented. With this in mind they are now focusing on projects that are planned for five years out, feeling that this allows sufficient time to deploy non-wires resources while still providing greater surety that the project's expected need is reasonable. BPA has also reduced its minimum cost threshold from $5M to $3M.

The lead time and cost criteria are used as a "stage one" filter to identify potential NWA candidate projects. Once stage one selection is complete, a "stage two" analysis is undertaken. In stage two analysis BPA considers more specifically the types of customers in the affected load areas, and identifies the types of non-wires alternatives that could potentially be applicable and effective. Once this team has identified strong project candidates, recommendations are made to the executive team regarding projects to pursue. Once executive approval is obtained, the project would then move to a different branch of BPA for execution.

As in the Northeast there are significant unanswered questions about how future non-wires alternatives to transmission projects will be funded. Currently, transmission construction projects are socialized over a large customer base, but a similar cost-allocation mechanism has not yet been identified that would allow costs of non-wires alternatives to be similarly allocated. BPA is currently considering approaches to address this issue.

California: PG&E (early 1990s pilot, new efforts in 2014)

One of the most widely publicized of the early T&D deferral projects was the Pacific Gas and Electric (PG&E) Model Energy Communities Program, commonly known as the "Delta project". The project ran from July 1991 through March 1993. Its purpose was to determine whether the need for a new substation that would otherwise be required to serve a growing "bedroom community" of 25,000 homes and 3000 businesses could be deferred through intensive efficiency investments. The largest portion of the project's savings was projected to come from a residential retrofit program targeted to homes with central air conditioning. Under the initial design, participating homes would receive free installation of low cost efficiency measures (e.g., CFLs, low flow showerheads, water heater blankets) during an initial site visit and be scheduled for follow up work with major measures such as duct sealing, air sealing, insulation, sun screening and air conditioner tune-ups. More than 2700 homes received such major measures. Later, the program changed its focus to promoting early replacement of older, inefficient central air conditioners with new efficient models. Other components of the Delta project included commercial building retrofits, a residential new construction program and a small commercial new construction program.

Evaluations suggested that the project produced 2.3 MW of peak demand savings. The savings did come at a higher cost than expected – roughly $3900 per kW. This can likely be attributed to a couple of key factors. First, the project had an extremely compressed timeframe. It was planned and launched within six months; the implementation phase was less than two years. A second related factor was that some of the efficiency strategies produced much lower levels of savings than initially estimated. Because of the compressed timeframe for the project, the switch in emphasis to the better performing program strategies could not occur early enough to keep total costs per kW at more reasonable levels. For example, the residential shell and duct repair efforts were initially projected to generate nearly 1.8 MW of peak demand savings but, in the end, produced only about 0.2 MW at a cost of over $16,000 per kW. In contrast, the early replacement residential central air conditioners produced 1.0 MW of peak savings – about 2.5 times the original forecast of about 0.4 MW – at a cost of about $900 per kW. The final evaluation of the project suggested that the savings achieved succeeded in deferring the need for the substation for at least two years.[24]

No other projects of this kind appear to have been pursued in California until very recently. Passage of Assembly Bill 327 in October 2013 required utilities to assess the locational benefits and costs of distributed resources (including efficiency), identify economically optimal locations for them, and put in place plans for their deployment. In response, PG&E started looking at specific capacity expansion projects at the distribution substation level that could be deferred if they could reduce load growth. The Company leveraged circuit-specific, 10-year, geo-spatial load forecasts[25] and identified roughly 150 distribution capacity expansion projects that would be needed over the next 5 years— and started developing criteria that would be useful in helping them select the potential deferral projects with the greatest likelihood of success. To narrow down the list, they focused on projects that:

- Were growth related rather than needed because of equipment maintenance issues;
- Had a projected in-service date at least 3 years into the future; and
- Had a projected normal operating deficiency of 2 MW or less at substation level to ensure that they would be realistically achievable in a two-year timeframe.

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[24] Pacific Gas and Electric Company Market Department, *"Evaluation Report: Model Energy Communities Program, Delta Project 1991-1994"*, July 1994.
[25] Using Integral Analytics proprietary "LoadSEER" software.

Applying these criteria reduced the number of projects being considered to about a dozen. PG&E then looked at each of the remaining projects more closely to better understand which customers were connected to those feeders and what their load profiles were like to determine if the needed reductions could be reasonably secured over the next two years. Through this process they ultimately selected four projects for which to deploy non-wires alternatives, including energy efficiency, for 2014-15. By the end of 2015 they expect to be able to show significant progress in developing their understanding of the strengths and potential limitations of these non-wires approaches, which will allow them to better integrate NWA approaches into future planning efforts. This current effort is discussed more thoroughly in the next section – detailed case studies – of this report.

Maine (2012 to present)

In 2010, the Maine Public Utilities Commission approved a settlement agreement reached by Central Maine Power and a variety of other parties regarding a large transmission system upgrade project. A key condition of the settlement was that there would be a pilot project to test the efficacy of non-wires alternatives. The first such pilot was to be in the Boothbay region. Another condition was that the non-wires pilot would be administered by an independent third party. Grid Solar, an active participant in case, was selected to be the administrator.

The Boothbay pilot began in the Fall of 2012 with the release of an RFP designed to procure 2.0 MW of non-wires resources. Rather than solicit a purely least cost mix of resources, the project aimed to ensure that a mix of resource types would be procured and tested by establishing desired minimums of 250 kW for each of four different resource categories: energy efficiency, demand response, renewable distributed generation and non-renewable distributed generation. A second RFP was issued in late May of 2013 after one of the original winning bids withdrew due to challenges in acquiring financing. As of the Summer of 2014, 1.2 MW of non-wires resources, including approximately 350 kW of efficiency resources, were deployed and operational; another 500 kW was expected to be operational by late 2014. Due to revised load forecasts that total of 1.7 MW is all that is now expected to be needed to defer the transmission investment. The cumulative revenue requirement for the non-wires solution is now forecast to be approximately one-third of what the cost would have been for the transmission solution. This project, as well as recent legislation that requires assessment and deployment of less expensive non-wires solutions in the future, is discussed in greater detail in the next section of this report.

Michigan: Indiana & Michigan/AEP (2014)

Indiana and Michigan (I&M), a subsidiary of American Electric Power (AEP), is currently forecasting that it will need to invest in an upgrade to a transformer at its substation in Niles, Michigan. The substation serves about 4400 residential customers, nearly 600 commercial customers and about 60 industrial customers. Peak load on the substation is currently 23.2 MW. It is forecast to grow by about 200 kW per year, though system planners need to address a possibility that peak loads will grow by 5% above normal weather levels – i.e. 210 kW per year.

I&M is currently considering a pilot project to use more aggressive efforts to promote energy efficiency investments to offset load growth and thereby defer the transformer upgrade. The efficiency program offerings would build on the system wide programs that are already offered across I&M's Michigan service territory, including both increased rebates for customers in Niles and more aggressive customer outreach and marketing efforts. There may also be efforts to explore integration of efficiency offerings with promotion of demand response and distributed generation.

Nevada: NV Energy (late 2000s)

In 2008 NV Energy faced a situation in a relatively rural portion of its service territory, east of Carson City, in which growth in demand was going to need to be met by either running the locally situated but relatively expensive Fort Churchill generating station more frequently or constructing a 30 mile, 345 kVA transmission line and new substation to bring less expensive power from the more efficient Tracy generating facility (situated further north, about 20 miles east of Reno) to the region. When the local county commission began expressing concerns about permitting construction of the substation, regulators instructed the Company to increase the intensity of its DSM efforts in the targeted region as an alternative to meeting the area's needs economically:

> *"…the concentration of DSM energy efficiency measures in Carson City, Dayton, Carson Valley and South Tahoe has the potential to reduce the run time required for the Ft. Churchill generation units. The increased marketing costs and increased incentives and subsequent reduction in program energy savings required to attain an increased participation in the smaller market area are estimated to be more than offset by reduced fuel costs. Sierra Pacific, d.b.a. NV Energy, will make a reasonable effort within the approved DSM budget and programs to concentrate DSM activities in this area…"*[26]

NV Energy pursued a variety of efforts to focus its existing efficiency programs more intensely on the Fort Churchill area through increased marketing and, in one case (Commercial building retrofit program), higher financial incentives.[27] It also offered an "Energy Master Planning Service" to the Carson City and Douglas County School districts, though both declined the service. Of these efforts, NV Energy's second refrigerator collection and recycling program (including a new element of CFL distributions) and the commercial retrofit program were together responsible for the vast majority of the increased DSM savings in the region.[28]

At the same time as these efficiency efforts were launched, NV Energy's transmission staff began re-conductoring the existing 120 kVA line to the region to increase its carrying capacity. The economic recession also hit at the same time, dampening growth. As a result, the Company

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[26] Jarvis, Daniel et al., "*Targeting Constrained Regions: A Case Study of the Fort Churchill Generating Area*", 2010 ACEEE Summer Study on Energy Efficiency in Buildings, Volume 5, pp. 178-189
[27] Sierra Pacific Power Company, 2010 Annual Demand Side Management Update Report, July 1, 2010, pp. 6-9.
[28] Ibid. and Jarvis et al.

has not had to revisit the need for either the additional power line and substation or increasing the run time of the Fort Churchill generating station. The project has also facilitated the beginnings of "rich conversations" between demand resource planners and transmission planners within the Company.[29]

New York: Con Ed (2003 to present)

Consolidated Edison (Con Ed), the electric utility serving New York City and neighboring Westchester County, has been perhaps the most aggressive in the US in integrating end use energy efficiency into T&D planning. Geographically targeted investment in efficiency at Con Ed began in 2003, when growth in demand was causing a number of Con Ed's distribution networks to approach their peak capacity. In its initial pilot phase, the Company established contracts with three ESCOs to provide load reductions in nine networks areas: five in midtown Manhattan, three in Brooklyn and one in The Bronx. In subsequent phases, four different ESCOs were contracted to deliver load reductions in 21 additional network areas: 13 in Manhattan, four on Staten Island and four in Westchester County. ESCOs were allowed to bid virtually any kind of permanent load reduction. However, through 2010, the only cost-effective bids submitted and accepted were solely for the installation of efficiency measures. All told, between 2003 and 2010, the Company employed geographically targeted efficiency programs to defer T&D system upgrades in more than one third of its distribution networks. The resulting savings were very close to forecast needs and provided more than $300 million in net benefits to ratepayers.[30] In some cases, the efficiency investments not only deferred T&D upgrades, but bought enough time to allow the utility to refine load forecasts to the point where some of the capacity expansions may never be needed.

After these successful distribution deferral projects were completed in 2012, Con Ed experienced a brief hiatus from non-wires projects simply because there were no distribution upgrade projects being planned that would meet the criteria for non-wires approaches (see detailed case study in following section for discussion of these criteria). That changed in the summer of 2013, when an extended heat wave placed severe capacity pressure on areas of Brooklyn and Queens, causing Con Ed to identify a greatly accelerated need for upgrades to its system in these areas. Con Ed subsequently decided to request approval for approximately $200M in investments to defer distribution system upgrades related to these capacity constraints.

That proposal was also made in the context of strong signals coming from New York's regulators indicating a pending re-structuring of the electric utility industry in the state, with a much greater expectation that in the near future the utilities will be responsible for taking advantage of all available resources for managing the grid in the most economic manner. In

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[29] Personal communication with Larry Holmes, NV Energy, 11/9/11.
[30] Gazze, Chris, Steven Mysholowsky, Rebecca Craft, and Bruce Appelbaum., "Con Edison's Targeted Demand Side Management Program: Replacing Distribution Infrastructure with Load Reduction", in Proceedings of the ACEEE 2010 Summer Study on Energy Efficiency in Buildings, Volume 5, pp. 117-129; updated estimates provided by Chris Gazze, formerly of Con Ed, February 11, 2011.

Commission Staff's view, this includes deploying all manner of Distributed Energy Resources (DERs) to their cost-effective levels. This viewpoint is clearly reflected in ConEd's Brooklyn-Queens filing and the associated RFI that ConEd has issued that includes an extraordinary level of flexibility regarding the creative use of non-wires approaches. The Brooklyn-Queens project is discussed in much greater detail in the following "detailed case studies" section of this report.

New York: Long Island Power Authority (2014)

PSEG Long Island[31] has submitted a proposed long-term plan to the Long Island Power Authority (LIPA) for its approval.[32] The plan includes initiatives designed to defer substantial transmission upgrades in the Far Rockaway region in southern Long Island and the South Fork region in eastern Long Island. Both include a proposed RFP to procure peak load relief, with any type of demand side measure – including energy efficiency – being eligible as long as it is commercially proven, is measurable and verifiable and is not duplicative of other programs already proposed for the areas.

In the case of the Far Rockaway region, the effort would be designed to help defer what would otherwise be a transmission reinforcement between the towns of East Garden City and Valley Stream in 2019. LIPA has already issued and received responses to an RFP for new generation, energy storage and demand response (GSDR) resources which may satisfy some or all of the need in the area. Thus, the proposed new RFP for demand-side resources is essentially a contingency plan. If deployed, it would seek to acquire 25 MW of "guaranteed capacity relief". PSEG Long Island has stated that the RFP process would be similar to Con Ed's process for addressing its Brooklyn-Queens constraint.

In the case of the South Fork region, the effort would be designed to help defer a $294 million capital investment in (primarily) new underground transmission cables and substation upgrades over the next eight years ($97 million by 2017 and the other $197 million through 2022). Approximately 20 MW of coincident peak capacity is needed by 2018, with more required in later years. It is expected that some of this need will be addressed by acquisition of storage resources through the GSDR RFP described above and 21.6 MW (nameplate capacity)[33] of solar PV procured through a different initiative. The RFP for demand side resources would seek at least 13 MW of guaranteed load relief, unless a parallel effort to acquire peak savings through a residential Direct Load Control program RFP acquires enough load control resources in the South Fork area to reduce the need.

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[31] PSEG Long Island is currently contracted to provide all aspects of LIPA's utility services, other than procurement of supply resources. Starting in January 2015, it will also be responsible for supply procurement as well.
[32] PSEG Long Island, *"Utility 2.0 Long Range Plan Update Document"*, prepared for the Long Island Power Authority, October 6, 2014.
[33] That equates to more like 10 MW of coincident peak capacity and even less in early evening hours when demand in the region is still very high (personal communication with Michael Voltz, PSEG Long Island, November 13, 2014).

As of the writing of this report, these efforts are just proposals. They are expected to be considered for approval by the Long Island Power Authority Board in December 2014.[34]

Oregon: Portland General Electric (early 1990s)

In 1992, Portland General Electric (PGE) began planning the launch of a pilot initiative to assess the potential for using DSM to cost-effectively defer distribution system upgrades; implementation began in early 1993.[35] The pilot focused on several opportunities for deferring both transformer upgrades planned for large commercial buildings and grid network system upgrades planned for downtown Portland, Oregon. The projects were identified from a review of PGE's five-year transmission and distribution plan. Though the PGE system was winter-peaking, downtown Portland was summer-peaking so the focus would be on efficiency measures that reduced cooling and other summer peak loads. To be successful, deferrals would need to be achieved in one to three years, with the lead time varying by project. In each case, the value of deferring the capital improvements was estimated. The estimates varied by area, but averaged about $35 per kW-year.[36]

Two different strategies were pursued. In the case of the individual commercial buildings, where peak demand reductions of several hundred kW per building were needed to defer transformer upgrades, the utility relied on existing system-wide DSM programs, but target marketed the programs to the owners of the buildings of interest using sales staff that already had relationships with the building owner or property management firm. For the grid network system objectives, where peak reductions of 10% to 20% for entire 10 to 15 block areas were needed, the utility contracted with ESCOs to deliver savings. The ESCO contracts had two-tier pricing structures designed to encourage comprehensive treatment of efficiency opportunities and deep levels of savings. The first tier addressed savings up to 20% of a building's electricity consumption. The second tier was a much higher price for savings beyond 20%.[37]

The results of the pilot were mixed. For example, savings in one of the targeted commercial buildings was nearly twice what was needed, deferring and possibly permanently eliminating the need for a $250,000 upgrade. However, savings for another building fell short of the amount of reduction needed to defer its transformer upgrade. While other options were being explored to bridge the gap, an unexpected conversion from gas to electric cooling of the building "eliminated any opportunity to defer the upgrade."[38]

The results for the first grid area network targeted were also very instructive. Of the 100 accounts in the area, the largest 20 accounted for more than three-quarters of the load. By

[34] Personal communication with Michael Voltz, PSEG Long Island, November 11, 2014.
[35] Personal communication with Rick Weijo, Portland General Electric, August 10, 2011.
[36] Weijo, Richard O. and Linda Ecker (Portland General Electric), "Acquiring T&D Benefits from DSM: A Utility Case Study", Proceedings of 1994 ACEEE Summer Study on Energy Efficiency in Buildings, Volume 2.
[37] Ibid.
[38] Ibid.

ultimately treating 12 of those 20, the ESCOs contracted by PGE actually succeeded in reducing load through efficiency measures by nearly 25% in just one year. That was substantially more than the 20% estimated to be necessary to defer the need for a distribution system upgrade. However, the utility's distribution engineering staff decided to proceed with construction of the upgrade before the magnitude of the achieved savings was known because they did not have sufficient confidence that the savings would be achieved and be reliable and persistent. It is also worth noting that the utility's marketing staff who were managing the ESCO's work were not even made aware of the decision to proceed with the construction until after it had begun – a telling indication of the lack of communication and trust between those responsible for energy efficiency initiatives and those responsible for distribution system planning.[39]

Despite some notable successes with its pilot, PGE has not subsequently pursued any additional efforts to defer distribution system upgrades through energy efficiency.[40]

Rhode Island: National Grid (2012 to present)

In 2006, Rhode Island adopted a "System Reliability Procurement" policy that required utilities to file plans every three years. Guidelines detailing what to include in those plans were developed by the state's Energy Efficiency and Resource Management Council (EERMC) and National Grid and approved by regulators in 2011 (see Appendix D). The guidelines make clear that plans must consider non-wires alternatives, including energy efficiency, whenever a T&D need meets all of the following criteria:

- It is not based on asset condition;
- It would cost more than $1 million;
- It would require no more than a 20% reduction in peak load to defer; and
- It would not require investment in the "wires solution" to begin for at least 36 months.[41]

For such cases, the plans must include analysis of financial impacts, risks, the potential for synergistic benefits, and other aspects of both wires and non-wires alternatives.

Based on these guidelines, National Grid proposed an initial pilot project in late 2011. The project was designed to test whether geographically targeted energy efficiency and demand response could defer the need for a new substation feeder to serve 5200 customers (80% residential, the remainder small businesses) in the municipalities of Tiverton and Little Compton. The pilot began in 2012 with the objective of deferring the $2.9 million feeder project for at least four years (i.e. from an initial estimated need date of 2014 until at least 2018). The load

[39] Ibid.
[40] Personal communication with Rick Weijo, Portland General Electric, August 10, 2011.
[41] These criteria are identical to internal guidelines National Grid had developed in 2010/2011 (personal communication with Lindsay Foley, National Grid, December 22, 2014).

reduction necessary to permit the deferral was estimated to be 150 kW in 2014, rising to about 1000 kW in 2018.[42]

The pilot was designed to leverage National Grid's statewide efficiency programs in a couple of ways. First, the Company is more aggressively marketing those statewide programs to customers in Tiverton and Little Compton. Second, it is using the same vendor that manages its statewide residential and small commercial efficiency retrofit programs to promote demand response measures in the two towns. Because the substation's peak load is in the summer, there is a strong emphasis on addressing cooling loads. Initially, the demand response offering was a wi-fi programmable controllable thermostat for homes with central air conditioning. However, when the saturations of central air proved to be lower than expected, the pilot was broadened to include demand response-capable plug load control devices for window air conditioners. Marketing of the program offerings was limited to "direct contact" with customers in the affected towns. National Grid recently reported to state regulators that the need for the new feeder has been pushed out from 2014 to 2015, suggesting that the peak load reduction that has been realized thus far has been large enough to defer the investment by one year.[43]

Vermont (mid-1990s pilot, statewide effort 2007 to present)

In 1995, Green Mountain Power (GMP), Vermont's second largest investor-owned electric utility at that time, launched an initiative – the first of its kind in the state – to defer the need for a new distribution line in the Mad River Valley – a region in the central part of the state made famous by the Sugarbush and Mad River ski resorts. Sugarbush, which was already the largest load on the line, had announced plans to add up to 15 MW of load associated with a new hotel, a new conference center and additional snow-making equipment. The existing line could not accommodate that kind of increase. Ensuing negotiations between GMP, Sugarbush and the state's ratepayer advocate ultimately led to an alternative solution in which Sugarbush would ensure that load on the distribution line – not just its load, but the total load of all customers – would not exceed the safe 30 MW level, and GMP would invest in an aggressive effort to promote investment in energy efficiency among all residential and business customers in the region. To meet its end of the bargain, GMP filed and regulators approved four efficiency programs targeted to the Mad River Valley, including a large commercial/industrial retrofit program, a small commercial/industrial retrofit program, a residential retrofit program that focused on homes with electric heat and hot water, and a residential new construction assessment fee program which imposed a mandatory fee on all new homes being constructed in the valley. The fee program paid for a home energy rating and offered both repayment of the fee and an additional incentive for building the home efficiently. The project as a whole came close to achieving its overall savings goal.

[42] Anthony, Abigail (Environment Northeast) and Lindsay Foley (National Grid), "Energy Efficiency in Rhode Island's System Reliability Planning", 2014 ACEEE Summer Study on Energy Efficiency in Buildings, Volume 10.
[43] Ibid.

Since that early project, Vermont has invested significant efforts in developing a thoughtful methodology for assessing the prudence of non-wired alternatives to capital investments in poles and wires. The Vermont Public Service Board (PSB) issued orders in Docket 7081 that established expectations for analysis of non-transmission alternatives, and in Docket 6290 for non-wires alternatives to distribution and sub-transmission projects. While the requirements vary slightly, similar approaches are used for both distribution and transmission needs. The state's distribution utilities and Vermont Electric Power Company (VELCO), the state's electric transmission provider, submit twenty-year forecasts of potential system constraints and construction projects as part of utility Integrated Resource Plans (IRPs) and a Long Range Transmission Plan (LRTP) every three years. The forecasts are updated annually. The forecasts include preliminary assessments of the applicability of non-wires alternatives based on criteria that have been agreed upon by Vermont System Planning Committee (VSPC), a statewide collaborative process for addressing electric grid reliability planning.[44] The VSPC helps Vermont fulfill an important public policy goal: to ensure that the most cost-effective solution gets chosen, whether it is a poles-and-wires upgrade, energy efficiency, demand response, generation, or a hybrid solution. The work of the VSPC is carried out by a broad cross section of stakeholders, including representatives from utilities, regulators, environmental advocates and Efficiency Vermont, and follows a highly prescribed process to assure that potential solutions are reviewed comprehensively.[45]

The current collaborative planning process was developed in response to Act 61, the 2005 legislation that clearly establishes the basis for the Public Service Board to require long range consideration of non-wires solutions as alternatives to T&D construction. Act 61 emerged in part as a result of public, regulatory, and legislative frustration with the Northwest Reliability Project, a transmission upgrade project that the Board ultimately felt it had to approve because, when permit applications were submitted there was no longer sufficient lead time to fairly consider NWAs. Act 61 also removed statutory spending caps for Efficiency Vermont, authorizing the Board to establish appropriate budgets. When the Board ordered budgets to increase beginning in 2007, it also required that a portion of the increase be devoted to special efforts to obtain additional savings in areas that the utilities had indicated had the potential to become constrained. Five geographic areas were initially targeted. At the time the Board required this geographic targeting effort primarily as a proof of concept, to assess Efficiency Vermont's ability to increase targeted savings while a better planning process was developed. Efficiency Vermont employed a number of program strategies in pursuit of their geographic goals, including enhanced account management approaches for commercial customers, a direct-install lighting program for small businesses, aggressive promotion of retail efficient lighting including community-based marketing approaches, and enhanced efforts to increase shell efficiency or fuel-switch electric heating customers. Vermont's process for evaluating the potential for non-

[44] http://www.vermontspc.com/
[45] http://www.vermontspc.com/library/document/download/599/GTProcessMap_final2.pdf

wires solutions is discussed in much greater detail in the following “detailed case studies” section of this report.

IV. Detailed Case Studies

1. Con Ed

Early History with Non-Wires Alternatives

Con Ed arguably has more on the ground experience with using geographically targeted energy efficiency to defer or avoid T&D investments than any other utility in North America. This geographically targeted investment in efficiency began in 2003, when growth in demand was causing a number of Con Ed's distribution networks to approach their peak capacity. Given the density of its customer base in and around New York City, much of the company's system is underground, making upgrades expensive and disruptive. Thus, the Company began to assess whether it would be feasible and cost-effective to defer such upgrades through locally-targeted end use efficiency, distributed generation, fuel-switching and other demand-side investments. At least initially, the focus was on projects "with need dates that were up to five years out and…required load relief that totaled less than 3% to 4% of the predicted network load."[46] However, a decision was later made to proceed with geographically-targeted demand resource investments whenever it was determined that such investments were likely to be both feasible and cost-effective.

For these early projects, the Company chose to contract out the acquisition of demand resources to energy service companies (ESCOs). To address reliability risks its contracts contained both "significant upfront security and downstream liquidated damage provisions", as well as rigorous measurement and verification requirements, including 100% pre- and post-installation inspections. Contract prices were established through a competitive bidding process, with the Company's analysis of the economics of deferment being used to establish the highest price it would be willing to pay for demand resources. Those threshold prices varied from network to network. When the amount of demand resources bid at prices below the cost-effectiveness threshold were insufficient to defer T&D upgrades, supply-side improvements were pursued instead.

In its initial pilot phase, the Company established contracts with three ESCOs to provide load reductions in nine network areas: five in midtown Manhattan, three in Brooklyn and one in The Bronx. In subsequent phases, four different ESCOs were contracted to deliver load reductions in 21 additional network areas: 13 in Manhattan, four on Staten Island and four in Westchester County. Though ESCOs were allowed to bid virtually any kind of permanent load reduction, all of the accepted bids were solely for the installation of efficiency measures. All told, between 2003 and 2010, the Company employed geographically targeted efficiency programs to defer T&D system upgrades in more than one third of its distribution networks.

[46] Gazze, Chris, Steven Mysholowsky, Rebecca Craft, and Bruce Appelbaum., "Con Edison's Targeted Demand Side Management Program: Replacing Distribution Infrastructure with Load Reduction", in Proceedings of the ACEEE 2010 Summer Study on Energy Efficiency in Buildings, Volume 5, pp. 117-129.

This approach had considerable success. In aggregate the level of peak load reduction for Phase 1, which ran through 2007, was approximately 40 MW – or 7 MW less than the contracted level.[47] As a result, Con Ed collected considerable liquidated damages from participating ESCOs. Load reductions in subsequent phases were close to those contracted in aggregate. Those aggregate results masked some differences across network areas. In particular, reductions in areas dominated by residential loads with evening peaks were achieved ahead of schedule while "ESCOs targeting commercial customers in daytime peaking networks struggled somewhat due to the economic recession."[48] On the other hand, the economic recession also had the effect of dampening baseline demand, offsetting most of the efficiency program shortfalls.[49] This highlights an important benefit of some efficiency programs – their savings can be tied, in part, to the same factors (e.g. the vitality of the economy) that cause demand growth to rise or fall. Put another way, participation in some efficiency programs tends to increase when load is growing more quickly and decrease when load is not growing quickly.

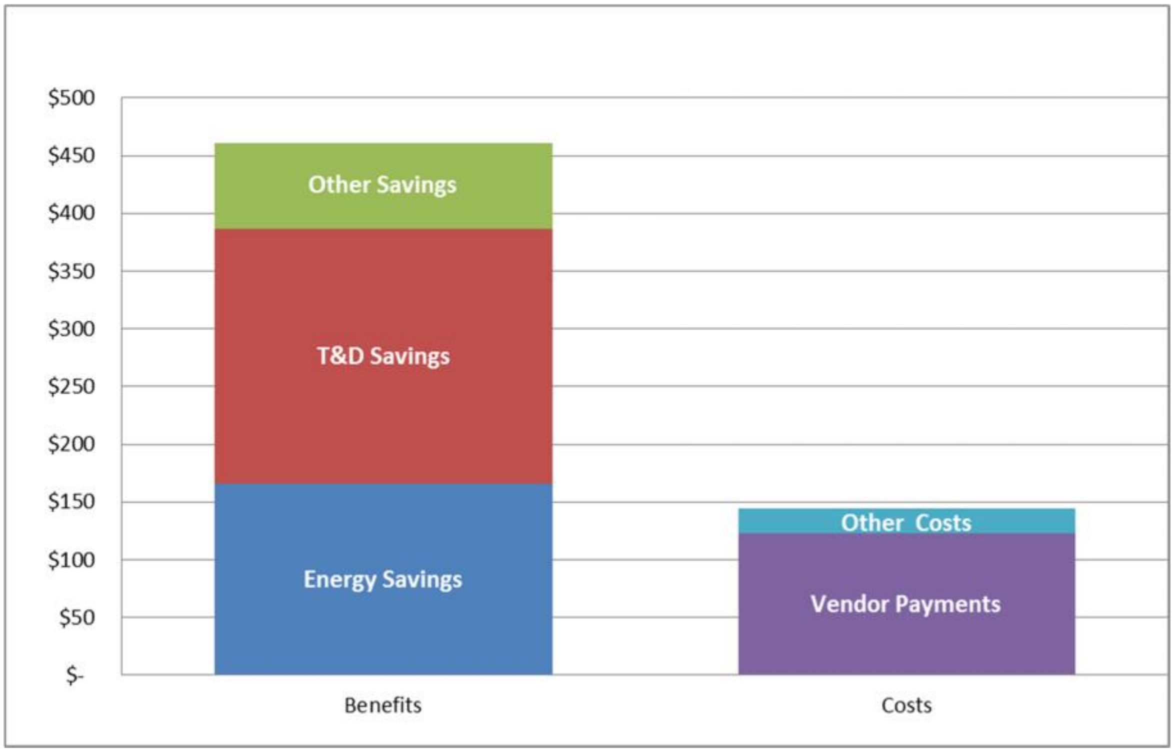
Another benefit of efficiency programs is that they can create a hedge against load growth uncertainty. As Con Ed put it:

> *"…using DSM to defer projects bought time for demand uncertainty to resolve, leading to better capital decision making. Moreover, widespread policy and cultural shifts favoring energy efficiency may further defer some projects to the point where they are never needed…In fact, Con Edison has projected that in the absence of this program it would have installed up to $85 million in capacity extensions that may never be needed."*[50]

As Figure 3 shows, from 2003 to 2010, Con Ed estimated that it saved more than $75 million when comparing the full costs of its geographically targeted efficiency programs to just the T&D costs that were avoided. When other efficiency benefits (e.g., energy savings and system capacity savings) were also considered, the efficiency investments were estimated to have saved Con Ed and its customers more than $300 million. It should be noted that these estimates include the benefits of the longer-than expected deferrals and even outright elimination of the need for some T&D projects that resulted from the downside hedge against forecasting uncertainty described above. The benefits of just the planned deferrals – i.e. what would have been realized had the projects only been deferred as initially forecast – were lower.

[47] Data obtained from graph in Gazze, Mysholowsky, Craft and Appelbaum (2010).
[48] Gazze, Mysholowsky, Craft and Appelbaum (2010).
[49] Gazze, Mysholowsky, Craft and Appelbaum (2010).
[50] Gazze, Chris et al., "Con Ed's Targeted Demand Side Management Program: Replacing Distribution Infrastructure with Load Reduction", in Proceedings of the ACEEE 2010 Summer Study on Energy Efficiency in Buildings, Volume 5, pp. 117-129.

Figure 3: NPV of Net Benefits of Con Ed's 2003-2010 Non-Wires Projects[51]

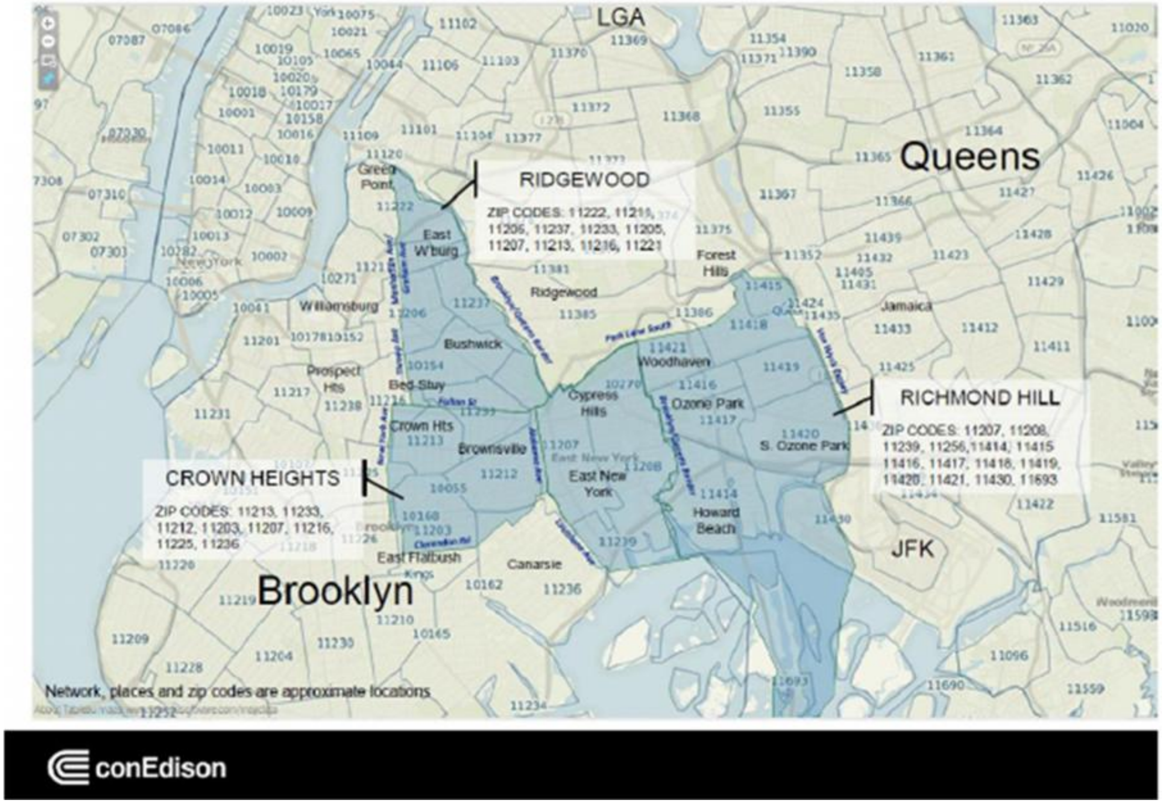


The Next Big Step - $200 Million Brooklyn-Queens Project

Building on this experience, in the summer of 2014 Con Ed requested regulatory approval to invest approximately $200M in a number of different approaches aimed at mitigating the immediate need for system reinforcement in areas of Brooklyn and Queens that surfaced during an extended heat wave in the summer of 2013 (see Figure 4).

[51] Cost and benefit data provided by Chris Gazze, February 11, 2011. Note that "other costs" includes program administration ($2.9 million), M&V ($9.2 million) and customer costs ($9.9 million).

Figure 4: Targeted Brooklyn-Queens Networks[52]



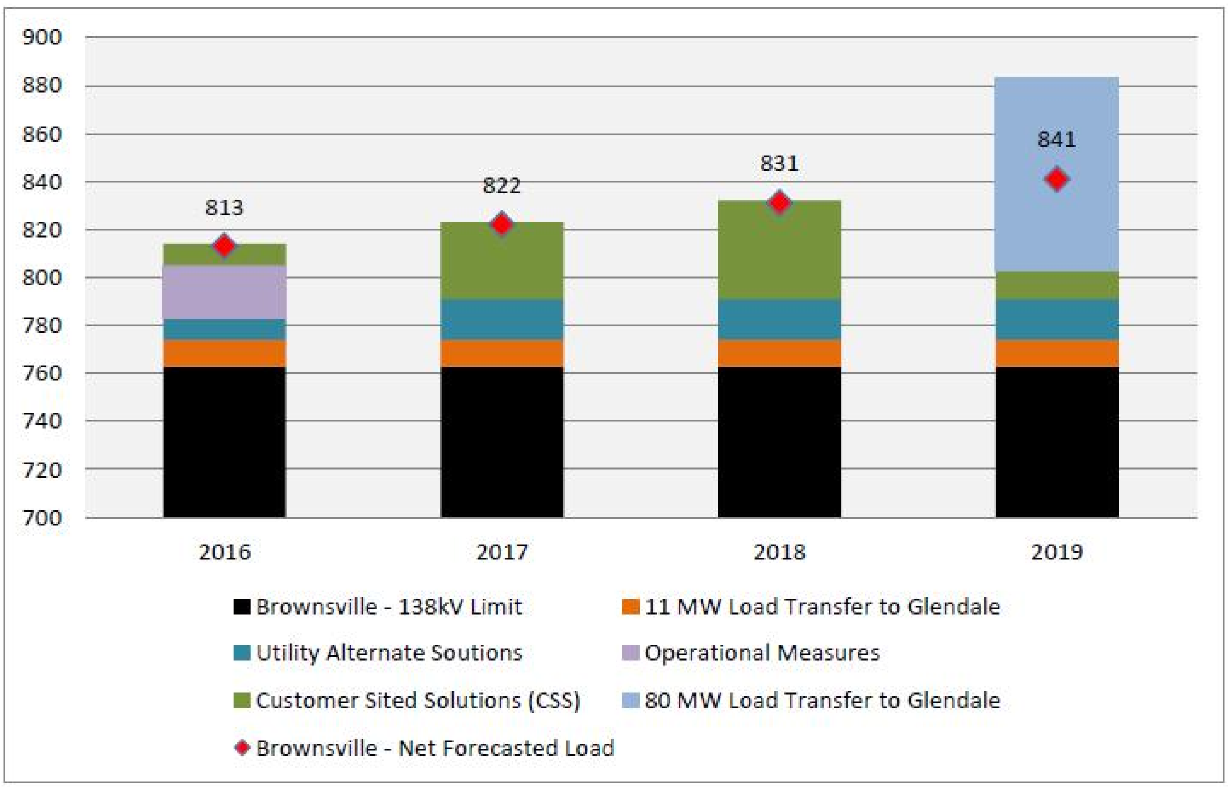
Con Ed knew that there would be capacity constraints in these areas in the future, but the extreme weather placed severe capacity pressure on the sub-transmission feeders that feed the Brownsville No.1 and No.2 substations (serving areas of Brooklyn and Queens), causing Con Ed to identify a greatly accelerated need for upgrades to its system in these areas.[53] Rather than proceeding with a traditional construction solution, Con Ed's proposal calls for it to achieve 41 MW in customer side solutions and another 11 MW of capacity savings through "non-traditional utility side solutions" between 2016 and 2018. This will be combined with another 11 MW of load transfers and 6 MW from the installation of new capacitors that will be operational by 2016 to meet the increased demand during this period. To be clear, Con Ed views these measures as a deferral, rather than a replacement strategy, that will allow delaying the construction of a new substation and associated other improvements from 2017 until 2019. Future upgrades at two other substations are expected to extend this deferral until 2026.[54]

[52] Consolidated Edison Company of New York Request for Information, July 15, 2014, p.11.
[53] Personal communication with Michael Harrington of Con Ed, July 24, 2014.
[54] Data regarding Con Ed's proposal are from Consolidated Edison Company of New York, Inc. Brownsville Load Area Plan, Case 13-E-0030, August 21, 2014.
http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=13-e-0030, filing # 518

The overall expected project cost of the combination of the $200M in customer-side and utility-side investments, along with costs associated with the load transfers, new capacitors, and upgrades at the two other substations is not available in the documents reviewed in preparing this paper. However, Con Ed does say that the cost of the alternative purely "poles and wires" solution would be about $1 billion."[55] This traditional solution would include "…expansion of Gowanus 345kV switching station into a new 345/138kV step-down station…and…construction of an area substation and new sub-transmission feeders that would have been constructed and in service by the summer of 2017…."[56]

Figure 5 below illustrates the annual contribution of each component that combined will provide the needed load relief for the Brownsville Load Area in Brooklyn and Queens. Both traditional "poles and wires" solutions and non-traditional alternatives are needed to meet the anticipated load. The blue "utility alternate solutions" and the green "customer-sited solutions" together make up the NWAs for which Con Ed has sought approval.

Figure 5: Brownsville Load Area Plan by Component: 2016-2019 [57]



[55] Brownsville Load Area Plan, p.10
[56] Brownsville Load Area Plan, p.10
[57] Brownsville Load Area Plan, p.22

Con Ed's past success with implementing non-wires solutions gives it what is perhaps a unique, experience-based level of confidence in the effectiveness of alternatives to distribution construction. Likely of equal importance in Con Ed's decision to request approval for the Brooklyn-Queens project are the strong signals coming from New York's regulators, initially through feedback in a rate case[58] and later reinforced through proposals to re-structure the electric utility industry in New York. In particular, New York's Public Service Commission Staff have indicated that they foresee that in the near future the utilities will be held increasingly responsible for managing the grid in the most economic manner. In Commission Staff's view, outlined in *Reforming the Energy Vision* (REV),[59] this includes deploying all manner of cost-effective Distributed Energy Resources (DERs), in an environment where their benefits are accurately measured and given full attribution. The REV proceeding is currently underway in New York and the outcomes are undecided at the time of this writing, but clearly Con Ed has reflected anticipated changes in the regulatory framework in its Brooklyn-Queens filing, which will provide the most comprehensive test to date of the principles outlined in the REV.

Consistent with its regulatory filing, Con Ed issued an RFI in July of 2014 under the title "*Innovative Solutions to Provide Demand Side Management to Provide Transmission and Distribution System Load Relief and Reduce Generation Capacity Requirements*". The RFI allows for an extraordinary level of flexibility regarding the creative use of non-wires approaches:

> *"Respondents are encouraged to submit alternative, creative proposals for DSM marketing, sales, financing, implementation, and maintenance, or transaction structures and pricing formulas that will achieve the demand reductions sought and maximize value to Con Edison's customers."*[60]

While the Brooklyn-Queens project is receiving much attention for its unprecedented scale and ambition as a non-wires project, a concurrent evolution in several aspects of Con Ed's overall approach to non-wires alternatives may be even more important in the long run. Four recent developments are particularly noteworthy:

- **Management structure**: Con Ed's management of analysis and deployment of non-wires alternatives has been elevated to higher level in the Company and become more integrated/inter-disciplinary;
- **Data-driven tools**: Con Ed is developing data driven tools to enable much more sophisticated analysis of non-wires options; and

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58 Personal communication with Michael Harrington, Con Ed, December 9, 2014.
59 NYS Department of Public Service Staff, *"Reforming the Energy Vision"*, Case 14-M-0101, 4/24/2014. http://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/26be8a93967e604785257cc40066b91a/$FILE/ATTK0J3L.pdf/Reforming%20The%20Energy%20Vision%20(REV)%20REPORT%204.25.%2014.pdf
60 Consolidated Edison Company of New York Request for Information, July 15, 2014, p.6

- **Research to support tools**: Con Ed is investing in research to generate data necessary to support the use of those tools.
- **Proposed shareholder incentive mechanism**: Con Ed has proposed a new mechanism for enabling shareholders to profit from investment in non-wires alternatives.

Evolution of Management Approach

Con Ed has taken significant steps in advancing internal communications and collaboration for the Brooklyn-Queens project that are expected to apply to other projects in the future. A working group has been formed within the company specific to this project that includes members of all relevant functional areas such as energy efficiency and demand management, distribution engineering, substation planning, electric operations, and the regional engineering groups that are responsible for Brooklyn/Queens. This has been done with the sponsorship, and under the guidance of one of Con Ed's Senior Vice-Presidents, who has championed the project and who regularly chaired early project meetings. Con Ed's senior management team regards the success of the Brooklyn-Queens project as highly important, and has brought organizational focus to it in a way that we did not observe in any of the other organizations we explored.[61]

Development of New Data-Driven Analytical Tools

With a focus on system and cost management, along with the growth in efficiency and demand management technology and associated customer strategies, Con Ed identified the need for increased visibility into customer and technology potential and economics on the demand side. To address this need, Con Ed, along with Energy & Environmental Economics (E3) and Navigant, has created the Integrated Demand Side Management (IDSM) Potential Model – a dynamic, geographically specific, and technology integrated analysis tool to assess the market potential and economics of efficiency and demand management for cost effective deferral or avoidance of capital expenditures required to meet growing customer demand. The IDSM project is groundbreaking in its ability to breakdown the in-depth analysis into geographically specific electric networks to best match the needs of electric system planners.

The IDSM project goes beyond traditional efficiency measure stalwarts (lighting) to give Con Ed a view into potential deployments of all commercially available and near-term available technologies potentially applicable to the Con Ed service territory. The IDSM project will enhance Con Ed's ability to identify and market to high potential market segments to achieve efficient and effective capital project deferral projects. The model will also enable analysis of various DSM scenarios to customize and optimize project results and maximize cost effectiveness. Lastly, the IDSM project can be extended for use beyond TDSM project analysis

[61] Maine and Vermont have addressed the cross-functional nature of successful NWA planning and implementation through collaboratives that include members of different organizations, but we are not aware of an example other than Con Ed where this level of collaboration has occurred within a single utility.

to support Con Ed's strategic planning and resource planning (forecasting) efforts by identifying the market potentials and impacts for any number of customer technology adoption scenarios.

Research to Support New Tools

Of course, analytical tools are only as good as the data put into them. Thus, Con Ed also embarked on a couple of research projects to support deployment of the IDSM.

In the first, Con Ed built up network profiles for eight test networks by collecting detailed granular customer data that accounts for building-level characteristics, and that are aggregated for up to 13 commercial and two residential segments for each electric network analyzed. Drawing from both internal billing data and external sources, the network profiles will include applicable service classes, meter information, annual and peak energy usage, air conditioning use, existing thermal storage, physical characteristics of the building, prior program participation, in-place DG/RE, end-use profiles, and more.

The second research task was a technology assessment to identify current and near-market technologies that have the potential to improve energy efficiency, support demand response, improve building operations, and maximize comfort. The assessment looked at the measures identified in a 2010 potential study, as well as additional technologies related at a minimum to lighting, controls, motors, HVAC, and thermal and battery storage. The project also looked at customer sited generation across a range of technology options.

In addition, the technology assessment included the develop of a measure specific load curve library by customer segment (e.g. 8760 and peak load curves for interior lighting measures for the retail customer segment) This tool connects the dots between the technology assessment and the network profiles to ensure the energy and demand reductions for measures being deployed for the specific customer segments are specific to the network(s) being analyzed. The tool does this by comparing the measure-segment load curves to the 8760 and peak load curves of the specific network. For example, the tool is able to assess the different impacts that residential lighting will have compared to commercial lighting in a night peaking network.

Proposal for Shareholder Incentives

Con Ed has proposed to the Commission that it defer the bulk of the costs associated with customer-side activities and recover them over a five-year amortization period, and for utility-side expenditures it has proposed ten-year recovery. Con Ed suggest that "The shorter amortization periods than those traditionally afforded in rates reflect the nature of the expenditures…where no physical asset exists".[62] Con Ed suggests that it should earn a rate of

[62] Consolidated Edison Company of New York, Inc., "*Petition for approval of Brooklyn/Queens Demand Management Program*", p.20. http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7bB2051869-3A4A-4A7D-BB24-D83835E2026F%7d

return equal to its overall approved rate of return, stating that "…ratemaking should make the Company indifferent to whether it invests in traditional or non-traditional solutions…."[63]

Further, Con Ed has proposed that the Commission establish up to a 100 basis point incentive on Brooklyn-Queens program investments that would be incremental to its approved rate of return so that it has a clear, direct interest in the success of the project. And lastly, the company has proposed that the Commission establish a shared savings incentive as well, with Con Ed earning 50% of the difference between the carrying costs of the traditional solution and the total annual collections for the Brooklyn-Queens program. As of this writing the Commission has not indicated how it will rule on these requests.

2. Maine (Boothbay) Pilot

Project History and Plan

In 2008, Central Maine Power proposed a $1.5 billion investment in the Maine Power Reliability Program (MPRP) to modernize and upgrade the state's transmission network. The project was challenged, with one party – GridSolar – proposing instead that the state invest in 800 MW of photovoltaics (100 MW in the first five years) to offset the need for the entire MPRP. In June of 2010, the Maine Public Utilities Commission approved a settlement agreement reached by Central Maine Power (CMP) and a variety of other parties, including GridSolar and several public interest advocates.[64] The settlement supported construction of most elements of the MPRP, but identified two areas – the Mid-Coast region and the city of Portland – where pilot projects to test the efficacy of non-transmission alternatives would be launched. The Mid-Coast pilot was later reduced to a smaller pilot in the Boothbay region, roughly 35 miles ("as the crow flies") northeast of Portland (see Figure 6 below).

[63] Ibid., p.21.
[64] Maine Public Utilities Commission, Order Approving Stipulation, Docket No. 2008-255, June 10, 2010.

Figure 6: Location of Maine (Boothbay) NTA Pilot[65]

The Boothbay pilot was to be a hybrid solution. It included some transmission system investments, including rebuilding of the Newcastle 115 kV substation ($2.8 million), installing a second 2.7 MVAR capacitor bank at Boothbay Harbor 34.5 kV bus ($0.5 million, and 2.4 MVAR power factor correction at Boothbay Harbor 12 kV level.[66] In addition, the plan initially called for approximately 2 MW of non-transmission resources to be procured (in lieu of an $18 million investment in rebuilding of a 34.5 kV line).

The settlement agreement called for an independent third party to administer the acquisition and management of the non-transmission resources. GridSolar was contracted to serve as a third party administrator. Though the selection was not based on a competitive solicitation, the Maine Public Utilities Commission did formally ask if other parties would be interested and did not receive any other expressions of interest. In a docket that is currently open, the Commission is exploring, among other things, whether there should be an independent third party administrator for such projects in the future and, if so, how such parties would be selected (see discussion on next steps below).

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[65] Map copied from U.S. Department of Interior, U.S. Geological Survey, *The National Atlas of the United States of America*, www.nationalatlas.gov.
[66] Jason Rauch, Maine Public Utilities Commission, *"Maine NTA Processes and Policies"*, presentation to the Vermont System Planning Committee's NTA Workshop, October 11, 2013.

GridSolar used a competitive solicitation process to procure the non-transmission alternatives. The initial RFP was released in late September 2012. Because it was a pilot, it was decided that the Boothbay project would not solely be designed to acquire the least-cost non-wires solution for the area. Rather, it would also test the efficacy of a wide variety of alternative resource options. To that end, the RFP made clear that, to the extent feasible, GridSolar would endeavor to cost-effectively acquire (i.e. at a cost less than the transmission alternative) at least 250 kW of each of the following categories of resources:

- Energy efficiency;
- Demand response;
- Renewable distributed generation (at least half of which should be from solar PV); and
- Non-renewable distributed generation (with preference for those with no net greenhouse gas emissions).[67]

The RFP called for all bidding resources to be "on-line and commercially operable" by July 1, 2013 – just nine months after issuance of the RFP and less than six months after the expected date of contract signing – and committed to remain in service for a least three years. Contracts would guarantee payments for that three year period, with an option to extend payments for up to an additional seven years if approved by the Commission. Failure to meet the contractual deadline would result in a penalty of $2/kW-month.[68]

The RFP produced 12 bids from six different NTA providers totaling almost 4.5 MW. This included bids for efficiency, demand response, solar PV, back-up generators, and battery storage.[69] Nine of the bids were submitted for approval to the Commission. The nine bids would collectively have provided 1.98 MW spread across five different resource types – 156 kW of efficiency, 250 kWh of demand response, 338 kW of solar PV, 736 kW of back-up generators, and 500 kW of battery storage. During a January 2013 technical conference, GridSolar was given "preliminary approval" to negotiate contracts on those nine bids.[70]

In April 2013 GridSolar reported it had executed or was close to executing almost all of the contracts. The one key exception was a contract with one provider – Maine Micro Grid – who had bid all of the demand response and battery resources and a portion of the solar and back-up generator resources being recommended. While there was agreement on the contract terms, Maine Micro Grid was having difficulty securing financing for the project[71] and ultimately

[67] GridSolar, LLC, "*Request for Proposals to Provide Non-Transmission Alternatives for Pilot Project in Boothbay, Maine Electric Region*", September 27, 2012.
[68] Ibid.
[69] GridSolar, "*Interim Report: Boothbay Harbor Sub-Region Smart Grid Reliability Pilot Project*", for Docket No. 2011-138, March 4, 2014.
[70] GridSolar, "*Implementation Plan & Final NTA Service Contracts*" (redacted version), for Docket no. 2011-138, April 5, 2013 (filed electronically on April 9, 2013.
[71] Ibid.

withdrew its bid, explaining that the limited contract commitment of three years was insufficient to satisfy investors "that the required 6-year holding period for the federal investment tax credit incentive would be satisfied."[72]

As a result, the Commission directed GridSolar to install a temporary back-up 500 kW diesel generator and issue a second RFP to fill the gap. The second RFP was issued on May 30, 2013. It produced 22 bids from ten different NTA providers totaling just over 4 MW. It too included bids for efficiency, demand response, solar PV, back-up generation and battery storage. The bid prices for all resources except energy efficiency went down in the second RFP. Even though the energy efficiency bid prices went up, efficiency resources remained by far the lowest cost resources (just by a smaller margin). After eliminating the most expensive bids, GridSolar recommended and received approval to proceed with putting in place contracts for the mix of resources summarized in Table 3. As discussed below, the final mix of NTAs contracted was slightly different from the mix shown in the table. The final contract prices were the same for the back-up generator (BUG) and demand response, but roughly $4 to $5 per kW-month higher for efficiency, solar PV and battery storage than the weighted three year prices shown in the table.[73]

Table 3: Recommended NTA Resources[74]

	RFP I*	RFP II	Totals	Pct.	Units	Weighted 3 Year Price	Weighted 10 Yr. (Levelized) Price
Efficiency	237.00	111.25	348.25	19%	7	$23.51	$10.47
Solar	168.83	106.77	275.60	15%	14	$46.05	$13.19
BUG (same)	500.00	500.00	500.00	27%	1	$17.42	$20.63
Demand Response	0.00	250.00	250.00	13%	1	$110.00	$57.65
Battery	0.00	500.00	500.00	27%	1	$163.70	$75.99
Total	905.83	1468.02	1873.85		24		

* RFP I excludes Maine Micro Grid project; Efficiency increased to reflect EMT contract option.

As of July 2014, approximately 1203 kW of NTA resources were deployed and operational.[75] An additional 500 kW battery storage unit is currently expected to be operational by the end of 2014,[76] bringing the total operational capacity to 1703 kW.[77] That is nearly 300 kW less than the

[72] GridSolar, *"Interim Report: Boothbay Harbor Sub-Region Smart Grid Reliability Pilot Project"*, for Docket No. 2011-138, March 4, 2014.
[73] GridSolar, *"Project Update: Boothbay Sub-Region Smart Grid Reliability Pilot Project"*, for Docket No. 2011-138, July 21, 2014.
[74] Table copied from GridSolar, *"Interim Report: Boothbay Harbor Sub-Region Smart Grid Reliability Pilot Project"*, for Docket No. 2011-138, March 4, 2014.
[75] GridSolar, *"Project Update: Boothbay Sub-Region Smart Grid Reliability Pilot Project"*, for Docket No. 2011-138, July 21, 2014.
[76] Personal communication with Dan Blais, GridSolar, October 14, 2014.
[77] Note that this value is about 170 kW less than shown in Table 3 above. That is because not all of the proposals initially approved for procurement were ultimately translated into contracts.

initially forecast need of 2.0 MW. However, in May 2014 Central Maine Power adjusted its forecast need for the 10-year planning horizon to be only 1.8 MW.[78] GridSolar had an option to acquire an additional 130 kW of efficiency resources from Efficiency Maine Trust. However, GridSolar, Commission Staff and other parties agreed not to pursue that option at that time, noting that it could be acquired later if necessary:

> *"A benefit of the NTA approach is that lump-investments and resource deployment can be more closely timed with need. To the extent that additional NTA resources are needed later to meet any increased load, they could be deployed at that time. The delay in investment saves ratepayers money."*[79]

Energy Efficiency Strategy

As noted above, energy efficiency resources were a key component in the mix of NTA resources procured for the Boothbay pilot, accounting for approximately one-fifth of the total NTA capacity that has been procured.

All of the efficiency resources procured to date have been provided by the Efficiency Maine Trust (EMT), the independent third party administrator of efficiency programs in the state. Before responding to the first RFP, EMT contracted for a quick high level assessment of efficiency opportunities in the region. One of the findings was that there was significant lighting efficiency potential in local small businesses, including significant opportunities to displace very inefficient incandescent lighting. Given that opportunity – and the very tight timeline originally anticipated for producing savings (contracts to be signed in January 2013 with requirements for NTAs to be operational by July 1, 2013) – EMT focused its efforts almost entirely on lighting.

EMT employed two strategies for acquiring the savings. Most importantly, it ran what it called a "direct drop" program. That involved a bulk purchase of LEDs that could replace incandescent and halogen spotlights and direct delivery of the LEDs to businesses that indicated they would install them. At the time of the delivery, EMT also assessed opportunities for more expensive upgrades. However, because many of the businesses are seasonal (relying on the summer tourism trade), both profit margins and the potential cost savings from efficiency are often modest, making it difficult to persuade them to make any substantial investments. EMT also provided an "NTA bonus" on its standard business efficiency incentives for customers in the affected region. Several businesses, including a local grocery store, took advantage of that offer.

EMT had to be careful to explain why these offers were being made, so that it was clear why only customers in the region of interest were eligible. Nevertheless, there were still some customers from just outside the region that initially expressed annoyance that they could not take

[78] Ibid.
[79] Ibid.

advantage of the NTA offers. EMT had to follow up with those customers to clarify the purpose of the program and rationale for the geographic limitations of the special offers.

It should be noted that Efficiency Maine has indicated that "it could easily have secured much more efficiency had the design of the RFP permitted more flexible bid response and longer duration commitment."[80]

Evaluation Strategy

The savings from efficiency measures in the project are estimated using the deemed values in EMT's Technical Reference Manual. As required by the RFP, those values are consistent with the values accepted for peak savings by the New England ISO in its forward capacity market.

GridSolar conducted its first test of 472 kW of active NTA resources on July 1, 2014. The BUG and demand response units were dispatched for an hour. Based on data from the units themselves, as well as data from the affected substation circuits, it appears that the capacity of these resources was as predicted.

Project Results

As noted above, to this point, the project appears to be performing as expected in terms of the magnitude of the resource being provided, though a key component for the future – battery storage – has not yet been tested.

With regards to cost, GridSolar has estimated that the project will be substantially less expensive than the transmission alternative.[81] Indeed, as shown in Figure 7, it estimates that the revenue requirements for the pilot project will be $17.6 million lower – a more than 60% savings – over the project's potential 10-year life than under the full transmission solution.[82] That is despite the intentional deployment of a range of NTAs that were not cost-optimized (so as to test a range of technology types in a pilot) and the fact that the pilot commitment to only three years of payments likely constrained potential bids. Moreover, that cost comparison is not adjusted for the substantial additional benefits that some of the NTAs provide, such as energy savings during non-peak periods.

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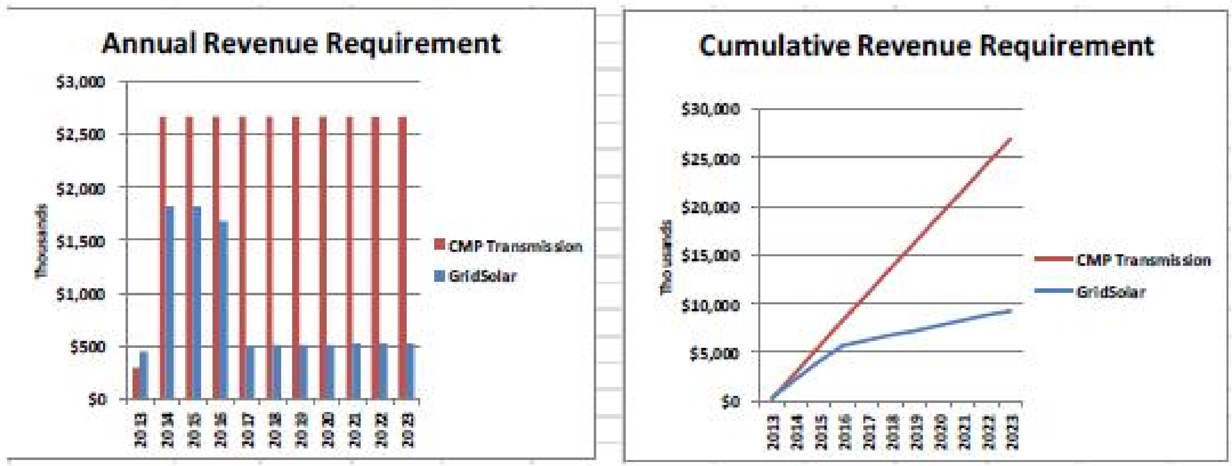
[80] GridSolar, *"Interim Report: Boothbay Harbor Sub-Region Smart Grid Reliability Pilot Project"*, for Docket No. 2011-138, March 4, 2014.

[81] As discussed above, there is a small transmission component to the pilot project. When we refer to the transmission alternative here, we are referring just to the more substantial additional transmission investment that would have had to be made in the absence of the NTA deployments.

[82] Though this analysis only looks at a 10-year horizon, GridSolar expects that the pilot project will permanently eliminate the need for the transmission alternative (GridSolar, *"Interim Report: Boothbay Harbor Sub-Region Smart Grid Reliability Pilot Project"*, for Docket No. 2011-138, March 4, 2014 and personal communication with Dan Blais, GridSolar, October 14, 2014.

Figure 7: Cost Comparison of Transmission and NTA Solutions for Boothbay



One other important result worth re-stating about the project is that many of the passive resources, particularly energy efficiency, were among the first to be deployed. As GridSolar noted in its March 2014 project updates, this "bought time" for other NTAs to be brought on line:

> *"…To date, the Pilot has deployed over 400 kW of passive NTA resources…These passive resources alone exceed the projected grid reliability requirements in the Boothbay subregion…for the initial years of the Pilot…the subregion will not reach the projected critical loads in which the full suite of NTA resources are needed to meet reliability requirements in the out years of the Pilot project. This demonstrates the dynamic and modular nature of NTA solutions, which be ratcheted up or down year to year, as conditions require – thus lowering net costs and preventing premature or stranded costs due to overbuilding.*

Moreover, as noted above, the ability to quickly deploy some of the NTA resources bought time to allow for an updated peak forecast which lowered the magnitude of the total NTA required to meet reliability needs from 2.0 to 1.8 MW.

The Future

In addition to continued implementation and evaluation of the Boothbay pilot, several other developments in Maine related to consideration of non-wires alternatives merit brief discussion.

First, and perhaps most importantly, the omnibus energy bill that became law in July 2013 contains important new language regarding consideration of NTAs. In particular, the bill requires the following:[83]

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[83] HP1128, LD1559, Item 1, 126th Maine State Legislature, "An Act to Reduce Energy Costs, Increase Energy Efficiency, Promote Electric System Reliability and Protect the Environment", Part C.

- No new transmission project of either (1) 69 kV or greater or (2) less than 69 kV with a project cost of at least $20 million can be built without consideration of NTAs;
- Assessment of NTAs must be performed by "an independent third party, which may be the commission or a contractor selected by the commission";
- The commission must "give preference" to NTAs when they are lower cost to ratepayers;
- When costs to ratepayers for a transmission project and NTAs are comparable, the commission must give preference to the option that produces the lowest air emissions (including greenhouse gases);
- If NTAs can address a need at lower total cost, but higher cost to ratepayers (because of socialization of the costs of transmission through ISO New England), the commission must "make reasonable efforts" to negotiate a cost-sharing agreement among the New England states that is similar to the cost-sharing treatment the transmission alternative would receive (the commission is given 180 days to negotiate such an agreement); and
- The commission is required to advocate "in all relevant venues" for similar treatment for analysis, planning and cost-sharing for NTAs and transmission alternatives.

The first NTA study required by the law is currently being undertaken in northern Maine (Docket 2014-00048). The Commission anticipates that two other potential Central Maine Power projects will trigger the study requirement.

Second, the Commission currently has an open docket in which it is considering whether to establish a permanent third party administrator of NTAs (initially Docket 2010-00267; now under Docket 2013-00519) and, if so, to establish how the administrator would be selected and overseen.[84] GridSolar has proposed that it become the state's coordinator. Other parties have some concerns. For example, Efficiency Maine Trust has expressed reservations about creating a new statewide third party administrator to manage consumer education, research and deployment of demand resources when it already plays that role for a subset of the resources (particularly energy efficiency and renewables). It has also expressed concern about inefficiencies in requiring it, as a regulated entity, to work through another regulated third party entity to get efficiency resources to be considered part of potential NTA solutions.[85] Instead, it suggests that cost-effective efficiency NTA resource be deployed in the future through the process EMT currently uses to make changes to its Triennial Plan.[86] GridSolar has itself recommended that in future projects efficiency resources should be procured "in partnership with EMT" and "outside the RFP process used to procure other NTA resources."[87]

[84] Maine calls this position a "Smart Grid Coordinator", perhaps in part because the role may be larger than just managing NTAs.
[85] Personal communication with Ian Burnes, Efficiency Maine Trust, September 17, 2014.
[86] Mr. Ian Burnes and Dr. Anne Stephenson, Direct Testimony, Docket No. 2013-00519, August 28, 2014.
[87] GridSolar, *"Interim Report: Boothbay Harbor Sub-Region Smart Grid Reliability Pilot Project"*, for Docket No. 2011-138, March 4, 2014.

3. PG&E

Legislative Requirements

PG&E, and presumably the other California electric utilities that are subject to the requirements of Assembly Bill 327 (AB 327), are in the early stages of identifying target areas that have rich potential for the deployment of non-wires alternatives. For PG&E, as these areas are identified, small pilot projects will be undertaken to test the potential for meeting growth-related needs through distributed resources rather than through construction of traditional poles and wires solutions. Signed by the Governor on October 7, 2013, AB 327 addresses several issues related to electric regulation and rates, and includes language laying out new expectations for resource planning, including the level of detail and rigor that utilities must apply. The law states that "Not later than July 1, 2015, each electrical corporation shall submit to the commission a distribution resources plan proposal to identify optimal locations for the deployment of distributed resources."[88] The Act further states that "…"distributed resources" means distributed renewable generation resources, energy efficiency, energy storage, electric vehicles, and demand response…." Sophisticated planning tools will be needed to meet the AB 327 requirement that these utilities must "Evaluate locational benefits and costs of distributed resources…." Until now, tools that can model distributed energy resources (DERs) have not been required.

Selection of Pilot Projects

In response to these requirements, PG&E has begun working with several vendors to explore different tools and approaches for meeting the requirement for developing locational benefits and costs and for applying these values along with load and growth forecasts to develop an optimized distributed resources deployment plan. As an approach to testing the viability of this type of planning and deployment, PG&E began looking specifically at distribution substation level projects that potentially required attention due to load growth.[89] The Company ultimately identified approximately 150 capacity expansion projects that would need to be addressed in the next five years absent any action to defer them. They then applied criteria to identify projects that would be most suitable to explore for non-wires approaches. To make this cut, projects needed to:

- Be growth-related rather than related to any type of equipment maintenance issues;
- Have projected in-service dates at least three years out from the analysis date; and
- Have projected normal operating deficiencies of 2MW or less at the substation level.

These criteria were selected for this concept-testing period to identify projects that would have a strong chance for success. Applying these criteria whittled the list down significantly— to about

[88] Section 769, California Assembly Bill 327
https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201320140AB327
[89] At PG&E, distribution substations range typically serve between 5000 and 30,000 customers, with a total peak load of about between 20 MW and 100 MW (personal communication with Richard Aslin, PG&E, December 14, 2014).

a dozen remaining projects that had the potential to be candidates for NWAs. PG&E looked more closely at the connected loads and customer profiles for these remaining projects to get a more detailed sense of the types of NWAs that might be relevant in each project, and whether NWAs could realistically achieve the necessary load reductions. Through this process of careful selection, PG & E has identified four projects that it will use to test NWAs in 2014-15. By the end of 2015 they are confident that they will have a much better understanding of the opportunity to use NWAs to defer or avoid poles and wires construction projects.

Efficiency Strategies

Given that these projects are still being developed for PG & E, there is not much actual experience to report on in terms of their approach to deploying energy efficiency in the four pilot areas. PG & E has a wide array of programs in its portfolio, so at present it is not planning to develop new program offerings for targeted areas. However, it is providing significantly larger incentives for custom C&I projects in targeted areas, and is working on making the non-trivial programming changes that will allow it to make corresponding changes for prescriptive measures. Making the programming changes that will allow tracking and reporting of different incentive levels in different areas is a critical step in developing the infrastructure that will allow successful use of DERs.

For residential customers, targeted measures include pool pumps and HVAC measures, with increased incentives available through the Upgrade California initiatives. PG&E is also doing an intense marketing campaign for its residential A/C cycling demand response program, and is offering increased incentives as well. To try to make sure that messaging is going to the right customers – to avoid the possibility that ineligible customers will want to take advantage of increased incentives – PG&E is primarily marketing the programs through installation contractors rather than using any kind of broad outreach campaign.

Outreach poses challenges related to making sure that the message gets to the right customers, but one of the additional challenges that PG&E has identified is the importance of getting the right message to customers in a way that won't cause them to worry about the lights going out. Many Californians remember rolling brownouts, and any hint that reliability is in question can evoke strong reactions. This may or may not be as much of an issue in jurisdictions that have no history of reliability issues.

Addressing Management Challenges

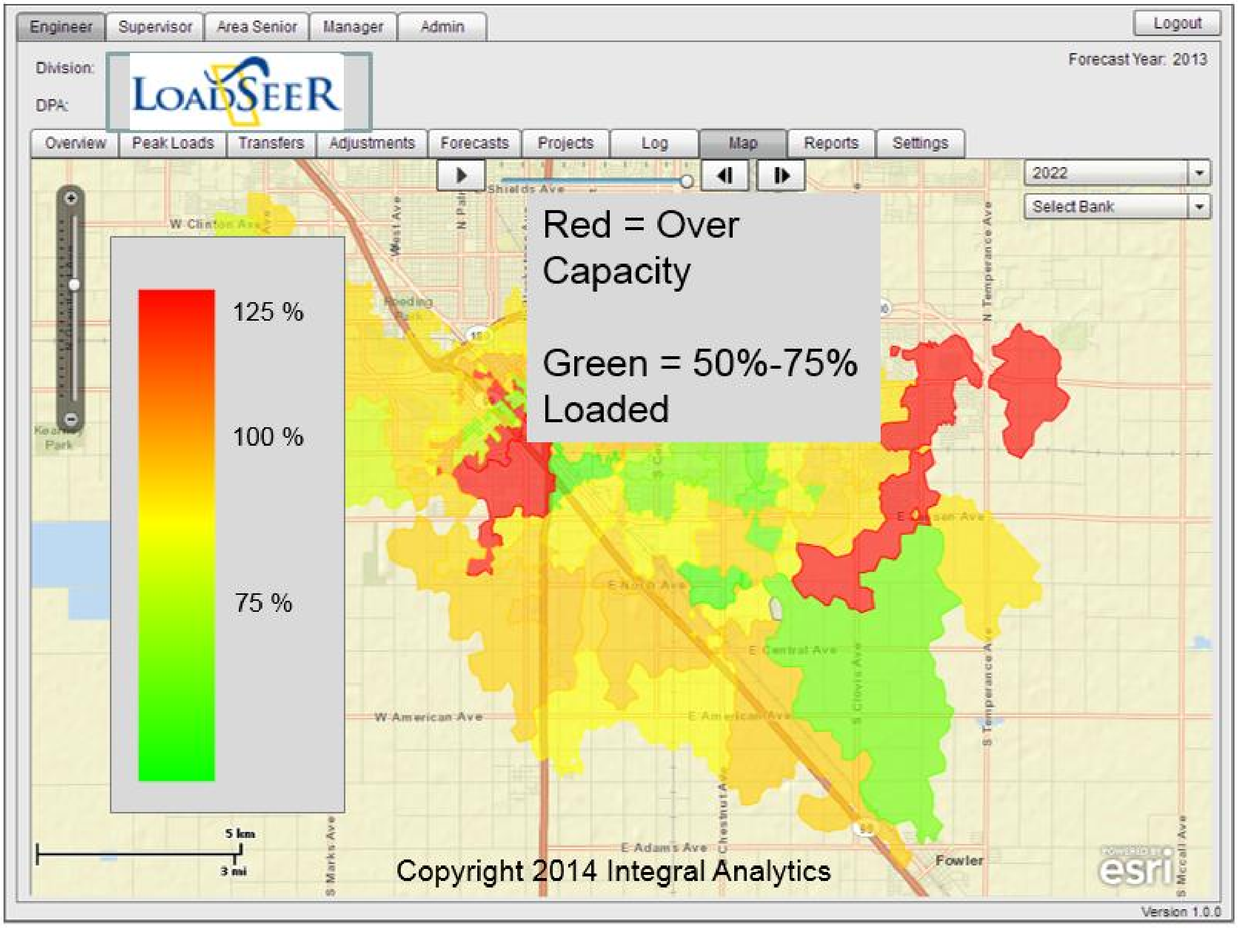
PG&E, like other utilities in this study, has identified challenges working across traditional utility organizational structures that typically have system planners operating in isolation from demand management and energy efficiency staff. PG&E, as well as other utilities with whom we talked, has found that system planners are often uncomfortable with the perceived level of uncertainty in non-wires solutions as compared with poles and wires solutions. Historically, the system planners' primary role is to provide certainty that the lights will stay on, and so the multifaceted complexity of non-wires solutions may seem less attractive than the alternatives with which they are more familiar.

PG&E staff are exploring organizational changes that might improve the cross-functional coordination of planning for alternatives to poles and wires. One of the steps that PG&E is undertaking to address planning integration between the two groups is – for the targeted substation projects – having dedicated customer energy solutions (CES) engineers and customer relationship managers work side-by-side with the distribution planning engineering teams. They are optimistic that through building these one-on-one relationships, and by having the engineers and customer relationship managers work "across the aisle", they will be able to provide the system planners with the level of assurance they require to more fully support potential NWAs.

Use of New Data-Driven Analytical Tools

Moving forward, PG&E is likely to take greater advantage of sophisticated analytics and smart grid data to refine its analyses of the optimal locations for DER approaches. Currently it is working with a number of third party vendors and consultants to test the applicability of different data-driven approaches that will provide greater assurance to planners by better addressing the unknowns in the current planning process. One of these vendors, Integral Analytics, has already developed tools that will map and forecast loads and develop "distributed" marginal pricing (DMP) at the circuit or even customer level, with far greater precision than the locational marginal pricing (i.e. avoided costs) that are currently used to evaluate demand side management programs. These models not only map current loads, but also model loads out into the future, with the capacity to provide data-driven predictions of when loads will exceed a circuit's capacity to deliver it, as illustrated in Figure 8. DMPs will allow the development of avoided costs for specific, local areas, which will in turn allow precise analysis of the costs and benefits associated with DER projects. Moreover, the incorporation of power flow analytics below the substation can identify avoided costs that are not captured in traditional approaches (e.g. service transformer "reverse flow" risk from photovoltaics, voltage benefits, power factor value, primary vs. secondary losses, etc.) but which enhance the cost-effectiveness of most DERs, if located in the areas of higher avoided costs.

Figure 8: Illustration of Integral Analytics LoadSEER Tool



Consistent with anecdotal reports from several of the jurisdictions surveyed for this study, one of the primary benefits of considering NWAs is that refinements to the load forecasting and planning process, coupled with improved collaboration between demand-side and distribution engineering, results in planned capacity expansion projects being deferred for reasons beyond just the projected impacts of deployed DERs.

Future Evaluation

As these pilots are just being developed at the time of this writing, there have not yet been any evaluations. However, PG&E will look very closely at the results of these pilots in the hope that DER approaches will become a much more prominent tool in its approach to reliably meeting its customers' energy needs.

4. Vermont

Early History

As discussed above, Vermont successfully tested the application of non-wires alternatives in the Mad River Valley in the mid-1990s. A few years later, the state embarked on a path to establishing an independent "Efficiency Utility" – soon thereafter named Efficiency Vermont – that would be charged with delivering statewide efficiency programs. However, the order creating Efficiency Vermont made clear that the state's T&D utilities would still be responsible for funding and implementing any additional efficiency programs that could be justified as cost-effective alternatives to investment in T&D infrastructure (though they could contract implementation to Efficiency Vermont). The Vermont Public Service Board also agreed to "initiate a collaborative process to establish guidelines for distributed utility planning".[90] That collaborative culminated in a set of guidelines approved by the Board in 2003 in Docket 6290. Among other things, the distribution utilities were required to file integrated resource plans every three years. Those plans must identify system constraints that could potentially be addressed through non-wires alternatives.[91] The order also led to the creation of a number of "area specific collaboratives" in which opportunities for deferring specific T&D upgrades through non-wires alternatives would be explored by the utilities, the State's Department of Public Service and other parties. However, none of those discussions led to implementation of any such alternatives.

Northwest Reliability Project

In 2003, VELCO,[92] the state's transmission utility, formally proposed a very controversial large project – the Northwest Reliability Project – to upgrade transmission lines from West Rutland to South Burlington. As required by Vermont law, VELCO filed an analysis of non-transmission alternatives. The analysis of a scenario including a combination of aggressive geographically targeted efficiency and distributed generation had a lower societal cost than the transmission line.[93] However, that option would involve much larger capital expenditures than the transmission line. Further, whereas much of the cost of the transmission option would be socialized across the New England Power Pool (Vermont pays a very small share of the portion of costs that are socialized across the region), the cost of the alternative path would be born entirely by Vermont ratepayers due to New England ISO rules. Those concerns, coupled with VELCO's concerns that the level of efficiency envisioned would be unprecedented, led the utility to argue in favor of the transmission option.[94] The Board ultimately approved VELCO's proposal in early 2005, but expressed concern and frustration with VELCO's planning process, namely that it did not consider alternatives, particularly efficiency, early enough in the process to make them truly viable options.[95]

[90] Vermont Public Service Board Order, Docket No. 5980, pp. 54-58.
[91] Vermont Public Service Board Order, Docket No. 6290.
[92] VELCO is Vermont's electric transmission-only company, formed in 1956 to create a shared electric grid in Vermont that could increase access to hydro-power for the state's utilities. http://www.velco.com/about
[93] La Capra Associates, "Alternatives to VELCO's Northwest Reliability Project", January 29, 2003.
[94] Ibid.
[95] Vermont Public Service Board, "Board Approves Substantially Conditioned and Modified Transmission System Upgrade", press release, January 28, 2005.

Act 61 – Institutionalizing Consideration of Non-Wires Alternatives

The approval of the transmission line contributed to the passage later that year of Act 61. Among other things, Act 61:

- required state officials to advocate for promotion of least cost solutions to T&D investments and equal treatment of the allocation of costs of both traditional T&D investments and non-wires alternatives "in negotiations and policy-making at the New England Independent System Operator, in proceedings before the Federal Energy Regulatory Commission, and in all other relevant venues…"
- required VELCO to regularly file a statewide transmission plan that looks forward at least 10 years; and
- eliminated the statutory spending cap for Efficiency Vermont, instructed the Board to determine the optimal level of efficiency spending, and made clear that cost-effectively deferring T&D upgrades should be one of the objectives the Board considers in establishing the budget.

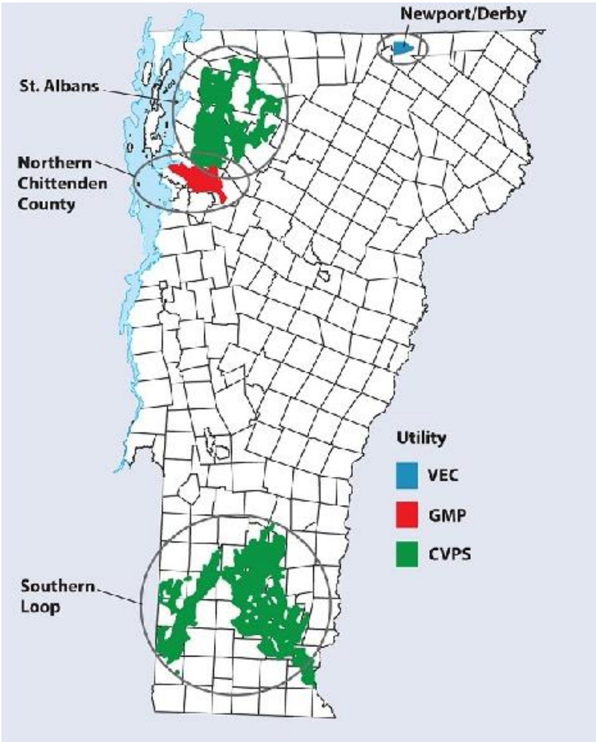
Key excerpts from Act 61 are provided in Appendix C.

Efficiency Vermont's Initial Geo-Targeting Initiative

In response to passage of Act 61, the Public Service Board increased Efficiency Vermont's budget by about $6.5 million (37%) in 2007 and $12.2 million (66%) in 2008 and ordered that all of the additional spending be focused on four geographically-targeted areas: northern Chittenden County, Newport, St. Albans, and the "southern loop" (see Figure 9).[96] Those areas had been identified by the state's utilities as areas in which there may be potential for deferring significant T&D investment. Collectively, these efforts became known as Efficiency Vermont's initial "geo-targeting" initiative. [97]

[96] Vermont Public Service Board, *Order Re: Energy Efficiency Utility Budget for Calendar Years 2006, 2007 and 2008*, 8/2/2006.
[97] Efficiency Vermont Annual Plan, 2008-2009.

Figure 9: Efficiency Vermont Geo-Targeting Regions (2007-2008)



Efficiency Vermont was given peak savings goals for these areas that represented a 7- to 10-fold increase in the peak savings it had historically been achieving in the areas through its statewide efficiency programs. To meet the goals Efficiency Vermont initiated intensive account management of large commercial and industrial customers, launched a small commercial direct install program, and locally increased marketing and promotion of CFLs.

Approximately one year into its delivery, one of the four initially targeted areas (Newport) was dropped from the geo-targeting program when the distribution utility determined that the substation whose rebuilding the program was intended to defer needed to be rebuilt for reasons other than load growth (i.e., "destabilization of the substation property due to river flooding").[98] Independent of that decision, a new target area – Rutland – was added to the program beginning in 2009.

An evaluation of the 2007-2009 geo-targeting efforts suggested the results were mixed. On the one hand, program participation was two to four times higher in the geo-targeted areas than statewide. Savings per participant were also higher – 20-25% higher for business customers and 30% higher for residential customers. The net result was summer peak savings that were three to five times higher in the first couple of years than would have been achieved under the statewide

[98] Navigant Consulting et al., *"Process and Impact Evaluation of Efficiency Vermont's 2007-2009 Geotargeting Program"*, Final Report, Submitted to Vermont Department of Public Service, January 7.

programs.[99] On the other hand, those summer peak savings were still 30% lower than Efficiency Vermont's goals for the targeted areas; winter peak savings were 60% lower than goals. Nevertheless, analysis of loads on individual feeders in geo-targeted areas suggests that geo-targeting program impacts "are detectable at the system level" and that the magnitude of savings observed at the utility system level were consistent with those estimated through evaluation of customer savings.[100]

Evaluation of the impacts of the observed peak demand reductions on the potential deferral of T&D investments was not conducted. However, Central Vermont Public Service (the state's largest utility at the time)[101] has observed that it "has not been required to schedule the deployment of additional system upgrades in Rutland, St. Albans and Southern Loop areas". While it is difficult to know the extent to which that situation should be attributed to the geo-targeting of DSM, to changes in economic conditions (i.e., the recent economic recession) and/or to other factors, the Company did recommend to the Board that geo-targeting of DSM continue.[102] One Vermont official similarly noted that

Vermont System Planning Committee

Subsequent to the passage of Act 61, the PSB initiated proceedings in Docket 7081 to develop a planning process that would ensure "full, fair and timely consideration of cost-effective non-transmission alternatives." The Public Service Board ultimately issued orders in 2007 approving an MOU between the major parties that established the Vermont System Planning Committee (VSPC) and charged it with carrying out this work.

The VSPC is a collaborative body. It brings together a wide range of viewpoints, including those of representative public stakeholders. There are six equally weighted voting contingents who are responsible for VSPC decisions on specific activities and projects:

- VELCO,
- large utilities with transmission,
- large utilities without transmission,
- other utilities without transmission,
- Efficiency Utilities (i.e. Efficiency Vermont and Burlington Electric Department) and renewable energy organizations, and
- public stakeholders.[103]

[99] Navigant Consulting et al., "Process and Impact Evaluation of Efficiency Vermont's 2007-2009 Geotargeting Program", Final Report, Submitted to Vermont Department of Public Service, January 7, 2011
[100] Navigant et al. (2011), p. 10.
[101] It was subsequently purchased and has become a part of Green Mountain Power.
[102] Silver, Morris, Counsel for Central Vermont Public Service, letter to the Vermont Public Service Board regarding "EEU Demand Resources Plan – Track C, Geotargeting", January 18, 2011.
[103] http://www.vermontspc.com/about/membership

The Public Service Board appoints the public stakeholders and the renewable energy representatives.

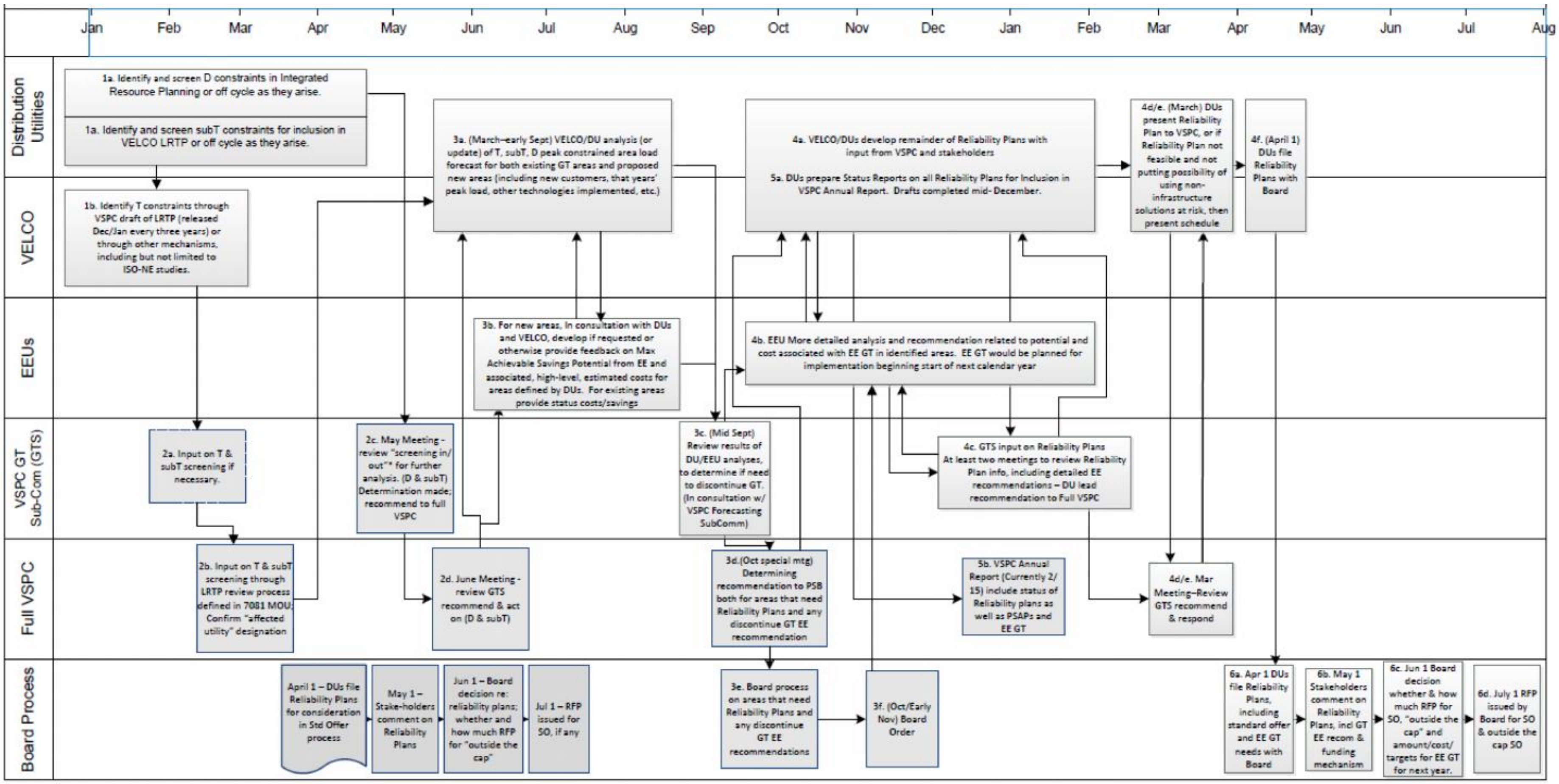
The VSPC process overcomes two significant barriers by first making sure that potential system constraints are identified as far in advance of their needed construction dates as possible, and secondly by ensuring that efficiency program planners are brought into the conversation early enough to determine whether efficiency is a viable alternative to construction given the particular customer segments that predominate in the targeted areas. Over time, the level of coordination in designing and implementing solutions has increased. In the first geographic targeting initiative undertaken by Efficiency Vermont in 2007, the state's utilities identified potentially constrained areas and then, with PSB approval, more-or-less handed the list to Efficiency Vermont. Now, with Efficiency Vermont serving as a fully participating member of the VSPC, a much more integrated approach is used, where the efficiency potential of constrained areas is investigated prior to their selection for geographically targeted efforts.

With the formation of the VSPC, significant efforts have also been invested in making sure that diverse viewpoints are represented in discussions regarding non-wires alternatives to both distribution and transmission construction. Further, a clear, well-documented and transparent process has been developed to make sure that results and decisions are firmly based on comprehensive consideration of evidence. This process has evolved over time. The current process is documented in Figure 10 below.[104]

In this process, VELCO, along with the large utilities that have transmission, is responsible for identifying bulk and predominantly bulk transmission system reliability improvement needs; the individual distribution utilities are responsible for identifying distribution and sub-transmission needs. Though they come from different dockets and legislation, in each case there is a requirement that these are identified on a three year basis, but project lists are also updated for the VSPC annually.

[104] http://www.vermontspc.com/library/document/download/599/GTProcessMap_final2.pdf

Figure 10: Vermont Geo-Targeting Process Map (as of 9/11/2013)



*"Screening" refers to the use of the Docket 7081 screening tool for bulk and predominantly bulk transmission and the Docket 6290 screening tool for subtransmission and distribution issues to determine their potential to be resolved through energy efficiency and/or alternatives such as generation or demand response (or a hybrid of transmission with efficiency and/or generation). An issue is "screened in" if it has potential for a non-wires solution and therefore requires a Reliability Plan, and "screened out" if no potential is found and, therefore, no Reliability Plan is required.

Key to abbreviations

D	distribution	LRTP	VELCO Long-Range Transmission Plan
DU	distribution utility	PSAP	project-specific action plan
EE	energy efficiency	RFP	request for proposal
EEU	energy efficiency utility	SO	standard offer
GT	geographic targeting	subT	subtransmission (subsystem)
GTS	VSPC Geotargeting Subcommittee	T	transmission (bulk/predominantly bulk)
		VSPC	Vermont System Planning Committee

As part of the development of T&D project lists, the utilities are required to use a set of "pre-screening" criteria to identify projects that might be candidates for non-wires alternatives. The key pre-screening criteria for distribution and sub-transmission projects are that the forecast "poles and wires" costs is greater than $250,000, that it is not required on an emergency basis, and that the need could be reduced by reductions in load.[105] For transmission projects to be considered for NWA approaches, the alternative needs to be projected to save at least $2.5M, needs to be able to be deferred or eliminated by a 25% or less reduction in load, does not need to be in place for at least one year into the future, and must not be needed for the purpose of meeting certain "stability" criteria related to grid performance. The VSPC reviews the utilities' initial project lists, including their pre-screening conclusions, and modifies them as appropriate. A recent example of a project list is provided in Table 4 below.

Table 4: Green Mountain Power 2014 Forecast of Distribution System Needs

Constraint	Load Growth related (Y/N)	MW Need	Year of need	Zonal identified MW available (potential study)	Further screening (Y/N)
Susie Wilson Substation Area	Yes		2037		No Continue to Monitor
Wilder - White River Junction Area	Reliability and Load Growth		2015		No
Waterbury	Reliability		2015		No
Winooski 16Y3 Feeder	No		2015		No
Hinesburg	Yes		2016		No
Dover Haystack	Yes		2015		No
Stratton	Reliability		2015		No
St Albans	Reliability and Load Growth		>10 years		Reliability Plan filed 4/2/14, Continue to Monitor
Miton	Yes		>10 years		No Continue to Monitor
Brattleboro	Yes		>10 years		No Continue to Monitor
Southern Loop	Yes		>10 years		No Continue to Monitor
Danby	Reliability and Load Growth		2016		No
Granite-Whetmore	Asset Management		2016		No
South Brattleboro	Reliability		2016		No
3309 Transmission	Reliability		2014		No Continue to Monitor / Refine the analysis
Rutland Area	Reliability		Existing Constraint		Reliability Plan filed 4/2/14, additional analysis required
Windsor Area	Reliability		2017		No

For projects that pass the initial screen, the VSPC then follows the collaboratively-developed process to consider non-wires solutions, with the efficiency and renewables alternatives given a detailed look by Efficiency Vermont and other stakeholders. To date this analysis has been

[105] http://www.velco.com/uploads/vspc/documents/ntascreening_6290.pdf

conducted with only limited use of smart grid data. Efficiency Vermont has a deep knowledge of its customer base through nearly fifteen years of program implementation, and can also easily track prior efficiency improvements that targeted customers made through participation in Efficiency Vermont initiatives. While there is diversity among Vermont's commercial and industrial customers, they are still mostly relatively small compared to the C&I base in other jurisdictions, and so far Efficiency Vermont has been able to assess these opportunities without the use of more detailed analytic tools.

Efficiency Vermont's Strategy and Planning group has been responsible for identifying opportunities to increase efficiency in targeted areas and for designing program approaches to capture that efficiency. Generally, the implementation of any geographically targeted energy efficiency alternatives has been managed by Efficiency Vermont in a manner that is highly coordinated with its other state-wide efforts. Since beginning to implement geographically targeted initiatives in 2007 Efficiency Vermont has been cognizant of the need for sensitivity when it determines to only offer certain programs to some, rather than all customers. For this reason, they have decreased the use of special incentives in targeted areas in favor of increased outreach and communications. For example, the use of account management strategies for C&I customers is increased in geographically targeted areas, meaning that smaller customers who would not have received the attention of individualized account managers in non-targeted areas do receive that attention in targeted areas. This account management approach also allows Efficiency Vermont to focus on projects that have the potential to produce higher peak savings than average, thus increasing the ability of efficiency to defer construction compared to an "average" project that did not receive this level of guidance from account managers.

Efficiency Vermont has not done competitive solicitations to identify vendors who will commit to delivering certain savings through strategies of their own devising. Rather they have designed and managed program initiatives internally, with limited use of third-party vendors to implement programs for which Efficiency Vermont has developed the parameters. However they are investigating the potential to use the targeted deployment of third-party approaches in the future, specifically those that make use of smart grid data to identify savings opportunities to engage customers who might otherwise not have been aware of them.

With the VSPC process in place, the relationship between level of effort and the amount of resource needed in a specific area is much, much stronger. Where the first of Efficiency Vermont's geographically targeted efforts involved a single goal that could be met through savings in any of several targeted areas, goals are now set that are specific to each targeted area, and that reflect the actual need in that area as determined by system planners.

The VSPC and the planning process for non-wires alternatives have matured significantly in Vermont. Conversations with the Public Service Department and Efficiency Vermont both suggest confidence in the process. Going forward, it is expected that the VSPC process will continue to be used to identify potential candidates for geographic targeting of NWAs.

V. Cross-Cutting Observations and Lessons Learned

Although the use of efficiency to meet T&D needs– either alone or in combination with other non-wires resources – is not yet widespread, it is fairly substantial and growing. That experience offers a number of insights, presented below, for jurisdictions considering the use of such resources in the future.

The Big Picture

1. Geographically Targeted Efficiency Can Defer Some T&D Investments

Projects run by Con Ed (from 2003 through 2012), Vermont (both the initial Green Mountain Power Project in the mid-1990s and more recent examples), PG&E's Delta Project in California (in the early 1990s), and portions of PGE's project in downtown Portland, Oregon (also in the early 1990s), all demonstrably achieved enough savings to defer some T&D investments for at least some period of time. Preliminary results from the first year of experience with new projects in Maine and Rhode Island suggest that they too are likely on track to defer T&D investments.

2. T&D Deferrals Can be Very Cost-Effective

The cost-effectiveness of geographically-targeted efficiency programs and other non-wires resources will unquestionably be project-specific. That said, though data on the cost-effectiveness of T&D deferrals is not available for all of the projects we have examined, the information that is available suggests that efficiency and other non-wires resources can be very cost-effective – i.e. potentially much less expensive than "poles and wires" alternatives. For example, Con Ed's evaluation suggests that its geographically targeted efficiency investments from 2003 to 2010 produced roughly $3 in total benefits for every $1 in costs; the T&D benefits alone were worth 1½ times the costs of the programs. Similarly, the revenue requirements for Maine's pilot project are forecast to be more than 60% lower than for the alternative transmission solution.

3. There Is Significant Value to the "Modular" Nature of Efficiency and Other NWAs

One of the advantages of energy efficiency and other non-wires alternatives is that they are typically very modular in nature. That is, they are usually acquired in a number of small increments – e.g. thousands of different efficiency measures across hundreds, if not thousands of different customers, across several years. In contrast, the pursuit of a "poles and wires" strategy typically requires a commitment to much larger individual investments – if not a singular investment.

The modularity of efficiency and other non-wires alternatives allows for a ramp up or a ramp down of effort, either in response to market feedback (e.g. if customer uptake is greater or lower than expected) or in response to changing forecasts of T&D need. For example, as discussed in the case study of the Maine pilot project, the magnitude of the non-wires resource needed to defer the transmission investment has declined from an initial estimate of 2.0 MW to 1.8 MW.

Moreover, perhaps in anticipation of possible future changes, a decision has been made to not yet contract for the last 0.1 MW of need because that can be addressed at a future time if it is still determined to be needed. Similarly, again as noted above, Con Ed has found that one of the biggest advantages of its non-wires projects is that they have "bought time" for the utility to better tune its forecasts, to the point in a number of cases where the T&D investments once thought to be needed are now not anticipated to ever be needed.

4. Policy Mandates Are Driving Most Deployments of NWAs

Virtually all of the examples of the use of non-wires alternatives that we have profiled in this report were at least initially driven by either legislative mandates, regulatory guidelines or types of regulatory feedback. Examples of such requirements are provided in Appendices A through D.

The importance of policy mandates may be partly indicative of the nature of the internal barriers to utility pursuit of non-wires solutions. Utilities tend to be fairly conservative institutions. That is consistent with their primary mission of "keeping the lights on". It is understandable that they would be reluctant to change practices that they know are successful in serving that mission. As noted above, there are also challenges associated with persuading system planners that demand side alternatives can also be reliable.

In addition, utilities' financial incentives are generally not well aligned with the objective of pursuing cost-effective alternatives to "poles and wires". Right now, utilities can face a choice of earning money for shareholders if they pursue a traditional T&D path (because they earn a rate of return on such capital investments) or making no money if they choose to deploy non-wires alternatives.[106] To our knowledge, Con Ed's proposal for shareholder incentives for the large new Brooklyn-Queens project is the only proposal of its kind that attempts to directly address this issue.

Implementation

5. Cross-Disciplinary Communication and Trust is Critical

This may seem self-evident, but it is critical nonetheless. T&D planners and engineers are often skeptical of the potential for end use efficiency and/or other demand resources to reliably substitute for poles, wires and other T&D "hardware". They worry that customers themselves are unreliable. Similarly, staff responsible for administration of programs that promote efficiency, load control, distributed generation or other demand resources typically do not fully

[106] Some utilities operate under capital spending caps. In such cases, the financial disincentives may be mitigated, at least in the short term, with money freed up from deployment of NWAs to defer or eliminate the need for some T&D investments effectively enabling the utility to invest in other T&D projects further down its priority list. However, if deployment of cost-effective NWAs is institutionalized, regulators could eventually respond by reducing capital spending caps.

understand the complexities of the reliability issues faced by T&D system planners. Both need to better understand the needs and capabilities of the other.

It can take time to develop the relationships and confidence necessary for efficiency program implementers and T&D system engineers to work together effectively. However, those relationships and that trust must be developed if efficiency programs are to successfully defer T&D investments.

Different jurisdictions and utilities have approached the challenge of facilitating cross-disciplinary collaboration differently. Con Ed has created a multi-disciplinary team that meets regularly under the direction of a Senior Vice President. PG&E has assigned field services engineers with customer-side experience to work side-by-side with distribution planning engineers on their pilot non-wires projects, with the expectation that the experience of working together will build trust and mutual understanding over time. Vermont's System Planning Committee serves a similar function, institutionalizing communication between system planners and those responsible for efficiency program delivery (as well as other stakeholders).

6. Senior Management Buy-in Is Invaluable

Senior management support for consideration of non-wires alternatives can be critical, if not essential, to facilitating the kind of cross-disciplinary collaboration that is necessary to be successful.

Senior management support will also be necessary to get to the point where consideration of cost-effective non-wires alternatives is routine and fully integrated into the way utilities run their businesses. As discussed further below, that, in turn, may require changes to utilities' financial incentives.

7. Smaller Is Easier

In general, all other things being equal, the smaller the size of the load reduction needed and the smaller the number of customers, the easier it is to plan and execute a non-wires solution. Smaller areas allow for greater understanding of both the customer mix and the savings or distributed generation opportunities associated with those customers. It is also generally easier to mobilize the existing demand resources delivery infrastructure (e.g. HVAC, lighting and/or other contractors) to meet a smaller need.

That is not to say that only small projects should be pursued, as the economic net benefits from larger projects also tend to be larger. Larger areas do offer one advantage: a more diverse range of customers and savings opportunities from which to choose in designing and implementing an NWA solution. A corollary to this point is that networked systems may be easier to address than radial systems because they allow for treatment of a larger number of customers to address a need. However, it is also important to recognize that larger projects with more customers over a larger geographic area will also be more complex and often require more lead time to plan and execute.

8. Distribution is Easier than Transmission

This may seem like just a corollary to the “smaller is easier”, as distribution projects are generally smaller than transmission projects. However, there is more to it than that. For one thing, distribution system planning is generally less technically complex and more “linear” – 1 MW of load reduction commonly translates to 1 MW (adjusted for losses) of reduced distribution infrastructure need. In transmission planning 1 MW of load reduction in an area does not necessarily translate to 1 MW of reduced infrastructure need. In addition, distribution system planning typically involves fewer parties so decision-making is often more streamlined. Moreover, distribution reliability planning criteria can be less stringent than transmission planning criteria, so there may be opportunities to use NWAs with shorter time horizons and/or with less certainty that forecast savings will be achieved (i.e. there can be more flexibility for utilities in the timing of distribution infrastructure upgrades).

Finally, and perhaps most importantly, the cost allocations for both distribution system investments and their non-wires alternatives will typically both be fully and equally born by local ratepayers. This is in stark contrast to the allocation of transmission costs, which are governed by regional frameworks that inherently bias investments in favor of traditional “poles and wires” solutions. Typically transmission investment costs are socialized across multi-state regions, so that the state in which the transmission investment is needed pays only a portion of the project costs. In the case of non-wires alternatives, the state in which the project is deployed is made to bear all of the costs. Clearly, until this is addressed, it will continue to be challenging to implement NWAs to defer transmission projects.

9. Integrating Efficiency with Other Alternatives Will be Increasingly Common and Important

In several of the examples that we examined in this report geographically-targeted efficiency programs were enough, by themselves, to defer the traditional T&D investment. However, in some cases efficiency was effectively paired with demand response and/or other non-wires alternatives. As the projects being considered become larger and more complex and the development of non-wires solutions becomes more sophisticated, we expect such multi-pronged solutions to become more common. That is certainly the case, for example, with Con Ed’s new Brooklyn-Queens project. Moreover, even a comprehensive suite of NWAs may be inadequate, by themselves, to address reliability concerns. In such cases, NWAs could potentially be paired with some T&D modifications, deferring only a portion of a larger T&D investment project.

10. "Big Data" and New Analytical Tools Enable More Sophisticated Strategies

Several of the geographic targeting projects that have occurred to date have found that the availability of savings was different from their initial expectations because their assumptions about the customers in the targeted areas were found to have been inaccurate. This was true for the Tiverton project in Rhode Island, where initial plans called for a substantial amount of demand response for residential central air conditioning systems, but where it turned out that the penetration of central air conditioning was much lower than originally expected. Similarly, Con Ed found that contractors weren't able to meet their savings targets in the later years of their initial geo-targeting efforts and attributed this to the lack of a detailed understanding of the types of customers and predominant end uses in the targeted areas.

Utilities have also faced uncertainty in assessing the cost-effectiveness of NWAs, in no small part because accurately assessing loads and growth is challenging, and utility system planners—who are responsible for assuring that the lights will stay on— may have some understandable bias towards high safety margins when assessing system capacity. Put another way, accurately valuing the economic benefits of alternatives to poles and wires approaches is not easy.

Reliable and malleable planning tools are needed that will allow more accurate modeling of loads at a much more detailed level, and that will provide a better accounting of available savings and the economic value associated with them. Understanding the opportunities available to customers within defined and specific geographies, coupled with detailed load and economic information, will allow utilities to plan NWA approaches with greater confidence and to yield greater economic benefits (i.e. from the use of more granular, locational avoided costs) in the process. In recognition of this, several utilities and third party vendors are rapidly developing tools to address these emerging needs. We are aware of efforts by Integral Analytics for PG&E and others, and by Energy + Environmental Economics (E3) for Con Ed. Navigant is also participating in projects for both of these utilities, and it is likely that others are exploring this space as well.

Integral Analytics has developed a suite of proprietary software tools specifically for the purpose of providing utilities with previously unavailable capability for assessing loads down to the acre level, and for developing avoided costs that are specific to each circuit. These tools would not only provide California utilities with the means to comply with AB327, but would also allow them to assess the need for load relief with much greater precision and to plan NWAs more reliably. Integral Analytics has made special efforts to engage distribution planners in the development of their tools, in recognition of the importance of their participation in identifying and proposing NWAs.

E3 is working closely with Con Ed, as discussed above, to develop a "Decision Tool Integrator" that will overcome the earlier challenges the utility faced in accurately assessing the availability of savings, and further will allow them to identify the combinations of non-wires and traditional approaches that will be best suited to achieving the required load relief in specific areas.

Impact Assessment

11. Impact Assessment Should Focus First on the T&D Reliability Need

Conceptually, assessment of geographically-targeted efficiency programs (and other non-wires resources for that matter) can address one or more of several key questions. Chief among them are:

1. Has the forecast T&D need changed? Has it moved further out into the future, or even been eliminated as a result of targeted programs?
2. To the extent that the forecast T&D need has changed, how much of that change is attributable to the deployment of geographically-targeted efficiency and/or other non-wires resources?
3. What is the magnitude of the T&D peak reduction (for efficiency or demand response) or production (for distributed generation or storage) that has been realized as a result of the deployment of efficiency and/or other non-wires resources? Note that the answer to this question might help inform the answer to the second question above.

To date, the principal focus of most jurisdictions' efforts to assess the impacts of NWAs has been on the first question: was the need for the T&D investment pushed out into the future? This is the most directly answerable question in the sense that it is really about how the current forecast of need has changed from the original forecast of need. It is also clearly the most important because it addresses the "bottom-line" metric that dictates whether money has been saved. In contrast, the second question – how much of the deferral is attributable to the non-wires alternatives – is challenging to address, in part because it begs the question of what "baseline" the evaluation is measuring against.

It is worth emphasizing that one of the key findings from non-wires projects has been that they often "buy time" to improve forecasts of need. Thus, one could argue that a non-wires solution should get "full credit" for a deferral even if the savings that the non-wires alternatives provided were not, by themselves, responsible for 100% of the difference between the old forecast and the new forecast of T&D need. As one Vermont official put it, in discussing a recent geo-targeting effort in the city of St. Albans:

> *"It is impossible to say that one thing deferred the project. But I would also argue that energy efficiency gave us the time to realize that we didn't need the project. As long as we follow a robust process for selecting geo-targeting areas, energy efficiency can be a 'no regrets' strategy, where even if it does not defer the project the efficiency investment is cost-effective (thanks to its avoided energy, capacity and other costs) and allows for more certainty as to the need for the infrastructure. In an energy system world where decisions must be made amidst so much uncertainty, geo-targeted efficiency's risk*

> *mitigation value increases above and beyond the risk value that we give to statewide programs."*[107]

That all said, traditional evaluation, measurement and verification (EM&V) of geographically targeted efficiency programs – both impact evaluation to determine how much T&D peak demand savings were realized and process evaluation to understand what worked well and what did not – can still provide a lot of value. However, that value may be more related to informing planning for future projects than for retrospectively "scoring" the effectiveness of the geo-targeting and/or assigning attribution for T&D deferrals.

[107] Personal communication with T.J. Poor, Vermont Public Service Department, December 23, 2014.

VI. Policy Recommendations

In virtually every jurisdiction profiled in this report, the impetus for consideration of lower cost non-wires solutions to address selected reliability needs has been driven (at least initially) by some form of government policy – either legislative requirements, regulatory requirements or feedback, or both. In this section of the report, we present what lessons learned from leading jurisdictions suggests about key policies. Specifically, we offer four policies that policy-makers should consider if they are to effectively advance consideration of alternatives – including, but not limited to geographically targeted efficiency programs – to transmission and/or distribution system investments. Note that though we use the terminology "non-wires solutions" because most of the focus of this report has been on the electricity sector, the same concepts should apply to "non-pipes solutions" for the natural gas sector.

Recommendation 1: Require Least Cost Approach to Meeting T&D Needs

This is the most basic, but also the most important policy for promoting consideration of alternatives to T&D investments. It is in place in every jurisdiction that is routinely assessing such alternatives on a routine basis. Because the barriers to non-wires alternatives – both institutional and financial – are so strong, this kind of requirement is necessary. It should be emphasized that though necessary, least cost requirements are not sufficient to ensure that economically optimal solutions to reliability needs are considered (see other policy recommendations below).

One other possible alternative would be an overhaul of the way utilities are regulated, including strong financial incentives for minimizing T&D costs imposed on ratepayers. That is the path that the state of New York appears to be pursuing. While intriguing, such a twist on the concept of performance regulation is untested and will be challenging to get right. That is not to say it should not be pursued – only that it needs to be done with great care, with regular evaluation to ensure it is producing the desired results, and perhaps with "backstop" minimum requirements to ensure that the expected and desired results are achieved.

Recommendation 2: Require Long-Term Forecast of T&D Needs

One of the keys to realizing the full benefits that efficiency, demand response, distributed generation, storage and/or other non-wires solutions can provide is ensuring that they can deployed with sufficient lead time to defer T&D investments. We have highlighted several cases in this report in which non-wires solutions could have been less expensive than the wires solutions, but were not pursued (at least in part) because of concern that there was not enough lead time to be certain that the reliability need would be met. Requiring a long-term forecast of T&D investments can significantly reduce the probability of such less than optimal outcomes. By long-term we mean at least 10 years. However, 20 years – as is currently required in Vermont – may be even better. While the accuracy of these forecasts will diminish the farther out into the future they go, a 20 year forecast will still do a better job at ensuring that insufficient lead time does not preclude deployment of cost-effective non-wires solutions.

Recommendation 3: Establish Screening Criteria for NWA Analyses

One way to help effectively institutionalize consideration of non-wires solutions is to establish a set of minimum criteria that would trigger a detailed assessment of non-wires solutions. Most of the jurisdictions discussed in this report have such criteria.

All such criteria start with a requirement that the project be load-related. As the Rhode Island guidelines put it, the need cannot be a function of the condition of the asset (e.g. to replace aging or malfunctioning equipment). Some jurisdictions, such as Vermont, have a short "form" that utilities must complete for each proposed project that provides more detail on this question.

Most jurisdictions have additional criteria related to one or more of the following:

- **Sufficient Lead Time Before Need.** The purpose of this criterion is to ensure that there is enough lead time to enable deferring a T&D investment.
- **Limits to the Size of Load Reduction Required.** The purpose of this criterion is to ensure that there is a substantial enough probability that the non-wires solution can be effective before investing in more detailed assessments. The maximum reduction can be linked to the previous criterion around lead time, as the longer the lead time the larger the reduction in load (and/or equivalent distributed generation level) that could be achieved through non-wires solutions.
- **Minimum Threshold for T&D Project Cost.** The purpose of this criterion is to ensure that the potential benefits of a T&D deferral are great enough to justify more detailed analysis.

Table 5 below provides a summary of the criteria currently in place for a number of the jurisdictions assessed in this report.

Table 5: Criteria for Requiring Detailed Assessment of Non-Wires Solutions

	Must Be Load Related	Minimum Years Before Need	Maximum Load Reduction Required	Minimum T&D Project Cost	Source
Transmission					
Vermont	Yes	1 to 3 4 to 5 6 to 10	15% 20% 25%	$2.5 Million	Regulatory policy
Maine	Yes			>69 kV or >$20 Million	Legislative standard
Rhode Island	Yes	3	20%	$ 1 Million	Regulatory policy
Pacific Northwest (BPA)	Yes	5		$3 Million	Internal planning criteria
Distribution					
PG&E (California)	Yes	3	2 MW		Internal planning criteria
Rhode Island	Yes	3	20%	$ 1 Million	Regulatory policy
Vermont	Yes		25%	$0.3 Million	Regulatory policy

Documents that lay out these requirements more formally and in more detail are provided for Vermont and Rhode Island in Appendices D, E and F.

Consistent with the integrated resource planning guideline discussed above, when projects pass such initial screening criteria, the utility should be required to conduct a more detailed assessment of the potential for reduced peak demand in the geographic area of interest through any combination of distributed resources, including additional energy efficiency, demand response, distributed generation and storage. The cost of such additional distributed resources should then be compared to their benefits. The level of depth of analysis would be a function of the magnitude of the deferral project. For projects for which the more detailed assessment suggests that greater EE and DR would have positive net benefits,[108] the utility should be required to pursue the non-wires solution.

Recommendation 4: Promote Equitable Cost Allocation for NTAs

Investments in transmission solutions to reliability needs are commonly socialized across power pools. For example, a large majority of the cost of a transmission investment in Maine can ultimately be borne by ratepayers in the other five states that are part of the New England grid. In contrast, there is no comparable mechanism to socialize the cost of non-transmission investments across the region[109] – even if they would just as effectively address the reliability

[108] As discussed earlier in the report, some NWAs, including energy efficiency, provide a number of benefits beyond deferral of T&D investments. All costs and benefits of both NWAs and traditional T&D investments should be included in any economic comparisons.

[109] Note that though there is currently no mechanism for socializing the costs of implementing NTAs, there is at least an open question as to whether the costs of *analyzing* NTAs could be socialized. Indeed, some costs of analysis of

concern at a substantially lower cost. In other words, if Maine invests in a non-transmission solution, it will have to bear the full cost of that approach. This is a huge economic barrier to consideration of cost-effective non-transmission investments. Legislation in some states now requires their state officials to advocate for equal treatment of transmission and non-transmission planning and cost allocation in negotiations with and proceedings before their independent system operators, the Federal Energy Regulatory Commission (FERC) and other bodies and fora. Excerpts from the Vermont and Maine legislative language are provided below:

Vermont Act 61, Section 8

"(5) The public service department, public service board, and attorney general shall advocate for these policies in negotiations and appropriate proceedings before the New England Independent System Operator, the New England Regional Transmission Operator, the Federal Energy Regulatory Commission, and all other appropriate regional and national forums. This subdivision shall not be construed to compel litigation or to preclude settlements that represent a reasonable advance to these policies.

(6) In addressing reliability problems for the state's electric system, Vermont retail electricity providers and transmission companies shall advocate for regional cost support for the least cost solution with equal consideration and treatment of all available resources, including transmission, strategic distributed generation, targeted energy efficiency, and demand response resources on a total cost basis. This subdivision shall not be construed to compel litigation or to preclude settlements that represent a reasonable advance to these policies.

Maine 2013 Omnibus Energy Bill, Part C, Sec. C-7 (35-A MRSA §3132)

15. Advancement of non-transmission alternatives policies. The commission shall advocate in all relevant venues for the pursuit of least-cost solutions to bulk power system needs on a total cost basis and for all available resources, including non-transmission alternatives, to be treated comparably in transmission analysis, planning and access to funding.

The greater the number of states that have such policies in place, the greater the likelihood that this barrier will be addressed. The question of what "comparable treatment" to socialization of traditional transmission and non-transmission investments means is not necessarily a simple one. It is likely to require careful thought and discussion among a number of stakeholders. States can play an important role in pressing for and shaping such discussions.

NTAs are already indirectly socialized. For example, VELCO, Vermont's transmission utility, currently recovers costs associated with its system planners through a regional tariff. Thus, when those planners work on NTAs, the costs of that work are effectively socialized across the regional. However, to our knowledge, no entity has yet tested whether other costs of analyzing NTAs (e.g. those born by other entities in a state) are recoverable through regional tariffs.

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Appendix A: California AB 327 (excerpt)

SEC. 8. Section 769 is added to the Public Utilities Code, to read:

769. (a) For purposes of this section, “distributed resources” means distributed renewable generation resources, energy efficiency, energy storage, electric vehicles, and demand response technologies.

(b) Not later than July 1, 2015, each electrical corporation shall submit to the commission a distribution resources plan proposal to identify optimal locations for the deployment of distributed resources. Each proposal shall do all of the following:

1) Evaluate locational benefits and costs of distributed resources located on the distribution system. This evaluation shall be based on reductions or increases in local generation capacity needs, avoided or increased investments in distribution infrastructure, safety benefits, reliability benefits, and any other savings the distributed resources provides to the electric grid or costs to ratepayers of the electrical corporation.
2) Propose or identify standard tariffs, contracts, or other mechanisms for the deployment of cost-effective distributed resources that satisfy distribution planning objectives.
3) Propose cost-effective methods of effectively coordinating existing commission-approved programs, incentives, and tariffs to maximize the locational benefits and minimize the incremental costs of distributed resources.
4) Identify any additional utility spending necessary to integrate cost-effective distributed resources into distribution planning consistent with the goal of yielding net benefits to ratepayers.
5) Identify barriers to the deployment of distributed resources, including, but not limited to, safety standards related to technology or operation of the distribution circuit in a manner that ensures reliable service.

(c) The commission shall review each distribution resources plan proposal submitted by an electrical corporation and approve, or modify and approve, a distribution resources plan for the corporation. The commission may modify any plan as appropriate to minimize overall system costs and maximize ratepayer benefit from investments in distributed resources.

(d) Any electrical corporation spending on distribution infrastructure necessary to accomplish the distribution resources plan shall be proposed and considered as part of the next general rate case for the corporation. The commission may approve proposed spending if it concludes that ratepayers would realize net benefits and the associated costs are just and reasonable. The commission may also adopt criteria, benchmarks, and accountability mechanisms to evaluate the success of any investment authorized pursuant to a distribution resources plan.

Appendix B: Maine 2013 Omnibus Energy Bill Excerpts

An Act To Reduce Energy Costs, Increase Energy Efficiency, Promote Electric System Reliability and Protect the Environment

PART C

Sec. C-1. 35-A MRSA §3131, sub-§4-B is enacted to read:

4-B. Nontransmission alternative. "Nontransmission alternative" means any of the following methods used either individually or combined to reduce the need for the construction of a transmission line under section 3132 or transmission project under section 3132-A: energy efficiency and conservation, load management, demand response or distributed generation.

Sec. C-2. 35-A MRSA §3132, sub-§2-C, ¶¶B and C, as enacted by PL 2009, c. 309, §2, are amended to read:

B. Justification for adoption of the route selected, including comparison with alternative routes that are environmentally, technically and economically practical; ~~and~~

C. Results of an investigation by an independent 3rd party, which may be the commission or a contractor selected by the commission, of nontransmission alternatives to construction of the proposed transmission line ~~including energy conservation, distributed generation or load management~~. The investigation must set forth the total projected costs of the transmission line as well as the total projected costs of the alternatives over the effective life of the proposed transmission line; and

Sec. C-3. 35-A MRSA §3132, sub-§2-C, ¶D is enacted to read:

D. A description of the need for the proposed transmission line.

Sec. C-4. 35-A MRSA §3132, sub-§5, as enacted by PL 1987, c. 141, Pt. A, §6, is amended to read:

5. Commission approval of a proposed line. The commission may approve or disapprove all or portions of a proposed transmission line and shall make such orders regarding its character, size, installation and maintenance as are necessary, having regard for any increased costs caused by the orders. The commission shall give preference to the nontransmission alternatives that have been identified as able to address the identified need for the proposed transmission line at lower total cost to ratepayers in this State. When the costs to ratepayers in this State of the identified nontransmission alternatives are reasonably equal, the commission shall give preference to the alternatives that produce the lowest amount of local air emissions, including greenhouse gas emissions.

Sec. C-5. 35-A MRSA §3132, sub-§6, as repealed and replaced by PL 2011, c. 281, §1, is amended to read:

6. Commission order; certificate of public convenience and necessity. In its order, the commission shall make specific findings with regard to the public need for the proposed transmission line. The commission shall make specific findings with regard to the likelihood that nontransmission alternatives can sufficiently address the identified public need over the effective life of the transmission line at lower total cost. Except as provided in subsection 6-A for a high-impact electric transmission line and in accordance with subsection 6-B regarding nontransmission alternatives, if the commission finds that a public need exists, after considering whether the need can be economically and reliably met using nontransmission alternatives, it shall issue a certificate of public convenience and necessity for the transmission line. In determining public need, the commission shall, at a minimum, take into account economics, reliability, public health and safety, scenic, historic and recreational values, state renewable energy generation goals, the proximity of the proposed transmission line to inhabited dwellings and alternatives to construction of the transmission line, including energy conservation, distributed generation or load management. If the commission orders or allows the erection of the transmission line, the order is subject to all other provisions of law and the right of any other agency to approve the transmission line. The commission shall, as necessary and in accordance with subsections 7 and 8, consider the findings of the Department of Environmental Protection under Title 38, chapter 3, subchapter 1, article 6, with respect to the proposed transmission line and any modifications ordered by the Department of Environmental Protection to lessen the impact of the proposed transmission line on the environment. A person may submit a petition for and obtain approval of a proposed transmission line under this section before applying for approval under municipal ordinances adopted pursuant to Title 30-A, Part 2, Subpart 6-A; and Title 38, section 438-A and, except as provided in subsection 4, before identifying a specific route or route options for the proposed transmission line. Except as provided in subsection 4, the commission may not consider the petition insufficient for failure to provide identification of a route or route options for the proposed transmission line. The issuance of a certificate of public convenience and necessity establishes that, as of the date of issuance of the certificate, the decision by the person to erect or construct was prudent. At the time of its issuance of a certificate of public convenience and necessity, the commission shall send to each municipality through which a proposed corridor or corridors for a transmission line extends a separate notice that the issuance of the certificate does not override, supersede or otherwise affect municipal authority to regulate the siting of the proposed transmission line. The commission may deny a certificate of public convenience and necessity for a transmission line upon a finding that the transmission line is reasonably likely to adversely affect any transmission and distribution utility or its customers.

Sec. C-6. 35-A MRSA §3132, sub-§6-B is enacted to read:

6-B. Reasonable consideration of nontransmission alternatives. If the commission determines that nontransmission alternatives can sufficiently address the transmission need under subsection 6 at lower total cost, but at a higher cost to ratepayers in this State than the proposed transmission line, the commission shall make reasonable efforts to achieve within 180 days an agreement among the states within the ISO-NE region to allocate the cost of the nontransmission alternatives among the ratepayers of the region using the allocation method used for transmission lines or a different allocation method that results in lower costs than the proposed transmission line to the ratepayers of this State.

For the purposes of this section, "ISO-NE region" has the same meaning as in section 1902, subsection 3.

The subsection is repealed December 31, 2015.

Sec. C-7. 35-A MRSA §3132, sub-§15 is enacted to read:

15. Advancement of nontransmission alternatives policies. The commission shall advocate in all relevant venues for the pursuit of least-cost solutions to bulk power system needs on a total cost basis and for all available resources, including nontransmission alternatives, to be treated comparably in transmission analysis, planning and access to funding.

Sec. C-8. 35-A MRSA §3132-A is enacted to read:

§ 3132-A. Construction of transmission projects prohibited without approval of the commission

A person may not construct any transmission project without approval from the commission. For the purposes of this section, "transmission project" means any proposed transmission line and its associated infrastructure capable of operating at less than 69 kilovolts and projected to cost in excess of $20,000,000.

1. Submission requirement. A person that proposes to undertake in the State a transmission project must provide the commission with the following information:

A. Results of an investigation by an independent 3rd party, which may be the commission or a contractor selected by the commission, of nontransmission alternatives to construction of the proposed transmission project. The investigation must set forth the total projected costs of the transmission project as well as the total projected costs of the nontransmission alternatives over the effective life of the proposed transmission project; and

B. A description of the need for the proposed transmission project.

2. Approval; consideration of nontransmission alternatives. In order for a transmission project to be approved, the commission must consider whether the identified need over the effective life of the proposed transmission project can be economically and reliably met using nontransmission alternatives at a lower total cost. During its review the commission shall give preference to nontransmission alternatives that are identified as able to address the identified need for the proposed transmission project at lower total cost to ratepayers. Of the identified nontransmission alternatives, the commission shall give preference to the lowest-cost nontransmission alternatives. When the costs to ratepayers of the identified nontransmission alternatives are reasonably equal, the commission shall give preference to the alternatives that produce the lowest amount of local air emissions, including greenhouse gas emissions.

3. Exception. A transmission project that is constructed, owned and operated by a generator of electricity solely for the purpose of electrically and physically interconnecting the generator to the transmission system of a transmission and distribution utility is not subject to this section.

Appendix C: Vermont Act 61 Excerpts

Sec. 8. ADVOCACY FOR REGIONAL ELECTRICITY RELIABILITY POLICY

It shall be the policy of the state of Vermont, in negotiations and policy-making at the New England Independent System Operator, in proceedings before the Federal Energy Regulatory Commission, and in all other relevant venues, to support an efficient reliability policy, as follows:

(1) When cost recovery is sought through region-wide regulated rates or uplift tariffs for power system reliability improvements, all available resources – transmission, strategic generation, targeted energy efficiency, and demand response resources – should be treated comparably in analysis, planning, and access to funding.

(2) A principal criterion for approving and selecting a solution should be whether it is the least-cost solution to a system need on a total cost basis.

(3) Ratepayers should not be required to pay for system upgrades in other states that do not meet these least-cost and resource-neutral standards.

(4) For reliability-related projects in Vermont, subject to the review of the public service board, regional financial support should be sought and made available for transmission and for distributed resource alternatives to transmission on a resource-neutral basis.

(5) The public service department, public service board, and attorney general shall advocate for these policies in negotiations and appropriate proceedings before the New England Independent System Operator, the New England Regional Transmission Operator, the Federal Energy Regulatory Commission, and all other appropriate regional and national forums. This subdivision shall not be construed to compel litigation or to preclude settlements that represent a reasonable advance to these policies.

(6) In addressing reliability problems for the state's electric system, Vermont retail electricity providers and transmission companies shall advocate for regional cost support for the least cost solution with equal consideration and treatment of all available resources, including transmission, strategic distributed generation, targeted energy efficiency, and demand response resources on a total cost basis. This subdivision shall not be construed to compel litigation or to preclude settlements that represent a reasonable advance to these policies.

* * * Transmission and Distribution Planning * * *

Sec. 9. 30 V.S.A. § 218c is amended to read:

§ 218c. LEAST COST INTEGRATED PLANNING

(d)(1) Least cost transmission services shall be provided in accordance with this subsection. Not later than July 1, 2006, any electric company that does not have a designated retail service territory and that owns or operates electric transmission facilities within the state of Vermont, in conjunction with any other electric companies that own or operate these facilities, jointly shall prepare and file with the department of public service and the public service board a transmission system plan that looks forward for a period of at least ten years. A copy of the plan shall be filed with each of the following: the house committees on commerce and on natural resources and energy and the senate committees on finance and on natural resources and energy. The objective of the plan shall be to identify the potential need for transmission system improvements as early as possible, in order to allow sufficient time to plan and implement more cost-effective non-transmission alternatives to meet reliability needs, wherever feasible. The plan shall:

(A) identify existing and potential transmission system reliability deficiencies by location within Vermont;

(B) estimate the date, and identify the local or regional load levels and other likely system conditions at which these reliability deficiencies, in the absence of further action, would likely occur;

(C) describe the likely manner of resolving the identified deficiencies through transmission system improvements;

(D) estimate the likely costs of these improvements;

(E) identify potential obstacles to the realization of these improvements; and

(F) identify the demand or supply parameters that generation, demand response, energy efficiency or other non-transmission strategies would need to address to resolve the reliability deficiencies identified.

(2) Prior to the adoption of any transmission system plan, a utility preparing a plan shall host at least two public meetings at which it shall present a draft of the plan and facilitate a public discussion to identify and evaluate non-transmission alternatives. The meetings shall be at separate locations within the state, in proximity to the transmission facilities involved or as otherwise required by the board, and each shall be noticed by at least two advertisements, each occurring between one and three weeks prior to the meetings, in newspapers having general circulation within the state and within the municipalities in which the meetings are to be held. Copies of the notices shall be provided to the public service board, the department of public

service, any entity appointed by the public service board pursuant to subdivision 209(d)(2) of this title, the agency of natural resources, the division for historic preservation, the department of health, the scenery preservation council, the agency of transportation, the attorney general, the chair of each regional planning commission, each retail electricity provider within the state, and any public interest group that requests, or has made a standing request for, a copy of the notice. A verbatim transcript of the meetings shall be prepared by the utility preparing the plan, shall be filed with the public service board and the department of public service, and shall be provided at cost to any person requesting it. The plan shall contain a discussion of the principal contentions made at the meetings by members of the public, by any state agency, and by any utility.

(3) Prior to the issuance of the transmission plan or any revision of the plan, the utility preparing the plan shall offer to meet with each retail electricity provider within the state, with any entity appointed by the public service board pursuant to subdivision 209(d)(2) of this title, and with the department of public service, for the purpose of exchanging information that may be relevant to the development of the plan.

(4) (A) A transmission system plan shall be revised:

(i) within nine months of a request to do so made by either the public service board or the department of public service; and

(ii) in any case, at intervals of not more than three years.

(B) If more than 18 months shall have elapsed between the adoption of any version of the plan and the next revision of the plan, or since the last public hearing to address a proposed revision of the plan and facilitate a public discussion that identifies and evaluates nontransmission alternatives, the utility preparing the plan, prior to issuing the next revision, shall host public meetings as provided in subdivision (2) of this subsection, and the revision shall contain a discussion of the principal contentions made at the meetings by members of the public, by any state agency, and by any retail electricity provider.

(5) On the basis of information contained in a transmission system plan, obtained through meetings held pursuant to subdivision (2) of this subsection, or obtained otherwise, the public service board and the department of public service shall use their powers under this title to encourage and facilitate the resolution of reliability deficiencies through nontransmission alternatives, where those alternatives would better serve the public good. The public service board, upon such notice and hearings as are otherwise required under this title, may enter such orders as it deems necessary to encourage, facilitate or require the resolution of reliability deficiencies in a manner that it determines will best promote the public good.

(6) The retail electricity providers in affected areas shall incorporate the most recently filed transmission plan in their individual least cost integrated planning processes, and shall cooperate

as necessary to develop and implement joint least cost solutions to address the reliability deficiencies identified in the transmission plan.

(7) Before the department of public service takes a position before the board concerning the construction of new transmission or a transmission upgrade with significant land use ramifications, the department shall hold one or more public meetings with the legislative bodies or their designees of each town, village, or city that the transmission lines cross, and shall engage in a discussion with the members of those bodies or their designees and the interested public as to the department’s role as public advocate.

Appendix D: Rhode Island Standards for Least Cost Procurement and System Reliability Planning (excerpt)

Chapter 2- System Reliability Procurement

Section 2.1 Distributed/Targeted Resources in Relation to T&D Investment

A. The Utility System Reliability Procurement Plan ("The SRP Plan") to be submitted for the Commission's review and approval on September 1, 2011 and triennially thereafter on September 1, shall propose general planning principles and potential areas of focus that incorporate non-wires alternatives (NWA) into the Company's distribution planning process for the three years of implementation beginning January 1 of the following year.

B. Non-Wires Alternatives (NWA) may include but are not limited to:
   a. Least Cost Procurement energy efficiency baseline services.
   b. Peak demand and geographically-focused supplemental energy efficiency strategies
   c. Distributed generation generally, including combined heat and power and renewable energy resources (predominately wind and solar, but not constrained)[110]
   d. Demand response
   e. Direct load control
   f. Energy storage
   g. Alternative tariff options

C. Identified transmission or distribution (T&D) projects with a proposed solution that meet the following criteria will be evaluated for potential NWA that could reduce, avoid or defer the T&D wires solution over an identified time period.
   a. The need is not based on asset condition.
   b. The wires solution, based on engineering judgment, will likely cost more than $1 million;
   c. If load reductions are necessary, then they are expected to be less than 20 percent of the relevant peak load in the area of the defined need;
   d. Start of wires alternative is at least 36 months in the future; and

   A more detailed version of these criteria may be developed by the distribution utility with input from the Council and other stakeholders.

D. Feasible NWAs will be compared to traditional solutions based on the following:
   a. Ability to meet the identified system needs;
   b. Anticipated reliability of the alternatives;

[110] In order to meet the statute's environmental goals, generation technologies must comply with all applicable general permitting regulations for smaller-scale electric generation facilities.

   c. Risks associated with each alternative (licensing and permitting, significant risks of stranded investment, sensitivity of alternatives to differences in load forecasts, emergence of new technologies)
   d. Potential for synergy savings based on alternatives that address multiple needs
   e. Operational complexity and flexibility
   f. Implementation issues
   g. Customer impacts
   h. Other relevant factors

E. Financial analyses of the preferred solution(s) and alternatives will be conducted to the extent feasible. The selection of analytical model(s) will be subject to Public Utilities Commission review and approval. Alternatives may include the determination of deferred investment savings from NWA through use of net present value of the deferred revenue requirement analysis or the net present value of the alternatives according to the Total Resource Cost Test (TRC). The selection of an NWA shall be informed by the considerations approved by the Public Utilities Commission which may include, but not be limited to, those issues enumerated in (D), the deferred revenue requirement savings and an evaluation of costs and benefits according to the TRC. Consideration of the net present value of resulting revenue requirements may be used to inform the structure of utility cost recovery of NWA investments and to assess anticipated ratepayer rate and bill impacts.

F. For each need where a NWA is the preferred solution, the distribution utility will develop an implementation plan that includes the following:
   a. Characterization of the need
      i. Identification of the load-based need, including the magnitude of the need, the shape of the load curve, the projected year and season by which a solution is needed, and other relevant timing issues.
      ii. Identification and description of the T&D investment and how it would change as a result of the NWA
      iii. Identification of the level and duration of peak demand savings and/or other operational functionality required to avoid the need for the upgrade
      iv. Description of the sensitivity of the need and T&D investment to load forecast assumptions.
   b. Description of the business as usual upgrade in terms of technology, net present value, costs (capital and O&M), revenue requirements, and schedule for the upgrade
   c. Description of the NWA solution, including description of the NWA solution(s) in terms of technology, reliability, cost (capital and O&M), net present value, and timing.
   d. Development of NWA investment scenario(s)
      i. Specific NWA characteristics

ii. Development of an implementation plan, including ownership and contracting considerations or options
iii. Development of a detailed cost estimate (capital and O&M) and implementation schedule.

G. Funding Plan

The Utility shall develop a funding plan based on the following sources to meet the budget requirement of the system reliability procurement plan. The Utility may propose to utilize funding from the following sources for system reliability investments:

i. Capital funds that would otherwise be applied towards traditional wires based alternatives;

ii. Existing Utility EE investments as required in Section I of these Standards and the resulting Annual Plans.

iii. Additional energy efficiency funds to the extent that the NWA can be shown to pass the TRC test with a benefit to cost ratio of greater than 1.0 and such additional funding is approved;

iv. Utility operating expenses to the extent that recovery of such funding is explicitly allowed;

v. Identification of significant customer contribution or third party investment that may be part of a NWA based on benefits that are expected to accrue to the specific customers or third parties.

vi. Any other funding that might be required and available to complete the NWA.

H. Annual SRP Plan reports should be submitted on November 1. Such reports will include but are not limited to:
  a. A summary of projects where NWA were considered;
  b. Identification of projects where NWA were selected as a preferred solution; and a summary of the comparative analysis following the criteria outlined in sections (D) and (E) above;
  c. Implementation plan for the selected NWA projects;
  d. Funding plan for the selected NWA projects;
  e. Recommendations on pilot distribution and transmission project alternatives for which it will utilize selected NWA reliability and capacity strategies. These proposed pilot projects will be used to inform or revise the system reliability procurement process in subsequent plans;
  f. Status of any previously selected and approved projects and pilots;

  g. Identification of any methodological or analytical tools to be developed in the year;
  h. Total SRP Plan budget, including administrative and evaluation costs.

I. The Annual SRP Plan will be reviewed and funding approved by the Commission prior to implementation.

Appendix E: Vermont Non-Transmission Alternatives Screening Form (9/27/12)

For use in screening to determine whether or not a transmission system ***reliability issue*** *requires non-transmission alternatives (NTA) analysis in accordance with the Memorandum of Understanding in Docket 7081. Projects intended for energy market-related purposes – "economic" transmission – and other non-reliability-related projects do not fall within the scope of the Docket 7081 process.*

Identify the proposed upgrade:
____

Date of analysis: ____

1. Does the project meet one of the following criteria that define the term "impracticable" *(check all that apply)*?
    a. Needed for a redundant supply to a radial load; or ❑
    b. Maintenance-related, addressing asset condition, operations, or safety; or ❑
    c. Addressing transmission performance, e.g., addition of high-speed protection or a switch to sectionalize a line; or ❑
    d. Needed to address stability or short circuit problems;[111] or ❑
    e. Other technical reason why NTAs are impracticable. *Attach detailed justification that must be reviewed by the VSPC.* ❑

    If any box above is checked, project screens out of full NTA analysis.

2. What is the proposed transmission project's need date? ________________________
    If the need for the project is based on existing or imminent reliability criteria violations (i.e., arising within one year based on the controlling load forecast), project screens out of full NTA analysis.

[111] "Stability" refers to the ability of a power system to recover from any disturbance or interruption. Instability can occur when there is a loss of synchronism at one or more generators (rotor angle stability), a significant loss of load or generation within the system (frequency stability), or a reactive power deficiency (voltage stability). Stability problems are influenced by system parameters such as transmission line lengths and configuration, protection component type and speed, reactive power sources and loads, and generator type and configuration. Due to the nature of instability, non-transmission alternatives involving addition of generation or reduction of load will not solve these problems.

3. Could elimination or deferral of all or part of the upgrade be accomplished by a 25% or smaller load reduction or off-setting generation of the same magnitude? *(See note.)* *If "no," project screens out of full NTA analysis.*	❑ Yes ❑ No
4. Is the likely reduction in costs from the potential elimination or deferral of all or part of the upgrade greater than $2.5 million. *(See note.)* *If "no," project screens out of full NTA analysis.*	❑ Yes ❑ No

Sign and date this form.
This analysis performed by: ______________________________
Print name & title

____
Company

____
Date

____
Signature

NTA Screening Form
Notes, examples and descriptions

Line 3 Non-transmission alternatives should be considered if the project can be altered or deferred with load reductions or off-setting generation, according to the schedule below, of existing peak load of the affected area at the time of the need for the preferred transmission alternatives. This schedule recognizes that deployment of a load reduction program in a specific area takes time to organize and implement. Therefore, the following assumptions including time and accrued load reduction should be considered when examining the load reduction:

Period	**Magnitude of load reduction and/or off-setting generation**
1-3 years	15% of peak load
5 years	20% of peak load
10 years	25% of peak load

Line 4 The $2.5 million is in year 2012 dollars and is adjusted for escalation in future years using the Handy Whitman transmission cost index. This threshold does not account for the expected costs of the NTAs, but rather only includes the expected savings to the cost of the transmission project.

Appendix F: Vermont Form for Selection of Distributed Utility Planning Areas (v. 28, 10/1/02)

The purpose of this form is to (1) guide the selection of DUP areas while (2) documenting which criteria apply to the decision.

Identity of the upgrade (description or project number): ______________________________

____

1.	Is the cost of the upgrade greater than $2,000,000? *(See note.)* *If so, check "Yes" and continue to Line 4; otherwise check "No" and. continue to Line* 2	Yes .☐ No ..☐
2.	Would the upgrade relieve a T&D delivery constraint in a Capacity Constrained Area? *(See note.)* *If so, check "Yes" and continue to Line* 3*; otherwise check "No" and* exclude *the expected upgrade from DU analysis.*	Yes .☐ No ..☐
3.	Is the cost of the upgrade less than $250,000? *(See note.)* *If so, check "Yes" and* exclude *the expected upgrade from DU analysis; otherwise check "No" and continue to Line 4.*	Yes .☐ No ..☐
4.	Is the upgrade driven by an emergency situation requiring the immediate replacement of equipment that has failed or is at imminent risk of failure? *If so, check "Yes" and* exclude *the upgrade from DU analysis; otherwise check "No" and continue to line 5.*	Yes .☐ No ..☐
5.	Does the upgrade constitute a minor change for the purpose of system tuning or efficiency improvements? *(See note.)* *If so, check "Yes," indicate which of the below upgrades are included (check all that apply), and* exclude *the upgrade from DU analysis. Otherwise check "No" and continue to line 6.*	Yes .☐ No ..☐
5.a	• installation or changes to relays, reclosers, fuses, switches, sectionalizers, breakers, breaker bypass switches, MOABs, capacitors, regulators, arresters, insulators, or meters	☐
5.b	• installation or replacement of underground getaways....................................	☐

5.c	• upgrade of substation bus work..	☐
5.d	• upgrade of substation structural work, fencing, or oil containment.................	☐
5.e	• installation or upgrade to SCADA	☐
5.f	• transformer swaps	☐
5.g	• addition of fans to transformers	☐
5.h	• balancing of feeder phases	☐
5.i	• replacement of deteriorated poles, crossarms, structures, poles and conduit; and replacement of wires on such equipment with the least-cost wires. *(See note.)*..	☐
5.j	• Other (please describe): ______________________________ ______________________________ ______________________________ ______________________________ (Attach further explanation if needed.))	☐
6.	Is the upgrade a line-reconstruction project pursuant to joint use agreements with telephone or CATV or pole-attachment tariff requirements? *If so, check "Yes" and* exclude *the upgrade from DU analysis; otherwise check "No" and continue to line 7.*	Yes .☐ No ..☐
7.	Is the upgrade the result of a customer's request for a specific equipment or service for which distributed resources would not be acceptable? *(See note.)* *If so, check "Yes," describe the situation,* ______________________________ ______________________________ ______________________________ ______________________________ *and* exclude *the expected upgrade from DU analysis; otherwise check "No" and continue to line 8.*	Yes .☐ No ..☐
8.	Is the upgrade required to remedy reliability, stability, or safety problems?	Yes .☐ No ..☐

If so, check "Yes" and continue to line 9; otherwise check "No" and skip to line 11.

9.	Could the scope and cost of the resulting project be reduced by a reduction in load level or by the installation of distributed generation? *(See note to clarify the extent of load reduction.)* *If so, check "Yes" and continue to line 10; otherwise check "No" and skip to line 11.*	Yes .☐ No ..☐
10.	Is the likely reduction in costs from the potential reduction in scope less than $250,000? *(See note.)* *If so, check "Yes" and* exclude *the upgrade from DU analysis; otherwise check "No" and continue to line 11.*	Yes .☐ No ..☐
11.	Would load reduction or generation allow for the elimination or deferral of all of the upgrade? *(See note to clarify the extent of load reduction.).* *If so, check "Yes" and proceed to* define *the scope and timing of the local DU analysis; otherwise check "No" and continue to line 12.*	Yes .☐ No ..☐
12.	Can the upgrade be implemented with different levels of capacity in the replacement equipment, with costs that could differ by more than $250,000? *If not, check "No" and* exclude *the expected upgrade from DU analysis; otherwise check "Yes" and proceed to* define *the scope and timing of the local DU analysis.*	Yes .☐ No ..☐

Remember to sign and date this form.

This analysis performed by ____________________ on ____________________

Name *Date*

____

Print Name

Notes, Examples, and Descriptions

Line 1	Any T&D project whose capital cost is expected to exceed $2 million (in year 2002 dollars, adjusted for inflation in future years), including any reasonably foreseeable related projects, sub-projects, and multiple phases, should be reviewed for the applicability of DUP.
Line 2	DUs may exclude from DUP analysis Non-Constrained Area Projects, as defined in the Docket No. 6290 MOU, of $2 million or less (determined as described in the note to line 1).
Line 3	Projects of less than $250,000 (in year 2002 dollars, adjusted for inflation in future years) may be excluded from DUP analysis. This step is intended to identify constrained situations in which the DU study would be disproportionately costly, compared to the budgeted project cost.
Line 5:	Minor projects that are only parts of a larger project should not be screened using this step. For example, a substation rebuild would include many of the items listed in 5.a–j, but would not be a project that is minor in size and scope. Therefore, larger projects such as substation rebuilds should be analyzed according to the criteria in lines 7 through 12.
Line 5i:	These situations do not include upgrading equipment *specifically* to *significantly* increase capacity, which should be reviewed at lines 11 and 12.
Line 7:	For example, the customer may be willing to pay for a distribution upgrade, but not for distributed resources. In other situations, the customer may be willing to pay for distributed resources, but may be unwilling to have the distributed resources on its premises, and resources elsewhere may not provide the required service.
Lines 9 and 11:	If reduction in present load by 25% and the elimination of all load growth would not affect the need for the project, or its cost, the project may be considered to be independent of load. The feasibility of the required load reductions will be reviewed in the resource-scoping stage of the DU analysis. The determination that load reductions would not avoid a particular investment can be established by reference to an approved policy (such as standards adopted to capture lost opportunities or simplify system operations). If so, indicate the document that specifies the policy.
Line 10:	This line addresses situations in which the upgrade is driven by considerations other than load growth, but the upgrade could be avoided, in whole or in part, by load reductions or distributed generation. Examples of situations in which significant costs may be avoidable, even though some part of the project is unavoidable, include the following: • Replacement of large transformers • looping projects or adding tie-lines to create first-contingency reliability

More rarely load reductions may reduce the costs of

- line relocations due to road or bridge reconstruction
- line relocations in response to local, state, or federal requests
- line rebuilds due to deterioration

Examples of situations in which loads would matter for these latter projects include (1) capacity increases planned to coincide with the relocation or rebuilding, and (2) lines that serve no customers along a considerable distance (e.g., over a mountain or through a wetland), where reduced loads at the other end of the line could be picked up by other facilities.

Lines 10 and 12: The $250,000 is in year 2002 dollars, to be adjusted for inflation in future years.

ENBRIDGE INTERROGATORY #16

INTERROGATORY

Reference: L.OEBStaff.1, page 128/129

Preamble:
"…the rationale, methodologies and concepts for using DSM to avoid or defer gas infrastructure are very similar to those for using DSM to avoid or defer electricity infrastructure. Consequently, many of the electricity IRP methodologies and concepts can and should be applied to gas infrastructure planning in Ontario." (page 128)

"While there are some important difference between electricity and gas resource planning, many of the best practices from electricity planning will apply to gas planning as well." (page 129)

Question:
Please explain the "important differences between electricity and gas resource planning".

RESPONSE

One difference is that electricity resource planning addresses generator capacity, generator energy, electricity transmission capacity and, to a lesser extent, electricity distribution capacity; while gas resource planning addresses gas pipeline capacity and gas storage options. Another difference is that, for reliability purposes, gas resource planning focuses on gas peak-day demand, while electricity planning focuses on electricity peak hour demand.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

ENBRIDGE INTERROGATORY #17

INTERROGATORY

Reference: L.OEBStaff.1, page 128

Preamble:
"There appear to be few examples of this sort of explicit incorporation of DSM in gas infrastructure planning in other jurisdictions… we are only aware of two examples where DSM is incorporated in gas infrastructure planning…"

Question:

a. Please provide a list of the natural gas utilities that currently use DSM programs to avoid or defer natural gas T&D investments. For each utility, please state whether the method is passive deferral or active deferral and also describe each utility including number of customers and total peak throughput.
b. Please describe how Vermont Gas Systems "routinely includes the impacts of its DSM programs in its integrated resource planning process".
c. Please describe the scope and objectives of the current study commissioned by the Massachusetts Department of Energy "to investigate the potential for gas DSM initiatives to defer or avoid the need for significant investments".
d. Further to (c), please also compare and contrast the objectives with those outlined by the Ontario Energy Board (as mentioned in the second paragraph on the page referenced).

RESPONSE

a. Synapse has not developed such a list.

b. Synapse has not investigated this issue beyond what was provided in the document cited.

c. The referenced study is provided as Exhibit M.Staff.EGDI.17, Attachment 1. As indicated in the Executive Summary, the study attempts to answer two questions: (i) what is the current demand for and capacity to supply natural gas in Massachusetts? (ii) If all technologically and economically feasible alternative energy resources are utilized, is any additional natural gas infrastructure needed, and if so, how much? Energy efficiency was one of the key "alternative energy resources."

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

d. The second question cited above in Exhibit M.Staff.EGDI.17, part c. is very much like the Ontario Energy Board's request for a study of the role that DSM should play in future gas planning efforts. Otherwise, Synapse has not prepared a detailed comparison of the objectives of the Massachusetts report and the Ontario Energy Board’s objectives.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

Massachusetts Low Gas Demand Analysis: Final Report

RFR-ENE-2015-012

Prepared for the Massachusetts Department of Energy Resources

January 7, 2015

AUTHORS

Elizabeth A. Stanton, PhD
Patrick Knight
Joseph Daniel
Bob Fagan
Doug Hurley
Jennifer Kallay
Ezgi Karaca
Geoff Keith
Erin Malone
Wendy Ong
Paul Peterson
Leo Silvestrini
Kenji Takahashi
Rachel Wilson

Synapse Energy Economics, Inc.

485 Massachusetts Avenue, Suite 2
Cambridge, Massachusetts 02139

617.661.3248 | www.synapse-energy.com

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1. EXECUTIVE SUMMARY

New England's natural gas infrastructure has become increasingly stressed during peak winter periods as regional demand for natural gas has grown. This situation has led to gas supply and transmission deficits into the region for the gas-fired electric generators during those winter months. Insufficient natural gas capacity for the electric sector has contributed to high wholesale gas prices to generators and thus high electricity prices. Furthermore, as non-gas generators retire and gas generators replace them, the New England electric system is becoming more dependent on natural gas generators. Governor Patrick directed the Department of Energy Resources (DOER) to determine whether or not new natural gas pipeline infrastructure is needed in the Commonwealth.

DOER retained Synapse Energy Economics (Synapse) to utilize current forecasts of natural gas and electric power under a range of scenarios, taking into consideration environmental, reliability and cost answering two key questions:

- What is the current demand for and capacity to supply natural gas in Massachusetts?
- If all technologically and economically feasible alternative energy resources are utilized, is any additional natural gas infrastructure needed, and if so, how much?

Eight scenarios (listed in Table ES-1) were evaluated from an economic and reliability perspective and were then assessed for compliance with the Massachusetts Global Warming Solutions Act (GWSA) targets.[1]

Table ES-1. Scenario key

Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6	Scenario 7	Scenario 8
Base Case Reference NG Price No Canadian Transmission	Base Case Low NG Price No Canadian Transmission	Base Case High NG Price No Canadian Transmission	Base Case Reference NG Price 2,400-MW Canadian Transmission	Low Demand Case Reference NG Price No Canadian Transmission	Low Demand Case Low NG Price No Canadian Transmission	Low Demand Case High NG Price No Canadian Transmission	Low Demand Case Reference NG Price 2,400-MW Canadian Transmission

Note: "Canadian transmission" refers to incremental transmission of system power from Québec. This transmission includes electricity both from hydroelectric and other generators.

From 2015 through 2019, electric generators have insufficient supply of natural gas, which results in spiking natural gas prices. Scarcity-driven high natural gas prices will force economic curtailment of

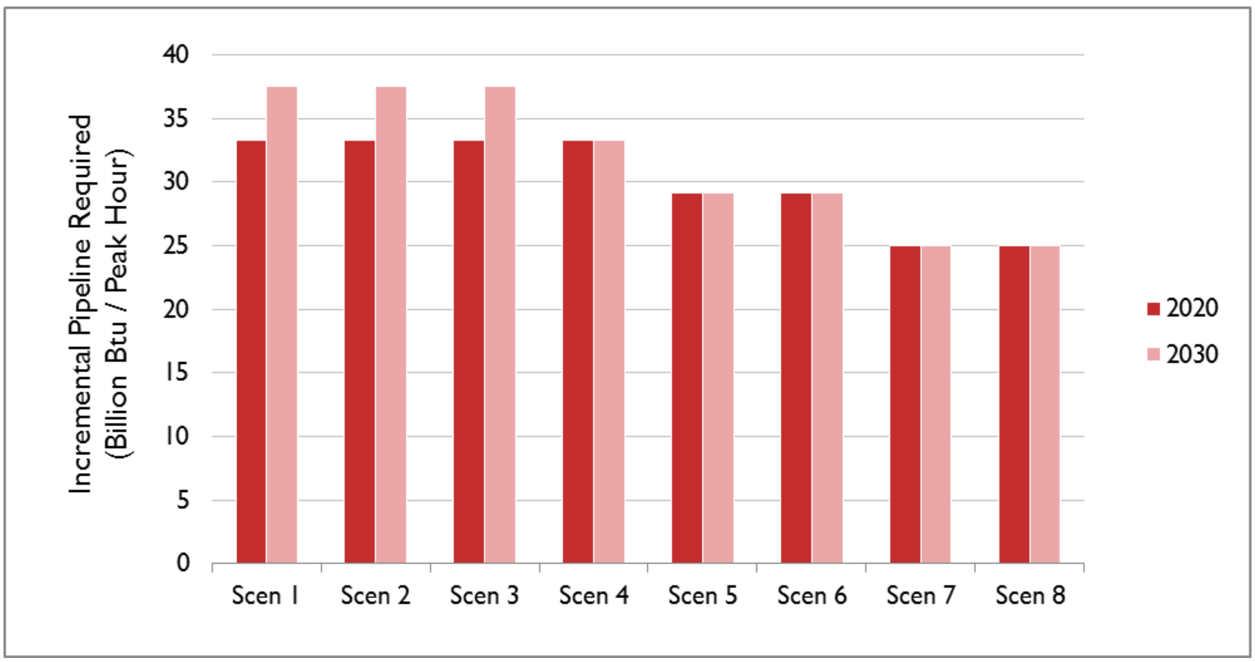
[1] Global Warming Solutions Act (GWSA), Chapter 298 of the Acts of 2008 as codified in M.G.L. Chapter 21N Climate Protection and Green Economy Act

natural gas-fired generators in favor of oil-fired units. The combination of increased oil utilization for electricity generation together with the use of emergency measures such as demand response and the ISO-NE Winter Reliability program (through January 2018) will allow electric demand to be met. From 2020 to 2030, existing and planned capacity plus incremental pipeline capacity balances system requirements.

Critical to this result is the assumption that winter peak hour gas shortages cannot be addressed using known measures (e.g. demand response or the addition of new natural gas pipeline) in years 2015 through 2019 and, as a result, gas prices are expected to reflect an out-of-balance market in those years. The electric sector responds to these high prices by shifting dispatch from gas to oil generation in the peak hour, reducing reliance on natural gas. In years 2020 through 2030, in contrast, winter peak hour gas shortages can be met using known measures (incremental pipeline) and, as a result, gas prices are expected to reflect an in-balance market in those years. The electric sector no longer has a price signal to shift dispatch away from gas generation in the peak hour, greatly increasing gas requirements and reducing reliance on oil in comparison to the previous period.

The amount of pipeline required differs based on scenario assumptions (see Figure ES-1). Year 2020 pipeline additions range from 25 billion Btu per peak hour to 33 billion Btu per peak hour (0.6 billion cubic feet (Bcf) per day to 0.8 Bcf per day).[2] Year 2030 pipeline additions range from 25 billion Btu per peak hour to 38 billion Btu per peak hour (0.6 Bcf to 0.9 Bcf per day).

Figure ES-1. Massachusetts gas capacity shortage during winter peak hour by scenario, 2020 and 2030



[2] Billion Btu can be converted to Bcf by multiplying billion Btu by 24 hours per day then dividing by 1,022 Btu per cubic foot.

Figure ES-2 compares Massachusetts natural gas capacity to the natural gas demand in the winter peak hour in three scenarios selected to highlight the progression of reducing gas shortages from a scenario with existing policies only, to the addition of technically and economically feasible alternative resources (i.e. renewable energy and energy efficiency measures), to the addition (inclusive of alternative measures) of new transmission from Canada:

- **Scenario 1: Base Case** is the base case with reference natural gas price and no incremental Canadian transmission,
- **Scenario 5: Low Demand** is the low energy demand case with reference natural gas price and no incremental Canadian transmission, and
- **Scenario 8: Low Demand + Incremental Canadian Transmission** is the low energy demand case with reference natural gas price and 2,400-MW incremental Canadian transmission.

In all scenarios electric sector gas use increases between 2019 and 2020 as gas pipeline constraints are reduced, price spikes become less frequent, resulting in lower gas prices. Lower gas prices reduce economic curtailment of gas-fired units and increase gas use while reducing reliance on oil-fired units and oil use.

Figure ES-2. Comparison of Massachusetts gas capacity and demand for selected scenarios in winter peak hour

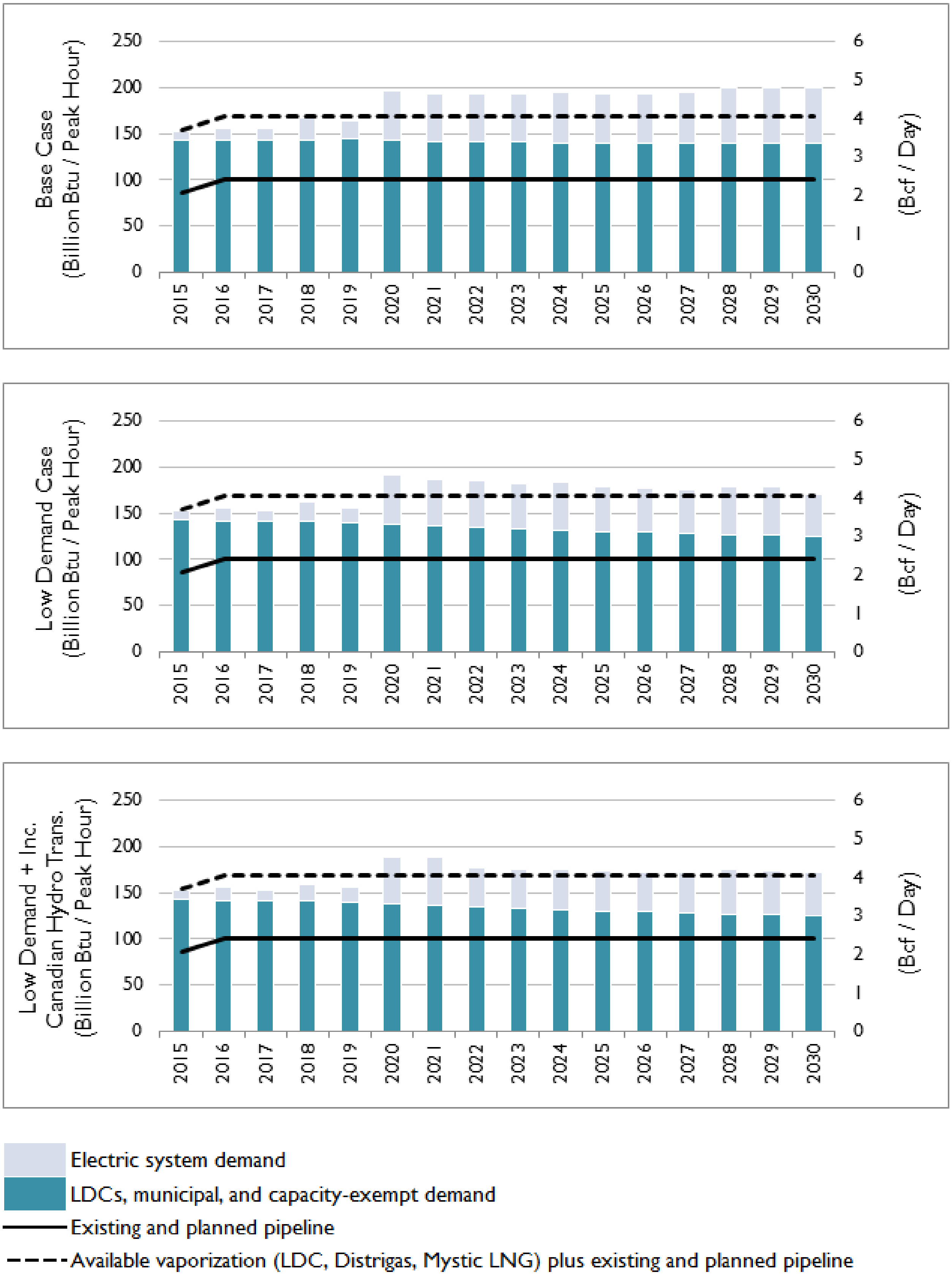
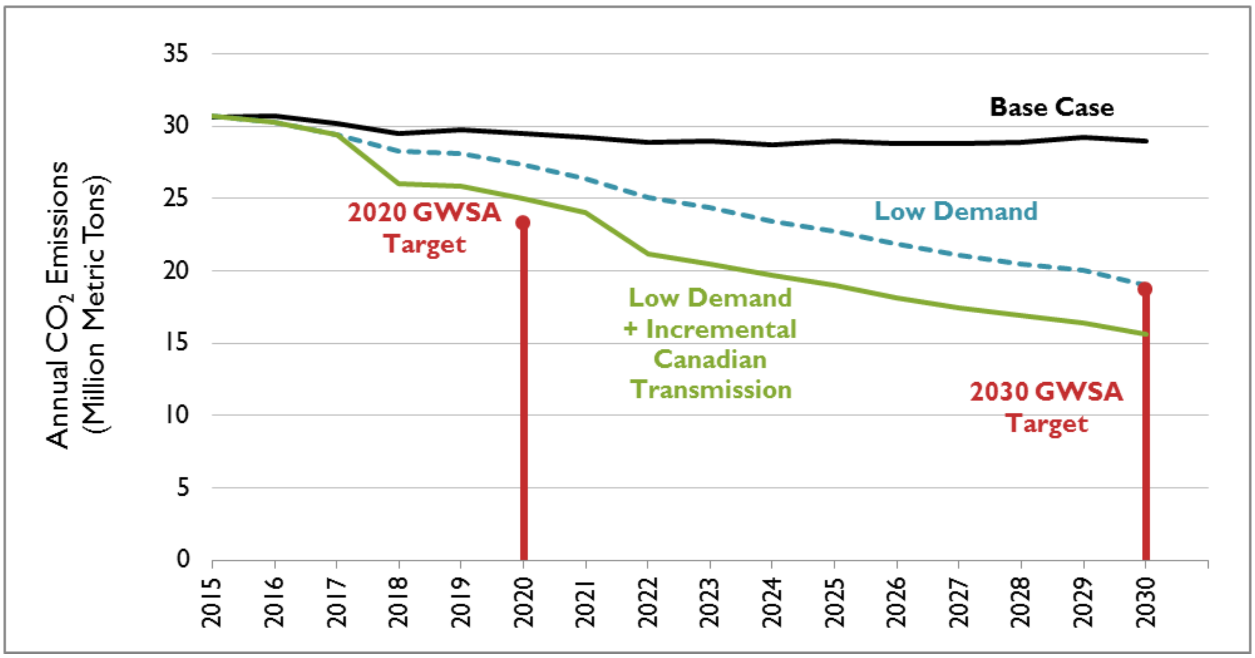


Figure ES-3 compares the projected emissions of Scenarios 1, 5 and 8 through 2030 with GWSA targets for the heating gas and electric sectors (refer to Section 4.3 for explanation of how targets are derived). The gas heating and electric sectors "2020 GWSA Target" depicted below would allow the GWSA 2020 emissions limit to be met, taking into account expected emissions from other sectors. While no scenario meets the GWSA targets for the heating gas and electric sectors in 2020, Scenario 8 (low energy demand case with reference natural gas price and 2,400-MW incremental Canadian transmission), shown below, and Scenario 7 (low energy demand case with high natural gas price and no incremental Canadian transmission) meet the target in 2030. Scenario 5 (low energy demand with reference natural gas price and no incremental Canadian transmission) exceeds the 2030 GWSA target by 0.4 million metric tons or 1 percent of the 2030 statewide emission target.

The 2020 emission level for Scenario 8 shows an approximately 1.6 million metric ton CO_2 gap from the target (25.0 million metric ton CO_2 compared with the target of 23.3 million metric tons). The December 2013 *GWSA 5-Year Progress Report* also identified a potential shortfall in greenhouse gas reductions by 2020 for the buildings—including energy efficiency—and the electric generation sectors.

Figure ES-3. Massachusetts GWSA compliance in heating gas and electric sector for selected scenarios



The difference in each scenario's costs from that of Scenario 1 (base case with reference natural gas price and no incremental Canadian transmission) is shown for Scenario 5 (low demand case with reference natural gas price and no incremental Canadian transmission) and Scenario 8 (low demand case with reference natural gas price and 2,400-MW incremental Canadian transmission) in Figure ES-4. Scenario 5 costs exceed those of Scenario 1 by less than $100 million in each year through 2020 and less than $200 million each year thereafter. In Scenario 8, the addition of new Canadian transmission in 2018 reduces overall costs in comparison to the low demand case without new transmission (Scenario 5) in 2018 and 2019 because of the large reduction in electric system costs provided by new transmission in those years. Starting in 2020, the Scenario 8 costs exceed those of Scenario 5 as more alternative resources are introduced.

Figure ES-4. Massachusetts difference in cost between Scenario 1 (Base Case) and selected scenarios

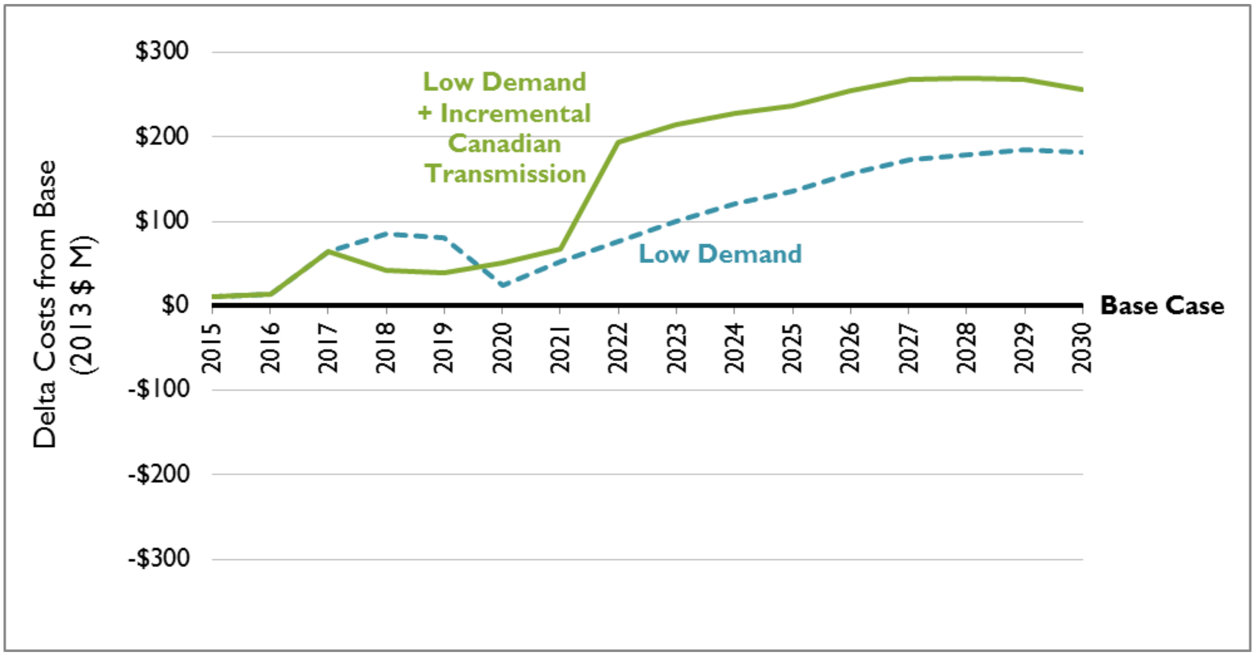


Table ES-2 reports the difference in each scenario's costs from that of Scenario 1 in net present value terms over the study period (2015 to 2030), along with the pipeline required by 2030. The addition of technically and economically feasible alternative measures (Scenario 5) adds $1,433 million in costs (i.e. capital, maintenance, fuel) to Scenario 1, while the addition of both these alternative measures and a 2,400-MW incremental Canadian transmission (Scenario 8) adds $2,157 million in costs to Scenario 1. Note that in the low natural gas price sensitivity, Massachusetts costs fall in comparison to scenarios run with the reference gas price. While Scenario 2 (base case, low gas price sensitivity, no incremental Canadian transmission) has $8.6 billion in cost savings compared to Scenario 1, Scenario 6 (low demand case, low gas price sensitivity, no incremental Canadian transmission) has $0.3 billion in added costs compared to Scenario 1. This difference in costs is due to the costs of implementing the low demand measures included in Scenario 6.

Table ES-2. Massachusetts difference in cost from Scenario 1 in net present value (million $), 2015 to 2030 compared to 2030 pipeline requirements

	Scen. 1	Scen. 2	Scen. 3	Scen. 4	Scen. 5	Scen. 6	Scen. 7	Scen. 8
NPV ($ M)	$0	-$8,611	$5,384	$840	$1,433	$389	$15,112	$2,157
2030 Pipeline (Bcf/day)	0.9	0.9	0.9	0.8	0.7	0.7	0.6	0.6

This study's results are sensitive to numerous assumptions made in our analysis. These assumptions have been caveated throughout the following report and include important assumptions regarding multiple topics, laid out in detail in the following report. Any interpretations of this study's results should make full consideration of all specified caveats.

2. INTRODUCTION

2.1. Purpose

The Massachusetts Department of Energy Resources (DOER) retained Synapse Energy Economics (Synapse) to determine, given updated supply and demand information, whether or not new natural gas pipeline infrastructure is required in the Commonwealth taking into consideration environmental issues, reliability, and costs.[3] Key questions for consideration included:

- What is the current demand for and capacity to supply natural gas in Massachusetts?
- If all technologically and economically feasible alternative energy resources are utilized, is any additional natural gas infrastructure needed, and if so, how much?

Caveats to model scope

Caveats are included in each of the following sections to summarize issues not included in this modeling study. Any interpretations of this study's results should make full consideration of all specified caveats.

- The scope of this study was restricted to expected Massachusetts natural gas demand and capacity only. We did not examine gas constraints in the wider region, nor did we examine the effect of expected gas demand or capacity constraints outside of the Commonwealth.
- The scope of this study was restricted to scenarios in which Massachusetts natural gas capacity constraints were resolved. We did not construct a scenario based on the assumption that incremental pipeline would not be an option.
- The scope of this study was to investigate the need for a new pipeline. We assumed neither that new pipeline and corresponding natural gas usage were necessary, nor that new pipeline and corresponding natural gas were unnecessary.
- The study determines whether or not each scenario modeled is or is not compliant with Massachusetts Global Warming Solutions Act (GWSA) compliant. We did not assume that Massachusetts would be in compliance with GWSA.
- The study examines the sensitivity of model results to changes in the price of natural gas and the addition of 2,400 MW of incremental Canadian transmission. Potential sensitivities of interest not modeled include: the availability in the winter peak hour of existing coal, nuclear, or other potentially at-risk generation; the combined sensitivity to a low or high gas price and the addition of incremental Canadian transmission; and

[3] RFR-ENE-2015-012

incremental Canadian resources assumed to be dedicated transmission of hydroelectric generation or any other resource.

- The study examined the period of 2015 through 2030. Although new natural gas infrastructure is not available until 2020, we analyzed years 2015 through 2019 as these years have changes to the natural gas system including reduced natural gas demand as a result of energy efficiency measures, and changes to the electric system as a result of generating unit retirements, energy efficiency measures, and alternative measures. The inclusion of these years permits more thorough analysis of differences among the scenarios.

2.2. Intent

This report presents information intended to inform state energy decision-makers as they develop and implement policies and actions with regards to Massachusetts' energy infrastructure. The information in this report can also assist state energy officials in addressing ISO-New England (ISO-NE) market rule changes that can enable increasing levels of alternative resources and demand response.

2.3. Analysis

This study considers a range of solutions to address Massachusetts' short- and long-term needs, taking into account system reliability, economic costs, and greenhouse gas reductions. All scenarios are evaluated from an economic and reliability perspective and are then assessed for compliance with GWSA. Our analysis was conducted in four steps:

1) Development of a base case and sensitivity assumptions
2) Feasibility study of alternative resources in a low energy demand case
3) Scenario modeling of eight scenario and sensitivity combinations
4) Assessment of natural gas capacity to demand balance in a winter peak event

2.4. Stakeholder Process

DOER, with the facilitation leadership of Raab Associates, hosted a stakeholder input process to solicit varied points of view and ensure that the list of solutions and metrics for evaluation were informed by stakeholder input. This process included three public stakeholder meetings held on October 15, October 30 and December 18, 2014. Prior to each meeting, Synapse posted meeting materials to a website for stakeholder review.[4] DOER made public high level summaries and encouraged stakeholders to submit written comments and suggestions, which were considered at all stages of the study process.

[4] http://synapse-energy.com/project/massachusetts-low-demand-analysis

2.5. Report Outline

Section 3 provides an overview of the model methodology and model design for this analysis of the Massachusetts gas sector from 2015 to 2030. It first describes the base case and low demand case, with the sensitivities associated with each scenario. It outlines the key outputs of the model runs: 1) sufficiency of gas pipeline capacity under winter peak event conditions, and 2) annual costs and emissions. This section then gives an overview of the feasibility analysis for the low energy demand case that is modeled as the base case with the addition of the maximum amount of technologically and economically feasible alternative demand and supply-side resources.

Section 4 presents model results for all eight scenarios and sensitivity combinations. It displays the difference between natural gas capacity and natural gas demand during a winter peak event in each scenario and sensitivity for each modeled year. Each scenario's annual costs compared to the base case are reported. This section also depicts total emissions from the Massachusetts' natural gas heating and electric sectors in 2020 and 2030 for each scenario compared to 2020 and 2030 GWSA targets for the buildings and electric sectors.

Section 5 describes our observations regarding these modeling results. Some of these observations include the sensitivity of winter peak hour requirements to gas prices, the impact of incremental Canadian transmission, and impacts of alternative measures to reduce Massachusetts' gas demands.

Caveats are discussed in each section of the report to summarize issues not included in this modeling study. Any interpretations of this study's results should make full consideration of all specified caveats.

Six appendices present detailed modeling assumptions and results:

- Appendix A presents the feasibility analysis for the low energy demand case;
- Appendix B presents assumptions used in modeling the base case;
- Appendix C presents assumptions used in modeling the low energy demand case;
- Appendix D presents assumptions regarding the sensitivity analysis of changes in the price of natural gas;
- Appendix E presents assumptions regarding the sensitivity analysis of the addition of incremental electric transmission from Canada; and
- Appendix F presents detailed tables of the model results.

3. Model Overview

Synapse analyzed eight future scenario-and-sensitivity combinations of the Massachusetts gas sector from 2015 through 2030. We modeled two future scenarios:

1) A **base case** representing existing policies in place, and
2) A **low energy demand case** in which the maximum feasible amount of additional alternative resources are utilized.

In addition, we tested each of these scenarios for their sensitivity to changes in the price of natural gas and the addition of 2,400 MW of incremental Canadian transmission as follows:

- Base case
    - No incremental Canadian transmission
        - Reference natural gas prices (Scenario 1)
        - Low natural gas prices (Scenario 2)
        - High natural gas prices (Scenario 3)
    - 2,400-MW incremental Canadian transmission
        - Reference natural gas prices (Scenario 4)
- Low energy demand case
    - No incremental Canadian transmission
        - Reference natural gas prices (Scenario 5)
        - Low natural gas prices (Scenario 6)
        - High natural gas prices (Scenario 7)
    - 2,400-MW incremental Canadian transmission
        - Reference natural gas prices (Scenario 8)

From this model we established the difference between natural gas capacity and natural gas demand during a winter peak event in each scenario and sensitivity for each modeled year, 2015 through 2030, and investigate the availability of additional measures to relieve shortage conditions.

Our analysis provides the following key outputs:

- **Sufficiency of Massachusetts' gas pipeline capacity under winter peak event conditions:** We modeled Massachusetts gas supply and demand under conditions defined by a winter peak event (as described in Section 3.2), taking account of the impact on energy storage of a "cold snap" or series of winter peak days.

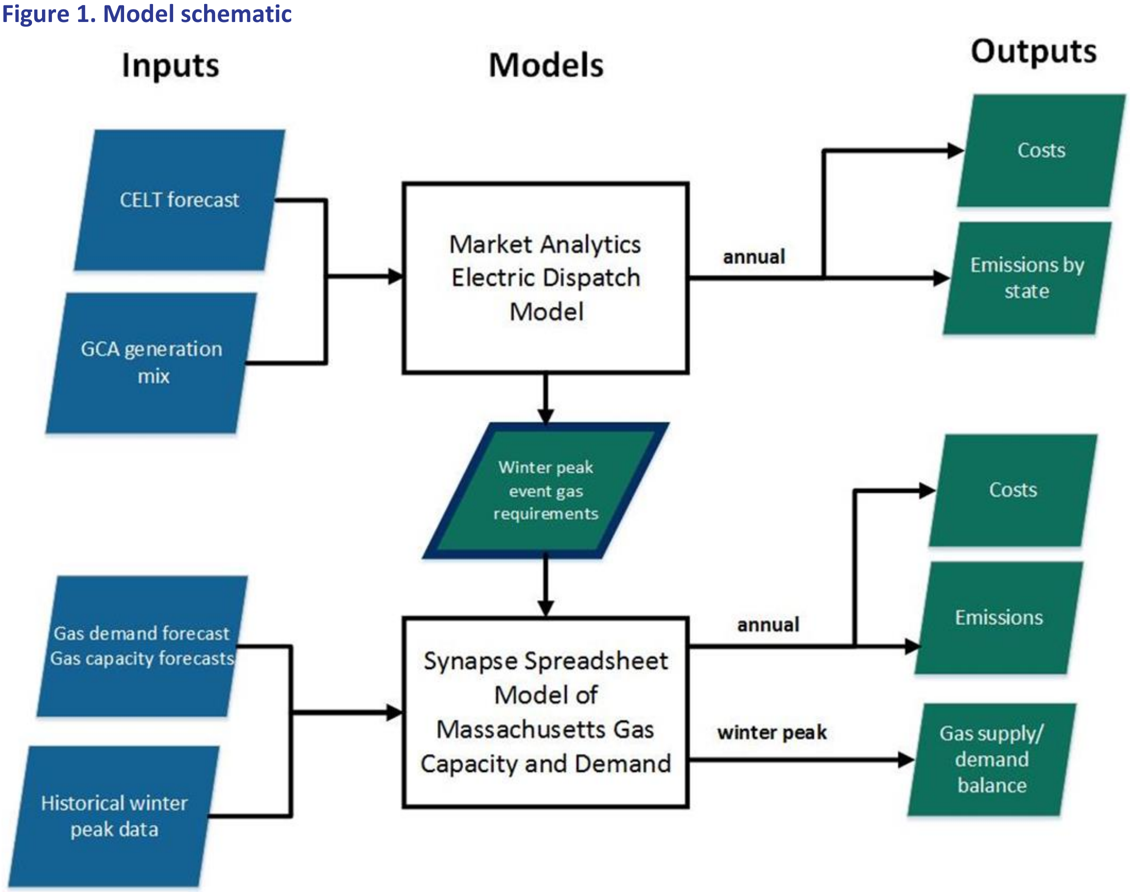
- **Annual costs and emissions:** We modeled fuel use, electric generation, variable and levelized capital energy costs, and greenhouse gas emissions on an annual basis. Annual costs and emissions were modeled based on expected (most likely) weather conditions, not extreme conditions. These expected weather conditions included the occurrence of winter high demand events. We then determined if additional pipeline capacity is needed to meet demand.

Reliability requirements were a basic criterion for all modeled scenarios.

3.1. Model Design

Model design for this analysis included Ventyx's Market Analytics electric dispatch model and a Synapse purpose-built spreadsheet model of Massachusetts gas capacity and demand (see Figure 1).

Figure 1. Model schematic



Note: "CELT" is the 2014 forecast of energy and load demand by ISO-New England and "GCA" is the Massachusetts Green Communities Act, per Synapse's 2014 analysis.

Electric-sector greenhouse gas emissions and cost modeling in Market Analytics

Synapse projected greenhouse gas emissions, electric system gas use, and wholesale energy prices using Ventyx's Market Analytics electric-sector simulation model of ISO-NE including its imports and exports. Market Analytics uses the PROSYM simulation engine to produce detailed results for hourly electricity prices and market operations based on a security-constrained chronological dispatch model. The PROSYM simulation engine optimizes unit commitment and dispatch options based on highly detailed information on generating units. This modeling includes detailed runs designed to estimate electric-sector gas requirements during the winter event peak hour. Although New England and regions exporting electricity to New England are modeled to portray economic dispatch of resources as accurately as possible, only generators located in Massachusetts' gas requirements, emissions and costs are considered in final model results.

A Synapse purpose-built model of Massachusetts natural gas capacity and demand

We developed a dynamic spreadsheet model of natural gas needs for an indicative winter peak event in Massachusetts, with annual analysis extending out to 2030. This model facilitates assessment of the balance of New England's gas capacity and demand under winter peak event conditions. Development of this model included Massachusetts-specific analysis of historical stress and shortage gas supply conditions, historical winter peak event conditions, and diversity and reliability of supply.

Gas requirements as defined in the model represent demand from residential, commercial, industrial, and electric-generation sectors in Massachusetts only:

- Local distribution companies (LDCs – local gas providers)
- Municipal light and gas companies (munis)
- Capacity exempt customers (customers that purchase gas supplies from third-party suppliers and are not required to take and pay for pipeline capacity that LDCs have under contract)
- Gas energy efficiency measures
- Gas reduction measures: Time varying rates, demand response, ISO-NE's Winter Reliability program, advanced building costs, renewable thermal policies, and in low energy demand case, various demand- and supply-side measures were included.
- Gas-fired electric generators located in Massachusetts.

Gas capacity as defined in the model represents existing and planned pipeline capacity, liquefied natural gas (LNG) storage and vaporization, and incremental pipeline capacity as needed to meet gas sector demand by scenario and year:

- Existing pipeline capacity: Algonquin Gas Transmission Company (AGT), Maritimes/Northeast Pipeline Company (M&NP); Tennessee Gas Pipeline Company (TGP)

- Planned pipeline capacity: Algonquin Incremental Market (AIM) pipeline capacity, which is an expansion of the AGT line, expected to be complete in 2017
- LDC's LNG storage and vaporization: National Grid (NGrid), Columbia, NSTAR, Liberty, Fitchburg Gas and Electric, Berkshire Gas, Holyoke, Middleboro
- Full GDF Suez LNG vaporization in Everett, MA with an allocation for Mystic electric generation plant
- Incremental pipeline capacity

The model assumes that the existing and planned pipeline and LNG vaporization capacity defined above (including the GDF Suez capacity and Canaport/M&NE Pipeline) is fully utilized to meet demand during the winter peak event and identifies if and when incremental capacity is needed. Incremental capacity is specified as pipeline capacity but it can also be supplied by additional LNG. The feasibility and cost of incremental LNG facilities are highly dependent on factors and conditions present at specific locations. Such an analysis was beyond the scope of this study. If additional LNG imports through the GDF Suez, Neptune, Excelerate or Canaport facilities are economical, the delivery of those supplies into the Massachusetts distribution system during the winter peak event would be limited by the capacity defined above. Similarly, new LNG facilities will require both additional storage and liquefaction capability to insure reliability comparable to that of a pipeline, which in most instances will drive its cost well above the cost of a new pipeline. However, we assume that market and economic factors will drive decisions as to the most feasible and cost-effective means for meeting natural gas demand.

In addition to modeling winter peak event conditions, Synapse's spreadsheet model estimates state and regional annual greenhouse gas emissions and costs related to Massachusetts' natural gas use. This gas-sector emissions and cost analysis includes expected displacement of other fossil fuels (coal and oil) where applicable. While gas forecasting is typically conducted in terms of a November-October year, our analysis was conducted in calendar years to facilitate comparisons with greenhouse gas emission reduction targets. To convert gas demand for November-October years into calendar years, we allocated split year demand into calendar year demand based on the ratio of each month's expected gas consumption using the updated monthly forecast data provided by NGrid.

3.2. Winter Peak Event

Massachusetts' gas demand is at its greatest during a very cold winter day. Our analysis of the sufficiency of Massachusetts natural gas capacity was conducted through the lens of a "winter peak event"—a series of particularly cold winter days under which high gas demands have the greatest potential to exceed gas capacity. For the purposes of this analysis, a winter peak event was defined as follows:

- Capacity and demand in the peak hour of an expected future "design day". Design days are used in gas LDCs' forecasts of future natural gas demand and are determined by calculating the effective degree days (a measure of expected heating demand) expected to occur under a specified probability (from once in 30 years to once in 50 years depending on the LDC).

- Gas requirements for electric generation were developed in Market Analytics to represent the coincident peak with LDCs' design day (the electric peak that coincides with the gas demand peak): for each year, the highest gas requirement for a January day from 6 to 7pm.[5]

- LDCs' five-year design day forecasts were applied to the January of the split year (e.g. 2015/16) and remain unadjusted from their most recent filing as provided to DOER.[6] For those years not provided by the companies, the average annual load growth rate for the given forecasted years was used to extrapolate the design day and annual forecasts out through 2019. From 2020 through 2030 design day and annual gas demand was projected using a 0.5-percent annual growth rate per DOER projections.[7]

- Sufficiency of natural gas capacity took into account the effects of a cold snap. Each Massachusetts LDC defines cold snaps differently using a series of the coldest days ranging from 10 to 24 days; the Commonwealth's two largest LDCs use ten and 14 days. For the purposes of this analysis, we will define a cold snap as a series of 12 cold weather days, with the design day occurring on the 12th day of the cold snap. In this model the length of the cold snap impacts the amount of LNG in storage facilities and the resulting rate of deliverable natural gas from storage.

Caveats to winter peak event

- This study examines the difference between Massachusetts' gas demand and capacity in an illustrative winter peak event hour. We did not analyze gas constraints in a specific historical or expected future hour.

3.3. Scenarios and Sensitivities

Synapse modeled a base and a low energy demand case of the following possible Massachusetts gas and electric systems (see Table 1). Both cases assume that there is no incremental transmission from Canada to New England and a reference natural gas price. In addition, we investigated model results' sensitivity to changes in the price of natural gas and to the addition of 2,400-MW in new transmission capacity from Canada to the New England hub.

[5] Eastern Interconnection Planning Collaborative (EIPC) *Draft Gas-Electric Interface Study Target 2 Report*, p.64-65.

[6] We used the latest Department of Public Utilities filings for all LDCs except NGrid and Columbia, which provided DOER with updated design day forecasts.

[7] According to background papers to the CECP, DOER assumed a 0.5-percent annual growth rate for Massachusetts gas demand after 2020. See Exhibit EAS-13 to MA DPU 14-86.

Table 1. Scenarios and sensitivities

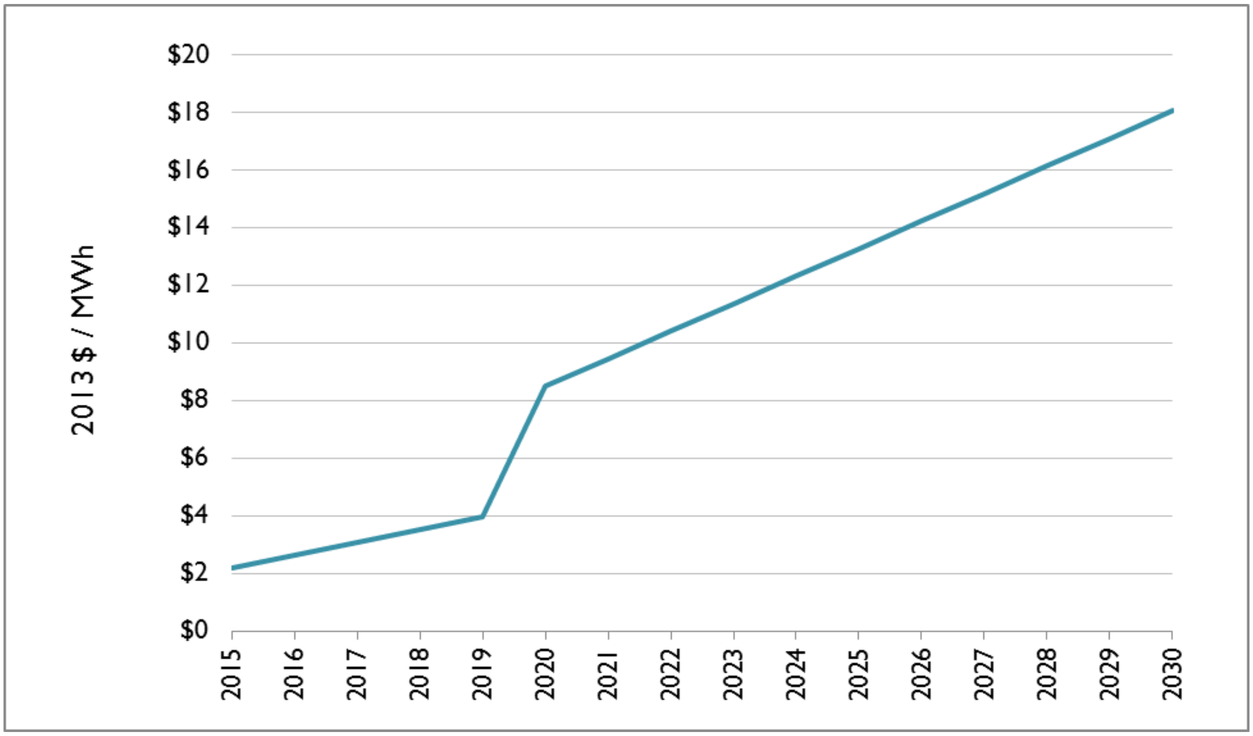
	No Incremental Canadian Transmission			2,400-MW Incremental
	Reference NG Price	**Low NG Price**	**High NG Price**	**Reference NG Price**
Base Case	*Base Case *Ref NG Price *No Canadian Transmission (Scenario 1)	*Base Case *Low NG Price *No Canadian Transmission (Scenario 2)	*Base Case *High NG Price *No Canadian Transmission (Scenario 3)	*Base Case *Ref NG Price *2,400-MW Canadian Transmission (Scenario 4)
Low Energy Demand Case	*Low Case *Ref NG Price *No Canadian Transmission (Scenario 5)	*Low Case *Low NG Price *No Canadian Transmission (Scenario 6)	*Low Case *High NG Price *No Canadian Transmission (Scenario 7)	*Low Case *Ref NG Price *2,400-MW Canadian Transmission (Scenario 8)

Note: "Canadian transmission" refers to incremental transmission of system power from Québec. This transmission includes electricity both from hydroelectric and other generators.

All scenarios and sensitivities include the carbon price forecast assumption used in the *Avoided Energy Supply Costs in New England: 2013 Report* (AESC 2013) for the electricity sector.[8] As depicted in Figure 2, RGGI prices extend to 2019; the Synapse "mid" CO_2 price forecast is used in AESC 2013 for 2020 and beyond.

[8] Hornby et al. 2013. Exhibit 4-1. Column 6 "Synapse" CO_2 emission allowance price.

Figure 2. AESC 2013 CO_2 price forecast



Base case

The base case is defined as the energy resource mix and forecasted energy demand expected under existing policy measures, using a reference natural gas price (see discussion under the "natural gas price sensitivity" subsection later in this section), and the assumption that there will be no incremental electric transmission from Canada in the 2015 to 2030 period.

Base case electric and gas loads were modeled using existing, well-recognized projections, including ISO-NE's latest CELT forecast for electric demand, the Massachusetts' LDCs' gas demand forecasts, and the most up-to-date gas demand information available regarding capacity exempt customers and municipal entities. Reductions to load from energy efficiency were modeled based on program administrators' data as filed with their respective Departments of Public Utilities.[9] These reductions were extended into the future using the following assumptions: (1) for states other than Massachusetts energy efficiency budgets remain constant over time in real terms; and (2) for Massachusetts energy efficiency remains constant as a 2.6-percent share of retail sales from 2015 through 2030.

The base case electric generation resource mix was modeled using the Market Analytics scenario designed by Synapse for DOER in early 2014 to provide an accurate presentation of Green Communities

[9] Program administrators are the entities that administer energy efficiency programs in the Commonwealth. Typically, program administrators are the same as utilities (e.g., NSTAR, National Grid), but also include non-utility entities such as the Cape Light Compact.

Act (GCA) policies as well as the Renewable Portfolio Standards—by class—of the six New England states. Synapse's GCA analysis for DOER was developed using the NERC 9.5 dataset, based on the Ventyx Fall 2012 Reference Case. We verified and updated these data with the most current information on gas prices, loads, retirements, and additions. This case assumes all existing policies—including the ISO-NE Winter Reliability program with its current sunset date, advanced building codes, renewable thermal technologies, and the recent DPU Order 14-04 on time-varying rates—and forecasted LNG and propane usage. We modeled distributed resources using ISO-NE's PV Energy Forecast Update, held constant after 2020. Detailed modeling assumptions for the base case are presented in Appendix B.

Caveats to base case

- The base case for this study includes only existing policies and <u>does not consider or account for currently developing policies or new legislations</u>.
- This study bases its base case projections of electric demand on ISO-NE's CELT 2014 forecast, with the exceptions of adjustments made to ISO-NE's energy efficiency projections (we base these instead on program administrator's latest three-year plans). Any inaccuracies in this forecast—including its accounting of new housing starts—have the potential to affect model results.
- This study bases its base case projections of distributed generation installation on ISO-NE's PV Energy Forecast Update by state, held constant after 2020 (see Appendix B). Any inaccuracies in this forecast have the potential to affect model results.
- This study assumes that gas heating demand is inelastic—that is, gas heating demand does not fluctuate with changes in the gas prices. While actual consumer fuel use is widely regarded to be largely insensitive to fuel prices in the short run, heating demand has the potential to exhibit more sensitivity to gas prices in the long run as customers change heating technologies. While this study does not model long-run sensitivity to increasing gas prices per se, it does include Massachusetts' existing policy for large-scale conversion to renewable thermal heating technologies per the DOER-commissioned CARTS study.[10]
- This study did not consider MA H.4164 expansion of gas distribution and the effect of this expansion on gas demand.[11] Inclusion of gas distribution expansion has the potential to change model results, to the extent that this expansion is not already

[10] http://www.neep.org/sites/default/files/products/NEEP%20ICS2%20FINAL%20REPORT%202013Feb11-Website.pdf; http://www.mass.gov/eea/docs/doer/renewables/thermal/carts-report.pdf

[11] MA H.4164 establishes a uniform classification standard for natural gas leaks. It also requires natural gas companies to repair serious leaks immediately, produce a plan for removing all leak-prone infrastructure, and provide a summary of their progress and a summary of work to be completed every five years.

accounted for in the LDC's heating gas demand forecasts through 2019 and the DOER-based growth rate for heating gas demand thereafter.[12]

- The modeling analysis presented in this study includes the coal unit retirement assumptions indicated in Table 2. Different assumptions have the potential to impact on model results.

Table 2. Modeled coal retirements

Unit Name	State	Retirement date
Bridgeport Harbor 3	CT	6/1/2017
Salem Harbor 3	MA	6/1/2014
Mount Tom	MA	10/1/2014
Brayton Point 1	MA	6/1/2017
Brayton Point 2	MA	6/1/2017
Brayton Point 3	MA	6/1/2017
Mead 1 (103 MW)	ME	none
Schiller 4	NH	1/1/2020
Schiller 6	NH	1/1/2020
Merrimack ST1 (114 MW)	NH	none
Merrimack ST2 (345 MW)	NH	none
S A Carlson 5	NY	1/1/2016

Low energy demand case

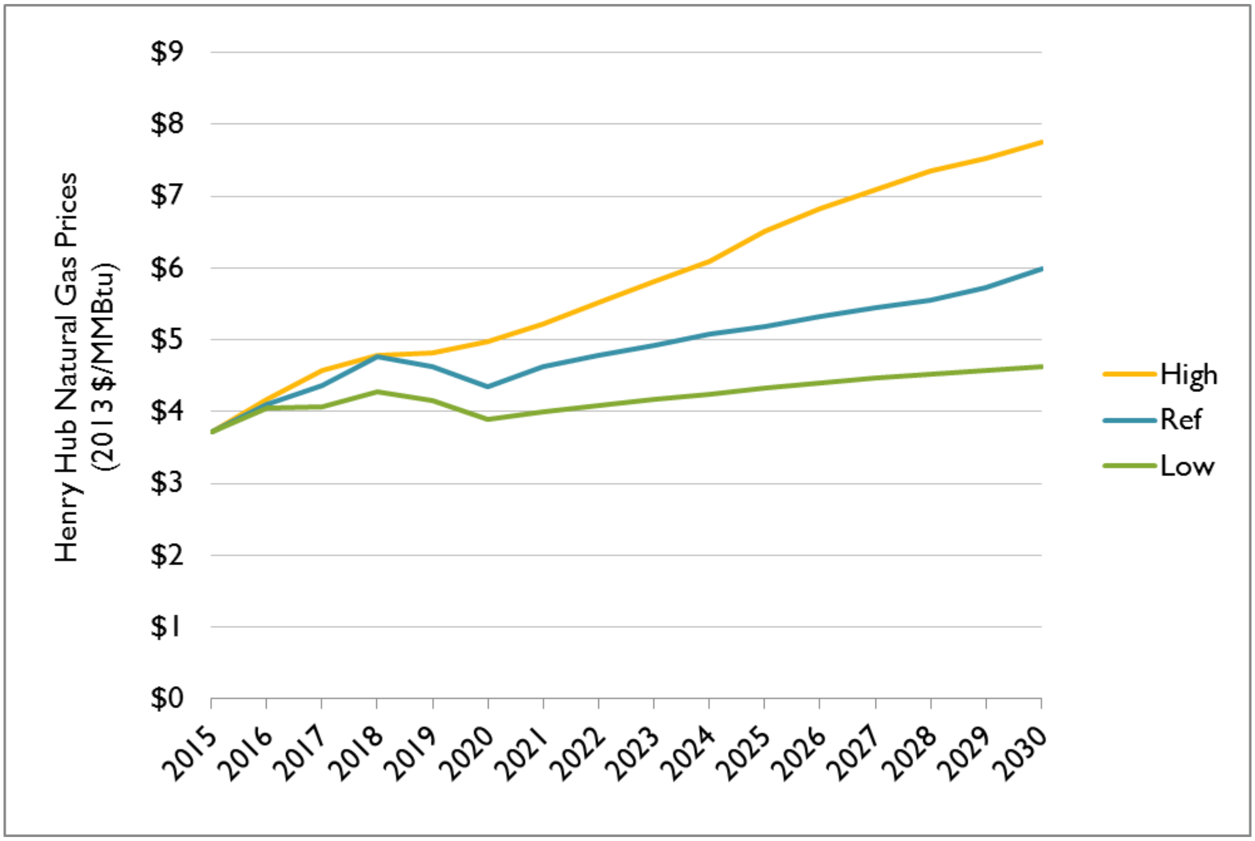
The low energy demand case was designed by making adjustments to the base case. In the low energy demand case, all alternative resources were utilized to the greatest extent that is determined to be feasible (the methodology for this feasibility assessment is described in Section 3.4). In this scenario, changes to public policy were assumed for Massachusetts only and not for the neighboring states. Detailed modeling assumptions for the low energy demand case are presented in Appendix C.

Natural gas price sensitivity

We investigated the sensitivity of modeling results to both increases and decreases in the expected price of natural gas. Figure 3 depicts the reference, low and high Henry Hub natural gas price forecasts for use in this analysis.

[12] According to background papers to the CECP, DOER assumed a 0.5-percent annual growth rate for Massachusetts gas demand after 2020. See Exhibit EAS-13 to MA DPU 14-86.

Figure 3. Reference Henry Hub natural gas prices



For the electric sector monthly average Henry Hub price forecasts were then adjusted for projections of the basis differential between Henry Hub and the Massachusetts (Algonquin) city gates designed to reflect the higher basis when gas demand approaches or exceeds capacity. We assume—based on preliminary modeling results—that the Massachusetts (and upstream) gas sector will remain out of balance from 2015 to 2019, but will be in balance from 2020 through 2030. Detailed assumptions used in the natural gas price sensitivity analysis are presented in Appendix D.

Caveats to natural gas price assumptions

- This study explores the sensitivity of model results to the range in natural gas prices described above. Still higher or lower natural gas prices have the potential to change model results.
- This study does not specifically examine the impact of natural gas exports on the potential range of gas prices. The low and high gas prices used in sensitivities were the “Low and High Oil and Gas Resource Cases” from the U.S. Department of Energy (DOE) and EIA’s *2014 Annual Energy Outlook* and were chosen to represent a range in future gas supplies available from shale reserves. DOE/EIA explicitly recognizes the uncertainty of gas availability from shale reserves and developed these alternate resource cases to address it.
- This study does not include a risk premium associated with natural gas price volatility.

- This study does not incorporate the dramatic decline in world crude oil prices or the decline in Henry Hub natural gas commodity prices that occurred during the course this analysis. While these changes will have an impact on the energy market economics in Massachusetts, and the annual cost estimates presented in this study, the DOE/EIA latest Short Term Energy Outlook (December 2014) shows that retail gas prices in the Northeast continue to have a significant price advantage over retail heating oil prices.[13] Furthermore, prices that occur during the winter peak event are driven more from the capacity constraints and pipeline basis differential prices than the cost of the commodity.

Incremental Canadian transmission sensitivity

We investigated the sensitivity of modeling results to the addition of 2,400 MW of new, incremental transmission of system power from Canada to the New England hub: one 1,200 MW line by 2018 and a second by 2022. Note that this transmission is assumed to be heavily weighted to be composed of hydroelectric-based generation, but includes power from other Canadian generators. Table 3 summarizes our basic assumptions for this sensitivity. We assume the capacity factor on these incremental lines will be 75 percent on average on a winter peak day and 71 percent in a winter peak hour. Our research underlying regarding Canadian transmission is presented in Appendix E. Note that Massachusetts is assumed to receive all power from these lines—as it would were the Commonwealth to purchase renewable or clean energy certificates associated with the generation or enter into long-term contracts with the generators—and therefore both pays the full costs of constructing the lines and claims the full emissions reductions associated with generation imported on the lines.

[13] U.S. Energy Information Administration, *Short-Term Energy Outlook, December 2014*, Table WF01, Average Consumer Prices and Expenditures for Heating Fuels During the Winter.

Table 3. Incremental Canadian transmission assumptions

Canadian Transmission HVDC 1	Annual Capacity Factor	Total Potential Capacity	Annual Net Levelized Cost	Annual Net Levelized Cost	Annual Energy Production	Peak Hour Gas Savings
	%	*MW*	*$/MWh*	*$/MMBtu NG*	*MMBtu NG*	*MMBtu NG*
2015	n/a	0	n/a	n/a	n/a	n/a
2016-2020	67%	1,200	$100	$839	59,161,536	6,840
2021-2030	n/a	0	n/a	n/a	n/a	n/a
Canadian Transmission HVDC 2	**Annual Capacity Factor**	**Total Potential Capacity**	**Annual Net Levelized Cost**	**Annual Net Levelized Cost**	**Annual Energy Production**	**Peak Hour Gas Savings**
	%	*MMBtu / yr*	*$/MMBtu*	*$/MMBtu NG*	*MMBtu NG*	*MMBtu NG*
2015	n/a	0	n/a	n/a	n/a	n/a
2016-2020	n/a	0	n/a	n/a	n/a	n/a
2021-2030	50%	1,200	$147	$1,231	44,150,400	6,840

Caveats to incremental Canadian transmission assumptions

- Both existing and incremental Canadian transmission is modeled as system power from Québec –that is, generation and its associated emissions are assumed to be an average or mix of Québécois resources, and not dedicated transmission of hydroelectric or any other resource. Average Québécois electric generation is treated as having zero greenhouse gas emissions in this study when in fact the emission rate associated with Québec imports is estimated to be 0.002 metric tons per MWh.[14] Incorporating the actual emissions associated with these imports in our study would have no appreciable impact on total emissions or GWSA compliance.

- While based on the most recent data for costs and in-service dates of proposed transmission lines, in this study, Canadian transmission lines are generic and do not represent any specific project. The costs and in-service dates of actual transmission lines would be expected to vary from the generic lines represented here. Changes to costs or in-service dates of these lines would be expected to impact model results.

3.4. Feasibility Analysis for Low Energy Demand Scenario

The low energy demand case is modeled as the base case with the addition of the maximum amount of alternative demand- and supply-side resources determined to be feasible. We performed feasibility analyses for alternative resources for 2015, 2020 and 2030. All alternative resources assessed to be both

[14] National Inventory Report 1990-2011, Part III. Environment Canada. 2013. p.71. Available at http://unfccc.int/files/national_reports/annex_i_ghg_inventories/national_inventories_submissions/application/zip/can-2013-nir-15apr.zip

technically feasible and practically achievable in Massachusetts for each year, but ignoring cost, were included in the economic feasibility analysis. For each such resource, the ratio of annual net costs to annual energy in MMBtu (annual-$/annual-MMBtu) was compared to a threshold for economic feasibility.

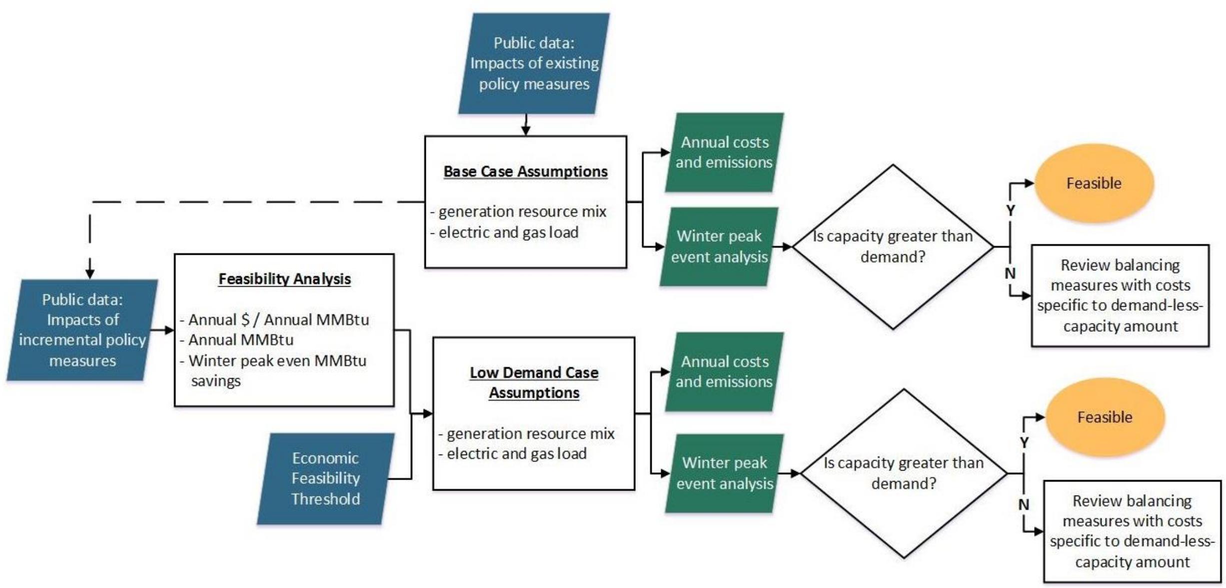
The estimated annual cost of a generic, scalable natural gas pipeline is used as the threshold for economic feasibility in this report. Using pipeline construction costs from the AIM project we assume a 95-percent utilization (chosen to represent the level of pipeline utilization at which operational flow orders are typically declared and shippers are held to strict tolerances on their takes from the pipeline) on 80 percent of winter days.[15] This study assumes that incremental pipeline capacity consists of non-specific generic projects that can be added in increments of 100,000 MMBtu per day and are in addition to the existing and planned capacity defined above. Based on this calculation, the economic threshold for including additional alternative resources in the model is $4/MMBtu.

Resources were assessed as either less or more expensive than the selected threshold:

- If Annual-$/annual-MMBtu are less costly than the economic feasibility threshold, then resources are included in the determination of the electric generation resource mix and electric and gas loads in the low energy demand case.
- If Annual-$/annual-MMBtu are more costly than the economic feasibility threshold, then resources are not included in the low energy demand case.

Figure 4 provides a schematic of the role of feasibility analysis in this modeling project.

Figure 4. Feasibility analysis schematic



[15] Algonquin Gas Transmission, AIM Project, FERC CP 14-96, February 2014

Measures included in the feasibility analysis meet two basic criteria:

1. These measures are incremental (i.e., over and above) the amounts of the same technologies associated with the same policy measures included in the base case.

2. These measures are associated with expected annual MMBtu savings in the analysis year; that is, they are technically and practically feasible.

For the purpose of the feasibility analysis, reduced natural gas consumption from displaced electric generators is calculated using an 8.4 MMBtu/MWh heat rate. This is the average annual natural gas marginal heat rate used by ISO-NE in 2013.[16] Detailed assumptions and results of the feasibility analysis are presented in Appendix A.

Table 4 reports the alternative measures included in the low energy demand case at the reference gas price along with the total annual savings potential for this group of measures.[17] Note that savings are incremental from the base case and incremental from the previous year. Measures that do not have annual MMBtu savings are included in the "balancing" phase of modeling (described in Section 3.5)—battery storage, pumped storage, demand response, and the ISO-NE Winter Reliability program—and not in the feasibility study.

[16] 2013 Assessment of the ISO-NE Electricity Markets. Potomac Economics. June 2014. p.44.

[17] Synapse conducted two rounds of analysis of this group of measures; the first round analyzed gas use, emissions, and cost impacts of a subset of these measures. After correcting for a calculation error in the supply curves, Synapse extrapolated the impact of the first round of measures to the entire group. Results for 2015 were unchanged. Very minor corrections were needed for 2020 in all gas price sensitivities, while 2030 saw a larger impact from these additional measures in each gas price sensitivity. The final results shown throughout this report reflect these changes.

Table 4. Alternative measures included in low energy demand case at reference gas price

		Total Annual Savings Potential (trillion Btu)
2015	Anaerobic digestion, landfill gas, converted hydro[18], small CHP	0.2
2020	Appliance standards, residential electric energy efficiency, commercial and industrial electric energy efficiency, anaerobic digestion, large CHP, landfill gas, converted hydro, low-income electric energy efficiency, small CHP, residential gas energy efficiency, commercial and industrial gas energy efficiency, low-income gas energy efficiency, Class 1 biomass power	30.9
2030	Residential gas energy efficiency, appliance standards, commercial and industrial gas energy efficiency, low-income gas energy efficiency, residential electric energy efficiency, commercial and industrial electric energy efficiency, anaerobic digestion, large CHP, landfill gas, converted hydro, small CHP, low-income electric energy efficiency, commercial PV, residential PV, Class 1 biomass power, utility-scale PV, small wind, Class 5 large wind, Class 4 large wind, Class 2 biomass power	129.9

Feasibility supply curve results are dependent on the choice of natural gas price sensitivity: alternative resources avoided different costs based on the assumed gas price. Overall, the results of the supply curve analysis were not very sensitive to low gas prices: the same set of resources clear the economic threshold in 2015 as in the reference gas price case. In 2020, one fewer resource clears with the low gas price, representing less than 1 trillion Btu of the total 31 trillion Btu cleared savings in the reference case. Sensitivity to the low gas price is greater in 2030, with two resources totaling 8 trillion Btu not clearing the economic threshold as a result of lower gas prices, compared to total cleared savings of 130 trillion Btu. The model exhibits somewhat higher sensitivity to a change to higher gas prices. In 2015, the higher gas price results in a new 2 billion Btu resource clearing the economic threshold, compared to total cleared savings of 235 billion Btu. In 2020, two additional resources clear the economic threshold, representing 9 trillion Btu cleared savings of the total 31 trillion Btu cleared savings in the reference case. In 2030, two new resources clear the economic threshold, raising the total amount of cleared savings from 130 trillion Btu to 264 trillion Btu. Detailed feasibility analysis results for the natural gas price sensitivities are presented in Appendix A.

Caveats to feasibility analysis assumptions and methodology

- In this study, only resources jointly deemed technically feasible and practically achievable in Massachusetts for each year, given our best understanding of the pace of policy change and resource implementation (but ignoring cost), were assessed for

[18] The inclusion of converted hydro addresses energy potential only and does not take into account the other environmental considerations which may be raised by the Commonwealth's environmental agencies, such as the Department of Fish and Game.

economic feasibility and potential inclusion in the low demand case. Technological advancements and new information regarding the expected pace of policy change and resource implementation would have the potential to result in the inclusion of different resources in the feasibility analysis, different alternative measures included in the low demand case and different model results for this case.

- In this study, resources are deemed "economically feasible" if they are less expensive than a threshold estimated as the per MMBtu cost of a generic, scalable natural gas pipeline. The choice of this threshold determines what alternative resources are or are not included in the low demand case. A different threshold for inclusion in the low demand case would result in the inclusion of different alternative measures, and different model results for the low demand case.

- This study only includes alternative measures that could potentially result from changes to Massachusetts policy, and not alternative measures brought about by policy changes in other New England states.

- The avoided costs attributed to alternative measures in this study are derived from the AESC 2013 (see Appendix A). Since the publication of AESC 2013 there have been changes to projected fuel prices, public policy, and the market structure in ISO-NE, all of which are expected to be included in modeling for the AESC 2015 that is currently in progress. Avoided costs modeled in AESC 2015 may be different—higher or lower—than those modeled in AESC 2013.

- Benefits to alternative measures not included in the low demand case include:

    - The avoided carbon cost of GWSA compliance (which was included only for energy efficiency measures in this study consistent with DPU 14-86)

    - Non-energy benefits including improved health, or reduced health costs, and new jobs related to alternative measures

- Costs to alternative measures not included in this study have the potential, if considered, to result in fewer resources deemed economic and included in the low demand case, changing the results of that case. Potential costs not included in the assessment of these measures include non-energy costs such as negative environmental impacts from alternative resource siting.

- The examination of possible alternative resources to be included in this feasibility analysis was not—and could not possibly be—comprehensive. Alternatives resources that were either not deemed to be reasonably available during the time frame of this study or of limited potential capability were not included in the supply curves for economic feasibility assessment. Resources not considered in the analysis include:

    - Solar panels installed on every sunny rooftop, and on every piece of land, where the installation is technically feasible

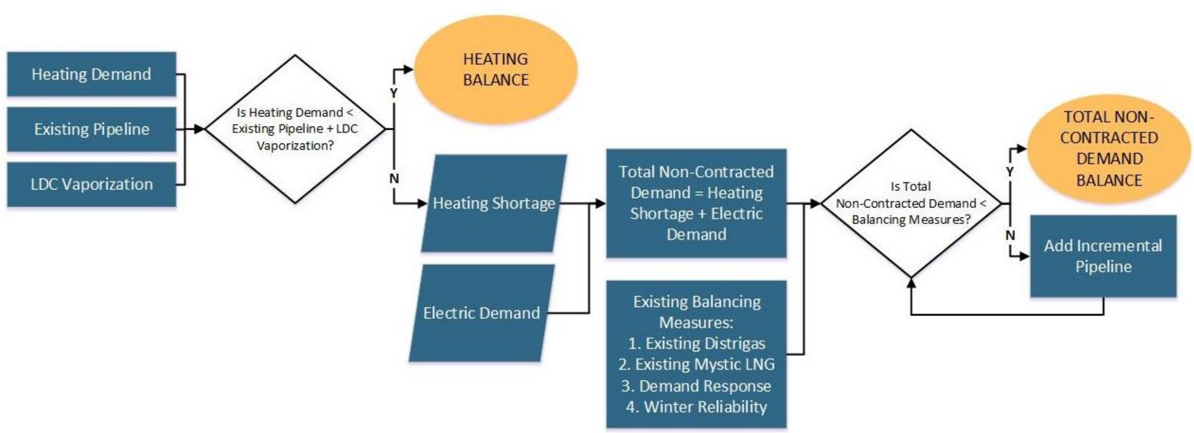
    - Unrestricted deployment of neighborhood-shared and community-shared solar

- Solar energy with no net-metering cap or restriction and without any type of restriction imposed by utility companies
- Co-location of solar panels with food production or other land uses
- Technological improvement in the lighting efficiency
- A public education campaign in Massachusetts similar to Connecticut's "Wait 'til 8" program
- Solar energy backed by batteries as a separate alternative resource
- Rate reforms such as peak time rebates and demand charges
- Transmission for wind firmed by hydro
- Smart appliances
- All new affordable-housing units built as zero-net-energy or net positive energy residences
- Net zero carbon zoning codes
- Voluntary trends towards green building
- Conversion to electric vehicles

3.5. Relationship between Capacity and Demand

The Synapse Massachusetts gas-sector model designed for this analysis examines the relationship between the Commonwealth's natural gas demand and natural gas capacity in the winter peak hour. This assessment of balance is accomplished as depicted in Figure 5:

Figure 5. Winter peak hour gas capacity and demand balancing schematic



First, in each scenario and year, heating demand (LDC, muni and capacity exempt gas demand less gas energy efficiency, reductions from advanced building codes and renewable thermal technologies, and (in the low demand case) other gas reduction demand measures) is compared with existing and planned (AIM project) pipeline capacity and existing vaporization capacity from LDC-owned storage.[19]

- If heating demand is less than existing and planned pipeline capacity plus LDC-owned storage, then the gas heating sector is in balance.
- If heating demand is greater than existing and planned pipeline capacity plus LDC-owned storage, then it is combined with electric demand as "non-contracted demand" in the next step.

Next, non-contracted demand (the sum of shortages in gas heating and gas required for gas-fired electric generation) is compared to balancing available from existing measures: Distrigas, Mystic LNG, and Demand Response (in all years), and the ISO-NE Winter Reliability Program (through 2018).

- If non-contracted demand is less than existing balancing measures, then the gas heating and electric sector is in balance. Existing balancing measures are:
  - "Distrigas" is existing LNG vaporization capacity less what is dedicated to Mystic directly available to the natural gas distribution system in Massachusetts.
  - "Mystic LNG" is existing LNG vaporization capacity directly available to the Mystic generating facility.
  - Electric demand response (available 2015 to 2019) is added at a minimum increment of 0.76 MMBtu of gas savings.
  - ISO-NE's Winter Reliability program (available 2015 to January 2018) is added at a minimum increment of 1.0 MMBtu of gas savings.
  - Incremental pipeline (available 2020 through 2030) is added at a minimum increment of 4.2 MMBtu per hour of gas.
- If non-contracted demand is greater than existing balancing measures, the incremental pipeline is added until a balance is achieved.

The balance criteria of gas demand no greater than 95-percent of gas capacity reflects the level of pipeline utilization at which operational flow orders are typically declared and shippers are held to strict tolerances on their takes from the pipeline. The impact of gas constraint on natural gas prices is thought to begin when gas demand rises above 80-percent of gas capacity. Gas prices associated with out-of-balance conditions are assumed in 2015 through 2019 in our model.

[19] LDC-owned storage is existing LNG storage used to provide vaporization during the peak hour throughout the 12-day cold snap. Propane storage is not available in this model as a balancing measure; existing propane storage facilities are sufficient for a 3-day cold snap.

Caveats to capacity and demand balance assessment methodology

- This study assumes that no additional LNG storage facilities will be sited in Massachusetts during the study period. This is based on expected challenges related to permitting, siting, financing and potential public opposition.

- This study assumes additions of a generic natural gas pipeline, available in 4.2 peak hour MMBtu increments and based on the per MMBtu costs of the AIM pipeline (see Appendix B). Although pipeline increments are added based on the requirement in the peak hour, incremental pipeline is assumed to be in use throughout the year. As a result, we have levelized the cost of these pipeline increments over an entire year. If a pipeline increment were only in use for a portion of the year, the implied levelized cost would be different.

- This study does not consider environmental impacts of pipeline siting and construction, nor does it consider the environmental impacts of natural gas extraction, such as those related to fracking.

- This study does not consider pipeline investments potential displacement of alternative resources, thereby slowing their growth.

- This study analyzes Massachusetts capacity during a winter peak event hour assuming that if demand exists, market forces will make it economic to utilize existing capacity. We do not examine the ability of specific supply basins to produce natural gas, or the impact on supply to Massachusetts of demand in other regions.

- Gas capacity constraints shown in this analysis may be higher than what is shown in the Forecast and Supply Plans filed by the Massachusetts LDCs due to the inclusion of capacity-exempt customer demand. LDCs, by regulation, do not acquire gas supply resources to serve capacity-exempt customers. Those customers, however, are firm gas customers that place demands on the system. In MA-DPU 14-111, the Massachusetts LDCs petitioned the DPU to allow them to acquire resources to serve up to 30 percent of the capacity-exempt load. In that petition, the LDCs estimated that the total capacity exempt load on a design day is approximately 294,200 Dth. The total capacity-exempt load is included in our analysis.

- Our analysis assumes LNG availability from Distrigas for import in the peak hour. If natural gas from this source is not available in the peak hour, the ability for the natural gas system to be in balance will be reduced.

- For this analysis, we have assumed the full vaporization capacity of the Distrigas LNG facility and the full capacity of the Maritimes & Northeast Pipeline are available in the peak hour. In order for markets to fully utilize this capacity, there must be sufficient supply supporting those facilities. The Distrigas LNG terminal relies on imported LNG. LNG markets are influenced by world supply and demand dynamics, which most recently have made it difficult for imported LNG to compete in U.S. markets. These dynamics have caused significant disruptions in deliveries to the Distrigas LNG facility in Everett, MA over the past few years. Similarly, for the Maritimes & Northeast Pipeline, one of its primary supply sources is the Canaport LNG facility in St. John, New Brunswick, Canada. That facility also relies exclusively on imported LNG, making its supply subject to the same market dynamics as the Distrigas LNG. Sable Island production, another major supply source for the Maritimes & Northeast Pipeline, is down to about 100 million cubic feet per day and there is speculation that production will soon cease.[20] The other major supply source for Maritimes & Northeast Pipeline is Encana's Deep Panuke project in Nova Scotia. That project has recently reached full production of 300 million cubic feet per day. However, according to Encana, the output is expected to drop to below 200 million cubic feet per day in the fourth year and below 100 million cubic feet per day by the eighth year.[21]

[20] EIA. "Production lookback 2013". January 2014. Available at http://www.eia.gov/naturalgas/review/production/2013/.

[21] Arugs Media. "Deep Panuke startup could mitigate gas price spikes". August 2013. Available at http://www.argusmedia.com/pages/NewsBody.aspx?id=860753&menu=yes

4. Model Results

This section presents model results for Massachusetts natural gas capacity and demand. Table 5 provides a key to the scenarios.

Table 5. Scenario key

Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6	Scenario 7	Scenario 8
Base Case Reference NG Price No Canadian Transmission	Base Case Low NG Price No Canadian Transmission	Base Case High NG Price No Canadian Transmission	Base Case Reference NG Price 2,400-MW Canadian Transmission	Low Demand Case Reference NG Price No Canadian Transmission	Low Demand Case Low NG Price No Canadian Transmission	Low Demand Case High NG Price No Canadian Transmission	Low Demand Case Reference NG Price 2,400-MW Canadian Transmission

Note: "Canadian transmission" refers to incremental transmission of system power from Québec. This transmission includes electricity both from hydroelectric and other generators.

4.1. Peak Hour Gas Shortages

Figure 6 displays the amount of winter peak hour supply—including existing pipeline, planned AIM pipeline, plus available LNG vaporization—needed to meet demand in Massachusetts during a winter peak event in three scenarios selected to highlight the progression of reducing gas shortages from a scenario with existing policies only, to the addition of technically and economically feasible alternative resources, to the addition (inclusive of alternative measures) of new transmission from Canada:

- **Scenario 1: Base Case** is the base case with reference natural gas price and no incremental Canadian transmission,
- **Scenario 5: Low Demand** is the low energy demand case with reference natural gas price and no incremental Canadian transmission, and
- **Scenario 8: Low Demand + Incremental Canadian Transmission** is the low energy demand case with reference natural gas price and 2,400-MW incremental Canadian transmission.

The dark blue area represents the demand from LDCs, municipal entities, and capacity-exempt demand in each year, which changes each year as a result of load growth and energy efficiency. Stacked on top in light blue is the peak hour natural gas demand from the Massachusetts electric system, which varies year-to-year as a result of the electric system reacting to changes in available resources and natural gas prices.

In all scenarios, winter peak hour gas requirements are heavily weighted towards LDC and muni demand. During the peak hour in 2015, on average across the scenarios, electric-system gas requirements were just 9 percent of total Massachusetts natural gas demand. As electric system gas consumption rises beginning in 2020 as natural gas price spikes decline, this value rises to 27 percent in 2020 and to 28 percent in 2030.

The solid line in Figure 6 represents existing and planned pipeline capacity and a dotted line represents this pipeline capacity plus the additional LNG vaporization from both existing LDC storage and Distrigas LNG. Any year in which the stacked blue columns exceed the dotted line is a year in which incremental pipeline is required to balance the system. Scenario 5 (low demand, reference gas price, no incremental Canadian transmission) and Scenario 8 (low demand, reference gas price, 2,400-MW incremental Canadian transmission) both require less incremental pipeline than Scenario 1 (base case, reference gas price, no incremental Canadian transmission) in every year.

Figure 6. Massachusetts peak hour demand and existing supply for Scenario 1, Scenario 5, and Scenario 8

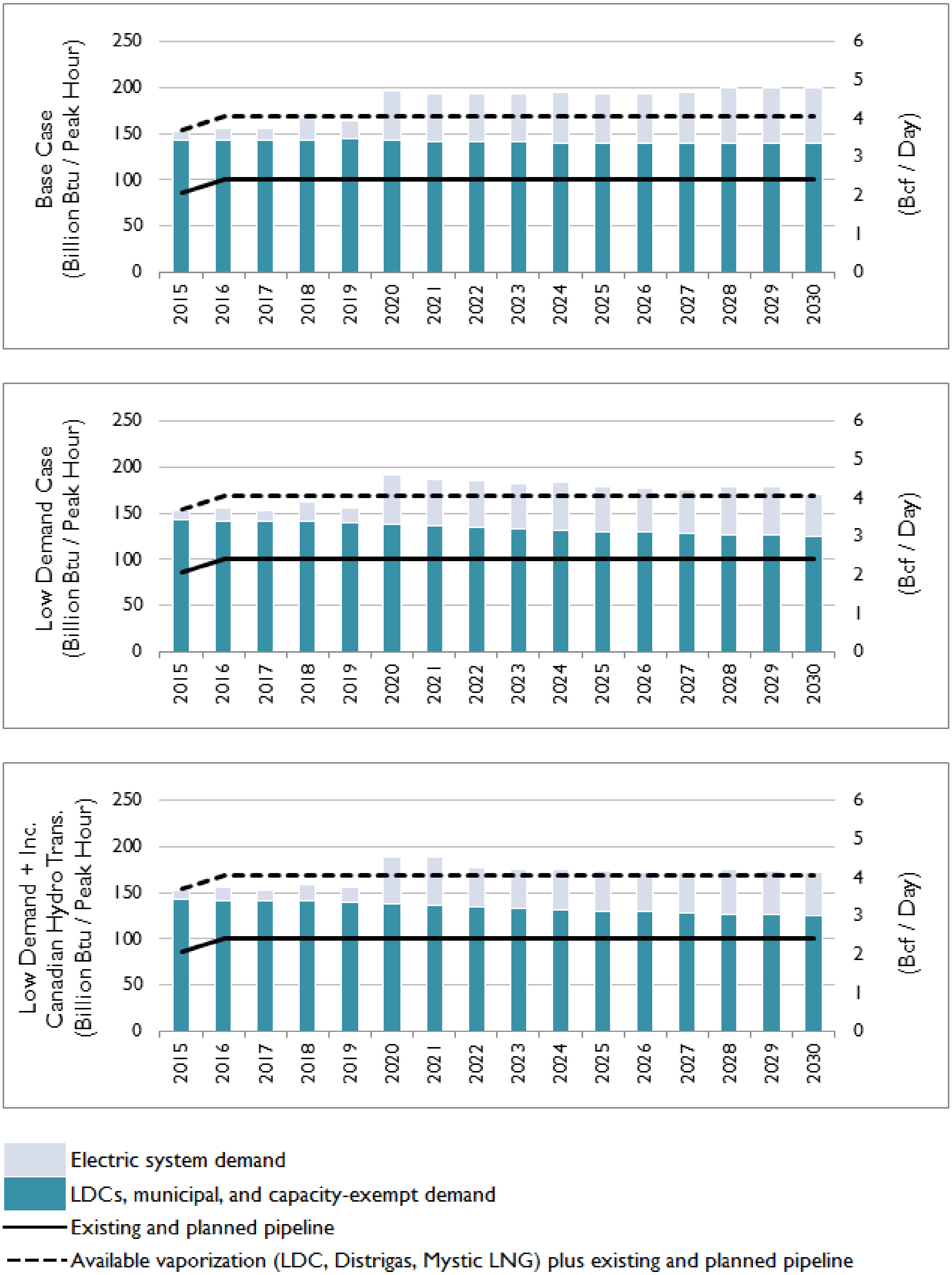
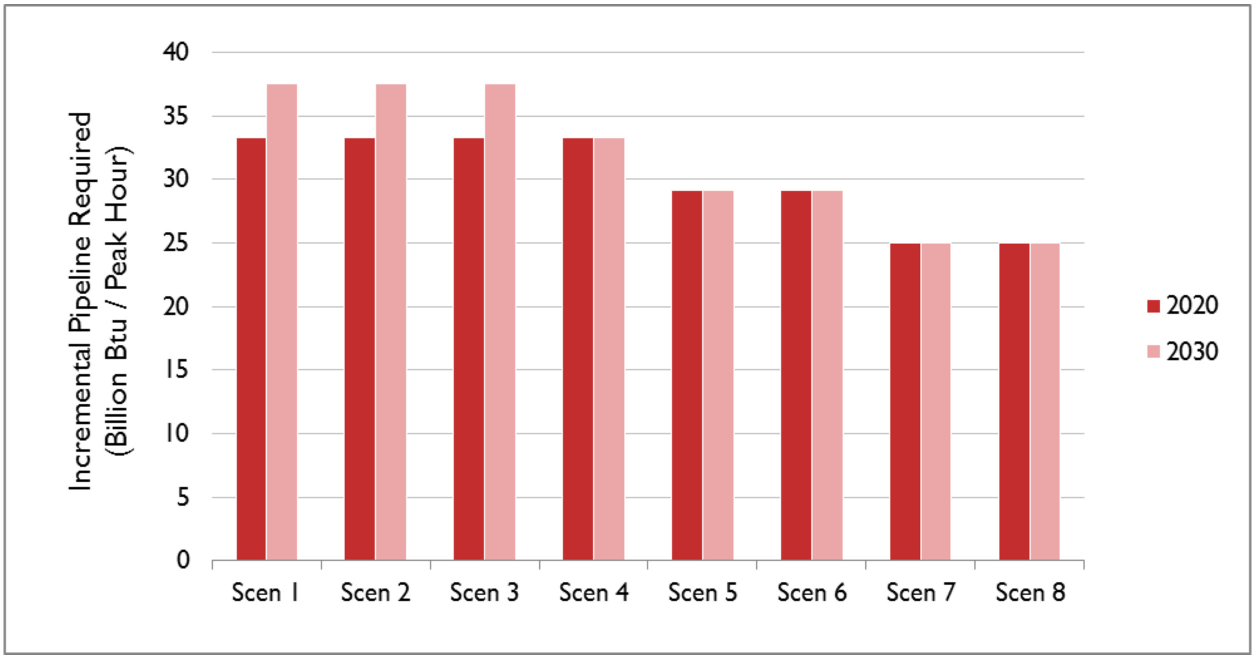


Figure 7 reports gas capacity shortage and incremental pipeline required in a winter peak event in all eight scenarios for 2020 and 2030 (in both years additional pipeline is reported as incremental to existing and planned pipeline). Scenario 8 (low demand, reference gas price, 2,400 MW of incremental Canadian transmission) has the smallest requirements. 2020 pipeline additions range from 25 billion Btu per peak hour to 33 billion Btu per peak hour (0.6 billion cubic feet (Bcf) per day to 0.8 Bcf per day).[22] 2030 pipeline additions range from 25 billion Btu per peak hour to 38 billion Btu per peak hour (0.6 Bcf to 0.9 Bcf per day.

Figure 7. Massachusetts gas capacity shortage in the winter peak hour in 2020 and 2030



From 2015 through 2019, electric generators have insufficient supply of natural gas, which results in spiking natural gas prices. Scarcity-driven high natural gas prices will force economic curtailment of natural gas-fired generators in favor of oil-fired units. The combination of increased oil utilization for electricity generation together with the use of emergency measures such as demand response and the ISO-NE Winter Reliability program (through January 2018) will allow electric demand to be met. From 2020 to 2030, existing and planned capacity plus incremental pipeline capacity balances system requirements.

Critical to this result is the assumption that winter peak hour gas shortages cannot be met using known measures (e.g. demand response or the addition of new natural gas pipeline) in years 2015 through 2019 and, as a result, gas prices are expected to reflect an out-of-balance market in those years. The electric sector responds to these high prices by shifting dispatch from gas to oil generation in the peak hour, reducing reliance on natural gas. In years 2020 through 2030, in contrast, winter peak hour gas

[22] Billion Btu can be converted to Bcf by multiplying billion Btu by 24 hours per day then dividing by 1,022 Btu per cubic foot.

shortages can be met using known measures (incremental pipeline) and, as a result, gas prices are expected to reflect an in-balance market in those years. The electric sector no longer has a price signal to shift dispatch away from gas generation in the peak hour, greatly increasing gas requirements in comparison to the previous period.

4.2. Annual Natural Gas Demand

Figure 8, Figure 9, and Figure 10 display Massachusetts' annual natural gas consumed for each scenario in 2015, 2020, and 2030, respectively. In 2015, annual natural gas consumption is largely constant across all scenarios, ranging from 417 to 427 trillion Btu per year (408 to 418 Bcf per year). In 2020, annual natural gas consumption increases for Scenario 2 as a result of the low natural gas price modeled, while it decreases in the low demand scenarios (Scenario 5 through 8) as a result of reduced natural gas demand from alternative measures and, in Scenario 8, the addition of incremental Canadian transmission. As a result, the range of annual natural gas consumption in 2020 is 439 to 523 trillion Btu per year (430 to 512 Bcf per year). This trend continues in 2030 as low demand measures and incremental Canadian transmission play a greater role in avoiding natural gas demand in selected scenarios. The range of annual natural gas consumption in 2030 is 360 to 520 trillion Btu per year (352 to 509 Bcf per year).

Figure 8. Massachusetts annual gas demand in 2015

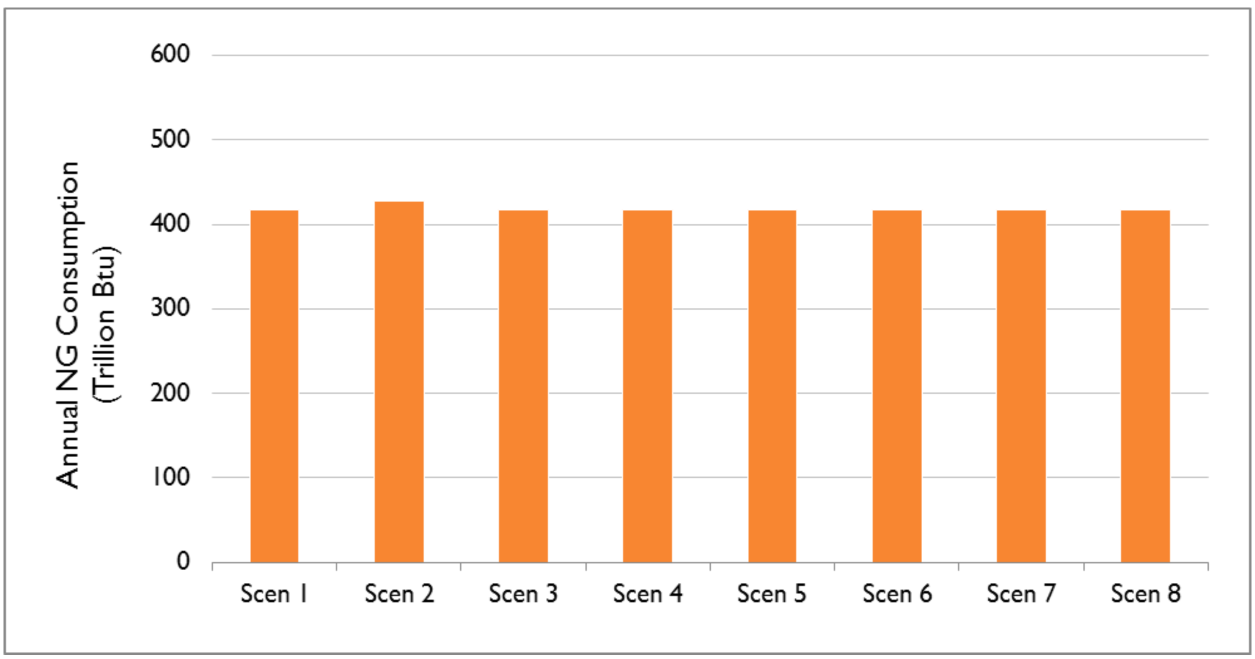


Figure 9. Massachusetts annual gas demand in 2020

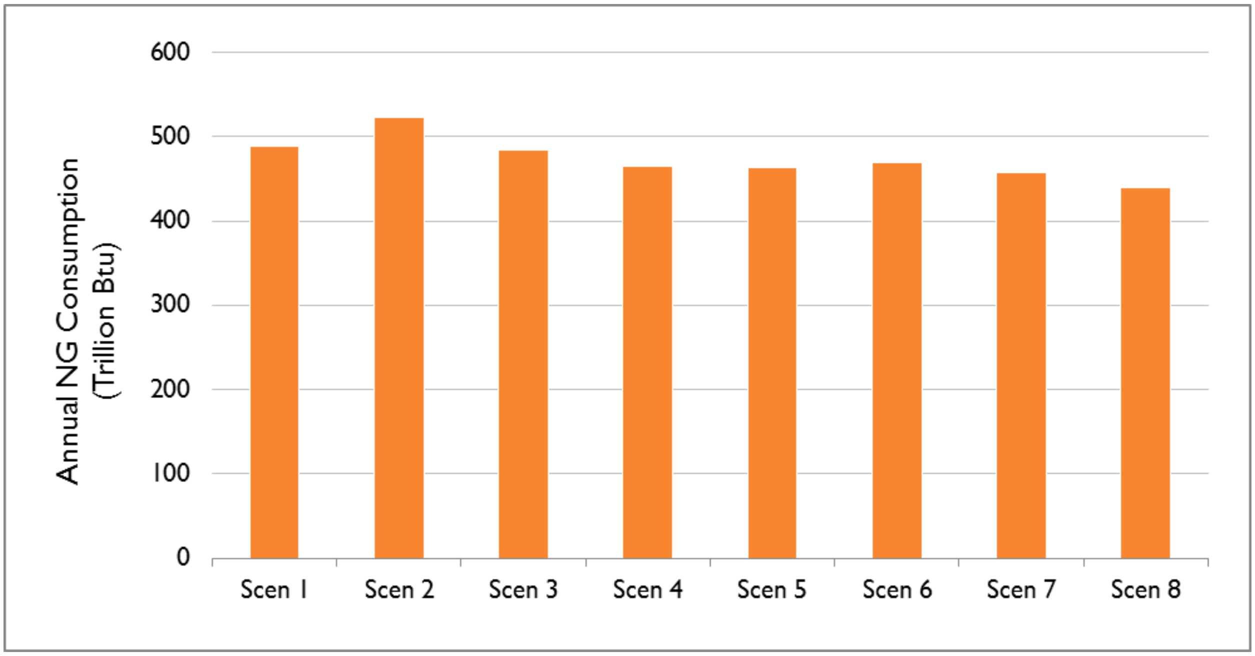
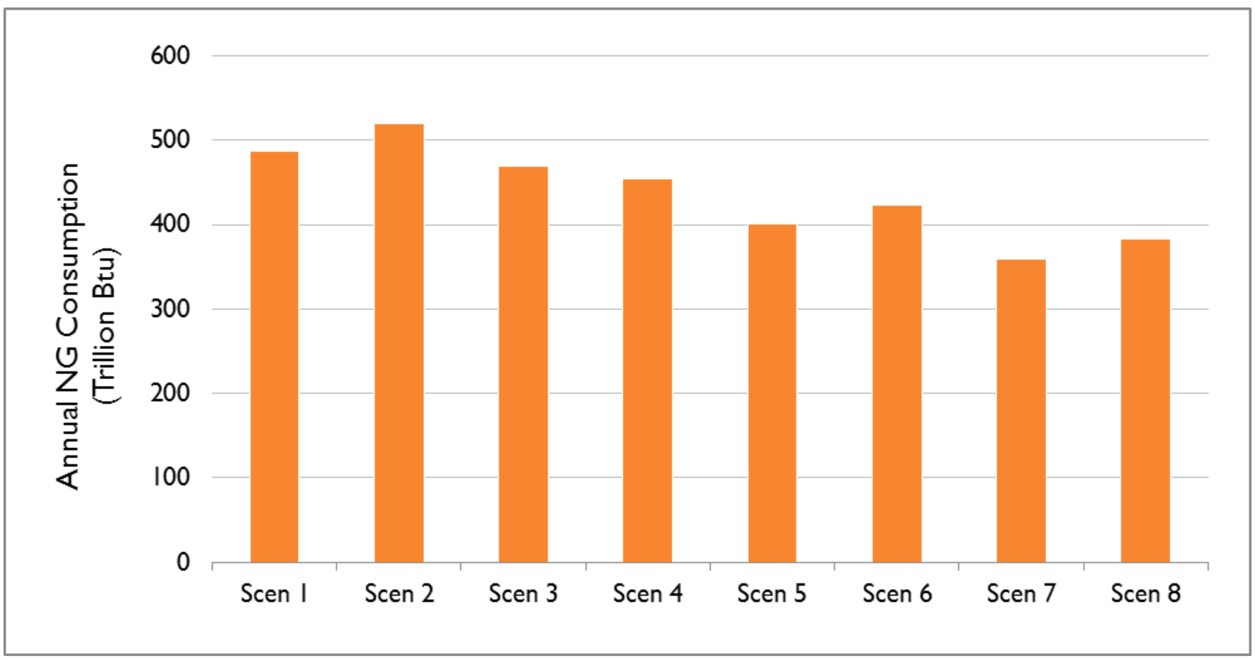


Figure 10. Massachusetts annual gas demand in 2030

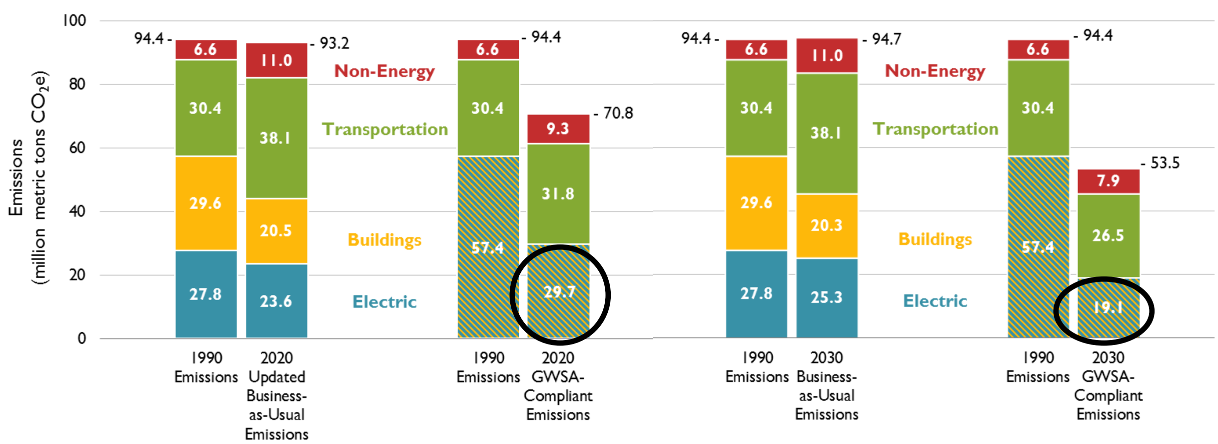


4.3. Annual CO_2 Emissions

Compliance with the Massachusetts 2008 climate law—the GWSA—is not a criterion for scenarios and sensitivities; rather, the Massachusetts emissions associated with each scenario and sensitivity are an output of the model. Massachusetts emissions are estimated according to the methodology set out in the *2008-2010 Massachusetts Greenhouse Gas Emissions Inventory* and include emissions associated with Massachusetts generation, out-of-state renewable energy certificate (REC) purchases, Canadian system power imports for which the Commonwealth has a particular claim, and emissions from residual sales as a share of imports from both out of state and out of region (see Appendix B for a more complete description).[23]

In MA-DPU Docket 14-86, the electric and buildings sectors in a GWSA compliant scenario have a combined emission allocation of 29.7 million metric tons in 2020 and 19.1 million metric tons of CO_2-e in 2030 (see Figures 2 and 5 of Corrected Amended Direct Testimony of Elizabeth A. Stanton, December 4, 2014, reproduced as Figure 11 here).[24] Note that 2030 emission targets are not specified by GWSA; per MA-DPU Docket 14-86 we have linearly interpolated the 2030 target based on the 2020 and 2050 targets. The allocation shown in Figure 11 is based on the assumption that emissions in the transportation and non-energy sectors will follow the December 2010 *Massachusetts Clean Energy and Climate Plan for 2020* (CECP).

Figure 11. Massachusetts 2020 and 2030 GWSA compliant emissions



Of this allocation we expect that, following the CECP, direct use of oil will emit 6.4 million metric tons of CO_2-e in 2020 and 0.4 million metric tons in 2030.[25] As a result, GWSA compliance cannot be achieved if combined emissions from the electric sector and direct use of gas exceed 23.3 million metric tons in 2020 or 18.7 million metric tons in 2030 (see Table 6).

[23] Note that imports from Canada include generation both from hydro resources and non-hydro resources.

[24] In MA DPU 14-86 the Massachusetts Departments of Energy Resources and Environmental Protection jointly petitioned MA-DPU to "commence an appropriate proceeding to determine whether the existing method of calculating the compliance costs associated with GHG emissions should be replaced by the marginal abatement cost curve methodology."(Joint Petition, May 26, 2014)

[25] This estimate of 2020 and 2030 oil heating emissions is based on information presented in MA-DPU 14-86 Exhibit EAS-8 and is calculated as oil heating business-as-usual emissions in those years less CECP emission reductions for oil heating in those years.

Table 6. Emissions available under GWSA target

	2020	2030
GWSA Target (% reduction below 1990 statewide levels)	25%	43%
GWSA Target (million metric tons CO_2-e)	70.8	53.5
CECP Non-Energy Sector Emissions (million metric tons CO_2-e)	9.3	7.9
CECP Transportation Sector Emissions (million metric tons CO_2-e)	31.8	26.5
CECP Building and Electric Sector Target (million metric tons CO_2-e)	29.7	19.1
CECP Building Sector Oil Emissions (million metric tons CO_2-e)	6.4	0.4
Emissions Available under GWSA Gas Heating and Electric Target	23.3	18.7

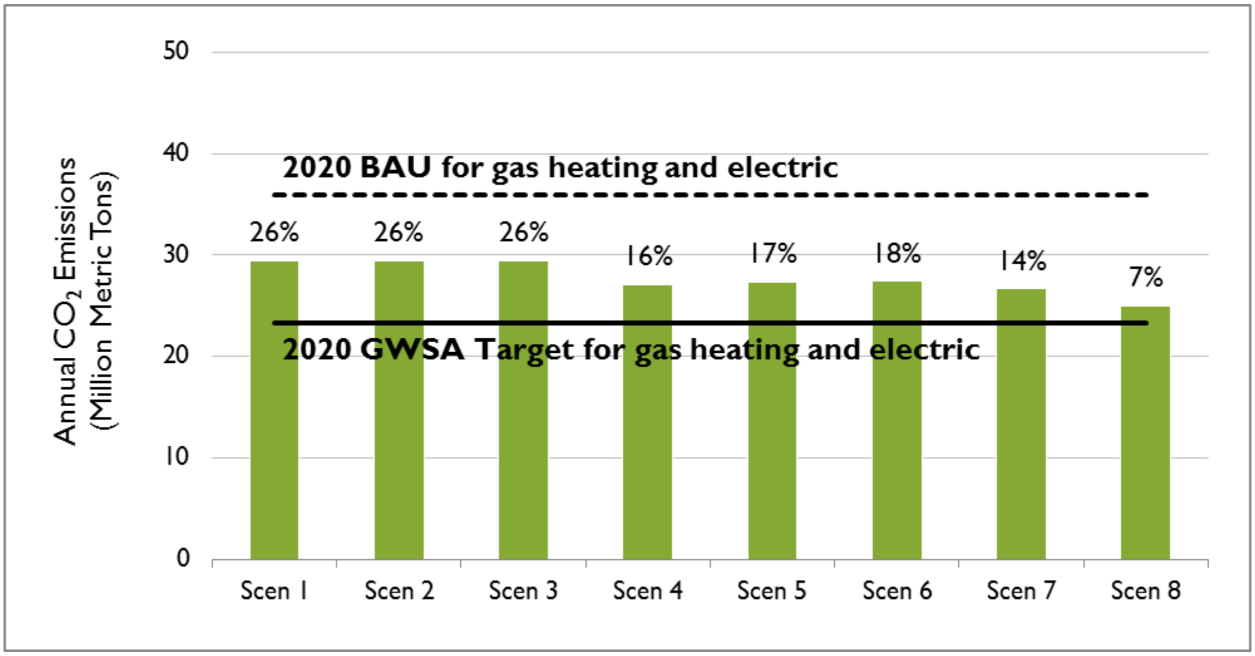
The "emissions available under GWSA gas heating and electric target" shown in the last row of Table 6 is a target for emission levels from natural gas heating and electricity generation that would allow the GWSA 2020 limit to be met, taking into account expected emissions from other sectors. Calculation of the target takes into account greenhouse gas emission reductions that could be achieved through successful implementation of a suite of policies identified in the CECP to reduce demand and emissions from the transport, non-energy and non-natural gas thermal sectors.[26] The economy-wide 2020 greenhouse gas emissions limit of 70.8 million metric tons CO_2-e, based on a 25 percent reduction from 1990 levels, will be achieved from a combination of strategies including reductions to building, electricity, transportation, land use and non-energy emissions.

Total emissions from Massachusetts' natural gas heating and electric sectors in 2020 and 2030 are presented in Figure 12 and Figure 13. Each figure is overlaid with two horizontal lines: one showing business-as-usual (BAU) emissions, and the other showing that year's GWSA target for the natural gas heating and electric sectors assuming that the non-energy, transportation and oil heating sectors will meet their CECP targets. Percentages refer to the degree to which each scenario under- or over-complies with the target.[27] While no scenario achieves GWSA compliance in the heating gas and electric sectors in 2020, Scenario 8 (low energy demand case with reference natural gas price and 2,400-MW incremental Canadian transmission), shown below, and Scenario 7 (low energy demand case with high natural gas price and no incremental Canadian transmission) meet compliance in 2030. Scenario 5 (low energy demand with reference natural gas price and no incremental Canadian transmission) exceeds 2030 GWSA compliance by 0.4 million metric tons or 1 percent of the 2030 statewide emission target.

[26] The CECP will be updated in 2015 as required by the GWSA, and every five years thereafter. This may result in revisions to the share of greenhouse gas reductions expected from, or allocated to, the buildings, electric, transportation and non-energy sectors in order to meet GWSA limits.

[27] The GWSA target for the natural gas and electric sectors assumes emissions in the transportation and non-energy sectors and direct use of oil as described in Appendix B.

Figure 12. Annual Massachusetts gas and electric sector emissions in 2020



Note: Percentages displayed in the above chart indicate the degree to which each scenario is above the 2020 GWSA target for the gas and electric sectors. For example, the emissions in Scenario 1 are 26 percent higher than the 2020 GWSA target for the gas and electric sectors.

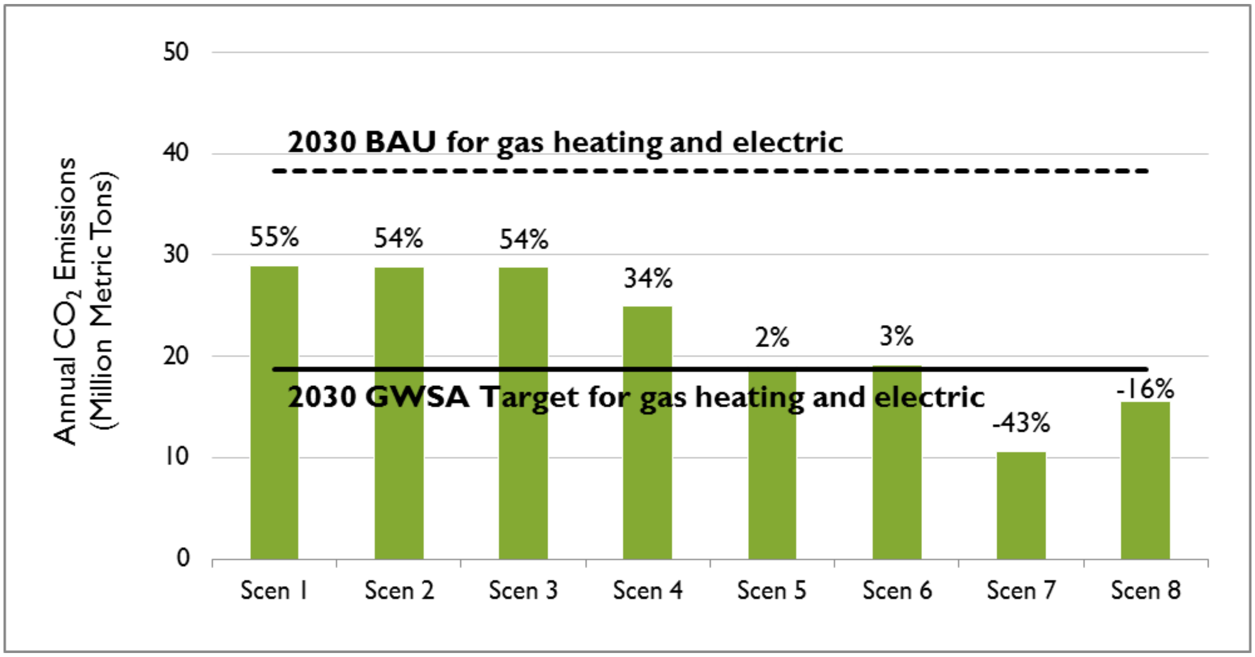
The emission level for Scenario 8 is the closest to compliance with the 2020 GWSA target (for heating and electric sectors), showing a 7-percent gap, equivalent to 1.6 million metric tons CO_2-e. The December 2013 *GWSA 5-Year Progress Report* also identified a potential shortfall in greenhouse gas reductions by 2020 for the buildings—including energy efficiency—and the electric generation sectors.

The "2020 GWSA Target for gas heating and electric" (23.3 million metric tons CO_2) is a target that would allow the GWSA 2020 emissions limit to be met, taking into account expected emissions from other sectors. The GWSA limit for state-wide greenhouse gas emissions in 2020 of 71 million metric tons CO_2 (a 25-percent reduction from 1990 baseline greenhouse gas emission levels) will require a combination of strategies including building, electricity, transportation, land use and non-energy emissions.

The emission estimates for Scenarios 1 through 8 in Figure 12 assume implementation of current Massachusetts policies. Scenarios 4 through 8 also include additional strategies determined to be economically and technically feasible by 2020 per the criteria set by the study, but do not reflect implementation of all policies considered in the CECP. Scenarios 4 and 8 include 2,400-MW of incremental Canadian transmission, 1,200-MW in 2018 and another 1,200-MW in 2022.

If additional renewable energy measures with costs higher than economic threshold (modeled in this study as the cost of incremental natural gas pipeline) were implemented for 2020 and 2030, this would serve to reduce and potentially close the gap between emission estimates from the modeled scenarios and the GWSA targets for the natural gas heating and electric sectors.

Figure 13. Annual Massachusetts gas and electric sector emissions in 2030



Note: Percentages displayed in the above chart indicate the degree to which each scenario is above the 2030 GWSA target for the gas and electric sectors. For example, the emissions in Scenario 1 are 55 percent higher than the 2030 GWSA target for the gas and electric sectors.

This approach assumes no change between 2020 and 2030 in the share of total reductions from the transportation and non-energy sectors. Transportation-related emissions are expected to rise under the CECP's business-as-usual assumptions. Policy impacts are expected to reduce emissions below business-as-usual levels. Incremental Canadian transmission is included for Scenario 4 and Scenario 8. Increased use of renewable energy in 2030—available at a higher cost than economic threshold used for this study—would reduce the emissions gap between modeled scenarios and GWSA targets.

Caveats to GWSA target assumptions

- Estimation of methane emissions from upstream leaks and other sources of emissions in the natural gas system—as well as all other life-cycle emission impacts of Massachusetts heating and electric sectors—was not in the scope of this study. Estimation of these impacts has the potential to increase greenhouse gas emissions in all scenarios. Synapse recommends that if life-cycle emission analysis is included in future scenarios it be included for all heating fuel and electric generation and alternative resources, and not for a subset of these resources.

- Estimation of emissions from leaks in the Massachusetts natural gas distribution system as well as potential emission reductions available from repairs to these leaks were not included in this study. An ICF study of Massachusetts gas leaks commissioned by MA-DPU was not released in time for use in this study. Synapse recommends that this information be considered in future studies. MA H.4164 establishes a uniform classification standard for natural gas leaks. It also requires natural gas companies to repair serious leaks immediately, produce a plan for removing all leak-prone infrastructure, and provide a summary of their progress and a summary of work to be completed every five years. The law further provides for the DPU to implement cost recovery mechanisms for LDC's to recover in a timely manner the costs of accelerated main replacement programs with intent of improving distribution system integrity, and reducing leaks and emissions. Leaks associated with interstate pipelines located in Massachusetts are minimal such that virtually all of methane emissions in Massachusetts are from distribution system pipe.

- This study does not analyze the impact that investments in pipeline infrastructure have on increasing the Commonwealth's long-term commitment to reliance on natural gas and the potential impact of this reliance on GWSA compliance.
- A Clean Energy and Climate Plan for 2030 has not yet been developed. The 2030 GWSA target is based on straight line extrapolation towards the 2050 limit and similar allocation of relative reductions from each sector as was assigned for 2020 in CECP.

4.4. Annual Costs

Figure 14 and Figure 15 depicts each scenario's annual costs as compared to costs in Scenario 1 (base case, reference gas price, no incremental Canadian transmission), respectively. Costs captured in this analysis are the costs that differ between the base case and other scenarios: the cost of gas delivery to LDCs and municipal entities, the system costs of Massachusetts's electric sector (estimated as product of Massachusetts sales and the wholesale price of energy as determined in Market Analytics), capital costs of new natural gas combine cycle plants needed to meet electric load, electric and gas energy efficiency, implementation of time-varying rates, avoided price spikes, and, in the low demand case, costs associated with gas and electric alternative resources.[28]

[28] Note that the costs associated with avoided price spikes are identical in all scenarios.

Figure 14. Annual costs for 2015-2030 as compared to Scenario 1, base case scenarios

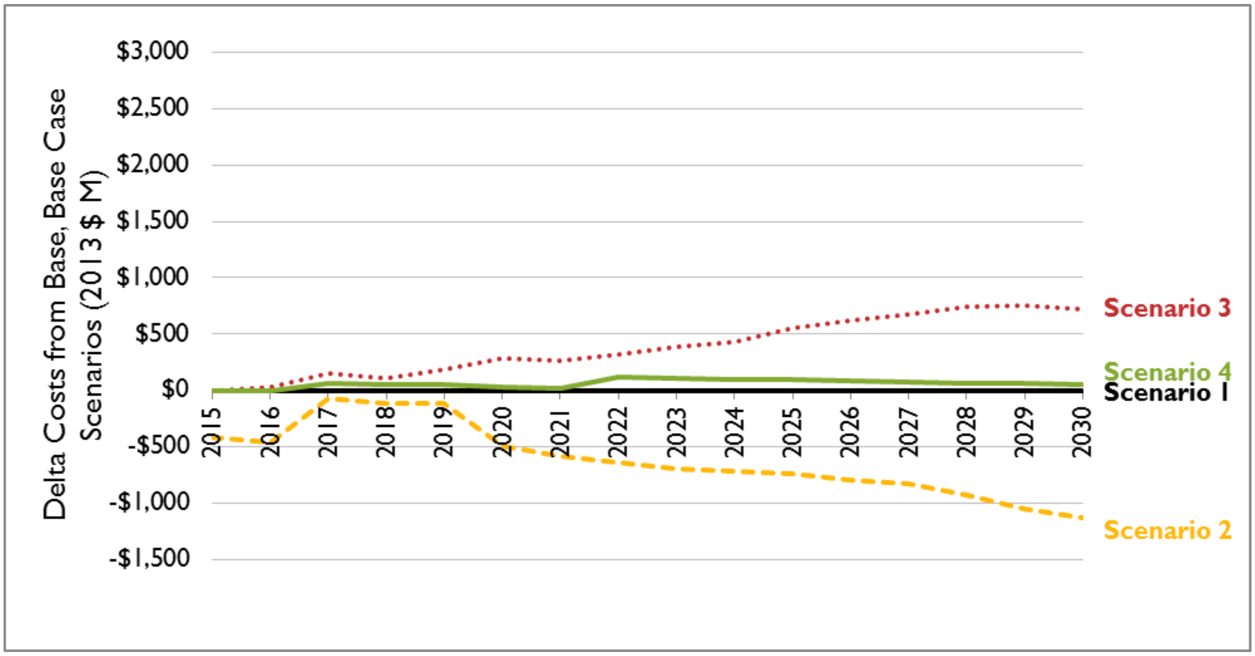


Figure 15. Annual costs for 2015-2030 as compared to Scenario 1, low demand case scenarios

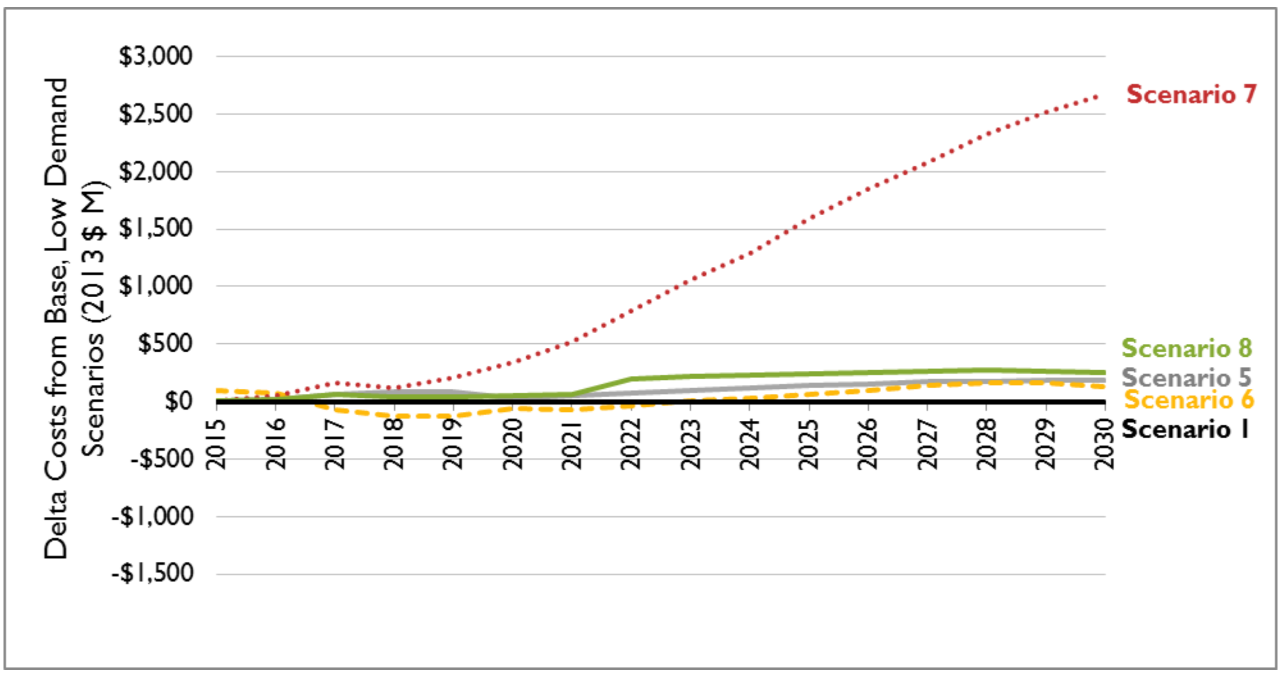


Table 7 reports the difference in each scenario's costs from that of Scenario 1 in net present value terms over the study period (2015 to 2030), compared to 2030 pipeline requirements. The addition of technically and economically feasible alternative measures (Scenario 5) adds $1,433 million in costs to Scenario 1, while the addition of both these alternative measures and a 2,400-MW incremental Canadian transmission (Scenario 8) adds $2,157 million in costs to Scenario 1. Note that in the low natural gas price sensitivity, Massachusetts costs fall in comparison to scenarios run with the reference gas price. While Scenario 2 (base case, low gas price sensitivity, no incremental Canadian transmission) has $8.6 billion in cost savings compared to Scenario 1, Scenario 6 (low demand case, low gas price sensitivity, no incremental Canadian transmission) has $0.3 billion in added costs compared to Scenario 1. This difference in costs is due to the costs of implementing the low demand measures included in Scenario 6.

Table 7. Net present value of difference in cost from Scenario 1 (in millions of 2013 dollars), 2015-2030 compared to 2030 pipeline requirements

	Scen. 1	Scen. 2	Scen. 3	Scen. 4	Scen. 5	Scen. 6	Scen. 7	Scen. 8
NPV ($ M)	$0	-$8,611	$5,384	$840	$1,433	$389	$15,112	$2,157
2030 Pipeline (Bcf/day)	0.9	0.9	0.9	0.8	0.7	0.7	0.6	0.6

Note: Assumes a 1.36 percent real discount rate per AESC 2013, Appendix B

5. OBSERVATIONS

In this section we lay out our observations from these results.

Price sensitivity of winter peak hour requirements to gas prices

Massachusetts' winter peak hour gas requirements are relatively insensitive to the range of gas prices explored in this analysis. Energy services are relatively inelastic (price insensitive)—particularly in the short run—and are modeled here as such. Changes to the gas price have a limited impact on dispatch in the electric sector in the peak hour, but the dominance of gas in the dispatchable resource mix is, already well established in 2015, only increasing over time. In contrast, annual gas requirements in the electric sector—and, therefore, electric-sector greenhouse gas emissions—do exhibit some sensitivity to gas prices in the range explored. Annual scenario costs, however, are very sensitive to gas prices.

Impact of incremental Canadian transmission

Incremental Canadian transmission at the level explored in this analysis—2,400-MW—reduces Massachusetts' winter peak hour gas requirements in 2030. It also reduces annual gas requirements and electric-sector greenhouse gas emissions while increasing overall costs.

Similarity in gas requirements across scenarios

Annual gas requirements across scenarios vary -10 to 7 percent per year from Scenario 1 (base case, reference gas price, no incremental Canadian transmission) in 2020 and -26 to 7 percent in 2030.

Impact of alternative measures

At the reference natural gas price, alternative measures reduce Massachusetts' gas requirements by 18 percent in 2030. The majority, or roughly 13 percentage points of this reduction, occurs in the electric sector. Capturing additional costs avoided by alternatives—such as costs of compliance with state environmental laws—has the potential to shift the economic feasibility assessments that determine this result. Also, additional program incentives or policies not currently in place as well as a different economic threshold could also impact the economic feasibility and resulting inclusion of additional alternative measures.

APPENDIX A: FEASIBILITY ANALYSIS

Alternative resources were assessed for feasibility. Resources that are determined to have annual MMBtu savings in 2015, 2020, or 2030 were included in that year's supply curve. Resources with annual-$/annual-MMBtu costs lower than an annual-$/annual-MMBtu cost economic threshold were modeled in the low energy demand case.

Avoided Costs

In this feasibility analysis all measures are assessed in terms of their total annual costs in the study year net of their avoided costs in that same year. As a proxy for analysis of avoided costs taking into consideration the load shape and year of implementation for each resource, we use the AESC 2013 avoided energy, capacity, transmission, distribution, and environmental compliance costs for each study year.[29] Avoided capacity, transmission and distribution costs are adjusted in relation to each resource's ISO-NE capacity credit. For energy efficiency resources only, AESC 2013 base case avoided environmental compliance costs are adjusted to include the costs of compliance with the GWSA, as described in the current MA-DPU Docket 14-86.[30] For all resources other than energy efficiency, avoided environmental compliance costs follow the AESC 2013 base case adjusted as appropriate to each resource (see Table 8).

[29] We assume that avoided energy costs are roughly proportional to gas prices (see AESC 2013 8-2 to 8-3 in support of this assumption). Using this assumption, we have updated the AESC 2013 avoided costs to reflect the natural gas prices used in this analysis using this assumption.

[30] MA-DPU 14-86, Amended Direct Testimony of Tim Woolf, September 11, 2014, Figure 4 represents these costs in levelized form.

Table 8. Avoided cost assumptions

		Electric Resources			Gas Resources	
		Energy Efficiency	*Non-EE, Distributed*	*Non-EE, Utility-Scale*	*Energy Efficiency*	*Non-EE, Distributed*
Avoided Energy	$/MWh	AESC 2013 Electric	AESC 2013 Electric	AESC 2013 Electric, Adj. for line losses	AESC 2013 Natural Gas	AESC 2013 Natural Gas
Avoided Environmental Compliance	$/MWh	DPU 14-86	AESC 2013 Electric	AESC 2013 Electric	DPU 14-86	None
Avoided Capacity	$/kW	AESC 2013 Electric	None	None	None	None
Avoided Transmission and Distribution	$/kW	AESC 2013 Electric	AESC 2013 Electric	None	AESC 2013 Natural Gas	AESC 2013 Natural Gas
Non-Energy Benefits	$/MWh	DPU 14-86	None	None	DPU 14-86	None
Capacity Revenue	$/kW	None	AESC 2013 Electric	AESC 2013 Electric	None	None

Many of the resources explored in the feasibility analysis have an impact on removing gas capacity constraints and, therefore, some impact on avoiding costs associated with constraint-elevated gas prices. However, in keeping with our assumption that a balance between gas capacity and demand is achieved in all scenarios, we do not capture this avoided cost here (although we do in modeling scenario costs, as described below). Similarly, alternatives resources may avoid some share of the cost of a new natural gas pipeline—and pipelines may avoid the cost of new alternative resources. We do not attempt to capture these costs in this feasibility analysis. Rather, we use the cost of a generic, scalable natural gas pipeline as the economic threshold determining which of the alternative resources in the feasibility analysis are included in the low demand case.

Resource Assessments

Synapse assessed 28 resources as potential alternative measures for inclusion in the low energy demand case. Detailed tables showing assumption by year and resources are presented below in this Appendix. Note that the costs described here use the reference natural gas price. Supply curves for all three natural gas prices are presented below.

Wind

For on-shore wind installations 10 kilowatts (kW) or less, incremental to wind in the base case, we assume a total potential capacity addition of 1 MW by 2015, 100 MW from 2016 to 2020, and 200 MW from 2021 to 2030 with an annual capacity factor of 16 percent. Annual levelized costs fall from $760 per megawatt-hour (MWh) in 2015 to $592/MWh in 2030.[31] (Net of avoided costs these values are $655/MWh and $457/MWh, respectively.) These assumptions are based personal communications with wind developers.[32]

For on-shore wind installation greater than 10 kW up to 100 kW, incremental to wind in the base case, we assume a total potential capacity addition of 1 MW by 2015, 100 MW from 2016 to 2020, and 300 MW from 2021 to 2030 with an annual capacity factor of 25 percent. Annual levelized costs fall from $218/MWh in 2015 to $156/MWh in 2030. (Net of avoided costs these values are $123/MWh and $32/MWh, respectively.) These assumptions are based on personal communications with wind developers.[33]

For Class 5 on-shore wind installation greater than 100 kW, incremental to wind in the base case, we assume a total potential capacity addition of 0 MW by 2015, 200 MW from 2016 to 2020, and 480 MW from 2021 to 2030 with annual capacity factors of 41 to 42 percent. Annual levelized costs fall from $113/MWh in 2020 to $111/MWh in 2030. (Net of avoided costs these values are $38/MWh and $8/MWh, respectively.) These assumptions are based on National Renewable Energy Laboratory (NREL) supply curves for New England wind regions.

For Class 4 on-shore wind installation greater than 100 kW, incremental to wind in the base case, we assume a total potential capacity addition of 0 MW by 2015, 0 MW from 2016 to 2020, and 800 MW from 2021 to 2030 with an annual capacity factor of 40 percent. Annual levelized costs are $118/MWh in 2030. (Levelized costs net of avoided costs are $14/MWh in 2030.) These assumptions are based on NREL supply curves for New England wind regions.

For off-shore wind installation, incremental to wind in the base case, we assume a total potential capacity addition of 0 MW by 2015, 800 MW from 2016 to 2020, and 4,000 MW from 2021 to 2030 with annual capacity factors of 44 to 45 percent. Annual levelized costs fall from $207/MWh in 2020 to $162/MWh in 2030. (Net of avoided costs these values are $133/MWh and $59/MWh, respectively.) These assumptions are based on NREL supply curves for New England wind regions.

In addition, we added costs to all large on-shore wind incremental to the base case, to represent the levelized cost of new transmission necessary to deliver incremental wind from Maine south to the major New England load centers. We assume a real, levelized cost of new transmission of $35 per MWh, based

[31] All dollar values in the memo are report in real (inflation-adjusted) 2013 dollars

[32] Personal Communications with Katrina Prutzman, Urban Green Energy. October 2014.

[33] Personal Communications with Trevor Atkinson, Northern Power. October 2014.

on a cost of $2.15 billion for 1,200 MW of capacity recovered over 30 years. This cost assumption is from work Synapse recently performed for DOER.[34]

Solar

For residential photovoltaic (PV) installations, incremental to PV in the base case, we assume a total potential capacity addition of200 kW by 2015, 5 MW from 2016 to 2020, and 200 MW from 2021 to 2030 with an annual capacity factor of 13 percent. Annual levelized costs fall from $211/MWh in 2015 to $163/MWh in 2030. (Net of avoided costs these values are $100/MWh and $19/MWh, respectively.) These cost and capacity factor assumptions for 2015 and 2020 are based on work done in 2013 for DOER;[35] 2030 assumptions are Synapse estimates.

For commercial PV installations, incremental to PV in the base case, we assume a total potential capacity addition of 1.6 MW by 2015, 50 MW from 2016 to 2020, and 800 MW from 2021 to 2030 with an annual capacity factor of 14 percent. Annual levelized costs fall from $184/MWh in 2015 to $149/MWh in 2030. (Net of avoided costs these values are $75/MWh and $9/MWh, respectively.) These cost and capacity factor assumptions for 2015 and 2020 are based on work done in 2013 for DOER; 2030 assumptions are Synapse estimates.

For utility-scale PV installations, incremental to PV in the base case, we assume a total potential capacity addition of 0 MW by 2015, 16 MW from 2016 to 2020, and 160 MW from 2021 to 2030 with an annual capacity factor of 15 percent. Annual levelized costs fall from $162/MWh in 2020 to $118/MWh in 2030. (Net of avoided costs these values are $76/MWh and $3/MWh, respectively.) These cost and capacity factor assumptions for 2015 and 2020 are based on work done in 2013 for DOER; 2030 assumptions are Synapse estimates.

Non-Powered Hydro Conversion

For hydro installations at dam sites that are not currently producing electricity, we assume a total potential capacity addition of 500 kW by 2015, 61 MW from 2016 to 2020, and 56 MW from 2021 to 2030 with an annual capacity factor of 38 percent. Annual levelized costs are constant over the study period at $63/MWh. (Net of avoided costs these values are -$35/MWh, -$37/MWh, and -$67/MWh, respectively.) These assumptions are based on an Ohio Case study of converting a dam site to generate electricity and the EIA's *Annual Energy Outlook* capital and operating costs forecast.[36]

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[34] Hornby, Rick, et al., *Memorandum: Incremental Benefits and Costs of Large-Scale Hydroelectric Energy Imports*, prepared by Synapse Energy Economics for the Massachusetts Department of Energy Resources, November 1, 2013.

[35] http://www.mass.gov/eea/docs/doer/rps-aps/doer-post-400-task-1.pdf

[36] http://www.hydro.org/tech-and-policy/developing-hydro/powering-existing-dams/
http://www.eia.gov/forecasts/capitalcost/pdf/updated_capcost.pdf

Landfill Gas

For landfill gas installations, incremental to landfill gas in the base case, we assume a total potential capacity addition of 300 kW by 2015, 20 MW from 2016 to 2020, and 6 MW from 2021 to 2030 with an annual capacity factor of 78 percent. Annual levelized costs are constant over the study period at $38/MWh. (Net of avoided costs these values fall from -$47/MWh in 2015 to -$75/MWh in 2030.) These assumptions are based on the 2012 U.S. Environmental Protection Agency's *Landfill Gas Energy* study.[37]

Anaerobic Digestion

For anaerobic digestion installations, incremental to anaerobic digestion in the base case, we assume a total potential capacity addition of 300 kW by 2015, 20 MW from 2016 to 2020, and 6 MW from 2021 to 2030 with an annual capacity factor of 90 percent. Annual levelized costs are constant over the study period at $47/MWh. (Net of avoided costs these values fall from -$54/MWh in 2015 to -$83/MWh in 2030.) These assumptions are based on a 2003 Wisconsin case study presented in the *Focus on Energy Anaerobic Digester Methane to Energy* statewide assessment.[38]

Biomass

For biomass Class 1 installations (with fuel costs of $3/MMBtu), incremental to biomass in the base case, we assume a total potential capacity addition of 0 MW by 2015, 20 MW from 2016 to 2020, and 20 MW from 2021 to 2030 with an annual capacity factor of 80 percent. Annual levelized costs are constant over the study period at $110/MWh. (Net of avoided costs these values fall from $27/MWh in 2020 to -$2/MWh in 2030.) These assumptions are based on analyses by EIA, Black & Veatch, and Office of Energy Efficiency and Renewable Energy (EERE).[39]

For biomass Class 2 installations (with fuel costs of $4/MMBtu), incremental to biomass in the base case, we assume a total potential capacity addition of 0 MW by 2015, 40 MW from 2016 to 2020, and 40 MW from 2021 to 2030 with an annual capacity factor of 80 percent. Annual levelized costs are constant over the study period at $128/MWh. (Net of avoided costs these values fall from $44/MWh in 2020 to $15/MWh in 2030.) These assumptions are based on analyses by EIA, Black & Veatch, and EERE.

For biomass Class 3 installations (with fuel costs of $10/MMBtu), incremental to biomass in the base case, we assume a total potential capacity addition of 0 MW by 2015, 40 MW from 2016 to 2020, and 60 MW from 2021 to 2030 with an annual capacity factor of 80 percent. Annual levelized costs are constant over the study period at $214/MWh. (Net of avoided costs these values fall from $130/MWh in 2020 to $102/MWh in 2030.) These assumptions are based on analyses by EIA, Black & Veatch, and EERE.

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[37] http://epa.gov/statelocalclimate/documents/pdf/landfill_methane_utilization.pdf

[38] http://www.mrec.org/pubs/anaerobic_report.pdf

[39] http://www.eia.gov/forecasts/capitalcost/pdf/updated_capcost.pdf; http://bv.com/docs/reports-studies/nrel-cost-report.pdf; http://www1.eere.energy.gov/bioenergy/pdfs/billion_ton_update.pdf

For biomass Class 4 installations (with fuel costs of $13/MMBtu), incremental to biomass in the base case, we assume a total potential capacity addition of 0 MW by 2015, 50 MW from 2016 to 2020, and 70 MW from 2021 to 2030 with an annual capacity factor of 80 percent. Annual levelized costs are constant over the study period at $259/MWh. (Net of avoided costs these values fall from $175/MWh in 2020 to $146/MWh in 2030.) These assumptions are based on analyses by EIA, Black & Veatch, and EERE.

CHP

For small combined heat and power (CHP) installations (estimated as 500 kW reciprocating engines), incremental to CHP in the base case, we assume a total potential capacity addition of 5 MW by 2015, 35 MW from 2016 to 2020, and 65 MW from 2021 to 2030 with an annual capacity factor of 50 percent. Annual levelized costs rise from $135/MWh in 2015 to $153/MWh in 2030. (Net of avoided costs these values are -$12/MWh and -$34/MWh, respectively.) These assumptions are based on ICF's 2013 *The Opportunity for CHP in the U.S.* report.[40]

For large combined heat and power (CHP) installations (estimated as 12.5 MW combustion turbines), incremental to CHP in the base case, we assume a total potential capacity addition of 0 MW by 2015, 25 MW from 2016 to 2020, and 50 MW from 2021 to 2030 with an annual capacity factor of67 percent. Annual levelized costs rise from $77/MWh in 2020 to $84/MWh in 2030. (Net of avoided costs these values are -$46/MWh and -$78/MWh, respectively.) These assumptions are based on ICF's 2013 *The Opportunity for CHP in the U.S.* report.

Electric Energy Efficiency

For residential electric energy efficiency installations, incremental to efficiency in the base case, we assume a total potential capacity addition of 0 MW by 2015, 28 MW from 2016 to 2020, and 64 MW from 2021 to 2030 with an annual capacity factor of 55 percent. Annual levelized costs are constant over the study period at $9/MWh. (Net of avoided costs these values are -$108/MWh in 2020 and -$128/MWh in 2030.) These assumptions are based on the Massachusetts Clean Energy and Climate Plan as modeled in DPU 14-86.

For commercial and industrial electric energy efficiency installations, incremental to efficiency in the base case, we assume a total potential capacity addition of 0 MW by 2015, 113 MW from 2016 to 2020, and 380 MW from 2021 to 2030 with an annual capacity factor of 55 percent. Annual levelized costs are constant over the study period at $31/MWh. (Net of avoided costs these values are -$86/MWh in 2020 and -$107/MWh in 2030.) These assumptions are based on the Massachusetts Clean Energy and Climate Plan as modeled in DPU 14-86.

For low-income electric energy efficiency installations, incremental to efficiency in the base case, we assume a total potential capacity addition of 0 MW by 2015, 3 MW from 2016 to 2020, and 7 MW from

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[40] http://www.aga.org/Kc/analyses-and-statistics/studies/efficiency_and_environment/Documents/The%20Opportunity%20for%20CHP%20in%20the%20United%20States%20-%20Final%20Report.pdf

2021 to 2030 with an annual capacity factor of %55 percent. Annual levelized costs are constant over the study period at $104/MWh. (Net of avoided costs these values are -$13/MWh and -$33/MWh, respectively.) These assumptions are based on the Massachusetts Clean Energy and Climate Plan as modeled in DPU 14-86.

Efficiency costs are modeled from program administrators' three-year plan data and are assumed to be the same on a $/MWh basis as the costs used for the base case. If efficiency costs were, instead, assumed to increase for additional increments of efficiency, even the efficiency sector with the highest costs—low-income gas measures—would require a cost escalation of more than 80 percent to exceed the economic threshold.

Federal Appliance Standard

For federal appliance standards, incremental to federal standards in the base case, we assume a total potential capacity addition of 0 MW by 2015, 216 MW from 2016 to 2020, and 619 MW from 2021 to 2030 with an annual capacity factor of 55 percent. Annual levelized costs rise from -$205/MWh in 2020 to -$205/MWh in 2030. (Net of avoided costs these values are -$390/MWh and -$343/MWh, respectively.) These savings and cost assumptions are based on the Massachusetts Clean Energy and Climate Plan as modeled in DPU 14-86.

Heat Pumps

For air source heat pump installation, incremental to heat pumps in the base case, we assume a total potential capacity addition of 6,307 annual MMBtu by 2015, 75,686 annual MMBtu from 2016 to 2020, and 1,127,727 annual MMBtu from 2021 to 2030. Annual levelized costs rise from $18/MMBtu in 2015 to $26/MMBtu in 2030. (Net of avoided costs these values are $17/MMBtu and $25/MMBtu, respectively.) These savings assumptions are based on DOER's assessment of the gas savings available from the measures described in Navigant's 2013 *Incremental Cost Study Phase Two Final Report*, the *Commonwealth Accelerated Renewable Thermal Strategy* and information from vendors.[41] Cost assumptions are based on a 2010 NREL webinar, *Residential Geothermal Heat Pump Retrofits*.[42]

For ground source heat pump installation, incremental to heat pumps in the base case, we assume a total potential capacity addition of 1,577 annual MMBtu by 2015, 18,922 annual MMBtu from 2016 to 2020, and 281,932 annual MMBtu from 2021 to 2030. Annual levelized costs rise from $16/MMBtu in 2015 to $22/MMBtu in 2030. (Net of avoided costs these values are $15/MMBtu and $20/MMBtu, respectively.) These savings and cost assumptions are based on DOER's assessment of the gas savings

[41] http://www.neep.org/sites/default/files/products/NEEP%20ICS2%20FINAL%20REPORT%202013Feb11-Website.pdf; http://www.mass.gov/eea/docs/doer/renewables/thermal/carts-report.pdf

[42] http://energy.gov/eere/wipo/downloads/doe-webinar-residential-geothermal-heat-pump-retrofits-presentation

available from the measures described in Navigant's 2013 *Incremental Cost Study Phase Two Final Report*, the *Commonwealth Accelerated Renewable Thermal Strategy* and information from vendors.[43]

Solar Hot Water

For solar hot water installation, incremental to solar hot water in the base case, we assume a total potential capacity addition of 1573 annual MMBtu by 2015, 18,896 annual MMBtu from 2016 to 2020, and 281,607 annual MMBtu from 2021 to 2030. Annual levelized costs rise from $53/MMBtu in 2015 to $86/MMBtu in 2030. (Net of avoided costs these values are $9/MMBtu and $32/MMBtu, respectively.) These savings assumptions are based on DOER's assessment of the gas savings available from the measures described in Navigant's 2013 *Incremental Cost Study Phase Two Final Report*, the *Commonwealth Accelerated Renewable Thermal Strategy* and information from vendors.[44] Cost assumptions are based on communications with solar hot water vendors.

Thermal Biomass

For thermal biomass installation, incremental to thermal biomass in the base case, we assume a total potential capacity addition of 6291 annual MMBtu by 2015, 75,586 annual MMBtu from 2016 to 2020, and 1,126,428 annual MMBtu from 2021 to 2030. Annual levelized costs are constant over the study period at $16/MMBtu. (Net of avoided costs these values are $9/MMBtu in 2015 and $7/MMBtu in 2020.) Cost and savings assumptions are based on DOER's assessment of the gas savings available from the measures described in Navigant's 2013 *Incremental Cost Study Phase Two Final Report*, the *Commonwealth Accelerated Renewable Thermal Strategy* and information from vendors.[45]

Gas Energy Efficiency

For residential gas energy efficiency installation, incremental to efficiency in the base case, we assume a total potential capacity addition of 0 annual MMBtu by 2015, 3,758,369 annual MMBtu from 2016 to 2020, and 5,290,473 MMBtu from 2021 to 2030. Annual levelized costs are constant over the study period at -$72/MMBtu. (Net of avoided costs these values are -$78/MMBtu in 2015 and -$79/MMbtu in 20230.) These assumptions are based on the Massachusetts Clean Energy and Climate Plan as modeled in DPU 14-86.

For commercial and industrial gas energy efficiency installation, incremental to efficiency in the base case, we assume a total potential capacity addition of 0 annual MMBtu by 2015, 4,121,834 annual MMBtu from 2016 to 2020, and 9,748,498 annual MMBtu from 2021 to 2030. Annual levelized costs are

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43 http://www.neep.org/sites/default/files/products/NEEP%20ICS2%20FINAL%20REPORT%202013Feb11-Website.pdf; http://www.mass.gov/eea/docs/doer/renewables/thermal/carts-report.pdf

44 http://www.neep.org/sites/default/files/products/NEEP%20ICS2%20FINAL%20REPORT%202013Feb11-Website.pdf; http://www.mass.gov/eea/docs/doer/renewables/thermal/carts-report.pdf

45 http://www.neep.org/sites/default/files/products/NEEP%20ICS2%20FINAL%20REPORT%202013Feb11-Website.pdf; http://www.mass.gov/eea/docs/doer/renewables/thermal/carts-report.pdf

constant over the study period at -$17/MMBtu. (Net of avoided costs these values are -$23/MMBtu in 2020 and -$25/MMBtu in 2030.) These assumptions are based on the Massachusetts Clean Energy and Climate Plan as modeled in DPU 14-86.

For low-income gas energy efficiency installation, incremental to efficiency in the base case, we assume a total potential capacity addition of 0 annual MMBtu by 2015, 584,036 annual MMBtu from 2016 to 2020, and 1,818,671 annual MMBtu from 2021 to 2030. Annual levelized costs are constant over the study period at -$9/MMBtu. (Net of avoided costs these values are -$15/MMBtu in 2020 and -$17/MMBtu in 2030.) These assumptions are based on the Massachusetts Clean Energy and Climate Plan as modeled in DPU 14-86.

Efficiency costs are modeled from program administrators' three-year plan data and are assumed to be the same on a $/MWh basis as the costs used for the base case. If efficiency costs were, instead, assumed to increase for additional increments of efficiency, even the efficiency sector with the highest costs—low-income gas measures—would require a cost escalation of more than 80 percent to exceed the economic threshold.

Feasibility Analysis Results

The feasibility analysis methodology employed in this report compares measures' annual-$/annual-MMBtu to thresholds for economic feasibility in annual-$/annual –MMBtu. Supply curves for 2015, 2020 and 2030 using the reference natural gas price are displayed in Figure 16, Figure 17 and Figure 18, and Table 9, Table 10, and Table 11. Measures with negative annual net levelized costs (i.e., net benefits) are shown in blue while measures with positive annual net levelized costs are shown in red. Due to large differences in the scale of resource availability, the supply curve for 2015 is presented in billion Btu and the supply curves for 2020 and 2030 are presented in trillion Btu. Table 12, Table 13, and Table 14 summarize the cost and savings for each measure available for each scenario in the Reference natural gas price case, while Table 21, Table 22, and Table 23 provide additional detail on costs and savings. Note that savings for each scenario remain the same across different natural gas prices, but net costs may change as a result of different avoided costs.

Supply curves for 2015, 2020 and 2030 using the low natural gas price are displayed in Table 15, Table 16, and Table 17. Supply curves for 2015, 2020 and 2030 using the high natural gas price are displayed in Table 18, Table 19, and Table 20.

Figure 16. Reference natural gas price supply curve for 2015 (billion Btu)

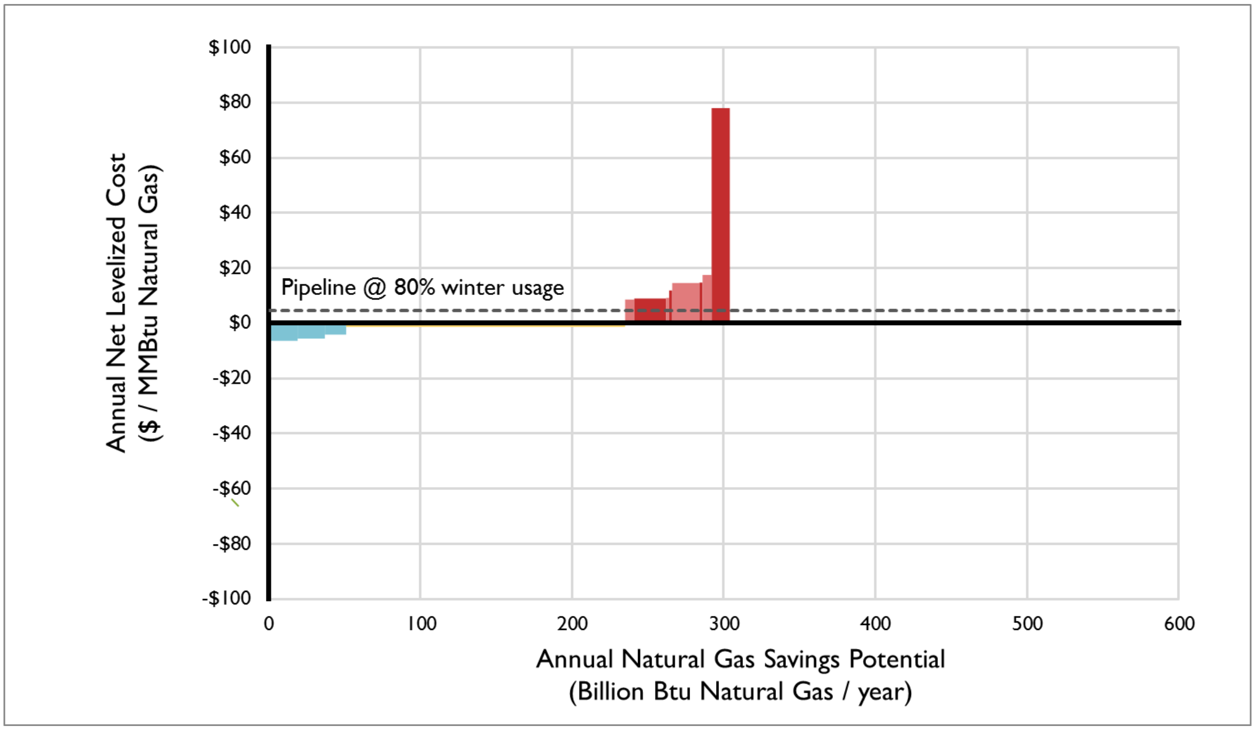

Table 9. Reference natural gas price supply curve for 2015 (billion Btu)

		Annual Net Levelized Cost ($/MMBtu)	*Annual Savings Potential (billion Btu)*
1	Anaerobic Digestion	-$6	20
2	Landfill Gas	-$6	17
3	Converted Hydro	-$4	14
4	Small CHP	-$1	184
Pipeline @ 80% winter usage		$4	-
5	Biomass Thermal	$9	6
6	Commercial PV	$9	21
7	Solar Hot Water	$9	2
8	Residential PV	$12	2
9	Wind (<100 kW)	$15	18
10	GS Heat Pump	$15	2
11	AS Heat Pump	$17	6
12	Wind (<10 kW)	$78	12

Figure 17. Reference natural gas price supply curve for 2020 (trillion Btu; note unit change from previous figures)

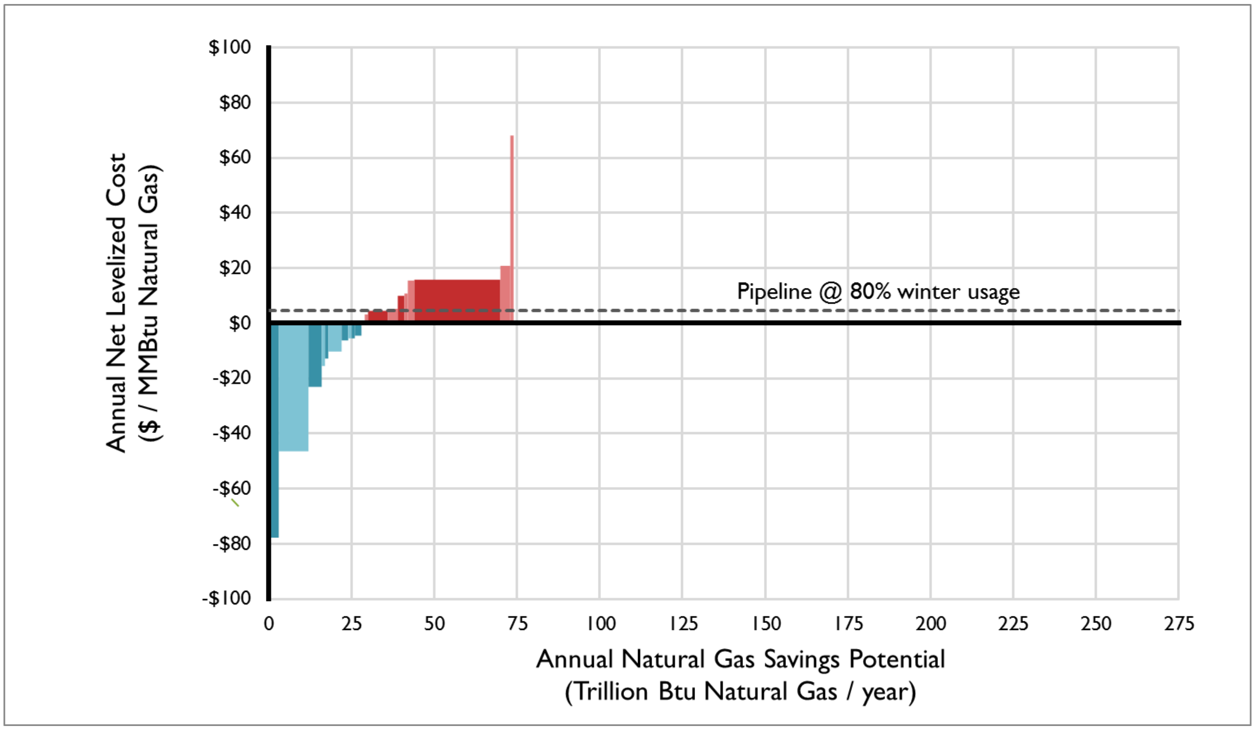

Table 10. Reference natural gas price supply curve for 2020 (trillion Btu)

		Annual Net Levelized Cost ($/MMBtu)	Annual Savings Potential (trillion Btu)
1	Res. Gas EE	-$78	4
2	Appliance Standards	-$46	9
3	CI Gas EE	-$23	4
4	LI Gas EE	-$15	1
5	Res. Electric EE	-$13	1
6	CI Electric EE	-$10	5
7	Anaerobic Digestion	-$6	1
8	Landfill Gas	-$5	1
9	Large CHP	-$5	1
10	Converted Hydro	-$4	2
11	LI Electric EE	-$2	0.1
12	Small CHP	$0.4	1
13	Biomass Power C1	$3	1
Pipeline @ 80% winter usage		$4	-
14	Large Wind C5	$5	6
15	Biomass Power C2	$5	2
16	Utility-Scale PV	$9	0.2
17	Biomass Thermal	$9	0.1
18	Wind (<100 kW)	$10	2
19	Commercial PV	$11	1
20	Residential PV	$13	0.05
21	Biomass Power C3	$16	2
22	Offshore Wind	$16	26
23	GS Heat Pump	$16	0.02
24	AS Heat Pump	$20	0.1
25	Biomass Power C4	$21	3
26	Solar Hot Water	$24	0.02
27	Wind (<10 kW)	$68	1

Figure 18. Reference natural gas price supply curve for 2030 (trillion Btu)

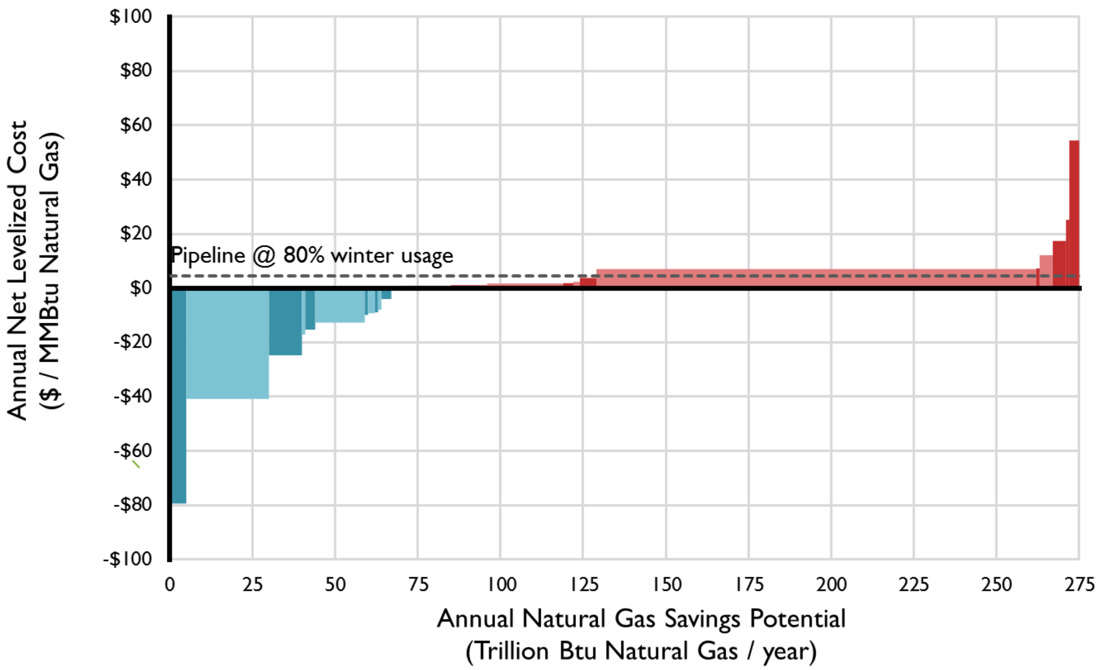

Table 11. Reference natural gas price supply curve for 2030 (trillion Btu)

		Annual Net Levelized Cost ($/MMBtu)	Annual Savings Potential (trillion Btu)
1	Res. Gas EE	-$79	5
2	Appliance Standards	-$41	25
3	CI Gas EE	-$25	10
4	LI Gas EE	-$17	2
5	Res. Electric EE	-$15	3
6	CI Electric EE	-$13	15
7	Anaerobic Digestion	-$10	0.4
8	Large CHP	-$9	2
9	Landfill Gas	-$9	0.3
10	Converted Hydro	-$8	2
11	Small CHP	-$4	2
12	LI Electric EE	-$4	0.3
13	Biomass Power C1	-$0.2	1
14	Utility-Scale PV	$0	2
15	Large Wind C5	$1	15
16	Commercial PV	$1	11
17	Large Wind C4	$2	24
18	Biomass Power C2	$2	2
19	Residential PV	$2	2
20	Wind (<100 kW)	$4	6
Pipeline @ 80% winter usage		$4	-
21	Offshore Wind	$7	132
22	Biomass Thermal	$7	1
23	Biomass Power C3	$12	4
24	Biomass Power C4	$17	4
25	GS Heat Pump	$20	0.3
26	AS Heat Pump	$25	1
27	Solar Hot Water	$32	0.3
28	Wind (<10 kW)	$54	2

Table 12. Reference gas price resource assessment summary for 2015

Electricity Technologies						
Technology	Annual Capacity Factor %	Total Potential Capacity MW	Annual Net Levelized Cost $/MWh	Annual Net Levelized Cost $/MMBtu NG	Annual Energy Production MMBtu NG	Peak Hour Gas Savings MMBtu NG
Wind (<10 kW)	16%	1	$655	$78	11,773	3
Wind (<100 kW)	25%	1	$123	$15	18,396	3
Large Wind C5	no incremental capacity available by 2015					
Large Wind C4	no incremental capacity available by 2015					
Offshore Wind	no incremental capacity available by 2015					
Utility-Scale PV	no incremental capacity available by 2015					
Commercial PV	14%	2	$75	$9	21,192	0
Residential PV	13%	0	$100	$12	2,391	0
Large CHP	no incremental capacity available by 2015					
Small CHP	50%	5	-$12	-$1	183,960	19
Landfill Gas	78%	0	-$47	-$6	17,325	2
Anaerobic Digestion	90%	0	-$54	-$6	19,868	2
Biomass Power C1	no incremental capacity available by 2015					
Biomass Power C2	no incremental capacity available by 2015					
Biomass Power C3	no incremental capacity available by 2015					
Biomass Power C4	no incremental capacity available by 2015					
Converted Hydro	38%	1	-$35	-$4	14,000	4
Res. Electric EE	55%	0	-$117	-$14	0	0
LI Electric EE	55%	0	-$22	-$3	0	0
CI Electric EE	55%	0	-$96	-$11	0	0
Appliance Standards	no incremental capacity available by 2015					
Direct Gas Reduction Technologies						
Technology	Annual Capacity Factor %	Total Potential Capacity MW	Annual Net Levelized Cost $/MWh	Annual Net Levelized Cost $/MMBtu NG	Annual Energy Production MMBtu NG	Peak Hour Gas Savings MMBtu NG
AS Heat Pump	0%	0	$0	$17	6,307	9
GS Heat Pump	0%	0	$0	$15	1,577	2
Solar Hot Water	0%	0	$0	$9	1,573	0
Biomass Thermal	0%	0	$0	$9	6,291	10
Res. Gas EE	0%	0	$0	-$78	0	0
LI Gas EE	0%	0	$0	-$15	0	0
CI Gas EE	0%	0	$0	-$23	0	0

Table 13. Reference gas price resource assessment summary for 2020

Electricity Technologies						
Technology	Annual Capacity Factor %	Total Potential Capacity MW	Annual Net Levelized Cost $/MWh	Annual Net Levelized Cost $/MMBtu NG	Annual Energy Production MMBtu NG	Peak Hour Gas Savings MMBtu NG
Wind (<10 kW)	16%	100	$572	$68	1,177,344	266
Wind (<100 kW)	25%	100	$84	$10	1,839,600	266
Large Wind C5	41%	200	$38	$5	6,033,888	532
Large Wind C4	Assuming wind projects built in 2020 are constructed in best wind locations (i.e., C5)					
Offshore Wind	44%	800	$133	$16	25,901,568	2,128
Utility-Scale PV	15%	16	$76	$9	216,337	0
Commercial PV	14%	50	$91	$11	662,256	0
Residential PV	13%	5	$106	$13	47,830	0
Large CHP	67%	25	-$46	-$5	1,232,532	59
Small CHP	50%	35	$3	$0	1,287,720	136
Landfill Gas	78%	20	-$46	-$5	1,155,000	144
Anaerobic Digestion	90%	20	-$52	-$6	1,324,512	144
Biomass Power C1	80%	20	$27	$3	1,177,344	144
Biomass Power C2	80%	40	$44	$5	2,354,688	289
Biomass Power C3	80%	40	$130	$16	2,354,688	289
Biomass Power C4	80%	50	$175	$21	2,943,360	361
Converted Hydro	38%	61	-$37	-$4	1,708,000	440
Res. Electric EE	55%	28	-$108	-$13	1,147,100	118
LI Electric EE	55%	3	-$13	-$2	138,528	14
CI Electric EE	55%	113	-$86	-$10	4,577,386	473
Appliance Standards	55%	216	-$390	-$46	8,736,000	902
Direct Gas Reduction Technologies						
Technology	Annual Capacity Factor %	Total Potential Capacity MW	Annual Net Levelized Cost $/MWh	Annual Net Levelized Cost $/MMBtu NG	Annual Energy Production MMBtu NG	Peak Hour Gas Savings MMBtu NG
AS Heat Pump	0%	0	$0	$20	75,686	104
GS Heat Pump	0%	0	$0	$16	18,922	26
Solar Hot Water	0%	0	$0	$24	18,896	0
Biomass Thermal	0%	0	$0	$9	75,586	125
Res. Gas EE	0%	0	$0	-$78	3,758,369	236
LI Gas EE	0%	0	$0	-$15	584,036	37
CI Gas EE	0%	0	$0	-$23	4,121,834	259

Table 14. Reference gas price resource assessment summary for 2030

Electricity Technologies						
Technology	Annual Capacity Factor *%*	Total Potential Capacity *MW*	Annual Net Levelized Cost *$/MWh*	Annual Net Levelized Cost *$/MMBtu NG*	Annual Energy Production *MMBtu NG*	Peak Hour Gas Savings *MMBtu NG*
Wind (<10 kW)	16%	200	$457	$54	2,354,688	532
Wind (<100 kW)	25%	300	$32	$4	5,518,800	798
Large Wind C5	42%	480	$8	$1	14,834,534	1,277
Large Wind C4	40%	800	$14	$2	23,546,880	2,128
Offshore Wind	45%	4,000	$59	$7	132,451,200	10,640
Utility-Scale PV	15%	160	$3	$0	2,163,370	0
Commercial PV	14%	800	$9	$1	10,596,096	0
Residential PV	13%	200	$19	$2	2,391,480	0
Large CHP	67%	50	-$78	-$9	2,465,064	118
Small CHP	50%	65	-$34	-$4	2,391,480	252
Landfill Gas	78%	6	-$75	-$9	346,500	43
Anaerobic Digestion	90%	6	-$83	-$10	397,354	43
Biomass Power C1	80%	20	-$2	$0	1,177,344	144
Biomass Power C2	80%	40	$15	$2	2,354,688	289
Biomass Power C3	80%	60	$102	$12	3,532,032	433
Biomass Power C4	80%	70	$146	$17	4,120,704	505
Converted Hydro	38%	56	-$67	-$8	1,568,000	404
Res. Electric EE	55%	64	-$128	-$15	2,604,729	269
LI Electric EE	55%	7	-$33	-$4	301,858	31
CI Electric EE	55%	380	-$107	-$13	15,382,106	1,589
Appliance Standards	55%	619	-$343	-$41	25,048,800	2,587
Direct Gas Reduction Technologies						
Technology	Annual Capacity Factor *%*	Total Potential Capacity *MW*	Annual Net Levelized Cost *$/MWh*	Annual Net Levelized Cost *$/MMBtu NG*	Annual Energy Production *MMBtu NG*	Peak Hour Gas Savings *MMBtu NG*
AS Heat Pump	0%	0	$0	$25	1,127,727	1,549
GS Heat Pump	0%	0	$0	$20	281,932	387
Solar Hot Water	0%	0	$0	$32	281,607	4
Biomass Thermal	0%	0	$0	$7	1,126,428	1,869
Res. Gas EE	0%	0	$0	-$79	5,290,473	332
LI Gas EE	0%	0	$0	-$17	1,818,671	114
CI Gas EE	0%	0	$0	-$25	9,748,498	612

Table 15. Low natural gas price supply curve for 2015 (billion Btu)

		Annual Net Levelized Cost ($/MMBtu)	*Annual Savings Potential (billion Btu)*
1	Anaerobic Digestion	-$5	20
2	Landfill Gas	-$5	17
3	Converted Hydro	-$3	14
4	Small CHP	$0.02	184
Pipeline @ 80% winter usage		$4	-
5	Biomass Thermal	$9	6
6	Commercial PV	$10	21
7	Residential PV	$13	2
8	GS Heat Pump	$15	2
9	Wind (<100 kW)	$16	18
10	Solar Hot Water	$17	2
11	AS Heat Pump	$18	6
12	Wind (<10 kW)	$79	12

Table 16. Low natural gas price supply curve for 2020 (trillion Btu; note unit change from previous table)

		Annual Net Levelized Cost ($/MMBtu)	Annual Savings Potential (trillion Btu)
1	Res. Gas EE	-$77	4
2	Appliance Standards	-$45	9
3	CI Gas EE	-$22	4
4	LI Gas EE	-$14	1
5	Res. Electric EE	-$11	1
6	CI Electric EE	-$8	5
7	Anaerobic Digestion	-$5	1
8	Landfill Gas	-$4	1
9	Large CHP	-$4	1
10	Converted Hydro	-$3	2
11	LI Electric EE	$0.3	0.1
12	Small CHP	$2	1
Pipeline @ 80% winter usage		$4	-
13	Biomass Power C1	$4	1
14	Large Wind C5	$6	6
15	Biomass Power C2	$7	2
16	Utility-Scale PV	$10	0.2
17	Biomass Thermal	$11	0.1
18	Wind (<100 kW)	$11	2
19	Commercial PV	$12	1
20	Residential PV	$14	0.05
21	Biomass Power C3	$17	2
22	GS Heat Pump	$17	0.02
23	Offshore Wind	$17	26
24	AS Heat Pump	$20	0.1
25	Biomass Power C4	$22	3
26	Solar Hot Water	$39	0.02
27	Wind (<10 kW)	$70	1

Table 17. Low natural gas price supply curve for 2030 (trillion Btu)

		Annual Net Levelized Cost ($/MMBtu)	Annual Savings Potential (trillion Btu)
1	Res. Gas EE	-$79	5
2	Appliance Standards	-$38	25
3	CI Gas EE	-$23	10
4	LI Gas EE	-$15	2
5	Res. Electric EE	-$12	3
6	CI Electric EE	-$10	15
7	Anaerobic Digestion	-$7	0.4
8	Landfill Gas	-$7	0.3
9	Large CHP	-$6	2
10	Converted Hydro	-$6	2
11	LI Electric EE	-$1	0.3
12	Small CHP	-$0.1	2
13	Biomass Power C1	$2	1
14	Utility-Scale PV	$3	2
15	Large Wind C5	$3	15
16	Commercial PV	$4	11
17	Large Wind C4	$4	24
18	Biomass Power C2	$4	2
Pipeline @ 80% winter usage		$4	-
19	Residential PV	$5	2
20	Wind (<100 kW)	$6	6
21	Offshore Wind	$9	132
22	Biomass Thermal	$10	1
23	Biomass Power C3	$14	4
24	Biomass Power C4	$20	4
25	GS Heat Pump	$21	0.3
26	AS Heat Pump	$26	1
27	Wind (<10 kW)	$57	2
28	Solar Hot Water	$68	0.3

Table 18. High natural gas price supply curve for 2015 (billion Btu)

		Annual Net Levelized Cost ($/MMBtu)	*Annual Savings Potential (billion Btu)*
1	Anaerobic Digestion	-$8	20
2	Landfill Gas	-$7	17
3	Converted Hydro	-$5	14
4	Small CHP	-$3	184
5	Solar Hot Water	$1	2
Pipeline @ 80% winter usage		$4	-
6	Biomass Thermal	$7	6
7	Commercial PV	$8	21
8	Residential PV	$10	2
9	Wind (<100 kW)	$13	18
10	GS Heat Pump	$15	2
11	AS Heat Pump	$17	6
12	Wind (<10 kW)	$77	12

Table 19. High natural gas price supply curve for 2020 (trillion Btu; note unit change from previous table)

		Annual Net Levelized Cost ($/MMBtu)	*Annual Savings Potential (trillion Btu)*
1	Res. Gas EE	-$80	4
2	Appliance Standards	-$50	9
3	CI Gas EE	-$25	4
4	LI Gas EE	-$17	1
5	Res. Electric EE	-$16	1
6	CI Electric EE	-$14	5
7	Anaerobic Digestion	-$9	1
8	Large CHP	-$9	1
9	Landfill Gas	-$8	1
10	Converted Hydro	-$7	2
11	LI Electric EE	-$5	0.1
12	Small CHP	-$3	1
13	Biomass Power C1	$1	1
14	Large Wind C5	$2	6
15	Biomass Power C2	$3	2
Pipeline @ 80% winter usage		$4	-
16	Utility-Scale PV	$7	0.2
17	Wind (<100 kW)	$7	2
18	Biomass Thermal	$7	0.1
19	Commercial PV	$8	1
20	Residential PV	$10	0.05
21	Biomass Power C3	$13	2
22	Offshore Wind	$13	26
23	Solar Hot Water	$13	0
24	GS Heat Pump	$16	0.02
25	Biomass Power C4	$18	3
26	AS Heat Pump	$20	0.1
27	Wind (<10 kW)	$65	1

Table 20. High natural gas price supply curve for 2030 (trillion Btu)

		Annual Net Levelized Cost ($/MMBtu)	Annual Savings Potential (trillion Btu)
1	Res. Gas EE	-$79	5
2	Appliance Standards	-$49	25
3	CI Gas EE	-$28	10
4	Res. Electric EE	-$24	3
5	CI Electric EE	-$21	15
6	LI Gas EE	-$20	2
7	Large CHP	-$18	2
8	Anaerobic Digestion	-$17	0.4
9	Landfill Gas	-$16	0.3
10	Converted Hydro	-$15	2
11	Small CHP	-$13	2
12	LI Electric EE	-$13	0.3
13	Biomass Power C1	-$7	1
14	Utility-Scale PV	-$6	2
15	Commercial PV	-$6	11
16	Large Wind C5	-$6	15
17	Large Wind C4	-$5	24
18	Residential PV	-$5	2
19	Biomass Power C2	-$5	2
20	Wind (<100 kW)	-$3	6
21	Offshore Wind	$0.4	132
22	Biomass Thermal	$4	1
Pipeline @ 80% winter usage		$4	-
23	Biomass Power C3	$5	4
24	Biomass Power C4	$11	4
25	GS Heat Pump	$20	0.3
26	AS Heat Pump	$26	1.1
27	Solar Hot Water	$31	0.3
28	Wind (<10 kW)	$47	2

Table 21. Reference gas price resource assessment for 2015

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)
Electricity Technologies																		
Technology	Annual Capacity Factor	Total Potential Capacity	Annual Energy Production	Annual Energy Production	Installed Cost	Lifetime	Real Levelization Rate	Annual Fixed O&M	Annual Variable O&M	Annual Levelized Fuel Cost	Annual Levelized Cost	Avoided Energy Cost	Avoided Capacity Cost	Capacity Payment Proxy	Annual Net Levelized Cost	Annual Net Levelized Cost	Winter Load Carrying Capcity	Peak Hour Gas Savings
	%	MW	MWh	MMBtu NG	$/kW	Yrs	%	$/kW-yr	$/MWh	$/MMBtu	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	$/MMBtu NG	%	MMBtu NG
Wind (<10 kW)	16%	1.0	1,402	11,773	$11,500	20	9.0%	$25	$0	$0	$760	$79		$26	$655	$78	35%	3
Wind (<100 kW)	25%	1.0	2,190	18,396	$5,000	20	9.0%	$25	$0	$0	$218	$79		$16	$123	$15	35%	3
Large Wind C5	no incremental capacity available by 2015																	
Large Wind C4	no incremental capacity available by 2015																	
Offshore Wind	no incremental capacity available by 2015																	
Utility-Scale PV	no incremental capacity available by 2015																	
Commercial PV	14%	1.6	2,523	21,192	$2,593	25	8.0%	$25	$0	$0	$184	$79		$30	$75	$9	0%	0
Residential PV	13%	0.2	285	2,391	$2,842	25	7.6%	$25	$0	$0	$211	$79		$33	$100	$12	0%	0
Large CHP	no incremental capacity available by 2015																	
Small CHP	50%	5	21,900	183,960	$2,181	10	15.4%	$0	$11	$11	$135	$107		$39	-$12	-$1	95%	19
Landfill Gas	78%	0.3	2,063	17,325	$1,421	20	9.0%	$132	$0	$0	$38	$73		$12	-$47	-$6	95%	2
Anaerobic Digestion	90%	0.3	2,365	19,868	$4,102	20	9.0%	$0	$0	$0	$47	$79		$22	-$54	-$6	95%	2
Biomass Power C1	no incremental capacity available by 2015																	
Biomass Power C2	no incremental capacity available by 2015																	
Biomass Power C3	no incremental capacity available by 2015																	
Biomass Power C4	no incremental capacity available by 2015																	
Converted Hydro	38%	0.5	1,667	14,000	$2,083	30	9.3%	$14	$0	$0	$63	$73		$24	-$35	-$4	95%	4
Res. Electric EE	55%	0	0	0							$9	$89	$37		-$117	-$14	55%	0
LI Electric EE	55%	0	0	0							$104	$89	$37		-$22	-$3	55%	0
CI Electric EE	55%	0	0	0							$31	$89	$37		-$96	-$11	55%	0
Appliance Standards	no incremental capacity available by 2015																	
Direct Gas Reduction Technologies																		
Technology				Potential Energy Production	Installed Cost	Lifetime	Real Levelization Rate	Annual Fixed O&M	Annual Variable O&M	Annual Levelized Fuel Cost	Annual Levelized Cost	Avoided Energy Cost	Avoided Capacity Cost	Capacity Payment Proxy		Annual Net Levelized Cost	Winter Load Carrying Capcity	Peak Hour Gas Savings
				MMBtu NG	$/MMBtu	Yrs	%	$/MMBtu-yr	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu		$/MMBtu NG	%	MMBtu NG
AS Heat Pump				6,307	$281,898	15	11%	$2,000	$0	$50	$18	$7				$17	95%	9
GS Heat Pump				1,577	$324,979	15	11%	$2,000	$0	$50	$16	$7				$15	95%	2
Solar Hot Water				1,573	$53	15	11%	$0	$0	$3,250	$53	$7				$9	17%	0
Biomass Thermal				6,291	$367,964	15	11%	$879	$0	$4.63	$16	$7				$9	95%	10
Res. Gas EE				0							-$72	$6				-$78	55%	0
LI Gas EE				0							-$9	$6				-$15	55%	0
CI Gas EE				0							-$17	$6				-$23	55%	0

Table 22. Reference gas price resource assessment for 2020

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)
Electricity Technologies																		
Technology	Annual Capacity Factor	Total Potential Capacity	Annual Energy Production	Annual Energy Production	Installed Cost	Lifetime	Real Levelization Rate	Annual Fixed O&M	Annual Variable O&M	Annual Levelized Fuel Cost	Annual Levelized Cost	Avoided Energy Cost	Avoided Capacity Cost	Capacity Payment Proxy	Annual Net Levelized Cost	Annual Net Levelized Cost	Winter Load Carrying Capcity	Peak Hour Gas Savings
	%	*MW*	*MWh*	*MMBtu NG*	*$/kW*	*Yrs*	*%*	*$/kW-yr*	*$/MWh*	*$/MMBtu*	*$/MWh*	*$/MWh*	*$/MWh*	*$/MWh*	*$/MWh*	*$/MMBtu NG*	*%*	*MMBtu NG*
Wind (<10 kW)	16%	100	140,160	1,177,344	$9,200	20	9.0%	$115	$0	$0	$676	$74		$29	$572	$68.12	35%	266
Wind (<100 kW)	25%	100	219,000	1,839,600	$4,000	20	9.0%	$25	$0	$0	$177	$74		$19	$84	$10	35%	266
Large Wind C5	41%	200	718,320	6,033,888	$2,359	20	9.7%	$50	$0	$0	$113	$69		$6	$38	$5	35%	532
Large Wind C4	Assuming wind projects built in 2020 are constructed in best wind locations (i.e., C5)																	
Offshore Wind	44%	800	3,083,520	25,901,568	$5,600	20	12.2%	$115	$0	$0	$207	$69		$6	$133	$16	35%	2,128
Utility-Scale PV	15%	16.00	25,754	216,337	$2,233	25	8.7%	$16	$0	$0	$162	$69		$18	$76	$9	0%	0
Commercial PV	14%	50	78,840	662,256	$2,842	25	8.0%	$24	$0	$0	$199	$74		$34	$91	$11	0%	0
Residential PV	13%	5	5,694	47,830	$2,943	25	7.6%	$24	$0	$0	$217	$74		$37	$106	$13	0%	0
Large CHP	67%	25	146,730	1,232,532	$1,750	20	9.7%	$0	$5	$7	$77	$90		$33	-$46	-$5	95%	59
Small CHP	50%	35	153,300	1,287,720	$2,457	10	15.4%	$0	$11	$12	$148	$101		$44	$3	$0	95%	136
Landfill Gas	78%	20	137,500	1,155,000	$1,421	20	9.0%	$132	$0	$0	$38	$69		$15	-$46	-$5	95%	144
Anaerobic Digestion	90%	20	157,680	1,324,512	$4,102	20	9.0%	$0	$0	$0	$47	$74		$25	-$52	-$6	95%	144
Biomass Power C1	80%	20	140,160	1,177,344	$4,175	30	8.0%	$105	$11	$3	$110	$69		$15	$27	$3	95%	144
Biomass Power C2	80%	40	280,320	2,354,688	$4,175	30	8.0%	$105	$11	$4	$128	$69		$15	$44	$5	95%	289
Biomass Power C3	80%	40	280,320	2,354,688	$4,175	30	8.0%	$105	$11	$10	$214	$69		$15	$130	$16	95%	289
Biomass Power C4	80%	50	350,400	2,943,360	$4,175	30	8.0%	$105	$11	$13	$259	$69		$15	$175	$21	95%	361
Converted Hydro	38%	61	203,333	1,708,000	$2,083	30	9.3%	$14	$0	$0	$63	$69		$31	-$37	-$4	95%	440
Res. Electric EE	55%	28	136,560	1,147,100							$9	$74	$42		-$108	-$13	55%	118
LI Electric EE	55%	3	16,491	138,528							$104	$74	$42		-$13	-$2	55%	14
CI Electric EE	55%	113	544,927	4,577,386							$31	$74	$42		-$86	-$10	55%	473
Appliance Standards	55%	216	1,040,000	8,736,000							-$273	$74	$42		-$390	-$46	55%	902
Direct Gas Reduction Technologies																		
Technology				Potential Energy Production	Installed Cost	Lifetime	Real Levelization Rate	Annual Fixed O&M	Annual Variable O&M	Annual Levelized Fuel Cost	Annual Levelized Cost	Avoided Energy Cost	Avoided Capacity Cost	Capacity Payment Proxy		Annual Net Levelized Cost	Winter Load Carrying Capcity	Peak Hour Gas Savings
				MMBtu NG	*$/MMBtu*	*Yrs*	*%*	*$/MMBtu-yr*	*$/MMBtu*	*$/MMBtu*	*$/MMBtu*	*$/MMBtu*	*$/MMBtu*	*$/MMBtu*		*$/MMBtu NG*	*%*	*MMBtu NG*
AS Heat Pump				75,686	$281,898	15	11%	$2,000	$0	$59	$20	$6				$20	95%	104
GS Heat Pump				18,922	$324,979	15	11%	$2,000	$0	$59	$18	$6				$16	95%	26
Solar Hot Water				18,896	$62	15	11%	$0	$0	$3,824	$62	$6				$24	17%	0
Biomass Thermal				75,586	$367,964	15	11%	$879	$0	$4.80	$16	$6				$9	95%	125
Res. Gas EE				3,758,369							-$72	$6				-$78	55%	236
LI Gas EE				584,036							-$9	$6				-$15	55%	37
CI Gas EE				4,121,834							-$17	$6				-$23	55%	259

Table 23. Reference gas price resource assessment for 2030

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)
Electricity Technologies																		
Technology	Annual Capacity Factor	Total Potential Capacity	Annual Energy Production	Annual Energy Production	Installed Cost	Lifetime	Real Levelization Rate	Annual Fixed O&M	Annual Variable O&M	Annual Levelized Fuel Cost	Annual Levelized Cost	Avoided Energy Cost	Avoided Capacity Cost	Capacity Payment Proxy	Annual Net Levelized Cost	Annual Net Levelized Cost	Winter Load Carrying Capcity	Peak Hour Gas Savings
	%	MW	MWh	MMBtu NG	$/kW	Yrs	%	$/kW-yr	$/MWh	$/MMBtu	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	$/MMBtu NG	%	MMBtu NG
Wind (<10 kW)	16%	200	280,320	2,354,688	$8,050	20	9.0%	$102	$0	$0	$592	$105		$30	$457	$54	35%	532
Wind (<100 kW)	25%	300	657,000	5,518,800	$3,500	20	9.0%	$25	$0	$0	$156	$105		$19	$32	$4	35%	798
Large Wind C5	42%	480	1,766,016	14,834,534	$2,359	20	9.7%	$50	$0	$0	$111	$97		$6	$8	$1	35%	1,277
Large Wind C4	40%	800	2,803,200	23,546,880	$2,460	20	9.7%	$50	$0	$0	$118	$97		$7	$14	$2	35%	2,128
Offshore Wind	45%	4,000	15,768,000	132,451,200	$4,760	20	11%	$102	$0	$0	$162	$97		$6	$59	$7	35%	10,640
Utility-Scale PV	15%	160	257,544	2,163,370	$1,600	25	8.7%	$14	$0	$0	$118	$97		$18	$3	$0	0%	0
Commercial PV	14%	800	1,261,440	10,596,096	$2,075	25	8.0%	$22	$0	$0	$149	$105		$35	$9	$1	0%	0
Residential PV	13%	200	284,700	2,391,480	$2,150	25	7.6%	$22	$0	$0	$163	$105		$39	$19	$2	0%	0
Large CHP	67%	50	293,460	2,465,064	$1,750	20	9.7%	$0	$5	$8	$84	$127		$34	-$78	-$9	95%	118
Small CHP	50%	65	284,700	2,391,480	$2,457	10	15.4%	$0	$11	$13	$153	$142		$46	-$34	-$4	95%	252
Landfill Gas	78%	6	41,250	346,500	$1,421	20	9.0%	$132	$0	$0	$38	$97		$16	-$75	-$9	95%	43
Anaerobic Digestion	90%	6	47,304	397,354	$4,102	20	9.0%	$0	$0	$0	$47	$105		$26	-$83	-$10	95%	43
Biomass Power C1	80%	20	140,160	1,177,344	$4,175	30	8.0%	$105	$11	$3	$110	$97		$15	-$2	$0	95%	144
Biomass Power C2	80%	40	280,320	2,354,688	$4,175	30	8.0%	$105	$11	$4	$128	$97		$15	$15	$2	95%	289
Biomass Power C3	80%	60	420,480	3,532,032	$4,175	30	8.0%	$105	$11	$10	$214	$97		$15	$102	$12	95%	433
Biomass Power C4	80%	70	490,560	4,120,704	$4,175	30	8.0%	$105	$11	$13	$259	$97		$15	$146	$17	95%	505
Converted Hydro	38%	56	186,667	1,568,000	$2,083	30	9.3%	$14	$0	$0	$63	$97		$32	-$67	-$8	95%	404
Res. Electric EE	55%	64	310,087	2,604,729							$9	$94	$44		-$128	-$15	55%	269
LI Electric EE	55%	7	35,936	301,858							$104	$94	$44		-$33	-$4	55%	31
CI Electric EE	55%	380	1,831,203	15,382,106							$31	$94	$44		-$107	-$13	55%	1,589
Appliance Standards	55%	619	2,982,000	25,048,800							-$205	$94	$44		-$343	-$41	55%	2,587
Direct Gas Reduction Technologies																		
Technology				Potential Energy Production	Installed Cost	Lifetime	Real Levelization Rate	Annual Fixed O&M	Annual Variable O&M	Annual Levelized Fuel Cost	Annual Levelized Cost	Avoided Energy Cost	Avoided Capacity Cost	Capacity Payment Proxy		Annual Net Levelized Cost	Winter Load Carrying Capcity	Peak Hour Gas Savings
				MMBtu NG	$/MMBtu	Yrs	%	$/MMBtu-yr	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu		$/MMBtu NG	%	MMBtu NG
AS Heat Pump				1,127,727	$281,898	15	11%	$2,000	$0	$82	$26	$9				$25	95%	1,549
GS Heat Pump				281,932	$324,979	15	11%	$2,000	$0	$82	$22	$9				$20	95%	387
Solar Hot Water				281,607	$86	15	11%	$0	$0	$5,353	$86	$9				$32	17%	4
Biomass Thermal				1,126,428	$367,964	15	11%	$879	$0	$5.16	$16	$9				$7	95%	1,869
Res. Gas EE				5,290,473							-$72	$8				-$79	55%	332
LI Gas EE				1,818,671							-$9	$8				-$17	55%	114
CI Gas EE				9,748,498							-$17	$8				-$25	55%	612

APPENDIX B: BASE CASE ASSUMPTIONS

Overview: The base case energy resource mix and demand model expected conditions under existing policy measures.

Gas prices: Reference natural gas prices are monthly NYMXEX prices escalated annually in proportion to the annual percentage changes in the Henry Hub prices from the 2014 AEO Reference Case (Tab 13, line 44). Monthly average Henry Hub price forecasts were then adjusted for projections in the basis differential between Henry Hub and the Massachusetts city gates designed to reflect the higher basis when gas demand is highest. Based on preliminary modeling results, we assume that the Massachusetts (and upstream) gas sector will remain out of balance from 2015 through 2019, but will be in balance from 2020 through 2030. In 2015 through 2019, we use a winter basis estimate as the daily November to March difference between Henry Hub and Algonquin City Gate daily prices in 2013/2014. For the summer months in 2015 through 2019, and for all months in the remaining years, we assume one constant basis differential for every day, calculated as the average difference between Henry Hub and Algonquin City Gate daily prices in the April through October of 2014. See Figure 3 and Figure 19.

Canadian transmission: There is no transmission from Canada incremental to what exists today. We used Ventyx's default assumptions to depict existing transmission from Canada, and use these assumptions in each of the model runs.

Carbon prices: The electric-sector carbon allowance price in the electricity sector is the *Avoided Energy Supply Costs in New England: 2013 Report* (AESC 2013) carbon price forecast[46] (see Figure 2); GWSA compliance is not a criterion for scenarios and sensitivities; rather, the Massachusetts emissions associated with each scenario and sensitivity are an output of the model.

Greenhouse gas emissions: Electric-sector emissions are calculated in the Market Analytics model. Massachusetts' share of these emissions is estimated using a methodology based on the *2008-2010 Massachusetts Greenhouse Gas Emissions Inventory*: all emissions from the Commonwealth's electric generator; emissions associated with Massachusetts purchase of out-of-state RECs and its claim on low-emission imports; a share of the residual New England electric emissions based on Massachusetts' requirements above its own generation, out-of-state REC purchases and claim on low-emission imports; and a share of the emissions from Quebec and the Maritimes based on New England's requirements above its own generation, out-of-state REC purchases and claim on low-emission imports.

Gas sector emissions (other than electric) are calculated as MMBtus of annual demand multiplied by a weighted average emissions rate for residential, commercial, industrial, and transportation sectors per

[46] Hornby et al. 2013. Exhibit 4-1. Column 6 "Synapse" CO_2 emission allowance price.

AEO 2014.[47] In each year, the weighted average emissions rate for all non-electric system natural gas demand is about 0.053 metric tons per MMBtu, or about 116 lbs per MMBtu.

GWSA compliance: GWSA compliance for years 2020 and 2030 was determined using data from the MA-DPU 14-86 docket by assuming that emissions from sectors other than gas or electric would (1) would be the same under all scenario-and-sensitivity assumptions, and (2) would approximate levels anticipated given the policy measures described in Massachusetts *Clean Energy and Climate Plan for 2020*.[48] Scenarios in which Massachusetts emits more than 23.3 million metric tons of CO_2 in 2020 in gas and electric sectors or more than 18.7 million metric tons in these sectors in 2030 do not achieve GWSA compliance (see Table 6). The 2030 GWSA reduction target below 1990 statewide levels of 43 percent was estimated following the method used in DPU 14-86: A linear trend was drawn between the Commonwealth's 2020 and 2050 emission reduction targets.

Energy efficiency: Reductions to load from energy efficiency were modeled based on program administrator's data as filed with the Department of Public Utilities, extended into the future using the following assumptions: (1) for states other than Massachusetts energy efficiency budgets remain constant over time in real terms; and (2) for Massachusetts energy efficiency remains constant as a share of load from 2015 through 2030. For Massachusetts electric efficiency: annual savings are 2.5 percent of program administrators' transmission-and-distribution-adjusted load in each year. For Massachusetts gas efficiency: annual savings are 1.1 percent of annual retail sales. Data on energy efficiency savings at winter peak were derived from the program administrators three-year reports. Costs are reported in Appendix A.

Time varying rates: Based on DPU's June 2014 Order 14-04 on time-varying rates we assume annual savings of 0.3 percent (2-percent annual savings assuming an 82-percent of customers on basic service out of the 37-percent residential share of load and a 50-percent opt in rate).[49] We assume winter peak savings 2.0 percent on the winter peak hour (13-percent average winter peak savings among four test groups modeled by Navigant assuming an 82-percent of customers on basic service out of the 37-percent residential share of load and a 50-percent opt in rate). Costs were estimated as a cost of $100 smart thermostat rebates paid in once in 2015 and again in 2025 (assuming a 10-year measure life).

Advanced Building Codes: Based on the assumptions in the Massachusetts Clean Energy and Climate Plan for 2020 ("CECP"), we assumed savings of 1.5 million metric tons of CO_2 reductions to be available from the Advanced Building Code policy currently in place in Massachusetts in 2020 and 2030.[50] Of

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[47] AEO 2014, Table 2.1 and Table 18.1. Available at http://www.eia.gov/forecasts/aeo/

[48] MA-DPU 14-86, Amended Direct Testimony of Elizabeth A. Stanton, September 11, 2014, Exhibits EAS-8 and EAS-13. CECP building sector oil emissions were calculated as the "Updated" business-as-usual buildings sector oil emission less anticipated oil energy efficiency and other CECP program savings.

[49] MA-DPU 14-04-B, "Anticipated Policy Framework for Time Varying Rates", June 12, 2014, http://www.mass.gov/eea/docs/dpu/orders/d-p-u-14-04-b-order-6-12-14.pdf. See also, Navigant (2014) *NSTAR Smart Grid Pilot: Final Technical Report*. Prepared for the U.S. DOE on behalf of NSTAR Gas and Electric Corporation.

[50] Massachusetts Office of Energy and Environmental Affairs. "Massachusetts Clean Energy and Climate Plan for 2020". 2010.

these reductions, we assume 0.9 million metric tons of reductions come from avoided natural gas consumption in both 2020 and 2030, using the ratio of natural gas to oil consumption in the business-as-usual case for each year as modeled in DPU 14-86. Using the average emission rate of residential natural gas consumption (0.053 metric tons per MMBtu), these emission reductions were then translated into MMBtu reductions. Given that this is an existing policy, costs are assumed to be zero.

Renewable thermal technologies: Based on the assumptions in Navigant's 2013 *Incremental Cost Study Phase Two Final Report*, the *Commonwealth Accelerated Renewable Thermal Strategy* and information from vendors, we assumed reduced CO_2 emissions of 1.2 million metric tons in 2020 and 5.8 million metric tons as a result of existing renewable thermal policy.[51] Per DOER, we assume 15 percent of the emission reductions from this existing policy take place in the form of reduced residential natural gas consumption (85 percent of CO_2 reductions apply to oil use). Using the average emission rate of residential natural gas consumption (0.053 metric tons per MMBtu), these emission reductions were then translated into MMBtu reductions. Given that this is an existing policy, costs are assumed to be zero. The renewable thermal reductions listed in the above supply curves (air- and ground-source heat pumps, solar hot water, and biomass thermal) are assumed to be incremental to the CARTS study, per DOER.

Demand response: Electric demand response is available as a balancing agent (discussed below) but not otherwise included in modeling.

Winter Reliability program: The ISO-NE Winter Reliability program is available as a balancing agent (discussed below) but not otherwise included in modeling.

Distributed generation: We modeled distributed resources using ISO-NE's PV Energy Forecast Update by state, held constant after 2020.[52] Total New England annual distributed generation is 1,695 GWh. Costs are reported in Appendix A.

Retirements: We modeled the retirements from current capacity shown in Table 24.

[51] http://www.neep.org/sites/default/files/products/NEEP%20ICS2%20FINAL%20REPORT%202013Feb11-Website.pdf; http://www.mass.gov/eea/docs/doer/renewables/thermal/carts-report.pdf

[52] ISO-NE, "PV Energy Forecast Update: Distributed Generation Forecast Working Group" presentation, December 15, 2014, Holyoke, MA. Slide 8.

Table 24. Unit retirements

Unit Name	Region	Fuel type	Retirement
Framingham 1	Boston	FO#2 NPCC	1/1/2020
Framingham 2	Boston	FO#2 NPCC	1/1/2019
Framingham 3	Boston	FO#2 NPCC	1/1/2019
Mystic 7	Boston	NG	1/1/2021
Mystic J1	Boston	FO#2 NPCC	1/1/2019
Salem Harbor 3	Boston	Coal	6/1/2014
Salem Harbor 4	Boston	FO#6 NPCC	6/1/2014
Waters River 1	Boston	NG	1/1/2021
West Medway 1	Boston	FO#2 NPCC	1/1/2020
West Medway 2	Boston	FO#2 NPCC	1/1/2020
Middletown 2	CT NE Centr	NG	1/1/2022
Middletown 3	CT NE Centr	NG	1/1/2022
Middletown 4	CT NE Centr	NG	1/1/2017
Montville 5	CT NE Centr	FO#6 NPCC	1/1/2020
Montville 6	CT NE Centr	FO#6 NPCC	1/1/2017
Norwich (North Main) 5	CT NE Centr	FO#2 NPCC	1/1/2022
Norwalk Harbor 1	CT Norwalk	FO#6 NPCC	6/1/2017
Norwalk Harbor 10	CT Norwalk	FO#2 NPCC	6/1/2017
Norwalk Harbor 2	CT Norwalk	FO#6 NPCC	6/1/2017
Bridgeport Harbor 2	CTSW	FO#6 NPCC	6/1/2017
Bridgeport Harbor 3	CTSW	Coal	6/1/2017
New Haven Harbor 1	CTSW	FO#6 NPCC	1/1/2021
Borden 1	Maritimes	FO#2 NPCC	1/1/2021
Borden 2	Maritimes	FO#2 NPCC	1/1/2023
Burnside 1	Maritimes	FO#2 NPCC	1/1/2026
Burnside 2	Maritimes	FO#2 NPCC	1/1/2026
Burnside 3	Maritimes	FO#2 NPCC	1/1/2026
Burnside 4	Maritimes	FO#2 NPCC	1/1/2026
Caribou ST CS1	Maritimes	FO#6 NPCC	1/1/2013
Caribou ST CS2	Maritimes	FO#6 NPCC	1/1/2015
Charlottetown 10	Maritimes	FO#6 NPCC	1/1/2028
Charlottetown 7	Maritimes	FO#6 NPCC	1/1/2015
Charlottetown 8	Maritimes	FO#6 NPCC	1/1/2020
Charlottetown 9	Maritimes	FO#6 NPCC	1/1/2023
Courtenay Bay 2	Maritimes	FO#6 NPCC	1/1/2025
Tusket 1	Maritimes	FO#2 NPCC	1/1/2021
Victoria Junction 1	Maritimes	FO#2 NPCC	1/1/2025
Victoria Junction 2	Maritimes	FO#2 NPCC	1/1/2025
Cherry Street 12	NEMA	FO#2 NPCC	1/1/2022
Lost Nation GT 1	NH	FO#2 NPCC	1/1/2019
Schiller 4	NH	Coal	1/1/2020
Schiller 6	NH	Coal	1/1/2020
Arthur Kill 1	NY	NG	1/1/2020
Astoria GT 1	NY	NG	1/1/2017
Astoria GT 11	NY	FO#2 NPCC	5/1/2014
Astoria GT 12	NY	FO#2 NPCC	5/1/2014
Astoria GT 13	NY	FO#2 NPCC	5/1/2014
Astoria GT 2-1	NY	NG	5/1/2016
Astoria GT 2-2	NY	NG	5/1/2016
Astoria GT 2-3	NY	NG	5/1/2016
Astoria GT 2-4	NY	NG	5/1/2016
Astoria GT 3-1	NY	NG	5/1/2016
Astoria GT 3-2	NY	NG	5/1/2016
Astoria GT 3-3	NY	NG	5/1/2016
Astoria GT 3-4	NY	NG	5/1/2016
Astoria GT 4-1	NY	NG	5/1/2016
Astoria GT 4-2	NY	NG	5/1/2016
Astoria GT 4-3	NY	NG	5/1/2016
Astoria GT 4-4	NY	NG	5/1/2016
Astoria GT 5	NY	NG	5/1/2014
Astoria GT 7	NY	NG	5/1/2014
Astoria GT 8	NY	NG	5/1/2014
Astoria ST2	NY	NG	7/30/2015
Barrett G1	NY	NG	1/1/2020
Barrett G1	NY	NG	1/1/2020
Barrett G10	NY	NG	1/1/2021
Barrett G11	NY	NG	1/1/2021
Barrett G12	NY	NG	1/1/2021
Barrett G2	NY	NG	1/1/2020
Barrett G3	NY	NG	1/1/2020
Barrett G4	NY	NG	1/1/2020
Barrett G5	NY	NG	1/1/2020
Barrett G6	NY	NG	1/1/2020
Barrett G7	NY	NG	1/1/2020
Barrett G8	NY	NG	1/1/2020
Barrett G9	NY	NG	1/1/2021
Charles P Keller 12	NY	NG	1/1/2017
Charles P Keller 13	NY	NG	1/1/2024
Danskammer 2	NY	NG	1/1/2014
East Hampton 1	NY	FO#2 NPCC	1/1/2020
East River 6	NY	NG	1/1/2026
East River 7	NY	NG	1/1/2015
Freeport 1 4	NY	FO#2 NPCC	1/1/2014
Freeport 2 3	NY	FO#2 NPCC	1/1/2023
Glenwood GT1	NY	FO#2 NPCC	1/1/2017
Glenwood GT2	NY	FO#2 NPCC	1/1/2022
Glenwood GT3	NY	FO#2 NPCC	1/1/2022
Gowanus 1-1	NY	FO#2 NPCC	1/1/2022
Gowanus 1-2	NY	FO#2 NPCC	1/1/2022
Gowanus 1-3	NY	FO#2 NPCC	1/1/2022
Gowanus 1-4	NY	FO#2 NPCC	1/1/2022
Gowanus 1-5	NY	FO#2 NPCC	1/1/2022
Gowanus 1-6	NY	FO#2 NPCC	1/1/2022
Gowanus 1-7	NY	FO#2 NPCC	1/1/2022
Gowanus 1-8	NY	FO#2 NPCC	1/1/2022
Gowanus 2-1	NY	NG	1/1/2021
Gowanus 2-2	NY	NG	1/1/2021
Gowanus 2-3	NY	NG	1/1/2022
Gowanus 2-4	NY	NG	1/1/2022
Gowanus 2-5	NY	NG	1/1/2022
Gowanus 2-6	NY	NG	1/1/2022
Gowanus 2-7	NY	NG	1/1/2022
Gowanus 2-8	NY	NG	1/1/2022
Gowanus 3-1	NY	FO#2 NPCC	1/1/2021

Table 13. Unit retirements (continued)

Unit Name	Region	Fuel type	Retirement
Gowanus 3-2	NY	FO#2 NPCC	1/1/2021
Gowanus 3-3	NY	FO#2 NPCC	1/1/2021
Gowanus 3-4	NY	FO#2 NPCC	1/1/2021
Gowanus 3-5	NY	FO#2 NPCC	1/1/2021
Gowanus 3-6	NY	FO#2 NPCC	1/1/2021
Gowanus 3-7	NY	FO#2 NPCC	1/1/2021
Gowanus 3-8	NY	FO#2 NPCC	1/1/2021
Gowanus 4-1	NY	FO#2 NPCC	1/1/2021
Gowanus 4-2	NY	FO#2 NPCC	1/1/2021
Gowanus 4-3	NY	FO#2 NPCC	1/1/2021
Gowanus 4-4	NY	FO#2 NPCC	1/1/2021
Gowanus 4-5	NY	FO#2 NPCC	1/1/2021
Gowanus 4-6	NY	FO#2 NPCC	1/1/2021
Gowanus 4-7	NY	FO#2 NPCC	1/1/2021
Gowanus 4-8	NY	FO#2 NPCC	1/1/2021
Hillburn GT 1	NY	NG	1/1/2022
Holtsville 1	NY	FO#2 NPCC	1/1/2024
Holtsville 10	NY	FO#2 NPCC	1/1/2025
Holtsville 2	NY	FO#2 NPCC	1/1/2024
Holtsville 3	NY	FO#2 NPCC	1/1/2024
Holtsville 4	NY	FO#2 NPCC	1/1/2024
Holtsville 5	NY	FO#2 NPCC	1/1/2024
Holtsville 6	NY	FO#2 NPCC	1/1/2025
Holtsville 7	NY	FO#2 NPCC	1/1/2025
Holtsville 8	NY	FO#2 NPCC	1/1/2025
Holtsville 9	NY	FO#2 NPCC	1/1/2025
Hudson Ave 4	NY	FO#2 NPCC	1/1/2020
Hudson Ave GT3	NY	FO#2 NPCC	1/1/2020
Hudson Ave GT5	NY	FO#2 NPCC	1/1/2020
Indian Point 2 GT1	NY	FO#2 NPCC	1/1/2019
Indian Point GT 2	NY	FO#2 NPCC	1/1/2021
Indian Point GT 3	NY	FO#2 NPCC	1/1/2020
L Street Jet 1	NY	FO#2 NPCC	1/1/2016
Narrows Gen 1	NY	NG	1/1/2022
Narrows Gen 2	NY	NG	1/1/2022
Narrows Gen 21	NY	NG	1/1/2022
Narrows Gen 22	NY	NG	1/1/2022
Narrows Gen 23	NY	NG	1/1/2022
Narrows Gen 24	NY	NG	1/1/2022
Narrows Gen 25	NY	NG	1/1/2022
Narrows Gen 26	NY	NG	1/1/2022
Narrows Gen 27	NY	NG	1/1/2022
Narrows Gen 3	NY	NG	1/1/2022
Narrows Gen 4	NY	NG	1/1/2022
Narrows Gen 5	NY	NG	1/1/2022
Narrows Gen 6	NY	NG	1/1/2022
Narrows Gen 7	NY	NG	1/1/2022
Narrows Gen 8	NY	NG	1/1/2022
Northport GT1	NY	FO#2 NPCC	1/1/2017
Port Jefferson GT1	NY	FO#2 NPCC	1/1/2016
Ravenswood 143	NY	NG	1/1/2025
Ravenswood G1	NY	NG	1/1/2017

Unit Name	Region	Fuel type	Retirement
Ravenswood G10	NY	NG	1/1/2019
Ravenswood G11	NY	NG	1/1/2019
Ravenswood G21	NY	NG	1/1/2019
Ravenswood G22	NY	NG	1/1/2019
Ravenswood G23	NY	NG	1/1/2019
Ravenswood G24	NY	NG	1/1/2019
Ravenswood G31	NY	NG	1/1/2019
Ravenswood G32	NY	NG	1/1/2019
Ravenswood G33	NY	NG	1/1/2019
Ravenswood G4	NY	NG	1/1/2019
Ravenswood G5	NY	NG	1/1/2019
Ravenswood G6	NY	NG	1/1/2019
Ravenswood G7	NY	NG	1/1/2019
Ravenswood G9	NY	NG	1/1/2019
Rochester 9 2	NY	NG	1/1/2019
S A Carlson 5	NY	Coal	1/1/2016
Shoemaker GT 1	NY	NG	1/1/2022
Shoreham GT 1	NY	FO#2 NPCC	1/1/2021
Shoreham GT 2	NY	FO#2 NPCC	1/1/2016
Southhold 1	NY	FO#2 NPCC	1/1/2014
West Babylon GT 4	NY	FO#2 NPCC	1/1/2021
West Coxsackie 1	NY	NG	1/1/2019
Cadillac GT 1	Quebec	FO#2 NPCC	1/1/2027
Cadillac GT 2	Quebec	FO#2 NPCC	1/1/2026
Cadillac GT 3	Quebec	FO#2 NPCC	1/1/2027
La Citiere GT 1	Quebec	FO#2 NPCC	1/1/2030
La Citiere GT 3	Quebec	FO#2 NPCC	1/1/2030
La Citiere GT 4	Quebec	FO#2 NPCC	1/1/2029
Brayton Point 1	MA	Coal	6/1/2017
Brayton Point 2	MA	Coal	6/1/2017
Brayton Point 3	MA	Coal	6/1/2017
Brayton Point 4	MA	FO#6 NPCC	6/1/2017
West Medway 3	MA	FO#2 NPCC	1/1/2020
Canal 1	SEMA	FO#6 NPCC	1/1/2020
Canal 2	SEMA	FO#6 NPCC	1/1/2020
Cleary 8	SEMA	FO#6 NPCC	1/1/2022
Somerset (MA) 2	SEMA	FO#2 NPCC	1/1/2021
Cape GT 4	SME	FO#2 NPCC	1/1/2020
Cape GT 5	SME	FO#2 NPCC	1/1/2020
Wyman-Yarmouth 1	SME	FO#6 NPCC	1/1/2017
Wyman-Yarmouth 2	SME	FO#6 NPCC	1/1/2017
Wyman-Yarmouth 3	SME	FO#6 NPCC	1/1/2020
Wyman-Yarmouth 4	SME	FO#6 NPCC	1/1/2022
Ascutney GT 1	VT	FO#2 NPCC	1/1/2013
Burlington NPCC 1	VT	FO#2 NPCC	1/1/2021
Gorge (Colchester) 1	VT	FO#2 NPCC	1/1/2015
Cabot 6	WCMA	NG	1/1/2015
Cabot 8	WCMA	NG	1/1/2013
Cabot 9	WCMA	NG	1/1/2013
Mount Tom	WCMA	Coal	10/1/2014
West Springfield 3	WCMA	FO#6 NPCC	1/1/2022

Additions: In addition to any generic natural-gas combined cycle units added to achieve reliability requirements, our electric-sector model includes the following new units and upgrades:

- Footprint Power Combined Cycle unit as of June 1, 2017 at 674 MW; located in ISO-NE Boston at the Salem Harbor site.
- Cape Wind as of January 1, 2016 at 136 MW, capacity increases on January 1, 2017 to 365 MW; located in ISO-NE SEMA.
- Northfield Mountain pumped storage capacity increases to 1,119.2 MW in 2015.

Capital costs: Capital costs of avoiding new NGCC construction are calculated using values from AEO 2014.[53] Capital costs associated with alternative, low-demand resources are discussed but not reported Appendix A.

Benefit of eliminating constraint-elevated prices: The benefit of eliminating elevated prices and price spikes related to natural gas capacity constrains is estimated as the product of base case gas demand in each month of each year modeled and the difference between two average natural gas price bases for that month: (1) the 2015 price basis; and (2) the actual model year basis.

Electric sales data: Electric sales, before demand-side measures, were taken from ISO-NE's CELT 2014.

Electric capacity data: The base case electric generation resource mix was modeled using the Market Analytics scenario designed by Synapse for DOER in early 2014 to provide an accurate presentation of Green Communities Act (GCA) policies as well as the Renewable Portfolio Standards—by class—of the six New England states. Synapse's GCA analysis for DOER was developed using the NERC 9.5 dataset, based on the Ventyx Fall 2012 Reference Case. We verified and updated these data with the most current information on gas prices, loads, retirements, and additions. Note that if load becomes too small or transmission constraints are reached, wind generation will back down or curtail.

Existing electric transmission from Canada: We used the Market Analytics default assumptions for the existing lines.

Gas LDC demand data: Base case gas demand, before demand-side measures, was modeled using the Massachusetts' LDCs' gas demand forecasts and the most up-to-date information available regarding capacity exempt customers.

- Planning year load includes company use, commercial and industrial customers, and heating and non-heating load of residential customers. It also accounts for energy efficiency adjustments, unbilled sales and losses, and adjustments for capacity exempt customers. Capacity exempt adjustments represent commercial and industrial capacity exempt and capacity exempt unaccounted for gas.

[53] Electricity Market Module. AEO 2014. Available at http://www.eia.gov/forecasts/aeo/assumptions/pdf/electricity.pdf

- Design year planning load was calculated using the design year daily effective degree days for each of five LDCs. All of the items included in planning year load calculations are included in the design year. NGrid provided updated planning year data that replaced their most recent filing.

- The reconstituted design year reflects the load projected by the LDCs in the design year but is then adjusted for all the energy efficiency expected by the LDCs' forecast (including capacity exempt) to generate an expected load prior to energy efficiency.

- LDC's five-year design day forecasts were applied to the January of the split year and remain unadjusted from their most recent filing as provided to DOER.[54] For those years not provided by the companies, the average annual load growth rate for the given forecasted years was used to extrapolate the design day and annual forecasts out through 2019. From 2020 through 2030 design day and annual gas demand was projected at a 0.5-percent annual growth rate per EIA projections using the AEO 2013 Demand Technology Case average annual natural gas consumption growth rate for New England.

- Design day planning load was calculated by using the design day effective degree days level.[55] Design day planning load includes the same items as design year and for three of the LDCs (Berkshires, NStar, and Liberty) the most recent LDC filing was used. Columbia and NGrid's design day loads were replaced with updated values provided through the stakeholder process. The design day value includes the LDCs' expected energy efficiency and is not "reconstituted."

Munis natural gas demand data: Demand for munis is modeled as a proxy based on the natural gas capacity under contract to these utilities in 2015.[56] This proxy demand is then forecasted to increase in each year using the same average growth rate as used by LDCs. Munis natural gas demand is roughly 2 percent of LDC natural gas demand in each year.

Gas capacity data: We model existing natural gas capacity from:

- Existing pipelines: Algonquin Gas Transmission Company (AGT), Maritimes/Northeast Pipeline Company (M&NP); Tennessee Gas Pipeline Company (TGP)

- Planned pipeline capacity: Algonquin Incremental Market (AIM) pipeline capacity, which is an expansion of the AGT line, expected to be complete in 2017

- LDC's LNG storage and vaporization: National Grid, Columbia, NSTAR, Liberty, Fitchburg Gas and Electric, Berkshire Gas, Holyoke, Middleboro

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[54] We used the latest Department of Public Utilities filings for all LDCs except NGrid and Columbia, which provided DOER with updated design day forecasts.

[55] Berkshire Gas Company. 2014. Long Range Forecast and Supply Plan. Prepared for the Massachusetts Department of Public Utilities.

[56] Tennessee Gas Pipeline informational postings, http://pipeline2.kindermorgan.com/Capacity/OpAvailPoint.aspx?code=TGP

- Full GDF Suez LNG vaporization at Everett, MA with an allocation for Mystic electric generation plant
- Existing propane: NGrid; Columbia; Fitchburg Gas and Electric; and Berkshire Gas

Where LDC demand forecasts do not extend to 2019 we extrapolated each LDC's demand based on its trend during the forecast period. LDC demand growth after 2019 is projected to be 0.5 percent per year, based on the assumptions developed for the CECP. Muni and capacity exempt demand growth is assumed to keep pace with LDC demand.

Winter peak: In the electric sector, in addition to our annual modeling, we reran January for each year in the analysis for the purpose of modeling the gas requirements in the winter peak hour. We modeled each January as a period of cold weather—defined as the CELT 2014 5-percent confidence interval or high case—assuming that all modeled regions (New England, New York, Quebec, and the Maritimes) all experience a relative cold snap. Winter peak energy efficiency and time-varying rate savings were also assumed. Peak hour data were as then extracted as the highest peak 6pm hour among days from January 13 through 31—in this way assuring that the peak hour falls in a period of at least 12 contiguous "cold snap" days.

In the gas sector, gas requirements were represented as each LDC's demand day requirements (including natural gas consumers commonly referred to as "capacity-exempt customers"), adjusted to an hourly requirement based on an assumption that 5.6 percent of daily peak demand falls during the peak hour.[57] We evaluated the effects of an extended cold snap by modeling design day load over a 12-day period, then applying the impacts extended use of stored natural gas natural storage on the available storage capacity. Our research determined that existing LNG storage facilities have sufficient capacity for 13 days using existing vaporizers. Propane storage is not available in this model as a balancing measure; existing propane storage facilities are sufficient for a 3-day cold snap. Gas capacity was adjusted to an hourly requirement assuming that 1/24 of daily capacity is available during the peak hour.

Constraint criteria: The balance criteria of gas demand no greater than 95-percent of gas capacity reflects the level of pipeline utilization at which operational flow orders are typically declared and shippers are held to strict tolerances on their takes from the pipeline. The impact of gas constraint on natural gas prices is thought to begin when gas demand rises above 80-percent of gas capacity. Gas prices associated with out-of-balance conditions are assumed in 2015 through 2019 in our model.

Balancing measures: We determined the least-cost set of measures that would eliminate constraints and balancing the Massachusetts gas sector. Balancing measures are shown in Table 25 and Table 26.

[57] Eastern Interconnection Planning Collaborative Draft Gas-Electric Interface Study Target 2 Report, p.64-65

Table 25. Balancing measures available in base case

2015 Balancing Measures	Increment	Total winter peak hour availability (MMBtu)	Total annual availability (MMBtu)	Winter peak hour availability (MMBtu)	Annual availability (MMBtu)	Hours of availability at winter peak per year (hours)	Annual cost ($)	Per MMBtu cost ($/MMBtu Annual)	Number of minimum increments available
Pipeline (long- and short-haul)	Minimum	0	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Winter Reliability Program	Minimum	29,434	29,434	1	150	150	$450	$3.00	29,434
Demand Response	Minimum	190	5,040	0.76	20	24	$1,326	$66	250
Pumped Storage	Minimum	0	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Battery Storage	Minimum	289	52,560	289	52,560	182	$20,051,425	$381	1
2020 Balancing Measures									
Pipeline (long- and short-haul)	Minimum	undetermined	undetermined	4,167	36,500,000	n/a	$51,100,000	$1.40	undetermined
Winter Reliability Program	Minimum	0	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Demand Response	Minimum	190	5,040	0.76	20	24	$1,326	$66	250
Pumped Storage	Minimum	4,043	367,920	2,022	183,960	182	$94,466,330	$257	2
Battery Storage	Minimum	1,444	52,560	289	10,512	182	$19,153,973	$364	5
2030 Balancing Measures									
Pipeline (long- and short-haul)	Minimum	undetermined	undetermined	4,167	36,500,000	n/a	$51,100,000	$1.40	undetermined
Winter Reliability Program	Minimum	0	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Demand Response	Minimum	190	5,040	0.76	20	24	$1,326	$66	250
Pumped Storage	Minimum	4,043	367,920	2,022	183,960	182	$94,466,330	$257	2
Battery Storage	Minimum	8,664	52,560	289	1,752	182	$15,509,561	$295	30

Table 26. Balancing measures available in low demand case

2015 Balancing Measures	Increment	Total winter peak hour availability (MMBtu)	Total annual availability (MMBtu)	Winter peak hour availability (MMBtu)	Annual availability (MMBtu)	Hours of availability at winter peak per year (hours)	Annual cost ($)	Per MMBtu cost ($/MMBtu Annual)	Number of minimum increments available
Pipeline (long- and short-haul)	Minimum	0	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Winter Reliability Program	Minimum	29,434	29,434	1	150	150	$450	$3.00	29,434
Demand Response	Minimum	760	20,160	0.76	20	24	$1,326	$66	1000
Pumped Storage	Minimum	0	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Battery Storage	Minimum	289	52,560	289	52,560	182	$20,051,425	$381	1
2020 Balancing Measures									
Pipeline (long- and short-haul)	Minimum	undetermined	undetermined	4,167	36,500,000	n/a	$51,100,000	$1.40	undetermined
Winter Reliability Program	Minimum	0	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Demand Response	Minimum	760	20,160	0.76	20	24	$1,326	$66	1000
Pumped Storage	Minimum	4,043	367,920	2,022	183,960	182	$94,466,330	$257	2
Battery Storage	Minimum	1,444	52,560	289	10,512	182	$19,153,973	$364	5
2030 Balancing Measures									
Pipeline (long- and short-haul)	Minimum	undetermined	undetermined	4,167	36,500,000	n/a	$51,100,000	$1.40	undetermined
Winter Reliability Program	Minimum	0	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Demand Response	Minimum	760	20,160	0.76	20	24	$1,326	$66	1000
Pumped Storage	Minimum	4,043	367,920	2,022	183,960	182	$94,466,330	$257	2
Battery Storage	Minimum	8,664	52,560	289	1,752	182	$15,509,561	$295	30

- Pipeline capacity (long- and short-haul[58]), incremental to existing and planned natural gas pipeline capacity in both the base and low demand cases, is assumed to be available in 100,000 MMBtu/day increments with a minimum increment of 100,000 MMBtu and a maximum increment of 500,000 MMBtu/day beginning in 2019. There are no economies of scale for differences in the size of these increments. The existing and planned pipeline capacity (included in modeling, not as a balancing measure) for 2020 includes the 342,000 MMBtu/day of capacity associated with the AIM project which is scheduled to be online by November 1, 2016. The cost assumptions associated with the incremental pipeline expansions are derived from the cost data submitted by Algonquin in its filing with the Federal Energy Regulatory Commission.[59]

- ISO-NE Winter Reliability program is an inventory buy-back program for oil, LNG and a very small portion of demand response that will be in effect for the next four winters: 2014/15, 2015/16, 2016/17 and 2017/18. In the both the base case and low demand case, the Winter Reliability program is not available as a balancing measure after 2018. In years it is available, Winter Reliability is always applied as a balancing measure directly after demand response, in order to simulate how ISO-NE develops its forecast for required inventory for the program. This program is then allowed to function as a balancer for up to 29,434 MMBtu per peak hour in 2015 (in both the base case and low demand case).

- Demand response in the electric sector is available for two 4-hour periods in each of three months: December, January and February. For Massachusetts, 25 MW of demand response is estimated to be available in the base case during each of these periods at a monthly cost of $1/kW-month, and an hourly cost of $500/MW. 100 MW is estimated to be available in the low demand case at the same cost per MW.

- Pumped storage, incremental to existing pumped hydro installations in both the base and low demand cases, is assumed to be available as follows: 0 MW by 2015, 560 MW from 2016 to 2020, and an additional 560 MW from 2021 to 2030 with an annual capacity factor of 15 percent. Annual levelized costs are constant over the study period at $257/MWh. These assumptions are based on a DOE and Electric Power Research Institute (EPRI) 2013 *Electricity Storage Handbook*. 60 The minimum facility size is assumption to 280 MW and we are not aware of evidence of economies of scale for larger installations. This balancing measure is more expensive than incremental pipeline and, therefore, is not used in any scenario or year.

- Battery storage is assumed to be available as follows in both the base and low demand cases: 40 MW by 2015, an additional 200 MW from 2016 to 2020, and an additional 1200 MW from 2021 to 2030 with an annual capacity factor of 15 percent. Annual levelized costs fall from $381/MWh in 2015 to $295/MWh in 2030. These assumptions are based on DOE/EPRI's 2013 *Electricity Storage Handbook*. The minimum facility size is

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[58] Long haul pipeline capacity transports gas from the Gulf Coast and Western Canada, Short haul capacity transports gas from storage fields and Marcellus Shale regions

[59] Algonquin Gas Transmission, AIM expansion, FERC CP-14-96.

[60] Table B-12. http://www.sandia.gov/ess/publications/SAND2013-5131.pdf

assumption to 40 MW and we are not aware of evidence of economies of scale for larger installations. This balancing measure is more expensive than incremental pipeline and, therefore, is not used in any scenario or year.

- In addition, we examined the utility of LNG imports in balancing scenarios and found that, while this capacity could be purchased for approximately $9.85 per MMBtu (the basis to European winter purchases of LNG) its reliability suffers from the problem of a time lag between identifying the need for the resources (and the price conditions to make it profitable) and the ability of ships to make delivery at the Massachusetts port.

APPENDIX C: LOW ENERGY DEMAND CASE ASSUMPTIONS

Overview: Low energy demand case energy is modeled as the base case with the addition of the maximum feasible amount of additional alternative resources.

Gas prices: As in base case.

Canadian transmission: As in base case.

Carbon prices: As in base case.

Greenhouse gas emissions: As in base case.

GWSA compliance: As in base case.

Energy efficiency: For Massachusetts electric efficiency: annual savings rise to 2.9 percent of program administrators' transmission-and-distribution-adjusted load by 2020; the annual share of savings remains constant through 2030. For Massachusetts gas efficiency: annual savings rise to 1.9 percent of annual retail sales by 2020; the annual share of savings remains constant through 2030. Energy efficiency savings at winter peak as in base case. Costs are reported in Appendix A.

Time varying rates: As in base case.

Advanced Building Codes: As in base case.

Renewable thermal technologies: As in base case.

Winter Reliability program: As in base case.

Distributed generation: Incremental to distributed generation in the base case, the alternative resources in Table 27 were added.

Table 27. Alternative resources added to low demand case at reference natural gas price

2015		2020		2030	
	Annual Savings Potential (billion Btu)		*Annual Savings Potential (trillion Btu)*		*Annual Savings Potential (trillion Btu)*
Anaerobic Digestion	20	Res. Gas EE	4	Res. Gas EE	5
Landfill Gas	17	Appliance Standards	9	Appliance Standards	25
Converted Hydro	14	CI Gas EE	4	CI Gas EE	10
Small CHP	184	LI Gas EE	1	LI Gas EE	2
		Res. Electric EE	1	Res. Electric EE	3
		CI Electric EE	5	CI Electric EE	15
		Anaerobic Digestion	1	Anaerobic Digestion	0.4
		Landfill Gas	1	Large CHP	2
		Large CHP	1	Landfill Gas	0.3
		Converted Hydro	2	Converted Hydro	2
		LI Electric EE	0.1	Small CHP	2
		Small CHP	1	LI Electric EE	0.3
		Biomass Power C1	1	Biomass Power C1	1
				Utility-Scale PV	2
				Large Wind C5	15
				Commercial PV	11
				Large Wind C4	24
				Biomass Power C2	2
				Residential PV	2
				Wind (<100 kW)	6

Retirements: As in base case.

Additions: As in base case plus alternative resources below the economic threshold in the feasibility analysis.

Capital costs: As in base case.

Benefit of eliminating constraint-elevated prices: As in base case.

Electric sales data: As in base case.

Electric capacity data: As in base case, adjusted to included alternative resources below the economic threshold in the feasibility analysis.

Existing electric transmission from Canada: As in base case.

Gas LDC demand data: As in base case, adjusted to included alternative resources below the economic threshold in the feasibility analysis.

Gas Muni demand data: As in base case.

Gas capacity data: As in base case.

Winter peak: As in base case.

Constraint criteria: As in base case.

Balancing measures: We determined the least-cost set of measures that would eliminate constraints and balancing the Massachusetts gas sector. Balancing measures are described above in Appendix B.

APPENDIX D: NATURAL GAS PRICE SENSITIVITY ASSUMPTIONS

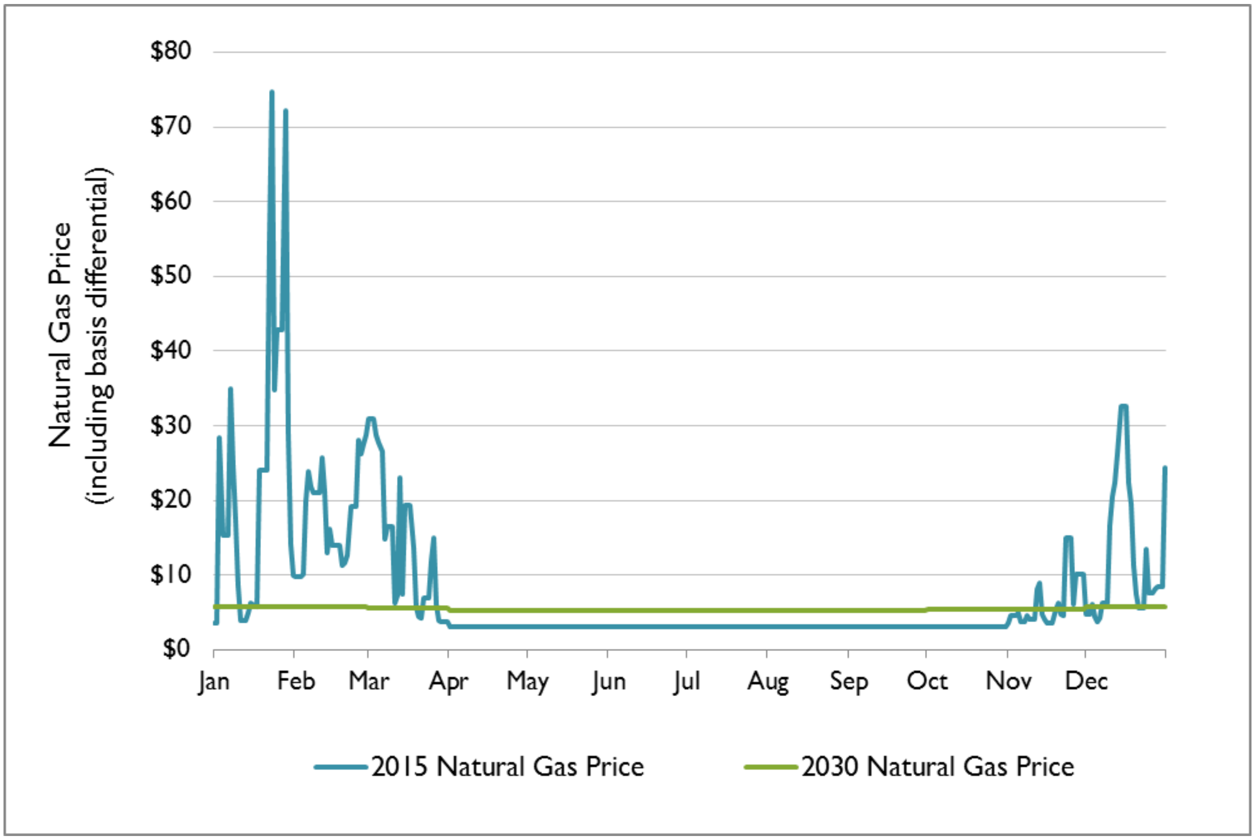
Natural gas price projections are Henry Hub prices developed from three sources: the October 2014 Short Term Energy Outlook (STEO) and the April 2014 Annual Energy Outlook (AEO) both issued by the DOE/ EIA; and the New York Mercantile Exchange (NYMEX) futures gas prices as of October 14, 2014.

In all three price sensitivities the historical monthly prices from January 2012 through October 2014 are from the STEO Figure 14. Also, in all three price sensitivities the monthly price projections from November 2014 through December 2015 are from the October 14, 2014 NYMEX close. The three price sensitivities vary beginning in January 2016. For the reference gas price, the monthly NYMXEX prices are escalated annually in proportion to the annual percentage changes in the Henry Hub prices from the 2014 AEO Reference Case (Tab 13, line 44). For the high gas price, the monthly NYMEX prices are escalated in proportion to the annual percentage changes in the Henry Hub prices from the 2014 AEO Low Oil and Gas Resource Case (Total Energy Supply, Disposition, and Price Summary, Low Oil and Gas Resource Case Table, line 57). For the low gas price, the Henry Hub prices from the 2014 AEO High Oil and Gas Resource Case (Total Energy Supply, Disposition, and Price Summary, High Oil and Gas Resource Table, line 57) were adjusted in 2019 and 2020 to align better with the prices from the reference price forecast. Without this adjustment, the low price case was higher than the reference case in those two years. The monthly NYMEX prices are then escalated in proportion to the annual percentage changes in the adjusted Henry Hub price trajectory from the 2014 AEO High Oil and Gas Resource Case (Total Energy Supply, Disposition, and Price Summary, High Oil and Gas Resource Table, line 57).

The Low and High Oil and Gas Resource Cases from the 2014 AEO were chosen to represent a range in future gas supplies available from shale reserves. DOE/EIA explicitly recognizes this uncertainty and developed these alternate resource cases to address it.

In 2015 through 2019, we use a winter basis estimate as the November to March difference between Henry Hub and Algonquin City Gate daily prices in 2013/2014. For the summer months in 2015 through 2019, and for all months in the remaining years we assume one constant basis differential for every day, calculated as the average difference between Henry Hub and Algonquin City Gate daily prices in the April through October of 2014. Figure 19 displays the daily reference gas price adjusted for the basis differential for 2015 and 2030.

Figure 19. Daily reference gas price adjusted for basis differential, 2015 and 2030



APPENDIX E: CANADIAN TRANSMISSION SENSITIVITY ASSUMPTIONS

This appendix provides information on Hydro Quebec (HQ) export strategies, data on existing power flows from Canada into New England, and recommendations for modeling assumptions. Table 28 summarizes modeling assumptions related to incremental transmission from Canada.

Table 28. Incremental Canadian transmission assumptions

Imports into New England	Generic HVDC 1	Generic HVDC 2
Model Cases	Canadian transmission only	Canadian transmission only
Nominal/Max	1200	1200
Summer Max	1200	1200
Winter Design Day Peak Hour (6 PM)	1200	1200
Winter Peak Day CF	0.75	0.75
Winter Peak Hour CF	0.71	0.71
Year Available	2018	2022
Comments/Source	Generic baseloaded import	Generic intermediate-loaded import
Flow Patterns	Historic Ph II pattern	Historic Ph II pattern
Ave Ann CF	0.67	0.50
Cost of Line ($2013)	$1.5 billion	$2.2 billion

Documentation of HQ Export Intentions

Synapse relied in part upon Hydro Quebec's (HQ) 2009-2013 Strategic Energy Plan, and HQ's 2012 Annual Report to document "Major Sources of Incremental Hydroelectric Energy" in our memo to the MA DOER, November 1, 2013[61]. Since that time, HQ has released a new annual report, but they have not yet posted any new Strategic Plan documents. HQ's 2013 Annual Report notes the following:

> Hydro-Québec Production is continuing talks regarding participation in projects to build transmission lines between Québec and certain states in the U.S. Northeast. These interconnections would enable us to increase our exports to those markets. (p. 12)

[61] Synapse Energy Economics, "Incremental Benefits and Costs of Large-Scale Hydroelectric Energy Imports", Prepared for the Massachusetts Department of Energy Resources, November 1, 2013. See, e.g., pages 8-9.

The information in the Annual Report (2013) does not clarify exactly how much capacity and/or annual energy HQ might be capable of providing to New England, for any given year or for any given price point. The 2009-2013 Strategic Plan clearly indicates that HQ plan to "Step Up Exports" but with Ontario, New York, New Brunswick, and New England all having access to HQ for energy, it's not certain what that means for New England. From the Strategic Plan:

> Objective 2: Step up exports.
>
> …
>
> As a result of recent and ongoing hydroelectric development projects, Hydro-Quebec Production expects to have the generating capacity needed to ensure export growth. By 2013, we will have nearly 24 TWh at our disposal. This margin of flexibility will enable us to increase the volume of our exports. (p. 25)

And

> Strategy 2 – Step up exports to New England and New York.
>
> …
>
> Hydro-Quebec Production is currently negotiating agreements to supply electricity, via this transmission line [Northern Pass], to these two U.S. distributors and other New England distributors, starting in the middle of the next decade.
>
> Other discussions are under way with State of New York authorities, including the New York Power Authority (NYPA) and the New York Independent System Operator (NYISO), with a view to increasing electricity sales to that market. The State of New York is considering a number of means, including imports of Québec hydropower, to reach its renewable energy goals and GHG emission reduction targets. (p. 27)

And

> We also plan to upgrade the New York interconnection (Chateauguay substation). With import and export capability, this interconnection plays a major role in energy interchanges between Quebec and the United States. We will coordinate the work with the U.S. operators to reduce impacts on service. We are considering other projects to ensure long-term operability and are keeping up our efforts to maintain or increase the exploitable capacity of all our interconnection facilities. We will increase our participation on technical committees with the operators of neighboring power grids and continue to make representations on joint operating rules and reliability standards for interconnected transmission systems. (p. 42)

HQ is on track to complete up to 3,000 MW of new wind energy integration (since ~2008) by 2015.[62] HQ is also continuing its development of hydroelectric resources.[63] HQ continues with an energy efficiency

[62] See e.g. http://www.hydroquebec.com/publications/en/others/pdf/depliant_eolienne_distribution.pdf.

[63] See Strategic Plan 2009-2013, Objective 1: Increase hydroelectric generating capacity, page 19.

program[64]. HQ is in the process of continuing to reinforce and upgrade its transmission network in southern Quebec, and other areas of the Province. For example, transmission reinforcement around Montreal is anticipated over the next five years:

> BOUT-DE-L'ÎLE 735-KV SECTION
>
> Hydro-Québec TransÉnergie (TransÉnergie) is adding a new 735-kV section at Bout-de-l'Île substation (located at east end of Montréal Island). This was originally a 315/120-kV station. The Boucherville – Duvernay line (line 7009), which passes by Bout-de-l'Île, will be looped into the new station. A new -300/+300-Mvar SVC will be integrated into the 735-kV section in 2013.
>
> The project also includes the addition of two 735/315-kV 1,650-MVA transformers in 2014. This new 735-kV source will allow redistribution of load around the Greater Montréal area and absorb load growth in eastern Montréal. This project will enable future major modifications to the Montréal area regional subsystem. Many of the present 120-kV distribution stations will be rebuilt into 315-kV stations and the Montréal regional network will be converted to 315-kV. The addition of a second -300/+300-Mvar SVC at Bout-de-l'Île in 2014 is also projected. [65]

Based on publicly available HQ information, it appears that there are no particular institutional impediments to increasing export levels to New England over the next decade. This is because 1) HQ continues to state that it plans to "step up exports", and 2) its investment in hydro and wind generation, demand side resources, and transmission reinforcement indicates ongoing activity that will allow for increased exports; and 3) it acknowledges activity to allow for exports associated with specific transmission projects to New England and New York.[66]

Existing Canadian Interconnections: Size, Flows, Capacity Factors, and Recommendations for Modeling

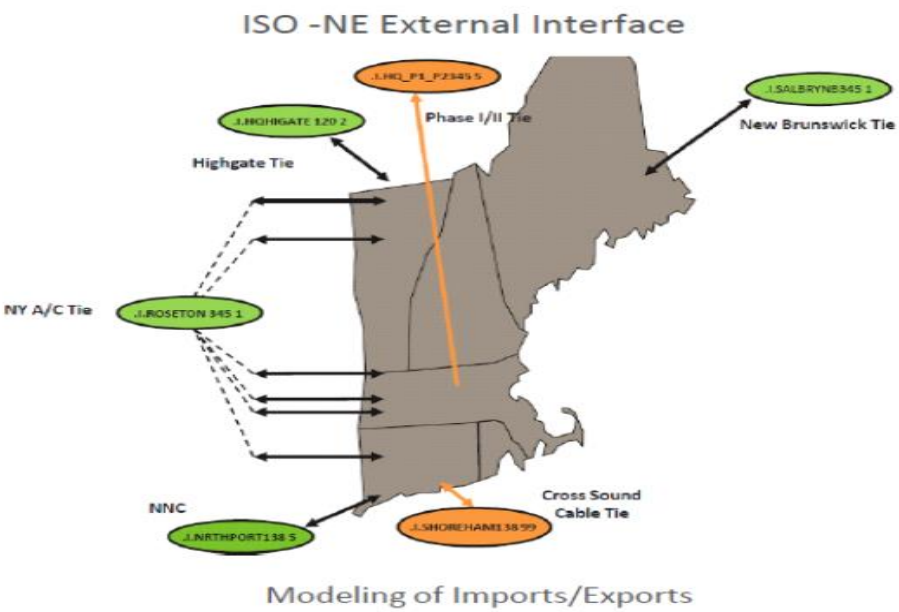
The figure below shows how ISO NE represents transfers to New England from importing points.

[64] See Strategic Plan 2009-2013, Objective 2: Step up energy efficiency efforts, page 50.

[65] NERC 2013 Long-Term Reliability Assessment, December 2013. NPCC-Quebec section. Page 122. See also the full section, pages 117-122. See also 2013 Annual Report, e.g., pages 15-19.

[66] Strategic Plan, p27, p42. Website, http://www.hydroquebec.com/hertel-new-york/en/project/. 2013 Annual Report, page 12.

Figure 20. ISO NE representation for imports



Source: ISO NE

Table 29 shows hourly utilization/capacity factors for the HQ Phase 2 path for 19 of the highest load days during the 2013-2014 winter season. These 19 days include the 9 days that contain the top 24 hours of winter season load, and generally reflect the days that could represent cold snap periods. While on a few of these very-high-load days, the peak load hours (hour ending 18-19, or the 6PM to 7PM time frame) see a utilization of 99 percent or greater, on average the utilization for these 2 critical hours is 83.9-85.5 percent.

Table 29. Summary of hourly capacity factor / utilization of Phase 2 during high load days in the Winter of 2013-2014

Capacity Factor / Hourly Utilization, Phase 2 Line - 19 High Load Days During December - February, 2013-2014
Note: 100% CF on a 1400 MW basis is equal to 70% CF on a 2000 MW basis.

Average of CF @ 1400	Column Label																			
Row Label	**12/17/2013**	**1/2/2014**	**1/3/2014**	**1/7/2014**	**1/8/2014**	**1/9/2014**	**1/21/2014**	**1/22/2014**	**1/23/2014**	**1/24/2014**	**1/25/2014**	**1/26/2014**	**1/27/2014**	**1/28/2014**	**1/29/2014**	**2/10/2014**	**2/11/2014**	**2/12/2014**	**2/13/2014**	**Grand Total**
1	99.7%	98.0%	78.9%	99.9%	99.5%	92.6%	100.0%	99.7%	99.7%	99.4%	100.0%	88.9%	89.1%	96.1%	100.0%	99.9%	89.1%	100.0%	89.0%	95.8%
2	99.7%	100.0%	78.4%	99.9%	99.5%	92.6%	100.0%	99.7%	98.2%	99.9%	100.0%	88.9%	89.0%	96.2%	100.1%	99.9%	89.1%	100.0%	89.1%	95.8%
3	99.7%	100.0%	78.3%	99.9%	93.4%	92.6%	92.5%	99.7%	99.7%	99.9%	100.0%	89.0%	89.0%	96.2%	100.0%	100.0%	89.1%	100.0%	89.1%	95.2%
4	99.7%	99.9%	78.4%	99.9%	89.9%	92.6%	78.0%	99.7%	99.7%	99.9%	100.0%	89.1%	92.6%	96.2%	100.0%	100.0%	89.1%	100.1%	89.1%	94.4%
5	98.3%	99.9%	81.9%	99.9%	82.0%	92.6%	46.4%	97.1%	99.7%	99.9%	100.0%	89.1%	92.6%	96.1%	100.1%	100.0%	89.1%	100.0%	89.0%	92.3%
6	99.1%	99.9%	68.9%	99.9%	81.9%	92.7%	46.4%	99.0%	99.7%	98.1%	93.1%	89.1%	92.6%	96.2%	100.0%	99.9%	89.1%	100.0%	89.1%	91.3%
7	69.1%	96.3%	81.3%	99.9%	78.4%	92.6%	78.0%	68.4%	97.2%	82.5%	88.9%	89.1%	97.0%	96.1%	100.0%	100.0%	89.1%	98.3%	89.1%	89.0%
8	89.3%	98.5%	79.1%	100.0%	81.9%	92.6%	91.9%	55.1%	97.2%	81.8%	89.0%	89.1%	99.9%	98.6%	100.0%	99.9%	89.1%	59.1%	92.5%	88.7%
9	99.5%	94.9%	84.4%	99.9%	94.8%	92.6%	98.9%	65.6%	97.2%	80.5%	89.0%	89.1%	99.9%	87.1%	100.0%	99.9%	99.7%	77.9%	92.6%	91.8%
10	94.7%	94.9%	83.8%	100.0%	95.3%	92.7%	99.0%	79.5%	97.2%	99.6%	89.0%	89.0%	94.9%	99.5%	100.1%	90.8%	96.8%	92.3%	92.5%	93.8%
11	92.6%	94.9%	52.3%	98.6%	92.6%	92.6%	99.0%	87.1%	86.1%	100.1%	89.0%	89.1%	95.9%	100.0%	100.0%	89.1%	90.7%	92.9%	90.5%	91.2%
12	92.6%	94.3%	93.1%	92.2%	92.7%	92.6%	99.1%	83.4%	85.7%	100.0%	89.1%	89.1%	96.4%	100.0%	100.1%	89.1%	89.1%	92.9%	89.8%	92.7%
13	99.6%	70.8%	99.7%	92.3%	92.6%	92.6%	99.1%	89.1%	96.8%	100.0%	88.9%	89.1%	90.1%	100.1%	100.2%	89.1%	89.1%	99.9%	89.8%	93.1%
14	99.6%	94.2%	96.2%	92.3%	92.7%	92.6%	99.1%	99.1%	97.2%	100.0%	89.0%	89.1%	89.5%	100.0%	100.2%	89.1%	89.1%	90.6%	89.8%	94.2%
15	99.6%	92.9%	92.9%	92.3%	92.6%	92.6%	99.1%	99.7%	97.2%	100.0%	88.9%	89.1%	83.1%	100.0%	100.2%	89.1%	89.1%	89.7%	89.8%	93.6%
16	99.6%	51.9%	89.4%	92.3%	92.6%	92.6%	98.5%	99.7%	96.8%	100.1%	88.9%	89.1%	89.6%	100.0%	100.1%	89.1%	89.1%	89.7%	86.9%	91.4%
17	99.5%	50.3%	89.3%	92.3%	92.6%	90.7%	67.5%	89.8%	71.6%	99.6%	88.9%	88.6%	79.9%	92.9%	100.1%	89.1%	89.1%	89.8%	86.9%	86.8%
18	99.6%	47.0%	85.7%	92.3%	85.5%	92.6%	57.8%	73.2%	46.5%	81.9%	88.9%	69.7%	83.0%	92.8%	100.1%	89.1%	89.1%	89.6%	83.6%	81.5%
19	99.5%	55.8%	92.6%	99.4%	88.9%	92.6%	71.5%	53.4%	38.9%	86.6%	88.9%	88.6%	83.1%	99.9%	100.0%	89.1%	89.1%	92.8%	83.5%	83.9%
20	99.5%	57.6%	90.6%	99.5%	92.6%	92.6%	56.6%	66.8%	40.1%	99.6%	88.9%	89.1%	89.6%	100.0%	100.0%	89.1%	89.1%	92.9%	89.6%	85.5%
21	99.5%	74.3%	87.4%	92.8%	92.7%	92.6%	65.1%	81.3%	43.7%	100.0%	88.9%	89.1%	89.8%	100.1%	100.0%	89.1%	91.9%	94.4%	89.6%	87.5%
22	99.4%	92.3%	92.6%	99.4%	92.6%	92.6%	77.7%	99.5%	43.8%	100.0%	88.9%	89.0%	96.6%	100.0%	100.0%	89.1%	84.9%	92.9%	89.6%	90.6%
23	99.4%	92.7%	99.6%	99.5%	92.6%	92.5%	87.9%	90.8%	55.3%	100.0%	88.9%	89.1%	92.9%	100.1%	92.3%	89.1%	99.4%	90.6%	89.6%	91.7%
24	99.4%	92.7%	99.8%	96.5%	92.7%	92.5%	96.3%	99.6%	85.0%	100.1%	88.9%	89.1%	92.8%	100.0%	89.1%	89.1%	100.1%	89.1%	89.7%	93.8%
Grand Total	**97.0%**	**85.2%**	**85.6%**	**97.1%**	**90.9%**	**92.5%**	**83.6%**	**86.5%**	**82.1%**	**96.2%**	**91.4%**	**88.2%**	**91.2%**	**97.7%**	**99.3%**	**93.3%**	**90.8%**	**92.3%**	**89.2%**	**91.1%**

Table 30. Summary of hourly capacity factor / utilization of New Brunswick Tie during high load days in the Winter of 2013-2014

NB Capacity Factor
800

Hour End	12/17/2013	1/2/2014	1/3/2014	1/7/2014	1/8/2014	1/9/2014	1/21/2014	1/22/2014	1/23/2014	1/24/2014	1/25/2014	1/26/2014	1/27/2014	1/28/2014	1/29/2014	2/10/2014	2/11/2014	2/12/2014	2/13/2014	Ave all Days
1	80%	56%	19%	85%	73%	97%	98%	91%	67%	73%	83%	96%	97%	97%	96%	81%	100%	91%	80%	82%
2	79%	51%	25%	78%	77%	97%	97%	83%	64%	63%	82%	98%	89%	97%	98%	98%	87%	87%	76%	80%
3	81%	45%	33%	74%	78%	96%	96%	78%	71%	66%	75%	97%	88%	97%	97%	96%	83%	89%	91%	81%
4	82%	36%	31%	79%	73%	94%	82%	68%	69%	67%	72%	97%	84%	97%	97%	97%	85%	87%	92%	79%
5	81%	23%	23%	71%	45%	95%	75%	60%	61%	75%	68%	97%	82%	97%	97%	93%	95%	87%	84%	74%
6	20%	10%	8%	86%	44%	75%	58%	63%	58%	67%	69%	96%	85%	80%	91%	84%	97%	90%	74%	66%
7	7%	7%	-11%	87%	48%	51%	68%	45%	39%	52%	68%	96%	56%	64%	55%	71%	80%	49%	79%	53%
8	-20%	1%	-21%	90%	82%	40%	79%	44%	49%	33%	69%	97%	58%	69%	47%	74%	77%	41%	81%	52%
9	14%	4%	-11%	87%	81%	33%	76%	40%	50%	42%	71%	97%	73%	90%	46%	85%	81%	57%	81%	58%
10	36%	-3%	18%	96%	95%	36%	97%	79%	28%	80%	79%	84%	94%	97%	85%	95%	98%	94%	97%	73%
11	51%	-12%	-5%	97%	95%	33%	98%	48%	27%	77%	81%	85%	97%	99%	89%	97%	98%	97%	98%	71%
12	57%	-23%	-22%	89%	93%	34%	98%	80%	26%	79%	89%	85%	95%	98%	88%	99%	97%	99%	83%	71%
13	46%	-23%	-11%	95%	93%	51%	100%	80%	55%	85%	93%	96%	98%	100%	88%	99%	99%	92%	99%	75%
14	36%	-9%	-15%	97%	93%	43%	99%	79%	61%	80%	95%	97%	96%	99%	92%	100%	99%	95%	99%	75%
15	45%	14%	-12%	96%	91%	42%	97%	76%	58%	79%	95%	96%	96%	98%	89%	96%	99%	94%	98%	76%
16	24%	11%	-11%	92%	92%	40%	95%	75%	55%	56%	97%	97%	96%	97%	84%	97%	97%	94%	97%	73%
17	11%	16%	10%	93%	93%	46%	62%	56%	46%	34%	96%	86%	95%	75%	69%	95%	70%	90%	80%	64%
18	3%	24%	22%	77%	94%	52%	60%	60%	44%	38%	98%	69%	84%	78%	82%	96%	74%	97%	100%	66%
19	8%	-16%	10%	78%	93%	61%	66%	58%	48%	68%	98%	70%	84%	88%	91%	92%	71%	95%	92%	66%
20	19%	-21%	24%	83%	92%	61%	69%	57%	35%	76%	97%	82%	96%	92%	83%	94%	71%	99%	77%	68%
21	32%	-20%	41%	92%	79%	57%	71%	55%	36%	77%	98%	89%	95%	78%	84%	97%	71%	98%	79%	69%
22	51%	-20%	45%	88%	86%	54%	76%	59%	47%	86%	98%	96%	98%	97%	85%	99%	75%	86%	99%	74%
23	60%	-2%	38%	97%	87%	55%	75%	94%	76%	88%	98%	85%	97%	98%	84%	99%	97%	98%	99%	80%
24	29%	39%	49%	83%	91%	52%	84%	85%	58%	80%	97%	83%	91%	80%	85%	100%	85%	56%	99%	75%
Ave all hrs	39%	8%	11%	87%	82%	58%	82%	67%	51%	68%	86%	90%	88%	90%	83%	93%	87%	86%	89%	71%

Table 31. Summary of hourly capacity factor / utilization of Highgate Tie during high load days in the Winter of 2013-2014

Highgate
225
CF

hr	12/17/2013	1/2/2014	1/3/2014	1/7/2014	1/8/2014	1/9/2014	1/21/2014	1/22/2014	1/23/2014	1/24/2014	1/25/2014	1/26/2014	1/27/2014	1/28/2014	1/29/2014	2/10/2014	2/11/2014	2/12/2014	2/13/2014	Grand Total
1	97.8%	97.8%	97.8%	93.3%	93.3%	93.3%	97.8%	97.8%	97.8%	95.6%	97.8%	97.8%	97.8%	97.8%	97.3%	98.2%	93.3%	93.3%	97.8%	96.5%
2	97.8%	97.8%	97.8%	93.3%	93.3%	93.3%	97.8%	98.2%	97.8%	97.3%	97.8%	97.8%	97.8%	97.8%	97.8%	98.2%	93.3%	93.3%	97.8%	96.6%
3	97.8%	97.8%	97.8%	93.3%	93.3%	93.3%	97.8%	97.8%	97.8%	98.2%	97.8%	97.8%	97.8%	97.8%	97.8%	98.2%	93.3%	93.3%	97.8%	96.7%
4	98.2%	97.8%	97.8%	93.3%	93.3%	93.3%	97.8%	97.8%	97.8%	97.8%	97.8%	97.8%	97.8%	97.8%	97.8%	98.2%	93.3%	93.3%	97.8%	96.7%
5	97.3%	97.8%	97.8%	93.3%	93.3%	93.3%	97.8%	95.6%	96.9%	97.8%	97.8%	97.8%	97.8%	97.8%	97.3%	98.2%	93.3%	93.3%	97.8%	96.4%
6	97.3%	97.8%	88.9%	93.3%	93.3%	93.3%	85.3%	10.7%	94.7%	95.1%	97.8%	97.8%	97.8%	97.8%	96.0%	98.2%	93.3%	93.3%	98.2%	90.5%
7	86.7%	97.8%	95.6%	93.3%	93.3%	93.3%	11.1%	17.3%	10.7%	4.0%	97.8%	97.8%	97.8%	97.8%	96.9%	97.3%	93.3%	93.3%	98.2%	77.5%
8	86.7%	97.8%	3.6%	93.3%	93.3%	93.3%	11.1%	81.3%	8.9%	0.0%	97.8%	97.8%	97.8%	97.8%	97.8%	96.9%	93.3%	93.3%	97.3%	75.7%
9	97.3%	97.8%	8.9%	93.3%	97.8%	93.3%	96.0%	11.1%	8.9%	0.0%	97.8%	97.8%	97.8%	97.8%	97.8%	97.8%	93.3%	96.4%	96.9%	77.8%
10	97.8%	97.8%	10.7%	93.3%	97.8%	93.3%	97.3%	8.9%	8.9%	0.0%	97.8%	97.8%	97.8%	97.8%	97.8%	97.8%	93.3%	97.3%	98.2%	78.0%
11	97.8%	97.8%	84.9%	93.3%	97.8%	93.3%	97.8%	8.9%	8.9%	2.2%	97.8%	97.8%	97.8%	94.2%	97.8%	93.3%	93.3%	97.8%	97.8%	81.6%
12	97.8%	97.3%	97.3%	93.3%	97.8%	93.3%	97.8%	10.7%	66.7%	95.6%	97.8%	97.8%	97.8%	97.8%	97.8%	93.3%	93.3%	98.2%	97.8%	90.5%
13	98.2%	86.7%	97.8%	93.3%	97.8%	93.3%	97.8%	95.6%	95.6%	97.8%	97.8%	97.8%	97.8%	97.8%	97.8%	93.3%	93.3%	98.2%	98.2%	96.1%
14	98.2%	97.3%	97.8%	93.3%	97.8%	93.3%	97.8%	97.8%	94.7%	97.3%	97.8%	97.8%	97.8%	97.8%	97.8%	93.3%	93.3%	98.2%	98.2%	96.7%
15	98.2%	97.3%	97.8%	93.3%	97.8%	93.3%	97.8%	97.8%	93.8%	97.8%	97.8%	97.8%	97.8%	97.8%	97.8%	93.3%	93.3%	98.2%	98.2%	96.7%
16	98.2%	86.7%	97.8%	93.3%	93.3%	93.3%	97.8%	97.8%	4.9%	97.3%	97.8%	97.8%	97.8%	97.8%	97.8%	93.3%	93.3%	98.2%	97.8%	91.2%
17	98.2%	86.2%	95.6%	93.3%	93.3%	93.3%	96.4%	96.0%	9.8%	93.8%	97.8%	98.2%	97.8%	97.8%	97.8%	93.3%	93.3%	98.2%	97.8%	90.9%
18	98.2%	86.2%	2.2%	93.3%	93.3%	93.3%	4.0%	11.1%	8.4%	2.7%	97.8%	98.2%	97.8%	97.8%	97.8%	93.3%	93.3%	97.3%	97.8%	71.8%
19	98.2%	86.2%	0.9%	93.3%	93.3%	93.3%	0.0%	8.9%	0.0%	2.2%	97.8%	98.2%	97.8%	97.8%	97.8%	93.3%	93.3%	98.2%	97.8%	71.0%
20	98.2%	86.2%	11.1%	93.3%	93.3%	93.3%	1.3%	8.9%	0.0%	95.6%	97.8%	98.2%	97.8%	97.8%	97.8%	93.3%	93.3%	98.2%	97.8%	76.5%
21	98.2%	97.3%	96.0%	93.3%	93.3%	93.3%	94.2%	8.9%	0.0%	97.8%	97.8%	97.8%	97.3%	97.8%	97.8%	93.3%	93.3%	97.8%	97.8%	86.5%
22	98.2%	97.8%	97.8%	93.3%	93.3%	93.3%	97.8%	10.7%	0.0%	97.3%	97.8%	97.8%	98.2%	97.8%	97.8%	93.3%	93.3%	97.8%	97.8%	86.9%
23	98.2%	97.8%	97.8%	93.3%	93.3%	93.3%	97.8%	95.6%	0.0%	96.9%	97.8%	97.8%	98.2%	97.8%	97.8%	93.3%	93.3%	97.8%	97.8%	91.3%
24	98.2%	97.8%	97.8%	93.3%	93.3%	93.3%	97.8%	97.8%	10.7%	97.8%	97.8%	97.8%	97.8%	97.8%	97.8%	93.3%	93.3%	97.8%	97.8%	92.0%
ave all hours	97.0%	94.9%	73.7%	93.3%	94.6%	93.3%	77.7%	56.8%	42.2%	69.1%	97.8%	97.9%	97.8%	97.6%	97.6%	95.2%	93.3%	96.4%	97.8%	87.6%

Crucially, the CF percentage listed is based on a winter benchmark limit of 1400 MW for the HQ Phase 2 line. As seen, on these cold days, usage rarely exceeds 1,400 MW (a few intervals show usage at as high as 100.2 percent during midday hours, but never more than 1400 MW during the critical hours). If using a different benchmark for capacity factor, or utilization – such as the maximum nominal rating of the path, 2000 MW—a capacity factor of 70 percent would represent a flow of 1,400 MW.

During other hours of the winter, flows reaching as high as 1,749 MW were seen on the HQ Phase 2 path. A number of days see many hours with flows exceeding 1,600 MW.

As shown in Table 30, the New Brunswick line should use a 67 percent capacity factor (on a base of 800 MW, or 536 MW), for the maximum flow during peak hours 6-7 PM. For peak days, a capacity factor/utilization value of 71 percent, or 568 MW should be used. The patterns can reflect the “total” column seen in Table 2 of this report.

Based on the same idea, and as seen in Table 31, the Highgate line should use a 75 percent capacity factor (on a base of 225 MW, or 168 MW), for the maximum flow during peak hours 6-7 PM. For peak days, a capacity factor/utilization value of 88 percent, or 198 MW should be used. The patterns can reflect the “total” column seen in Table 3 of this report.

As is documented in the following tables (Table 32 through Table 41), existing patterns of energy transfer over the HQ Phase II interconnection, Highgate, and the path from New Brunswick illustrate that even in the absence of winter capacity contracts for the full aggregate capacity of the interconnections, HQ imports large amounts of energy to New England during winter periods. We surmise this is due primarily to the economics of importing Canadian energy during high-priced winter periods.

Table 32. Recommendations for modeling existing paths

Imports into New England	HQ Phase II (DC)	New Brunswick (AC)	Highgate (DC)
Nominal/Max	2,000/1,400	1,000/800	225/198
Winter Design Day Max	1,400/1,190	568	198
Ave Ann Capacity Factors (from Nominal Max)	67 percent	40 percent	80 percent
Flow Patterns	Per recent history (2013/14). See monthly CF by peak/off-peak periods	Per recent history (2013/14). See monthly CF by peak/off-peak periods	Per recent history (2013/14). See monthly CF by peak/off-peak periods
Source/Comment	Historical data	Historical data / note increase in 2013/14 with Pt. Lepreau back online	Historical data

The following three tables show the utilization of the Phase II line based on data from 2011-present.

Table 33. HQ Phase II average monthly flows into New England by peak and off-peak periods (negative indicates import to New England from Quebec)

		2011	2012	2013	2014	2011-2014 Avg
Off-peak	*Jan*	-1,270	-1,237	-1,405	-1,326	-1,308
	Feb	-1,297	-1,164	-1,331	-1,304	-1,273
	Mar	-799	-1,290	-1,416	-1,344	-1,220
	Apr	-909	-1,231	-1,191	-1,241	-1,141
	May	-945	-1,015	-1,321	-1,039	-1,078
	Jun	-982	-1,164	-1,434	-1,000	-1,150
	Jul	-1,128	-1,417	-1,264	-1,096	-1,226
	Aug	-858	-1,228	-1,493	-1,282	-1,220
	Sep	-436	-1,029	-961	-1,152	-898
	Oct	-764	-1,406	-1,473		-1,202
	Nov	-657	-1,016	-1,428		-1,039
	Dec	-1,261	-1,399	-1,403		-1,355
	Off-peak Avg	-945	-1,218	-1,345	-1,198	-1,175
Peak	*Jan*	-1,371	-1,399	-1,392	-1,347	-1,377
	Feb	-1,377	-1,422	-1,337	-1,330	-1,367
	Mar	-1,333	-1,498	-1,396	-1,393	-1,404
	Apr	-1,451	-1,485	-1,470	-1,488	-1,474
	May	-1,549	-1,270	-1,476	-1,552	-1,460
	Jun	-1,495	-1,456	-1,532	-1,366	-1,462
	Jul	-1,456	-1,637	-1,354	-1,427	-1,467
	Aug	-1,348	-1,537	-1,543	-1,508	-1,483
	Sep	-813	-1,260	-1,114	-1,373	-1,138
	Oct	-1,446	-1,503	-1,531		-1,495
	Nov	-1,279	-1,294	-1,505		-1,357
	Dec	-1,459	-1,451	-1,428		-1,446
	Peak Avg	-1,364	-1,435	-1,424	-1,421	-1,410
Annual Avg		**-1,144**	**-1,321**	**-1,383**	**-1,304**	**-1,287**

Source: ISO NE SMD Interchange Data, 2011-2014. Tabulation by Synapse. Note: Peak periods are defined as weekdays, from hour-ending 8AM to hour-ending 11PM.

Table 33 shows that average monthly peak period flows during the winter are generally more than 1,300 MW even in the absence of any firm capacity commitments by HQ. The patterns show relatively high average utilization of the path.

Table 34. Maximum HQ Phase II import levels, 2011-2014 (negative indicates import to New England from Quebec)

		2011	2012	2013	2014	2011-2014 Max
Off-peak	*Jan*	-1,505	-1,662	-1,696	-1,632	-1,696
	Feb	-1,604	-1,584	-1,606	-1,647	-1,647
	Mar	-1,554	-1,652	-1,651	-1,599	-1,652
	Apr	-1,585	-1,746	-1,636	-1,619	-1,746
	May	-1,646	-1,723	-1,719	-1,670	-1,723
	Jun	-1,646	-1,737	-1,816	-1,575	-1,816
	Jul	-1,641	-1,801	-1,789	-1,622	-1,801
	Aug	-1,641	-1,745	-1,705	-1,725	-1,745
	Sep	-1,609	-1,723	-1,689	-1,731	-1,731
	Oct	-1,610	-1,853	-1,742		-1,853
	Nov	-1,629	-1,706	-2,516		-2,516
	Dec	-1,647	-1,631	-1,789		-1,789
	Off-peak Max	-1,647	-1,853	-2,516	-1,731	-2,516
Peak	*Jan*	-1,599	-1,749	-1,691	-1,648	-1,749
	Feb	-1,589	-1,701	-1,609	-1,651	-1,701
	Mar	-1,580	-1,717	-1,812	-1,626	-1,812
	Apr	-1,601	-1,746	-1,638	-1,753	-1,753
	May	-1,688	-1,736	-1,753	-1,762	-1,762
	Jun	-1,657	-1,733	-1,794	-1,677	-1,794
	Jul	-1,650	-1,842	-1,795	-1,696	-1,842
	Aug	-1,640	-1,835	-1,700	-1,738	-1,835
	Sep	-1,611	-1,796	-1,669	-1,758	-1,796
	Oct	-1,670	-1,820	-1,832		-1,832
	Nov	-1,662	-1,789	-1,716		-1,789
	Dec	-1,781	-1,613	-1,748		-1,781
	Peak Max	-1,781	-1,842	-1,832	-1,762	-1,842
Annual Max		**-1,781**	**-1,853**	**-2,516**	**-1,762**	**-2,516**

Source: ISO NE SMD Interchange Data, 2011-2014. Tabulation by Synapse

Table 34 shows that winter (December-February) period peak exports to New England have reached at least 1,781 MW (December 2011), and often reach levels that exceed 1,600 MW. Summer peak period maximums are greater than 1,800 MW.

Table 35. HQ Phase II average annual capacity factor and monthly patterns (negative indicates import to New England from Quebec)

		2011	2012	2013	2014	2011-2014 Total	2013 Capacity Factor	
							1,800 MW	*2,000 MW*
Off-peak	*Jan*	-518,228	-484,784	-528,188	-498,561	-2,029,761	83%	75%
	Feb	-456,555	-419,097	-468,643	-458,917	-1,803,212	81%	73%
	Mar	-300,602	-505,669	-577,756	-548,381	-1,932,408	91%	82%
	Apr	-349,021	-472,553	-438,207	-456,594	-1,716,375	72%	65%
	May	-370,378	-381,537	-496,738	-407,095	-1,655,748	78%	71%
	Jun	-361,193	-447,019	-573,719	-383,978	-1,765,909	95%	85%
	Jul	-460,115	-555,599	-475,306	-412,158	-1,903,178	75%	68%
	Aug	-322,589	-461,889	-585,235	-522,954	-1,892,667	92%	83%
	Sep	-160,429	-411,642	-368,944	-423,821	-1,364,836	61%	55%
	Oct	-311,590	-528,506	-553,758		-1,393,854	87%	79%
	Nov	-241,640	-373,903	-548,381		-1,163,924	91%	82%
	Dec	-494,397	-570,828	-549,972		-1,615,197	87%	78%
	Off-peak Total	-4,346,737	-5,613,026	-6,164,847	-4,112,459	-20,237,069		
Peak	*Jan*	-460,571	-492,501	-512,283	-495,529	-1,960,884	73%	65%
	Feb	-440,792	-477,634	-427,786	-425,755	-1,771,967	68%	61%
	Mar	-490,717	-527,202	-469,111	-467,890	-1,954,920	66%	60%
	Apr	-487,473	-498,927	-517,586	-523,693	-2,027,679	75%	67%
	May	-545,304	-467,396	-543,192	-546,131	-2,102,023	77%	69%
	Jun	-526,297	-489,094	-490,282	-458,953	-1,964,626	71%	64%
	Jul	-489,315	-576,230	-498,161	-525,005	-2,088,711	71%	64%
	Aug	-495,895	-565,449	-543,282	-506,760	-2,111,386	77%	69%
	Sep	-286,128	-403,348	-374,345	-483,349	-1,547,170	54%	49%
	Oct	-485,988	-553,160	-563,540		-1,602,688	80%	72%
	Nov	-450,134	-455,319	-505,708		-1,411,161	73%	66%
	Dec	-513,656	-487,483	-502,764		-1,503,903	71%	64%
	Peak Total	-5,672,270	-5,993,743	-5,948,040	-4,433,065	-22,047,118		
Annual Total		**-10,019,007**	**-11,606,769**	**-12,112,887**	**-8,545,524**	**-42,284,187**		
1,800 MW Avg CF		64%	74%	77%	72%	72%		
2,000 MW Avg CF		57%	66%	69%	65%	64%		

Source: ISO NE SMD Interchange Data, 2011-2014. Tabulation by Synapse.

Table 36. Highgate average annual flows (negative indicates import to New England from Quebec)

		2011	2012	2013	2014	2011-2014 Avg
Off-peak	*Jan*	-215	-187	-214	-211	-207
	Feb	-205	-175	-213	-216	-202
	Mar	-141	-159	-218	-206	-182
	Apr	-151	-216	-194	-120	-170
	May	-170	-129	-183	-97	-144
	Jun	-130	-159	-180	-120	-148
	Jul	-165	-183	-205	-96	-162
	Aug	-122	-158	-206	-154	-160
	Sep	-121	-126	-208	-168	-156
	Oct	-134	-20	-176		-111
	Nov	-72	-91	-215		-127
	Dec	-145	-187	-212		-182
	Off-peak Avg	-148	-150	-202	-154	-164
Peak	*Jan*	-218	-218	-219	-196	-213
	Feb	-220	-215	-217	-217	-217
	Mar	-217	-219	-220	-215	-218
	Apr	-220	-218	-215	-216	-217
	May	-199	-187	-188	-177	-188
	Jun	-179	-206	-219	-217	-205
	Jul	-212	-205	-215	-217	-212
	Aug	-209	-209	-217	-217	-213
	Sep	-207	-214	-218	-212	-213
	Oct	-169	-47	-194		-136
	Nov	-209	-99	-217		-174
	Dec	-216	-219	-218		-218
	Peak Avg	-206	-187	-213	-209	-203
Annual Avg		**-176**	**-167**	**-207**	**-180**	**-183**

Source: ISO NE SMD Interchange Data, 2011-2014. Tabulation by Synapse.

Table 37. Highgate maximum flows (negative indicates import to New England from Quebec)

		2011	2012	2013	2014	2011-2014 Max
Off-peak	*Jan*	-222	-221	-221	-221	-222
	Feb	-222	-220	-221	-222	-222
	Mar	-222	-221	-221	-222	-222
	Apr	-222	-221	-222	-221	-222
	May	-223	-220	-222	-220	-223
	Jun	-212	-221	-222	-218	-222
	Jul	-219	-221	-222	-219	-222
	Aug	-218	-221	-222	-217	-222
	Sep	-221	-221	-222	-217	-222
	Oct	-210	-219	-222		-222
	Nov	-218	-222	-418		-418
	Dec	-221	-221	-222		-222
	Off-peak Max	-223	-222	-418	-222	-418
Peak	*Jan*	-221	-221	-221	-221	-221
	Feb	-222	-221	-221	-221	-222
	Mar	-222	-222	-222	-222	-222
	Apr	-222	-221	-222	-222	-222
	May	-222	-221	-222	-220	-222
	Jun	-220	-220	-222	-218	-222
	Jul	-219	-221	-222	-218	-222
	Aug	-210	-221	-222	-218	-222
	Sep	-219	-220	-222	-218	-222
	Oct	-219	-219	-222		-222
	Nov	-220	-226	-222		-226
	Dec	-221	-221	-222		-222
	Peak Max	-222	-226	-222	-222	-226
Annual Max		**-223**	**-226**	**-418**	**-222**	**-418**

Table 38. Highgate average annual capacity factor and monthly capacity factor patterns (negative indicates import to New England from Quebec)

		2011	2012	2013	2014	2011-2014 Total	2013 CF *225 MW*
Off-peak	*Jan*	-87,742	-73,118	-80,335	-79,512	-320,707	101%
	Feb	-72,097	-62,974	-75,013	-75,965	-286,049	104%
	Mar	-53,091	-62,346	-88,913	-84,098	-288,448	112%
	Apr	-57,796	-82,906	-71,456	-44,079	-256,237	95%
	May	-66,492	-48,665	-68,698	-37,873	-221,728	87%
	Jun	-47,849	-61,063	-72,172	-46,186	-227,270	95%
	Jul	-67,278	-71,765	-76,928	-36,096	-252,067	97%
	Aug	-45,957	-59,576	-80,746	-62,638	-248,917	102%
	Sep	-44,635	-50,356	-80,053	-61,880	-236,924	106%
	Oct	-54,594	-7,428	-66,336		-128,358	84%
	Nov	-26,615	-33,415	-82,371		-142,401	109%
	Dec	-56,744	-76,490	-83,230		-216,464	105%
	Off-peak Total	-680,890	-690,102	-926,251	-528,327	-2,825,570	
Peak	*Jan*	-73,368	-76,672	-80,596	-72,306	-302,942	91%
	Feb	-70,302	-72,350	-69,524	-69,345	-281,521	88%
	Mar	-79,806	-77,239	-73,939	-72,128	-303,112	84%
	Apr	-73,806	-73,263	-75,742	-76,139	-298,950	88%
	May	-70,151	-68,744	-69,075	-62,302	-270,272	78%
	Jun	-63,041	-69,048	-69,976	-73,072	-275,137	81%
	Jul	-71,158	-72,042	-79,156	-79,825	-302,181	90%
	Aug	-77,046	-76,914	-76,515	-72,848	-303,323	87%
	Sep	-72,895	-68,405	-73,348	-74,556	-289,204	85%
	Oct	-56,889	-17,218	-71,405		-145,512	81%
	Nov	-73,708	-34,762	-72,789		-181,259	84%
	Dec	-76,177	-73,731	-76,624		-226,532	87%
	Peak Total	-858,347	-780,388	-888,689	-652,521	-3,179,945	
Annual Total		**-845,758**	**-1,539,237**	**-1,470,490**	**-1,814,940**	**-1,180,848**	
1,000 MW Avg CF		10%	78%	75%	92%	80%	

Table 39. New Brunswick average flows (negative indicates import to New England from New Brunswick)

		2011	2012	2013	2014	2011-2014 Avg
Off-peak	*Jan*	38	47	-164	-604	-164
	Feb	143	181	-408	-667	-186
	Mar	40	-37	-241	-509	-193
	Apr	-97	-253	-208	-300	-214
	May	-177	-173	-320	-111	-194
	Jun	-220	-132	-532	-191	-272
	Jul	-247	-127	-576	-400	-333
	Aug	-169	-115	-642	-371	-328
	Sep	-236	-136	-581	-309	-315
	Oct	-119	-208	-365		-228
	Nov	-29	-204	-367		-202
	Dec	-16	-121	-526		-220
	Off-peak Avg	-92	-107	-412	-382	-239
Peak	*Jan*	159	113	-118	-564	-111
	Feb	226	313	-439	-676	-139
	Mar	-22	-29	-276	-510	-203
	Apr	-127	-295	-173	-311	-227
	May	-153	-118	-487	-92	-214
	Jun	-304	-69	-531	-165	-265
	Jul	-270	-10	-677	-423	-350
	Aug	-260	-18	-673	-422	-338
	Sep	-301	49	-628	-320	-305
	Oct	-96	-186	-414		-236
	Nov	-4	-126	-349		-157
	Dec	-28	-33	-479		-183
	Peak Avg	-102	-36	-436	-386	-230
Annual Avg		**-97**	**-73**	**-424**	**-384**	**-235**

Table 40. New Brunswick maximum flows (negative indicates import to New England from New Brunswick)

		2011	2012	2013	2014	2011-2014 Max
Off-peak	*Jan*	-386	-242	-589	-808	-808
	Feb	-404	-147	-818	-802	-818
	Mar	-438	-832	-792	-801	-832
	Apr	-497	-590	-433	-648	-648
	May	-439	-600	-675	-581	-675
	Jun	-632	-512	-791	-508	-791
	Jul	-639	-600	-810	-687	-810
	Aug	-586	-424	-810	-649	-810
	Sep	-615	-369	-817	-757	-817
	Oct	-326	-449	-746		-746
	Nov	-339	-438	-738		-738
	Dec	-293	-491	-806		-806
	Off-peak Max	-639	-832	-818	-808	-832
Peak	*Jan*	-314	-270	-751	-800	-800
	Feb	-286	-81	-816	-803	-816
	Mar	-438	-803	-797	-797	-803
	Apr	-540	-665	-476	-656	-665
	May	-484	-557	-814	-649	-814
	Jun	-572	-461	-792	-505	-792
	Jul	-603	-363	-804	-676	-804
	Aug	-645	-349	-803	-675	-803
	Sep	-761	-292	-803	-728	-803
	Oct	-408	-419	-774		-774
	Nov	-374	-509	-802		-802
	Dec	-325	-474	-806		-806
	Peak Max	-761	-803	-816	-803	-816
Annual Max		**-761**	**-832**	**-818**	**-808**	**-832**

Table 41. New Brunswick average annual capacity factor and monthly patterns (negative indicates import to New England from New Brunswick)

		2011	2012	2013	2014	2011-2014 Total	2013/14 CF *1,000 MW*
Off-peak	*Jan*	15,664	18,463	-61,656	-227,137	-254,666	65%
	Feb	50,420	65,154	-143,501	-234,812	-262,739	73%
	Mar	15,128	-14,428	-98,212	-207,516	-305,028	59%
	Apr	-37,268	-97,018	-76,630	-110,556	-321,472	33%
	May	-69,352	-65,020	-120,457	-43,701	-298,530	12%
	Jun	-81,050	-50,590	-212,937	-73,395	-417,972	22%
	Jul	-100,961	-49,728	-216,497	-150,221	-517,407	43%
	Aug	-63,441	-43,325	-251,677	-151,371	-509,814	43%
	Sep	-86,764	-54,570	-222,986	-113,734	-478,054	34%
	Oct	-48,680	-78,368	-137,250		-264,298	39%
	Nov	-10,720	-74,947	-140,848		-226,515	42%
	Dec	-6,266	-49,279	-206,310		-261,855	59%
	Off-peak Total	-423,290	-493,656	-1,888,961	-1,312,443	-4,118,350	
Peak	*Jan*	53,399	39,628	-43,518	-207,549	-158,040	53%
	Feb	72,160	105,044	-140,638	-216,171	-179,605	61%
	Mar	-8,237	-10,201	-92,818	-171,496	-282,752	44%
	Apr	-42,532	-99,003	-60,803	-109,547	-311,885	29%
	May	-53,943	-43,496	-179,102	-32,261	-308,802	8%
	Jun	-107,011	-23,261	-169,792	-55,539	-355,603	14%
	Jul	-90,848	-3,372	-248,955	-155,745	-498,920	40%
	Aug	-95,778	-6,701	-236,822	-141,932	-481,233	36%
	Sep	-106,069	15,611	-211,070	-112,745	-414,273	29%
	Oct	-32,221	-68,300	-152,221		-252,742	39%
	Nov	-1,465	-44,479	-117,427		-163,371	31%
	Dec	-9,923	-11,158	-168,727		-189,808	43%
	Peak Total	-422,468	-149,688	-1,821,893	-1,202,985	-3,597,034	
Annual Total		**-845,758**	**-643,344**	**-3,710,854**	**-2,515,428**	**-7,715,384**	
1,000 MW Avg CF		10%	7%	42%	38%	23%	

Additional figures and data below illustrate the patterns of Canadian flow to New England during the cold snap week in early January, 2014, along with power prices and system load on January 7, 2014.

Figure 21. Canadian imports to New England, week of January 2, 2014 (negative numbers represent imports to New England from Canada)

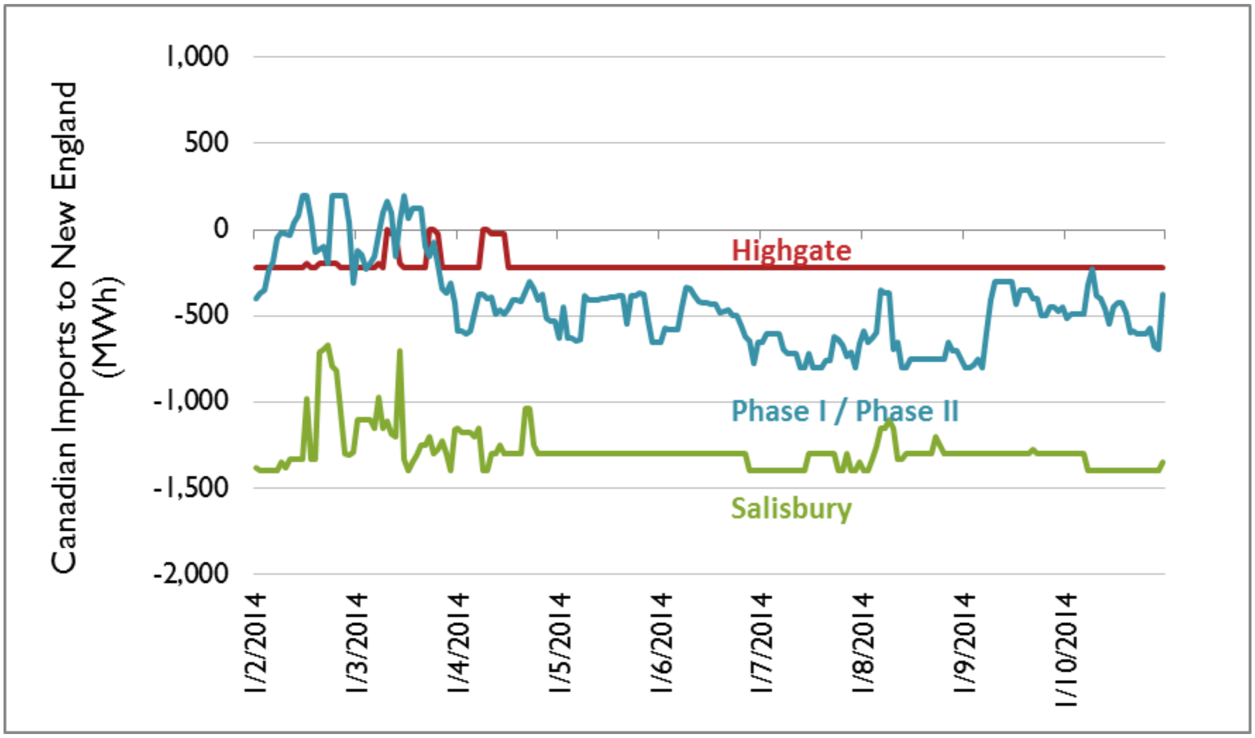


Figure 22. Canadian imports to New England, week of January 2, 2014 (negative numbers represent imports to New England from Canada)

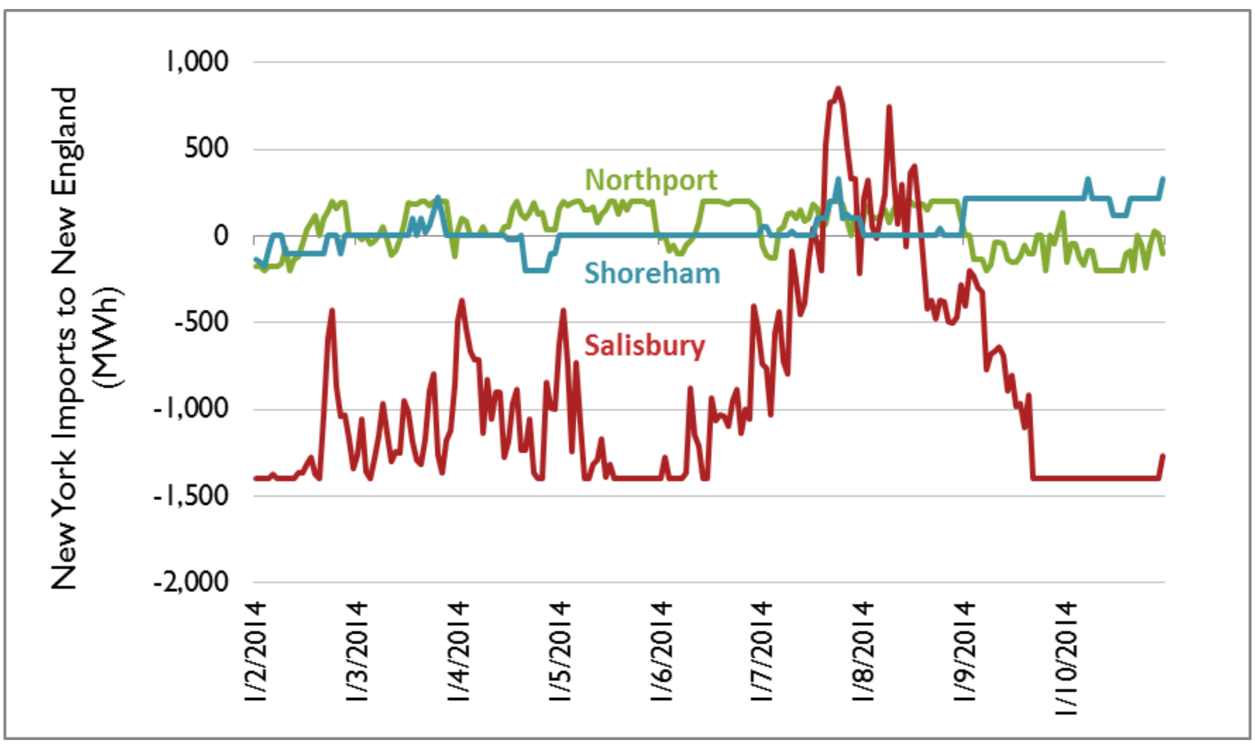


Figure 23. ISO-NE system load, January 7, 2014

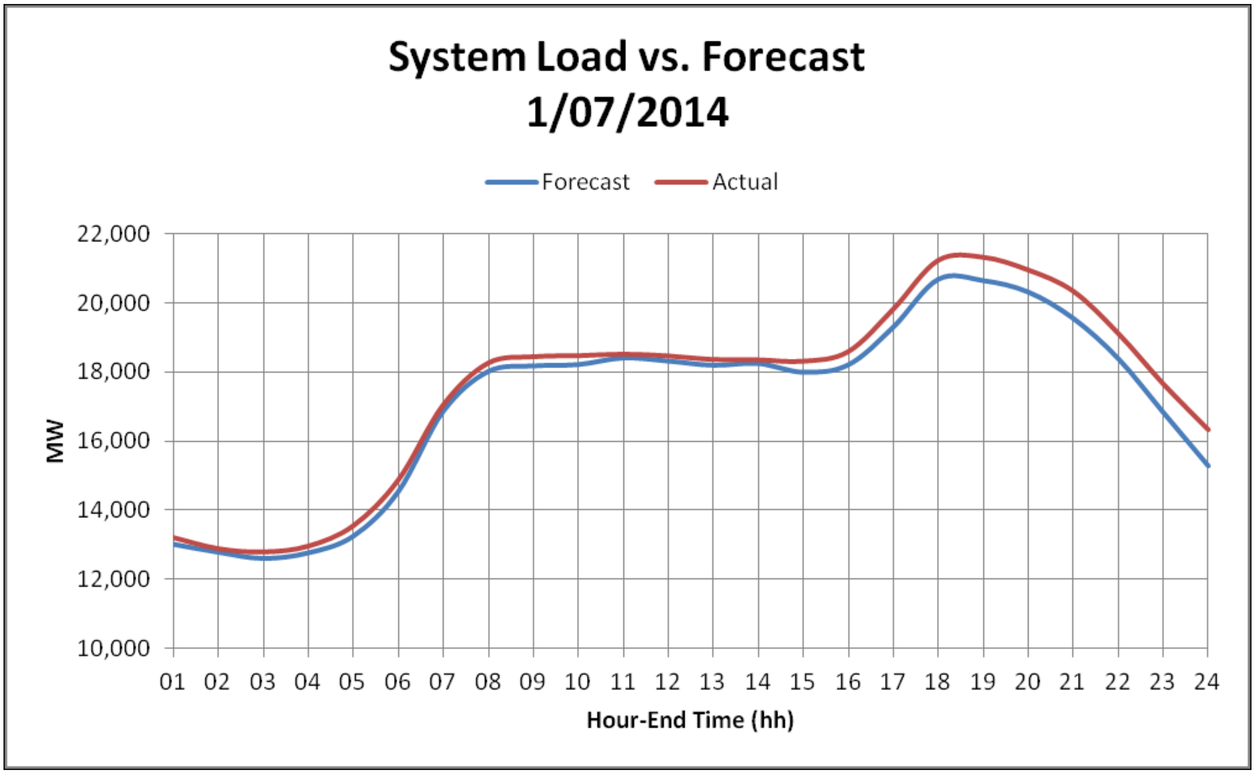


Figure 24. HQ Interface prices, cold snap period, January 2014

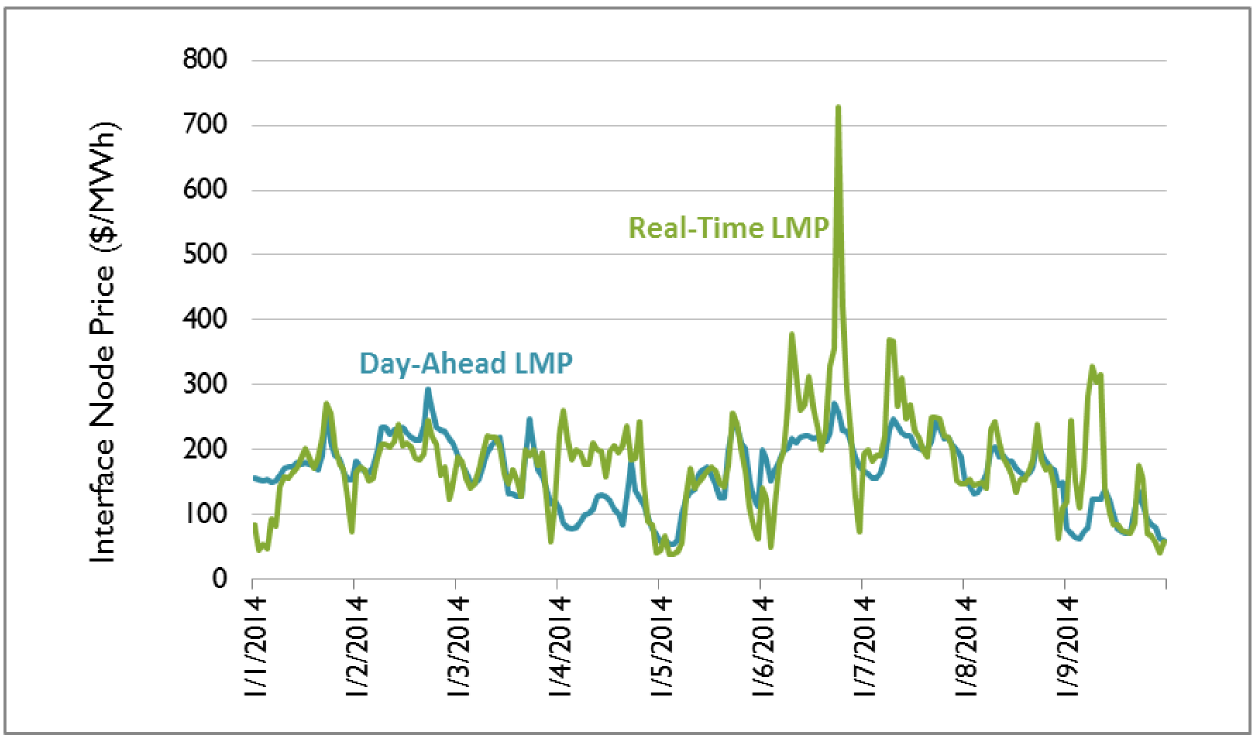


Table 42. Modeling recommendations on new transmission to New England

Imports into New England	Generic HVDC 1	Generic HVDC 2	HQ Phase II Expand to Max Rating
Model Cases	Canadian transmission only	Canadian transmission only	Canadian transmission only
Nominal/Max	1,100	1,100	200
Summer Max	1,100	1,100	200
Winter Peak Day MW	1,100	1,100	200
Year Available	2018	2022	2020
Comments/Source	Generic "baseloaded" import	Generic intermediate import	Increase – for extreme peak periods only – after New York upstate upgrades complete
Flow Patterns	TBD	TBD	TBD
Avg Ann CF	.67	.5	Available only on extreme peak days

Table 42 lists the two recommended new Canadian transmission sources for the incremental Canadian transmission sensitivity run, totaling 2,200 MW, plus an assumption that the Phase II facility will be able to operate at its maximum rating by 2020. Synapse assumes one new line will be available by 2018, and a second by 2022, in our sensitivity for new Canadian transmission.

1) The two generic lines represent any of a number of possible Canadian generation source points, through Maine, New Hampshire, Vermont, or possibly even Connecticut paths. They are based on the same information available to Synapse in November 2013. See data in Table 43, taken from the November 1, 2013 Memo to MA DOER.

2) The incremental Phase II capacity is based in part on the observations in ISO NE's "2013 Draft Economic Study" which looked at the production cost and emissions impacts of various configurations that would increase the Phase II limits up to the maximum 2,000 MW equipment ratings. Also, we note that ongoing proceedings in New York State indicate that by 2020, there is likely to be substantial upgrade of the major west-to-east constrained paths in upstate New York that contribute to the loss-of-source contingency event limitations on Phase II.

3) We note that the total of the Phase II and the generic new lines results in a total incremental Canadian transmission capacity to New England of 2,400 MW on peak days when New England pricing allows increased flows, in the Canadian transmission sensitivity.

Table 43. From Table A-1, Synapse 11/1/13 Memo, Expanded potential transmission paths, new projects

Route / Path	VT Route / overland + submarine	ME Route 1 / overland	ME Route 2 / overland + submarine	NH Route / Northern Pass	CHPE II / submarine
Proxy	Clean energy express	Northeast Energy Link	Green Line	Northern Pass	
Capacity (MW)	1,000	1,100	1,000	1,200	1,000
Estimated Capital Costs (2013 $ B)	$1.50	$2.20	$2.50	$1.40	$2.00
Cost Normalized to 1200 MW (2013 $ B)	$1.80	$2.40	$3.00	$1.40	
Injection	Canada-VT border	Orrington	Orrington / ME Yankee	NH-VT border	CT via submarine path from QC
Terminus	VT - 345 kV Southern	MA - Tewksbury	MA - Boston	NH - 345 kV Deerfield	
Project Developer Estimated In-Service date	2019	2016	NA	2016	
Synapse modeling In-Service date	2018	2020	2022	2015	
Project Type	New	New	New	New	New
Energy Sources					

Other source material:

4) CRA report for Northern Pass assumes full 1,200 MW import on winter peak day (http://northernpass.us/assets/permits-and-approvals/FERC_TSA_Filing_CharlesRiverAssoc_analysis.pdf, page 33)

5) Northern Pass amended application to US DOE 1200 MW baseload power, Page 1, Page 73[67]

6) TDI Clean Power Express, application to US DOE for presidential permit, 1,000 MW. No statement on baseload, or CF.

[67] United States of America before the Department of Energy Office of Electricity Delivery and Energy Reliability Northern Pass Transmission LLC Docket No. PP-371 Amended Application July 1, 2013

Also, we note that a new line from Canada of roughly 1,100 MW will result in a range of energy transfer up to as much as 8.4 TWh into New England. However, the total transfer could be only roughly half that amount if the line is operated in more of an "intermediate" than a "baseload" mode. Two lines will lead to an increase in imports of potentially twice those amounts. Table 44 documents the increases in Canadian exports that would be required to accommodate operation of these lines at the utilization levels listed in the table.

Table 44. Estimate of total annual energy from imports from new sources, given (TWh)

		Avg Annual Capacity Factor		
		50%	**67%**	**80%**
Line Capacity (MW)	**1,000**	4.4	5.9	7.0
	1,100	4.8	6.5	7.7
	1,200	5.3	7.0	8.4

APPENDIX F: DETAILED PRELIMINARY MODEL RESULTS

See the next eight pages for detailed model results for each scenario.

Scenario 1: Base Case - Reference Gas Price - No Hydro

This scenario requires a pipeline.

Peak Hour

Billion NG Btu per Hour	Heating Demand			Heating Balancing		Heating Delta		Non-Contracted Demand		Non-Contracted Balancing					Non-Contracted Delta	
	LDCs, Munis, Capacity Exempt	*Gas EE*	*Gas Reduction Measures*	*Existing Pipeline Capacity*	*Existing LDC Vaporization*	*Supply less Demand*	*Demand as a % of Supply*	*Heating Demand Shortage*	*MA Electric System*	*Existing Distrigas Vaporization*	*Mystic LNG Injection*	*Demand Response*	*Winter Reliability*	*Incremental Pipeline*	*Supply less Demand*	*Demand as a % of Supply*
2015	157	-8	-7	86	37	-19	116%	19	14	19	12	0.1	4		2	95%
2016	160	-9	-8	100	37	-6	104%	6	14	19	12				11	63%
2017	162	-11	-9	100	37	-6	104%	6	12	19	12				13	59%
2018	165	-12	-10	100	37	-6	105%	6	23	19	12				2	95%
2019	168	-13	-11	100	37	-7	105%	7	20	19	12				5	85%
2020	169	-14	-12	100	37	-6	104%	6	54	19	12			33	5	92%
2021	169	-15	-13	100	37	-5	104%	5	52	19	12			33	8	88%
2022	170	-15	-14	100	37	-4	103%	4	52	19	12			33	8	87%
2023	171	-16	-15	100	37	-4	103%	4	53	19	12			33	8	88%
2024	172	-16	-16	100	37	-3	102%	3	55	19	12			33	6	90%
2025	173	-17	-16	100	37	-3	102%	3	53	19	12			33	8	87%
2026	174	-17	-17	100	37	-2	102%	2	53	19	12			33	9	86%
2027	174	-17	-18	100	37	-2	102%	2	56	19	12			33	6	90%
2028	175	-18	-19	100	37	-2	101%	2	60	19	12			38	7	90%
2029	176	-18	-20	100	37	-2	101%	2	60	19	12			38	7	90%
2030	177	-18	-21	100	37	-2	101%	2	61	19	12			38	6	92%

Annual

Trillion NG Btu per Year	Heating Demand			Non-Contracted		Total
	LDCs, Munis, Capacity Exempt	*Gas EE*	*Gas Reduction Measures*	*MA Electric System*	*Winter Reliability*	
2015	262	-15	-12	181	0	417
2016	267	-17	-14	185	0	421
2017	270	-20	-15	200	0	435
2018	274	-22	-17	199	0	434
2019	278	-24	-19	205	0	440
2020	279	-26	-21	256	0	489
2021	280	-27	-22	247	0	478
2022	282	-28	-23	233	0	463
2023	283	-29	-25	236	0	465
2024	284	-30	-26	248	0	477
2025	286	-31	-27	254	0	482
2026	287	-31	-29	255	0	482
2027	289	-32	-30	254	0	480
2028	290	-32	-32	270	0	496
2029	291	-32	-33	274	0	500
2030	293	-32	-34	261	0	487

Million Metric Tons CO2 per Year	Heating Demand			Non-Contracted		Total	GWSA Emissions	
	LDCs, Munis, Capacity Exempt	*Gas EE*	*Gas Reduction Measures*	*MA Electric Inventory*	*Winter Reliability*		*Maximum allowable for complicance*	*Compliant?*
2015	14	-1	-1	18	0	31	-	-
2016	14	-1	-1	18	0	31	-	-
2017	14	-1	-1	18	0	30	-	-
2018	14	-1	-1	17	0	29	-	-
2019	15	-1	-1	17	0	30	-	-
2020	15	-1	-1	17	0	29	23	No
2021	15	-1	-1	17	0	29	-	-
2022	15	-1	-1	17	0	29	-	-
2023	15	-2	-1	17	0	29	-	-
2024	15	-2	-1	17	0	29	-	-
2025	15	-2	-1	17	0	29	-	-
2026	15	-2	-2	17	0	29	-	-
2027	15	-2	-2	17	0	29	-	-
2028	15	-2	-2	17	0	29	-	-
2029	15	-2	-2	17	0	29	-	-
2030	16	-2	-2	17	0	29	19	No

2013 $ M per Year	"Total" Costs										"Delta" Costs				Delta Costs from Base
	LDCs, Munis, Capacity Exempt	*Gas EE*	*Electric EE PA*	*TVR*	*Avoided Price Spikes*	*Incremental Pipeline*	*MA Electric System*	*Demand Response*	*Winter Reliability*	*Total*	*Gas Reduction Measures*	*Low Demand Resources Capital*	*Other Resouces Capital*	*Total*	
2015	$873	$138	$507	$97	$0	$0	$2,181	$0	$12	$3,808	$0	$0		$0	
2016	$971	$158	$577	$0	$0	$0	$2,300	$0	$0	$4,007	$0	$0		$0	
2017	$1,024	$181	$641	$0	$0	$0	$2,239	$0	$0	$4,086	$0	$0		$0	
2018	$1,117	$199	$695	$0	$0	$0	$2,290	$0	$0	$4,301	$0	$0		$0	
2019	$1,085	$215	$737	$0	$0	$0	$2,272	$0	$0	$4,309	$0	$0		$0	
2020	$1,013	$232	$775	$0	-$3,479	$40	$2,089	$0	$0	$670	$0	$0		$0	
2021	$1,069	$244	$811	$0	-$3,430	$40	$2,127	$0	$0	$860	$0	$0		$0	
2022	$1,098	$253	$844	$0	-$3,321	$40	$2,204	$0	$0	$1,118	$0	$0		$0	
2023	$1,125	$257	$874	$0	-$3,327	$40	$2,287	$0	$0	$1,257	$0	$0		$0	
2024	$1,162	$263	$901	$0	-$3,481	$40	$2,334	$0	$0	$1,219	$0	$0		$0	
2025	$1,180	$269	$923	$97	-$3,440	$40	$2,403	$0	$0	$1,471	$0	$0		$0	
2026	$1,205	$274	$943	$0	-$3,460	$40	$2,484	$0	$0	$1,485	$0	$0		$0	
2027	$1,231	$277	$961	$0	-$3,477	$40	$2,546	$0	$0	$1,578	$0	$0		$0	
2028	$1,258	$281	$973	$0	-$3,579	$45	$2,653	$0	$0	$1,630	$0	$0		$0	
2029	$1,293	$283	$984	$0	-$3,597	$45	$2,773	$0	$0	$1,780	$0	$0		$0	
2030	$1,350	$284	$997	$0	-$3,575	$45	$2,855	$0	$0	$1,956	$0	$0		$0	

Scenario 2: Base Case - Low Gas Price - No Hydro

This scenario requires a pipeline.

Peak Hour

Billion NG Btu per Hour	Heating Demand			Heating Balancing		Heating Delta		Non-Contracted Demand		Non-Contracted Balancing					Non-Contracted Delta	
	LDCs, Munis, Capacity Exempt	*Gas EE*	*Gas Reduction Measures*	*Existing Pipeline Capacity*	*Existing LDC Vaporization*	*Supply less Demand*	*Demand as a % of Supply*	*Heating Demand Shortage*	*MA Electric System*	*Existing Distrigas Vaporization*	*Mystic LNG Injection*	*Demand Response*	*Winter Reliability*	*Incremental Pipeline*	*Supply less Demand*	*Demand as a % of Supply*
2015	157	-8	-7	86	37	-19	116%	19	14	19	12	0.1	4		2	95%
2016	160	-9	-8	100	37	-6	104%	6	14	19	12				11	63%
2017	162	-11	-9	100	37	-6	104%	6	12	19	12				13	59%
2018	165	-12	-10	100	37	-6	105%	6	23	19	12				2	95%
2019	168	-13	-11	100	37	-7	105%	7	20	19	12				5	85%
2020	169	-14	-12	100	37	-6	104%	6	54	19	12			33	5	92%
2021	169	-15	-13	100	37	-5	104%	5	52	19	12			33	7	89%
2022	170	-15	-14	100	37	-4	103%	4	52	19	12			33	8	87%
2023	171	-16	-15	100	37	-4	103%	4	54	19	12			33	7	89%
2024	172	-16	-16	100	37	-3	102%	3	55	19	12			38	10	85%
2025	173	-17	-16	100	37	-3	102%	3	54	19	12			38	12	83%
2026	174	-17	-17	100	37	-2	102%	2	54	19	12			38	12	82%
2027	174	-17	-18	100	37	-2	102%	2	56	19	12			38	10	85%
2028	175	-18	-19	100	37	-2	101%	2	60	19	12			38	7	90%
2029	176	-18	-20	100	37	-2	101%	2	61	19	12			38	6	91%
2030	177	-18	-21	100	37	-2	101%	2	61	19	12			38	6	92%

Annual

Trillion NG Btu per Year	Heating Demand			Non-Contracted		Total
	LDCs, Munis, Capacity Exempt	*Gas EE*	*Gas Reduction Measures*	*MA Electric System*	*Winter Reliability*	
2015	262	-15	-12	192	0	427
2016	267	-17	-14	195	0	431
2017	270	-20	-15	200	0	435
2018	274	-22	-17	199	0	434
2019	278	-24	-19	205	0	440
2020	279	-26	-21	291	0	523
2021	280	-27	-22	303	0	534
2022	282	-28	-23	300	0	530
2023	283	-29	-25	299	0	528
2024	284	-30	-26	295	0	524
2025	286	-31	-27	297	0	524
2026	287	-31	-29	299	0	526
2027	289	-32	-30	296	0	523
2028	290	-32	-32	296	0	522
2029	291	-32	-33	297	0	523
2030	293	-32	-34	294	0	520

Million Metric Tons CO2 per Year	Heating Demand			Non-Contracted		Total	GWSA Emissions	
	LDCs, Munis, Capacity Exempt	*Gas EE*	*Gas Reduction Measures*	*MA Electric Inventory*	*Winter Reliability*		*Maximum allowable for complicance*	*Compliant?*
2015	14	-1	-1	18	0	31	-	-
2016	14	-1	-1	18	0	31	-	-
2017	14	-1	-1	18	0	30	-	-
2018	14	-1	-1	17	0	29	-	-
2019	15	-1	-1	17	0	30	-	-
2020	15	-1	-1	17	0	29	23	No
2021	15	-1	-1	17	0	29	-	-
2022	15	-1	-1	17	0	29	-	-
2023	15	-2	-1	17	0	29	-	-
2024	15	-2	-1	17	0	29	-	-
2025	15	-2	-1	17	0	29	-	-
2026	15	-2	-2	17	0	29	-	-
2027	15	-2	-2	17	0	29	-	-
2028	15	-2	-2	17	0	29	-	-
2029	15	-2	-2	17	0	29	-	-
2030	16	-2	-2	17	0	29	19	No

2013 $ M per Year	"Total" Costs										"Delta" Costs				Delta Costs from Base
	LDCs, Munis, Capacity Exempt	*Gas EE*	*Electric EE PA*	*TVR*	*Avoided Price Spikes*	*Incremental Pipeline*	*MA Electric System*	*Demand Response*	*Winter Reliability*	*Total*	*Gas Reduction Measures*	*Low Demand Resources Capital*	*Other Resouces Capital*	*Total*	
2015	$873	$138	$507	$97	$0	$0	$1,770	$0	$12	$3,397	$0	$0		$0	-$411
2016	$957	$158	$577	$0	$0	$0	$1,850	$0	$0	$3,542	$0	$0		$0	-$464
2017	$952	$181	$641	$0	$0	$0	$2,239	$0	$0	$4,014	$0	$0		$0	-$72
2018	$1,002	$199	$695	$0	$0	$0	$2,290	$0	$0	$4,186	$0	$0		$0	-$115
2019	$974	$215	$737	$0	$0	$0	$2,272	$0	$0	$4,198	$0	$0		$0	-$111
2020	$909	$232	$775	$0	-$3,479	$40	$1,694	$0	$0	$171	$0	$0		$0	-$499
2021	$922	$244	$811	$0	-$3,430	$40	$1,696	$0	$0	$281	$0	$0		$0	-$578
2022	$937	$253	$844	$0	-$3,321	$40	$1,720	$0	$0	$473	$0	$0		$0	-$645
2023	$953	$257	$874	$0	-$3,327	$40	$1,767	$0	$0	$565	$0	$0		$0	-$692
2024	$972	$263	$901	$0	-$3,481	$45	$1,798	$0	$0	$497	$0	$0		$0	-$722
2025	$982	$269	$923	$97	-$3,440	$45	$1,852	$0	$0	$728	$0	$0		$0	-$743
2026	$995	$274	$943	$0	-$3,460	$45	$1,897	$0	$0	$693	$0	$0		$0	-$791
2027	$1,009	$277	$961	$0	-$3,477	$45	$1,931	$0	$0	$746	$0	$0		$0	-$832
2028	$1,025	$281	$973	$0	-$3,579	$45	$1,961	$0	$0	$706	$0	$0		$0	-$925
2029	$1,033	$283	$984	$0	-$3,597	$45	$1,976	$0	$0	$724	$0	$0		$0	-$1,055
2030	$1,045	$284	$997	$0	-$3,575	$45	$2,033	$0	$0	$829	$0	$0		$0	-$1,127

Scenario 3: Base Case - High Gas Price - No Hydro

This scenario requires a pipeline.

Peak Hour

Billion NG Btu per Hour	Heating Demand			Heating Balancing		Heating Delta		Non-Contracted Demand		Non-Contracted Balancing					Non-Contracted Delta	
	LDCs, Munis, Capacity Exempt	*Gas EE*	*Gas Reduction Measures*	*Existing Pipeline Capacity*	*Existing LDC Vaporization*	*Supply less Demand*	*Demand as a % of Supply*	*Heating Demand Shortage*	*MA Electric System*	*Existing Distrigas Vaporization*	*Mystic LNG Injection*	*Demand Response*	*Winter Reliability*	*Incremental Pipeline*	*Supply less Demand*	*Demand as a % of Supply*
2015	157	-8	-7	86	37	-19	116%	19	14	19	12	0.1	4		2	95%
2016	160	-9	-8	100	37	-6	104%	6	14	19	12				11	63%
2017	162	-11	-9	100	37	-6	104%	6	12	19	12				13	59%
2018	165	-12	-10	100	37	-6	105%	6	23	19	12				2	95%
2019	168	-13	-11	100	37	-7	105%	7	19	19	12				5	85%
2020	169	-14	-12	100	37	-6	104%	6	52	19	12			33	7	90%
2021	169	-15	-13	100	37	-5	104%	5	52	19	12			33	8	88%
2022	170	-15	-14	100	37	-4	103%	4	51	19	12			33	9	85%
2023	171	-16	-15	100	37	-4	103%	4	52	19	12			33	9	86%
2024	172	-16	-16	100	37	-3	102%	3	54	19	12			33	7	89%
2025	173	-17	-16	100	37	-3	102%	3	53	19	12			33	8	87%
2026	174	-17	-17	100	37	-2	102%	2	53	19	12			33	9	86%
2027	174	-17	-18	100	37	-2	102%	2	52	19	12			33	10	84%
2028	175	-18	-19	100	37	-2	101%	2	56	19	12			33	6	90%
2029	176	-18	-20	100	37	-2	101%	2	60	19	12			38	7	90%
2030	177	-18	-21	100	37	-2	101%	2	57	19	12			38	10	86%

Annual

Trillion NG Btu per Year	Heating Demand			Non-Contracted		Total
	LDCs, Munis, Capacity Exempt	*Gas EE*	*Gas Reduction Measures*	*MA Electric System*	*Winter Reliability*	
2015	262	-15	-12	182	0	417
2016	267	-17	-14	187	0	423
2017	270	-20	-15	195	0	430
2018	274	-22	-17	196	0	431
2019	278	-24	-19	201	0	436
2020	279	-26	-21	251	0	484
2021	280	-27	-22	242	0	473
2022	282	-28	-23	227	0	457
2023	283	-29	-25	229	0	458
2024	284	-30	-26	241	0	469
2025	286	-31	-27	244	0	471
2026	287	-31	-29	241	0	468
2027	289	-32	-30	238	0	465
2028	290	-32	-32	256	0	482
2029	291	-32	-33	258	0	484
2030	293	-32	-34	244	0	470

Million Metric Tons CO2 per Year	Heating Demand			Non-Contracted		Total	GWSA Emissions	
	LDCs, Munis, Capacity Exempt	*Gas EE*	*Gas Reduction Measures*	*MA Electric Inventory*	*Winter Reliability*		*Maximum allowable for complicance*	*Compliant?*
2015	14	-1	-1	18	0	31	-	-
2016	14	-1	-1	18	0	31	-	-
2017	14	-1	-1	18	0	30	-	-
2018	14	-1	-1	17	0	29	-	-
2019	15	-1	-1	17	0	30	-	-
2020	15	-1	-1	17	0	29	23	No
2021	15	-1	-1	17	0	29	-	-
2022	15	-1	-1	17	0	29	-	-
2023	15	-2	-1	17	0	29	-	-
2024	15	-2	-1	17	0	29	-	-
2025	15	-2	-1	17	0	29	-	-
2026	15	-2	-2	17	0	29	-	-
2027	15	-2	-2	17	0	29	-	-
2028	15	-2	-2	17	0	29	-	-
2029	15	-2	-2	17	0	29	-	-
2030	16	-2	-2	17	0	29	19	No

2013 $ M per Year	"Total" Costs										"Delta" Costs				Delta Costs from Base
	LDCs, Munis, Capacity Exempt	*Gas EE*	*Electric EE PA*	*TVR*	*Avoided Price Spikes*	*Incremental Pipeline*	*MA Electric System*	*Demand Response*	*Winter Reliability*	*Total*	*Gas Reduction Measures*	*Low Demand Resources Capital*	*Other Resouces Capital*	*Total*	
2015	$873	$138	$507	$97	$0	$0	$2,181	$0	$12	$3,808	$0	$0		$0	$0
2016	$985	$158	$577	$0	$0	$0	$2,312	$0	$0	$4,033	$0	$0		$0	$26
2017	$1,072	$181	$641	$0	$0	$0	$2,338	$0	$0	$4,233	$0	$0		$0	$147
2018	$1,120	$199	$695	$0	$0	$0	$2,389	$0	$0	$4,403	$0	$0		$0	$102
2019	$1,133	$215	$737	$0	$0	$0	$2,407	$0	$0	$4,492	$0	$0		$0	$183
2020	$1,159	$232	$775	$0	-$3,479	$40	$2,231	$0	$0	$958	$0	$0		$0	$289
2021	$1,206	$244	$811	$0	-$3,430	$40	$2,249	$0	$0	$1,119	$0	$0		$0	$259
2022	$1,268	$253	$844	$0	-$3,321	$40	$2,354	$0	$0	$1,439	$0	$0		$0	$321
2023	$1,330	$257	$874	$0	-$3,327	$40	$2,466	$0	$0	$1,640	$0	$0		$0	$383
2024	$1,397	$263	$901	$0	-$3,481	$40	$2,528	$0	$0	$1,647	$0	$0		$0	$428
2025	$1,478	$269	$923	$97	-$3,440	$40	$2,653	$0	$0	$2,019	$0	$0		$0	$548
2026	$1,546	$274	$943	$0	-$3,460	$40	$2,766	$0	$0	$2,108	$0	$0		$0	$624
2027	$1,605	$277	$961	$0	-$3,477	$40	$2,847	$0	$0	$2,253	$0	$0		$0	$675
2028	$1,665	$281	$973	$0	-$3,579	$40	$2,988	$0	$0	$2,368	$0	$0		$0	$738
2029	$1,697	$283	$984	$0	-$3,597	$45	$3,118	$0	$0	$2,530	$0	$0		$0	$750
2030	$1,750	$284	$997	$0	-$3,575	$45	$3,180	$0	$0	$2,680	$0	$0		$0	$724

Scenario 4: Base Case - Reference Gas Price - Hydro

This scenario requires a pipeline.

Peak Hour

Billion NG Btu per Hour	Heating Demand			Heating Balancing		Heating Delta		Non-Contracted Demand		Non-Contracted Balancing					Non-Contracted Delta	
	LDCs, Munis, Capacity Exempt	*Gas EE*	*Gas Reduction Measures*	*Existing Pipeline Capacity*	*Existing LDC Vaporization*	*Supply less Demand*	*Demand as a % of Supply*	*Heating Demand Shortage*	*MA Electric System*	*Existing Distrigas Vaporization*	*Mystic LNG Injection*	*Demand Response*	*Winter Reliability*	*Incremental Pipeline*	*Supply less Demand*	*Demand as a % of Supply*
2015	157	-8	-7	86	37	-19	116%	19	14	19	12	0.1	4		2	95%
2016	160	-9	-8	100	37	-6	104%	6	14	19	12				11	63%
2017	162	-11	-9	100	37	-6	104%	6	12	19	12				13	59%
2018	165	-12	-10	100	37	-6	105%	6	21	19	12				4	87%
2019	168	-13	-11	100	37	-7	105%	7	16	19	12				8	74%
2020	169	-14	-12	100	37	-6	104%	6	53	19	12			33	6	91%
2021	169	-15	-13	100	37	-5	104%	5	52	19	12			33	8	88%
2022	170	-15	-14	100	37	-4	103%	4	51	19	12			33	10	85%
2023	171	-16	-15	100	37	-4	103%	4	46	19	12			33	15	76%
2024	172	-16	-16	100	37	-3	102%	3	51	19	12			33	10	85%
2025	173	-17	-16	100	37	-3	102%	3	51	19	12			33	11	83%
2026	174	-17	-17	100	37	-2	102%	2	53	19	12			33	9	86%
2027	174	-17	-18	100	37	-2	102%	2	48	19	12			33	14	78%
2028	175	-18	-19	100	37	-2	101%	2	52	19	12			33	10	84%
2029	176	-18	-20	100	37	-2	101%	2	54	19	12			33	9	87%
2030	177	-18	-21	100	37	-2	101%	2	52	19	12			33	11	84%

Annual

Trillion NG Btu per Year	Heating Demand			Non-Contracted		Total
	LDCs, Munis, Capacity Exempt	*Gas EE*	*Gas Reduction Measures*	*MA Electric System*	*Winter Reliability*	
2015	262	-15	-12	181	0	417
2016	267	-17	-14	185	0	421
2017	270	-20	-15	197	0	432
2018	274	-22	-17	177	0	412
2019	278	-24	-19	185	0	420
2020	279	-26	-21	232	0	465
2021	280	-27	-22	222	0	454
2022	282	-28	-23	192	0	421
2023	283	-29	-25	196	0	425
2024	284	-30	-26	213	0	441
2025	286	-31	-27	217	0	444
2026	287	-31	-29	217	0	444
2027	289	-32	-30	217	0	443
2028	290	-32	-32	233	0	459
2029	291	-32	-33	237	0	463
2030	293	-32	-34	228	0	454

Million Metric Tons CO_2 per Year	Heating Demand			Non-Contracted		Total	GWSA Emissions	
	LDCs, Munis, Capacity Exempt	*Gas EE*	*Gas Reduction Measures*	*MA Electric Inventory*	*Winter Reliability*		*Maximum allowable for complicance*	*Compliant?*
2015	14	-1	-1	18	0	31	-	-
2016	14	-1	-1	18	0	31	-	-
2017	14	-1	-1	18	0	30	-	-
2018	14	-1	-1	15	0	27	-	-
2019	15	-1	-1	15	0	27	-	-
2020	15	-1	-1	15	0	27	23	No
2021	15	-1	-1	15	0	27	-	-
2022	15	-1	-1	13	0	25	-	-
2023	15	-2	-1	13	0	25	-	-
2024	15	-2	-1	13	0	25	-	-
2025	15	-2	-1	13	0	25	-	-
2026	15	-2	-2	13	0	25	-	-
2027	15	-2	-2	13	0	25	-	-
2028	15	-2	-2	13	0	25	-	-
2029	15	-2	-2	13	0	25	-	-
2030	16	-2	-2	13	0	25	19	No

2013 $ M per Year	"Total" Costs										"Delta" Costs				Delta Costs from Base
	LDCs, Munis, Capacity Exempt	*Gas EE*	*Electric EE PA*	*TVR*	*Avoided Price Spikes*	*Incremental Pipeline*	*MA Electric System*	*Demand Response*	*Winter Reliability*	*Total*	*Gas Reduction Measures*	*Low Demand Resources Capital*	*Other Resouces Capital*	*Total*	
2015	$873	$138	$507	$97	$0	$0	$2,181	$0	$12	$3,808	$0	$0		$0	$0
2016	$971	$158	$577	$0	$0	$0	$2,300	$0	$0	$4,007	$0	$0		$0	$0
2017	$1,024	$181	$641	$0	$0	$0	$2,298	$0	$0	$4,145	$0	$0		$0	$59
2018	$1,117	$199	$695	$0	$0	$0	$2,210	$0	$0	$4,221	$0	$0	$129	$129	$49
2019	$1,085	$215	$737	$0	$0	$0	$2,192	$0	$0	$4,229	$0	$0	$129	$129	$49
2020	$1,013	$232	$775	$0	-$3,479	$40	$1,989	$0	$0	$570	$0	$0	$129	$129	$29
2021	$1,069	$244	$811	$0	-$3,430	$40	$2,014	$0	$0	$747	$0	$0	$129	$129	$16
2022	$1,098	$253	$844	$0	-$3,321	$40	$2,000	$0	$0	$914	$0	$0	$318	$318	$114
2023	$1,125	$257	$874	$0	-$3,327	$40	$2,076	$0	$0	$1,046	$0	$0	$318	$318	$107
2024	$1,162	$263	$901	$0	-$3,481	$40	$2,116	$0	$0	$1,001	$0	$0	$318	$318	$99
2025	$1,180	$269	$923	$97	-$3,440	$40	$2,177	$0	$0	$1,245	$0	$0	$318	$318	$92
2026	$1,205	$274	$943	$0	-$3,460	$40	$2,250	$0	$0	$1,251	$0	$0	$318	$318	$84
2027	$1,231	$277	$961	$0	-$3,477	$40	$2,307	$0	$0	$1,339	$0	$0	$318	$318	$78
2028	$1,258	$281	$973	$0	-$3,579	$40	$2,404	$0	$0	$1,377	$0	$0	$318	$318	$64
2029	$1,293	$283	$984	$0	-$3,597	$40	$2,520	$0	$0	$1,522	$0	$0	$318	$318	$60
2030	$1,350	$284	$997	$0	-$3,575	$40	$2,589	$0	$0	$1,685	$0	$0	$318	$318	$47

Scenario 5: Low Demand Case - Reference Gas Price - No Hydro

This scenario requires a pipeline.

Peak Hour

Billion NG Btu per Hour	Heating Demand			Heating Balancing		Heating Delta		Non-Contracted Demand		Non-Contracted Balancing					Non-Contracted Delta	
	LDCs, Munis, Capacity Exempt	*Gas EE*	*Gas Reduction Measures*	*Existing Pipeline Capacity*	*Existing LDC Vaporization*	*Supply less Demand*	*Demand as a % of Supply*	*Heating Demand Shortage*	*MA Electric System*	*Existing Distrigas Vaporization*	*Mystic LNG Injection*	*Demand Response*	*Winter Reliability*	*Incremental Pipeline*	*Supply less Demand*	*Demand as a % of Supply*
2015	157	-8	-7	86	37	-19	116%	19	14	19	12	0.6	4		2	95%
2016	160	-10	-8	100	37	-4	103%	4	14	19	12				13	59%
2017	162	-13	-9	100	37	-4	103%	4	12	19	12				15	52%
2018	165	-15	-10	100	37	-4	103%	4	23	19	12				5	84%
2019	168	-17	-11	100	37	-3	102%	3	16	19	12				12	62%
2020	169	-19	-12	100	37	-1	101%	1	53	19	12			29	6	90%
2021	169	-20	-13	100	37	1	99%	0	51	19	12			29	9	85%
2022	170	-22	-14	100	37	2	98%	0	50	19	12			29	10	83%
2023	171	-23	-15	100	37	4	97%	0	49	19	12			29	12	81%
2024	172	-25	-16	100	37	5	96%	0	51	19	12			29	9	84%
2025	173	-26	-16	100	37	6	95%	0	48	19	12			29	12	80%
2026	174	-27	-17	100	37	8	94%	0	48	19	12			29	12	79%
2027	174	-28	-18	100	37	9	94%	0	48	19	12			29	12	79%
2028	175	-29	-19	100	37	10	93%	0	51	19	12			29	9	85%
2029	176	-30	-20	100	37	11	92%	0	53	19	12			29	7	88%
2030	177	-31	-21	100	37	12	91%	0	46	19	12			29	14	76%

Annual

Trillion NG Btu per Year	Heating Demand			Non-Contracted		Total
	LDCs, Munis, Capacity Exempt	*Gas EE*	*Gas Reduction Measures*	*MA Electric System*	*Winter Reliability*	
2015	262	-15	-12	182	0	417
2016	267	-19	-14	184	0	418
2017	270	-23	-15	193	0	424
2018	274	-27	-17	189	0	419
2019	278	-30	-19	193	0	421
2020	279	-34	-21	240	0	464
2021	280	-37	-22	224	0	445
2022	282	-40	-23	205	0	423
2023	283	-43	-25	202	0	418
2024	284	-45	-26	212	0	425
2025	286	-48	-27	211	0	421
2026	287	-50	-29	208	0	416
2027	289	-52	-30	203	0	409
2028	290	-54	-32	214	0	418
2029	291	-56	-33	213	0	416
2030	293	-58	-34	200	0	401

Million Metric Tons CO2 per Year	Heating Demand			Non-Contracted		Total	GWSA Emissions	
	LDCs, Munis, Capacity Exempt	*Gas EE*	*Gas Reduction Measures*	*MA Electric Inventory*	*Winter Reliability*		*Maximum allowable for complicance*	*Compliant?*
2015	14	-1	-1	18	0	31	-	-
2016	14	-1	-1	18	0	30	-	-
2017	14	-1	-1	17	0	29	-	-
2018	14	-1	-1	16	0	28	-	-
2019	15	-2	-1	16	0	28	-	-
2020	15	-2	-1	16	0	27	23	No
2021	15	-2	-1	15	0	26	-	-
2022	15	-2	-1	14	0	25	-	-
2023	15	-2	-1	13	0	24	-	-
2024	15	-2	-1	12	0	23	-	-
2025	15	-3	-1	12	0	23	-	-
2026	15	-3	-2	11	0	22	-	-
2027	15	-3	-2	10	0	21	-	-
2028	15	-3	-2	10	0	20	-	-
2029	15	-3	-2	9	0	20	-	-
2030	16	-3	-2	8	0	19	19	No

2013 $ M per Year	"Total" Costs										"Delta" Costs				Delta Costs from Base
	LDCs, Munis, Capacity Exempt	*Gas EE*	*Electric EE PA*	*TVR*	*Avoided Price Spikes*	*Incremental Pipeline*	*MA Electric System*	*Demand Response*	*Winter Reliability*	*Total*	*Gas Reduction Measures*	*Low Demand Resources Capital*	*Other Resouces Capital*	*Total*	
2015	$873	$138	$507	$97	$0	$0	$2,191	$1	$11	$3,817	$0	$2		$2	$11
2016	$962	$179	$580	$0	$0	$0	$2,281	$0	$0	$4,001	$0	$19		$19	$14
2017	$1,009	$214	$651	$0	$0	$0	$2,246	$0	$0	$4,120	$0	$30		$30	$64
2018	$1,092	$246	$714	$0	$0	$0	$2,292	$0	$0	$4,344	$0	$41		$41	$85
2019	$1,054	$277	$770	$0	$0	$0	$2,238	$0	$0	$4,338	$0	$52		$52	$80
2020	$976	$308	$821	$0	-$3,479	$35	$1,970	$0	$0	$631	$0	$63		$63	$24
2021	$1,022	$335	$869	$0	-$3,430	$35	$1,938	$0	$0	$768	$0	$143		$143	$52
2022	$1,041	$359	$915	$0	-$3,321	$35	$1,942	$0	$0	$971	$0	$224		$224	$76
2023	$1,059	$376	$957	$0	-$3,327	$35	$1,953	$0	$0	$1,053	$0	$303		$303	$100
2024	$1,085	$396	$996	$0	-$3,481	$35	$1,926	$0	$0	$957	$0	$382		$382	$120
2025	$1,092	$416	$1,031	$97	-$3,440	$35	$1,915	$0	$0	$1,147	$0	$461		$461	$136
2026	$1,106	$435	$1,064	$0	-$3,460	$35	$1,922	$0	$0	$1,102	$0	$539		$539	$156
2027	$1,121	$454	$1,096	$0	-$3,477	$35	$1,907	$0	$0	$1,135	$0	$616		$616	$173
2028	$1,136	$472	$1,121	$0	-$3,579	$35	$1,931	$0	$0	$1,115	$0	$693		$693	$178
2029	$1,158	$489	$1,146	$0	-$3,597	$35	$1,965	$0	$0	$1,194	$0	$770		$770	$185
2030	$1,199	$506	$1,172	$0	-$3,575	$35	$1,955	$0	$0	$1,292	$0	$846		$846	$182

Scenario 6: Low Demand Case - Low Gas Price - No Hydro

This scenario requires a pipeline.

Peak Hour

Billion NG Btu per Hour	Heating Demand			Heating Balancing		Heating Delta		Non-Contracted Demand		Non-Contracted Balancing					Non-Contracted Delta	
	LDCs, Munis, Capacity Exempt	*Gas EE*	*Gas Reduction Measures*	*Existing Pipeline Capacity*	*Existing LDC Vaporization*	*Supply less Demand*	*Demand as a % of Supply*	*Heating Demand Shortage*	*MA Electric System*	*Existing Distrigas Vaporization*	*Mystic LNG Injection*	*Demand Response*	*Winter Reliability*	*Incremental Pipeline*	*Supply less Demand*	*Demand as a % of Supply*
2015	157	-8	-7	86	37	-19	116%	19	14	19	12	0.6	4		2	95%
2016	160	-10	-8	100	37	-4	103%	4	14	19	12				13	59%
2017	162	-13	-9	100	37	-4	103%	4	12	19	12				15	52%
2018	165	-15	-10	100	37	-4	103%	4	23	19	12				5	84%
2019	168	-17	-11	100	37	-3	102%	3	18	19	12				10	68%
2020	169	-19	-12	100	37	-1	101%	1	53	19	12			29	6	90%
2021	169	-20	-13	100	37	1	99%	0	51	19	12			29	9	85%
2022	170	-22	-14	100	37	2	98%	0	50	19	12			29	10	84%
2023	171	-23	-15	100	37	4	97%	0	50	19	12			29	11	82%
2024	172	-25	-16	100	37	5	96%	0	51	19	12			29	9	85%
2025	173	-26	-16	100	37	6	95%	0	51	19	12			29	10	84%
2026	174	-27	-17	100	37	8	94%	0	50	19	12			29	10	83%
2027	174	-28	-18	100	37	9	94%	0	48	19	12			29	12	80%
2028	175	-29	-19	100	37	10	93%	0	50	19	12			29	10	83%
2029	176	-30	-20	100	37	11	92%	0	53	19	12			29	7	88%
2030	177	-31	-21	100	37	12	91%	0	49	19	12			29	11	81%

Annual

Trillion NG Btu per Year	Heating Demand			Non-Contracted		Total
	LDCs, Munis, Capacity Exempt	*Gas EE*	*Gas Reduction Measures*	*MA Electric System*	*Winter Reliability*	
2015	262	-15	-12	182	0	417
2016	267	-19	-14	186	0	420
2017	270	-23	-15	196	0	427
2018	274	-27	-17	192	0	422
2019	278	-30	-19	196	0	424
2020	279	-34	-21	245	0	470
2021	280	-37	-22	232	0	453
2022	282	-40	-23	212	0	430
2023	283	-43	-25	209	0	425
2024	284	-45	-26	216	0	429
2025	286	-48	-27	213	0	424
2026	287	-50	-29	208	0	416
2027	289	-52	-30	201	0	407
2028	290	-54	-32	209	0	413
2029	291	-56	-33	208	0	411
2030	293	-58	-34	193	0	394

Million Metric Tons CO2 per Year	Heating Demand			Non-Contracted		Total	GWSA Emissions	
	LDCs, Munis, Capacity Exempt	*Gas EE*	*Gas Reduction Measures*	*MA Electric Inventory*	*Winter Reliability*		*Maximum allowable for complicance*	*Compliant?*
2015	14	-1	-1	18	0	31	-	-
2016	14	-1	-1	18	0	30	-	-
2017	14	-1	-1	17	0	29	-	-
2018	14	-1	-1	16	0	28	-	-
2019	15	-2	-1	16	0	28	-	-
2020	15	-2	-1	16	0	27	23	No
2021	15	-2	-1	15	0	26	-	-
2022	15	-2	-1	14	0	25	-	-
2023	15	-2	-1	13	0	24	-	-
2024	15	-2	-1	12	0	23	-	-
2025	15	-3	-1	12	0	23	-	-
2026	15	-3	-2	11	0	22	-	-
2027	15	-3	-2	10	0	21	-	-
2028	15	-3	-2	10	0	21	-	-
2029	15	-3	-2	9	0	20	-	-
2030	16	-3	-2	9	0	19	19	No

2013 $ M per Year	"Total" Costs										"Delta" Costs				Delta Costs from Base
	LDCs, Munis, Capacity Exempt	*Gas EE*	*Electric EE PA*	*TVR*	*Avoided Price Spikes*	*Incremental Pipeline*	*MA Electric System*	*Demand Response*	*Winter Reliability*	*Total*	*Gas Reduction Measures*	*Low Demand Resources Capital*	*Other Resouces Capital*	*Total*	
2015	$873	$138	$507	$97	$0	$0	$2,279	$1	$11	$3,905	$0	$2		$2	$99
2016	$948	$179	$580	$0	$0	$0	$2,356	$0	$0	$4,062	$0	$17		$17	$73
2017	$938	$214	$651	$0	$0	$0	$2,187	$0	$0	$3,990	$0	$26		$26	-$70
2018	$980	$246	$714	$0	$0	$0	$2,203	$0	$0	$4,143	$0	$35		$35	-$123
2019	$946	$277	$770	$0	$0	$0	$2,151	$0	$0	$4,143	$0	$44		$44	-$123
2020	$876	$308	$821	$0	-$3,479	$35	$1,998	$0	$0	$559	$0	$53		$53	-$58
2021	$881	$335	$869	$0	-$3,430	$35	$1,985	$0	$0	$675	$0	$115		$115	-$70
2022	$888	$359	$915	$0	-$3,321	$35	$2,030	$0	$0	$906	$0	$177		$177	-$34
2023	$897	$376	$957	$0	-$3,327	$35	$2,083	$0	$0	$1,022	$0	$240		$240	$4
2024	$907	$396	$996	$0	-$3,481	$35	$2,097	$0	$0	$951	$0	$302		$302	$34
2025	$909	$416	$1,031	$97	-$3,440	$35	$2,123	$0	$0	$1,172	$0	$365		$365	$65
2026	$914	$435	$1,064	$0	-$3,460	$35	$2,171	$0	$0	$1,159	$0	$427		$427	$102
2027	$919	$454	$1,096	$0	-$3,477	$35	$2,200	$0	$0	$1,225	$0	$490		$490	$137
2028	$926	$472	$1,121	$0	-$3,579	$35	$2,267	$0	$0	$1,241	$0	$552		$552	$163
2029	$925	$489	$1,146	$0	-$3,597	$35	$2,327	$0	$0	$1,325	$0	$614		$614	$159
2030	$928	$506	$1,172	$0	-$3,575	$35	$2,344	$0	$0	$1,409	$0	$677		$677	$130

Scenario 7: Low Demand Case - High Gas Price - No Hydro

This scenario requires a pipeline.

Peak Hour

Billion NG Btu per Hour	Heating Demand: LDCs, Munis, Capacity Exempt	Heating Demand: Gas EE	Heating Demand: Gas Reduction Measures	Heating Balancing: Existing Pipeline Capacity	Heating Balancing: Existing LDC Vaporization	Heating Delta: Supply less Demand	Heating Delta: Demand as a % of Supply	Non-Contracted Demand: Heating Demand Shortage	Non-Contracted Demand: MA Electric System	Non-Contracted Balancing: Existing Distrigas Vaporization	Non-Contracted Balancing: Mystic LNG Injection	Non-Contracted Balancing: Demand Response	Non-Contracted Balancing: Winter Reliability	Non-Contracted Balancing: Incremental Pipeline	Non-Contracted Delta: Supply less Demand	Non-Contracted Delta: Demand as a % of Supply
2015	157	-8	-7	86	37	-19	116%	19	14	19	12	0.6	4		2	95%
2016	160	-10	-8	100	37	-4	103%	4	14	19	12				13	59%
2017	162	-13	-9	100	37	-4	103%	4	12	19	12				15	52%
2018	165	-15	-10	100	37	-4	103%	4	25	19	12				3	92%
2019	168	-17	-11	100	37	-3	102%	3	16	19	12				12	62%
2020	169	-19	-12	100	37	-1	101%	1	52	19	12			25	3	94%
2021	169	-20	-13	100	37	1	99%	0	51	19	12			25	6	90%
2022	170	-22	-14	100	37	3	98%	0	49	19	12			25	7	87%
2023	171	-23	-15	100	37	4	97%	0	44	19	12			25	12	79%
2024	172	-25	-16	100	37	6	96%	0	44	19	12			25	12	78%
2025	173	-26	-17	100	37	7	95%	0	41	19	12			25	16	72%
2026	174	-27	-18	100	37	9	94%	0	43	19	12			25	13	77%
2027	174	-28	-19	100	37	10	93%	0	39	19	12			25	17	69%
2028	175	-29	-20	100	37	11	92%	0	41	19	12			25	15	73%
2029	176	-30	-22	100	37	13	91%	0	45	19	12			25	11	80%
2030	177	-31	-23	100	37	14	90%	0	39	19	12			25	18	69%

Annual

Trillion NG Btu per Year	Heating Demand: LDCs, Munis, Capacity Exempt	Heating Demand: Gas EE	Heating Demand: Gas Reduction Measures	Non-Contracted: MA Electric System	Non-Contracted: Winter Reliability	Total
2015	262	-15	-12	182	0	417
2016	267	-19	-14	184	0	418
2017	270	-23	-15	189	0	421
2018	274	-27	-17	187	0	417
2019	278	-30	-19	189	0	417
2020	279	-34	-21	232	0	457
2021	280	-37	-22	211	0	432
2022	282	-40	-24	190	0	408
2023	283	-43	-25	185	0	401
2024	284	-45	-27	190	0	402
2025	286	-48	-28	181	0	391
2026	287	-50	-30	177	0	384
2027	289	-52	-31	166	0	371
2028	290	-54	-33	178	0	381
2029	291	-56	-34	171	0	372
2030	293	-58	-36	160	0	359

Million Metric Tons CO2 per Year	Heating Demand: LDCs, Munis, Capacity Exempt	Heating Demand: Gas EE	Heating Demand: Gas Reduction Measures	Non-Contracted: MA Electric Inventory	Non-Contracted: Winter Reliability	Total	GWSA Emissions: Maximum allowable for complicance	GWSA Emissions: Compliant?
2015	14	-1	-1	18	0	31	-	-
2016	14	-1	-1	18	0	30	-	-
2017	14	-1	-1	17	0	29	-	-
2018	14	-1	-1	16	0	28	-	-
2019	15	-2	-1	16	0	28	-	-
2020	15	-2	-1	15	0	27	23	No
2021	15	-2	-1	13	0	25	-	-
2022	15	-2	-1	11	0	23	-	-
2023	15	-2	-1	10	0	21	-	-
2024	15	-2	-1	8	0	19	-	-
2025	15	-3	-1	7	0	18	-	-
2026	15	-3	-2	5	0	16	-	-
2027	15	-3	-2	4	0	15	-	-
2028	15	-3	-2	3	0	14	-	-
2029	15	-3	-2	2	0	12	-	-
2030	16	-3	-2	0	0	11	19	Yes

2013 $ M per Year	"Total" Costs: LDCs, Munis, Capacity Exempt	Gas EE	Electric EE PA	TVR	Avoided Price Spikes	Incremental Pipeline	MA Electric System	Demand Response	Winter Reliability	Total	"Delta" Costs: Gas Reduction Measures	Low Demand Resources Capital	Other Resouces Capital	Total	Delta Costs from Base
2015	$873	$138	$507	$97	$0	$0	$2,191	$1	$11	$3,817	$0	$3		$3	$12
2016	$976	$179	$580	$0	$0	$0	$2,288	$0	$0	$4,023	$0	$35		$35	$51
2017	$1,056	$214	$651	$0	$0	$0	$2,272	$0	$0	$4,192	$0	$62		$62	$168
2018	$1,096	$246	$714	$0	$0	$0	$2,279	$0	$0	$4,335	$0	$88		$88	$123
2019	$1,101	$277	$770	$0	$0	$0	$2,251	$0	$0	$4,398	$0	$115		$115	$204
2020	$1,117	$308	$821	$0	-$3,479	$30	$2,072	$0	$0	$869	$0	$142		$142	$341
2021	$1,152	$335	$869	$0	-$3,430	$30	$1,959	$0	$0	$915	$2	$464		$466	$521
2022	$1,201	$359	$915	$0	-$3,321	$30	$1,937	$0	$0	$1,121	$2	$785		$787	$790
2023	$1,249	$376	$957	$0	-$3,327	$30	$1,916	$0	$0	$1,202	$2	$1,105		$1,108	$1,053
2024	$1,300	$396	$996	$0	-$3,481	$30	$1,843	$0	$0	$1,084	$2	$1,425		$1,427	$1,292
2025	$1,364	$416	$1,031	$97	-$3,440	$30	$1,818	$0	$0	$1,316	$2	$1,744		$1,746	$1,591
2026	$1,413	$435	$1,064	$0	-$3,460	$30	$1,788	$0	$0	$1,270	$3	$2,062		$2,065	$1,850
2027	$1,454	$454	$1,096	$0	-$3,477	$30	$1,724	$0	$0	$1,280	$3	$2,379		$2,382	$2,084
2028	$1,495	$472	$1,121	$0	-$3,579	$30	$1,717	$0	$0	$1,256	$3	$2,696		$2,699	$2,324
2029	$1,510	$489	$1,146	$0	-$3,597	$30	$1,702	$0	$0	$1,279	$3	$3,012		$3,015	$2,514
2030	$1,543	$506	$1,172	$0	-$3,575	$30	$1,619	$0	$0	$1,294	$3	$3,327		$3,330	$2,668

Scenario 8: Low Demand Case - Reference Gas Price - Hydro

This scenario requires a pipeline.

Peak Hour

Billion NG Btu per Hour	Heating Demand			Heating Balancing		Heating Delta		Non-Contracted Demand		Non-Contracted Balancing					Non-Contracted Delta	
	LDCs, Munis, Capacity Exempt	*Gas EE*	*Gas Reduction Measures*	*Existing Pipeline Capacity*	*Existing LDC Vaporization*	*Supply less Demand*	*Demand as a % of Supply*	*Heating Demand Shortage*	*MA Electric System*	*Existing Distrigas Vaporization*	*Mystic LNG Injection*	*Demand Response*	*Winter Reliability*	*Incremental Pipeline*	*Supply less Demand*	*Demand as a % of Supply*
2015	157	-8	-7	86	37	-19	116%	19	14	19	12	0.6	4		2	95%
2016	160	-10	-8	100	37	-4	103%	4	14	19	12				13	59%
2017	162	-13	-9	100	37	-4	103%	4	12	19	12				15	52%
2018	165	-15	-10	100	37	-4	103%	4	19	19	12				8	73%
2019	168	-17	-11	100	37	-3	102%	3	16	19	12				12	62%
2020	169	-19	-12	100	37	-1	101%	1	50	19	12			25	5	90%
2021	169	-20	-13	100	37	1	99%	0	51	19	12			25	5	92%
2022	170	-22	-14	100	37	2	98%	0	43	19	12			25	13	76%
2023	171	-23	-15	100	37	4	97%	0	42	19	12			25	14	75%
2024	172	-25	-16	100	37	5	96%	0	44	19	12			25	12	78%
2025	173	-26	-16	100	37	6	95%	0	44	19	12			25	12	78%
2026	174	-27	-17	100	37	8	94%	0	44	19	12			25	13	78%
2027	174	-28	-18	100	37	9	94%	0	45	19	12			25	11	80%
2028	175	-29	-19	100	37	10	93%	0	49	19	12			25	7	87%
2029	176	-30	-20	100	37	11	92%	0	48	19	12			25	8	85%
2030	177	-31	-21	100	37	12	91%	0	46	19	12			25	10	83%

Annual

Trillion NG Btu per Year	Heating Demand			Non-Contracted		Total
	LDCs, Munis, Capacity Exempt	*Gas EE*	*Gas Reduction Measures*	*MA Electric System*	*Winter Reliability*	
2015	262	-15	-12	182	0	417
2016	267	-19	-14	184	0	418
2017	270	-23	-15	193	0	424
2018	274	-27	-17	171	0	401
2019	278	-30	-19	174	0	403
2020	279	-34	-21	215	0	439
2021	280	-37	-22	203	0	424
2022	282	-40	-23	170	0	388
2023	283	-43	-25	169	0	384
2024	284	-45	-26	185	0	398
2025	286	-48	-27	181	0	392
2026	287	-50	-29	182	0	390
2027	289	-52	-30	176	0	382
2028	290	-54	-32	192	0	396
2029	291	-56	-33	190	0	393
2030	293	-58	-34	182	0	383

Million Metric Tons CO2 per Year	Heating Demand			Non-Contracted		Total	GWSA Emissions	
	LDCs, Munis, Capacity Exempt	*Gas EE*	*Gas Reduction Measures*	*MA Electric Inventory*	*Winter Reliability*		*Maximum allowable for complicance*	*Compliant?*
2015	14	-1	-1	18	0	31	-	-
2016	14	-1	-1	18	0	30	-	-
2017	14	-1	-1	17	0	29	-	-
2018	14	-1	-1	14	0	26	-	-
2019	15	-2	-1	14	0	26	-	-
2020	15	-2	-1	13	0	25	23	No
2021	15	-2	-1	12	0	24	-	-
2022	15	-2	-1	10	0	21	-	-
2023	15	-2	-1	9	0	20	-	-
2024	15	-2	-1	8	0	20	-	-
2025	15	-3	-1	8	0	19	-	-
2026	15	-3	-2	7	0	18	-	-
2027	15	-3	-2	7	0	17	-	-
2028	15	-3	-2	6	0	17	-	-
2029	15	-3	-2	6	0	16	-	-
2030	16	-3	-2	5	0	16	19	Yes

2013 $ M per Year	"Total" Costs										"Delta" Costs				Delta Costs from Base
	LDCs, Munis, Capacity Exempt	*Gas EE*	*Electric EE PA*	*TVR*	*Avoided Price Spikes*	*Incremental Pipeline*	*MA Electric System*	*Demand Response*	*Winter Reliability*	*Total*	*Gas Reduction Measures*	*Low Demand Resources Capital*	*Other Resouces Capital*	*Total*	
2015	$873	$138	$507	$97	$0	$0	$2,191	$1	$11	$3,817	$0	$2		$2	$11
2016	$962	$179	$580	$0	$0	$0	$2,281	$0	$0	$4,001	$0	$19		$19	$14
2017	$1,009	$214	$651	$0	$0	$0	$2,246	$0	$0	$4,120	$0	$30		$30	$64
2018	$1,092	$246	$714	$0	$0	$0	$2,120	$0	$0	$4,173	$0	$41	$129	$170	$42
2019	$1,054	$277	$770	$0	$0	$0	$2,068	$0	$0	$4,168	$0	$52	$129	$181	$39
2020	$976	$308	$821	$0	-$3,479	$30	$1,873	$0	$0	$529	$0	$63	$129	$192	$51
2021	$1,022	$335	$869	$0	-$3,430	$30	$1,829	$0	$0	$654	$0	$143	$129	$272	$67
2022	$1,041	$359	$915	$0	-$3,321	$30	$1,747	$0	$0	$770	$0	$224	$318	$541	$194
2023	$1,059	$376	$957	$0	-$3,327	$30	$1,756	$0	$0	$851	$0	$303	$318	$621	$215
2024	$1,085	$396	$996	$0	-$3,481	$30	$1,721	$0	$0	$748	$0	$382	$318	$700	$228
2025	$1,092	$416	$1,031	$97	-$3,440	$30	$1,703	$0	$0	$930	$0	$461	$318	$779	$237
2026	$1,106	$435	$1,064	$0	-$3,460	$30	$1,707	$0	$0	$882	$0	$539	$318	$857	$254
2027	$1,121	$454	$1,096	$0	-$3,477	$30	$1,689	$0	$0	$912	$0	$616	$318	$934	$268
2028	$1,136	$472	$1,121	$0	-$3,579	$30	$1,709	$0	$0	$888	$0	$693	$318	$1,011	$269
2029	$1,158	$489	$1,146	$0	-$3,597	$30	$1,736	$0	$0	$961	$0	$770	$318	$1,088	$268
2030	$1,199	$506	$1,172	$0	-$3,575	$30	$1,717	$0	$0	$1,049	$0	$846	$318	$1,164	$256

ENBRIDGE INTERROGATORY #18

INTERROGATORY

Reference: L.OEBStaff.1, page 129

Preamble:
"The existing cost-benefit screening tests can and should be used for evaluating DSM programs targeted at gas infrastructure. [Enbridge IRP Scope Study, P.7] This is unnecessary and is likely to result in a distraction of resources and time. The existing cost-benefit screening tests can and should be used for evaluating DSM programs targeted at gas infrastructure. It will be necessary to modify some of the inputs, but the same tests can be used."

Question:
Please specify which tests and related inputs need to be modified in order to evaluate DSM programs targeted at gas infrastructure.

RESPONSE

The text referred to above was misquoted. The actual text reads as follows:

> Enbridge indicates that it might need to develop a new cost-benefit test for screening DSM programs focused on addressing gas infrastructure [Enbridge IRP Scope Study, P.7] This is unnecessary and is likely to result in a distraction of resources and time. The existing cost-benefit screening tests can and should be used for evaluating DSM programs targeted at gas infrastructure. It will be necessary to modify some of the inputs, but the same tests can be used.

DSM programs targeted at gas infrastructure should be evaluated using the same tests as other gas DSM programs: the Total Resource Cost test and the Utility Cost test. They avoided costs that are input to these two tests may need to be modified in order to better reflect the value of avoiding gas infrastructure costs at peak periods.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

ENBRIDGE INTERROGATORY #19

INTERROGATORY

Reference: L.OEBStaff.1, page 129

Preamble:
"…many electricity integrated resource plans take roughly six months to conduct…"

Question:

a. Please describe the scope and objectives of the electricity integrated resource plans referenced.
b. Please identify any jurisdictions or utilities that have used case studies to develop their integrated resource planning programs (electric and natural gas).

RESPONSE

a. This response is based on Synapse' extensive experience with reviewing electricity integrated resource plans, and is not based on any one utility's planning process. In general, the scope and objectives of IRP is to identify the optimal combination of supply-side and demand-side electricity resources to best serve customers over the short-, medium- and long-term.

b. Synapse did not conduct a search of jurisdictions or utilities that have used case studies for IRP purposes.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

ENBRIDGE INTERROGATORY #20

INTERROGATORY

Reference: L.OEBStaff.1 p.128

Preamble:
10.1 – "This suggests that demand response programs, where customers are provided specific incentives and tools to postpone or avoid gas consumption during peak periods, could play a significant role in mitigating gas infrastructure needs. Enbridge should include a comprehensive assessment of demand response potential in its gas infrastructure planning study."

Question:

a. Please further expand on what types of demand response programs and/or technologies SEE believes would be able to postpone or avoid natural gas consumption during peak periods.
b. Please elaborate on how this assessment will differ in scope from an assessment of EGD's current Interruptible Rates structure and philosophy.

RESPONSE

a. Synapse has not investigated the specific demand response programs and/or technologies that could be used to postpone or avoid natural gas consumption during peak periods.

b. Synapse has not reviewed EGD's current Interruptible Rates structure and philosophy.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

UNION INTERROGATORY #1

INTERROGATORY

Reference: L.OEBStaff.1, Page 9

Preamble:
At Section 3.1.2, Synapse states "Enbridge has significantly greater net benefits ($664 million) than Union ($140 million)."

Question:
Please confirm that Synapse is comparing Enbridge's 5-year TRC benefits to only one-year of TRC benefits for Union.

RESPONSE

Confirmed. Union provided only one year's cost-effectiveness information, while Enbridge provided cost-effectiveness for each year in the five year plan term.

A more consistent comparison is to review each utility's 2016-only TRC net benefits. Enbridge's 2016 TRC net benefits are approximately $116 million, while Union's 2016 TRC net benefits are approximately $140 million.

Note that this adjustment does not materially change the benefit-cost ratio analysis presented in Exhibit L.OEBStaff.1, page 9, because Enbridge's TRC benefit-cost ratios are consistent across each year of the plan and for the plan aggregate, ranging from a low of 2.39 in 2018, to a high of 2.43 in 2016, for a plan average of 2.42. Union's 2016 TRC benefit-cost ratio is 1.99.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

UNION INTERROGATORY #2

INTERROGATORY

Reference: L.OEBStaff.1, Page 9

Preamble:
At Section 3.1.2, Synapse states "Enbridge has significantly greater net benefits ($852 million) than Union ($176 million)."

Question:
Please confirm that Synapse is comparing Enbridge's 5-year PAC benefits to only one-year of PAC benefits for Union.

RESPONSE

Confirmed. Union provided only one year's cost-effectiveness information, while Enbridge provided cost-effectiveness for each year in the five year plan term.

A more consistent comparison is to review each utility's 2016-only PAC net benefits. Enbridge's 2016 PAC net benefits are approximately $150 million, while Union's 2016 PAC net benefits are approximately $179 million.

Note that this adjustment does not materially change the benefit-cost ratio analysis presented in Exhibit L.OEBStaff.1, page 9, because Enbridge's PAC benefit-cost ratios are consistent across each year of the plan and for the plan aggregate, ranging from a low of 3.95 in 2018, to a high of 4.12 in 2016, for a plan average of 4.02. Union's 2016 PAC benefit-cost ratio is 5.25.

Also note that while responding to Exhibit M.Staff.UNION.18, a few small typographical errors were discovered that amounted to a less than 1% difference in the presented data. These errors have been corrected in Exhibit M.Staff.UNION.18 Attachment 1 to be consistent with the utility's filing. This explains why Union's 2016 PAC net benefits were adjusted from $176 million to $179 million.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

UNION INTERROGATORY #3

INTERROGATORY

Reference: L.OEBStaff.1, Page 10

Preamble:
"Therefore, the average Union C&I customer uses over twice as much gas (91,013 m3 per year) as the average Enbridge C&I customer (40,761 m3 per year)."

Question:
Please confirm that Synapse understands that Large Volume customers are included in Page 10, Section 3.2, however they are not eligible for customer incentives.

RESPONSE

Confirmed. Note that the referenced citation is intended to indicate customer usage *on average*, across all sizes and rate classes within the C&I sector.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

UNION INTERROGATORY #4

INTERROGATORY

Reference: L.OEBStaff.1, Page 25; EB-2015-0029, Exhibit A, Tab 3, Page 6, Table 2

Preamble:
"Both Enbridge and Union plans to spend about 2 percent of their total program budget on EM&V activities (Enbridge Gas Distribution, 2015a, Exh. B, Tab 1, Sch. 4, p. 3-5; Union Gas Limited, 2015a, Exh. A, Tab 3, p. 6). This level of proposed budget on evaluation may be insufficient. SEE Action (2012) notes that the 3 to 6 percent range is only a rough guideline because evaluation needs and the relative EM&V roles of program administrators and independent third-party evaluators vary significantly between different jurisdictions and program administrators. Nevertheless, in light of our findings of evaluation plan gaps over the next five years, Enbridge and Union may need more budget on their evaluation activities."

Question:
Union's proposed evaluation budget for 2016 equates to $2.302 million, out of a total $57.254 million budget, or 4.0% (EB-2015-0029, Exhibit A, Tab 3, Page 6). Please provide the calculations to show how Synapse calculated the 2% figure noted in the evidence.

RESPONSE

Synapse calculated the 2% figure by summing the program-specific evaluation costs ($1,002,000) and dividing it by the total program-specific costs ($44,573,000) (EB-2015-0029, Exhibit A, Tab 3, Page 6).

In error, this analysis did not include the non-program-specific evaluation costs (an additional $1.3 million annually), which would have brought the evaluation budget to approximately 4% of the total budget. The table below provides supporting analysis (the data in the table is from Union's Plan, Exh. A, Tab 3, page 6, Table 2).

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

Union's Costs ($000)	2016	2017	2018	2019	2020	2016-2020
Residential Resource Acquisition Evaluation	559	709	859	859	859	3,845
C&I Resource Acquisition Evaluation	189	189	189	189	189	945
Performance-Based Evaluation	35	35	35	35	35	175
Low-Income Evaluation	219	212	225	244	262	1,162
Program-Specific Evaluation Total	1,002	1,145	1,308	1,327	1,345	6,127
Program Subtotal (all costs)	44,573	48,070	52,787	52,795	53,899	252,124
Program-Specific Evaluation /Program Subtotal (all costs) (%)	**2.25%**	**2.38%**	**2.48%**	**2.51%**	**2.50%**	**2.43%**
Portfolio Evaluation (non-program specific)	1,300	1,300	1,300	1,300	1,300	6,500
Total Evaluation Budget	2,302	2,445	2,608	2,627	2,645	12,627
Total DSM Budget Pre-Inflation	56,308	54,212	58,429	58,437	59,541	286,927
Total Evaluation Budget / Total DSM Budget Pre-Inflation ($)	**4.09%**	**4.51%**	**4.46%**	**4.50%**	**4.44%**	**4.40%**

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

UNION INTERROGATORY #5

INTERROGATORY

Reference: L.OEBStaff.1, Page 30

Preamble:
"A typical products program provides cash incentives to homeowners, or takes a mid-to-upstream approach by providing incentives directly to retailers, distributors or manufacturers of the equipment so that customers ultimately pay a lower price. This type of program is essential for homeowners just looking to replace their old space heating and hot water equipment, especially when the homeowners' HVAC equipment has failed or broken and they need to replace the equipment immediately. Without such a program, homeowners are more likely to purchase lower cost, standard efficiency equipment. This type of products program is typically offered in other jurisdictions, and should be included as part of the utilities' portfolio of programs."

"Both utilities should develop a residential products offering to promote the installation of high efficiency space heating and water heating equipment. This type of program is essential especially when the homeowners' HVAC equipment has failed or broken and they need to replace the equipment immediately."

Question:
In making this recommendation, please provide Synapse's understanding of the measure cost effectiveness which are most comparable in relation to Ontario's code, climate, 2016 filed avoided costs, discount rate and TRC methodology for the following stand-alone measures on a prescriptive basis. Please include the relevant findings from Synapse's comprehensive literature review of best practices and discussion papers.

- Furnaces
- Boilers
- Condensing water heaters
- Tankless water heaters
- HRVs

RESPONSE

Synapse was tasked with reviewing the proposed DSM programs and commenting on the program design elements that could be modified or improved. The Synapse recommendation referenced above is intended provide general guidance and direction, and is not intended to indicate a specific quantitative

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

outcome (see Exhibit L.OEBStaff.1, page 2; see also Exhibit M.Staff.EGDI.4). Therefore, we have not estimated the requested data as it is beyond the scope of our work.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

UNION INTERROGATORY #6

INTERROGATORY

Reference: L.OEBStaff.1, Page 31

Preamble:
"Union's program description does not specify whether a customer is required to install two measures in order to participate in the program."

Question:
Please confirm at Exhibit A, Tab 3, Appendix C, Page 5, Union states that in Union's Home Reno Rebate Offering, participants must complete at least two eligible energy efficiency upgrades.

RESPONSE

Confirmed; Union's appendix on its evaluation plan (Exhibit A, Tab 3, Appendix C, Page 5) indicates that the Home Reno Rebate offering has "been designed to encourage homeowners to install two or more measures in their home." However, Union's program description section (Exhibit A, Tab 3, Appendix A, Pages 3-8), which describes in detail its proposed DSM programs, does not specify whether a customer is required to install two measures in order to participate in the program

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

UNION INTERROGATORY #7

INTERROGATORY

Reference: L.OEBStaff.1, Page 34

Preamble:
"If the audits are required for participation, then the full cost of the audits should be covered by the utility incentive." … "As another example, some states require the participant to cover part of the audit costs, but will waive the audit costs if the customer installs at least one of the major measures recommended through the audit. This provides additional motivation to customers to install more comprehensive measures."

Question:
Please confirm in Union's response to Exhibit B.T5.Union.LPMA.29 part a) that Union states the typical cost of the D and E assessments is $500. The rebate is provided if the customer installs at least two of the major measures recommended. Union has structured its $500 assessment rebate to cover the cost of the assessments.

RESPONSE

Confirmed.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

UNION INTERROGATORY #8

INTERROGATORY

Reference: L.OEBStaff.1, Page 63; EB-2011-0327, Union Gas Limited Settlement Agreement, January, 31, 2012; Exhibit A, Tab 3, Appendix A, Pages 83-87

Preamble:
At Section 5.5.4, Synapse states “Union describes its Low Income Multi-Family offering as a demonstration. Although this program is a new program and will be ramping up, this program should be rolled out as a full program rather than piloted”.

Question:

a. The Low Income Multi-Family Offering has two eligible markets: Social and Assisted Housing and Market Rate (Private Market). Given that Union has had a Low Income Multi-Family Offering available to the Social and Assisted Housing market since 2012, please confirm that the statement above is incorrect.
b. Please confirm that Synapse understands that the Market Rate sector within Union’s Low Income Multi-Family Offering is new and will undergo a demonstration project in 2015, with a program launch starting in 2016.

RESPONSE

a. We now see that Union proposes a demonstration for only the "extension of the current offering to market rate buildings that are occupied by low income tenants" (Union Gas Limited, 2015a, Exh. A, Tab 3, App. A, pp. 72).

b. We now understand that Union proposes the demonstration for market rate buildings in 2015 only.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

UNION INTERROGATORY #9

INTERROGATORY

Reference: L.OEBStaff.1, Page 64; EB-2015-0029, Exhibit A, Tab 3, Appendix A, Page 84; EB-2015-0049, Exhibit B, Tab 2, Schedule 1, Page 40

Preamble:
At Section 5.5.4, Synapse states that "the difference in incentives between Enbridge and Union is significant and the drivers of this difference are not explained".

Question:
Please confirm that the difference between incentives is that Union's incentive structure is based on lifetime natural gas savings whereas Enbridge's incentive structure is based on first year natural gas savings.

RESPONSE

We now see that Union incents customers in its Low Income Multi-Family offering using a dollar per lifetime savings metric.

Please also see Exhibit M.Staff.EGDI.9 and Exhibit M.Staff.EP.12.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

UNION INTERROGATORY #10

INTERROGATORY

Reference: L.OEBStaff.1, Page 67; EB-2015-0029, Exhibit A, Tab 3, Appendix A, Pages 73-74

Preamble:
At Section 5.5.6, Synapse states that “Union is offering this measure as a stand-alone program, rather than within its core low income programs”. At Exhibit A, Tab 3, Appendix A, Pages 73-74, Union states that “during the initial audit an assessment of the furnace will be made to determine if it’s at end-of-life and if it qualifies for an incentive under the Furnace End-of-Life Upgrade offering”.

Question:
Please confirm that Synapse understands that Union is providing this offering within the Home Weatherization offering as well as a standalone offering.

RESPONSE

It is not clear from the filing that Union is providing this offering within the Home Weatherization offering as well as a standalone offering, because furnace replacement is not listed as a measure in the Home Weatherization offering. Additionally, the excerpt above discusses identification and referral of leads to the Furnace End-of-Life Upgrade offering rather than implementation within the Home Weatherization offering.

We can confirm that we support Union implementing furnace replacement within its Home Weatherization offering, if this is occurring. In this case, we further emphasize that the duplication of efforts across the two programs could and should be streamlined, possibly by eliminating the Furnace End-of-Life offering.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

UNION INTERROGATORY #11

INTERROGATORY

Reference: L.OEBStaff.1, Page 69

Preamble:
"Union should not turn away builders that are not already enrolled in the program, as doing so would create lost opportunities". As outlined at Exhibit A, Tab 3, Appendix A, Section 1.5, the Optimum Home program is a multi-phased process over multiple years which is reflected in the design and evolution of the targets for the program. Union would like to understand Synapse's recommendation in this context.

Question:
Given that the Optimum Home offering is a multi-year process with each participating builder, and the next scheduled update for the Ontario Building Code is January 1, 2017, please provide more detail for how Synapse is recommending the program structure would be condensed to fit within the 2016 calendar year.

RESPONSE

Synapse is not recommending that the program structure be condensed to fit within the 2016 calendar year, nor are we suggesting that Union abandon its multi-phased process over multiple years. The offering's multi-year design is a reasonable approach for a residential new construction program.

Synapse is recommending that Union not discontinue the Optimum Home offering at the end of 2016 due to the expected release of an updated building code in January 2017. As noted on page 69 of L.OEBStaff.1, we disagree with Union's proposed approach, and recommend that the utility "commit to continuing support of a new construction offering, whatever the design of the new building code may be."

If Union adopts our recommendation to continue the Optimum Home program past 2016, then it could continue to enroll new builders during the entire term of the plan. We acknowledge that the curriculum for the multi-phased process may need to be adjusted to accommodate the revised building code. However, Union may find that, because of the revised building code, builders require more than before the expertise and assistance of the Optimum Home offering to understand the modifications to the codes and how they can construct homes that exceed the new standards.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

UNION INTERROGATORY #12

INTERROGATORY

Reference: L.OEBStaff.1, Pages 71-72

Preamble:
"Both Enbridge and Union expect to spend a sizable portion of their portfolio budgets on this offering. Enbridge expects to spend on average 8 percent of its annual budget on this offering (about $6.4 million), while Union expect to spend about 6 percent of its annual budget on average each year (about $2.9 million). Comparatively, all of the gas program administrators in Massachusetts expect to spend about $3.9 million CAD ($3.1 million USD) each year of their 2016-2018 efficiency plans, which is about 1.5 percent of the annual budget. Enbridge and Union should assess the offering budget to determine whether it can be reduced, or should at least justify the seemingly high amount budgeted for this new offering."

Union would like to understand the findings from Synapse's review of leading jurisdictions.

Question:
Please provide the following data for each behavioural gas-only offering identified for the most recent available calendar year:

- Year offering was initiated
- Annual budget
- Number of residential single family[8] customers
- Number of Home Energy Report recipients
- Number of Home Energy Reports delivered per calendar year
- Inclusion of Online Portal (yes/no)
- Breakdown of vendor cost per customer (fixed/variable) including all components such as licensing fee, postage, etc.

RESPONSE

Refer to Exhibit M.Staff.UNION.12, Attachment 1, which is an excerpt from the April 30, 2015 draft of the Massachusetts 2016-2018 energy efficiency plan for both gas and electric program administrators that summarizes the statewide behavioural energy efficiency program.

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[8] Single family defined as residential single-detached, semi-detached, row house unit, and duplex premises.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

d. Residential Whole House: Behavioral/Feedback Initiatives

RESIDENTIAL WHOLE HOUSE	**CORE INITIATIVE** **RESIDENTIAL BEHAVIORAL/FEEDBACK INITIATIVES**
Overview and Key Objectives	The primary goal of the Behavioral core initiative is to encourage customer level behavioral change to conserve energy. Behavioral initiatives seek to identify the motivational factors that cause residential customers to actively employ personal energy saving actions and/or participate in energy efficiency programs. The PAs are continuously exploring opportunities to leverage behavioral science in the service of securing energy efficiency. Several PAs introduced and evaluated behavior based initiatives within their respective territories in previous plan periods. These initiatives varied in size and scope and include different implementation mechanisms along with a mix of vendors. One program, the Home Energy Report, has moved from trial to full implementation by the largest PAs and is described more fully under implementation. **Target Market:** All residential customers
	New Enhancements: • Continued review of opportunities in the marketplace, new vendor offers, and opportunities to incorporate behavioral science based messaging into existing program marketing and customer engagement efforts. • Some PAs may explore offering behavior initiatives that have the ability to provide near real time electric consumption feedback, and have that ability to offer a mobile based application in addition to traditional web based or paper reporting. Some PAs may also look to see what potential exists to tie in home automation and smart appliances and other controls where applicable. Some electric PAs may leverage funding from their Grid Modernization Plan in areas where energy efficiency and grid modernization cross over. • Continue to evaluate and explore PA opportunities to leverage home automation technologies including eligible wireless enabled thermostats and their associated communication tools as well as other custom engagement tools for behavioral

RESIDENTIAL WHOLE HOUSE	**CORE INITIATIVE** **RESIDENTIAL BEHAVIORAL/FEEDBACK INITIATIVES**
	messaging.
Core Initiative Design	**Measures Promoted:** Behavioral initiatives focus on motivating energy-conserving actions that residents can control, such as programming thermostats, monitoring and adjusting home temperatures via wireless-enabled thermostats or turning off or down power using equipment and electronics. Behavioral initiatives also cross-promote participation in other initiatives with specific measures including HES, lighting, and products offerings. **Implementation Strategy:** The most prevalent behavioral initiative currently deployed by multiple PAs is the Home Energy Report ("HER") model. PAs assign participants to the program and participants are offered an opt-out option. The HER program assigns qualifying customers to treatment and control groups. The treatment groups receive mailer-based reports on an ongoing basis and have access to an online portal. Control groups are retained for the purposes of evaluation. Customers are treated as a group indefinitely, or until the PAs decide to stop treating customers. The HER program prompts energy savings through two primary paths: • Educational reports • Educational reports *and* customer interaction with their online platform. The HER details and benchmarks customers' energy usage against their past usage and against similar homes in the area. Customers also have the option of opting-in to an online platform to gain greater feedback on their energy usage.
Delivery Mechanism	The HER model is individually contracted by each participating PA with a single vendor. The vendor works with each participating PA individually to define the treatment group within the PAs customer group, the treatment periodicity, engagement mechanisms (generally mail, email and web portal) and content from a limited number of

RESIDENTIAL WHOLE HOUSE	**CORE INITIATIVE** **RESIDENTIAL BEHAVIORAL/FEEDBACK INITIATIVES**
	vendor designed options.
Marketing Overview	The current initiative uses an opt-out model, therefore does not employ additional marketing beyond direct offerings to selected customers.
Three-Year Deployment Strategy/Roadmap	PAs actively deploying HER initiatives intend to continue. PAs intend to continue to monitor opportunities for amendments to the current HER model and new behavioral initiative opportunities. The field of behavioral energy efficiency is evolving, with new product offers from vendors as well as new opportunities created by technology and engagement tools. The behavioral arena is ripe for experimentation. A benefit of the Massachusetts efficiency program regime is having multiple creative Program Administrators with varied territories where a variety of approaches can be explored and tested in the field. The Cape Light Compact already deploys an alternate behavioral approach and pioneered early learning in the field. In the 2016-2018 period many PAs will be exploring how the emergence of home automation and smart appliances and other controls may be tied into behavioral efforts. Some PAs may explore offering behavioral initiatives that have the ability to provide near real time electric consumption feedback, and/ or have the ability to offer a mobile based application in addition to traditional web based or paper reporting.
Special Notes	

e. Residential Products: Heating and Cooling (electric)

RESIDENTIAL PRODUCTS	**CORE INITIATIVE** **RESIDENTIAL HEATING AND COOLING - Electric**
Overview and Key Objectives	The primary objective of the Residential Heating and Cooling core initiative is to encourage consumers to purchase the most efficient heating, ventilation and air condition (“HVAC”) and heat pump water heating technologies available when replacing older, less efficient equipment, and when considering equipment in new construction. The initiative also seeks to encourage contractors who service and install residential central air conditioning (“CAC”) equipment and air source

UNION INTERROGATORY #13

INTERROGATORY

Reference: L.OEBStaff.1, Page 84

Preamble:
"To ensure that recommended measures are implemented, Union should (a) collect the costs for the technical assistance from the customer if a customer does not implement the recommendations from the technical assistance, then Union should; (b) require execution of an agreement including customer energy savings commitments, and/or (c) require implementation of all recommended measures that meet certain conditions (e.g., a payback period of 1.5 years or less)."

Question:

a. Please confirm that Synapse understands that Union's Large Volume customers would already be paying for the cost of the program through their utility distribution rates.
b. Please confirm that different companies in different market segments are likely to have different capital project hurdle rates (payback period).

RESPONSE

a. Confirmed.

b. Confirmed. The referenced passage is not proposing a specific hurdle rate/payback period. Further, Synapse did not intend to suggest that one specific hurdle rate/payback period would be suitable for all industries. Synapse notes that the referenced passage contains errors and should instead read:

> To ensure that recommended measures are implemented, Union should consider (a) collecting the costs for the technical assistance from the customer if a customer does not implement the recommendations from the technical assistance; (b) requiring execution of an agreement including customer energy savings commitments, and/or (c) requiring implementation of all recommended measures that meet certain conditions (e.g., a payback period of 1.5 years or less).

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

UNION INTERROGATORY #14

INTERROGATORY

Reference: L.OEBStaff.1, Pages 104-105

Preamble:
"Note that Union's proposed approach is particularly problematic because it accounts not only for input assumption updates, but also changes in implementation. It also proposes annual target updates. Accounting for implementation changes and updating the performance incentive annually removes the benefits of applying a multi-year plan. Through a multi-year plan, a utility has the flexibility to achieve the overall multi-year goal at a pace that is suitable for its service territory, customers, and energy markets, which may not be the same pace every year."

Question:
Please confirm Synapse understands that Union needs to meet annual scorecard targets in order to achieve a shareholder incentive.

RESPONSE

Confirmed. The Board's DSM Framework states that: "In order to earn the maximum <u>annual</u> shareholder incentive, the gas utilities will be expected to propose both <u>challenging</u> natural gas savings targets and address the key priorities outlined in Section 6.2. The incentive payment is ultimately commensurate with results." [emphasis added] (Report of the Ontario Energy Board, December 22, 2014, page 22).

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

UNION INTERROGATORY #15

INTERROGATORY

Reference: L.OEBStaff.1, Page 113; EB-2015-0029, Exhibit A, Tab 1, Appendix B, Page 2

Preamble:
"Financing can expand energy efficiency efforts while mitigating ratepayer impacts by shifting away from incentives or rebates to greater participant contributions over time." This is contrary to Union's understanding given that "rebates and incentives are the most valued program feature by residential, single family, and commercial-industrial mass market customers."

Question:
Please explain in detail, including examples, where this has been demonstrated to be successful in leading jurisdictions.

RESPONSE

There are many programs in the United States and Canada that successfully pair incentives with financing to encourage participation in energy efficiency programs. Please see examples in SEEAction's 2014 Report entitled Financing Energy Improvements on Utility Bills: Market Updates and Key Program Design Considerations for Policymakers and Administrators, available at: https://www4.eere.energy.gov/seeaction/system/files/documents/onbill_financing.pdf.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

UNION INTERROGATORY #16

INTERROGATORY

Reference: L.OEBStaff.1, Page 119 and 122

Preamble:
At Section 9.2.3, Synapse states, “relevant literature consistently recommends that best practice with regard to regulatory reporting is to maintain the planned input assumptions, at least for the savings on which performance incentives are based.”

And,

At Section 9.2.5 Synapse states, “the precedent in Ontario is to apply updated evaluation results to shareholder incentives and the LRAM. It is important to maintain regulatory precedent on such matters, to provide consistency to the utilities developing and implementing the plan and to participating stakeholders.”

Question:
Would Synapse agree that the Board’s policy regarding the application of best available information to determining shareholder incentive is not in line with best practice? If so, please explain why maintaining consistency with this regulatory precedent is more important than adopting best practices. Is Synapse aware of other jurisdictions where regulatory policies on this issue have evolved?

RESPONSE

Note that for this issue, while the literature may recommend a certain practice, jurisdictions regularly implement practices that differ from the literature recommendations. This is because it is a policy decision for regulators to decide the extent to which evaluation impacts should effect utility shareholder incentives and program results. Jurisdictions take different approaches on when and how to apply evaluation results.

In Ontario, the Board has previously visited this issue and established a policy for how to address updated input assumptions, and that decision was partially based on ensuring consistency with the electric CDM program policies. It is important to maintain regulatory precedent on such matters, to provide consistency to the utilities developing and implementing the plan and to participating stakeholders. Only extenuating circumstances should cause the Board to revisit this policy, and such conditions are not apparent in the current proceeding.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

Regulatory policies have evolved on this issues in Massachusetts as summarized in the referenced section of the report (specifically pages 120 into 121). The Massachusetts D.P.U. 11-120 docket fully addresses the evolution of this issue in the state.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

UNION INTERROGATORY #17

INTERROGATORY

Reference: L.OEBStaff.1, Pages 126-127

Preamble:
Synapse states that "Ontario's approach of accounting for savings persistence as part of the EUL is consistent with common practice." Under Section 9.4.1, recommendation # 2, Synapse then recommends that "The Board could consider accounting for savings persistence using one of a combination of the methods identified above." (four methods are listed on Page 127).

Question:
If Union is already following common industry practice, how does Synapse justify spending additional ratepayer dollars as per recommendation #2?

RESPONSE

In June 2015, the Board determined that "a formal persistence study should be given priority to provide support for the persistence of savings associated with large custom commercial and industrial DSM programs" (Ontario Energy Board, Decision and Order, EB-2014-0273, June 4, 2015, p. 7).

The Board has already determined that it is appropriate to evaluate savings persistence. Synapse's recommendations are intended to inform the formal persistence study. Our report focused primarily on program design in addition to other aspects of DSM program implementation, and was not a formal evaluation of savings persistence. As such, conducting a formal persistence study focused entirely on this one topic is likely to provide in-depth and insightful assessments of savings persistence in Ontario.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

UNION INTERROGATORY #18

INTERROGATORY

Reference:

A. L.OEBStaff.1, Page 9, Table 5
B. L.OEBStaff.1, Page 11, Table 9
C. L.OEBStaff.1, Page 12, Table 11
D. L.OEBStaff.1, Page 12, Table 10
E. L.OEBStaff.1, Page 13

Question:

a. Please provide the calculations and the data sources used for Reference A (L.OEBStaff.1, Page 9, Table 5).
b. Please provide the calculations and the data sources used for Reference B (L.OEBStaff.1, Page 11, Table 9).
c. Please provide the calculations and the data sources used for Reference C (L.OEBStaff.1, Page 12, Table 11).
d. Please confirm that Reference C (L.OEBStaff.1, Page 12, Table 11) allocates overhead/administration costs to the individual programs as well as the portfolio level, whereas Reference D (L.OEBStaff.1, Page 12, Table 10) allocates all overhead/administration costs at the portfolio level.
e. On Page 13, Section 3.2, Synapse states "For Union, in 2012, 23% of the budget was spent on residential and low income programs resulting in about 5% of the overall savings, and the C&I program comprised 77% of the budget to obtain 95% of the savings." Please provide the calculations and the data sources used to generate the percentages.

RESPONSE

a. Refer to Exhibit M.Staff.UNION.18, Attachment 1, which is a Microsoft Excel workbook with formulas indicating how the tables were populated using Union's source data. Note that in responding to this request, a few small typographical errors were discovered that amounted to a less than 1% difference in the presented data. These errors have been corrected in the attached to be consistent with the utility's filing.

b. See Union-18, part a.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

c. Confirmed; the tables are consistent with each companies' evidence (Union: Exh. A, Tab 3, p 6, Table 2; Enbridge: Exh. B, Tab 1, Sch. 4, pp. 3-5, and Exhibit I. T3. EGDI.EP.18). Union provided the overhead and administrative costs at the customer sector level, whereas Enbridge did not provide allocations at the customer sector level. Also, see Union-18, part a.

d. See Union-18, part a. Specifically, refer to the "Union Offering Analysis" tab.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

Ontario Gas DSM Data Review

UNION Budget & Savings Analysis

August 12, 2015

BY PROGRAM

TABLE FOR REPORT

UNION 2016-2020 TOTAL					
Program / Sector	**Total Utility Costs ($)**	**% of Total Costs**	**Lifetime Savings (M3)**	**% of Total Savings**	**Cost of Saved Energy ($/M3)**
Resource Acquisition	**176,547,000**	**58%**	**5,816,035,529**	**94%**	**0.0304**
Residential	81,029,000	27%	653,283,919	11%	0.1240
C&I Total	95,518,000	32%	5,162,751,610	84%	0.0185
Market Transformation	**1,042,000**	**0.3%**	**-**	**0%**	
Residential	1,042,000	0.3%	-	0%	
Low Income	**66,183,000**	**22%**	**282,123,495**	**5%**	**0.2346**
Low Income	66,183,000	22%	282,123,495	5%	0.2346
Performance Based Total	**4,365,000**	**1.4%**	**60,000,000**	**1%**	**0.0728**
C&I	4,365,000	1.4%	60,000,000	1%	0.0728
Large Volume	**3,988,000**	**1.3%**	**-**	**0%**	
C&I	3,988,000	1.3%	-	0%	
Portfolio Subtotal	**252,125,000**	**83.5%**	**6,158,159,024**	**100%**	**0.0409**
Other Costs	34,803,000	12%	-		
Inflation	14,977,000	5%	-		
Portfolio Total	***301,905,000***	***100%***	***6,158,159,024***	***100%***	***0.0490***

SUPPORTING ANALYSIS

UNION TOTAL UTILITY COSTS								
Program / Sector	**2016**	**2017**	**2018**	**2019**	**2020**	**2016-2020**	**% of Total**	*Source*
Resource Acquisition	**30,825,000**	**34,185,000**	**37,403,000**	**37,067,000**	**37,067,000**	**176,547,000**	**58%**	Sum of Res and C&I
Residential Total	12,145,000	15,349,000	17,845,000	17,845,000	17,845,000	81,029,000	27%	*Exh. A, Tab 3, p 6, Table 2*
C&I Total	18,680,000	18,836,000	19,558,000	19,222,000	19,222,000	95,518,000	32%	*Exh. A, Tab 3, p 6, Table 2*
Market Transformation	**1,042,000**	**-**	**-**	**-**	**-**	**1,042,000**	**0%**	Equal to Res
Residential	1,042,000	-	-	-	-	1,042,000	0%	*Exh. A, Tab 3, p 6, Table 2*
Low Income Total	**11,349,000**	**12,284,000**	**13,514,000**	**14,088,000**	**14,948,000**	**66,183,000**	**22%**	Equal to Low Income
Low Income	11,349,000	12,284,000	13,514,000	14,088,000	14,948,000	66,183,000	22%	*Exh. A, Tab 3, p 6, Table 2*
Performance Based Total	**548,000**	**843,000**	**1,088,000**	**833,000**	**1,053,000**	**4,365,000**	**1%**	Equal to C&I
C&I	548,000	843,000	1,088,000	833,000	1,053,000	4,365,000	1%	*Exh. A, Tab 3, p 6, Table 2*
Large Volume	**809,000**	**758,000**	**783,000**	**807,000**	**831,000**	**3,988,000**	**1%**	Equal to C&I
C&I	809,000	758,000	783,000	807,000	831,000	3,988,000	1%	*Exh. A, Tab 3, p 6, Table 2*
Portfolio Subtotal	**44,573,000**	**48,070,000**	**52,788,000**	**52,795,000**	**53,899,000**	**252,125,000**	**84%**	Sum of programs
All Programs & Sectors	**12,681,000**	**7,979,000**	**8,637,000**	**9,669,000**	**10,814,000**	**49,780,000**	**16%**	Sum of other costs and inflation
Other Costs	11,735,000	6,142,000	5,642,000	5,642,000	5,642,000	34,803,000	12%	*Exh. A, Tab 3, p 6, Table 2*
Inflation	946,000	1,837,000	2,995,000	4,027,000	5,172,000	14,977,000	5%	*Exh. A, Tab 3, p 6, Table 2*
Portfolio Total	***57,254,000***	***56,049,000***	***61,425,000***	***62,464,000***	***64,713,000***	***301,905,000***	***100%***	Sum of programs and all costs
Year-to-Year Change		-2%	10%	2%	4%			

LIFETIME SAVINGS (M3)								
Program / Sector	**2016**	**2017**	**2018**	**2019**	**2020**	**2016-2020**	**% of**	
Resource Acquisition	**1,109,631,656**	**1,148,519,100**	**1,185,792,799**	**1,186,045,987**	**1,186,045,987**	**5,816,035,529**	**94%**	Sum of Res and C&I
Residential Total	89,941,084	120,074,931	147,587,176	147,840,364	147,840,364	653,283,919	11%	*Exh. A, Tab 3, App. A p 15, Table 6*
C&I Total	1,019,690,572	1,028,444,169	1,038,205,623	1,038,205,623	1,038,205,623	5,162,751,610	84%	*Exh. A, Tab 3, App. A p 43, Table 13*
Low Income Total	**51,492,897**	**53,397,574**	**55,907,554**	**60,062,460**	**61,263,010**	**282,123,495**	**5%**	Equal to Low Income
Low Income	51,492,897	53,397,574	55,907,554	60,062,460	61,263,010	282,123,495	5%	*Exh. A, Tab 3, App. A p 89, Table 31*
Performance Based	**-**	**1,250,000**	**7,750,000**	**18,250,000**	**32,750,000**	**60,000,000**	**1%**	Equal to C&I
C&I	-	1,250,000	7,750,000	18,250,000	32,750,000	60,000,000	1%	*Exh. A, Tab 3, App. A p 60, Table 22*
Portfolio Total	**1,161,124,553**	**1,203,166,674**	**1,249,450,353**	**1,264,358,447**	**1,280,058,997**	**6,158,159,024**	**100%**	Sum of programs
Year-to-Year Change		4%	4%	1%	1%			

UNION COST OF SAVED ENERGY ($/M3)						
Program / Sector	**2016**	**2017**	**2018**	**2019**	**2020**	**2016-2020**
Resource Acquisition	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**
Residential Total	0.14	0.13	0.12	0.12	0.12	0.12
C&I Total	0.02	0.02	0.02	0.02	0.02	0.02
Low Income Total	**0.22**	**0.23**	**0.24**	**0.23**	**0.24**	**0.23**
Low Income	0.22	0.23	0.24	0.23	0.24	0.23
Performance Based		**0.67**	**0.14**	**0.05**	**0.03**	**0.07**
C&I		0.67	0.14	0.05	0.03	0.07
Portfolio Total	**0.05**	**0.05**	**0.05**	**0.05**	**0.05**	**0.05**
Year-to-Year Change		-6%	6%	0%	2%	

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BY CUSTOMER SECTOR, 2016-2018 TOTAL

TABLE FOR REPORT

UNION 2016-2020 TOTAL					
Program / Sector	Total Utility Costs ($)	% of Total Costs	Lifetime Savings (M3)	% of Total Savings	Cost of Saved Energy ($/M3)
Residential	**82,071,000**	**27%**	**653,283,919**	**11%**	**0.1256**
Resource Acquisition	81,029,000	27%	653,283,919	11%	0.1240
Market Transformation	1,042,000	0%	-	0%	
Commercial & Industrial	**103,871,000**	**34%**	**5,222,751,610**	**85%**	**0.0199**
Resource Acquisition	95,518,000	32%	5,162,751,610	84%	0.0185
Performance Based	4,365,000	1%	60,000,000	1%	0.0728
Large Volume	3,988,000	1%	-	0%	
Low Income Total	**66,183,000**	**22%**	**282,123,495**	**5%**	**0.2346**
Low Income	66,183,000	22%	282,123,495	5%	0.2346
Portfolio Subtotal	**252,125,000**	**84%**	**6,158,159,024**	**100%**	**0.0409**
Other Costs	34,803,000	12%	-		
Inflation	14,977,000	5%	-		
Portfolio Total	***301,905,000***	***100%***	***6,158,159,024***	***100%***	***0.0490***

SUPPORTING ANALYSIS

UNION TOTAL UTILITY COSTS							
Sector / Program	2016	2017	2018	2019	2020	2016-2020	% of Total
Residential	**13,187,000**	**15,349,000**	**17,845,000**	**17,845,000**	**17,845,000**	**82,071,000**	**33%**
Resource Acquisition	12,145,000	15,349,000	17,845,000	17,845,000	17,845,000	81,029,000	32%
Market Transformation	1,042,000	-	-	-	-	1,042,000	0%
Commercial & Industrial	**20,037,000**	**20,437,000**	**21,429,000**	**20,862,000**	**21,106,000**	**103,871,000**	**41%**
Resource Acquisition	18,680,000	18,836,000	19,558,000	19,222,000	19,222,000	95,518,000	38%
Performance Based	548,000	843,000	1,088,000	833,000	1,053,000	4,365,000	2%
Large Volume	809,000	758,000	783,000	807,000	831,000	3,988,000	2%
Low Income Total	**11,349,000**	**12,284,000**	**13,514,000**	**14,088,000**	**14,948,000**	**66,183,000**	**26%**
Low Income	11,349,000	12,284,000	13,514,000	14,088,000	14,948,000	66,183,000	26%
Portfolio Subtotal	**44,573,000**	**48,070,000**	**52,788,000**	**52,795,000**	**53,899,000**	**252,125,000**	**84%**
All Programs & Sectors	**12,681,000**	**7,979,000**	**8,637,000**	**9,669,000**	**10,814,000**	**49,780,000**	**16%**
Other Costs	11,735,000	6,142,000	5,642,000	5,642,000	5,642,000	34,803,000	12%
Inflation	946,000	1,837,000	2,995,000	4,027,000	5,172,000	14,977,000	5%
Portfolio Total	***57,254,000***	***56,049,000***	***61,425,000***	***62,464,000***	***64,713,000***	***301,905,000***	***100%***

UNION LIFETIME SAVINGS (M3)							
Sector / Program	2016	2017	2018	2019	2020	2016-2020	% of
Residential	**89,941,084**	**120,074,931**	**147,587,176**	**147,840,364**	**147,840,364**	**653,283,919**	**11%**
Resource Acquisition	89,941,084	120,074,931	147,587,176	147,840,364	147,840,364	653,283,919	11%
Market Transformation	-	-	-	-	-	-	0%
Commercial & Industrial	**1,019,690,572**	**1,029,694,169**	**1,045,955,623**	**1,056,455,623**	**1,070,955,623**	**5,222,751,610**	**85%**
Resource Acquisition	1,019,690,572	1,028,444,169	1,038,205,623	1,038,205,623	1,038,205,623	5,162,751,610	84%
Performance Based	-	1,250,000	7,750,000	18,250,000	32,750,000	60,000,000	1%
Large Volume	-	-	-	-	-	-	0%
Low Income Total	**51,492,897**	**53,397,574**	**55,907,554**	**60,062,460**	**61,263,010**	**282,123,495**	**5%**
Low Income	51,492,897	53,397,574	55,907,554	60,062,460	61,263,010	282,123,495	5%
Portfolio Total	**1,161,124,553**	**1,203,166,674**	**1,249,450,353**	**1,264,358,447**	**1,280,058,997**	**6,158,159,024**	**100%**

UNION COST OF SAVED ENERGY ($/M3)						
Sector / Program	2016	2017	2018	2019	2020	2016-2020
Residential	**0.15**	**0.13**	**0.12**	**0.12**	**0.12**	**0.13**
Resource Acquisition	0.14	0.13	0.12	0.12	0.12	0.12
Market Transformation						
Commercial & Industrial	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**
Resource Acquisition	0.02	0.02	0.02	0.02	0.02	0.02
Performance Based		0.67	0.14	0.05	0.03	0.07
Large Volume						
Low Income Total	**0.22**	**0.23**	**0.24**	**0.23**	**0.24**	**0.23**
Low Income	0.22	0.23	0.24	0.23	0.24	0.23
Portfolio Total	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**

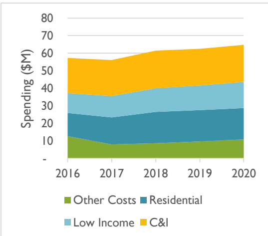
Ontario Gas DSM Data Review

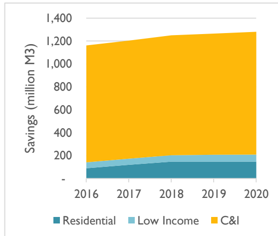
UNION Budget & Savings Analysis

August 12, 2015

BY CUSTOMER SECTOR, 2016-2018 ANNUALLY

FIGURES FOR REPORT





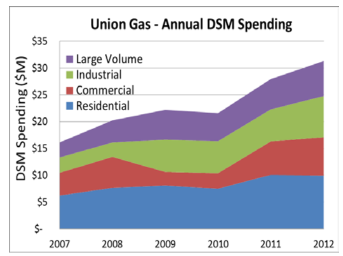
SUPPORTING ANALYSIS

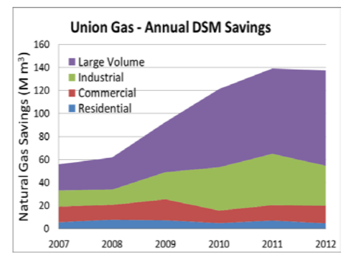
Spending ($M)					
Customer Sector	**2016**	**2017**	**2018**	**2019**	**2020**
Residential	13	15	18	18	18
Low Income	11	12	14	14	15
Other Costs	13	8	9	10	11
C&I	20	20	21	21	21
Total	57	56	61	62	65

Savings (million M3)					
Customer Sector	**2016**	**2017**	**2018**	**2019**	**2020**
Residential	90	120	148	148	148
Low Income	51	53	56	60	61
C&I	1,020	1,030	1,046	1,056	1,071

2012 Comparison				
Customer Sector	**Spending**		**Savings**	
Residential	7	23%	6	4%
C&I	24	77%	134	96%
Total	31	100%	140	100%

Source: estimated from the figures below, from 2015-2020 DSM Framework, December 2014, pages 10, 14.





Ontario Gas DSM Data Review

UNION Cost-Effectiveness Analysis

August 12, 2015

Total Resource Cost Test

TABLE FOR REPORT

Union 2016 TRC Plus Test					
Program / Sector	**TRC Plus Costs**	**Unassigned Costs**	**Benefits**	**Net Benefits**	**BCR**
Resource Acquisition	117,426,427	12,714,231	270,415,793	140,275,134	2.078
Low Income Total	7,981,140	4,106,838	12,227,629	139,651	1.012
Portfolio Total	***125,407,567***	***16,821,069***	***282,643,422***	***140,414,785***	***1.987***

SUPPORTING ANALYSIS

Union 2016 TRC Plus Test						
Program / Sector	**TRC Plus Costs**	**Unassigned Costs**	**Benefits**	**Net Benefits**	**BCR**	*Source*
Residential Resource Acquisition	12,407,946	6,165,311	25,952,169	7,378,912	1.40	*Exh. A, Tab 3, App. A, p. 23.*
C&I Resource Acquisition	105,018,481	6,548,920	244,463,624	132,896,222	2.20	*Exh. A, Tab 3, App. A, pp. 48-49.*
Total Resource Acquisition	**117,426,427**	**12,714,231**	**270,415,793**	**140,275,134**	**2.08**	Sum of residential and C&I
Low-Income Total	**7,981,140**	**4,106,838**	**12,227,629**	**139,651**	**1.01**	*Exh. A, Tab 3, App. A, p. 96.*
Portfolio Total	**125,407,567**	**16,821,069**	**282,643,422**	**140,414,785**	**1.99**	Sum of Resource Acquisition and Low Income

Program Administrator Cost Test

TABLE FOR REPORT

Union 2016 PAC Test					
Program / Sector	**PAC Costs**	**Unassigned Costs**	**Benefits**	**Net Benefits**	**BCR**
Resource Acquisition	18,110,862	12,714,231	211,760,958	180,935,865	6.870
Low Income Total	7,299,019	4,106,838	9,791,947	- 1,613,910	0.859
Portfolio Total	***25,409,881***	***16,821,069***	***221,552,905***	***179,321,955***	***5.246***

SUPPORTING ANALYSIS

Union 2016 TRC Plus Test						
Program / Sector	**TRC Plus Costs**	**Unassigned Costs**	**Benefits**	**Net Benefits**	**BCR**	*Source*
Residential Resource Acquisition	5,979,759	6,165,311	16,996,332	4,851,262	1.40	*Exh. A, Tab 3, App. A, p. 24*
C&I Resource Acquisition	12,131,103	6,548,920	194,764,626	176,084,603		*Exh. A, Tab 3, App. A, pp. 50-51.*
Total Resource Acquisition	**18,110,862**	**12,714,231**	**211,760,958**	**180,935,865**	**6.87**	Sum of residential and C&I
Low-Income Total	**7,299,019**	**4,106,838**	**9,791,947**	**- 1,613,910**	**0.86**	*Exh. A, Tab 3, App. A, p. 97.*
Portfolio Total	**25,409,881**	**16,821,069**	**221,552,905**	**179,321,955**	**5.25**	Sum of Resource Acquisition and Low Income

Ontario Gas DSM Data Review

Customer & Sales Data

August 12, 2015

Customer & Sales

TABLE FOR REPORT

Union 2014 Customer Sectors					
Customer Sector	Customers	% of Customers	Sales (million M3)	% of Sales	Usage per Customer
Residential	1,299,273	92%	3,270	23%	2,517
C&I	119,755	8%	10,934	77%	91,302
Total	1,419,028	100%	14,204	100%	10,010

SUPPORTING ANALYSIS

Enbridge & Union Customer and Sales Data					
Utility	Year	Customer Sector	Sales (Million m3)	Customers	Source
Union	2014	Residential	3,270	1,299,273	Exh. A, Tab 1, App. A, Sch. 4-5.
Union	2014	C&I	10,934	119,755	Exh. A, Tab 1, App. A, Sch. 4-5.
Union	2014	Total	14,204	1,419,028	Exh. A, Tab 1, App. A, Sch. 4-5.

ENERGY PROBE RESEARCH FOUNDATION INTERROGATORY #1

INTERROGATORY

Reference: No Reference –Data/information Sources

Question:

a. Please indicate the primary sources used by Synapse in conducting its work e.g. Published Materials (such as EGD and Union Annual Reports) and prior and Current Applications and Interrogatories.
b. Please indicate whether, in conducting its work, Synapse met with EGDI and Union to clarify questions about the existing and proposed Programs Measures and Offers. If not, why was this not done?
c. Is Synapse concerned that without checking facts, certain statements about programs and measures may not be accurate?

RESPONSE

a. Please refer to the References section of the report, found at L.OEBStaff.1, pages 132-137.

b. No, Synapse did not meet with EGDI and Union while preparing its report. We relied on the material presented by the utilities in the case proceeding, including their DSM plans and responses to interrogatories. Also, the OEB staff assisted us in locating relevant material and data within the case proceeding or in historical proceedings as needed.

c. The findings and recommendations within the Synapse report are true and accurate to the best of our knowledge.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

ENERGY PROBE RESEARCH FOUNDATION INTERROGATORY #2

INTERROGATORY

Reference: No Reference - Billing Analysis

Question:

a. Please define the scope of a Billing Analysis as described in the Report.
b. Please provide an example of a billing analysis for a Residential RA Program/Offer (Union/EGD preferred).
c. Please provide billing analysis for a Residential MT Program/offer (EGDI/Union preferred)

RESPONSE

a. A billing analysis typically requires at least 9 to 12 months of both pre-retrofit and post-retrofit energy consumption data. It is recommended that a billing analysis use regression analysis to adjust the post-retrofit consumption data for all substantive explanatory (independent) variables that affect energy consumption such as weather, occupancy schedules, industrial throughput, control set points, and operating schedules. This approach is equivalent to the International Performance Measurement and Verification Protocol (IPMVP) Option C: Whole Facility Analysis. For more information, see SEE Action (2012). Energy Efficiency Program Impact Evaluation Guide, page 4-6, available at https://www4.eere.energy.gov/seeaction/system/files/documents/emv_ee_program_impact_guide_0.pdf

b. A billing analysis for a residential single-family retrofit offering such as Enbridge's Home Energy Conservation offering and Union's Home Reno Rebate offering will require, as discussed in Exhibit M.Staff.EP.2, part a., 9 to 12 months of pre- and post-retrofit energy consumption data. Key independent variables for adjusting the baseline consumption data should include weather at a minimum.

c. As discussed in Exhibit L.OEBStaff.1, page 35, a billing analysis is not useful for new construction projects as there is no pre-construction baseline data. In contrast, a large-scale consumption data billing analysis (as discussed in Exhibit L.OEBStaff.1, page 21) is often used for evaluating the impacts of residential behavior programs. In such an analysis, billing data for a treatment group and a control group are compared to each other.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

ENERGY PROBE RESEARCH FOUNDATION INTERROGATORY #3

INTERROGATORY

Reference: L, OEB Staff 1, Synapse Report Page 32; Recommendations Page 32

Preamble:
“Guiding Principle 5 encourages the utilities to achieve higher customer participation levels.

Requiring two measures per customer could decrease participation as customers that are able or willing to install only one DSM measure are turned away from the program. Guiding Principle 6 addresses minimization of lost opportunities, and as discussed above, this program requirement could result in lost savings opportunities”.

Question:

a. Please confirm the “as filed” participation levels and participation rates for each year of the plan for the EGDI Home Retrofit Program.
b. For either a single “deep measure” or Phased approach (2 measures over the plan period) please provide the following:
    - Participation and Participation rates for each Synapse scenario.
    - The Incentive and other program budget increase.
    - The $/CCM and Cost/Benefit compared to EGD Base plan.
c. Does Synapse understand that the EGD RA Scorecard and Shareholder Incentive is a function of installation of two “deep measures”? [Exhibit B, Tab 1, Schedule 4, Page 10, Table 8: 2016 Resource Acquisition Scorecard].
d. How would Synapse propose to amend the scorecard and provide details and compare the result in terms of achievement and shareholder incentive to EGDI’s baseline proposal?

RESPONSE

a. Please refer to the table below, which is based on Enbridge’s DSM Plan, Exh. B, Tab 1, Sch. 4, pages 10-14.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

Year	Home Energy Retrofit Participants		
	Lower	Middle	Upper
2016	5,631	7,508	11,262
2017	7,500	10,000	15,000
2018	9,259	12,346	18,519
2019	9,711	12,948	19,422
2020	10,109	13,478	20,218

b. Synapse was tasked with reviewing the proposed DSM programs and commenting on the program design elements that could be modified or improved. The Synapse recommendation referenced above is intended provide general guidance and direction, and is not intended to indicate a specific quantitative outcome (see Exhibit L.OEBStaff.1, page 2; see also Exhibit M.Staff.EGDI.4). Therefore, we have not estimated the requested data as it is beyond the scope of our work.

c. Yes.

d. Synapse would not amend the scorecard.

   By design, an incentive mechanism is intended to motivate actions that would not otherwise be taken in the absence of the incentive mechanism. The utilities could maintain the current scorecard design to ensure focus on installing two measures per customer. Our recommendation is simply that customers looking to install one measure should not be turned away from the program; our recommendation is not that the utilities should only focus on one measure per customer or should remove focus from installing two measures per customer.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

ENERGY PROBE RESEARCH FOUNDATION INTERROGATORY #4

INTERROGATORY

Reference: L, OEB Staff 1, Synapse Report, HRP Recommendations Page 32

Preamble:

4. Enbridge should increase the offering incentive cap to be greater than $2,000. For example, Enbridge could be consistent with Union's incentive cap of $5,000.

5. Enbridge should reconsider its tiered incentive structure, and consider offering a sliding scale incentive structure that should start at a lower savings level than the current 15 percent savings. This would to accommodate some customers that could just install one measure at a time.

Questions:
Please provide the Impact of these Recommendations on the EGD HRP:

- Participation Rates
- Incentives
- Budgets
- Achievement
- Scorecard and
- Shareholder Incentive

RESPONSE

Synapse was tasked with reviewing the proposed DSM programs and commenting on the program design elements that could be modified or improved. The Synapse recommendation referenced above is intended provide general guidance and direction, and is not intended to indicate a specific quantitative outcome (see Exhibit L.OEBStaff.1, page 2; see also Exhibit M.Staff.EGDI.4). Therefore, we have not estimated the requested data as it is beyond the scope of our work.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

ENERGY PROBE RESEARCH FOUNDATION INTERROGATORY #5

INTERROGATORY

Reference: L, OEB Staff 1, Synapse Report, HRP Recommendations Page 32

Preamble:

6. If Enbridge continues to offer a tiered incentive structure or offers a sliding-scale incentive, then it should lower the amount of savings required to achieve the various incentive levels or increase the level of incentives. As currently structured, a customer is required to achieve a significant reduction in usage in order to receive a relatively limited incentive amount.

7. Enbridge should consider providing incentives such that they are structured on a per square-foot basis, or on a percentage-of-total-project-cost basis for insulation measures. In addition, it should provide prescriptive incentives for other measures similar to Union's incentive structures. Such a structure provides flexibility to the customer, thereby allowing households of different sizes, shapes, and energy consumption to participate.

Question:

a. Please provide an example of a tiered incentive structure (indicate measure(s)) and the anticipated impact of Recommendation 6 on the following relative to EGDI's plan:
   - Participation and participation rates
   - Achievement CCM and Efficiency $/CCM
b. For Recommendation 7, please provide example(s) and provide estimates of impact(s) on EGDI and Union:
   - Participation and Participation Rates
   - Incentives
   - Budgets
   - Achievements (CCM) and Efficiency $/CCM)
   - Scorecard
   - Shareholder Incentive

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

RESPONSE

a. Examples of tiered incentive structures are discussed in Exhibit L.OEBStaff.1, pages 45-46, 76. In addition, New Jersey's Home Performance with Energy Star program uses a tiered incentive approach.[9]

Regarding the request to provide estimates of the impacts of such examples, Synapse was tasked with reviewing the proposed DSM programs and commenting on the program design elements that could be modified or improved. Recommendation 6 is intended to improve the incentive structure proposed by Enbridge while minimally impacting its design. It is intended provide general guidance and direction, and is not intended to indicate a specific quantitative outcome. Therefore, we have not estimated the requested data as it is beyond the scope of our work.

b. Refer to L.OEBStaff.1, pages 33-34, where it states:

> This is the approach used in Massachusetts, where utilities offer up to 75 percent of the costs for insulation projects. Massachusetts' programs also provide air sealing at no cost to the customer, as well as incentives for heating and water heating systems in addition to the insulation incentives. The incentive provided for heating and water heating varies according to the type of unit installed, but typically ranges between $246 and $1,975 per unit.

For more information, refer to Exhibit M.Staff.EP.5, Attachment 1, page 7, which is an excerpt from the November 2, 2012 Massachusetts 2013-2015 energy efficiency plan for both gas and electric program administrators.

Regarding the request to provide estimates of the impacts of such an example, Synapse was tasked with reviewing the proposed DSM programs and commenting on the program design elements that could be modified or improved. The Synapse recommendation referenced above is intended provide general guidance and direction, and is not intended to indicate a specific quantitative outcome (see Exhibit L.OEBStaff.1, page 2; see also Exhibit M.Staff.EGDI.4). Therefore, we have not estimated the requested data as it is beyond the scope of our work.

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[9] For more information, refer to: http://www.njcleanenergy.com/residential/programs/home-performance-energy-star/benefits-and-incentives

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

<table>
<tr><th>SECTOR</th><th>PROGRAM</th><th>CORE INITIATIVE</th><th colspan="3">ADMINISTERED BY</th></tr>
<tr><td rowspan="2">RESIDENTIAL</td><td rowspan="2">WHOLE HOUSE</td><td rowspan="2">HOME ENERGY SERVICES</td><td rowspan="2">ELECTRIC & GAS PAs</td><td>●</td><td>JOINT</td></tr>
<tr><td></td><td>PA - SPECIFIC</td></tr>
<tr><td rowspan="2">Core Initiative Overview</td><td colspan="5">Key Objectives:

To offer single family (1-4 units) residential customers energy efficiency recommendations and incentives that enable those customers to identify and implement cost-effective energy efficiency improvements. The Home Energy Services (“HES”) Core Initiative utilizes outreach mechanisms, cross-marketing, incentives, and financing to make it easy, clear, and compelling for customers to participate in all residential energy efficiency programs. The program exemplifies a program-as-a-system approach where all components work together to support the success of achieving deeper energy savings per customer.</td></tr>
<tr><td colspan="5">New Enhancements:

The PAs are considering various initiatives for implementation over the next three years. However, as the redesigned market model continues into the next three year plan, it is our recommendation that new initiatives are phased in throughout the three-year plan. As Independent Installation Contractors and Home Performance Contractors are still familiarizing themselves with the new program model, we believe it is best to allow adequate time for the contractors to become proficient.

Also, to ensure proper roll out, the PAs recommend allowing for adequate planning of timelines for various initiatives to include a test period and review prior to launch. The PAs are fully committed to the enhancements listed below and will make every attempt to roll out, where feasible, any new enhancements, prior to the noted timelines

The PAs are also making strides towards deeper savings. Some examples include the PAs’ exploration of:
Targeted customer segmentation outreach (best opportunities to fit the customer’s needs)</td></tr>
</table>

	Packaging of measures Whole house incentives (for multi-unit, single-family homes) Targeted hard-to-reach (such as Efficient Neighborhoods+) Pre-weatherization incentives Inclusion of renovation and deeper savings measures incentives Early retirement incentives for heating and cooling equipment Targeting of higher tiered appliances for incentive offerings Potential for engagement with the Massachusetts Clean Energy Center, if applicable • PAs plan to investigate the opportunity to incorporate cost-effective new technologies and measures (e.g. advanced insulation including spray foam insulation). PAs plan to work with the evaluation team to review measures by Q2 2013. • PAs intend to explore offering recognition events to encourage contractors to maintain high quality work, highlight best practices and recognize various program partners for excelling in their profession. PAs plan to work with Contractor Best Practices Group on ways to highlight quality installers and installations. • PAs plan to explore enhanced customer follow-up strategies to encourage increased major measure implementation. Strategies may include targeted emails and mailings. This is an ongoing effort. • PAs intend to investigate online options for customer sign-up/tracking by enhancing web/mobile friendly applications for ease of customer use. For example, PAs would like to explore capturing customer interest in receiving a Home Energy Assessment through the online portal. The HES Core Initiative plan to work with other initiatives to coordinate implementation with the statewide marketing group. • PAs intend to define the hard to reach/hard to serve market and explore solutions. PAs plan to investigate options to overcome tenant-landlord barriers to program participation, focusing on clear program outreach to maximize savings and benefits from this hard to reach/ hard to serve market. PAs plan to build on lessons learned from past experience. Please refer the Efficient Neighborhoods+. • PAs plan to review evaluation results from the 2012 Pre-weatherization barrier initiative, which offered incentives to evaluate conditions and remediate health and safety barriers such as knob and

	tube wiring, dryer vents, and combustion safety. Based on the analysis, PAs intend to design a standard pre-weatherization barrier offer and may review incentives for other barriers. Please refer to the Action Plan section on Pre-weatherization. • PAs intend to continue supporting the development of highly qualified Home Performance Contractors ("HPCs") and Independent Insulation Contractors ("IICs") by offering various training subsidies for workforce development needs such as technical skills, business skills, and sales trainings. This is an ongoing effort. • PAs intend to explore a shared incentive approach in multi-unit (2-4 unit) buildings to maximize the incentive among all units in the building to achieve deeper energy savings. This approach will address a whole-building approach as opposed to a unit-focused approach. The PAs plan to identify a program model by Q3 2013 with implementation by Q2 2014. • PAs plan to continue engagement with community groups and initiatives to market HES. Refer to the *Elements of a Community Model* section submitted as part of Metric #2 of the "2011 Community Outreach Report", as well as the Community Engagement description in Section III.H.2 of this Plan. This is an ongoing effort. • PAs intend to test the efficacy of enhanced incentives to increase penetration into hard to reach markets, such as 2-4 unit dwellings and economically challenged neighborhoods in 2013. PAs will seek to incorporate lessons learned from a similar program offered in the early 2000s. PAs intend to use lessons learned from the 2013 trial offer to implement a broad offering in 2014 and beyond. • PAs plan to review the HPC evaluation results to identify any variations in customer experience and implementation rates to develop strategies for continued improvements. Recommendations may be implemented among Lead Vendor Energy Specialists and Home Performance Contractors. This is an ongoing effort. • PAs anticipate offering deeper energy savings based upon lessons learned from the major renovations, including additions and deep energy retrofit pilots. Significant research is necessary to develop the trainings needed to build the contractor infrastructure to implement this initiative successfully. Currently, efforts are underway to create a manual for deep energy retrofit components, but key trainings will be needed to ensure a quality end-product. The PAs plan to offer new approaches to these efforts with key trade allies by Q1 2014. PAs intend to explore possible partnerships and incentive offerings with trade allies such as fuel dealers, general

	contractors, roofers, and siding contractors to increase customer participation by promoting the HES initiative. Based on evaluations, these efforts may take some continued efforts. The PAs plan to continue offer information to interested contractors and plan to work with other initiatives to offer materials by Q2 2013. PAs plan to review the results of the 2011 "Packaged Measures Pilot" for lessons learned to develop a cost-effective package or bundle of incentives for customers to implement multiple deeper energy savings measures. Based on evaluations, these efforts may take some continued efforts. The PAs plan to offer information to interested contractors and work with other initiatives to offer a new packaged measure for a limited time promotional timeframe by Q3-2013.
Core Initiative Design	The HES core initiative is committed to a comprehensive whole-house approach and seeks to maximize energy savings. The initiative directs customers using natural gas for space heating to their gas provider and customers using electric, oil or propane for space heating to their electric provider. It is also recognized that exceptions to this guideline may occur (*e.g.*, specialized high bill complaints, community outreach programs, etc.). In these cases, and unless there are prior mutual agreements between the gas and electric PAs, the PAs will seek to negotiate in good faith to achieve a resolution that serves the common interests of both PAs, the interests of the consumer, and maximizes savings opportunities on a fuel-neutral basis. The initiative is committed to achieving maximum program success and deeper energy savings. The program aims to make distinctions indiscernible to consumers. The service is intended to be customizable, providing personalized information and incentives to a broad group of customers. Customers are guided to the appropriate program services, including targeted energy efficiency information, advanced diagnostics, and efficiency rebates and incentives. Low-income customers are referred to appropriate low-income programs. The PAs currently offer one single comprehensive assessment, called the Home Energy Assessment. This assessment is an in-home visit designed to provide general information and education about energy efficiency and identify opportunities and challenges for energy saving installations. With the customer's permission, Compact Fluorescent Lights ("CFLs") are installed for no cost in all appropriate locations, as are low-flow shower heads, faucet aerators and programmable thermostats (as needed and qualified). The instant energy savings realized during the Home Energy Assessment are intended, on average, to exceed

	the expected average cost to deliver this visit. Additionally, during this visit, customers' specific needs will be evaluated, and opportunities for subsequent direct installation measures may be identified. Customers will be directed to other energy-efficiency resources as appropriate. The Home Energy Assessment also includes a variety of diagnostic techniques such as infrared scanning (temperature permitting). Wherever feasible, full installation of targeted cost-effective air sealing is provided at no cost to the customer. In all cases where the customer elects the fully subsidized air sealing offer, or installation of insulation, a blower door test and combustion safety test will be performed pre and post installation to maximize air leakage reduction and maintain combustion safety standards. If specific energy-efficient improvements require professional contractors, or a customer contribution, the Energy Specialist explains the contractor services required to install recommended measures, as well as all available energy efficiency financial incentives. Another visit, the Special Home Visit, may be scheduled for those customers interested in measure screening such as a refrigerator screening or in "no heat" emergency situations where a pre-screening for an applicable incentive is required. An Energy Specialist will perform a quick assessment of the home for energy efficiency opportunities, install instant savings measures (where appropriate), and screen the refrigerator or heating system for upgrade eligibility. A customer may be scheduled for a Special Home Visit as determined during the initial intake process. To ensure all work is completed to the PAs' standards, the Quality Assurance Visit allows all work to be inspected. This may be done through a combination of methods, including a phone survey, postcard, e-mail or actual site visit by the lead vendor and/or a third-party PA-approved vendor. Quality inspections are performed to ensure that contractor-installed measures are accurate, professional, and safely installed based on initiative standards, as well as to ensure savings. The PAs strive to maximize energy savings by promoting and supporting contractor training and education in an effort to establish a broader workforce knowledgeable of proper installation techniques. The goal is to have a sustainable and experienced workforce focused on achieving maximum energy savings and ready and able to meet customer demand.
Marketing Overview	**Target Market:**

	The HES initiative target market is all non-low-income residential customers living in single family houses or one- to four-unit buildings that are not part of a larger site where an association exists (such as a condo association with multiple 4-unit buildings). The initiative aims to reach the aforementioned customers who are interested in making their homes more energy efficient. HES is a fuel-blind initiative.
	Strategy: Outreach and marketing efforts will be expanded and PAs plan to explore building relationships with realtors, home improvement contractors, architects and others involved in renovations of one-to-four family homes. Marketing efforts will be designed to meet the objectives of reaching more customers (going broader into the customer base) and maximizing energy savings opportunities (going deeper into each home to find ways to save energy). The PAs will also continue market segmentation work to strategically target customers with the most opportunity as to increase the rate of audits that result in energy efficiency measure recommendations. The PAs plan to work closely with Independent Installation Contractors and Home Performance Contractors as a means to increase participation and consumer savings. Further, the PAs plan to continue to seek new ways to identify, educate and reach landlords and other hard to reach/ hard to serve customers to increase participation. Efforts may include targeted marketing based on identified key demographics to better reach the 2-4 unit property sector. The initiative's multi-media outreach campaign will focus on partnerships with local media outlets or affiliates, radio, print advertising, web-based marketing through various social media sites, and through part of the consolidated website, www.masssave.com, which integrates all of the Massachusetts energy efficiency programs and incentives into a single source web-based outlet. Current forms of multi-media outreach include: • Mass Save® website (enhanced via the Statewide Integrated Energy Efficiency Website) • Bill inserts • Highly visible billboards • Radio, print and visual media advertising • Registry of Motor Vehicle advertising

- Cinema advertising
- New media advertising (advanced online options)
- Targeted outreach through Community-based Outreach Initiatives ("CBOs"). These initiatives utilize community outreach for promoting this program and the array of incentives available.

Individual Program Administrators may conduct additional marketing, such as behavior feedback mechanisms, if applicable and may ramp their marketing up or down as needed to meet participation and budget goals.

Technologies/Incentives

The following is a list of targeted end uses, recommended technologies, and incentives offered:

Targeted End Use	Technology	Incentive
In Unit Lighting	Compact Fluorescent Light Bulbs	No Cost to Customer
In Unit Lighting	LED technology	limited (subject to planning and budget impact)
Water Conservation	Faucet Aerators and Showerheads	No Cost to Customer
Heating and Cooling	Programmable Thermostats – electric heat	No Cost to Customer
Electricity Conservation	Smart Strips (where applicable)	No Cost to Customer
Heating and Cooling	Targeted cost effective air sealing	No Cost to Customer
Weatherization	Attic Insulation Wall Insulation Basement/Crawl Space Insulation Rim Joist Insulation DHW insulation Pipe Insulation	75% Incentive up to $2,000
Appliances	ENERGY STAR® Rated Refrigerator	$150 For Qualified Replacements
Heating	Heating System	Varies by type
Water Heating	Water Heating	Varies by type

	Additionally: • 0% financing HEAT Loan offers $500-$25,000 with terms from 2 - 7 years for qualified customers • Alternative insulation types, if cost effective, (*e.g.*, spray foam, rock wool) will be incorporated into the program offers • Pre-weatherization offers • Early heating system and heat pump water heater replacement rebates • The PAs will work with the MTAC to include new measures or technologies as appropriate.
Delivery Mechanism	The program is delivered by lead vendors selected through a competitive bidding process. Lead vendors are responsible for managing and training market based participants such as participating IICs and HPCs. Additional lead vendor responsibilities include: • Consistent statewide training • Data reporting • Achieving aggressive savings • Customer satisfaction • Quality control standards • Scheduling requirements • Technical Assistance • Maintain and report health and safety information Two groups of participating contractors, Home Performance Contractors ("HPCs"), and Independent Installation Contractors ("IICs") provide services in addition to those services offered by the lead vendor. All participating contractors must meet program eligibility and requirements. HPCs independently recruit customers, provide Home Energy Assessments, and implement weatherization measures. IICs provide installation of weatherization measures for those customers who received a Home Energy Assessment from the lead vendor. IICs also have the opportunity to independently recruit customers and refer them to the lead vendor for the Home Energy Assessment. In order to receive incentives or program rebates, customers are required to have a Home Energy Assessment through either the PAs lead vendor or via a participating Home Performance Contractor to

	identify and prioritize all cost-effective energy efficiency upgrades. Insulation work, whether performed by a Home Performance Contractor or Independent Installation Contractor, will have a quality control inspection performed by the PA-vendor, or third party vendor when the work is complete. This will ensure that high quality is maintained, and installations meet BPI standards or similar standards set by the PAs. After a competitive bidding process, the PAs contracted with a third-party Quality Control ("QC") vendor to perform QC inspections of program implementation vendors, and participating contractors. The QC vendor will provide valuable information and feedback to the HES members on successes and identify areas of possible improvement. The HES members are working together toward a "best practices" approach to provide a more coordinated statewide training to reinforce quality installation techniques in HES. It is expected that training requirements will increase over time in order for contractors to retain their status as a HES participating contractor. Additionally, contractors must maintain a high level of customer satisfaction to continue participating in the initiative.
Three-Year Deployment Strategy/Roadmap	With the numerous enhancements that have been identified for this initiative, HES will continue to prioritize the enhancements that will lead to the most benefits for the largest number of customers. PAs intend to better capture and utilize property data for the purpose of identifying properties with potential installation opportunities to implement targeting marketing efforts. PAs will continue to explore new technologies in conjunction with significantly increasing the implementation of known cost effective measures. PAs intend to continue to develop the proficiency of participating contractors through establishing qualification/training guidelines using the BPI or its equivalent as a benchmark. Please see Core Initiative Overview section for near term and longer term enhancements that will be explored in this three-year plan.
Special Notes	HES underwent significant changes in 2011, and numerous enhancements are proposed to continually address customer needs. The priorities have been made to address the most customers with the biggest savings impacts. The PAs will continue to refine the priorities as evaluations are completed. The key to proposed efforts will be to research, train, and test theories before full-blown implementation to ensure that the PAs are addressing opportunities with the best information available. One key effort, Efficient Neighborhoods+, will address hard to reach/hard to serve customers in economically challenged neighborhoods. For further detail, please refer to section III.F.6.b.i.

ENERGY PROBE RESEARCH FOUNDATION INTERROGATORY #6

INTERROGATORY

Reference: L, OEB Staff 1, Synapse Report Page 40

Preamble:
Measure Mix. Both Enbridge and Union should consider providing incentives for measures other than thermostats and instant hot water saving measures.

Question:

a. Please confirm specifically what Synapse recommends regarding PT and Water saving measures. Indicate how many homes will receive the offers. Provide the estimated participation rates and the Cost per home and total budget for each of EGDI and Union.
b. For the other measures listed in the Reference, please provide a shortlist and indicate if based on Synapse's experience, if they will pass the TRC and PAC test.
c. Please provide for shortlisted offers, ballpark estimates for the levels of participation rates and Budgets required.

RESPONSE

a. Synapse elaborates on its specific recommendations in L.OEBStaff.1, pages 38-39, where it states:

> Both Enbridge and Union should consider providing incentives for measures other than thermostats and instant hot water saving measures. For example, Massachusetts gas energy efficiency program administrators offer hot water boilers, furnaces, select heating system controls including retrofit boiler reset controls, gas water-heating equipment, and heat recovery ventilator equipment. Even though such measures are included as part of the single-family retrofit offering, they could also be provided through a products program to ensure that all customers are served by a range of DSM technologies and to increase participation.

Also refer to L.OEBStaff.1, page 30, Section 5.2.4 Residential Products.

Regarding the data requested, Synapse was tasked with reviewing the proposed DSM programs and commenting on the program design elements that could be modified or improved. The Synapse recommendation referenced above is intended provide general guidance and direction, and is not intended to indicate a specific quantitative outcome (see Exhibit L.OEBStaff.1, page 2;

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

see also Exhibit M.Staff.EGDI.4). Therefore, we have not estimated the requested data as it is beyond the scope of our work.

b. Please refer to Exhibit M.Staff.EP.6, Attachment 1, which is an excerpt from the April 30, 2015 draft of the Massachusetts 2016-2018 energy efficiency plan for both gas and electric program administrators.[10] As indicated in the attachment, the Massachusetts gas program administrators' statewide TRC benefit-cost ratio for the Residential Heating & Cooling Equipment initiative is 1.21 in 2016, 1.26 in 2017, 1.30 in 2018, which is 1.26 over the 2016-2018 three-year term. The PAC test is not required in Massachusetts, so we cannot provide example benefit-cost ratios using the PAC test. However, the PAC test benefit-cost ratios are typically higher than the TRC test, so it is likely that a residential products program will be cost-effective under the PAC test as well as the TRC test.

c. Synapse was tasked with reviewing the proposed DSM programs and commenting on the program design elements that could be modified or improved. The Synapse recommendation referenced above is intended provide general guidance and direction, and is not intended to indicate a specific quantitative outcome (see Exhibit L.OEBStaff.1, page 2; see also Exhibit M.Staff.EGDI.4). Therefore, we have not estimated the requested data as it is beyond the scope of our work.

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[10] Massachusetts Program Administrators. (2015a). 2016-2018 Massachusetts Joint Statewide Three-Year Electric and Gas Energy Efficiency Plan. Retrieved from http://ma-eeac.org/wordpress/wpcontent/uploads/2016-2018-DRAFT-Electric-Gas-Energy-Efficiency-Plan.pdf

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

IV.D. Cost Effectiveness

1. Summary Table

Statewide Gas

April 30, 2015

April 30 Plan Draft
Data Tables

2016 Total Resource Cost Test (2016$)

Program	Benefit-Cost Ratio	Net Benefits	Total TRC Test Benefits	Costs			
				Total Program Costs	Performance Incentive	Participant Costs	Total TRC Test Costs
A - Residential	**1.59**	**100,141,901**	**270,800,294**	**119,845,321**	**3,882,517**	**46,456,914**	**170,658,392**
A1 - Residential Whole House	1.79	94,763,411	214,042,011	89,370,083	3,405,267	26,151,012	119,278,600
A1a - Residential New Construction	2.25	21,409,309	38,470,736	9,254,814	611,319	7,151,420	17,061,427
A1b - Residential Multi-Family Retrofit	2.33	11,229,296	19,652,317	8,329,739	314,981	-258,454	8,423,021
A1c - Residential Home Energy Services - Measures	1.86	68,894,389	148,863,070	58,231,532	2,224,798	19,258,046	79,968,682
A1d - Residential Home Energy Services - RCS	0.00	-10,499,643	0	10,483,626	16,017	0	10,499,643
A1e - Residential Behavior/Feedback Program	2.12	3,730,060	7,055,887	3,070,373	238,151	0	3,325,827
A2 - Residential Products	1.21	9,677,537	56,758,283	26,176,191	477,250	20,305,903	47,080,746
A2a - Residential Heating & Cooling Equipment	1.21	9,677,537	56,758,283	26,176,191	477,250	20,305,903	47,080,746
A2b - Residential Consumer Products		0	0	0	0	0	0
A2c - Residential Lighting		0	0	0	0	0	0
A3 - Residential Hard-to-Measure	0.00	-4,299,047	0	4,299,047	0	0	4,299,047
A3a - Residential Statewide Marketing	0.00	-929,919	0	929,919	0	0	929,919
A3b - Residential Statewide Database	0.00	-109,624	0	109,624	0	0	109,624
A3c - Residential DOER Assessment	0.00	-457,969	0	457,969	0	0	457,969
A3d - Residential EEAC Consultants	0.00	-177,592	0	177,592	0	0	177,592
A3e - Residential Sponsorships & Subscriptions	0.00	-153,913	0	153,913	0	0	153,913
A3f - Residential HEAT Loan	0.00	-1,331,837	0	1,331,837	0	0	1,331,837
A3g - Residential Workforce Development	0.00	-249,302	0	249,302	0	0	249,302
A3h - Residential R&D and Demonstration	0.00	-525,880	0	525,880	0	0	525,880
A3i - Residential Education	0.00	-363,013	0	363,013	0	0	363,013
B - Low-Income	**1.67**	**29,484,962**	**73,327,421**	**42,514,057**	**1,145,547**	**0**	**43,842,459**
B1 - Low-Income Whole House	1.73	30,865,353	73,327,421	41,133,667	1,145,547	0	42,462,069
B1a - Low-Income Single Family Retrofit	1.31	6,543,650	27,439,790	20,445,258	355,194	0	20,896,140
B1b - Low-Income Multi-Family Retrofit	2.13	24,321,702	45,887,631	20,688,409	790,352	0	21,565,928
B2 - Low-Income Hard-to-Measure	0.00	-1,380,390	0	1,380,390	0	0	1,380,390
B2a - Low-Income Statewide Marketing	0.00	-317,980	0	317,980	0	0	317,980
B2b - Low-Income Statewide Database	0.00	-42,608	0	42,608	0	0	42,608
B2c - Low-Income DOER Assessment	0.00	-226,119	0	226,119	0	0	226,119
B2d - Low-Income Energy Affordability Network	0.00	-738,524	0	738,524	0	0	738,524
B2e - Low-Income Sponsorships & Subscriptions	0.00	-55,160	0	55,160	0	0	55,160
C - Commercial & Industrial	**2.34**	**75,240,803**	**131,350,366**	**39,848,433**	**2,232,264**	**13,887,528**	**56,109,563**
C1 - C&I New Construction	2.42	27,320,555	46,560,187	14,038,013	797,514	4,350,807	19,239,632
C1a - C&I New Buildings & Major Renovations	2.72	17,474,255	27,654,835	7,670,450	490,683	1,988,021	10,180,580
C1b - C&I Initial Purchase & End of Useful Life	2.09	9,846,300	18,905,352	6,367,563	306,831	2,362,786	9,059,052
C2 - C&I Retrofit	2.39	49,386,580	84,790,179	24,344,088	1,434,750	9,536,720	35,403,599
C2a - C&I Existing Building Retrofit	2.36	38,517,879	66,901,698	17,828,257	1,132,938	9,364,108	28,383,819
C2b - C&I Small Business	3.12	3,704,454	5,454,218	1,434,322	96,753	217,635	1,749,764
C2c - C&I Multifamily Retrofit	2.36	7,164,247	12,434,263	5,081,509	205,059	-45,023	5,270,016
C2d - C&I Upstream Lighting		0	0	0	0	0	0
C3 - C&I Hard-to-Measure	0.00	-1,466,333	0	1,466,333	0	0	1,466,333
C3a - C&I Statewide Marketing	0.00	-357,373	0	357,373	0	0	357,373
C3b - C&I Statewide Database	0.00	-39,847	0	39,847	0	0	39,847
C3c - C&I DOER Assessment	0.00	-398,975	0	398,975	0	0	398,975
C3d - C&I EEAC Consultants	0.00	-172,522	0	172,522	0	0	172,522
C3e - C&I Sponsorships & Subscriptions	0.00	-79,301	0	79,301	0	0	79,301
C3f - C&I Workforce Development	0.00	-62,390	0	62,390	0	0	62,390
C3g - C&I R&D and Demonstration	0.00	-355,925	0	355,925	0	0	355,925
Grand Total	**1.76**	**204,867,666**	**475,478,081**	**202,207,812**	**7,260,328**	**60,344,442**	**270,610,415**

IV.D. Cost Effectiveness

1. Summary Table

Statewide Gas

April 30, 2015

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Data Tables

2017 Total Resource Cost Test (2016$)							
Program	Benefit-Cost Ratio	Net Benefits	Total TRC Test Benefits	Costs			
				Total Program Costs	Performance Incentive	Participant Costs	Total TRC Test Costs
A - Residential	**1.65**	**111,728,270**	**283,814,674**	**120,466,760**	**4,123,151**	**47,020,728**	**172,086,403**
A1 - Residential Whole House	1.87	104,434,842	224,823,863	89,786,728	3,603,087	26,645,388	120,389,022
A1a - Residential New Construction	2.28	21,377,065	38,060,222	8,921,893	604,765	7,112,428	16,683,156
A1b - Residential Multi-Family Retrofit	2.39	11,732,206	20,168,644	8,300,991	323,856	-225,329	8,436,437
A1c - Residential Home Energy Services - Measures	1.98	79,207,836	160,321,365	58,663,542	2,436,250	19,758,290	81,113,529
A1d - Residential Home Energy Services - RCS	0.00	-10,725,617	0	10,713,931	11,686	0	10,725,617
A1e - Residential Behavior/Feedback Program	1.83	2,843,350	6,273,633	3,186,372	226,530	0	3,430,283
A2 - Residential Products	1.26	12,040,976	58,990,810	25,932,484	520,064	20,375,340	46,949,834
A2a - Residential Heating & Cooling Equipment	1.26	12,040,976	58,990,810	25,932,484	520,064	20,375,340	46,949,834
A2b - Residential Consumer Products		0	0	0	0	0	0
A2c - Residential Lighting		0	0	0	0	0	0
A3 - Residential Hard-to-Measure	0.00	-4,747,548	0	4,747,548	0	0	4,747,548
A3a - Residential Statewide Marketing	0.00	-1,416,997	0	1,416,997	0	0	1,416,997
A3b - Residential Statewide Database	0.00	-106,713	0	106,713	0	0	106,713
A3c - Residential DOER Assessment	0.00	-452,575	0	452,575	0	0	452,575
A3d - Residential EEAC Consultants	0.00	-175,940	0	175,940	0	0	175,940
A3e - Residential Sponsorships & Subscriptions	0.00	-202,357	0	202,357	0	0	202,357
A3f - Residential HEAT Loan	0.00	-1,311,466	0	1,311,466	0	0	1,311,466
A3g - Residential Workforce Development	0.00	-253,623	0	253,623	0	0	253,623
A3h - Residential R&D and Demonstration	0.00	-458,637	0	458,637	0	0	458,637
A3i - Residential Education	0.00	-369,241	0	369,241	0	0	369,241
B - Low-Income	**1.68**	**29,674,485**	**73,131,729**	**42,143,428**	**1,130,140**	**0**	**43,457,244**
B1 - Low-Income Whole House	1.74	31,043,738	73,131,729	40,774,175	1,130,140	0	42,087,991
B1a - Low-Income Single Family Retrofit	1.31	6,520,187	27,378,617	20,414,775	347,537	0	20,858,430
B1b - Low-Income Multi-Family Retrofit	2.16	24,523,550	45,753,112	20,359,400	782,603	0	21,229,561
B2 - Low-Income Hard-to-Measure	0.00	-1,369,253	0	1,369,253	0	0	1,369,253
B2a - Low-Income Statewide Marketing	0.00	-316,785	0	316,785	0	0	316,785
B2b - Low-Income Statewide Database	0.00	-41,968	0	41,968	0	0	41,968
B2c - Low-Income DOER Assessment	0.00	-222,480	0	222,480	0	0	222,480
B2d - Low-Income Energy Affordability Network	0.00	-733,765	0	733,765	0	0	733,765
B2e - Low-Income Sponsorships & Subscriptions	0.00	-54,255	0	54,255	0	0	54,255
C - Commercial & Industrial	**2.29**	**72,611,995**	**129,033,922**	**39,978,190**	**2,165,222**	**14,136,543**	**56,421,927**
C1 - C&I New Construction	2.33	26,766,840	46,860,067	14,424,622	791,003	4,824,066	20,093,227
C1a - C&I New Buildings & Major Renovations	2.55	16,810,564	27,684,225	8,121,626	481,484	2,238,985	10,873,661
C1b - C&I Initial Purchase & End of Useful Life	2.08	9,956,276	19,175,842	6,302,996	309,519	2,585,080	9,219,566
C2 - C&I Retrofit	2.35	47,183,364	82,173,855	24,215,359	1,374,219	9,312,477	34,990,491
C2a - C&I Existing Building Retrofit	2.28	35,823,129	63,710,343	17,640,756	1,064,036	9,123,645	27,887,215
C2b - C&I Small Business	3.03	3,766,409	5,620,451	1,518,218	97,489	237,276	1,854,042
C2c - C&I Multifamily Retrofit	2.45	7,593,826	12,843,061	5,056,386	212,695	-48,444	5,249,235
C2d - C&I Upstream Lighting		0	0	0	0	0	0
C3 - C&I Hard-to-Measure	0.00	-1,338,209	0	1,338,209	0	0	1,338,209
C3a - C&I Statewide Marketing	0.00	-356,517	0	356,517	0	0	356,517
C3b - C&I Statewide Database	0.00	-38,640	0	38,640	0	0	38,640
C3c - C&I DOER Assessment	0.00	-390,918	0	390,918	0	0	390,918
C3d - C&I EEAC Consultants	0.00	-168,946	0	168,946	0	0	168,946
C3e - C&I Sponsorships & Subscriptions	0.00	-77,892	0	77,892	0	0	77,892
C3f - C&I Workforce Development	0.00	-47,949	0	47,949	0	0	47,949
C3g - C&I R&D and Demonstration	0.00	-257,347	0	257,347	0	0	257,347
Grand Total	**1.79**	**214,014,751**	**485,980,325**	**202,588,377**	**7,418,513**	**61,157,271**	**271,965,574**

IV.D. Cost Effectiveness

1. Summary Table

Statewide Gas

April 30, 2015

2018 Total Resource Cost Test (2016$)

Program	Benefit-Cost Ratio	Net Benefits	Total TRC Test Benefits	Costs: Total Program Costs	Costs: Performance Incentive	Costs: Participant Costs	Costs: Total TRC Test Costs
A - Residential	**1.68**	**117,050,413**	**290,422,739**	**121,147,384**	**4,166,311**	**47,580,732**	**173,372,326**
A1 - Residential Whole House	1.88	107,438,627	229,082,849	90,623,431	3,609,528	27,055,858	121,644,222
A1a - Residential New Construction	2.34	22,163,247	38,726,599	8,814,363	611,839	7,092,882	16,563,353
A1b - Residential Multi-Family Retrofit	2.44	12,187,156	20,634,495	8,282,365	328,429	-200,540	8,447,339
A1c - Residential Home Energy Services - Measures	2.00	81,996,833	164,240,613	59,376,433	2,447,239	20,163,515	82,243,780
A1d - Residential Home Energy Services - RCS	0.00	-10,852,026	0	10,842,873	9,154	0	10,852,026
A1e - Residential Behavior/Feedback Program	1.55	1,943,417	5,481,141	3,307,397	212,867	0	3,537,724
A2 - Residential Products	1.30	14,278,295	61,339,891	25,857,444	556,784	20,524,875	47,061,596
A2a - Residential Heating & Cooling Equipment	1.30	14,278,295	61,339,891	25,857,444	556,784	20,524,875	47,061,596
A2b - Residential Consumer Products		0	0	0	0	0	0
A2c - Residential Lighting		0	0	0	0	0	0
A3 - Residential Hard-to-Measure	0.00	-4,666,509	0	4,666,509	0	0	4,666,509
A3a - Residential Statewide Marketing	0.00	-1,397,320	0	1,397,320	0	0	1,397,320
A3b - Residential Statewide Database	0.00	-103,982	0	103,982	0	0	103,982
A3c - Residential DOER Assessment	0.00	-447,426	0	447,426	0	0	447,426
A3d - Residential EEAC Consultants	0.00	-174,467	0	174,467	0	0	174,467
A3e - Residential Sponsorships & Subscriptions	0.00	-195,183	0	195,183	0	0	195,183
A3f - Residential HEAT Loan	0.00	-1,294,330	0	1,294,330	0	0	1,294,330
A3g - Residential Workforce Development	0.00	-243,719	0	243,719	0	0	243,719
A3h - Residential R&D and Demonstration	0.00	-440,442	0	440,442	0	0	440,442
A3i - Residential Education	0.00	-369,640	0	369,640	0	0	369,640
B - Low-Income	**1.70**	**30,186,137**	**73,109,214**	**41,609,435**	**1,129,142**	**0**	**42,923,077**
B1 - Low-Income Whole House	1.77	31,722,918	73,109,214	40,072,655	1,129,142	0	41,386,296
B1a - Low-Income Single Family Retrofit	1.34	6,950,731	27,431,645	20,033,277	351,089	0	20,480,914
B1b - Low-Income Multi-Family Retrofit	2.18	24,772,187	45,677,569	20,039,378	778,053	0	20,905,382
B2 - Low-Income Hard-to-Measure	0.00	-1,536,781	0	1,536,781	0	0	1,536,781
B2a - Low-Income Statewide Marketing	0.00	-503,173	0	503,173	0	0	503,173
B2b - Low-Income Statewide Database	0.00	-41,269	0	41,269	0	0	41,269
B2c - Low-Income DOER Assessment	0.00	-219,150	0	219,150	0	0	219,150
B2d - Low-Income Energy Affordability Network	0.00	-720,901	0	720,901	0	0	720,901
B2e - Low-Income Sponsorships & Subscriptions	0.00	-52,288	0	52,288	0	0	52,288
C - Commercial & Industrial	**2.29**	**72,668,545**	**128,803,202**	**39,879,040**	**1,899,399**	**14,213,609**	**56,134,658**
C1 - C&I New Construction	2.34	27,182,613	47,432,178	14,469,109	667,028	5,059,651	20,249,565
C1a - C&I New Buildings & Major Renovations	2.59	17,097,336	27,861,814	8,114,643	394,374	2,223,754	10,764,479
C1b - C&I Initial Purchase & End of Useful Life	2.06	10,085,278	19,570,364	6,354,467	272,654	2,835,897	9,485,086
C2 - C&I Retrofit	2.35	46,761,525	81,371,024	24,134,337	1,232,371	9,153,957	34,609,499
C2a - C&I Existing Building Retrofit	2.27	35,051,674	62,584,296	17,532,965	978,096	8,962,519	27,532,622
C2b - C&I Small Business	3.07	3,837,897	5,694,230	1,514,458	97,196	243,616	1,856,333
C2c - C&I Multifamily Retrofit	2.51	7,871,955	13,092,498	5,086,914	157,080	-52,177	5,220,544
C2d - C&I Upstream Lighting		0	0	0	0	0	0
C3 - C&I Hard-to-Measure	0.00	-1,275,594	0	1,275,594	0	0	1,275,594
C3a - C&I Statewide Marketing	0.00	-347,750	0	347,750	0	0	347,750
C3b - C&I Statewide Database	0.00	-37,430	0	37,430	0	0	37,430
C3c - C&I DOER Assessment	0.00	-382,942	0	382,942	0	0	382,942
C3d - C&I EEAC Consultants	0.00	-165,399	0	165,399	0	0	165,399
C3e - C&I Sponsorships & Subscriptions	0.00	-75,421	0	75,421	0	0	75,421
C3f - C&I Workforce Development	0.00	-67,555	0	67,555	0	0	67,555
C3g - C&I R&D and Demonstration	0.00	-199,098	0	199,098	0	0	199,098
Grand Total	**1.81**	**219,905,094**	**492,335,156**	**202,635,860**	**7,194,853**	**61,794,341**	**272,430,061**

IV.D. Cost Effectiveness

1. Summary Table

Statewide Gas

April 30, 2015

2016-2018 Total Resource Cost Test (2016$)

Program	Benefit-Cost Ratio	Net Benefits	Total TRC Test Benefits	Costs: Total Program Costs	Costs: Performance Incentive	Costs: Participant Costs	Costs: Total TRC Test Costs
A - Residential	**1.64**	**328,920,585**	**845,037,707**	**361,459,465**	**12,171,979**	**141,058,375**	**516,117,122**
A1 - Residential Whole House	1.85	306,636,879	667,948,723	269,780,242	10,617,882	79,852,257	361,311,843
A1a - Residential New Construction	2.29	64,949,621	115,257,557	26,991,070	1,827,923	21,356,730	50,307,936
A1b - Residential Multi-Family Retrofit	2.39	35,148,659	60,455,456	24,913,094	967,266	-684,323	25,306,797
A1c - Residential Home Energy Services - Measures	1.95	230,099,058	473,425,049	176,271,506	7,108,287	59,179,850	243,325,991
A1d - Residential Home Energy Services - RCS	0.00	-32,077,286	0	32,040,429	36,857	0	32,077,286
A1e - Residential Behavior/Feedback Program	1.83	8,516,827	18,810,661	9,564,142	677,549	0	10,293,834
A2 - Residential Products	1.26	35,996,809	177,088,984	77,966,120	1,554,098	61,206,117	141,092,176
A2a - Residential Heating & Cooling Equipment	1.26	35,996,809	177,088,984	77,966,120	1,554,098	61,206,117	141,092,176
A2b - Residential Consumer Products		0	0	0	0	0	0
A2c - Residential Lighting		0	0	0	0	0	0
A3 - Residential Hard-to-Measure	0.00	-13,713,103	0	13,713,103	0	0	13,713,103
A3a - Residential Statewide Marketing	0.00	-3,744,236	0	3,744,236	0	0	3,744,236
A3b - Residential Statewide Database	0.00	-320,318	0	320,318	0	0	320,318
A3c - Residential DOER Assessment	0.00	-1,357,970	0	1,357,970	0	0	1,357,970
A3d - Residential EEAC Consultants	0.00	-527,998	0	527,998	0	0	527,998
A3e - Residential Sponsorships & Subscriptions	0.00	-551,452	0	551,452	0	0	551,452
A3f - Residential HEAT Loan	0.00	-3,937,634	0	3,937,634	0	0	3,937,634
A3g - Residential Workforce Development	0.00	-746,644	0	746,644	0	0	746,644
A3h - Residential R&D and Demonstration	0.00	-1,424,958	0	1,424,958	0	0	1,424,958
A3i - Residential Education	0.00	-1,101,894	0	1,101,894	0	0	1,101,894
B - Low-Income	**1.69**	**89,345,584**	**219,568,364**	**126,266,920**	**3,404,829**	**0**	**130,222,780**
B1 - Low-Income Whole House	1.74	93,632,008	219,568,364	121,980,496	3,404,829	0	125,936,356
B1a - Low-Income Single Family Retrofit	1.32	20,014,568	82,250,053	60,893,309	1,053,821	0	62,235,484
B1b - Low-Income Multi-Family Retrofit	2.16	73,617,440	137,318,311	61,087,187	2,351,008	0	63,700,872
B2 - Low-Income Hard-to-Measure	0.00	-4,286,424	0	4,286,424	0	0	4,286,424
B2a - Low-Income Statewide Marketing	0.00	-1,137,937	0	1,137,937	0	0	1,137,937
B2b - Low-Income Statewide Database	0.00	-125,845	0	125,845	0	0	125,845
B2c - Low-Income DOER Assessment	0.00	-667,748	0	667,748	0	0	667,748
B2d - Low-Income Energy Affordability Network	0.00	-2,193,190	0	2,193,190	0	0	2,193,190
B2e - Low-Income Sponsorships & Subscriptions	0.00	-161,703	0	161,703	0	0	161,703
C - Commercial & Industrial	**2.31**	**220,521,342**	**389,187,490**	**119,705,663**	**6,296,886**	**42,237,679**	**168,666,148**
C1 - C&I New Construction	2.36	81,270,008	140,852,432	42,931,744	2,255,546	14,234,524	59,582,424
C1a - C&I New Buildings & Major Renovations	2.61	51,382,155	83,200,874	23,906,718	1,366,542	6,450,761	31,818,719
C1b - C&I Initial Purchase & End of Useful Life	2.08	29,887,853	57,651,558	19,025,026	889,004	7,783,764	27,763,705
C2 - C&I Retrofit	2.37	143,331,470	248,335,058	72,693,784	4,041,340	28,003,155	105,003,588
C2a - C&I Existing Building Retrofit	2.31	109,392,682	193,196,337	53,001,978	3,175,069	27,450,272	83,803,656
C2b - C&I Small Business	3.07	11,308,760	16,768,898	4,466,997	291,437	698,526	5,460,138
C2c - C&I Multifamily Retrofit	2.44	22,630,028	38,369,822	15,224,809	574,834	-145,644	15,739,795
C2d - C&I Upstream Lighting		0	0	0	0	0	0
C3 - C&I Hard-to-Measure	0.00	-4,080,135	0	4,080,135	0	0	4,080,135
C3a - C&I Statewide Marketing	0.00	-1,061,640	0	1,061,640	0	0	1,061,640
C3b - C&I Statewide Database	0.00	-115,916	0	115,916	0	0	115,916
C3c - C&I DOER Assessment	0.00	-1,172,835	0	1,172,835	0	0	1,172,835
C3d - C&I EEAC Consultants	0.00	-506,867	0	506,867	0	0	506,867
C3e - C&I Sponsorships & Subscriptions	0.00	-232,613	0	232,613	0	0	232,613
C3f - C&I Workforce Development	0.00	-177,894	0	177,894	0	0	177,894
C3g - C&I R&D and Demonstration	0.00	-812,370	0	812,370	0	0	812,370
Grand Total	**1.78**	**638,787,511**	**1,453,793,561**	**607,432,049**	**21,873,694**	**183,296,054**	**815,006,050**

Notes:

The Benefit-Cost Ratio is the Total TRC Test Benefits divided by the Total TRC Test Costs.
The Net Benefits are the Total TRC Test Benefits minus the the Total TRC Test Costs.
For supporting information on the Total TRC Test Benefits, see Table IV.D.3.1.i.
For supporting information on the Total Program Costs, see Table IV.C.1.
For supporting information on the Performance Incentive, refer to the Performance Incentive Model.
The Total TRC Costs are the sum of the Total Program Costs, Performance Incentives, and Participant Costs.

ENERGY PROBE RESEARCH FOUNDATION INTERROGATORY #7

INTERROGATORY

Reference: L, OEB Staff 1, Synapse Report, Pages 30-42- Residential RA Programs

Question:

a. Please provide for each of EGD and Union a Summary Tabulation of Synapse-recommended Program changes over the 5 year plan period.
b. For each major category (Single Family Retrofit, Residential Products) please provide estimates of resulting changes to Participation/participation rates, Budgets and Achievements (CCM). If possible, estimate Average Efficiency $/CCM.
c. Compare and contrast the Synapse changes/enhancements to the Program plans filed by EGDI and Union.
d. Based on the above response please provide a revised Scorecard and Shareholder Incentive structure and estimates for each Utility.

RESPONSE

a. Please refer to L.OEBStaff.1, Appendix A: Summary of Recommendations, Section 5.3 Residential Resource Acquisition Programs, pages A3 to A5.

b. through d. Synapse was tasked with reviewing the proposed DSM programs and commenting on the program design elements that could be modified or improved. The Synapse recommendation referenced above is intended provide general guidance and direction, and is not intended to indicate a specific quantitative outcome (see Exhibit L.OEBStaff.1, page 2; see also Exhibit M.Staff.EGDI.4). Therefore, we have not estimated the requested data as it is beyond the scope of our work.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

ENERGY PROBE RESEARCH FOUNDATION INTERROGATORY #8

INTERROGATORY

Reference: Synapse Report with Energy Futures Group: Rate and Bill Impacts of Vermont Energy Efficiency Programs, for Vermont Public Service Department

Question:

a. Please indicate the relative roles of Synapse and Energy Futures in the Referenced Study.
b. Please summarize how Rate and Bill Impacts should be evaluated for Participants and non-participants in Energy Efficiency Programs.
c. Using Synapse's experience in other jurisdictions, for example in Vermont as referenced above, please provide a framework and methodology for estimating rate and bill impacts for Participants and Non participants from the EGDI and Union DSM Programs over the period 2015-2020. Discuss the various components of costs and benefits (e.g. Avoided Costs) and assumptions in such an analysis.
d. Please indicate, and provide details, if in Synapse's opinion, the required data are available in this case to conduct such an analysis. If so, should in Synapse's view, this analysis be done to inform the Board and Stakeholders regarding impacts for participants and non-participants, including whether the $2.00/customer per month bill "cap" guideline is/is not appropriate as some intervenor experts suggest?
e. Does Synapse have an opinion as to whether the budgets and resulting bill impacts proposed by EGDI and Union are appropriate?

RESPONSE

Synapse has not completed a report with Energy Futures Group on rate and bill impacts in Vermont. Synapse completed a report and accompanying analysis on the rate and bill impacts of energy efficiency programs in Vermont in 2014 for the Vermont Public Service Department, but it was an independent analysis. Therefore, we are uncertain which report Energy Probe is referencing.

Assuming that Energy Probe is referencing the 2014 independent analysis that Synapse completed for the Vermont Public Service Department,[11] then this report is not referenced in L.OEBStaff.1, nor was it relied upon to develop L.OEBStaff.1. Synapse was not asked by the Ontario Energy Board to investigate

[11] See Woolf, T., E. Malone, J. Kallay. 2014. Rate and Bill Impacts of Vermont Energy Efficiency Programs. Synapse Energy Economics for the Vermont Public Service Department.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

the rate and bill impacts accompanying the gas utilities' DSM plans. Therefore, we have not responded to the above questions as they are beyond the scope of our work.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

ENERGY PROBE RESEARCH FOUNDATION INTERROGATORY #9

INTERROGATORY

Reference: L, OEB Staff 1, Synapse Report Page 59

Question:

a. Please confirm whether under the existing LI programs, both EGDI and Union will provide funding for minor health and safety problem remediation.
b. Please explain why the proposals set out at EGDI's Evidence [Exhibit B, Tab 2, Schedule 1 Page 35] are not appropriate.
c. Please indicate your views on how much should the LI DSM Program spend to address health and safety issues -distinguish owned vs rented SF homes. Include in your response the line/delineation between health and safety improvements and DSM/Energy Efficiency improvements.

RESPONSE

a. Union provides funding for health and safety problem remediation.

   EGDI provides a carbon monoxide monitor in the event there is no one in the home (EGDI's Evidence, Exhibit B, Tab 2, Schedule 1, page 43). However, this does not sufficiently address common health and safety barriers to weatherization experienced by homeowners.

b. We do not see detailed proposals for health and safety problem remediation on this page so we cannot comment on the appropriateness of the proposals.

c. The primary delineation between health and safety improvements and energy efficiency improvements is that many health and safety improvements have little or no energy savings.

   We do not offer a specific recommendation as to how much the utilities should spend to address health and safety issues. This will depend on the types of health and safety improvements the utility decides to offer, the cost to the utility to incent customers to make these improvements and the estimated number of homes that will experience these issues. As Synapse did not have access to this detailed information, we recommended that EGDI consider offering incentives to address as many of the health and safety barriers to weatherization as possible.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

ENERGY PROBE RESEARCH FOUNDATION INTERROGATORY #10

INTERROGATORY

Reference: L, OEB Staff 1, Synapse Report Page 62 Recommendation 2

Preamble:
2. Enbridge and Union should consider adding early replacement measures, heating equipment repairs, boilers, water heaters (including tankless and solar hot water), windows, duct sealing, duct insulation, and boiler reset control measures to their offerings.

Question:

a. Has Synapse screened any of the proposed measures? If so, please provide this information.
b. For each measure, please provide an estimate of the # participants, Measure cost (gross installed and DSM program cost per home.
c. Please provide the annual incremental cost/budget for each measure/offer and the total over the 5 year program assuming all measures screen positive at the portfolio level.

RESPONSE

a. No, Synapse did not screen any measures.

b. and c. Synapse was tasked with reviewing the proposed DSM programs and commenting on the program design elements that could be modified or improved. The Synapse recommendation referenced above is intended provide general guidance and direction, and is not intended to indicate a specific quantitative outcome (see Exhibit L.OEBStaff.1, page 2; see also Exhibit M.Staff.EGDI.4). Therefore, we have not estimated the requested data as it is beyond the scope of our work.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

ENERGY PROBE RESEARCH FOUNDATION INTERROGATORY #11

INTERROGATORY

Reference: L, OEB Staff 1, Synapse Report Pages 62-63

Question:

a. Please confirm and provide references for EGDI and Union existing offers for MF Social Housing (publicly funded Affordable MF Housing).
b. Please confirm the EGDI MF Demonstration is for Market Rate Multi-Family housing.
c. Please provide a list of Jurisdictions with LI DSM programs for Market Rate MF Buildings.
d. For the Measures listed on Page 63 Is Synapse aware/not aware whether these have been screened by EGDI or Union at the Portfolio level. Has Synapse screened the measures listed? If so please provide the results.
e. For Market Rate MF Buildings (as opposed to Social Housing) please provide the criteria for LI Program enrollment and financial assistance in the jurisdictions listed on page 63.

RESPONSE

a. EGDI and Union's existing offers for MF social housing is integrated into their respective Low Income Multi-Family offerings. Please see Enbridge Gas Distribution 2015b, Exh. B, Tab 2, Sch. 1, pp. 34, 36-41 and Union Gas Limited, 2015a, Exh. A, Tab 3, App. A, pp. 83-87 for details.

b. Union's MF Demonstration is for Market Rate Multi-Family housing. EGDI's Market Rate Multi-Family housing offering is a full scale offering. They had a demonstration in 2013 which launched into the full scale program in Q3 2014 (Enbridge Gas Distribution 2015b, Exh. B, Tab 2, Sch. 1, p. 38).

c. Synapse was tasked with reviewing the proposed DSM programs and commenting on the program design elements that could be modified or improved. Synapse reviewed leading programs in other jurisdictions to provide examples in support its recommendations. However, Synapse was not asked to amass a list of all LI DSM programs for Market Rate MF as requested here. Therefore, this request is beyond the scope of our work.

d. We assume that this question concerns the following statement on page 63:

> Neither Enbridge nor Union offers all of the measures expected in a comprehensive program. Neither appears to provide any early replacement measures. Also, the plans do not include heating equipment repairs, furnaces, water heaters (including tankless

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

> and solar hot water), programmable thermostats, duct sealing and insulation, boiler reset control measures or pipe wrap. They also appear to neglect measures in common area spaces which, though often electric, can be key to achieving coordinated and cost-efficient delivery across gas and electric.

We are not aware whether these measures have been screened by EGDI or Union.

Synapse did not screen any measures.

a. Please see Nowak, S., Kushler, M., Witte, P., & York, D. (2013). Leaders of the Pack: ACEEE's Third National Review of Exemplary Energy Efficiency Programs, available at http://aceee.org/research-report/u132 for the information we used to support our recommendations.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

ENERGY PROBE RESEARCH FOUNDATION INTERROGATORY #12

INTERROGATORY

Reference: L OEB Staff .1 Synapse Report Pages 62-63

Preamble:
Enbridge's incentive for custom measures is $0.40/m3 (Enbridge Gas Distribution 2015b, Exh. B, Tab 2, Sch. 1, pp. 34) while Union's is $0.10/m3 (Union Gas Limited, 2015a, Exh. A, Tab 3, App. A, p. 84).

While different service territories may warrant slightly different incentives—this can be acceptable as long as the difference is explained—the difference in incentives between Enbridge and Union is significant and the drivers of this difference are not explained. Union does not offer an incentive for operational improvements.

Question:
Please indicate, based on Synapse's knowledge of other jurisdictions, the range of incentives and provide a view whether an Incentive of 0.40/m3 or 0.10/m3 may be appropriate. Please indicate eligible measures in your response.

RESPONSE

We did not perform this analysis, therefore, we cannot comment on the appropriateness of a specific incentive level.

Please also see Exhibit M.Staff.EGDI.9 and Exhibit M.Staff.UNION.9.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

ENERGY PROBE RESEARCH FOUNDATION INTERROGATORY #13

INTERROGATORY

Reference: L, OEB Staff 1, Synapse Report Page 64

Preamble:
This offering provides measures offered in the Home Weatherization and Furnace End-of-Life Upgrade offerings for aboriginal customers. Its delivery model targets the Band Councils of each of the 13 Aboriginal reserves (Enbridge Gas Distribution 2015 b, Exh. A, Tab 3, App. A, pp. 77-80).

Question:

a. Please confirm the Reference refers to Union's Evidence. If not, please provide the correct reference.
b. Should this offer be included in the other Union and EGDI SF LI programs? If so, please indicate whether the measure is likely to screen positive (singly or at the portfolio level).

RESPONSE

For clarity, the quoted text is on page 66 of the Synapse Report, which discusses the Aboriginal Offering (Union Only). The responses below are in reference to this offering.

a. Yes, the reference refers to Union's evidence.

b. This offering could possibly be included in Union's Single Family Low Income offering; however, these two offerings have different delivery models. Therefore, it is uncertain whether the offerings could be combined, and we cannot comment on the cost-effectiveness of such offerings.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

ENERGY PROBE RESEARCH FOUNDATION INTERROGATORY #14

INTERROGATORY

Reference: L, OEB Staff 1, Synapse Report Page 72

Preamble:
Note that Union includes its behaviour offering as part of its Resource Acquisition program, while Enbridge categorizes it as part of its Market Transformation program. Both utilities' offerings are addressed in this section on Market Transformation programs for ease of reference, and to be consistent with the Guidelines where it states that Market Transformation "programs should also focus on influencing consumer behaviour and attitudes that support reduction in natural gas consumption (Ontario Energy Board, 2014a, p. 13)."

Question:

a. Synapse indicates that both EGDI's and Union's Behavior Offers are under RA. Please clarify this.
b. Please indicate whether the offers are not consistent with OEB guidance and with other jurisdictions.
c. Please comment on the Scorecard, Targets and Budgets for this Offer

RESPONSE

a. Synapse has not indicated that both Enbridge and Union's behaviour offerings are under the Resource Acquisition program. The above quoted text clearly indicates how we addressed both offerings within the Market Transformation program section of our report, even though Union considers it to be within the Resource Acquisition program.

b. Based on our analysis in Exhibit L.OEB Staff.1, Section 5.6.3 Residential Behaviour, pages 71-73, the proposed behavioural offerings are consistent with OEB guidance.

c. Synapse addressed in its report whether the proposed performance metrics (e.g., savings or participants or something else) are appropriate, as discussed in Exhibit L.OEB Staff.1, Section 6.2.4 Appropriateness of Proposed Metrics, pages 101-103. Synapse did not address in its report the appropriateness of the proposed target values within the metrics (e.g., a certain level of m^3 savings or the number of participants). Therefore, we have not responded to the above question as it is beyond the scope of our work.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

ENERGY PROBE RESEARCH FOUNDATION INTERROGATORY #15

INTERROGATORY

Reference: L, OEB Staff 1, Synapse Report Pages 73

Question:
Please comment on the Scorecard and targets for this program

RESPONSE

Synapse addressed in its report whether the proposed performance metrics (e.g., savings or participants or something else) are appropriate, as discussed in Exhibit L.OEB Staff.1, Section 6.2.4 Appropriateness of Proposed Metrics, pages 101-103. Synapse did not address in its report the appropriateness of the proposed target values within the metrics (e.g., a certain level of m3 savings or the number of participants). Therefore, we have not responded to the above question as it is beyond the scope of our work.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

ENERGY PROBE RESEARCH FOUNDATION INTERROGATORY #16

INTERROGATORY

Reference: L, OEB Staff 1, Synapse Report Pages 101 and 102

Preamble:
1. The Board should continue to allow shareholder incentive metrics that motivate the utilities to save energy and increase customer participation in the DSM programs.

2. The Board should consider requiring the utilities to develop metrics or other mechanisms that focus on program cost-effectiveness. Such a metric would ensure that the utilities keep costs low while achieving significant savings

Question:

a. Please provide Synapse's assessment for each Utility's RA MT and Performance Scorecards, whether the proposed weightings between Savings CCM and Participants is/is/not appropriate.
b. Please provide the Metrics to be used for Cost Effectiveness Incentives e.g. $/CCM. Indicate if the metric(s) are only applicable to RA programs or to other programs such as MT and Performance.
c. Please indicate how a $/CCM incentive would be weighted relative to targets particularly for exceeding 100%.

RESPONSE

a. Synapse addressed in its report whether the proposed performance metrics (e.g., savings or participants or something else) are appropriate, as discussed in Exhibit L.OEB Staff.1, Section 6.2.4 Appropriateness of Proposed Metrics, pages 101-103. Synapse did not address in its report the appropriateness of the proposed weighting across the metrics. Therefore, we have not responded to the above question as it is beyond the scope of our work.

b. Cost-effectiveness is typically measured in terms of net benefits or using a benefit-cost ratio. Therefore, a cost-effectiveness metric for shareholder incentive purposes could be based on the total net benefit dollars achieved, or certain benefit-cost ratio thresholds. A net benefits metric is preferable to a benefit-cost ratio because it is more granular and could better encourage the utilities to maximize benefits while minimizing costs. The cost-effectiveness metric could apply to resource acquisition offerings and/or programs, or to the total portfolio costs and benefits taking into account market transformation and overhead costs.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

c. A cost-effectiveness metric (measured in net benefits) could be weighted relative to targets similarly to how current metrics are weighted relative to targets. A planned level of net benefits would be established during the plan proceeding, and the utilities' actual net benefits would be compared to the planned value to determine the earned shareholder incentives.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

ENERGY PROBE RESEARCH FOUNDATION INTERROGATORY #17

INTERROGATORY

Reference: L OEB Staff .1 Synapse Report Page 105

Preamble:
The Board should reject both Enbridge's and Union's proposed shareholder incentive target adjustment mechanisms because the overall five-year savings goal targets that the utilities are required to achieve should not be adjusted during the course of the plan.

Question:
Please clarify how adjustments to avoided costs, measures assumptions or free rider rates should be addressed during the term of the plan.

RESPONSE

Please refer to Exhibit L.OEBStaff.1, Chapter 9 Use of Input Assumptions in Evaluation. Specifically, Section 9.2 addresses how new or updated input assumptions should be applied during the plan term, while section 9.3 addresses free-ridership.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

GREEN ENERGY COALITION INTERROGATORY #1

INTERROGATORY

Question:
In the absence of constraints from the Board's Guidelines, would Synapse agree that in setting 6 year DSM budgets economically optimal plans should seek to ramp up at a manageable rate to obtain all cost-effective and achievable efficiency, from all rate groups?

RESPONSE

In such a hypothetical situation that removes policy constraints, Synapse agrees that plans should optimize cost-effectiveness, and that budgets should be set accordingly.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

GREEN ENERGY COALITION INTERROGATORY #2

INTERROGATORY

Reference: Pp. 8-9

Question:
Does Synapse agree that each of the following components should be included in the avoided costs of the gas utilities in estimating the benefits of DSM?

a. Reductions in the cost of complying with greenhouse gas emission regulations (e.g., a carbon price);
b. Commodity price suppression effects (DRIPE);
c. Avoided capital investment and related operating costs for distribution system capacity;
d. Avoided capital investment and related operating costs for utility-owned transmission and storage;
e. The avoidable costs of contracts for new upstream transportation infrastructure (e.g., on TCPL) to serve load growth.

If the answer to any portion of this question is anything other than an unqualified "yes," please explain your answer.

RESPONSE

Yes. To elaborate on part a., reduction in the cost of complying with current and reasonably anticipated future greenhouse gas emission regulations should be included in the avoided costs of the gas utilities.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

GREEN ENERGY COALITION INTERROGATORY #3

INTERROGATORY

Reference: P. 101

Preamble:
"The more customers that participate, the less of an impact the rate increases required to fund energy efficiency will have on customers' bills…"

Question:
Does Synapse agree that each of the following components would reduce the rate effects of the gas DSM portfolios:

a. Reductions in the cost of complying with greenhouse gas emission regulations (e.g., a carbon price);
b. Commodity price suppression effects (DRIPE);
c. Avoided capital investment and related operating costs for distribution system capacity;
d. Avoided capital investment and related operating costs for utility-owned transmission and storage;
e. Reduced purchases of the highest-priced gas that the utilities would have purchased each day, resulting in a lower average cost of gas in rates;

If the answer to any portion of this question is anything other than an unqualified "yes," please explain your answer.

RESPONSE

Each of the above components would reduce the rates on customers' bills.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

GREEN ENERGY COALITION INTERROGATORY #4

INTERROGATORY

Question:
Please provide Synapse's best estimate of natural gas supply DRIPE in the North American markets.

RESPONSE

Synapse was tasked with reviewing the proposed DSM programs and commenting on the program design elements that could be modified or improved. Therefore, we have not estimated the requested data as it is beyond the scope of our work.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

GREEN ENERGY COALITION INTERROGATORY #5

INTERROGATORY

Question:
If Synapse is aware of any estimates of the delivery DRIPE for natural gas into Ontario, please provide such estimate.

RESPONSE

Synapse has not researched estimates of the delivery DRIPE for natural gas into Ontario.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

GREEN ENERGY COALITION INTERROGATORY #6

INTERROGATORY

Question:
Please provide Synapse's best estimate of the prices of carbon allowances in a cap-and-trade program to achieve:

a. The reductions required by the US Clean Power Plan final rules.
b. The reductions to which Ontario is committed (reduction of jurisdictional emissions by about 26% from 2013 to 2030).

RESPONSE

Synapse was tasked with reviewing the proposed DSM programs in Ontario and commenting on the program design elements that could be modified or improved. Our report does not address the cost of carbon compliance. Therefore, we have not estimated the requested data as it is beyond the scope of our work.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

GREEN ENERGY COALITION INTERROGATORY #7

INTERROGATORY

Question:
Is Synapse aware of any analysis of the marginal cost or market price required for carbon reductions of the magnitude and speed of Ontario's commitment? If so, please provide cites to those studies.

RESPONSE

Synapse was tasked with reviewing the proposed DSM programs in Ontario and commenting on the program design elements that could be modified or improved. Our report does not address the cost of carbon compliance, so we did not research analyses on the marginal cost or market price required for carbon reductions of the magnitude and speed of Ontario's commitment. Therefore, the above question is beyond the scope of our work.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

GREEN ENERGY COALITION INTERROGATORY #8

INTERROGATORY

Question:
Regarding the discussion of gas infrastructure planning in Section 10, please explain whether peak-hour gas demand driving the need for additional gas infrastructure will be affected by system-wide gas DSM.

a. Please provide any studies of which Synapse is aware that estimate those effects.

RESPONSE

In general, system-wide gas DSM will reduce gas peak demand, because it will reduce the consumption of those gas end-uses that operate during peak periods and that are made more efficient.

a. Synapse has not conducted a review of studies that estimate those effects.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

GREEN ENERGY COALITION INTERROGATORY #9

INTERROGATORY

Question:
Regarding the statement that "[i]t will be particularly important to modify avoided costs to reflect the value of avoiding peak hour gas consumption" on page 129:

a. What method would Synapse recommend for estimating the effect of reductions in peak hour gas consumption due to DSM on infrastructure investment?
    i. Include studies, reports, memoranda, regulatory filings and other documentation available to Synapse that explain and illustrate this method.
b. Enbridge's analysis of avoided distribution infrastructure computes savings per peak-day m3. Does Synapse believe that the using peak-hour, rather than peak-day, conditions will significantly affect the value of gas DSM?
c. Does Synapse believe that the distribution system is designed for normal-weather peak loads or design peak loads?
    i. Should infrastructure savings be computed per m3 of normal peak load or m3 of design-peak load?
d. Does Synapse believe that utility-owned transmission and storage infrastructure (e.g., Union's Dawn storage, Union's Dawn-Parkway transmission, and Enbridge's GTA Segment A transmission) should be included as avoidable infrastructure?
    i. To the extent that lower load allows a utility to reduce the share of utility-owned transmission and storage infrastructure that is charged to distribution customers (through reallocation, release, or long-term contract), should the utility treat that as an avoided cost?
e. Is Synapse aware of any specific infrastructure projects that are under consideration by Enbridge for deferral through targeted DSM?
f. What process should Enbridge follow to identify and pursue avoidable or deferrable infrastructure projects?
g. Does Synapse have an opinion as to how long it should take Enbridge and Union to identify targeted infrastructure projects and ramp up DSM in the relevant areas?

RESPONSE

a. Synapse has not investigated the current gas avoided cost methodology in detail, and has not investigated alternative methods for estimating the effect of reductions in peak hour gas consumption would be. Our main point on this topic is best described as follows: *if the current*

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

methods do not properly account for the value of reducing gas peak demand, then "it will be particularly important to modify avoided costs to reflect the value of avoiding peak hour gas consumption."

b. Using avoided costs on gas savings per peak day may be sufficient for gas infrastructure planning.

c. Synapse has not investigated or formed an opinion on this issue.

d. Synapse has not investigated or formed an opinion on this issue.

e. Synapse has not investigated this issue.

f. Synapse has not investigated or formed an opinion on this issue.

g. Synapse has not investigated or formed an opinion on this issue.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

GREEN ENERGY COALITION INTERROGATORY #10

INTERROGATORY

Reference: Section 5.2.3, p. 30

Preamble:
Synapse states that "both utilities should provide customers with zero or low interest financing to address lack of funding…"

Question:

a. Is Synapse suggesting that financing offers be (1) in lieu of rebates or other financial incentives; (2) as a complement to rebates or other financial incentives (i.e. the customer can take both); or (3) as an optional alternative to rebates or other financial incentives?
b. Does Synapse agree that there is a program (DSM) cost to buying down interest rates for financing?
c. Given prevailing interest rates and/or the best market-based interest rates Synapse believes are likely to be accessible in Ontario, what is the cost of buying a 10 year loan for a $5000 home retrofit project down to zero percent interest? Please provide an estimate even if caveats are necessary regarding the typical or best market rate that might be accessed (i.e. even if largely an illustrative example).
d. Would Synapse agree that such buy-down costs can be comparable to or even greater than the cost of rebates or other financial incentives designed to drive investment in efficiency measures? If not, why not?
e. Is Synapse aware of any examples in which the offer of financing substantially increased market penetration (i.e. an increase in the number of customers who would not have made the improvements absent the loan) of whole house retrofits or thermal envelop improvements to homes? If so, please provide examples, including estimates of the extent to which net participation or net savings increased.
f. Does Synapse believe that the offer of financing can substantially increase market penetrations of efficiency measures in other markets, or for other efficiency measures? If so, for which other markets or measures? For all such markets or measures please provide examples to support your conclusions.

RESPONSE

a. Financing offers generally work as a complement to rebates or other financial incentives to increase the savings achieved through participation, re-engage with previous participants, and attract new participants.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

b. Yes, the cost to buy down the interest rates is generally included in the DSM program budget.

c. and d. Synapse was tasked with reviewing the proposed DSM programs and commenting on the program design elements that could be modified or improved. The Synapse recommendation referenced above is intended provide general guidance and direction, and is not intended to indicate a specific quantitative outcome (see Exhibit L.OEBStaff.1, page 2; see also Exhibit M.Staff.EGDI.4). Therefore, we have not estimated the requested data as it is beyond the scope of our work.

e. Yes. On page 115 of Exhibit L.OEBStaff.1, Synapse provided the following example:

> A case from the Pacific Gas & Electric (PG&E) EnergySmart Grocer (ESG) program suggests that on-bill financing does promote more comprehensive upgrades. The ESG program offers prescriptive financial incentives to mid-to-large size grocery stores and supermarkets, and started offering on-bill financing in 2012 in order to increase the comprehensiveness of efficiency projects and produce more energy savings from each project. As a result, the average number of measures per project was double the number of measures installed for projects without on-bill financing (OBF) (Geers & Rosendo, 2014).

f. Synapse believe that a well-designed financing program can substantially increase market penetrations of efficiency measures and/or program participation rates. Financing is especially helpful to increase market penetration of efficiency measures in underserved market segments such as low-income, multi-family, and small business market segments. Please refer to Exhibit M.Staff.GEC.10 part e.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

GREEN ENERGY COALITION INTERROGATORY #11

INTERROGATORY

Reference: Section 5.3.2, p. 32

Preamble:
Synapse states that requiring two major measures is problematic because it decreases the likelihood that some customers which have only one measure will miss an opportunity. It gives an example of a situation in which "a customer's furnace needs replacing but their insulation and other building envelop measures in sufficiently efficient."

Question:
Given that all new furnace purchase in Ontario must now be condensing furnaces - and that it is good technical practice to perform air sealing (which counts as a major measure) before installing insulation - does Synapse's concern about the requirement for two major measures still hold?

RESPONSE

Our recommendation is simply that customers looking to install one measure should not be turned away from the program; our recommendation is not that the utilities should only focus on one measure per customer or should remove focus from installing two measures per customer.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

GREEN ENERGY COALITION INTERROGATORY #12

INTERROGATORY

Reference: Section 5.8.2, p. 83

Question:
Regarding large volume customers:

a. Is Synapse aware of any evidence from Ontario or any other jurisdiction to suggest that large volume customers will acquire all cost-effective savings on their own, without utility DSM program support? If so, please document the basis for the conclusion.
b. If not, is Synapse aware of any evidence from Ontario or any other jurisdiction to suggest that large volume customers typically do not acquire all cost-effective savings on their own, without utility DSM support? If so, please document the basis for that conclusion.
c. Is Synapse aware of any evidence from any jurisdiction to suggest that well-designed self-direct programs for large customers typically have very low NTG ratios (and/or high free ridership)? If so, please provide examples and references.

RESPONSE

a. Synapse is not aware of any evidence to suggest that large volume customers will acquire all cost-effective savings on their own.

b. Synapse is aware that large volume customers (often, from the industrial sector) typically do not acquire all cost-effective savings on their own. See, e.g.:
   - U.S. Department of Energy. 2015. Barriers to Industrial Energy Efficiency: Report to Congress.
   - State & Local Energy Efficiency Action Network. 2014. Industrial Energy Efficiency: Designing Effective State Programs for the Industrial Sector.
   - Chittum, Anna. 2011. Follow the Leaders: Improving Large Customer Self-Direct Programs. ACEEE report No. IE112.
   - Synapse Energy Economics. Commercial & Industrial Customer Perspectives on Massachusetts Energy Efficiency Programs. Prepared for the Massachusetts Energy Efficiency Advisory Council. April 3, 2012. Please refer to Exhibit M.Staff.GEC.12, Attachment 1.

c. The term "well-designed" was not defined in this interrogatory. For the purpose of answering this question, we assume that "well-designed" means maximizing public benefit as specified in

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

Chittum 2011 (Chittum, Anna. 2011. Follow the Leaders: Improving Large Customer Self-Direct Programs. ACEEE report No. IE112.) That is, a well-designed program focuses on energy savings and has adequate oversight, measurement and verification of savings (using the same M&V standards for other industrial programs), and follow up.

Synapse is not aware of any evidence from any jurisdiction to suggest that well-designed self-direct programs for large customers typically have very low net-to-gross ratios or high free ridership.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

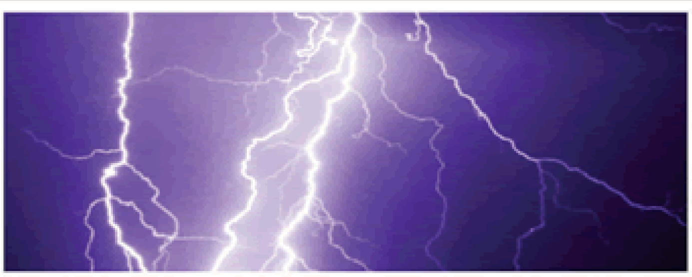
Synapse
Energy Economics, Inc.

Commercial & Industrial Customer Perspectives on Massachusetts Energy Efficiency Programs

Prepared for the Massachusetts Energy Efficiency Advisory Council

April 3, 2012

Tim Woolf, Jennifer Kallay, Erin Malone,
Tyler Comings, Melissa Schultz, and Janice Conyers



485 Massachusetts Ave.
Suite 2
Cambridge, MA 02139
617.661.3248
www.synapse-energy.com

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Executive Summary

This report includes a forecast of economic conditions in Massachusetts for 2013 through 2015, as well as a survey of commercial and industrial (C&I) customer perspectives on the Massachusetts energy efficiency programs. The Massachusetts Energy Efficiency Advisory Council (EEAC) asked Synapse Energy Economics, Inc. (Synapse) to conduct this assessment in order to inform the development of the Three-Year Statewide Energy Efficiency Plans for 2013 through 2015.

The primary purpose of this report is to assess the extent to which C&I customers are likely to participate in the Massachusetts energy efficiency programs over the next few years. The economic forecast is intended to provide an indication of the extent to which economic conditions might create barriers to C&I customer participation in the energy efficiency programs. The survey is intended to assess the variety of barriers that C&I customers face with regard to energy efficiency program participation.

Economic Forecast

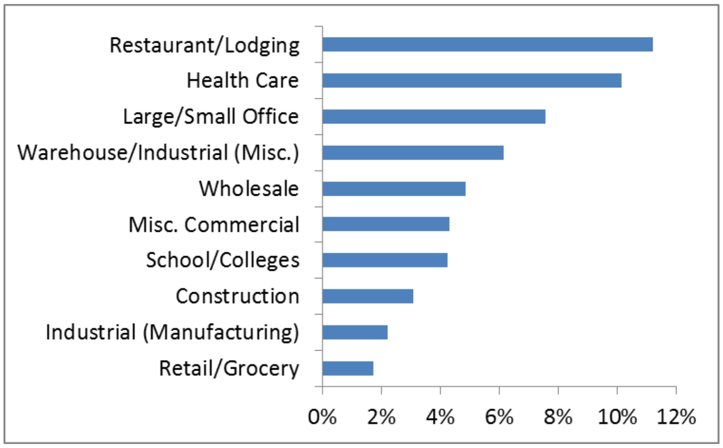
Our economic forecast relies upon historic and forecast data from Moody's Analytics, a source that is fequently used by planning agencies for economic forecasts. We present forecasts for the five regions of the state, based on county borders: (1) Bristol County, (2) Greater Boston, (3) Central Massachusetts, (4) Cape Cod and the Islands, and (5) Western Massachusetts. We also present economic forecasts for several industry types including: construction, healthcare, industrial, large/small office, miscellaneous commercial, restaurant/lodging, retail/grocery, schools/colleges, warehouse industrial, and wholesale.

The economic forecast suggests that, in general, the state's economy will see improved performance over the next several years. At the statewide level, gross state product, construction activity, residential construction permits, and retail sales are expected to grow, while unemployment rates, business bankruptcies, and commercial rental vacancy rates are expected to decline. The same overall trend of improvement can be seen within each region, as well. One exception to this trend is gross state product and retail sales in the Cape Cod/Islands region, which are expected to stay essentially flat between now and 2015.

On a statewide basis, most industries are projected to grow in Massachusetts over the next few years. Figure ES-1 below presents the forecast of employment growth, in percentage terms over 2011 through 2015, by the different industry types. Note that the growth rates by industry are different in the different regions of the state, and in some regions there are several industries that are expected to see reduced employment levels over this period. This regional information is presented in Section 2.2.

Healthcare and office industries are projected to grow strongly in every region of the state, and both are large components of every region's employment. Restaurant/lodging is projected to grow significantly in every region except the Cape/Islands. Construction is projected to have robust growth in Bristol, but less growth in other regions. Bristol County, the region hit hardset by the economic downturn in Massachusetts, is expected to see a large fall in unemployment over the 2011 through 2015 period, in part due to the construction growth expected there.

Figure ES-1. Employment Growth in Massachusetts, Percentage Increase 2011 – 2015



Survey Methodology

We began our survey by identifying a set of targets for customer types to interview. We planned to interview a total of 40 customers across the state. We identified a target set of customers to interview by first spreading the 40 interviews across the five state regions based on economic activity in those regions; and second by spreading the interviews in each region across the different industry types according to the level of economic activity within each industry type. We limited our target set of interviews to medium and large C&I customers, and we excluded governmental agencies from the target set. Furthermore, we attempted to focus our interviews on customers that have not participated in the Massachusetts energy efficiency programs for at least the past five years.

We then collected customer contact information from the Massachusetts energy efficiency program administrators and a few other stakeholders. We sent invitations to all of the 137 customers provided to us that were eligible and included contact information. Many of these customers did not respond to, or declined, our invitation. We conducted a total of 36 interviews.

The interviews that we conducted are presented by region and industry type in Table ES-1. Since a large number of customers did not respond to the survey invitations, the distribution of interviews by region and industry were determined more by customer interest and availability than by the information and priorities that we used to determine the target region and industry distribution. Nonetheless, the set of interviews that we were able to conduct is close enough to the target region and industry distribution that we believe it will provide the geographic and industry diversity that we set out to survey.

The one exception is that the vast majority of our interviews were with customers that have participated in the Massachusetts energy efficiency programs. We did not receive as many non-participant contacts from the stakeholders, and those that we did contact were much less likely to participate in our survey than the program participants. It is important to note that our survey results are likely to be influenced by the fact that so many of the respondents are program participants.

Table ES-1. Interviews Completed, by Industry Type and Region

Industry Type	Boston	Central Mass	Cape Cod	Western Mass	Bristol County	**Total**
Heavy industry	2	1	0	5	1	**9**
Warehouses & Distribution	0	0	0	1	0	**1**
Retail	1	1	0	1	2	**5**
Office	5	1	0	3	0	**9**
Schools & Colleges	4	0	0	0	0	**4**
Healthcare	3	1	1	0	0	**5**
Restaurants & Lodging	1	1	0	0	0	**2**
Miscellaneous	0	0	0	0	1	**1**
Total	**16**	**5**	**1**	**10**	**4**	**36**

It is also important to note that a sample size this small will not provide results that can be considered statistically significant. Nonetheless, we believe the results from these interviews provide useful insights for the EEAC and other stakeholders, consistent with the purpose of this study.

Survey Results

Overview of Common Themes

Most customers that we interviewed were program participants at some level and stated that they either will participate or are considering participating in programs in the next few years. In general, the customers we interviewed consider energy efficient equipment regularly when they make purchasing decisions.

Another theme we heard from most of our interviews was that payback period was the main criteria for evaluating energy efficiency investments and that energy efficiency investment payback periods compete with the payback periods for other capital investment projects.

A third theme we heard from many customers we interviewed was that capital constraints are a key barrier to moving forward with energy efficiency projects. Many customers have access to capital, but energy efficiency projects have to compete with other projects for that capital.

A fourth theme is that the general process for vetting and approving energy efficiency investments is similar across many customers. Projects are scoped, analyzed, and proposed on an annual basis and submitted to a higher level team for review and approval. Energy efficiency investments are frequently categorized as discretionary expenditures.

A fifth theme is that financing mechanisms, such as loans, are seldom, if ever, used. Instead, customers use existing capital to pay for the efficiency projects up-front, despite the widely recognized fact that the efficiency cost savings are experienced over many years.

It is clear from even our small sample that there are many different types of customers with different needs and barriers to participating in energy efficiency programs. This diversity of customers creates a significant challenge for program administrators, because reaching additional customers and achieving deeper levels of savings per customer will likely require offering program technical and financial support that is more tailored to the unique needs of the many different types of electric and gas customers.

Positive Feedback

Many of the customers provided positive feedback on the programs. Some of the highlights include the following points.

- Many customers were grateful for the sustained incentives and technical assistance provided by energy efficiency program administrators over the years, and indicated that energy efficiency investments could not compete with other capital investments without the incentives and technical assistance received.
- Several customers mentioned that they appreciate the level of outreach that they receive from energy efficiency program administrators and have had a long-standing, trusting relationship with their account executives.
- Some customers recognized and appreciated the variety of efforts and approaches (such as the upstream lighting program and the Memorandum of Understanding approach) that the energy efficiency program administrators are leveraging.
- Several customers recognized the positive impacts of the program administrators' efforts over time, such as the ability to accelerate energy efficient product development and manufacturing and make energy efficient solutions affordable.

Summary of Barriers Identified by Customers

The barriers to participation that have emerged from the interviews can be organized in two categories: customer barriers and program barriers. Customer barriers are barriers that stem from a customer's internal decision-making processes. Program barriers are barriers that stem from the way the programs are designed or administered. The customer barriers were subdivided into the following categories: customer's capital constraints, economic climate, unsupportive corporate review and approval process, the customer is convinced it has done all the efficiency measures it can within its facilities, or distrust of new technology.

The program barriers were subdivided into the following categories: insufficient marketing and outreach, high transaction costs, inadequate responsiveness and timing, limited measures offered through the programs, insufficient incentives, the desire to opt out of the energy efficiency charge, the programs are not tailored to the unique needs of customers, and other barriers.

Figures ES-2 and ES-3 present a summary of the number of times each of these barriers was mentioned by customers in our interviews.[1] In general, program barriers were mentioned more frequently than customer barriers. Insufficient marketing and outreach as well as customer's capital constraints were mentioned most often, with transaction costs the next most frequently mentioned barrier.

[1] Note that each customer mentioned more than one barrier, and not all customers identified the same number of barriers. We present these figures simply to provide a summary of the frequency with which the different barriers were identified.

Figure ES-2. Customer Barriers Mentioned in the Interviews

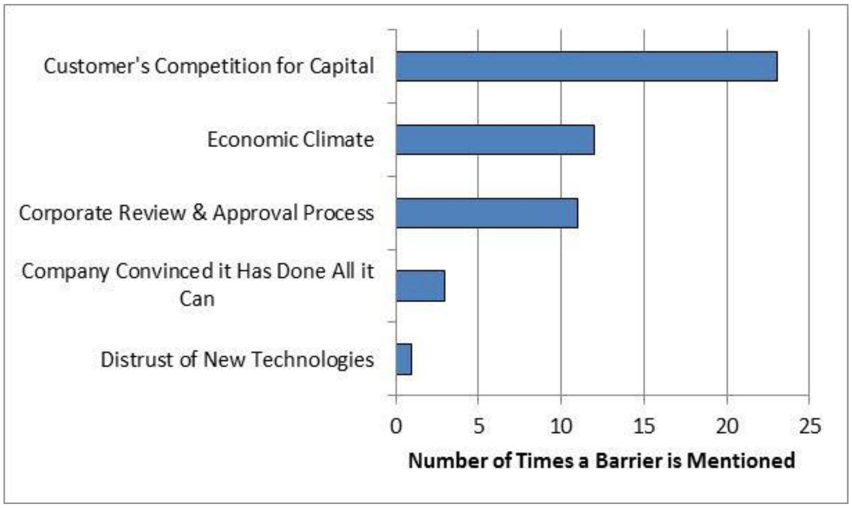
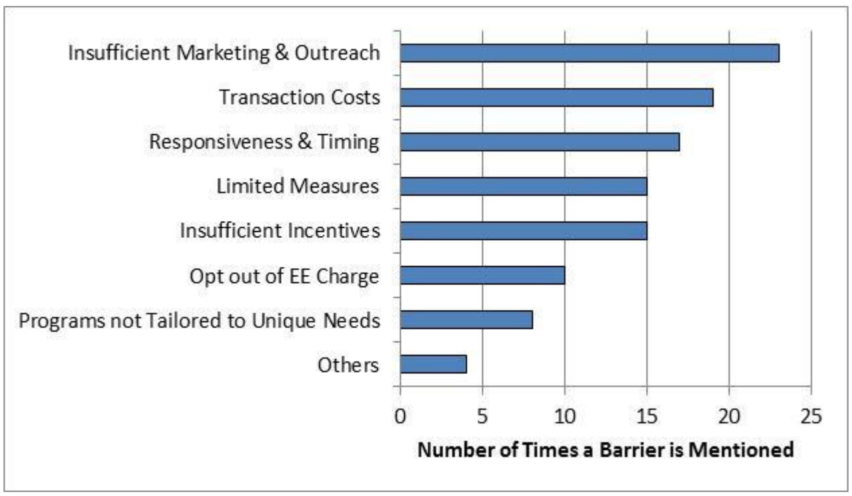


Figure ES-3. Program Barriers Mentioned in the Interviews



Customer Barriers

Customer's capital constraints. This is one of the most frequently cited and important barriers that customers face in energy efficiency program participation. Many customers, although not all, do not have a problem accessing capital. Their chief problem is with the competition for capital between energy efficiency investments and other investments, especially those investments that are more germane to the core business of the customer. Some customers have global operations, and face competition for capital in Massachusetts, in the United States, and elsewhere in the world. This competition for capital is so important to customers that it results in greater adherence to payback period constraints, as that is often the criteria that is used to determine which project deserves the constrained capital. Further, some customers mentioned that the significant upfront cost of efficiency measures, especially larger projects beyond lighting upgrades, created a barrier to participation.

Economic climate. The economy appears to have a relatively indirect impact on a customer's ability to participate in efficiency program, as many customers were not clear on the connection between economic conditions and efficiency program participation. When asked, customers held several views on the extent to which the economy affects their participation:

- Some customers do not see the economy as a barrier to participation.
- Other customers were quick to mention that the economy has affected their employee base, profit, or capital availability, making it more difficult to undertake nonessential projects.
- Some customers see efficiency as even more important in tight economic conditions, as a means to better manage budgets and reduce costs with minimal capital outlay.
- For other customers, the downturn in the economy exacerbates the competition for capital problems discussed above, in that capital might be harder to access or payback periods may need to be shorter.
- Still other customers noted that in a tight economic context they are more likely to let existing equipment run through its useful life, rather than retrofit it early. This creates a barrier to implementing efficiency measures as there is often insufficient time and resources to identify and procure the most efficient option at the time of equipment failure.

Unsupportive corporate review and approval process. Many customers noted that they have no problem getting support from corporate executives to implement energy efficiency projects. However, corporate decision-making practice often requires efficiency projects to compete for capital with investments that are more germane to a customer's business (see above), and sometimes corporate practices place very tight payback periods constraints on all investments, limiting the energy efficiency measures that can obtain corporate approval.

Customer convinced it has done all it can. This was not a commonly identified barrier, as only three customers identified this barrier. When mentioned, it was seen as a transient barrier that would disappear over time. Customers mentioned that they had done several efficiency projects, and that, while additional savings opportunities likely exist within their buildings, the savings are not likely to outweigh the transaction costs. One customer indicated that savings opportunities from the next generation of efficient equipment would likely propel them to participate in the future.

Distrust of new technology. Only one of the customers interviewed indicated that they were reluctant to implement energy efficiency measures because they did not trust or fully understand the efficiency technology. This customer was concerned that reducing energy consumption could reduce its production capability.

Other barriers. A few customers mentioned barriers or topics that did not fit into the categories above. These include: people have been lulled into a sense of security with prices of electricity and natural gas being relatively low, and participants are distracted by other energy projects like solar or geothermal.

Program Barriers

Insufficient marketing and outreach. Many of the customers feel that the program administrators could be more proactive in reaching out to and educating customers about efficiency opportunities. Some customers felt program administrators were inconsistent in their outreach, or had limited contact with their representative. Others thought that, while the program administrators do reach out to them, the customer was driving the process and had previously researched the opportunities. Several customers noted that their gas program administrator has not reached out to them with energy efficiency opportunities, or provided any technical or financial support. This is particularly troubling to several customers who are very active in the electric efficiency programs and who believe they have significant gas efficiency opportunities. Some customers have regular, annual cycles of budgeting and investing in energy efficiency equipment, and they would prefer that the program administrators coordinate their program services with the customer's annual cycle.

<u>High transaction costs</u>. Many customers indicated that the paperwork and legwork involved in participation is too great, and that the overall process needs to be simplified. Some customers claimed that, for long lead-time projects, the time required to receive a financial incentive, as well as the uncertainty about obtaining a financial incentive, especially across program years, create a barrier to their participation.

<u>Inadequate responsiveness and timing</u>. Several customers thought their program administrator was unresponsive to their needs, and a few customers attributed it to the program administrators being overworked. Others thought it was difficult to time their participation, such as when major equipment fails and needs to be replaced immediately, or during new construction when projects need to go forward and cannot be held up by program participation.

<u>Limited measures offered through the programs</u>. Many customers expressed a desire for the programs to be more flexible and to allow the customers to recommend efficiency projects to undertake. Other customers suggested that specific equipment, such as more efficient elevators, should be offered incentives through the programs.

<u>Insufficient financial incentives</u>. Many customers noted that they would implement additional efficiency measures if they were provided with greater financial incentives. Additional financial incentives would help overcome the competition for capital that many customers face, as well as reduce the payback periods needed to meet corporate requirements. Many companies indicated that there is not enough coverage of technical support costs or availability of technical support in general. Some customers wished the programs offered different incentive structures and better addressed upfront costs as well as costs over the life of the measure.

<u>Desire to opt out of the energy efficiency charge</u>. Many customers claimed that they would be able to achieve much greater energy efficiency saving if they were able to keep all of the funds that they contribute to the Massachusetts energy efficiency programs and dedicate those funds to efficiency projects at their own facilities. This was especially true among the large customers, including those in the industrial, healthcare and schools/colleges industry types.

<u>Programs not tailored to unique needs</u>. Some customers thought that the program administrators did not make an effort to understand the unique needs of their industry. This was especially true for customers in the healthcare industry.

<u>Other barriers</u>. A few customers mentioned barriers or topics that did not fit into the categories above. These include: (a) the lack of transparency with regard to the amount that the customer is providing to efficiency program funding is a barrier when employees try to convince management to take advantage of efficiency programs offered by the

program administrators; and (b) customers appear to be confused by the number of energy efficiency providers in the market (i.e., ESCOs vs. renewable installers vs. lighting manufacturers/distributors vs. utilities/municipal aggregators/municipals).

Implications for Energy Efficiency Programs

The results of our economic forecast and customer survey lead us to draw the following conclusions with regard to energy efficiency program planning.

1. The Three-Year Energy Efficiency Plans should include savings goals that recognize that (1) the Massachusetts economy is forecasted to improve steadily over the next few years, (2) many customers do not see the state of the economy as a barrier to participation in the energy efficiency programs, (3) many customers have additional efficiency opportunities in their facilities and (4) many customers have an interest in participating in the programs again. In fact, several customers noted that in a tight economy they might be more likely to participate in energy efficiency programs as one of the few options they have to cut costs (as long as the payback periods are short enough).

2. The Three-Year Energy Efficiency Plans should recognize the potential savings available from the C&I New Construction programs, given that the economic forecast indicates that business construction activity is expected to steadily increase over the next few years.

3. Encouraging customers to adopt a deeper level of efficiency measures will likely require additional efforts to overcome some of the key barriers identified above, particularly customer budget limits and competition for capital, burdensome transaction costs of participating in the efficiency programs, and limited efficiency measures available by the efficiency programs.

4. Encouraging customers to adopt a deeper level of efficiency measures will also likely require increased engagement from the program administrators' account executives and efficiency support staff. This will be important both to reduce the transaction costs associated with the energy efficiency programs and to better serve the unique needs of the different customers.

5. The Three-Year Energy Efficiency Plans should recognize that many customers have apparently not received much outreach regarding gas efficiency opportunities, and that additional outreach and support from gas program administrators might lead to increased gas efficiency savings.

6. Program administrators should be required to collect and report more comprehensive data regarding the customers who participate in their energy efficiency programs. A better understanding of customer participation would provide the program administrators with very useful information about where the untapped efficiency opportunities lie and how to pursue them. It would also be very useful to identify and track the different types of participation, including: active participants (i.e., recent participants), inactive participants (i.e., past participants), non-participants, and proactive participants (where the customer prefers to take the lead with assistance from the program administrator) versus reactive participants (where the customer prefers the program administrator to take the lead).

Recommendations for Further Research

Our survey indicates that there are several areas where additional research might help to increase the participation of C&I customers over the next few years.

1. Most importantly, it would be helpful to continue efforts to better assess the perspectives of the C&I customers who have not participated in the Massachusetts energy efficiency programs to date.
2. It may be helpful to conduct statewide research into opportunities for reducing the transaction costs (including timing concerns) associated with participation in the energy efficiency programs. This could include a statewide effort to identify best practices within the state and from other parts of the country.
3. It may be helpful to conduct statewide research into training the program administrators' account representatives and support staff so that they have a better understanding of the needs of different customer types and different industries. This could include a statewide effort to train account executives and support staff and to share knowledge and experience across the program administrators.
4. It may be helpful to conduct statewide research into ways to expand the types of efficiency measures eligible for financial support, reduce the time required to accept measures for eligibility, and streamline the process that is used in deciding measure eligibility.
5. It may be helpful to conduct statewide research into opportunities for the gas program administrators to better coordinate their outreach and support services with electric program administrators.
6. It may be helpful to conduct statewide research into practices for spending the efficiency budgets more evenly over the course of a year, in order to avoid the year-end blitz that sometimes occurs in order to meet annual targets.

1. Introduction

Background

The 2010-2012 Massachusetts Joint Three-Year Electric and Gas Energy Efficiency Plans were the first statewide three-year plans that put the Massachusetts electric and gas energy efficiency program administrators on a path to meeting the 2008 Green Communities Act mandate that "electric and natural gas resource needs shall first be met through all available energy efficiency and demand reduction resources that are cost effective or less expensive than supply." Given that this first three-year plan was a ramp up to more aggressive levels of energy savings than had ever been achieved in the state, each year of the three-year plan had budget and savings targets that were higher than the previous year.

The 2010 electric C&I savings goals were nearly met (i.e., 98 percent of the goal was achieved), using 85 percent of the planned budget. The 2010 gas C&I savings goals were also nearly met (i.e., 95 percent of the goal was achieved), using 75 percent of the budget. However, the program administrators were not as successful in meeting their 2011 C&I program savings goals. Preliminary year-end statewide results for 2011 indicate that the electric and gas program administrators were short of their C&I savings goals and were not able to spend all of their remaining C&I budget to close the gap.[2]

Concerned that this trend might continue in 2012 and into the next three-year plan, the Massachusetts Energy Efficiency Advisory Council contracted Synapse Energy Economics to investigate the barriers that C&I customers face in participating in energy efficiency programs. The EEAC is specifically interested in determining whether the economic recession is a key factor preventing or delaying C&I customers' participation in the energy efficiency programs. The primary purpose of understanding these barriers to C&I customers is to determine whether they can be addressed in planning and designing the programs for the 2013-2015 Energy Efficiency Plans.

Organization of the Report

In order to investigate the barriers, real and perceived, to commercial and industrial participation in energy efficiency programs, we first present a forecast of the state's economic activity. This near-term forecast is intended to provide context for targeting C&I customers in Massachusetts over the period coinciding with the 2013 – 2015 Three-Year Energy Efficiency Investment Plan.

Next, as background to Synapse's investigation, we summarize the results of measurement and verification (M&V) studies conducted on the Massachusetts C&I programs over the past two years. This summary presents some of the barriers to C&I participation identified in recent research, and provides a foundation for our customer survey.

We then present the results of surveys of several C&I customers, in order to develop a better picture of the barriers they face in participating in the Massachusetts energy efficiency programs, as well as an indication of their expected participation in these

[2] Preliminary year-end results for 2011, presented by the Massachusetts program administrators to the EEAC, February 2012.

programs over the next few years. The survey covers medium and large C&I customers across a variety of industry types, and across several regions of the state.

Finally, we evaluate the findings of the economic forecast and surveys, and discuss the implications of these findings for the 2013 – 2015 Massachusetts energy efficiency programs.

Appendix A of this report presents a more detailed discussion of the M&V study results. Appendix B provides the survey questionnaire and interview questions used by Synapse in this study, while important questionnaire responses and the complete interview notes for each customer are provided in Appendix C.

2. Economic Forecasts

2.1 Methodology

Data Source

Our economic forecast relies upon historic and forecast data from Moody's Analytics (formerly Economy.com). Moody's is a common source for economic projections, one that is used by utilities in Massachusetts and other planning agencies.[3] Table 2.1 presents the data that are available for this study from Moody's. As indicated, some of the data are available for each county and for the state as a whole, while some of the data are available only for the state as a whole.

Table 1.1 Moody's Data by Source and Geography

Moody's Data	Geography	Primary Historical Source
Business Bankruptcies	State	Office of US District Courts
Construction Put-in-Place (non-residential)	State	US Census
Industry Employment (23 industries)	County, State	Bureau of Labor Statistics (BLS)
Gross State Product	County, State	Bureau of Economic Analysis (BEA)
Labor Force	County, State	Bureau of Labor Statistics (BLS)
Residential Permits (single and multi-family)	County, State	US Census
Rental Vacancy Rate	State	US Census
Retail Sales	County, State	US Census
Unemployment[4]	County, State	Bureau of Labor Statistics (BLS)

In our results below, we present the actaul data for these metrics for the years of 2006 through 2011, in order to provide some historical context. We then present Moody's forcast of this data for the years 2012 through 2015, in order to coincide with the planning horizon for the 2013 – 2015 Three-Year Energy Efficiency Plans.

Regional Definitions

In order to capture the regional differences in economic activity, we analyzed data for five different regions of the state. These regions are defined on the basis of county borders, in order to allow us to apply the Moody's county data to our five regions. We present economic forecast for the following regions: (1) Bristol County, (2) Greater Boston, (3) Central Massachusetts, (4) Cape Cod and the Islands, and (5) Western

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3 It is important to note that forecasts of any kind are fallible, because unforeseen circumstances can always arise. While the Moody's forecasts are well respected and frequently used, they should be seen as estimates to be used for identifying trends but not to be used for providing precise predictions.

4 The unemployment rate is the percentage of individuals in the "labor force" (i.e. those who are working or actively looking for work) who have not found employment, as collected by the Bureau of Labor Statistics. Therefore, it does not include those who have stopped looking for work. Also, part-time employees are all considered "employed" even if they are looking for full-time work (BLS refers to this as "part time for economic reasons"). Monthly unemployment rates are typically "seasonally adjusted" to account for month-to-month variations from seasonal industries; however, annual unemployment is usually not adjusted in this manner.

Massachusetts. Table 2.2 indicates the five regions that we analyze and the counties that are within each region.

Table 2.2 Massachusetts Regions by County

Region	County
Bristol County	Bristol County
Greater Boston	Suffolk County Middlesex County Plymouth County Norfolk County Essex County
Central Massachusetts	Worcester County
Cape Cod/Islands	Barnstable County Dukes County Nantucket County
Western Massachusetts	Hampden County Hampshire County Berkshire County Franklin County

Industry Types

Moody's presents its economic forecasts by industry type, using the North American Industry Classification System (NAICS). We made two minor modifications to the indsutry types for our study. First, we aggregated the NAICS data into a slightly smaller list of industries, for presentation and simplicity purposes.

Second, we aligned the new Synapse aggregations with the industry types used in the Point380 study, which used slightly different labels and categories for its industry types.[5] We have, to the best of our ability, mimicked the aggregations used in Moody's and Point380 studies. However, due to limited granularity in the Moody's data, we have had to combine categories (e.g., Warehouse/Industrial and Miscellaneous). Also, construction and wholesale trade were not presented in the Point380 studies, but are included in Moody's data. Lastly, Moody's categorizes government as large/small office, whereas the Point380 study spread this over many industry types.

Table 2.3 presents the industry types presented in the Moody's forecasts, as well as our version of the industry types.

[5] The Point380 study is described in more detail below.

Table 2.3 Industry Aggregation Scheme

Moody's Industry Types	Synapse Industry Types
Construction	Construction
Healthcare	Healthcare
Manufacturing	Industrial (manufacturing)
Admin/Waste Management Finance/Insurance Government Information Management of Companies Professional/Scientific Real Estate	Large/Small Office
Arts/Entertainment/Recreation Farms Other Services	Misc. Commercial
Food/Accommodation	Restaurant/Lodging
Retail Trade	Retail/Grocery
Education Services	School/College
Mining, Quarrying, etc. Utilities Warehouse and Transportation	Warehouse/Industrial (misc.)
Wholesale Trade	Wholesale

Figure 2.1 below shows the percent of total employment that each industry type represents, for each of the five regions in Massachusetts. As indicated, large and small offices dominate the employment in all regions, especially in the Boston region. Healthcare is a significant employer in all regions of the state, as is retail/grocery. Manufacturing is a dominant employer in Bristol County, Cental Massachusetts and Western Massachusetts, and with fewer employees on Cape Cod and the Islands.

Figure 2.1 Massachusetts 2011 Industry Employment by Region

Other Sources of Economic Forecasts

We considered using other sources for economic forecasts, if only to provide a comparison or a check against the Moody's forecast. After a brief review of the other economic forecasts that are readily available, we decided not to use any of them, because they either relied upon the same Moody's forecast that we use, or they do not provide data and forecasts at the county level and therefore could not be used for our forecast of the five different regions of Massachusetts.

We asked several of the electric and gas program administrators for access to the economic forecasts that they use for their own purposes. One program administrator provided us its forecast, but noted that it is based on the Moody's forecast. Another program administrator declined to provide us with their economic forecast, because it is also based upon the Moody's forecast and would only be redundant. A third program administrator noted that they do use a different source for their economic forecasts, but they declined to provide us with their forecasts because they are proprietary.

The New England Economic Partnership (NEEP) is a member-supported, non-profit organization dedicated to providing objective economic analyses and forecasts. Twice a year the NEEP publishes macroeconomic forecasts of the New England region and its six individual states. Their most recent forecasts were published in November 2011 and are available to members. Upon investigation we learned that the NEEP forecasts also rely upon the Moody's forecasts, and do not provide forecasts at the county level.[6] Therefore, we did not pursue this source any further.

2.2 Economic Forecast Results

As a whole, the Massachusetts economy has faired slightly better than the US economy throughout the recent economic downturn. In terms of unemployment, the state has tracked at one percent or more below the national unemployment rate. As of the close of 2011, the state was showing a 6.8 percent unemployment rate, compared to 8.5 percent for the U.S.[7]

The latest Business Confidence Index from the Associated Industries of Massachusetts (AIM) shows that business optimism in the state has been rising in recent months. This index takes a monthly survey of businesses' economic outlook for the current year compared to the prior year. As seen in Figure 1.2 below, the recently released index of 52.8 for January 2012 is the highest it has been since May 2011. An index level of 50 is deemed a neutral outlook.

While optimism among the group has been rising since October 2011, expectations for a fast economic recovery have been mitigated somewhat by the crisis in Europe, especially since Massachusetts is reliant on export business with Europe.[8]

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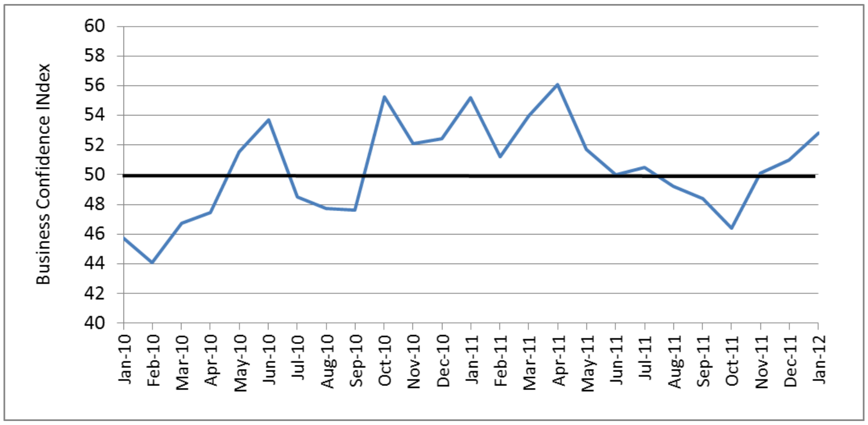
6 We contacted Mike Goodman (of UMass-Dartmouth) and Alan Clayton-Matthews (of Northeastern University) both of whom are part of New England Economic Partnership. They could only provide state-level forecasts and these were only available to NEEP members.

7 Based on December 2011 data from the Bureau of Labor Statistics.

8 Comment from Andre Mayer at AIM, see: http://www.aimnet.org/AM/Template.cfm?Section=Business_Confidence_Index

Figure 1.2 Business Confidence Index (Decemeber 2010 – January 2012)



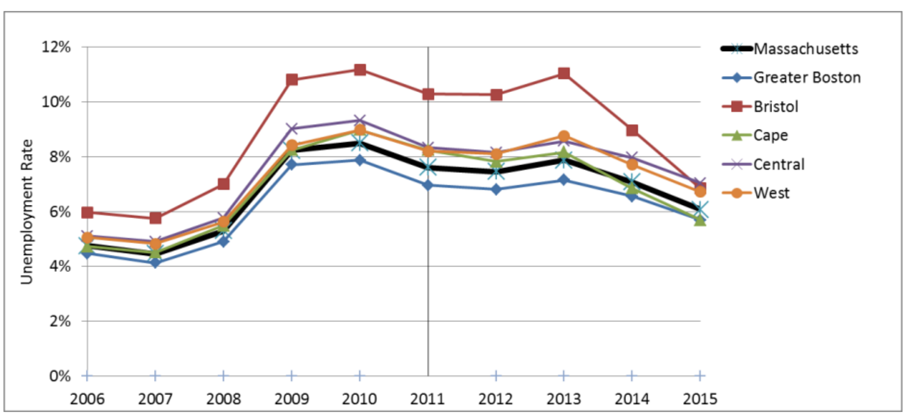
Source: Associated Industries of Massachusetts

Unemployment Rates

The Massachusetts economy is highly diverse by region. This means that parts of the state have been more insulated from the downturn than others. Bristol County has been hit the hardest of any region in recent years, in part due to its reliance on heavy industries (such as manufacturing) which has seen production downturns.

According to the economic forecast that we used, the unemployment picture is projected to improve in the state and its regions over the next few years. Typically, employment lags behind the economic performance, since some industries are only willing to hire once their business picks up significantly. This explains why, according to the Moody's forecasts, unemployment in Massachusetts is expected to increase slightly through 2013, then fall back below seven percent for the following two years.[9] The unemployment rate is projected to fall precipitously for Bristol County (from 11 percent in 2013 to around seven percent in 2015), with the rate for all other regions (including the state as a whole) falling to between 5.5 percent and seven percent by 2015.

Figure 2.3 Current and Projected Unemployment Rate by Region (2011 – 2015)

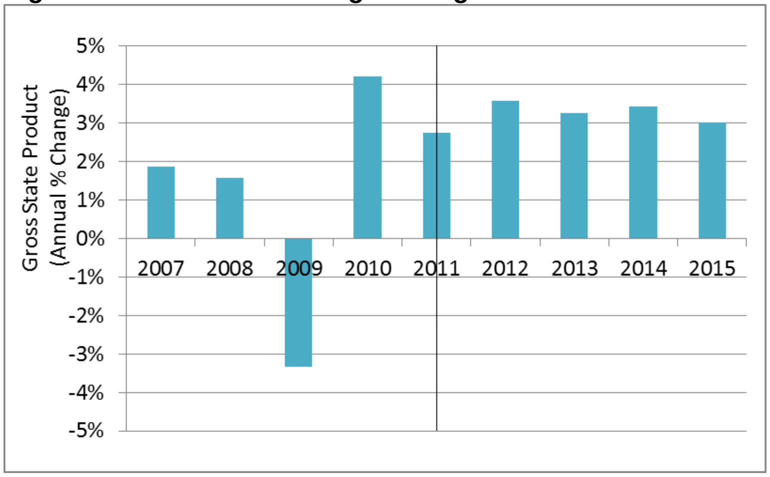


9 The Moody's forecast data lag behind the most recent data available on unemployment by two months. This explains the recent decreases in unemployment, which were more than expected but not accounted for in Figure 2.3.

Gross State Product

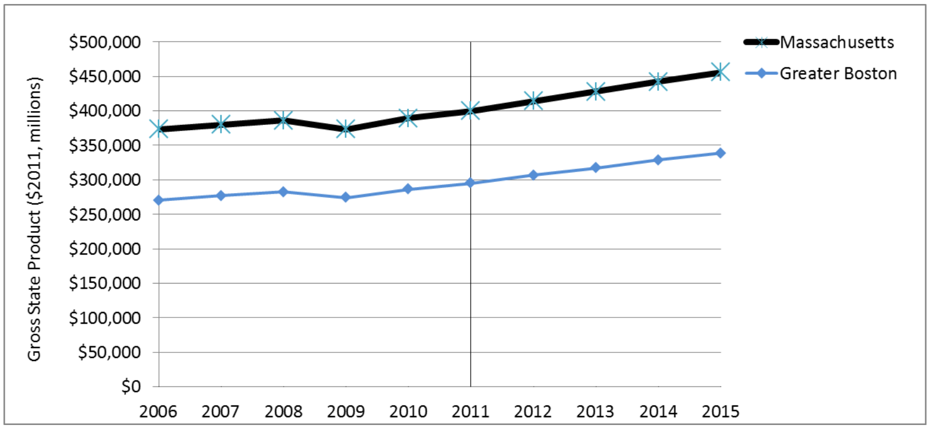
Figure 2.4 presents the annual percentage change in real (i.e., adjusted for inflation) gross state product for the historic years of 2007 – 2011, and forecasts for 2012 – 2015. This forecast suggests that gross state product will increase to annual growth rates higher than those that existed prior to the downturn in 2009.

Figure 2.4 Annual Percentage Change in Real Gross State Product: Massachusetts



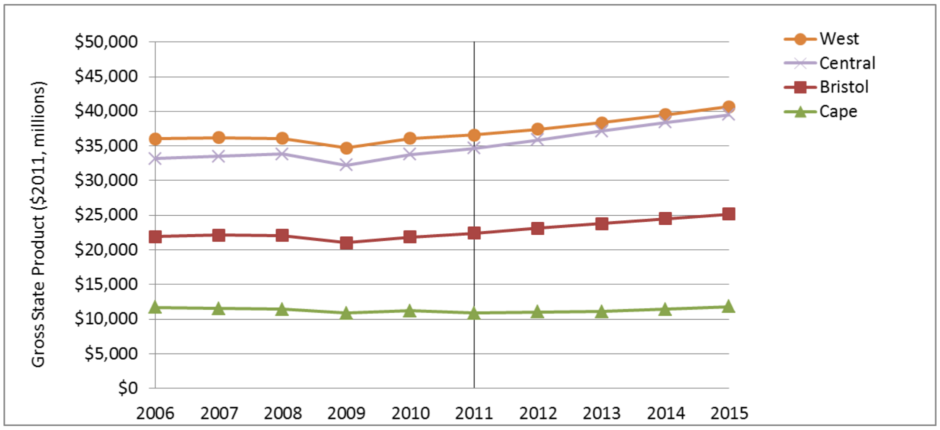
Figures 2.5a and 2.5b (below) show the gross state product forecasts by region (in 2011 dollars).[10] As indicated, steady growth in gross state product is expected over the next few years, except for the Cape and Islands region where gross state product remains essentially flat.

Figure 2.5a Gross State Product: Massachusetts and Greater Boston (million$)



10 We use two charts to present the gross state product because the results for Boston and the state require a different scale than the results for the other regions.

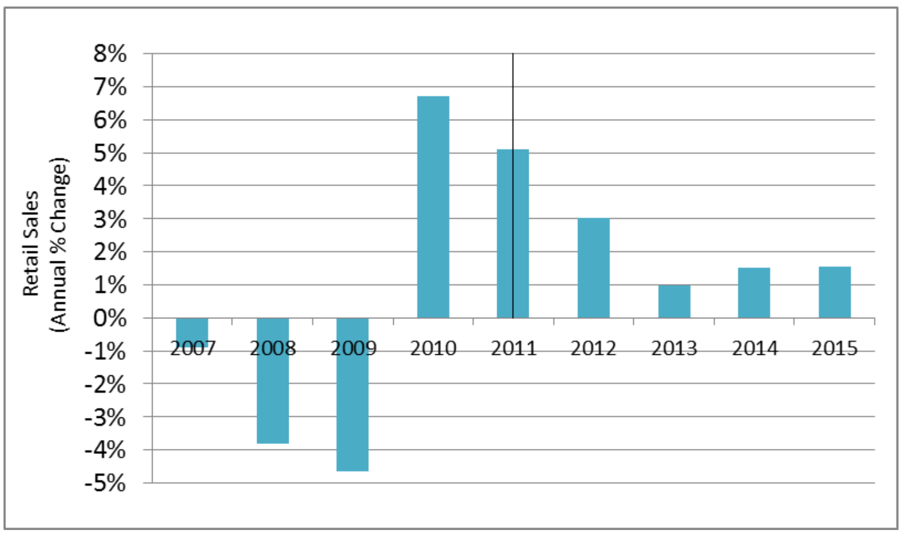
Figure 2.5b Gross State Product: Cape, West, Bristol, and Central Regions (million$)



Retail Sales

Retail sales is a large component of gross state product—accounting for more than 26 percent of gross state product in Massachusetts. After a significant drop in 2007 through 2009, retail sales rose sharply in 2010 and 2011, and are predicted to rise modestly in the coming years. 2.6 presents the annual percentage change of real (i.e., adjusted for inflation) retail sales by year for the state.

Figure 2.6 Annual Percentage Change in Real Retail Sales: Massachusetts



Figures 2.7a and 2.7b show the retail sales forecasts by region (in 2011 dollars).).[11] As indicated, steady growth in retail sales is expected over the next few years, except for the Cape and Islands region where retail sales remain essentially flat.

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[11] We use two charts to present the retail sales because the results for Boston and the state require a different scale than the results for the other regions.

Figure 2.7a Retail Sales: Massachusetts and Greater Boston (millions$)

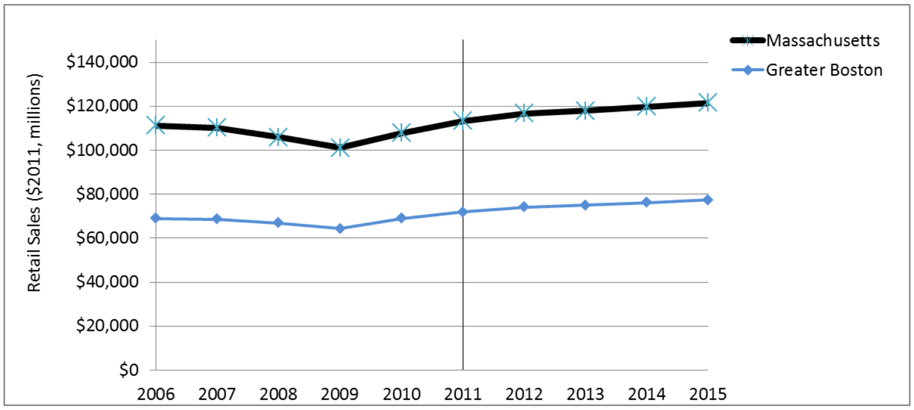
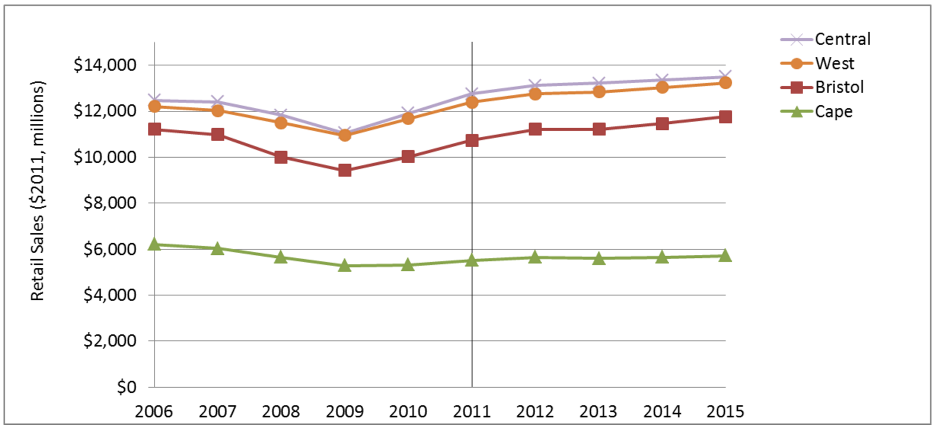


Figure 2.7b Retail Sales: Cape, West, Bristol, and Central Regions (millions$)



Construction Activity

Construction activity has declined in recent years (during the economic downturn), but is expected to pick up in the coming years in Massachusetts. Figures 2.8 and 2.9 show the increases in business construction investments and residential permits, respectively. These indicators are important for the state's economic outlook, and also offer a glimpse of the opportunities for residents and businesses to implement new efficiency measures—whether in a new building, an addition, or renovation of an old space.

Figure 2.8 Business Construction Activity in Massachusetts (2011 – 2015)

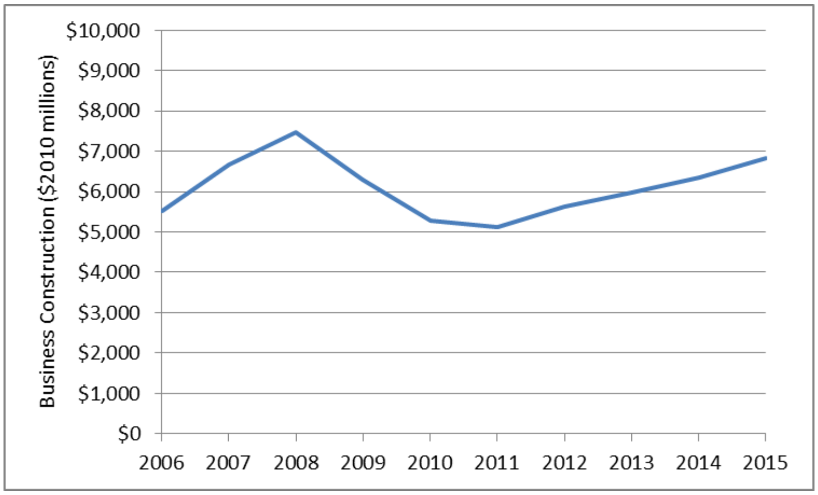
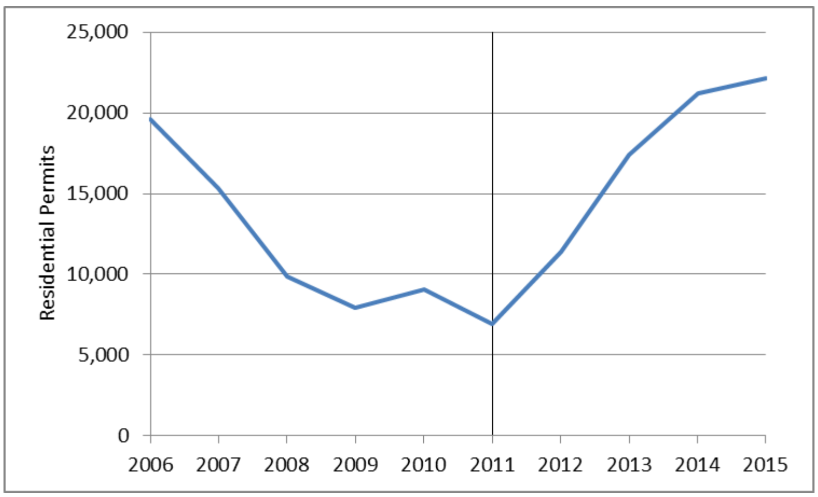


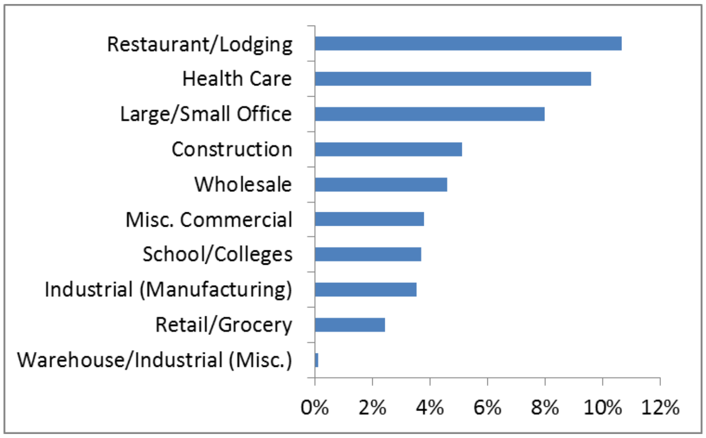
Figure 2.9 Residential Permits in Massachusetts (2011 – 2015)



Employment Growth by Industry

Most industries are projected to experience employment growth in Massachusetts in the period between 2011 and 2015, including manufacturing. Figure 2.10 shows the percentage increase in employment for each business type from 2011 to 2015. Restaurant/lodging, office, and healthcare industries are projected to experience employment growth of the most, with each industry projected to grow more than eight percent over the period. Industries such as industrial (manufacturing) and warehouse/industrial are expected to experience less employment growth.

Figure 2.10 Percentage Employment Growth in Massachusetts by Industry (2011 – 2015)



These results are presented below in Figures 2.11a-e, separately by region. Interestingly, healthcare and office industries are projected to grow strongly in every region of the state (and both are large components of every region's employment); restaurant and lodging are projected to grow significantly in every region except the Cape/Islands; and construction is projected to have robust growth in Bristol, but little growth in other regions. This feeds into the large projected fall in unemployment in Bristol presented earlier; five industries in this region are expected to grow 9% or more in terms of employment.

Figure 2.11a Percentage Employment Growth in Greater Boston by Industry (2011 – 2015)

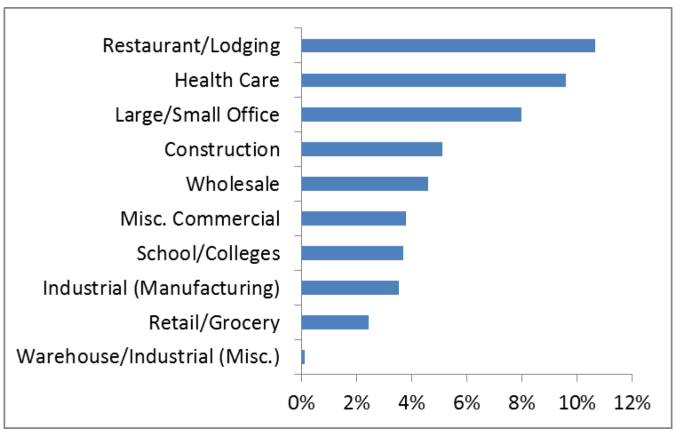


Figure 2.11b Percentage Employment Growth in Bristol County by Industry (2011 – 2015)

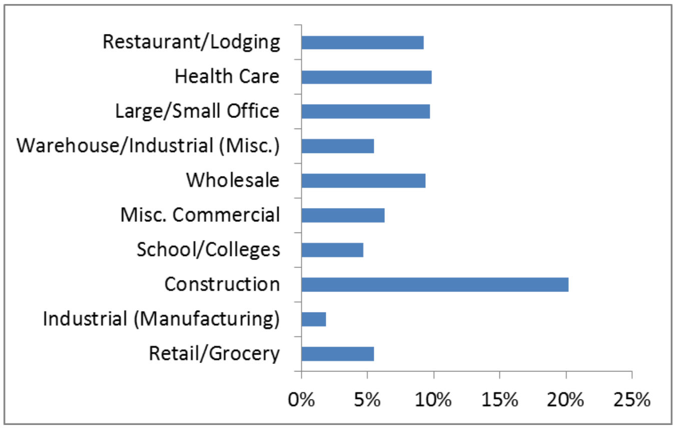


Figure 2.11c Percentage Employment Growth in Cape/Islands (2011 – 2015)

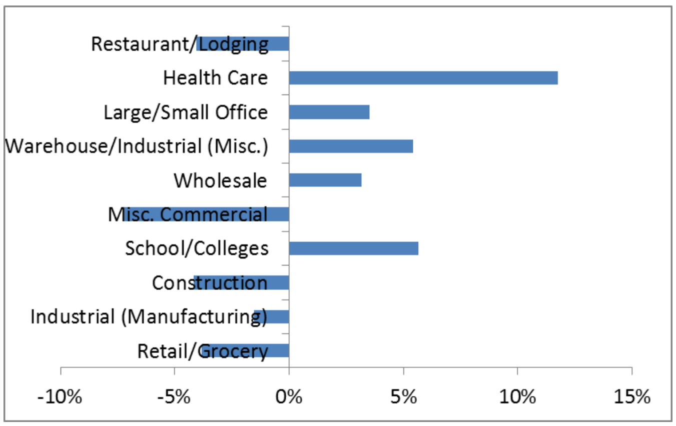


Figure 2.11d Percentage Employment Growth in Central Massachusetts (2011 – 2015)

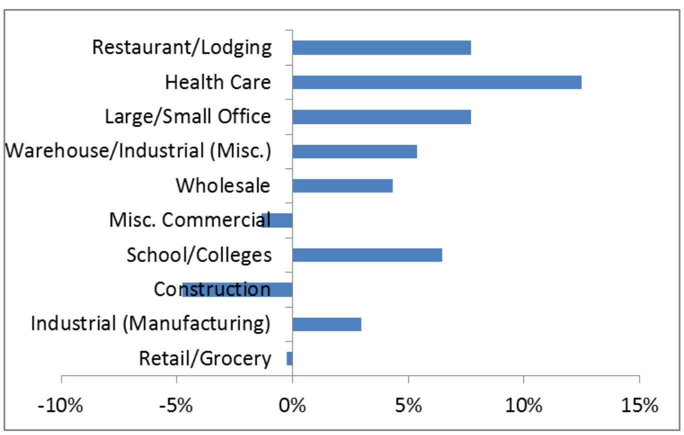
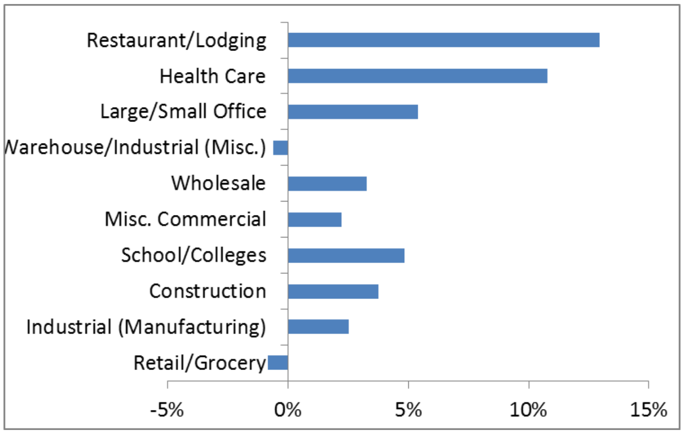


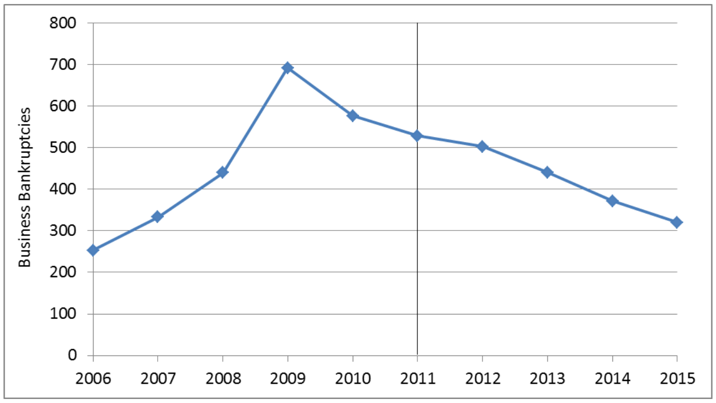
Figure 2.11e Percentage Employment Growth in Western Massachusetts (2011 – 2015)



Business Bankruptcies

Figure 2.12 presents historic and forecasted business bankruptcies in Massachusetts. Consistent with the positive trend in other economic indicators, bankruptcies are expected to decline over the next several years.

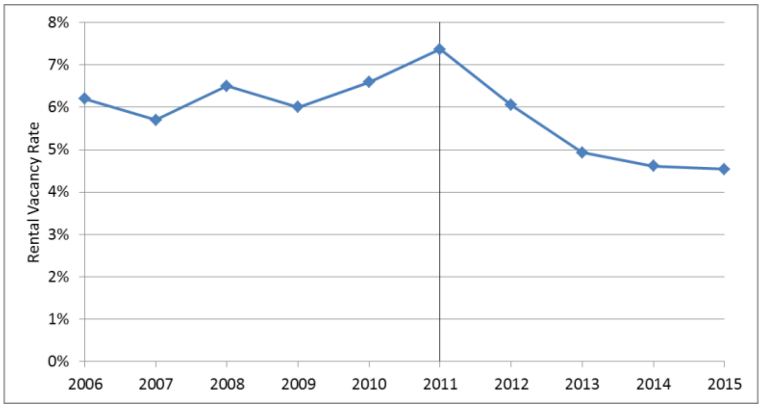
Figure 2.12 Business Bankruptcies: Massachusetts



Commercial Retail Vacancy Rate

Figure 2.13 presents the historic and forecasted commercial rental vacancy rate for Massachusetts. As indicated, the vacancy rates are expected to decline over the next few years.

Figure 2.13 Commercial Rental Vacancy Rate: Massachusetts



Summary

The economic forecast suggests that, in general, the state's economy will improve over the next several years. At the statewide level, gross state product, construction activity, residential construction permits, and retail sales are expected to grow, while unemployment rates, business bankruptcies, and commercial rental vacancy rates are expected to decline. The same overall trend of improvement can be seen within each region, as well. One exception to this trend is gross state product and retail sales in the Cape Cod/Islands region, which are expected to stay essentially flat between now and 2015.

Healthcare and office industries are projected to grow strongly in every region of the state, and both are large components of every region's employment. Restaurant/lodging is projected to grow significantly in every region except the Cape/Islands. Construction is projected to have robust growth in Bristol, but less growth in other regions. Bristol County, the region hit hardset by the economic downturn in Massachusetts , is expected to see a large fall in unemployment over the 2011 – 2015 period, in part due to construction growth.

3. Participation Barriers Identified From Other Sources

3.1 Measurement and Verification Studies

Massachusetts energy efficiency program administrators routinely conduct measurement and verification (M&V) studies of the commercial and industrial (C&I) energy efficiency programs. Among other things, these studies investigate customer perspectives regarding energy efficiency.

To inform our survey, we reviewed the results of recent M&V research, focusing on the C&I process evaluation and market characterization studies performed in the past two years. Based on our review, these studies suggest the following key barriers and, in some cases, potential solutions, to C&I participation in energy efficiency programs:

- Financial barriers. These include cost of efficiency investments, incentives and financing availability, capital availability, and payback periods associated with installing efficient equipment. Even with large financial incentives available, there are still instances when participants face significant upfront costs for the time and resources required to conduct technical assessments or lifecycle cost analyses. Additionally, companies often have a limited amount of capital available to spend on efficiency projects. Increased incentives related to technical assistance and increased availability of financing are often recommended as methods to overcome cost barriers, and are generally seen as an attractive and important component to participation.
- The recent economic downturn. This most notably impacts the new construction market, including lack of available capital, customers' apprehension toward capital investments, and efficiency investments competing against other capital projects within a company. For customers who participate in efficiency programs during an economic downturn, the amount of the incentive plays an increasingly important role in the decision to participate. Recommended methods to address the economic mindset of customers include increasing financial incentives, focusing on more cost-effective technologies and/or customers with stable financial conditions, and developing creative marketing programs.
- Customer awareness and program marketing barriers. This includes lack of customer awareness about efficiency programs, the advantages and drawbacks of different types of customer outreach methods (e.g., direct contact compared to marketing materials), and difficulty in reaching key decision makers and/or target markets. A key challenge for efficiency programs is reaching eligible customers with information about program offerings and the process for participation. Program Administrators typically market efficiency programs to C&I customers through account executives who serve as the main point of contact between customers and program administrators, and are therefore responsible for informing their customers of relevant energy efficiency opportunities. For this customer sector, personal relationships are particularly important in recruiting participants and the direct outreach conducted by program staff and vendors is central in reaching customers who ultimately chose to participate in programs. Furthermore, who the account executives or program managers contact influences program participation greatly. Recommendations include improving

marketing materials, hosting "lunch and learns," and educating customers as well as Program Administrator staff.

- Program design and administration barriers. This includes burdensome and time-consuming processes for participation, Program Administrator staffs' lack of available time and technical knowledge, customers' lack of understanding regarding efficiency strategies and measures, availability of certain technologies, and lack of technical assistance. A number of studies suggested that participating in efficiency programs could be streamlined, especially the application process required for participation. Despite the relatively large incentives offered, program staff reported that some customers are reluctant to assume the additional time and cost required by participation. Additionally, account executives mentioned being too busy or lack of staff as an issue. Some studies suggested that program administrator's skill sets could be more diverse, and that program administrators often lack technical knowledge. One recurring issue relates to the types of measures offered through the program administrators programs. One recommendation was that there should be something in between a straight forward prescriptive approach and full building modeling.
- Timing of participation as a barrier. This includes lack of early involvement by the program administrators in efficiency projects. For example, some projects require early involvement of the program administrators to ensure that all relevant energy efficiency improvements are incorporated into the customer's building design.

Additional barriers to participation include: (a) the need to obtain corporate approval to participate; (b) customers' hesitation to adopt new technology; and (c) customers already as efficient as is feasible, and (d) rapidly changing building codes. For some clients, who may operate their facilities on a 24/7 basis, the need for equipment reliability and ease of maintenance is paramount.

A more detailed discussion of the key barriers to efficiency program participation identified in the Massachusetts M&V studies is presented in Appendix A of this report.

As might be expected, our survey results discuss many of these same issues.

3.2 Comments at January 2012 EEAC Meeting

The majority of the EEAC's January 10, 2012 monthly meeting was devoted to hearing comments from the public regarding the development of the 2013 through 2015 three-year energy efficiency plans. Summarized below are the written comments filed in follow up to the January 10, 2012 meeting, related to participation barriers.

Measures and Incentives Structures

A Better City (ABC) recommends increased flexibility in program offerings, as it finds that the current programs are too limited, with significant incentives for low-savings measures such as lighting, but comparatively little support for the major building infrastructure improvements that can substantially reduce energy consumption (ABC, 5). ABC states that many building owners feel that they have reached the limit of what can be accomplished under the current utility programs, but are certain that much deeper savings can be found in their properties (ABC, 5). More specifically, ABC argues that incentives to replace aging HVAC systems are inadequate to drive early retirement, and suggests that paybacks approach five years to incent owners to make the large-scale capital investments that drive deep energy savings (ABC, 6).

Medical Academic and Scientific Community Organization, Inc. (MASCO) and Health Care Without Harm note that once healthcare facilities move beyond installing "low-hanging fruit," sophisticated energy conservation systems will need to be addressed in order to reap additional savings (MASCO, 1; Health Care Without Harm, 1-2). Such sophisticated systems do not function properly without certain synergistic sequences and/or behaviors, which the current incentive programs do not address (MASCO, 1). MASCO urges that prescriptive specifications and sequences be linked to operational and maintenance best practices (MASCO, 1).

MASCO also explains that as healthcare reimbursement rates decline, some hospitals lacking financial resources and/or depth in their facility departments may need a larger cost share from utilities to meet project costs (MASCO, 1; Health Care Without Harm, 1-2). Such support can be tied to conditions such as utility/client MOUs, institutional energy master plans, finances, and adjusted lifecycle savings, perhaps with utility payback coming from later energy savings (MASCO, 1-2).

Northeast Energy Efficiency Partnerships (NEEP) understands that an ongoing challenge and area of focus by the program administrators has been moving customers from initial assessment of energy saving opportunities to actually installing measures (NEEP, 5). NEEP recommends exploring the possibility of adapting for mid-size businesses the Memoranda of Understanding (MOUs) that have helped large C&I customers take a multi-year approach to efficiency investment (NEEP, 5). MASCO and Health Care Without Harm recommend that efficiency programs consider development of a joint strategic MOU as standard practice between all relevant utilities and large accounts (MASCO, 2; Health Care Without Harm, 1-2). MASCO suggests that such an approach would widen and deepen hospital participation, optimize projects, enable projects with longer returns on investment, and reduce barriers by minimizing the time needed to develop multiple MOUs (MASCO, 2). ABC also recommends negotiating a single, consolidated MOU, as it may have significant advantages and would allow building owners to effectively leverage time and personnel (ABC, 4).

Medium Sized Customers

ABC highlights that larger customers with dedicated utility account representatives are more satisfied with their program administrator program experience, while small and medium sized customers have a more challenging time navigating the programs (ABC, 3). ABC suggests that such a barrier could be addressed by having utility representatives offer a package of incentives and a single point of contact to assist during program participation (ABC, 3). ABC notes the gap in program offerings for customers between 300 kW and 700 kW, which could be removed by increasing the ceiling for the direct install program from 300 kW up to 500 kW and lowering the level for facilities to be appointed an Account Executive from 700 kW down to 500 kW (ABC, 3-4). Further, ABC recommends that the program administrators provide increased guidance on developing custom measure retrofits to small and medium sized customers (ABC, 4). ABC also notes that program application forms and marketing materials can be confusing, creating a barrier for smaller companies that do not have dedicated staff to manage energy projects (ABC, 4). ABC also notes that landlord-tenant split incentive issues are a well-known barrier in the commercial real estate market that could be overcome with focused utility efforts to bring both parties into the retrofit process in support of mutually beneficial building improvements (ABC, 5).

Better Data for Customers and About Customers

ABC suggests that the lack of easily accessible and transparent energy consumption data is a barrier to reducing energy use for office tenants, building owners, and other utility customers (ABC, 2). ABC recommends the development of a utility sub-metering program to help defray costs of metering equipment installations (ABC, 2). ABC also recommends that efficiency programs encourage widespread adoption of EPA's Energy Star Portfolio Manager, as such an approach could improve building energy use monitoring and significantly aid building owners in their efforts to evaluate energy savings investments (ABC, 2-3). Finally, ABC recommends allowing for better access to real-time or interval meter energy consumption data by providing commercial customers with web-based tools that better organize and present real-time data (ABC, 3).

MASCO and Health Care Without Harm argue that customers need data at a more granular level than currently is available so as to integrate energy management and clinical operations to target efforts, detect and correct aberrational usage, monitor and maintain conservation measures, and incent and track behavior change (MASCO, 1; Health Care Without Harm, 1-2). MASCO contends that standardized sub-metering, water and steam monitoring specifications, and protocols could be developed to push vendors for lower costs, and to widely deploy accurate systems (MASCO, 1).

Mass Energy Consumers Alliance (Mass Energy) recommends that the program administrators be required to collect and report data about who is served and how in ways that would provide for meaningful planning, monitoring and evaluation (Mass Energy, 3). Mass Energy argues that better data will lead to better, more cost-effective programing (Mass Energy, 3).

4. Customer Survey

4.1 Customer Survey Methodology

The purpose of the survey component of Synapse's investigation was to gather additional information about the perceived current and future barriers to C&I participation in Massachusetts's energy efficiency programs, with specific attention to the role of the economy. We use the language "perceived current and future barriers" because this information has been self-reported by C&I customers and, as such, represents their opinions about the barriers to participation that they face.

Survey Development

To determine the content and design of its surveys, Synapse worked with the EEAC, conducted interviews with EEAC members and consultants, reviewed recent studies related to C&I participation, and attended the January EEAC meeting, which was devoted to receiving input from residential and C&I customers to inform the upcoming three-year plans. Questions were developed both to compare directly with the results of existing research, and to delve deeper into areas of particular interest to the EEAC.

Each survey consisted of two parts: a questionnaire, followed by a one-on-one interview. The questionnaire collected information that could be easily provided in written format, including both quantitative and qualitative information. The same questionnaire was used for both participants and non-participants.

Interview questions (all qualitative) were developed to provide a framework for the one-on-one interviews; however, interviewers were given the freedom to "go off-script," in order to ask follow-up or clarifying questions, to allow for open dialogue with the customer, and to address specific issues brought up in the customer's responses to the questionnaire.

Two versions of the interview questions were prepared; one for participants and one for non-participants. Non-participants were defined as customers who had not participated in C&I energy efficiency programs within the past five years, or had never participated.

The questionnaires and interview questions, for participants and non-participants, are provided in Appendix B of this report.

Selection of the Targeted Survey Pool

We then identified a set of targets for customer types to interview. We planned to interview a total of 40 customers across the state. We identified a target set of customers to interview by first spreading the 40 interviews across the five state regions based on economic activity in those regions; and second by spreading the interviews in each region across the different industry types according to the level of economic activity by industry type. In addition, the EEAC Executive Committee asked Synapse to focus our interviews on:

- Non-participants, as this segment of the population may have more significant savings opportunities. Non-participants were defined as customers who had not participated in C&I energy efficiency programs within the past five years, or had never participated.

- Medium-to-large C&I customers, as these customers often have significant savings opportunities. Medium-to-large C&I customers were defined by electric Program Administrators (PAs) as customers with a demand of greater than 300 kW. Medium-to-large C&I customers are defined differently among gas PAs. However, one gas PA suggested that medium-to-large C&I customers can be characterized by a usage of 10,000 therms or more annually.
- Non-governmental customers, as the reasons for governmental customer non-participation are better understood, and a number of initiatives are ongoing to address barriers to participation by governmental customers.

The resulting targets by region and industry type are presented in Table 4.1, below.

Table 4.1 Survey Targets by Region and Industry Type

Region and Industry Type Targets						
Industry Type	Boston	Central Mass	Cape Cod	Western Mass	Bristol County	Total
Heavy industry	1	1	1	1	1	5
Warehouses & Distribution	0	1	0	1	1	3
Retail	1	1	1	1	1	5
Office	6	2	1	2	1	12
Schools & Colleges	1	1	0	1	0	3
Healthcare	3	1	1	1	1	7
Restaurants & Lodging	2	1	1	1	1	6
Miscellaneous	0	0	0	0	0	0
Total	13	8	5	8	6	40

Point380 Energy Efficiency Market Opportunity Study

National Grid and NSTAR recently hired Point380 to conduct an energy efficiency market opportunity assessment of their service territories. Synapse was provided a copy of the Point380 study, to help inform our survey design.[12]

The purpose of the Point380 study is to provide National Grid and NSTAR with a general framework for understanding where the greatest remaining energy efficiency program opportunities exist. The study provides a high-level projection of energy efficiency opportunities by end-use, customer type, building type, and energy use (electric and natural gas).

We used the Point380 study to inform which industries to focus on in our survey. We reviewed the results of the Point380 study to identify those industries that offer the greatest potential for energy efficiency savings.

The two figures below, taken directly from the Point380 study, illustrate how we used the study. The first chart indicates the opportunity for commercial electric efficiency savings,

[12] Point380, *Energy Efficiency Market Opportunity Model*, Final Deliverables/Report Deck, prepared for National Grid and NSTAR, January 17, 2012, The results were provided to Synapse in four slide decks: Overview, Slide Deck 1a, Slide Deck 1b, and Slide Deck 2.

according to the different industries and end-uses. It indicates that six industries—small office, large office, health, retail, college, and grocery—offer the majority of electric efficiency savings.

The second chart indicates the opportunity for commercial electric efficiency savings available per account, i.e., savings available for any one customer. From the perspective of an energy efficiency program administrator, it is much easier to achieve efficiency savings from those industries that have a high level of savings per account. This chart indicates that the largest amount of efficiency savings per account is available from four industries: large office, health, college, and grocery.

We reviewed this information to help us focus on those industries that offer the greatest opportunity for efficiency savings. In this case, for commercial electric opportunities, we concluded that we should attempt to give priority to the six industries that show the greatest potential in the two charts below: small office, large office, health, retail, college, and grocery.

Figure 4.1 Sample Result from Point380 Study: Commercial Electric Opportunity.

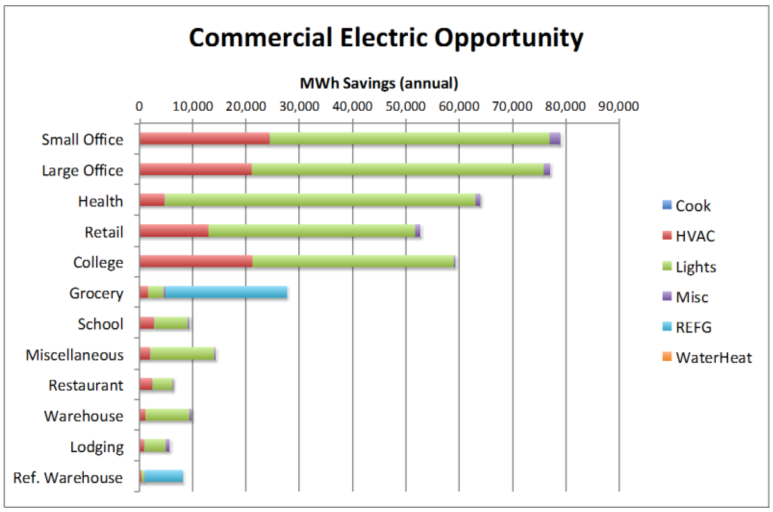
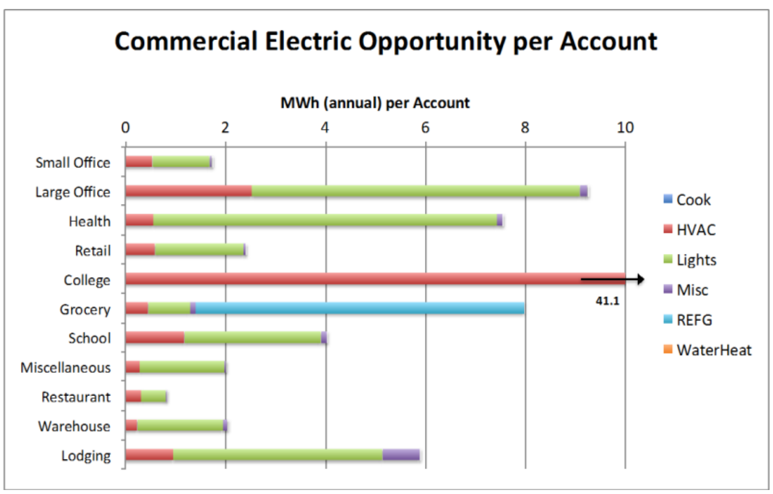


Figure 4.2 Sample Result from Point380 Study: Commercial Electric Opportunity/Account.



We also looked at the results for the industrial sector and for the gas end-uses. The following bullets summarize how we used the results of the Point380 study:

- As mentioned above, for the commercial electric customers we gave priority to interviewing customers from the following industries: small office, large office, health, retail, college, and grocery. This is based on the charts above, from slides 25 and 26 of the Point380 slide deck 1a.
- For the commercial gas customers, we gave priority to interviewing customers from the following industries: office, health, college, restaurant, and hotel. This is based on slides 32 and 33 of the Point380 slide deck 1a.
- For the industrial electric customers, we gave priority to interviewing customers from the following industries: industrial machinery, electronics, rubber/plastics, and chemicals. This is based on slides 13 and 14 of the Point380 slide deck 1b.
- For industrial gas customers, we gave priority to interviewing the following industries: food, chemicals, rubber / plastics, and paper. This is based on slides 20 and 21 of the Point380 slide deck 1b.

It is important to note that the Point380 results were used by Synapse simply for prioritizing which industries to invite for interviews. It was not intended to exclude industries, or limit survey participation by specific industries.

The Final Survey Pool

We then collected customer contact information from the Massachusetts energy efficiency program administrators and a few other stakeholders. We sent invitations to all 137 of the customer contacts that we received that were eligible and included contact information. Many of these customers did not respond to, or declined, our invitation. We conducted a total of 36 interviews. An additional four customers returned the questionnaire, but could not be reached to schedule an interview.[13]

The interviews that we conducted are presented by region and industry type in Table 4.2. Since a large number of customers did not respond to the survey invitations, the actual region and industry distribution was determined more by customer interest and availability than by the information and priorities that we used to determine the target region and industry distribution. Nonetheless, the set of interviews that we were able to conduct is close enough to the target region and industry distribution that we believe it will provide the geographic and industry diversity that we set out to survey.

The one example of where our customer set does not align with the intended target is that the vast majority of our interviews were with customers that have participated in the Massachusetts energy efficiency programs. We did not receive as many non-participant contacts from the stakeholders, and those that we did contact were much less likely to participate in our survey than the program participants.[14] Additionally, some non-participant contacts that the stakeholders provided were actually program participants.

[13] These four customers are not included in our discussion of the survey results. However, their responses to the questionnaire are included at the end of Appendix C.

[14] The participation levels of the 137 customers to whom we sent invitations was approximately 31% participants and 41% non-participants, while 28% were not identified as either a participant or non-participant. The customers who responded to our invitation and participated in the survey were throught to comprise a roughly similar percentage of participation levels. In interviewing customers, 8 customers who were provided to us as

Table 4.2 Actual Surveys Completed, by Industry Type and Region

Industry Type	Boston	Central Mass	Cape Cod	Western Mass	Bristol County	**Total**
Heavy industry	2	1	0	5	1	**9**
Warehouses & Distribution	0	0	0	1	0	**1**
Retail	1	1	0	1	2	**5**
Office	5	1	0	3	0	**9**
Schools & Colleges	4	0	0	0	0	**4**
Healthcare	3	1	1	0	0	**5**
Restaurants & Lodging	1	1	0	0	0	**2**
Miscellaneous	0	0	0	0	1	**1**
Total	**16**	**5**	**1**	**10**	**4**	**36**

It is important to note that sample sizes this small will not provide results that can be considered statistically significant. In addition, because these customers were not chosen at random it is quite possible that the survey results suffer from "selection bias." Nonetheless, we believe the results from these interviews provide useful anecdotes and insights for the EEAC and other stakeholders, consistent with the purpose of this study.

Survey Implementation

Using the contact information provided by the program administrators and EEAC members, Synapse sent invitations to the potential survey pool of 137 contacts via email.

The first part of the survey, the questionnaire, was attached to the email invitation. Once a customer completed the questionnaire, a one-on-one interview (approximately 30 – 40 minutes in length) was scheduled to delve deeper into specific interest areas, including any that were raised in the customer's responses to the questionnaire. Most interviews were conducted over the phone; however, customers were given the option to be interviewed in person, and some did choose that option.

In order to encourage customers to be more forthright with Synapse, the survey was conducted confidentially. As such, while selected questionnaire responses and interview notes for each surveyed customer have been provided in Appendix C of this report, all customer- and interviewee-identifying information have been removed.[15]

4.2 Customer Survey Results

Overview of Common Themes

We noticed many common themes among the customers that we interviewed. For example, most customers that we interviewed were past program participants at some

non-participants revealed that they were actually program participants, and 14 customer that were originally unidentified revealed that they were program participants. Therefore, the participation levels of the final 36 customers surveyed is as follows: 6 customers were non-participants (17%) and 30 customers (83%) were participants.

15 The characterization of barriers evolved as we surveyed customers. Because of this, the "Barriers to Participation" section in the interview notes in Appendix C varies depending on when the customer was interviewed.

level and stated that they either will participate or are considering participating in programs in the next few years.[16] In general, the customers we interviewed consider energy efficient equipment regularly when they make purchasing decisions.

Another theme we heard from most of our interviews was that payback period is the main criteria for evaluating energy efficiency investments and that energy efficiency investment payback periods compete with the payback periods for other capital investment projects. The payback threshold for moving forward with energy efficiency investments was remarkably consistent across industries and regions. Most customers require projects to have payback periods of four years or less. However, projects with payback periods of three to four years are rarely approved. Projects with payback periods of two to three years are sometimes considered, but approval is uncertain and depends largely on the economics of the other projects that are competing for capital in a given year. A project with a payback of two years or less is typically considered to be worthwhile and is approved.

A third theme we heard from many customers we interviewed was that capital constraints are a key barrier to moving forward with energy efficiency projects. All projects that are submitted (whether they are related to energy efficiency and energy consuming equipment replacement or not) compete for capital investment dollars using payback as the key criteria and taking into the account the nature of the need for the project. Energy efficiency investments are frequently categorized as discretionary, not required, expenditures.

A fourth theme is that the general process for vetting and approving energy efficiency investments is similar across many customers. Projects are scoped, analyzed, and proposed on an annual basis and submitted to a higher level team for review and approval.

A fifth theme is that financing mechanisms, such as loans, are seldom, if ever, used. Instead, customers primarily use available capital to pay for their energy efficiency investments, supplemented by the contributions from the energy efficiency programs. A sixth theme is that many customers were generally confused by the number of different energy efficiency program administrators in the market and what each provider could provide. Some customers had facilities served by both municipals and utilities. Also, some customers mentioned that they were also working directly with ESCOs, renewable installers, and manufacturers/distributors of lighting products, among other third parties.

It is clear from even our small sample that there are many different types of customers with different needs and barriers to participating in energy efficiency programs. For example, some customers are proactively looking for energy efficiency opportunities, prefer to scope an energy efficiency project using their own internal resources, and prefer to obtain program administrator resources with little technical support from the program administrators. Other customers do not have the resources to be proactive and scope projects, and prefer regular contact from program administrators on program offerings and savings opportunities. This diversity of customers creates a significant challenge for program administrators, because reaching additional customers and achieving deeper levels of savings per customer will likely require offering program technical and financial

[16] Specifically, when asked whether a customer plans to participate in the efficiency programs within the next three years, 27 customers said “yes,” 2 said “no,” and 7 said “maybe.” The four additional customers that completed the questionnaire but not the interview all indicated “maybe.”

support that is more tailored to the unique needs of the many different types of electric and gas customers.

Positive Feedback

Many of the customers interviewed provided positive feedback on the programs. Some of the highlights include the following points, which are amplified with a few anecdotes.

Many customers were grateful for the sustained incentives and technical assistance provided by energy efficiency program administrators over the years and indicated that energy efficiency investments could not compete with other capital investments without the incentives and technical assistance received.

- One customer is a regular participant and is totally committed to energy efficiency, but cannot do efficiency projects without the program administrator's rebates. The efficiency savings from equipment installations does not allow the customer to reach its required payback on its own. The combination of energy savings, maintenance savings, and rebates allows the customer to meet its two years or less payback objective.
- Another customer has mostly focused on lighting opportunities and has been transitioning to new lighting over the past 10-13 years. The customer stated that every step the customer takes improves long run expenses and, even though they must do this in a phased approach to maximize incentives and manage the capital investment, they aim to eventually reach all of the lighting retrofit opportunities in the building.
- A third customer indicated that it has mostly tapped out its gas opportunities using incentives that the customer has accessed 2 or 3 times. The incentives have helped the customer achieve the payback criteria and helped energy efficiency projects compete with other capital investment projects that were on the table, resulting in project prioritization, approval, and implementation.

Several companies mentioned that they appreciate the level of outreach that they receive from energy efficiency program administrators and have had a long-standing, trusting relationship with their account executives.

- One customer stated that it has a true partnership with his energy efficiency program administrator and feels strongly that the energy efficiency program administrator is representing the customer's interests and needs. The customer appreciates the support provided by the energy efficiency program administrator to help the customer complete efficiency projects. The partnership is a win-win for both parties. The customer has national operations and acknowledges that Massachusetts energy efficiency programs are way ahead of most energy efficiency programs across the country and that Massachusetts has been very proactive in its approach to efficiency. The customer especially appreciates the ability to work with the energy efficiency program administrator to meet the customer's needs.
- Another customer stated that they appreciate and trust the energy efficiency program administrator's guidance on energy efficiency products and services.

Some companies recognized the variety of efforts and approaches that the energy efficiency program administrators are leveraging as well as the positive impacts of these efforts over time.

- One customer likes the concept of the upstream lighting program. The customer stated that this program shows that the energy efficiency program administrators are trying to help their customers get incentive dollars without having to submit a lot of paperwork.
- One customer has worked closely with its energy efficiency program administrator to design a custom three-year efficiency plan for its property through a Memorandum of Understanding (MOU). Through the MOU, the customer set aggressive goals and has been successful in meeting those goals. The energy efficiency program administrator has been able to provide greater amounts of funding than in previous years of participation, which allowed the customer to design a significant efficiency investment plan.
- Another customer felt strongly that the biggest benefit of these programs over time has been to accelerate energy efficient product development and manufacturing and make energy efficient solutions affordable options for companies.

Summary of Barriers Identified by Customers

The barriers to participation that have emerged from the interviews can be organized into two categories: customer barriers and program barriers. Customer barriers are barriers that stem from a customer's internal decision-making processes.[17] Program barriers are barriers that stem from the way the programs are designed or administered.

Customer Barriers

The customer barriers consist of the following:

- Customer's capital constraints: this category addresses a customer's tight capital investment budgets, and efficiency projects competing against other investment projects that are more germane to a customer's core business.
- Economic climate: this category addresses economic issues that might influence a customer's decision to participate in programs, such as reduced capital availability because business is slow or there is not enough time to devote to efficiency because the customer has had layoffs, and responsibilities are divided among fewer employees.
- Unsupportive corporate review and approval process: this category addresses the difficulty in receiving corporate or management approval to spend on efficiency measures.
- Company is convinced it has done all it can : this category addresses the customer perception that it doesn't have any more efficiency measures it can implement within its facilities..
- Distrust of new technology: this category addresses whether a customer distrusts efficiency measures, including perceiving efficiency measures as requiring more maintenance and upkeep.

[17] It is important to note that the efficiency programs, by their very nature, are designed to remove barriers to participation in efficiency projects. However, customers identified aspects of the programs that they perceive as barriers.

Program Barriers

The program barriers consist of the following:

- Insufficient marketing and outreach: this category addresses how aware customers are about efficiency programs and opportunities, and how regularly they hear from program administrators.
- High transaction costs: this category addresses the process required for program participation, including paperwork and time devoted to program participation.
- Inadequate responsiveness and timing: this category addresses how quickly the program administrators respond to a customer's needs (i.e., when equipment fails and needs immediate replacing), as well as the timeliness of program administrators outreach to customers about participation in programs, .
- Limited measures offered through the programs: this category addresses the appropriateness and adequateness of measures offered through the efficiency programs.
- Insufficient incentives: this category addresses the appropriateness and adequateness of incentive levels and rebates offered through the efficiency programs.
- Desire to opt out of the energy efficiency charge: this category tracks customer's mention of the energy efficiency charge or the system benefits charge as a barrier to greater efficiency savings. Some large customers would prefer to opt out of the charge and use the funds they would normally contribute to the charge within their business, with the stipulation that such funds can only be used for efficiency projects. While this is not necessarily a participation barrier created by the design or implementation of the efficiency programs, some customers argued that such a change would allow them to spend more on efficiency projects and achieve greater savings.
- Programs not tailored to unique needs: this category tracks customer's mention that the programs are not designed to meet their needs.

Figures 4.3 and 4.4 present a summary of the number of times each of the barriers was mentioned by customers in our interviews.[18] In general, program barriers were mentioned about twice as frequently as customer barriers. Of the program barriers mentioned, insufficient marketing and outreach and transaction costs were the most frequently mentioned barrier.

[18] Note that each customer mentioned more than one barrier, and not all customers identified the same number of barriers. We present these figures simply to provide a summary of the frequency with which the different barriers were identified.

Figure 4.3 Customer Barriers Mentioned in the Interviews

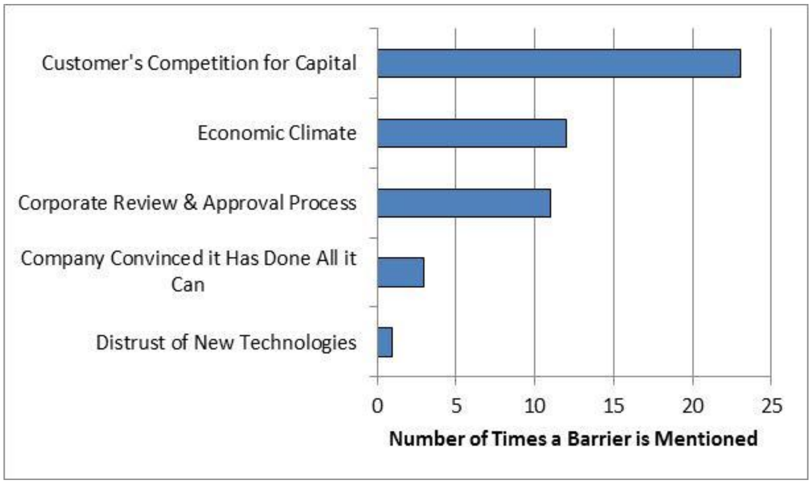
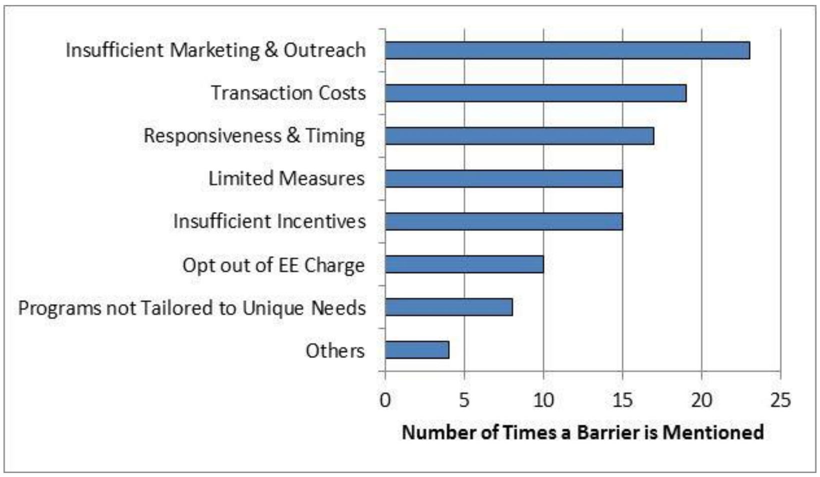


Figure 4.4 Program Barriers Mentioned in the Interviews



Tables 4.3 and 4.4 present a summary of the barriers identified by each customer during its individual interview.[19] Each customer is identified by its region and industry. A "yes" in the table indicates that the barrier affects the customer, while a "maybe" indicates that the barrier could affect the customer depending on certain circumstances. For example, a "maybe" within the "corporate review and approval process" category could be because the customer is under new ownership and is uncertain how responsive the new ownership will be to energy efficiency projects.

[19] Note that the number given to each surveyed customer in Tables 4.3 and 4.4 corresponds to the interview number identified in each customer's interview notes included in Appendix C.

Table 4.3 Barriers Identified in Customer Interviews - Customer Barriers

Company Information				Expect to Participate in Next 3 Years?					
#	Region	Industry	Participant		Customer's Capital Constraints	Economic Climate	Corporate review & approval process	Company distrust of new technologies	Company convinced it has done all it can
1	Bristol County	Heavy Industry	Yes	Maybe	Yes				
2	Bristol County	Retail	Yes	Yes	Yes				
3	Bristol County	Miscellaneous	Yes	Yes	Yes	Yes	Yes		
4	Boston	Schools & Colleges	Yes	Yes			Yes		
5	Western Mass	Retail	Yes	Yes	Yes	Yes			
6	Boston	Healthcare	Yes	Yes	Yes				
7	Boston	Office	Yes	Yes		Yes	Yes		
8	Boston	Restaurants & Lodging	Yes	Yes					
9	Boston	Office	Yes	Yes	Yes				
10	Central Mass	Heavy Industry	Yes	Yes	Yes				Yes
11	Western Mass	Office	Yes	Maybe	Yes	Yes			
12	Boston	Office	Yes	Yes	Yes	Yes			
13	Central Mass	Healthcare	Yes	Yes	Yes	Yes	Yes		
14	Boston	Schools & Colleges	Yes	Yes	Yes				
15	Boston	Schools & Colleges	Yes	Yes					
16	Boston	Healthcare	Yes	Yes	Yes				
17	Boston	Schools & Colleges	Yes	Yes		Yes			
18	Western Mass	Heavy Industry	No	Yes	Yes		Maybe		
19	Central Mass	Retail	Yes	Yes					
20	Central Mass	Office	Yes	Yes	Maybe	Maybe			
21	Boston	Healthcare	Yes	Maybe	Yes	Yes			
22	Western Mass	Heavy Industry	Yes	Yes	Yes				
23	Western Mass	Heavy Industry	Yes	Yes	Yes				
24	Western Mass	Heavy Industry	Yes	Yes	Yes				
25	Western Mass	Heavy Industry	Yes	Yes	Yes				
26	Bristol County	Retail							
27	Central Mass	Restaurants & Lodging	Yes	Yes			Maybe		
28	Boston	Office	no	No			Yes		
29	Boston	Office	Yes	Yes			Maybe		
30	Boston	Heavy Industry	No	Maybe	Yes	Yes			
31	Western Mass	Heavy Industry	No	Yes			Yes		
32	Boston	Heavy Industry	Yes						Maybe
33	Western Mass	Office	no	Yes			Maybe		
34	Western Mass	Warehouses & Distribution	no	Maybe	Yes			Yes	Maybe
35	Cape Cod	Healthcare	Yes	No	Yes	Yes			
36	Boston	Retail	Yes	Yes	Maybe	Yes	Yes		

Table 4.4 Barriers Identified in Customer Interviews - Program Barriers

Company Information			Program Design & Administration Barriers							
#	Region	Industry	Insufficient Incentives	Insufficient Marketing & Outreach	Transaction Costs	Responsiveness & Timing	Limited Measures	Programs not Tailored to Unique Needs	Opt out of SBC	Others
1	Bristol County	Heavy Industry	Yes	Yes					Yes	Yes
2	Bristol County	Retail	Yes	Yes	Yes					
3	Bristol County	Miscellaneous		Yes	Yes	Maybe	Yes			
4	Boston	Schools & Colleges					Yes	Yes		Yes
5	Western Mass	Retail		Yes	Yes		Yes			
6	Boston	Healthcare				Yes	Yes			
7	Boston	Office	Yes	Yes	Yes					Yes
8	Boston	Restaurants & Lodging		Yes	Yes	Yes		Yes		
9	Boston	Office		Yes		Yes	Yes			
10	Central Mass	Heavy Industry					Yes		Yes	
11	Western Mass	Office		Yes						
12	Boston	Office	Yes	Yes		Yes				
13	Central Mass	Healthcare			Yes					
14	Boston	Schools & Colleges	Yes				Yes	Yes	Yes	
15	Boston	Schools & Colleges	Yes	Yes		Yes	Yes		Yes	Yes
16	Boston	Healthcare	Yes				Yes	Yes	Yes	
17	Boston	Schools & Colleges			Yes	Yes	Yes	Yes	Yes	
18	Western Mass	Heavy Industry		Yes						
19	Central Mass	Retail	Yes	Yes	Yes	Yes	Yes	Yes		
20	Central Mass	Office		Yes		Yes				
21	Boston	Healthcare	Yes	Yes			Yes	Yes		
22	Western Mass	Heavy Industry	Yes	Yes	Yes	Yes			Yes	
23	Western Mass	Heavy Industry	Yes	Yes	Yes	Yes			Yes	
24	Western Mass	Heavy Industry	Yes	Yes	Yes	Yes			Yes	
25	Western Mass	Heavy Industry	Yes	Yes	Yes	Yes			Yes	
26	Bristol County	Retail	Yes							
27	Central Mass	Restaurants & Lodging			Maybe		yes			
28	Boston	Office		Maybe				Yes		
29	Boston	Office			Maybe					
30	Boston	Heavy Industry		Yes	Yes					
31	Western Mass	Heavy Industry		Maybe	Yes		Maybe			
32	Boston	Heavy Industry		Maybe		Yes				
33	Western Mass	Office			Yes	Yes				
34	Western Mass	Warehouses & Distribution			Yes		Yes			
35	Cape Cod	Healthcare	Maybe			Yes				
36	Boston	Retail		Yes	Yes	Yes				

Customer Barriers

Each of the customer barriers summarized above is discussed in more detail below. It is worth noting that many of the customer barriers are not mutually exclusive, leading to the appearance of overlaps. For example, when asked whether the economy affected a customer's business, the person interviewed may have discussed reduced capital or reduced payback periods, which are addressed in both the customer's capital constraints and corporate review and approval barrier categories. When quantifying whether a customer considers a situation to pose a participation barrier, we adhered to the barrier definitions discussed above and only considered the situation a barrier when the customer explicitly identified it as such.

<u>Customer's capital constraints</u>. This is one of the most frequently cited and important barriers that customers face in energy efficiency program participation. Many customers, although not all, do not have a problem accessing capital.[20] Their chief problem is with the competition for capital between energy efficiency investments and other investments, especially those investments that are more germane to the core business of the customer. Some companies have global operations, and face competition for capital in Massachusetts, in the United States, and elsewhere in the world. This competition for capital is so important to customers that it results in greater adherence to payback period constraints, as that is often the criteria that is used to determine which project deserves the constrained capital. Further, some customers mentioned that the significant upfront cost of efficiency measures, especially larger projects beyond lighting upgrades, created a barrier to deeper participation.

<u>Economic climate</u>. The economy appears to have a relatively indirect impact on a customer's ability to participate in efficiency program, as many customers were not clear on the connection between economic conditions and efficiency program participation. When asked, customers held several views on the extent to which the economy affects their participation:

- Some customers do not see the economy as a barrier to participation.[21]
- Other customers were quick to mention that the economy has affected their employee base, profit, or capital availability, making it more difficult to undertake nonessential projects.
- Some customers see efficiency as even more important in tight economic conditions, as a means to better manage budgets and reduce costs with minimal capital outlay.
- For other customers, the downturn in the economy exacerbates the competition for capital problems discussed above, in that capital might be harder to access or payback periods may need to be shorter.
- Still other customers noted that in a tight economic context they are more likely to let existing equipment run through its useful life, rather than retrofit it early. This creates a barrier to implementing efficiency measures as there is often insufficient

[20] This may be partly a result of the fact that our survey was limited to medium and large C&I customers.

[21] This may be partly a result of the fact that our survey primarily included those customers that have participated in the energy efficiency programs in recent years.

time and resources to identify and procure the most efficient option at the time of equipment failure.

Economic climate. The economy was a relatively intangible impact on customer's ability to participate in efficiency program, as many customers were not clear on the connection between economic conditions and efficiency program participation. Some customers were quick to mention that, over the past few years, the economy had impacted their employee base, profit, or capital availability. Many of these customers indicated that their business recently experienced improvements, consistent with upturn observed in the larger economy. However, the ways in which the ebbs and flows in the economy influence the customer's ability to participate in energy efficiency programs was unclear.

- Some customers see efficiency as even more important in tight economic conditions; a means to better manage budgets and reduce costs with minimal capital outlay.
- For other customers, the downturn in the economy exacerbated the competition for capital problems discussed above, in that capital might be harder to access or payback periods may need to be shorter.

Still other customers noted that in a tight economic context they are more likely to let existing equipment run through its useful life, rather than retrofit it early. This creates a barrier to implementing efficiency measures as there is often insufficient time and resources to identify and procure the most efficient option at the time of equipment failure. .

Unsupportive corporate review and approval process. Some customers noted that they have no problem getting support from corporate executives to implement energy efficiency projects. However, corporate decision-making practice often requires efficiency projects to compete for capital with investments that are more germane to a customer's business (see above), and sometimes corporate practices place very tight payback periods constraints on all investments, limiting the energy efficiency measures that can obtain corporate approval. Some customers noted that their corporate executives expect to see clear reductions in their energy bills as a result of energy efficiency, and when the bills increase (due to other factors such as rate cases) the corporate executives reach the conclusion that the energy efficiency has not been successful in reducing energy bills.

Customer is convinced it has done all it can. This was not a commonly identified barrier as only three customers identified this barrier. When mentioned, it was seen as a transient barrier that would disappear over time. Customers mentioned that they had done several efficiency projects, and that, while additional savings opportunities likely exist within their buildings, the savings are not likely to outweigh the transaction costs. One customer indicated that savings opportunities from the next generation of efficient equipment would likely propel them to participate in the future.

Distrust of new technology. Only one of the customers interviewed indicated that they were reluctant to implement energy efficiency measures because they did not trust or fully understand the efficiency technology.[22] This customer was concerned that reducing energy consumption could reduce its production capability.

[22] This may be partly a result of the fact that we primarily surveyed energy efficiency program participants.

Other barriers. A few customers mentioned barriers or topics that did not fit into the categories above. These include: people have been lulled into a sense of security with prices of electricity and natural gas being relatively low, and participants are distracted by other energy projects like solar or geothermal.

Program Barriers

Each of the program barriers summarized above is discussed in more detail below. It is important to note that the efficiency programs, by their very nature, are designed to remove barriers to participation in efficiency projects. However, customers identified issues that they see as "barriers" in the way programs are designed or administered, and recommended ways to enhance the programs to better remove barriers to efficiency implementation.

Insufficient marketing and outreach. Many of the customers feel that the program administrators could be more proactive in reaching out to and educating customers about efficiency opportunities. Some customers felt program administrators were inconsistent in their outreach, or had limited contact with their representative. Others thought that, while the program administrators do reach out to them, the customer was driving the process and had previously researched the opportunities. Several customers noted that their gas program administrator has not reached out to them with energy efficiency opportunities, or provided any technical or financial support. This is particularly troubling to several customers who are very active in the electric efficiency programs and who believe they have significant gas efficiency opportunities. Some customers have regular, annual cycles of budgeting and investing in energy efficiency equipment, and they would prefer that the program administrators coordinate their program services with the customer's annual process.

High transaction costs. Many customers indicated that the paperwork and legwork involved in participation is too great, and that the overall process needs to be simplified. Some customers claimed that, for long lead-time projects, the time required to receive a financial incentive as well as the uncertainty about obtaining a financial incentive, especially across program years, create a barrier to their participation.

Inadequate responsiveness and timing. Several customers thought their program administrator was unresponsive to their needs, and a few customers attributed it to the program administrators being overworked. Others thought it was difficult to time their participation, such as when major equipment fails and needs to be replaced immediately, or during new construction when projects need to go forward and cannot be held up by program participation. One customer noted that the time required to get new lighting technologies approved for the Design Lights Consortium (DLC) list was so great that by the time a technology gets approved for the list it is out-of-date; that many of the technologies on the DLC list are out-of-date; and that the list does not include a lot of cost-effective emerging technologies.

Limited measures offered through the programs. Many customers expressed a desire for the programs to be more flexible and to allow the customers to recommend efficiency projects to undertake. Other customers suggested that specific equipment, such as elevators, should be incented through the programs. One customer put a lot of resources into working with a lighting manufacturer to develop a highly efficient LED lighting product to meet their exact needs, but the program administrators took a long time to review the product, and then rejected it because it did not meet the specifications of the lighting program.

Insufficient financial incentives. Many customers noted that they would implement additional efficiency measures if they were provided with greater financial incentives. Additional financial incentives would help overcome the competition for capital that many customers face, as well as reduce the payback periods needed to meet corporate requirements. Many companies indicated that there is not enough coverage of technical support costs or availability of technical support in general. Some customers wished the programs offered different incentive structures and better addressed upfront costs as well as costs over the life of the measure. Some customers mentioned that after completion of an efficiency project they were not provided with the full financial incentive that was originally anticipated from the program administrator.

Desire to opt out of the energy efficiency charge. Many customers claimed that they would be able to achieve much greater energy efficiency saving if they were able to keep all of the funds that they contribute to the Massachusetts energy efficiency programs and dedicate those funds to efficiency projects at their own facilities. This was especially true among the large customers, including those in the industrial, healthcare and schools/colleges industry types.

Programs not tailored to unique needs. Some customers thought that the program administrators did not make an effort to speak their industries' language, or that they did not understand the unique needs of their industry. This was especially true for customers in the healthcare industry, where the program emphasis on lighting and HVAC controls do not make as much sense.

Other barriers. A few customers mentioned barriers or topics that did not fit into the categories above. These include: (a) the lack of transparency with regard to the amount that the customer is providing to efficiency program funding is a barrier when employees try to convince management to take advantage of efficiency programs offered by the program administrators; and (b) customers appear to be confused by the number of energy efficiency providers in the market (i.e., ESCOs vs. renewable installers vs. lighting manufacturers/distributors vs. utilities/municipal aggregators/municipals).

Themes within Regions and Industries

The limited number of customers that participated in our survey by region and industry, and the wide variety of responses provided through the survey, made it difficult to identify themes regarding barriers to participation by region or industry. To demonstrate this point, Tables 4.5 through 4.8 provide the customer and program barriers by region and industry, as well as the number of interviews completed within the respective region or industry. We are reluctant to draw many conclusions about themes across regions or across industries from such a limited set of data.

One theme that did emerge was from the healthcare industry. Some members of the healthcare industry noted that the economic climate has had a big effect on them, given that revenues are declining due to government changes to the healthcare industry. They also felt that the efficiency programs were not tailored to their unique needs.

Table 4.5 Customer Barriers by Region

Regions	Interviews	Customer Barriers					
		Customer's Capital Constraints	Economic Climate	Corporate review & approval process	Distrust of new technologies	Company convinced it has done all it can	Total
Boston	16	8	6	5	0	1	**20**
Central Mass	5	3	2	2	0	1	**8**
Cape Cod	1	1	1	0	0	0	**2**
Western Mass	10	8	2	3	1	1	**15**
Bristol County	4	3	1	1	0	0	**5**
Total	**36**	**23**	**12**	**11**	**1**	**3**	**50**

Table 4.6 Program Barriers by Region

Regions	Interviews	Program Design & Administration Barriers								
		Insufficient Incentives	Insufficient Marketing & Outreach	Transaction Costs	Responsiveness & Timing	Limited Measures	Programs not Tailored to Unique Needs	Opt out of SBC	Others	Total
Boston	16	6	10	6	8	8	7	4	3	**52**
Central Mass	5	1	2	3	2	3	1	1	0	**13**
Cape Cod	1	1	0	0	1	0	0	0	0	**2**
Western Mass	10	4	8	8	5	3	0	4	0	**32**
Bristol County	4	3	3	2	1	1	0	1	1	**12**
Total	**36**	**15**	**23**	**19**	**17**	**15**	**8**	**10**	**4**	**111**

Table 4.7 Customer Barriers by Industry

Industry Types	Interviews	Customer Barriers					
		Customer's Capital Constraints	Economic Climate	Corporate Review & Approval Process	Distrust of New Technologies	Company Convinced it Has Done all it can	Total
Heavy industry	10	8	1	2	0	2	**13**
Warehouses & Distribution	1	1	0	0	1	1	**3**
Retail	5	3	2	1	0	0	**6**
Office	8	4	4	4	0	0	**12**
Schools & Colleges	4	1	1	1	0	0	**3**
Healthcare	5	5	3	1	0	0	**9**
Restaurants & Lodging	2	0	0	1	0	0	**1**
Miscellaneous	1	1	1	1	0	0	**3**
Total	**36**	**23**	**12**	**11**	**1**	**3**	**50**

Table 4.8 Program Barriers by Industry

Industry Types	Interviews	Program Barriers								
		Insufficient Incentives	Insufficient Marketing & Outreach	Transaction Costs	Responsiveness & Timing	Limited Measures	Programs not Tailored to Unique Needs	Opt out of SBC	Others	Total
Heavy industry	10	5	9	6	5	2	0	6	1	**34**
Warehouses & Distribution	1	0	0	1	0	1	0	0	0	**2**
Retail	5	3	4	4	2	2	1	0	0	**16**
Office	8	2	6	3	4	1	1	0	1	**18**
Schools & Colleges	4	2	1	1	2	4	3	3	2	**18**
Healthcare	5	3	1	1	2	3	2	1	0	**13**
Restaurants & Lodging	2	0	1	2	1	1	1	0	0	**6**
Miscellaneous	1	0	1	1	1	1	0	0	0	**4**
Total	**36**	**15**	**23**	**19**	**17**	**15**	**8**	**10**	**4**	**111**

Customer Anecdotes

Some customer comments and stories have struck us as important and interesting. A summary of such themes and stories are provided below.

- The interviewee feels that the program administrators do not understand healthcare at all. An assessment was conducted at the customer's business that (1) identified projects that had already been implemented (2) identified measures that are not able to be implemented in a healthcare environment (i.e., occupancy sensors and programmable thermostats with setback) and (3) did not identify opportunities that the customer was interested in (the assessment focused entirely on short term quick fixes and ignored projects with larger capital outlays). They looked at lighting in healthcare the same as for an office building, which does not work.
- If the customer does participate in the next three-years, the person interviewed stressed that gas savings needed to become a stronger focus for the customer, whether or not the program administrator's efficiency program allow opportunities and incentives for gas savings. The person interviewed felt that gas incentives were not as generous as on the electric side, and that the gas programs were not as well structured as, and even appeared disconnected from, the electric programs.
- The customer has made some effort to get up to speed on the program administrator's terminology, but it has taken special time and effort. The language is overly technical and very specific to the program administrator's process. Also, if the customer asks the program administrator a general question it is frequently directed to fill out an application before it can get this question answered. As it is too early in the process for an application to be submitted, the discussion usually stops there and efficiency opportunities are not captured.
- The program administrators are not up to speed on new developments. It can take a long time for them to come to grips with some of the possibilities of new products or projects.
- Program administrators do not treat the customer like it knows anything. Most large customers are pretty sophisticated. It would be nice if the program administrators treated them with that sophistication and understood that they are not babes in the woods.
- The customer has limited contact with its program administrators, and was not informed by its program administrators about efficiency programs. The customer was generally aware that the program administrators offer efficiency programs because it has locations in Connecticut, and has retrofitted lighting in all of its Connecticut locations through Connecticut Light and Power. However, the customer has a limited understanding of the Massachusetts efficiency programs.
- Some lighting upgrades received pushback from the customer's ownership, particularly because the color and brightness of the light was not quite right and it was changing the aesthetics of the building. The customer was not able to buy the light bulbs with the correct aesthetics right off a shelf. They had to special order them because the one that was on the approved list for program administrators rebates was not readily available. The customer had to find a light that was qualified for a rebate and then test the aesthetics of it in its building. The special order took many weeks to a couple months to arrive. It would have been easier to purchase the light bulb that was more readily available. The bulb the customer ultimately ended up buying was more expensive, so the initial cost of the program

was greater than if they had been able to use the light bulbs that were more readily available. However the rebates offered through the program made the overall cost less than the initial bulbs.

- The customer knew of the local incentives and brought in an energy consultant that helped shape the program and to get the process streamlined through the program administrator. The consultants helped the customer from start to finish doing the reporting back to the program administrator on the fixtures installed, any other controls, what the kWh saved were. Hiring the consultant was something that just made sense to the customer, knowing that, by working through the consultants, they would handle all the applications and processing and calculations. It just made sense to give the customer time to focus on what they were doing day-to-day but also to give leverage to make sure they were capitalizing on the programs to the best of the customer’s ability. It was well worth the investment in time having the consultants. The customer was able to achieve the maximum benefits and rebate.
- The customer has seen a reduction in inpatients and elective healthcare services that would normally generate revenue, which the person interviewed attributes to the economy and lack of spending. Elective surgeries such as cosmetic surgeries are not taking place. This could change once the economy gets better. Notably, pregnancies are down from previous years, which also decreases future projections of revenue. This is because if a baby is delivered at the customer ‘s facilities, ultimately the baby is likely to become a user of the facilities due to the history and familiarity.
- It would be great if the customer’s building was sub-metered and would likely help their ability to participate. The customer is an office tenant in a building set up for retail. There is one meter for the entire building with six floors. The overall energy consumption of the building is divided up to each tenant by square footage, not based off usage. The first floor is going to use more energy because they are retail establishments with restaurants and kitchens, which use more energy than an office. The customer was not even aware that this was the billing arrangement until about two years ago when the person interviewed looked into it. Now as the company considers new office spaces, sub-metering is a huge consideration.
- One customer stated that “the economy itself is not good. We’re extremely slow right now. I’m laying people off tomorrow because there isn’t enough work for them. There’s no sense bringing them in and turning the lights on if I can’t make enough money to pay for it.” However, energy efficiency is seen by the customer as an opportunity to save money, so long as the payback is high, such as lighting measures. “When times are slow you have to cut back spending every place you can. Spending a few dollars to put in new light fixtures which is going to save us thousands of dollars over the long run makes sense to do it. It helps the environment and it helps your costs. It’s a no brainer.”
- Overall, the interviewee was very unclear as to the distinction between the incentives offered by the program administrators verses other third parties verses federal tax credits, etc. The interviewee considered them all one in the same and seemed willing to work with any party that could provide an incentive.
- The customer’s relationship with their gas provider is new, but they were very satisfied with the process. They recently converted from oil to gas and received incentives towards a new gas boiler. They said their rep was excellent and eager to help.

- Most of the customer's energy efficiency activity has been in new construction, for which the customer received no rebates. The customer estimates they have achieved low savings to date for renovations/retrofits of existing equipment and space.
- The gas program administrator does not reach out to them much on efficiency issues. The gas program administrator representative is more of an account rep for billing than for efficiency. They met with the gas program administrator representative about two years ago, but have not seen him since.
- The customer makes energy efficiency decisions for their entire chain, which extends well beyond Massachusetts. They make decisions about what to purchase regardless of whether they will be getting rebates. They also did a lot of lighting upgrades to their office building without any rebates. However, they can do more efficiency investments with the funds provided by the rebates. Also, there is often a lot of deeper efficiency measures that they could adopt but that they do not adopt because of the paperwork necessary for the rebates. They build a lot of new buildings, and they are all alike; cookie-cutter. But every time they want to get rebates from the new construction program they have to re-apply from scratch. They often do not bother. Also, they typically lease the buildings and pay the energy bills. They do not bother to apply for the new construction program because of the paperwork, and because they have to chase the builder down for all the invoices. It is not worth it. They do not know if the builder goes after the new construction program rebates.
- Of course budget limitations pose a barrier. The person interviewed could think of $10 to spend for every $1 available. The customer would always like to do more efficiency, but budgets do not always allow for it.
- The economic downturn did not strongly affect the customer. To some degree the customer was tight on money, and so obtaining funding for energy efficiency was a little bit difficult prior to the program administrator's involvement in developing the long-term efficiency plan with the customer. The customer returned to a healthy financial state relatively quickly and does not expect its financial health to change going forward.
- Over the past 4 or 5 years, the customer has been pretty aggressive with energy conservation, and the person interviewed thinks they received back about 10 percent to 20 percent of what they put in. They wonder where the other 80 percent of money is going and how it is being distributed. Not sure if what that 80 percent is used for offsets the savings that the customer would get if it had been allowed to use it for efficiency.
- At the end of the last two years, the program administrator has practically doubled incentive levels for certain measures. This tells the person interviewed that the program administrators are over collecting the funds, and are literally looking to burn money by end of year.
- The cost with incentives was not the problem. The physical space prohibited the customer from being able to install more efficient equipment. The customer was presented with discounts or incentives that would largely cover the cost of the measures, but the customer was not convinced that they were going to be able to take advantage of them anyway. Most of the time the systems are running wide open. To turn the system back would potentially reduce the customer's ability to operate the system successfully with lower electricity flows.

- The last time the customer participated, they found the process much easier. They could submit to the program administrator receipts from efficiency equipment and related paperwork. Now, everything needs to be preapproved by the program administrator before the equipment can be purchased. While this adds an extra step to the participation process, the real issue is that if you need new equipment you need it now, and cannot wait for preapproval.
- The customer is working with, and still working with the program administrator, and are making "damn little progress and damn slow progress for rebates and stuff, and as far as I know I won't be getting a nickel. I put a lot of time and effort into it." The customer has not heard anything from the people that would be giving them the incentive, primarily because the engineering firm has not provided the engineering study. The customer started the audit process in the middle of summer 2011, and as of March 2012, had not received the engineering study.

Customer Recommendations

A few customers made specific recommendations for improving the efficiency programs that are not addressed above. These suggestions are summarized below, similar to the anecdotal themes and stories summarized above.

- Several of the customers we interviewed indicated that they would be interested in financing options provided by the program administrators, such as pay-as-you-save or on-bill financing, primarily to mitigate the competition for capital and to reduce the payback period of efficiency measures. One person interviewed recommended allowing customers to pay off efficiency investments on their bill, but in such a way that the monthly payment does not exceed the monthly savings. This would also relieve him of having to ask management for capital to invest in efficiency projects.
- One customer suggested that the program administrators provide a program mentor responsible for introducing efficiency projects to the customer and to go through the energy audit and stick with the customer as a contact throughout the process. It's not like the program administrators just comes into your building, screws in CFLs, and walk away. You actually have to do something. You have to revise the operating strategy of the systems, and that requires a lot of time and effort. Working with someone to understand what it is actually going to take to participate would be useful.
- The customer suggested that the program administrators revisit customers who were at one point interested in efficiency but did not follow through to see why they may have been put on hold. If he were trying to see why customers are not participating in programs, then that is where he would start asking questions. If there are open applications where things never came through to fruition that could be a good area to explore and follow up.
- Sometimes the customer would like to do a custom project that requires technical and engineering support. That money would have to come out of another expense budget, and with the economy the way it is, that pool of money can be very tight. Program administrators will offer to partially fund technical support, but it would help if the program administrators were more aggressive in helping customers clearly identify a project in terms of what it will save and cost the customer to implement it. This creates a clear picture on what project would look like, which would be beneficial. Some projects have stalled for years because they are just concepts that have not been fully developed. Technical support could clearly define

the best projects and opportunities, which would be a good use of money. The person interviewed recommended that the program administrators pay the full amount of the technical study. As currently structured, the customer could do a study, but would have to pay for half of it while the program administrators pay the other half. If the project does not get built, the money spent on the technical study is seen by management as a waste of money. This is a hard step for the customer to get past.

- The customer experienced delays during its initial enrollment in the program. A lot of data was required from the customer regarding its energy use, which pushed back the installation process. The person interviewed recommended simplifying the logistical process for participation.
- The person interviewed recommended that the program administrators divide the amount of funding available by their MW or kWh goals as a way of allocating incentive dollars. Reward or incent each kWh saved by customers in the same way. Sometimes program administrators cannot fund a project because it does not meet the program requirements. If a customer cannot do a project with the program administrators funding, it would be hard to convince that customer to do any more efficiency if they were already turned down by the program administrator. If a customer can prove that a project saved energy, they should be rewarded with the incentive. Large customers should have incentives for being aggressive as it is getting harder and harder to find efficiency projects.

5. Implications for Energy Efficiency Programs

The results of our economic forecast and customer survey lead us to draw the following conclusions with regard to energy efficiency program planning.

1. The Three-Year Energy Efficiency Plans should include savings goals that recognize that (1) the Massachusetts economy is forecasted to improve steadily over the next few years, (2) many customers do not see the state of the economy as a barrier to participation in the energy efficiency programs, (3) many customers have additional efficiency opportunities in their facilities and (4) many customers have an interest in participating in the programs again. In fact, several customers noted that in a tight economy they might be more likely to participate in energy efficiency programs as one of the few options they have to cut costs (as long as the payback periods are short enough).
2. The Three-Year Energy Efficiency Plans should recognize the potential savings available from the C&I New Construction programs, given that the economic forecast indicates that business construction activity is expected to steadily increase over the next few years. Several customers noted that they find efficiency measures easier to implement at the time of renovation and new construction, relative to their retrofit opportunities.
3. Encouraging customers to adopt a deeper level of efficiency measures will likely require additional efforts to overcome some of the key barriers identified above, particularly customer budget limits and competition for capital, burdensome transaction costs of participating in the efficiency programs, and limited efficiency measures available by the efficiency programs.
4. Encouraging customers to adopt a deeper level of efficiency measures will also likely require increased engagement from the program administrators' account executives and efficiency support staff. This will be important both to reduce the transaction costs associated with the energy efficiency programs and to better serve the unique needs of the different customers.
5. The Three-Year Energy Efficiency Plans should recognize that many customers have apparently not received much outreach regarding gas efficiency opportunities, and that additional outreach and support from gas program administrators might lead to increased gas efficiency savings.
6. Program administrators should be required to collect and report more comprehensive data regarding the customers who participate in their energy efficiency programs. A better understanding of customer participation would provide the program administrators with very useful information about where the untapped efficiency opportunities lie and how to pursue them. It would also be very useful to identify and track the different types of participation, including: active participants (i.e., recent participants), inactive participants (i.e., past participants), non-participants, and proactive participants (where the customer prefers to take the lead with assistance from the program administrator) versus reactive participants (where the customer prefers the program administrator to take the lead).

Recommendations for Further Research

Our survey indicates that there are several areas where additional research might help to increase the participation of C&I customers over the next few years.

1. Most importantly, it would be helpful to continue efforts to better assess the perspectives of the C&I customers who have not participated in the Massachusetts energy efficiency programs to date.
2. It may be helpful to conduct statewide research into opportunities for reducing the transaction costs (including timing concerns) associated with participation in the energy efficiency programs. This could include a statewide effort to identify best practices within the state and from other parts of the country.
3. It may be helpful to conduct statewide research into training the program administrators' account representatives and support staff so that they have a better understanding of the needs of different customer types and different industries. This could include a statewide effort to train account executives and support staff and to share knowledge and experience across the program administrators.
4. It may be helpful to conduct statewide research into ways to expand the types of efficiency measures eligible for financial support, reduce the time required to accept measures for eligibility, and streamline the process that is used in deciding measure eligibility.
5. It may be helpful to conduct statewide research into opportunities for the gas program administrators to better coordinate their outreach and support services with electric program administrators.
6. It may be helpful to conduct statewide research into practices for spending the efficiency budgets more evenly over the course of a year, in order to avoid the year-end blitz that sometimes occurs in order to meet annual targets.

Appendix A – Massachusetts M&V Studies

Over the past two years, numerous measurement and verification (M&V) studies have been conducted on the Massachusetts C&I programs. We reviewed recent M&V studies in an effort to better understand the current customer perspectives regarding energy efficiency. Our review focused on the following process evaluation and market characterization studies:[23]

- Study 1: Small Business Direct Install program KEMA and NMR Group, Inc. *Project 7 General Process Evaluation - Final Report; MA EE Programs Large C&I Evaluation*, February 16, 2011.
- Study 2: The Cadmus Group, Inc. and Opinion Dynamics Corporation. *Massachusetts Non-Residential Small Business Direct Install Program: Multi-Tier Program Structure Assessment - 2010 Process Evaluation*, July 7, 2011.
- Study 3: Tetra Tech. *Industry Practices and Policies on EE Program Rebates/Incentives – Final Report*, January 25, 2011.
- Study 4: KEMA. *Supply Chain Profile Project 1A New Construction Market Characterization*, June 8, 2011.
- Study 5: KEMA and Itron. *Project 6B: Comprehensive Design Approach Process Evaluation Final Report*, May 17, 2011.
- Study 6: KEMA and NMR Group, Inc. *Final Report Project 1B Chain & Franchise Market Characterization*, June 7, 2011.

Below, we summarize the key barriers to efficiency program participation as well as the suggested approaches to overcome these barriers, as detailed in the above mentioned studies.

Financial Barriers

<u>Cost of Energy Efficiency and Financing Availability</u>

Customers' principal objection to using energy efficient equipment or design is financial constraints, particularly the higher first capital costs associated with efficiency (Study 2, at 22, 26; Study 4, at 4-3, 4-19; Study 6, at 7-6, 7-21 through 7-24. 7-39). While the upfront costs are a concern for most customers, other customers weigh the full cost of efficient equipment during system selection (Study 4, at 4-23). For example, in a study that interviewed architects, design engineers and construction managers as part of the evaluation of the large C&I programs offered by Massachusetts Program Administrators, market actors generally agreed that clients who own and operate buildings are more willing to consider increased first costs in a trade-off for lower operating costs (Study 4, at 1-1, 4-23). Consequently, owner/operators are more likely to pursue incentives (Study 4, at 4-23). Respondents reported that more sophisticated clients, such as colleges and universities, biotechnology firms, and laboratory facilities raise additional concerns that "higher service type [equipment] requires more mechanics, more controls and more oversight to run them properly as opposed to just starting them up and running the system" (Study 4, at 4-3, 4-23). They consider the ability of their staff to control and

[23] The studies are available on the EEAC website: http://www.ma-eeac.org/EM&V%20Studies.htm

maintain equipment, the cost of maintenance and replacement, and the risk of equipment failure (Study 4, at 4-23). In these cases, it appears that incentives may not offset the risks of unfamiliar equipment and unknown maintenance reliability (Study 4, at 4-23; See also Study 4, at 4-8, 4-11,4-19 through 4-20).

Even with large financial incentives available, there are still instances when participants face upfront costs that they would not necessarily face if an alternative approach to energy efficiency were used (Study 5, at 4-15 through 4-18). For example, with the Comprehensive Design Approach (CDA) program, the upfront costs of completing a TA study -- a model of energy efficiency measures that maximizes the energy savings of the entire project – creates a financial constraint for customers (Study 5, at 4-15 through 4-18). One architect noted that "not every client is willing to put up the money for a technical study. Sometimes it's a cash-flow issue or the customer just isn't convinced that putting up the additional money is justified. More of our customers would do the program if they didn't have to pay this money up-front" (Study 5, at 4-15 through 4-18).

Increased financing, and incentives as further discussed below, is often recommended as a method to overcome cost barriers, and is generally seen as an attractive and important component to participation[24] (Study 1, at 9-3 through 9-4; Study 2, at 1, 22; Study 6, at 6-17 through 6-18, 7-7 through 7-8). A respondent in one study stressed the importance of further developing financing options, explaining that, "just like we have an industry set up and working for ESCOs, we need an industry on the financial end that is set up and can respond in the same way. We don't have the same market as, [for example] a customer says, 'I want to do some energy efficiency. How do I start?' … 'Here's a whole list of people you can go to. They'll hand-hold you through the entire process.' I don't have the same thing on the financial side" (Study 1, at 6-16). Program Administrators could also consider expanding financial or technical assistance offerings for life cycle cost analysis to demonstrate the longer term value of accepting higher first costs (Study 4, at 5-6).

<u>Program Financial Incentives and Payback Periods</u>

Financial incentives offered through the Massachusetts Program Administrators' C&I programs[25] are a strong motivation for customer participation[26] (Study 1, at 6-8; Study 2,

24 One study stated that, among all participants who received financing, more than half report that it was extremely important in their decision to install equipment (Study 2, at 22-23). In addition, nearly half of participants who received financing off-bill would have been unlikely to install the energy efficient equipment if financing had not been available (Study 2, at 22-23). Offering zero interest on-bill financing for 24 months is a program modification that has the potential to encourage those customers not motivated by interest free financing alone to install energy efficient equipment (Study 2, at 27-30).

25 A study that reviewed rebate and incentive programs in key states attempted to make comparisons of incentive levels for similar programs (Study 3, at 1-1). The study found that Massachusetts commercial rebates examined for lighting were on the low end of lighting rebates offered in other states (Study 3, at 3-1; see 3-14 through 3-21). Custom rebates comparisons are less straightforward, but Massachusetts rebates appear moderate relative to the other similar programs (Study 3, at 3-1). One California program rebates a lower percentage of costs but has a higher maximum amount that will be covered (Study 3, at 3-1). Massachusetts is somewhat unique in offering a separate program for small business customers that includes incentives covering 70 percent of installed cost (Study 3, at 3-1). These are identical to many of the surrounding states, but they are often offered by the same program administrators as Massachusetts (Study 3, at 3-1). Finally, Massachusetts rebates appear to be at the high end of offerings in other states for hot-air furnaces. (Study 3, at 3-1; see 3-14 through 3-21).

26 One customer interviewed during a study of the Comprehensive Design Approach (CDA) program stated that "the main motivator is the incentive paid to include certain technologies. That is the trump card" (Study 5 at 4-20). "While the lower operational costs are a selling point, the major motivator is defraying the upfront capital

at 1, 22, 32; Study 5 at 4-20, 4-28; Study 6, at 7-7 through 7-8, 7-21 through 7-24). While financial incentives promote participation and are important in the decision-making process of customers, customers often feel that the incentive is not high enough (Study 2, at 26, 31). Equipment costs and monetary constraints are commonly cited as reasons customers chose not to participate in efficiency programs, despite the financial incentive available (Study 2, at 22, 26; Study 4, at 4-3, 4-19; Study 5, at 5-1). The manager of a program stated, "unless a customer is branding themselves as a green building or constructing as a demonstration buildings, the energy savings and incentive amounts are just not enough" (Study 5 at 6-31). Even customers that participate in the program would prefer higher incentives, as even higher incentive levels would allow them to install more energy efficiency technologies, thus further reducing the energy usage of their facilities or buildings (Study 2, at 25-26, 31; Study 5, at 4-20, 4-28). Therefore, offering higher incentives is one of the most common suggestions for improving program participation (Study 1, at 6-13, 6-18; Study 2, at 25; Study 3, at 4-1; Study 5, at 5-1).

However, incentive levels can be difficult to set accurately for each program and within each Program Administrator's service territory (Study 2, at 13; Study 5, at 5-4 through 5-5). For example, beginning in 2010, the Program Administrators began transitioning to a uniform statewide delivery model for the Small Business Direct Install program (see, Study 2). As part of this transition, the Program Administrators established a statewide 70 percent incentive level for the program, which meant a significant increase for one PA, a slight increase for another, and consistency with existing levels for two other PAs (Study 2, at 13). There are different views among the Program Administrator staff on the preferred incentive level (Study 2, at 13). While there has been an effort to align incentive levels, some Program Administrators would like to raise the incentive level in the future (Study 2, at 13). In contrast, other Program Administrator representatives commented that the 70% incentive may be too high (Study 2, at 13). Further, implementing the new incentive level caused some challenges for vendors promoting the program and recruiting customers in the field (Study 2, at 13). As an obvious rule, the better the incentive, the more people participate (Study 2, at 13). Further, another study suggests that, to address the first-cost barrier, Program Administrators consider alternative incentive approaches such as tiered incentives for higher levels of efficiency (Study 4, at 5-6).

Additionally, the payback period of an efficiency investment is directly linked to financial incentives. Incentives help reduce the payback period for a project and this provides the impetus to use energy efficient measures (Study 5 at 4-20, 4-28; Study 1, at 6-6). In one study a customer was quoted to say, "As a client, you're going to want to get the most value for your dollar, and you're going to want to implement the measure that's going to give you the best paybacks. In order to entice a customer to do more than that, the incentives would have to be larger because the client needs better payback in order to push it through management. If I'm a client, and if I have a corporate policy that says I don't do anything [with] less than a two-year payback, well, that might be something you can do for the first measure, maybe that second measure that you've identified. But that

costs of construction" (Study 5 at 4-20; 4-27). Often times, the incentive is a precursor to participation. For example, one architect noted that he is not able to get daylight dimming systems into his K-12 school projects unless the first cost is subsidized by a utility incentive (Study 4 at 4-7). A CDA participant summed up his satisfaction with the level of financial incentive received by stating: "it essentially allowed me to internally get optimal systems over the lifecycle of the facility to run at the cheapest cost. So anytime I can put some money in upfront to get those systems, it helps the sustaining operational team to provide the lowest price of our product (Study 5, at 4-20)."

third, fourth, and fifth measure, even with the incentive that you're offering, is not going to get it within his restrictions" (Study 1, at 6-13).

In a weakened economic environment, customers are not going to be able to do a project that has a long payback period, and instead are looking for quick savings with paybacks as short as six-months (Study 1, at 5-3, 6-13). One technical staff respondent said that in their experience when programs "buy down the project to a one-year payback" more companies moved forward with projects (Study 1, at 6-18). He went on to say that they currently do that for some special cases but that customers rarely see a one-year payback because of stipulations or incentive caps (Study 1, at 6-18). In addition, this respondent noted that "every time we have specials and we offer more money for the customers then everybody comes flocking to the door" (Study 1, at 6-18; see also Study 1, at 9-5).

<u>Economic Conditions</u>

The recent economic downturn is commonly cited as a barrier to efficiency investments (Study 3, at 4-1; Study 5, at 4-15 through 4-18; Study 6, at 6-5, 6-12 through 6-17). One study quoted a number of program staff members on the economic climate:

> "In order to achieve the ambitious goals that we have I think the barrier is the availability of capital. You can have the best program in the world … and you can have some great information about the energy savings or the impact to production. If a client does not have the access to capital, they're not going to implement anything. It's the most critical piece of the equation. You can get them to do that first measure that's really attractive, and it can save a bunch of dollars. But they're not going to implement that third, fourth, fifth measure without realizing those energy savings first, because they need access to capital" (Study 1, at 6-12 through 6-13).

> "Right now, it's not only the actual state of the economy, but the general conception that now is not the time to act for any capital investment. It's just I got to keep the doors open. I got to attract new business. I cannot focus on saving energy. Even when I have a facilities manager in front of me who says, I agree with this, I'm ready to pull the trigger. It's just if I go to my senior management and say the utility company is willing to make a very attractive funding offer, their response is going to be, do we have orders in the hopper to support a capital investment? Unless the answer is absolutely yes, we're going to limp along with what's there. Now it's improved over the last year, but that/s still a major barrier" (Study 1, at 6-12 through 6-13; see also Study 6, at 7-21 through 7-24).

> "There's a number of companies around here that have money and want to invest the money, but because they're not sure where things are going, they're sitting on the cash. They're not putting it back into the business yet. They will do what they need to do for

> maintenance, but when it comes to expansion or improvement, unless they're feeling very secure about the economy, it becomes a real struggle" (Study 1, at 6-11).
>
> "In a good economy, I could sell ice to an Eskimo, literally. You walk in, the project costs X amount of dollars, we're going to give you 15 percent to 20 percent. It all has to do with economics. And we're in a horrible economy, and there is little or no capital funds available" (Study 1, at 6-16 through 6-17).
>
> "The issue seems to be that the incentive levels, in some areas, [do not reflect the] economic straits our customers are in. Formerly, if you showed someone there was an investment with a three-year payback, you could tell by the body language right away: "Yes, I'm all over this". Whereas, now, customers we work with over the years who have always done a nice project a year are now saying it doesn't matter how good the payback is. I need to confirm my doors are going to be open next month and I'm meeting payroll. I'm not in a position to make capital investments" (Study 1, at 6-12 through 6-13).
>
> "The feedback we get from facilities managers is … when I do an efficiency project, I'm competing with capital projects with the rest of my company. So literally, I walk in with an efficiency project, and one of the manufacturing managers walks in with a request to do something else. And you know, we have to compete to say which is of greater benefit? It's not like I have an open door to the management committee that says keep bringing me more efficiency projects. I have to sell it as an attractive investment. We'll get some tools to help us present that to the facilities manager, which he could then use to present to his management team, which in many cases are out of state. I guess what I'm getting at is a package of technical and marketing tools that help us promote going deeper. Right now, I have a mandate [to achieve deeper savings] and it's kind of up to me to figure out what that is, how to do it" (Study 1, at 9-9 through 9-10; see also Study 6, at 7-21 through 7-24).

The market for new construction is particularly impacted by the economic downturn (Study 5, at 4-15 through 4-18, 4-29, 6-28, 7-46). Even with the availability of incentives, the ability of builders to pursue energy efficient design is challenged (Study 5, at 6-28). One PA staff member said that "over the last couple years, a lot of [the issue] has been that people aren't building buildings. So now there are not enough buildings being built, and the ones that are being built are on such a shoestring budget that they can't proceed with putting efficiency measures in (Study 5, at 4-15 through 4-18)." National Grid estimated that new construction projects had declined by 50 percent in the past several years (Study 5, at 6-28). "With the current economic conditions, there is no new construction at all," said one WMECO representative (Study 5, at 6-28). The existence of this barrier is also supported by comments made by several of the CDA participants that were interviewed (Study 5, at 4-15 through 4-18). "There has been less new construction and a renewed focus on looking at existing facilities and how to retrofit all the systems," said one (Study 5, at 4-15 through 4-18).

For customers who participate in efficiency programs during an economic downturn, the amount of the incentive plays an increasingly important role in the decision to participate (Study 5, at 4-29). One customer noted that market conditions made them focus on their energy efficiency budget and as a result, incentives became very critical in their decision to install energy efficiency equipment in several projects in 2009 (Study, 5 at 4-29).

Increasing incentives is one approach to overcome the economic downturn. In one study, a respondent said "given the economy, if the incentives were a little bit higher, where you could bring down that payback period for the customer" (Study 1, at 6-11). Other approaches used by multiple programs to overcome the economic downturn were to focus on specialty lighting and other emerging technologies with significant market potential, and emphasize comprehensive approaches to energy efficiency at customer sites (Study 3, at 4-1). Another approach to overcome the economic downturn was to find more creative ways of marketing the programs (Study 3, at 4-1). Other AEs said that they focus on customers with stable financial conditions who have capital available that they are willing to invest in projects (Study 1, at 5-3).

One study stated that, while there is no remedy for the downturn in new construction, it is possible to mitigate the budgetary concerns of customers (Study 5, at 6-28). A successful program design may benefit from shifting the emphasis from incentives to long-term savings (Study 5, at 6-28). Sometimes, incentives are not enough for a customer to assume the additional time and responsibility required to participate (Study 5, at 6-28). Incentives, while substantial in dollar terms, may not have the desired influence if the incentive is weak relative to the entire cost of the project (Study 5, at 6-28).

Customer Awareness and Program Marketing

A key challenge for efficiency programs is reaching eligible customers with information about program offerings and the process for participation (Study 1 at 6-14, 9-4; Study 2, at 32; Study 5, at 6-26; Study 6, at 6-5, 6-16 through 6-17). One architect noted that smaller clients "usually don't have a clue" about incentive programs (Study 4, at 4-22; Study 6, at 6-5). In some instances, customers are aware that their PA offers programs to help customers save energy, however, after being read a description of specific programs, respondents said they had not heard anything about it (Study 2, at 21; Study 1, at 6-5). Customer awareness of more specialized programs, such as the CDA program, is particularly low[27] (Study, 5 at 4-13, 5-1, 6-26).

27 Conversely, one study noted that design teams did not believe customers were unaware of the CDA track and therefore did not view it as a barrier to participation (Study, 5 at 4-13). Architects expressed the viewpoint that large customers with a local presence have already had past experiences with efficiency programs and were typically already aware of incentive opportunities (Study, 5 at 4-13). "Given the emphasis on LEED, green buildings design, and energy efficiency regulations, most organizations are already familiar with such programs," said the representative of one architectural firm (Study, 5 at 4-13; 6-26). On the other hand, design firms considered new building developers from outside the region to be in need of more education regarding program opportunities (Study, 5 at 4-13).

Program Administrators typically market efficiency programs to C&I customers through account executives or word of mouth, instead of through marketing materials[28] (Study 5, at 4-29, 5-1 through 5-4). Account executives serve as the main point of contact between customers and PAs, and are therefore responsible for informing their customers of relevant energy efficiency opportunities (Study 5, at 5-1 through 5-4). One technical consultant felt that the PAs are somewhat responsible for the level of participation in programs (Study 5 at 4-20 through 4-21). He explained: "Utility program staff drives the decision to participate in a certain track, not the customers" (Study 5 at 4-20 through 4-21). One study noted that personal relationships are important in recruiting participants (Study 1 at 6-3). Based on survey results in another study, the direct outreach conducted by program staff and vendors is central in reaching customers who ultimately chose to participate in the program (Study 2, at 32; Study 1 at 6-9).

Marketing efficiency programs to customers through account executives or word of mouth successfully increases participation for some programs, but may not reach all potential participants. In some instances, account executives have a general understanding of the programs, but are not familiar enough with the details to fully describe the benefits of the programs to potential participants (Study 5, at 5-1 through 5-4). One study noted that, given the program's use of in-person contact and the fact that information about the program is often disseminated by word of mouth, it is not surprising that marketing messages have not reached a larger proportion of non-participating customers (Study 2, at 21).

Using education materials and brochures to market to potential participants has its advantages and drawbacks as well (Study 2, at 21). According to program staff and their customers, few, if any, marketing materials are available to inform customers about the CDA track (Study 5 at 4-23). Design team members and a majority of participants that the study team interviewed noted few or no instances of receiving advertisements, brochures, or flyers describing the CDA (Study 5 at 4-23). Without such materials describing the program, it places the responsibility on the PAs to keep a look out for potential customers (Study 5 at 4-24). The PA cannot expect customers to be cognizant of the program and to seek out information (Study 5 at 4-24).

When marketing material is available, AEs reported that customers may not read mail or email, therefore these methods generally garner a low response rate (Study 1 at 6-10). Further, while many partial participants note that direct mail is a good way to reach them about program opportunities, this type of outreach may not always reach the key decision-makers at customer facilities (Study 2, at 21). In one study an account executive was concerned whether they are reaching the appropriate decision-maker. "Are those e-mails getting out to the right people within that facility that are familiar with energy efficiency and can make those decisions?" he/she wondered (Study 1 at 6-6; See also Study 1 at 6-17).

Who the account executives or program managers contact influences program participation. For example, a common sentiment among architects, engineers, and construction managers is that "more awareness and outreach is needed to the architectural and engineering community" (Study 4, at 5-5). On the other hand, several respondents suggested that the program managers currently focus more outreach and

28 Roughly 75 percent of the participants interviewed in one study did not recall receiving any marketing materials but noted that they were in contact with account executives (Study 5, at 4-29).

attention on engineers, and therefore the architectural community is less informed (Study 4, at 4-22). They also recommend distribution of mailers to the design firms - not just architects[29] but also to electrical engineers (Study 4, at 4-25).

Further, identifying a program's target market can be difficult for Program Administrators. National Grid indicated that it has been difficult for the program to gain traction because "it is very hard to determine who the players are" (Study 5, at 6-30). The program manager identified this issue as one of the most significant barriers faced by the program (Study 5, at 6-30). "A customer could be anyone from a dentist to a national firm," he noted (Study 5, at 6-30). If the program cannot clearly identify the target market, it is difficult to target outreach efforts and as a result the core message suffers (Study 5, at 6-30). One technical staff member mentioned a need to identify remaining opportunities and concentrate marketing efforts on those opportunities (Study 1 at 6-18). He went on to say: "We offer all of our programs to all of our customers all the time. What I'm hoping is that with the vast information base that we've built, we can now turn that into more of a market penetration-type study. We've got a lot of customers who have gone through our programs for lighting. The measure life for lighting can be 10 to 20 years and once you do the lighting once you know that facility is pretty much shut down for offering lighting opportunities for a substantial amount of time" (Study 1 at 6-18).

While it is important to extend the reach of the program, the Program Administrators are challenged by the need to maintain a balance of resource allocations (Study 5, at 6-26). "Of course, there are always improvements to be made in marketing, but marketing is so expensive that you don't want to spend so much that you have less incentive money to give to the customers," said one program manager (Study 5, at 6-26). "Ideally, the message has to be not only effective, but also communicated in a way that doesn't cost a lot of money" (Study 5, at 6-26).

The studies we reviewed recommended a number of ways to improve customer outreach and marketing,[30] which are summarized as follows:

- It is generally recommended that the PAs aggressively utilize both direct communication and printed marketing material to advertise programs and educate customers about programs (Study 2, at 21, 32; Study 4, at 5-8; Study, 5 at 4-34, 5-1).
- Marketing materials and tools could be improved by: making them more informative, simple, easy to understand, possibly including a checklist of ways to reduce energy costs; including more customer testimonials or case studies; and introducing technical concepts to customers (Study 1 at 1-10, 6-1, 6-17 through 6-18; Study 4, at 4-25).
- The Program Administrators should engage state and local government, the design and construction community, academic institutions, real estate associations to increase participation (Study 4 at 5-7, 5-8).

29 In the same study, the study team hypothesizes that architects do not fully recognize their roles as key contacts and drivers to engage clients/projects with the energy efficiency programs (Study 4, at 4-23). Architects are juggling multiple tasks and typically doing so under the pressure of project deadlines (Study 4, at 4-23). Consequently, many architects view energy efficiency as one of many competing objectives and do not recognize, as design team leaders, their potential influence in engaging their clients and the PA's to optimize efficiency (Study 4, at 4-23).

30 See Study 4, at 4-22, 5-8; Study 5, at 4-34, 5-1; Study 6, at 6-17 through 6-18.

- An effective implementation plan should take advantage of the favorable environment of "green building" (Study 5, at 6-27).
- Since account executives are usually the first to hear about new construction projects, the PAs should ensure that they are well informed about the programs so that they can explain the program requirements and benefits to customers when they are first in contact about a potentially qualifying project (Study 5, at 5-1 through 5-4, 6-27).
- Educate potential design team members about programs through "lunch and learn" events and making presentations at professional meetings attended by architects and engineers (Study 4, at 4-25, 5-7, 5-8; Study 5, at 5-1 through 5-4, 4-14).
- Lunch and learns should be combined with direct communications (Study 5, at 6-28 through 6-30).[31]
- Regarding deep savings, one program staff member noted the importance of developing long-term efficiency plans with customers[32] (Study 1, at 9-1).
- One study suggests that, for the Small Business Direct Install program, the facility audits associated with this program presents an opportunity both to document the condition of existing facility equipment and educate customers about the PA program offering that may suit their energy efficiency needs in the future (Study 2, at 2, 21, 32-33).

One AE emphasized the importance of persistence, saying "just be persistent and get in front of these people. Sometimes you have to beat it over their heads, because I've worked very closely with facility managers throughout my career, and if what you can offer them isn't spelled out clearly in front of them, and you don't follow up and be diligent, then they may not participate" (Study 1, at 6-17; see also Study 1 at 6-10; Study 5, at 6-28 through 6-30). There is a fine line, however, between maintaining follow-up communication and pestering the customer or design team (Study 5, at 6-28 through 6-30). Program reminders should be brief and merely serve to remind the design team of their options (Study 5, at 6-28 through 6-30). Another study suggested that a cohesive system of documenting and monitoring the status of program leads is important to the success of program implementation (Study 5, at 6-30).

31 This study that suggest combining education events with direct communication further states that one of the greatest barriers to participation is "turning intentions into action" (Study 5, at 6-28 through 6-30). While presentations to customers and the design community is a reliable method of program outreach, the impression of these presentations is often short-lived (Study 5, at 6-28 through 6-30). The evaluation team found that program outreach was ineffective in the long-term without consistent program interaction (Study 5, at 6-28 through 6-30). One program manager explained further: "We did a round of lunch-and-learns, but later the architects forget about it. This incentive program is at the bottom of the designer's priority list because it does not provide them any revenue but only more work for the same amount of money. Our staff calls them every few months just to check in and remind them that the program is there" (Study 5, at 6-28 through 6-30).

32 This study elaborated on this point to say that: "Instead of just going in and saying 'what do you need today, what would you like to look at today?' we're trying to put in a long-term plan with the customer, to say, 'let's talk about all your opportunities, and let's make a list of them, and let's prioritize that list, and let's do the things that you can do now this year and then which things you want to plan to do next year. 'Try and get them to look more long term and holistically about doing energy efficiency. There's a lot more emphasis on that" (Study 1, at 9-1).

Program Design and Administration Barriers

Process for Participation

A number of studies suggested that participating in efficiency programs could be streamlined, especially the application process required for participation (Study 4 at 5-5 through 5-6; Study 5 at 4-33, 6-37; Study 6, at 6-17 through 6-18). Since vendors provide a crucial service to the programs - creation of projects - it is not surprising that two technical staff respondents suggested streamlining program processes so that they do not, as one respondent put it, “impede the sales process” (Study 1 at 6-18). Moving to one application and consolidating programs across the state were generally thought to be good steps towards creating a program free from such impediments (Study 1 at 6-18).

One study suggested streamlining the application process by reducing the amount of paperwork that is required for participation[33] (Study 4 at 5-7). In one study, interviewees chose not to participate in programs due to the perception that program participation is a difficult process and that the paperwork requirements are burdensome (Study 6, at 6-5, 6-16 through 6-17, 7-21 through 7-24). One architect stated that “gathering all the information and filling out the forms can take 40 hours or more for which we don’t charge the client” (Study 5 at 4-1 through 4-14). In order to resolve this burden, this architect suggested placing the paperwork burden on the PA staff and the technical consultants[34] (Study 5 at 4-1 through 4-14).

Additionally, the time required to participate is a potential barrier or drawback for customers (Study 1 at 9-6; Study 4 at 4-19 through 4-20; 5-7). Despite the relatively large incentives offered, program staff reported that some customers are reluctant to assume the additional time and cost required by participation (Study 5 at 6-31). Since technical staff respondents are keenly aware that time is a barrier for customers, nearly all of them mentioned working closely with customers and other stakeholders to provide results as quickly as possible (Study 1 at 9-6). One respondent said that although “sometimes [we] take longer than expected; sometimes it is [due] to the customer” (Study 1 at 9-6).

Finally, design firms reported that confusion regarding eligibility requirements was a barrier (Study 5 at 4-18 through 4-19). One participant complained that he received conflicting information about eligibility requirements from a single Sponsor depending on if he was speaking to the account executive or PA staff (Study 5 at 4-18 through 4-19). Further, in another study, interviewees suggested various reasons for not participating, including a customer‘s proposed project doesn‘t qualify (Study 6, at 6-16 through 6-17).

Program Administrators’ Staffing Skills and Availability

Studies suggested that PA’s skill sets could be more diverse, and that PAs often lack technical knowledge. “Probably the biggest thing that would get better savings is making sure that the reps are aware of the broad technologies that are available, that you don't have somebody who's got a background in variable frequency drives and that's all they know. The reps have to have a broad range of what's available and be able to talk intelligently about that with customers” (Study 1 at 9-4). Some studies suggested

33 Respondents mentioned burdensome paperwork as an impediment to participation (Study 2, at 26).

34 The same study cited Efficiency Maine as an example, stating that the Efficiency Maine program makes it clear to prospective customers that the burden of paperwork will not fall upon them but upon program staff (Study 5 at 6-31). “No additional work is required,” explained the program manager (Study 5 at 6-31).

increasing the number of architects, engineers, and lighting designers on the PA's efficiency staff (Study 4 at 5-7, 5-8; Study 5 at 4-1 through 4-14). The PA's staff seem to be in agreement, with one saying "I always wish my knowledge base is greater than it is to offer more to customers. We're being asked to dive deeper with customers and find complex offerings" (Study 1, at 6-1 through 6-2).

Additionally, AEs mentioned being too busy or lack of staff as an issue[35] (Study 1, at 6-1 through 6-2, 9-6). Another said that "It's just that [applications are] coming in large amounts, whether it's a small job or a big job. And like I said, until just recently, we've gotten some more bodies over there to help those people out, so it's starting to get better. But for a while, some projects just sat there" (Study 1, at 6-10). Several AEs noted the staff shortages as an impediment to identifying projects (Study 1, at 5-4). One respondent said we need "some more people just to be able to take the time and really explain to the customers, do some more analysis for [customers], and let them see why they should [proceed with project]" (Study 1, at 6-4, 6-10).

Customers' Lack of Understanding regarding Efficiency Strategies and Measures

One study found that architects', design engineers', and construction managers' understanding of best practices for efficient equipment, including lighting, HVAC, and building shell technologies, varied considerably (Study 4 at 4-6 through 4-13). For example, the study found no consistent trends in respondents' views on what constitutes best practices in regard to HVAC equipment (Study 4 at 4-10). Further, optimal envelope design continues to be a source of debate among architects and construction professionals, while confusion persists about how to piece together the different components of the wall and roof assemblies (Study 4, at 4-12, 4-13). One architect asked that the utilities provide a description of an energy efficient wall assembly (Study 4, at 4-13; see also Study 4 at 5-6). One architect suggested that the programs should be made "more understandable to architects, and maybe provide examples of good lighting practices" (Study 4 at 5-5 through 5-6).

Technologies

One recurring issue relates to the types of measures offered through the PAs programs (Study 1 at 9-7). In one study, the most common suggestion for improving the program included offering additional qualifying equipment, which could entail more equipment within a specific end-use as well as a wider range of end-uses (Study 2, at 25). Additionally, one architecture firm complained that the prescriptive programs were a little too prescriptive and had had an issue with a certain lighting specification (Study 4, at 4-25). Their suggestion was that there should be something in between a straight forward prescriptive approach and full building modeling (Study 4, at 4-25). One chain respondent mentioned that they are not in agreement with the PAs on the type of products specified for LED lighting (Study 6, at 7-39). According to this respondent, their locations use a type of LED lighting that is not approved for installation by the PAs (Study 6, at 7-39).

35 "I think it does come down to a personnel issue in house. Maybe if we had more program managers [and] engineering staff [to] do projects a little faster to prove the benefits to the customers. Sometimes we have the applications from the customer, they are looking to do a project, and we have put it through the steps of what the savings are going to be and what the incentive is going to be. And that can sometimes take a little while to get done because we have so many jobs. And so sometimes a customer gets a little discouraged because of the time it takes. And if we had more personnel working on that end, I think, we could get these jobs out the door a little faster" (Study 1, at 5-4; see also Study 1, at 9-6).

Additionally, the technical support staff respondents cited the lack of low-cost high-savings projects because they have been done already or due to the type of customers enrolled in the programs (Study 1 at 9-7). One respondent said we‘re “limited by what types of facilities and what‘s going on in those facilities” (Study 1 at 9-7). They went on to elaborate, “once you do the lighting and lighting controls, you could probably do some HVAC controls… but HVAC equipment typically doesn‘t have an incentive that induces people to retrofit it so you wait until that stuff dies to replace [it]” (Study 1 at 9-7). Another respondent commented on working with customers to “see beyond lighting” saying that “there are certainly more things that a customer can do. Maybe just take advantage of more prescriptive measures or get into their HVAC equipment… refrigeration measures, the more complex measures” (Study 1 at 9-7). However, this respondent was quick to follow-up their comment that more complex measures “come at a price. And that‘s where sometimes it‘s in conflict with what our goals are” (Study 1 at 9-7).

Lack of Technical Assistance

In one study, few respondents indicated that they received technical assistance from the program (Study 4, at 4-24). Most architects we spoke with indicated that they either have not received any services, have received services but couldn’t identify what they were, or have received energy modeling assistance (indirectly) or lighting design assistance (Study 4, at 4-24).

Timing of Participation

Another great challenge of program implementation is establishing participation in the earliest stages of the design process (Study 5, at 6-32). For example, the CDA requires early involvement of the PAs to ensure that all relevant energy efficiency improvements are incorporated into the customer’s building design (Study 5, at 4-15 through 4-18). Unfortunately, customers do not always make contact with the PAs during the conceptual design stage and therefore the opportunity to use the CDA is often lost (Study 5, at 4-15 through 4-18). As one non-participant said, “timing was the major issue for us. We were a little slow in getting the local utility involved in the beginning of the project” (Study 5 at 4-32; see also Study 5, at 4-29, 5-1 through 5-4). One major developer and construction management firm noted that in the past they haven’t received feedback from the utilities in a timely manner (Study 4, at 4-24). Further, architects and engineers are not able to consistently identify the most appropriate point during the design process to contact PA’s (Study 4, at 4-24). Others reported that certain customers, such as hospitals, have long-term budgeting processes, and therefore AEs have to reach out to them far in advance of project initiation (Study 1, at 5-3).

Ideally, program staff should intercept the customer and design team during the of conceptual design phase of the project, if not earlier (Study 5, at 6-32). In order to have an impact on the project design, utilities must engage the customers early, be consistently engaged throughout the course of a project, and meet project milestones (Study 4, at 4-24).

Other Barriers

A number of other reasons were cited by the various studies as barriers to participation. For example, the need to obtain corporate approval to participate is seen by customers as a barrier to participation (Study 2, at 22, 26).

Other perceived barriers related to customer hesitation to use new technology. For some clients, who may operate their facilities on a 24/7 basis, the need for equipment reliability and ease of maintenance is paramount (Study 4, at 4-3; Study 6, at 7-6, 7-21 through 7-24). Furthermore, they don't want to be "guinea pigs" for new technologies, and they cannot afford to be "embarrassed" by a system failure (Study 4, at 4-3; Study 6, at 7-6). Other cited challenges related to new technologies include convincing clients to use unproven technologies, specifying and coordinating more sophisticated equipment and controls (i.e. constructability of the design), and communications between different types of equipment (Study 4 at 4-19 through 4-20; Study 1, at 6-15; Study 6, at 7-6, 7-21 through 7-24).

Efficiency saturation was also cited as a barrier to further participation. Because of the length of time that C&I programs have been running in Massachusetts some of the technical staff reported that they are beginning to circle back around to customers they have already done projects with (Study 1 at 9-7). One respondent commented "we've been doing energy efficiency programs for 20 years and we've done projects at every one of these customers more than two or three times"[36] (Study 1 at 9-7).

One respondent stated that the rapid code changes have made things difficult for his staff (Study 4 at 4-17). The implication is that the extra time needed to master the code changes is eating into A&E firms' project fees (Study 4 at 4-17). A few architects stated they "have to pay more attention" to their designs because of new code requirements and that they now implement measures that would have before been considered alternative energy efficiency measures (Study 4 at 4-17).

36 An account executive was quoted to say that "unfortunately, you reach a saturation point, and I'm at that point now with the biggest customers. There's only so efficient that you can be. Unless there is a change in technology, then you can only change so much lighting, you can only change so many motors. It comes to a point where you've hit all the biggest customers. And then you start moving down to the next quartile of size of customers that are within the realm of the programs that we are responsible for" (Study 1, at 5-4; see also Study 1, at 6-14).

Appendix B – Survey Tools

Questionnaire Sent Out With Invitations

Synapse Energy Economics, Inc.
485 Massachusetts Ave., Suite 2
Cambridge, MA 02139
617-661-3248

Survey of Commercial & Industrial Customer Perspectives on Massachusetts Energy Efficiency Programs

On behalf of the Massachusetts Energy Efficiency Advisory Council, Synapse Energy Economics is currently investigating incentives and barriers to commercial- and industrial-sector participation in the Massachusetts energy efficiency programs. This survey represents the first phase of our study, and will be followed up by a phone or in-person interview with respondents to discuss pertinent details. A staff member at Synapse will be in touch to schedule this interview.

The answers you provide to this survey will be shared as part of a Synapse report to the Advisory Council. All information that could be used to identify you or your company will be kept strictly confidential, and will not be presented in our report.

Thank you for participating, and for helping to inform the development of the Massachusetts energy efficiency programs.

If you have any questions about this survey, please contact Janice Conyers at Synapse: 617-453-7020 or JConyers@Synapse-Energy.com. Please SUBMIT using the button at the top right, or email as an attachment.

Company Information

1) **Company name:**

2) **Company address:**

3) **Company product(s) / service(s):**

4) **Approximate number of company employees located in Massachusetts:**

   - ◯ 1 to 4.
   - ◯ 5 to 9.
   - ◯ 10 to 19.
   - ◯ 20 to 50.
   - ◯ Greater than 50.

5) **Building ownership:**

   ◯ Owned. ◯ Leased.

6) **Electricity provider:**

7) **Natural gas provider:**

Information about the Person(s) Being Interviewed

8) Name(s):

9) Title(s):

10) General responsibilities:

11) Which specific responsibilities does your job include? (Choose all that apply.)

- ☐ Administration
- ☐ Building operations/maintenance management
- ☐ Property management
- ☐ Construction management
- ☐ Engineering
- ☐ Purchasing and procurement
- ☐ Financial management
- ☐ Environmental management
- ☐ Owner/Founder/President/CEO
- ☐ Other (please specify)

Information about Energy Usage

12) Average monthly electric bill.
(Please provide what information you have readily available. Please explain whether the information is for a particular building, a facility, a division within the company, the company as a whole, or some other grouping.)

Electricity consumption (in kWh):

Electricity cost (in dollars):

13) Annual electric costs as a percent of annual operating expenses.
(Please choose one of the following, based upon your best estimate.)

- ○ One percent or less.
- ○ Between five and one percent.
- ○ Between ten and five percent.
- ○ Between twenty and ten percent.
- ○ Twenty percent or greater.

14) Average monthly natural gas bill.
(Please provide whatever information you have readily available. Please explain whether the information is for a particular building, a facility, a division within the company, the company as a whole, or some other grouping.)

Gas consumption (in therms):

Gas cost (in dollars):

15) Annual natural gas costs as a percent of annual operating expenses.
(Please choose one of the following, based upon your best estimate.)

- ○ One percent or less.
- ○ Between five and one percent.
- ○ Between ten and five percent.
- ○ Between twenty and ten percent.
- ○ Twenty percent or greater.

16) When purchasing new equipment, does your company consider the efficiency with which that equipment consumes energy?

17) If the answer to the question above is yes, what criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facilities? (Choose all that apply.)

- ☐ Internal rate of return.
- ☐ Payback period.
- ☐ Benefit-cost ratio.
- ☐ Energy bill savings.
- ☐ Other. (Please describe.)
- ☐ The company has not specified criteria regarding efficiency measures.

Information about Awareness of the Mass. Energy Efficiency Programs

18) Prior to being contacted for this interview, were you aware of the energy efficiency programs offered by your electric and gas utilities?

- ○ Yes.
- ○ No.

19) Have you ever been solicited to participate in any energy efficiency program? (Choose all that apply.)

- ☐ By your gas company.
- ☐ By your electric company.
- ☐ By someone else. (Please specify.)

20) Has your company ever participated in the energy efficiency programs offered by your electric or gas utility? (Choose all that apply.)

- ☐ Yes, within the past three years.
- ☐ Yes, prior to the past three years.
- ☐ No.

21) If your company has participated in the energy efficiency programs offered by your electric and gas utilities within the past three years:

Please name one or two things about the program that worked well for your company.

Please name one or two things about the program that did not work well for your company.

22) Based on your current knowledge of the efficiency programs offered by your electric and gas utilities, does your company plan to participate these programs within the next three years?

- ◯ Yes.
- ◯ Maybe.
- ◯ No.

If not, why not.

Scheduling a Follow-Up Interview

As mentioned above, you will be contacted by a staff member at Synapse to schedule a phone or in-person interview as a follow-up to this survey. During the interview, you will be asked a series of specific questions designed to address the following overarching topics:

- How well do the Massachusetts energy efficiency programs address your company's needs?
- What are the primary barriers that your company faces in participating in the Massachusetts energy efficiency programs?
- How can the programs be changed to provide greater value to your company? How can they be changed to help overcome the barriers?
- What is the likelihood that your company will participate in the Massachusetts energy efficiency programs in the next three years?

Thank you for taking the time to fill out this survey; your input is greatly appreciated! Please save your answers and return the completed survey to Synapse as an attachment to an email Please address the email to JConyers@Synapse-Energy.com

You may also submit your completed survey using the submit button at the top right.

Interview Questions for Program Participants

Specific follow-up questions to be asked in person of respondents who completed Synapse's survey for program participants.

These questions are not provided to the interviewee in advance.

General questions:

1. How important are energy costs to your company?
    a. What level of priority do you give energy costs? High, medium, low?
    b. Who sets the priority?
    c. How is the priority communicated? What is it based on?
2. Please describe the decision-making process that your company undertakes to decide whether to implement an energy efficiency measure.
    a. Who makes the request? What department of the company?
    b. How is a request communicated?
    c. Who makes the decision? What department of the company?
    d. How is the decision made? Which metrics are used (e.g., hurdle rates, payback periods, age of equipment)?
    e. How is the decision communicated?
3. Please expand upon your answer to question 17 in Synapse's survey for program participants. (What criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facilities?)
4. Please explain why the company chose to participate in the Massachusetts energy efficiency programs.
    a. Reduced costs?
    b. Improved services?
    c. Improved operations?
    d. Environmental benefits?
    e. Other?
5. How well did the representative of the energy efficiency program administrator understand your company's interests and needs?
    a. What could the representative have done differently to address your company's interests and needs better?
6. Did your company decide not to implement any efficiency measures that were offered through the energy efficiency programs?
    a. If yes, please explain why not.

7. Do you plan to participate in Massachusetts energy efficiency programs in the next three years?
    a. If yes, what factors are motivating you to participate again?
    b. If no, why not?
        i. What is the most significant barrier to your participation?
        ii. What are the other barriers to your participation?
        iii. What could be done differently to help motivate you to participate?

Specific Questions: (to be asked if the respondent has not provided sufficient detail to the general questions above)

8. To what extent do budget limitations pose a barrier to your company's participation in energy efficiency programs?
    a. Who in your company sets the budgets?
    b. Where do energy costs and energy efficiency investments fit within the company's budget structure?
9. To what extent do financing limitations pose a barrier to your company's participation in energy efficiency programs?
    a. Who in your company makes the decisions about financing opportunities and limitations?
    b. What sort of financing opportunities does you company provide with regard to energy efficiency investments.
10. In general, how does the current state of the economy affect your interest and ability to participate in the energy efficiency programs?

7.

If time allows:

11. What type of support did your company receive through the Massachusetts energy efficiency programs? (Choose all that apply.)

    Equipment rebates.

    Technical support.

    Energy audit or technical assessment.

    Loans or other forms of financing.

    Other. (Please describe.)

12. Approximately how much are you expecting to save as a result of participating in the Massachusetts energy efficiency programs? (Please provide whatever information you have readily available.)

    Energy savings (kWh, therms) per month.

Bill savings (dollars) per month.

Percent reduction in overall energy consumption.

Payback period.

Other. (Please describe.)

Interview Questions for Program NON-Participants

Specific follow-up questions to be asked in person of respondents who completed Synapse's survey for program non-participants.

These questions are not provided to the interviewee in advance.

General questions:

1. How important are energy costs to your company?
    a. What level of priority do you give energy costs? High, medium, low?
    b. Who sets the priority?
    c. How is the priority communicated? What is it based on?
2. Has your company purchased or installed equipment in the past three years that consumes a significant amount of electricity, gas or oil?
    d. In purchasing this equipment, did your company consider the implications of your energy bills?
    e. Did you company consider purchasing equipment that is more efficient than standard practice?
3. Please describe the decision-making process that your company undertakes to decide whether to implement an energy efficiency measure.
    f. Who makes the request? What department of the company?
    g. How is a request communicated?
    h. Who makes the decision? What department of the company?
    i. How is the decision made? Which metrics are used (e.g., hurdle rates, payback periods, age of equipment)?
    j. How is the decision communicated?
4. Please expand upon your answer to question 17 in Synapse's survey for program non-participants. (What criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facilities?)
5. For those customers that were aware of the Massachusetts energy efficiency programs prior to this interview (answered yes to question 18 in Synapse's survey for program non-participants): How did you become aware?
6. If you were aware of the Massachusetts energy efficiency programs prior to this interview, why has the company not participated in them to date?
    k. What is the most significant barrier to your participation?
    l. What are the other barriers to your participation?
    m. What could be done differently to help motivate you to participate?
7. Have you communicated with a representative of the Massachusetts energy efficiency program administrators?

n. How well did the representative understand your company's interests and needs?

o. What could the representative have done differently to better address your company's interests and needs?

8. For those customers that were not aware of the Massachusetts energy efficiency programs prior to this interview (answered no to question 18 in Synapse's survey for program non-participants): Do you plan to purchase equipment in the next three years that consumes a significant amount of energy? If so, would you be interested in participating in a program that offers you financial incentives and technical support for installing energy efficiency equipment?

   p. If yes, what are the main reasons for doing so?

   q. If no, why not?

      i. What is the most significant barrier to your participation?

      ii. What are the other barriers to your participation?

      iii. What could be done differently to help motivate you to participate?

Specific Questions: (to be asked if the respondent has not provided sufficient detail to the general questions above)

9. To what extent do budget limitations pose a barrier to your company's participation in energy efficiency programs?

   r. Who in your company sets the budgets?

   s. Where do energy costs and energy efficiency investments fit within the company's budget structure?

10. To what extent do financing limitations pose a barrier to your company's participation in energy efficiency programs?

   t. Who in your company makes the decisions about financing opportunities and limitations?

   u. What sort of financing opportunities does you company provide with regard to energy efficiency investments.

11. In general, how does the current state of the economy affect your interest and ability to participate in the energy efficiency programs?

Appendix C – Survey Responses

Survey of Commercial and Industrial Customer Perspectives of Massachusetts Energy Efficiency Programs

Interview Notes

Region: Bristol County

Industry: Heavy Industry

Person(s) Interviewed: Energy Systems Program Manager

Interview Number: 1

Key Questionnaire Responses

Note: question numbers correspond to the order in which questions are asked in the questionnaire.

4) Approximate number of company employees located in Massachusetts:

Greater than 50.

5) Building ownership:

Owned.

13) Annual electric costs as a percent of annual operating expenses:

Declined to respond.

15) Annual natural gas costs as a percent of annual operating expenses:

Declined to respond.

16) When purchasing new equipment, does your company consider the efficiency with which that equipment consumes energy?

Yes.

17) If the answer to question 16 is yes, what criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facility?

Internal rate of return; Payback period; Benefit-cost ratio; Energy bill savings.

18) Prior to being contacted for this interview, were you aware of the energy efficiency programs offered by your electric and gas utilities?

Yes.

20) Has your company ever participated in the energy efficiency programs offered by your electric or gas utility?

Yes, within the past three years, and prior to the past three years.

21) If your company has participated in the energy efficiency programs offered by your electric and gas utilities within the past three years:

Please name one or two things about the program that worked well for your company:

Being allowed to pass the rebate on to the contractors so I did not need to ask for as much capital.

Please name one or two things about the program that did not work well for your company:

Engineering support to help move projects along.

22) Based on your current knowledge of the efficiency programs offered by your electric and gas utilities, does your company plan to participate in these programs within the next three years?

Maybe. Capital is very tight. Changes in financing options might help move projects forward.

Predetermined Interview Questions

1. How important are energy costs to your company?

The customer preferred not to disclose its energy use as a percentage of annual operating expenses through the questionnaire, but stated during the interview that energy costs comprise a large enough percentage to be a motivating factor. Partly because Massachusetts has some of the highest energy rates in the United States, the customer recently took steps to reduce costs by opening a location overseas and is considering opening a location in a southern state. The customer has tried to lower consumption, and program participation is important to the customer for staying competitive.

2. Please describe the decision-making process that your company undertakes to decide whether to implement an energy efficiency measure.

The customer annually considers capital investment projects. Projects that are presented to management as absolutely necessary to business operations and sales are prioritized as Tier 1 projects, and receive the requested capital. Capital projects not absolutely necessary for business operations are categorized as Tier 2 projects, and receive financing based on the value (i.e., savings potential or improved quality) the project can bring to the customer. Energy projects are never prioritized as Tier 1 projects because the person interviewed could never say that the business cannot continue without an energy efficiency project. Efficiency projects then compete with other capital investment projects on a value added basis, and may take a number of years to receive the required capital.

The customer’s annual review of capital investments can differ from year to year. The annual review depends on the amount of capital the customer has available to allocate to the proposed projects, and the projects that have been proposed in a given year. In some years efficiency projects have received a lot of capital, and other years only small projects are completed (including 2012).

Efficiency is seen as non-essential, although something the customer would like to do. Goes in cycles: some years more capital spending on other big projects, followed by a lull where efficiency can fit into.

3. What criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facilities?

Efficiency equipment combined with the utility incentive generally needs to provide a payback between 2 and 3 years for the company to install the efficient equipment. The customer generally does not consider a payback beyond 5 years.

4. Please explain why the company chose to participate in the Massachusetts energy efficiency programs.

The customer stated that it has participated in efficiency programs a number of times. The person interviewed indicated that, in the past, either he would contact the utility company directly to enquire about rebates when the customer was considering an efficiency project, or the utility would contact him. When the utility contacted him, it was usually at the end of the year, and the utility explained that it was short of meeting its goals and would offer him a higher incentive than normal if the customer participated that year. In recent years, the utility has reached out to the customer more in the middle of the year than at the end of the year. Sometimes the customer would be in the process of considering an efficiency project when the utility called, and the additional incentive allowed the customer to move forward with the efficiency project. The person interviewed found that having the utility contact him at the end of the year aligned well with the customer's internal capital planning schedule (see response to question 2).

5. How well did the representative of the energy efficiency program administrator understand your company's interests and needs?

The person interviewed indicated that experiences with account representatives have been generally positive and did not have anything negative to say about the representatives.

6. Did your company decide not to implement any efficiency measures that were offered through the energy efficiency programs?

n/a – see description of company's decision making process in question 2.

7. Do you plan to participate in Massachusetts energy efficiency programs in the next three years?

Maybe. The person interviewed recommended making a number of program design changes that would better allow the customer to participate in the future. First, the customer strongly recommended greater transparency in program spending and funding. The customer noted that it puts a lot of money towards efficiency programs through its utility bills, but cannot track how much it is actually spending because rates are not transparent. Further, the customer feels that it is putting a lot of money towards efficiency projects, without getting the full advantage of the programs. The person interviewed recommend that, instead of charging the customer the amount collected through its utility bills, allow the customer to retain the money, with the understanding that that exact amount of money would have to spent on efficiency projects at the customer. That money could only be used for efficiency projects at the customer, and could not be used for other capital investments within the customer. This would relieve the person interviewed from having to ask management for capital to invest in efficiency projects. Such a change would help tremendously in moving projects forward. This may require a policy change before it can happen, but it does need to happen.

Second, the person interviewed recommended considering on-bill financing for large commercial customers, similar to the program offered to small commercial customers. He recommended allowing customers to pay off efficiency investments on their bill, but in such a way that the monthly payment does not exceed the monthly savings. This would also relieve him of having to ask management for capital to invest in efficiency projects.

8. To what extent do budget limitations pose a barrier to your company's participation in energy efficiency programs?

See description of company's decision making process in question 2.

9. To what extent do financing limitations pose a barrier to your company's participation in energy efficiency programs?

See description of company's decision making process in question 2.

10. In general, how does the current state of the economy affect your interest and ability to participate in the energy efficiency programs?

See description of company's decision making process in question 2. Because the customer's annual review of capital projects can vary from year to year, every year it can be difficult to count on capital availability for efficiency projects. It depends not only on economy but also on business model and company's business cycle.

The person interviewed also stated that the economy has definitely been very tight for the past 2 or 3 years. Also, the customer is recently under new ownership, and the person interviewed is unsure how that will change the customer's long-term operations.

People have been lulled into a sense of security with prices of electricity and natural gas being suppressed. Back in 2008, everyone was through the roof trying to figure out how to conserve because budgets were getting out of control. Now with this long period of sustained pricing, efficiency is not on the top of people's mind, so that definitely plays into companies' decision making.

Barriers to Participation

A. Financial limits

B. Economic downturn

Maybe.

C. Customer awareness and marketing

D. Program design and administration

At the end of the last two years, the utility has practically doubled incentive levels for certain measures. This tells the person interviewed that the utilities are over collecting the funds, and are literally looking to burn money by end of year.

The customer indicated that greater engineering support from the Program Administrators would allow it to convince management that efficiency projects are worthwhile. The customer does not have the man power to do a study that would determine whether an efficiency project could benefit the customer. Energy efficiency is only a portion of a person's job at the customer, and when a potential efficiency project is identified, it can sit in a database waiting for someone to fully define the project. Management won't consider projects that are not fully developed. The person interviewed indicated that they have reached out to the utility to see if they would fund such an engineering analysis for a potential project, but found that the assistance offered by the utility was not compelling to participate. According to the person interviewed, the utility would only offer to pay a certain amount for evaluations, but only after the customer decided to go ahead with the project, whereas the customer needed the assistance before it could go ahead with a project.

Sometimes the customer would like to do a custom project that requires technical and engineering support. That money would have to come out of another expense budget, and with the economy the way it is, that pool of money can be very tight. Utilities will offer to partially fund technical support, but if the utilities were more aggressive in helping companies clearly identify a project in terms of what it will save and cost the company to implement it. This creates a clear picture on what project would look like, which would be beneficial. Some projects have stalled for years because they're just concepts that haven't been fully developed. Technical support could clearly define the best projects and opportunities, which would be a good use of money. Help get projects in front of management and identify rebate opportunities. Person interviewed recommended that the utility pay the full amount of the technical study. As currently structured, the customer could do a study and would have to pay for half of it, but then the project doesn't get built so it's seen as a waste of money. This is a hard step for the customer to get past. Don't have expense money to spend on reports. Expense money has been really tight in the past few years.

E. Corporate review and approval process

Yes – see description of company's decision making process in question 2.

F. Timing of program administrators

G. Customer distrust of new technologies

H. Customer convinced it has done all it can.

I. Others

People have been lulled into a sense of security with prices of electricity and natural gas being suppressed. Back in 2008, everyone was through the roof trying to figure out how to conserve because budgets were getting out of control. Now with this long period of sustained pricing, efficiency is not on the top of people's mind, so that definitely plays into companies' decision making.

Other Comments

The person interviewed noted that it has a CHP system, and would like to install another system as it is a tremendous efficiency project, but that standby rates hurt its full potential.

The person interviewed stated that MOU agreements between large customers and utility company has value, but would prefer it were a more open process and allow others to see what incentives work for other customers.

Survey of Commercial and Industrial Customer Perspectives of Massachusetts Energy Efficiency Programs

Interview Notes

Region: Bristol County

Industry: Retail

Person(s) Interviewed: n/a

Interview Number: 2

Key Questionnaire Responses

The Company did not provide the questionnaire.

Predetermined Interview Questions

1. How important are energy costs to your company?

n/a

2. Please describe the decision-making process that your company undertakes to decide whether to implement an energy efficiency measure.

The persons interviewed prepare a proposal regarding an efficiency project for the CFO to review. If acceptable, the CFO approves the project and provides the capital investment.

3. What criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facilities?

An efficiency measure's ROI needs to be between 2 and 3 years in order for the customer to install the measures. The CFO of the customer is receptive to and generally will approve efficiency projects with a low payback period.

4. Please explain why the company chose to participate in the Massachusetts energy efficiency programs.

A third-party energy company approached the customer about two years ago and surveyed its locations for efficiency opportunities. The third-party energy company offered rebates from the utility combined with on-bill financing structured so that the monthly on-bill repayment charge would break even with the monthly savings. As a result, the customer upgraded lighting in 5 or 6 of its 12 locations in Massachusetts. The zero dollars out of pocket and a 2 to 2.5 year payback allowed the customer to easily go forward with the efficiency projects.

The customer was always interested in efficiency but was not actively seeking projects when the third-party energy company approached it. Previously, the customer looked for efficiency projects and was told there were no opportunities available in its locations.

5. How well did the representative of the energy efficiency program administrator understand your company's interests and needs?

The customer has limited contact with its utility, and was not informed by its utility about efficiency programs. The customer was generally aware that the utility's offer efficiency programs because it has locations in Connecticut, and has retrofitted lighting in all of its Connecticut locations through Connecticut Light and Power. However, the customer had a limited understanding of the Massachusetts efficiency programs.

Competitive suppliers regularly contact the customer, some of which offer efficiency measures. Lighting efficiency is being aggressively pushed by third parties at the moment. The customer was indifferent as to whether its utility or a third party provided efficiency services and incentives, so long as the financial incentives offered are in line with the customer's goals.

6. Did your company decide not to implement any efficiency measures that were offered through the energy efficiency programs?

The customer has looked into HVAC equipment, but the ROI is usually 5 to 10 years which is not worth the investment to the customer. The customer would love to do more than lighting retrofits.

The customer has locations in Connecticut, and is aware that CL&P packages lighting with HVAC incentives. The customer is more likely to consider such a packaged offering if the ROI stays within 2 to 3 years.

7. Do you plan to participate in Massachusetts energy efficiency programs in the next three years?

Yes, although likely not directly through the utility. The customer plans to upgrade lighting in a couple of its Massachusetts locations in the next few years through the third-party energy company.

8. To what extent do budget limitations pose a barrier to your company's participation in energy efficiency programs?

The customer has a set number of capital dollars available for investment. Efficiency projects may compete against other investment projects depending on the projects proposed in a given year. If the project has a 2 to 3 year payback, then it will likely receive approval along with the other proposed 2 to 3 year payback projects.

9. To what extent do financing limitations pose a barrier to your company's participation in energy efficiency programs?

The customer favors an on-bill repayment structure. The customer feels like there is a lot of legwork involved in accessing federal and state incentives for efficiency. If the financial incentives were research and packaged together, the customer would be more likely to participate.

10. In general, how does the current state of the economy affect your interest and ability to participate in the energy efficiency programs?

The customer was not very affected by the economy and has been doing alright. 2008 and 2009 were a little slow, but the customer has been pleased since then.

Barriers to Participation

A. Financial limits

The customer is very receptive to on-bill repayment.

B. Economic downturn

C. Customer awareness and marketing

Yes. The customer was unaware of the utility's program offerings, and had not been in touch with its utility.

D. Program design and administration

Legwork involved in accessing incentives.

E. Corporate review and approval process

no so long as short payback period.

F. Timing of program administrators

G. customer distrust of new technologies

H. customer convinced it has done all it can.

Yes, to some degree. The customer previously thought they had done all they could until a third party approached them to conduct an audit. While the customer has only done lighting projects, they are unwilling to install measures with a longer payback.

I. Others

Other Comments

Survey of Commercial and Industrial Customer Perspectives of Massachusetts Energy Efficiency Programs

Interview Notes

Region: Bristol County

Industry: Miscellaneous

Person(s) Interviewed: Executive Director

Interview Number: 3

Key Questionnaire Responses

Note: question numbers correspond to the order in which questions are asked in the questionnaire.

4) Approximate number of company employees located in Massachusetts:

n/a

5) Building ownership:

Owned.

13) Annual electric costs as a percent of annual operating expenses:

One percent or less.

15) Annual natural gas costs as a percent of annual operating expenses:

Between five and one percent.

16) When purchasing new equipment, does your company consider the efficiency with which that equipment consumes energy?

Yes.

17) If the answer to question 16 is yes, what criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facility?

Payback period; Energy bill savings.

18) Prior to being contacted for this interview, were you aware of the energy efficiency programs offered by your electric and gas utilities?

Yes

20) Has your company ever participated in the energy efficiency programs offered by your electric or gas utility?

Yes, with the past three years and prior to the past three years.

21) If your company has participated in the energy efficiency programs offered by your electric and gas utilities within the past three years:

Please name one or two things about the program that worked well for your company:

Energy efficient common hallway lighting, bulb replacement with CFL's, replace torchiere lamps.

Please name one or two things about the program that did not work well for your company:

Greater focus on gas/heating measures.

22) Based on your current knowledge of the efficiency programs offered by your electric and gas utilities, does your company plan to participate in these programs within the next three years?

Yes.

Predetermined Interview Questions

1. How important are energy costs to your company?

Energy costs are very important to the customer. The person interviewed oversees housing complexes, but each housing unit does not pay for its own utilities. Energy is one of the major line items on the budget for this customer.

2. Please describe the decision-making process that your company undertakes to decide whether to implement an energy efficiency measure.

The Executive Director is the decision maker. If there's a way to save money, she will take advantage of it.

3. What criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facilities?

The shorter payback the better. If a decent, favorable return was expected from an efficiency project, it would certainly be considered.

4. Please explain why the company chose to participate in the Massachusetts energy efficiency programs.

The a certain state department assertively recommended taking advantage of the efficiency programs, and the person interviewed wanted to get the audit taken care of so that the customer could consider what else could look to do in the future.

Bill savings was another motivating factor. Energy is a huge line item on the budget for this customer. The customer does not have a lot of money available beyond paying for its energy bill, so they have to save money everywhere they can.

The customer seemed to have trouble bringing all the pieces together for funding, scheduling, logistics, and participation in the utility programs.

5. How well did the representative of the energy efficiency program administrator understand your company's interests and needs?

The person interviewed could not recall whether they participated through the utility program or a third party like CSG.

6. Did your company decide not to implement any efficiency measures that were offered through the energy efficiency programs?

Some projects were considered, but the utility company informed them that it would not have produced enough savings so it was eliminated from the list because the utility was not willing to do it. The person interviewed found this to be an unfavorable aspect of the program.

7. Do you plan to participate in Massachusetts energy efficiency programs in the next three years?

The customer will participate anytime there is anything you can offer. The customer can only participate when equipment needs replacing, and is not likely to proactively retire equipment early.

When asked how the program could be improved going forward, the person interviewed indicated that they would participate again, although anything that simplified the process would be good.

8. To what extent do budget limitations pose a barrier to your company's participation in energy efficiency programs?

Yes. The customer's budgets are very controlled. It won't have the money on hand to upgrade equipment until the equipment needs to be replaced. Efficiency has not been factored into the customer's capital investment plan as it's not high on the priority list.

9. To what extent do financing limitations pose a barrier to your company's participation in energy efficiency programs?

The person interviewed was not well informed about financing opportunities but may have been interested if given more information.

10. In general, how does the current state of the economy affect your interest and ability to participate in the energy efficiency programs?

The customer's income has been relatively stagnant for the past few years – not decreasing but definitely not increasing. The customer recently developed a capital investment plan that should consistently provide annual funds for improvements, but very few dollars will be put towards efficiency upgrades. If the economy improves, the customer does not expect it would start doing efficiency projects immediately – there's just too many other things. The customer just needs to pay its bills.

Barriers to Participation

A. Financial limits

Yes. Budget and capital are very tight for the customer. Efficiency is not considered a priority, although energy costs are very important to the customer.

B. Economic downturn

Yes. Less income available for capital improvements.

C. Customer awareness and marketing

To some degree. The person interviewed was not well informed about financing opportunities.

D. Program design and administration

The customer experienced delays during its initial enrollment in the program. A lot of data was required from the customer regarding its energy use, which pushed back the installation process. The person interviewed recommended simplifying the logistical process for participation.

Some projects were considered, but the utility company informed them that the project would not have produced enough savings so it was eliminated from the list because the utility was not willing to do it.

The person interviewed felt that there was a bigger push towards electric measures, and would have liked to see more heating measures.

E. Corporate review and approval process

F. Timing of program administrators

Yes. customer can only participate when equipment needs to be replaced.

G. customer distrust of new technologies

H. customer convinced it has done all it can.

No. customer would like to do more but does not have the budget available.

I. Others

Other Comments

The customer has received favorable feedback on common lighting upgrades, which the person interviewed found encouraging.

Survey of Commercial and Industrial Customer Perspectives of Massachusetts Energy Efficiency Programs

Interview Notes

Region: Boston

Industry: Schools & Colleges

Person(s) Interviewed: Manager of Sustainable Engineering and Utility Planning

Interview Number: 4

Key Questionnaire Responses

Note: question numbers correspond to the order in which questions are asked in the questionnaire.

4) Approximate number of company employees located in Massachusetts:

Greater than 50.

5) Building ownership:

Owned.

13) Annual electric costs as a percent of annual operating expenses:

One percent or less.

15) Annual natural gas costs as a percent of annual operating expenses:

One percent or less.

16) When purchasing new equipment, does your company consider the efficiency with which that equipment consumes energy?

Yes.

17) If the answer to question 16 is yes, what criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facility?

Payback period.

18) Prior to being contacted for this interview, were you aware of the energy efficiency programs offered by your electric and gas utilities?

Yes.

20) Has your company ever participated in the energy efficiency programs offered by your electric or gas utility?

Yes, within the past three years, and prior to the past three years.

21) If your company has participated in the energy efficiency programs offered by your electric and gas utilities within the past three years:

Please name one or two things about the program that worked well for your company:

Customized MOU, 3 year program, generous incentives.

Please name one or two things about the program that did not work well for your company:

Nothing for gas/thermal.

22) Based on your current knowledge of the efficiency programs offered by your electric and gas utilities, does your company plan to participate in these programs within the next three years?

Yes.

Predetermined Interview Questions

1. How important are energy costs to your company?

Energy costs are not a significant consideration for the customer, especially compared to a large manufacturer. The customer would not need to lay off employees if energy costs increased. Energy costs are not going to change the customer's competitiveness. The customer is going to be able to obtain the energy it needs to operate its facilities.

2. Please describe the decision-making process that your company undertakes to decide whether to implement an energy efficiency measure.

An engineer at the customer needs to ask a number of division or department directors for approval for an energy efficiency project. This process of approval can be long and slow, sometimes taking years for approval. Management needs to be convinced through reasonable justification that the potential savings are worth moving internal funds from the designated energy cost bucket, to the capital project budget bucket.

As further discussed in question 4, the increased amount of efficiency funding beginning in 2010 caught management's attention and made management more receptive to approving efficiency projects, which made for a more efficient internal approval process. It took the increase in available utility funding and a large efficiency investment plan for management to see the value in efficiency.

3. What criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facilities?

n/a

4. Please explain why the company chose to participate in the Massachusetts energy efficiency programs.

Beginning in 2010, the customer worked closely with its utility to design a custom three-year efficiency plan for its property through a Memorandum of Understanding (MOU). Through the MOU, the customer set aggressive goals and has been successful in meeting those goals. The utility provided greater amounts of funding than in previous years of participation, which allowed the customer to design a large efficiency investment plan. The customer's efficiency plan was funded in roughly equal amounts by the utility MOU, internal capital, and the reinvestment of savings resulting from efficiency projects.

5. How well did the representative of the energy efficiency program administrator understand your company's interests and needs?

The relationship between the customer and utility is generally positive, and the two parties are in regular contact. The customer found that the utility's engineers and technical assistance were improved during this period of participation from previous experiences with the utility.

6. Did your company decide not to implement any efficiency measures that were offered through the energy efficiency programs?

n/a

7. Do you plan to participate in Massachusetts energy efficiency programs in the next three years?

The customer hopes to extend the efficiency plan it currently has with its utility for the next three-years, but has not yet discussed the opportunities and plan with the utility or internally with management. The customer expects to reference the success with its current three-year plan to receive approval from management.

If the customer does participate in the next three-years, the person interviewed stressed that gas savings needed to become a stronger focus for the customer, whether or not the utility's efficiency program allow opportunities and incentives for gas savings. The person interviewed felt that gas incentives were not as generous as on the electric side, and that the gas programs were not as well structured as and even appeared disconnected from the electric programs. The customer acknowledged that it is not a typical gas customer in that it has in place a co-generation facility and has a number of labs that require chilled water and steam. To address gas efficiency projects, the customer needs to spend a significant amount of time developing an engineering analysis. In the past, the potential savings were not worth this effort. The person interviewed indicated that the utility is getting better at providing this service and has employed more people, but greater improvement is needed.

8. To what extent do budget limitations pose a barrier to your company's participation in energy efficiency programs?

The customer is hopeful that there will not be budget limitations for efficiency program participation in future years. However, the customer has not yet begun to plan for next year or future years, so is not yet fully aware of its budget availability.

9. To what extent do financing limitations pose a barrier to your company's participation in energy efficiency programs?

The person interviewed indicated that greater transparency with regard to the amount that the customer is providing to program funding would better allow him to convince management to take advantage of efficiency programs offered by the utilities. He said that he is aware of the amount the customer pays through the system benefits charge, but cannot see its full contribution via other charges on the bill. He understood that by reducing consumption he would pay less into the efficiency pool of funds, and considered aggressive participation the only way to keep the energy budget in control. Going forward, if he could show management the amount of money they're contributing to efficiency, that would allow him to convince management that they need to go up to the trough and get their share of program funding, or else they would be subsidizing someone else's program participation.

10. In general, how does the current state of the economy affect your interest and ability to participate in the energy efficiency programs?

The economic downturn did not strongly affect the customer. To some degree the customer was tight on money, and so obtaining funding for energy efficiency was a little bit difficult prior to the utility's involvement in developing the long-term efficiency plan with the customer. The customer returned to a healthy financial state relatively quickly and does not expect its financial health to change going forward.

Barriers to Participation

J. Financial limits

K. Economic downturn

L. Customer awareness and marketing

M. Program design and administration

Gas programs need improvement

N. Corporate review and approval process

Potentially – depends on size of funding and potential savings.

O. Timing of program administrators

P. Customer distrust of new technologies

Q. Customer convinced it has done all it can.

R. Others

The person interviewed indicated that greater transparency with regard to the amount that the customer is providing to program funding would better allow him to convince management to take advantage of efficiency programs offered by the utilities.

Survey of Commercial and Industrial Customer Perspectives of Massachusetts Energy Efficiency Programs

Interview Notes

Region: Western Massachusetts

Industry: Retail

Person(s) Interviewed: Corporate Energy - Retail Facilities Mgr.

Interview Number: 5

Key Questionnaire Responses

Note: question numbers correspond to the order in which questions are asked in the questionnaire.

4) Approximate number of company employees located in Massachusetts:

3,000 employees.

5) Building ownership:

Both owned and leased.

13) Annual electric costs as a percent of annual operating expenses:

Unsure.

15) Annual natural gas costs as a percent of annual operating expenses:

Unsure.

16) When purchasing new equipment, does your company consider the efficiency with which that equipment consumes energy?

Absolutely. Efficiency is one of the main factors in consideration.

17) If the answer to question 16 is yes, what criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facility?

n/a

18) Prior to being contacted for this interview, were you aware of the energy efficiency programs offered by your electric and gas utilities?

Yes.

20) Has your company ever participated in the energy efficiency programs offered by your electric or gas utility?

Yes.

21) If your company has participated in the energy efficiency programs offered by your electric and gas utilities within the past three years:

Please name one or two things about the program that worked well for your company:

Flexibility and creativeness in allowing custom programs that are unique. Resources provided by utility to develop projects. Overall MassSAVE program is very easy to work with.

Please name one or two things about the program that did not work well for your company:

Nothing.

22) Based on your current knowledge of the efficiency programs offered by your electric and gas utilities, does your company plan to participate in these programs within the next three years?

Yes.

Predetermined Interview Questions

1. How important are energy costs to your company?

Extremely important. Energy is the only controllable cost in the customer's operations. The use of more efficient equipment has a dramatic impact on the customer's bottom line and its profitability. The lower the customer can keep those costs, either through the commodity itself or reducing the consumption, the more dramatic an impact it will have on the customer's bottom line.

2. Please describe the decision-making process that your company undertakes to decide whether to implement an energy efficiency measure.

Upper management is supportive of efficiency. The person interviewed submits a project proposal to upper management for approval after the utility has approved the project. However, as discussed in question 3, the ROI has to be within 2 years for management to approve an efficiency project.

3. What criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facilities?

The customer looks at the ROI. While the customer considers the equipment's expected life and the specific building and area that the building is in, the bottom line is that the project needs to have a 2 year ROI. The equipment also has to be a quality piece of equipment and meet the customer's need.

4. Please explain why the company chose to participate in the Massachusetts energy efficiency programs.

The customer is a regular participant. Sometimes the person interviewed seeks out the utility rebates, while at other times the utility approaches the customer. The customer has a national reach and works closely with utilities around the country.

The customer's headquarters are located in Massachusetts, which includes its manufacturing facility, distribution center, corporate offices, flagship store, as well as a number of retail stores. The customer is totally committed to energy efficiency, so both types of facilities have participated extensively in efficiency programs.

The customer cannot do efficiency projects without the utility's rebates. The efficiency savings from equipment installations does not allow the customer to reach its required ROI on its own. The combination of energy savings, maintenance savings, and rebates allows the customer to meet its 2 years or less ROI objective.

5. How well did the representative of the energy efficiency program administrator understand your company's interests and needs?

The customer works very closely with its utilities and has so for the last five or six years. The customer has a true partnership with its utility and feels that the utility is absolutely representing its interests and needs.

MassSAVE has been a key partner to the customer in achieving efficiency goals for its facilities. By far Massachusetts utilities are extremely ahead of most utility companies across the country and have been proactive in their approach to efficiency. The person interviewed has had a lot of input and involvement in program development, especially lighting for the retail sector. The utility has tailored its efficiency programs to meet the customer's needs and far exceed anyone across the country. The Massachusetts utilities are head and shoulders above everybody. At first the customer planned for efficiency projects that did not qualify for rebates from the utility. The person interviewed finally met the right people at the utility and worked with them on what the customer was trying to accomplish. The utility agreed that they should be incentivizing the type of projects the customer was looking into, and provided the rebate to the customer.

The person interviewed is very appreciative of the support provided by the utilities to help the customer complete the efficiency projects. It's a win-win for both of them.

6. Did your company decide not to implement any efficiency measures that were offered through the energy efficiency programs?

The customer was unable to pursue an LED lighting upgrade project for exterior lighting primarily because the ROI was about 3 years. The LED technology is still quite expensive and the savings did not allow for a low enough ROI. The utility was flexible and tried to lower the ROI. The customer likely would have gone with the project if the ROI had been 2.5 years.

7. Do you plan to participate in Massachusetts energy efficiency programs in the next three years?

Yes. Likely within the next 2 months.

8. To what extent do budget limitations pose a barrier to your company's participation in energy efficiency programs?

Although blessed with the financial and professional support of upper management, budget limitations may pose a challenging barrier beginning this year. The customer is looking very closely at projects, and the ROI requirement may even come down to 1.5 years. The primary reason for the budget constraint is the state of the economy.

9. To what extent do financing limitations pose a barrier to your company's participation in energy efficiency programs?

The customer does not elect to take the offered financing options. This is a corporate decision. The customer would prefer to purchase the equipment out right to take advantage of any tax opportunities or depreciation, or the ability to claim the equipment as an asset.

10. In general, how does the current state of the economy affect your interest and ability to participate in the energy efficiency programs?

The customer does not have a lot of capital to spend at the moment. The customer has done a lot of projects and has hit most of its efficiency objectives, but right now upper management is looking to spend money in other places. There are different priorities for the limited funds that are available at this time, and efficiency projects are competing with those projects for the limited capital available. It's not that the customer wouldn't consider efficiency and wouldn't look to fund projects through another way in the future, but at the moment the customer is not taking such actions.

Barriers to Participation

A. Financial limits

n/a, so long as ROI is within 2 years.

B. Economic downturn

Yes. The customer has limited capital available and efficiency projects are now competing against other capital investments.

C. Customer awareness and marketing

n/a

D. Program design and administration

There are a couple areas for which the utility has eliminated rebates (some lighting measures for example). This may prevent some companies from participating in efficiency programs because they may not have the capital available that the rebate would have otherwise provided. There are some programs where the utility does not allow a company to receive rebates for using more efficient equipment (motors and drives for example). That may not eliminate a company's ability to upgrade equipment but it may make the more efficient equipment less attractive to a company.

The utilities could provide more technical support to companies. It's not as if the utilities do not provide technical support, but they could adopt a more proactive approach. The utilities do not do enough to promote energy conservation or access to funds that are available to a company. The customer felt like it had to do more leg work to participate in the program then should have been required. The person interviewed was coming up with the efficiency ideas, because he had the experience and knowledge to know what projects to look for. He searches out projects to bring to the utility's attention and doesn't think the utility does a good enough job bringing efficiency opportunities to the customer. He has not had a utility representative recommend looking into specific equipment for potential efficiency opportunities. The utilities promote energy conservation but they do not promote specific technology. The utilities do promote efficient technology at their annual forums which are beneficial, but if the person interviewed did not attend those forums he likely would not have been made aware of the projects and technology that is available.

E. Corporate review and approval process

No, so long as ROI is within 2 years.

F. Timing of program administrators

G. Customer distrust of new technologies

H. Customer convinced it has done all it can

I. Others

Other Comments

The person interviewed feels that going forward efficiency opportunities will get better because the cost of efficiency products and materials has dropped. The customer will be better able to meet its objectives as technology changes and as more affordable projects and materials become available.

Survey of Commercial and Industrial Customer Perspectives of Massachusetts Energy Efficiency Programs

Interview Notes

Region: Boston

Industry: Healthcare

Person(s) Interviewed: Energy Manager

Interview Number: 6

Key Questionnaire Responses

Note: question numbers correspond to the order in which questions are asked in the questionnaire.

4) Approximate number of company employees located in Massachusetts:

Greater than 50.

5) Building ownership:

Owned.

13) Annual electric costs as a percent of annual operating expenses:

One percent or less.

15) Annual natural gas costs as a percent of annual operating expenses:

One percent or less.

16) When purchasing new equipment, does your company consider the efficiency with which that equipment consumes energy?

n/a

17) If the answer to question 16 is yes, what criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facility?

Payback period; Energy bill savings; The customer has not specified criteria regarding efficiency measures.

18) Prior to being contacted for this interview, were you aware of the energy efficiency programs offered by your electric and gas utilities?

Yes.

20) Has your company ever participated in the energy efficiency programs offered by your electric or gas utility?

Yes, within the past three years.

21) If your company has participated in the energy efficiency programs offered by your electric and gas utilities within the past three years:

Please name one or two things about the program that worked well for your company:

Provided needed funds to continue efficiency efforts.

Please name one or two things about the program that did not work well for your company:

Processing of applications was painfully slow and inconsistent.

22) Based on your current knowledge of the efficiency programs offered by your electric and gas utilities, does your company plan to participate in these programs within the next three years?

Yes.

Predetermined Interview Questions

1. How important are energy costs to your company?

Very important.

2. Please describe the decision-making process that your company undertakes to decide whether to implement an energy efficiency measure.

If equipment is not working, needs replacing, or inefficient, then the person interviewed will find funding through the customer's capital process. The capital process usually takes 3-12 months.

3. What criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facilities?

The customer takes each equipment purchase on a case-by-case basis. Payback plays a part. The average payback the customer looks for is 3 years. Overall costs and benefits of the equipment are considered, such as reduction in utility bills. Availability of funds to purchase equipment is also considered.

4. Please explain why the company chose to participate in the Massachusetts energy efficiency programs.

Program participation helped the customer fund efficiency projects. The person interviewed conducted a building assessment to learn which efficiency projects could qualify for incentives or rebates, and then approached the utility. During site visits, the utility recommended other projects that the customer could do that would qualify for additional funding. The customer found this helpful as it gave them more money. The program incentives offered were about what the customer expected prior to contacting the utility. The incentives are helpful and can help the customer spend more on future projects. Sometimes the incentives can determine whether a project goes forward, other times it does not. The incentive is not the only determinant.

The customer tries to participate every year. The customer is currently working on an MOU with its utility that would provide for a three year efficiency incentive program. The person interviewed likes the idea of the MOU, but is in the early phases of discussion and so it is too early to provide feedback on the MOU and negotiation process. It looks promising so far.

5. How well did the representative of the energy efficiency program administrator understand your company's interests and needs?

Pretty well. However, the participation process was not smooth as there were delays in communication. There was a lot of inconsistency. Sometimes the person interviewed would receive five calls in one week from the utility, and then the utility wouldn't return calls for months (i.e., feast then famine). There does not seem to be a particular time of year that this happens.

6. Did your company decide not to implement any efficiency measures that were offered through the energy efficiency programs?

No. The customer knew ahead of time which projects were going to be completed.

7. Do you plan to participate in Massachusetts energy efficiency programs in the next three years?

Definitely. There are still opportunities in HVAC and other areas that the customer hopes to implement.

8. To what extent do budget limitations pose a barrier to your company's participation in energy efficiency programs?

Of course budget limitations pose a barrier. The person interviewed could think of $10 to spend for every $1 available. The customer would always like to do more efficiency, but budgets do not always allow for it.

9. To what extent do financing limitations pose a barrier to your company's participation in energy efficiency programs?

customer has not considered financing.

10. In general, how does the current state of the economy affect your interest and ability to participate in the energy efficiency programs?

Yes. Two or three years ago the amount of money available to spend on projects was reduced. The customer is slowly improving, just like the economy.

Barriers to Participation

A. Financial limits

Always a constraint for consideration.

B. Economic downturn

Is a consideration but does not seem like a barrier for the customer.

C. Customer awareness and marketing

D. Program design and administration

The person interviewed wished that the utility programs were less stringent and rigid. He wished the programs would let customers be more creative and employ alternative ways to be more efficient. Other products could be incentivized that customers should be allowed to submit for incentives.

The utility company doesn't seem to have enough people to do the work that's needed. Delays in communication make completing projects difficult. It's not that the people are not doing a good job, it's that they have too much workload.

E. Corporate review and approval process

F. Timing of program administrators

G. Customer distrust of new technologies

H. Customer convinced it has done all it can.

I. Others

Other Comments

Survey of Commercial and Industrial Customer Perspectives of Massachusetts Energy Efficiency Programs

Interview Notes

Region: Boston

Industry: Office

Person(s) Interviewed: Assistant Property Manager

Interview Number: 7

Key Questionnaire Responses

Note: question numbers correspond to the order in which questions are asked in the questionnaire.

4) Approximate number of company employees located in Massachusetts:

5 to 9.

5) Building ownership:

Owned.

13) Annual electric costs as a percent of annual operating expenses:

Between five and one percent.

15) Annual natural gas costs as a percent of annual operating expenses:

Between five and one percent.

16) When purchasing new equipment, does your company consider the efficiency with which that equipment consumes energy?

Yes.

17) If the answer to question 16 is yes, what criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facility?

Internal rate of return; Payback period; Benefit-cost ratio; Energy bill savings.

18) Prior to being contacted for this interview, were you aware of the energy efficiency programs offered by your electric and gas utilities?

Yes.

20) Has your company ever participated in the energy efficiency programs offered by your electric or gas utility?

Yes, within the past three years and prior to the past three years.

21) If your company has participated in the energy efficiency programs offered by your electric and gas utilities within the past three years:

Please name one or two things about the program that worked well for your company:

VFDs; re-lamping for energy savings; light sensors.

Please name one or two things about the program that did not work well for your company:

n/a

22) Based on your current knowledge of the efficiency programs offered by your electric and gas utilities, does your company plan to participate in these programs within the next three years?

Yes.

Predetermined Interview Questions

1. How important are energy costs to your company?

Hugely important. Only controllable cost. The customer can control the quantity of use by controlling load through controls, as well as improve the quality of equipment by improving its longevity. The customer reviews its energy budgets very thoroughly each year.

2. Please describe the decision-making process that your company undertakes to decide whether to implement an energy efficiency measure.

The customer manages properties and brings efficiency projects to the attention of the building owner. The owner can then decide whether to make the capital investment, or pass the cost of the project onto the tenants. Property owners typically chose to make the investment as it makes the property more attractive and allows equipment to last longer.

3. What criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facilities?

The customer focuses on the largest area of consumption, which is usually HVAC and elevators. The customer also looks into the low-hanging fruit such as lighting and timers.

4. Please explain why the company chose to participate in the Massachusetts energy efficiency programs.

The property management customer works with a third party engineering company to audit properties and put together a program for the property owner. Every property is audited annually.

At the end of last year, the utility approached the customer and offered significantly larger program incentives than in previous years. The customer found this surprising because normally it finds that there is not enough money available at the end of each year.

5. How well did the representative of the energy efficiency program administrator understand your company's interests and needs?

6. Did your company decide not to implement any efficiency measures that were offered through the energy efficiency programs?

7. Do you plan to participate in Massachusetts energy efficiency programs in the next three years?

8. To what extent do budget limitations pose a barrier to your company's participation in energy efficiency programs?

9. To what extent do financing limitations pose a barrier to your company's participation in energy efficiency programs?

10. In general, how does the current state of the economy affect your interest and ability to participate in the energy efficiency programs?

New construction has the most opportunity for savings, and building owners will usually try to include as much efficiency as possible during new construction projects. However, the downturn in the economy has reduced the amount of new construction activities. More renovations have taken place as the focus is on getting savings.

Since March 2009, the customer has seen improvements each year, and improvements increase from year to year.

Efficiency products seem cheaper and more available since the downturn in the economy.

Barriers to Participation

A. Financial limits

B. Economic downturn

Economy and participation rates have been getting better each year. Expect efficiency program participation to continue improving.

C. Customer awareness and marketing

The property management customer works with owners and tenants. Often the amount of time required to work with individual tenants to participate in efficiency programs is not worth the time and potential savings to the customer, especially because the response rate for tenants is not great.

The person interviewed identified three barriers: timing, education, and familiarity. The time commitment needed to participate is too great. "Analysis paralysis" could be overcome by greater education on behalf of the utility. Familiarity with the participation process and efficiency products could improve participation.

D. Program design and administration

Upfront incentives are a bigger motivator than rebates. With rebates, the amount you expect to receive could differ from the amount you actually get, and sometimes the rebate arrives much later than anticipated, making it hardtop plan for.

E. Corporate review and approval process

Building owners normally have interest in efficiency, but don't normally have the time and don't prioritize or commit to projects. Because there is no deadline for action, projects won't get the appropriate attention and action.

F. Timing of program administrators

G. Customer distrust of new technologies

H. Customer convinced it has done all it can.

I. Others

Participants are distracted by other energy projects like solar or geothermal. It's not clear what project can give you the biggest bang for your buck and provide largest savings. Customers often cannot participate in every activity at the same time.

Other Comments

Survey of Commercial and Industrial Customer Perspectives of Massachusetts Energy Efficiency Programs

Interview Notes

Region: Boston

Industry: Office

Person(s) Interviewed: Environmental Program Manager

Interview Number: 8

Key Questionnaire Responses

Note: question numbers correspond to the order in which questions are asked in the questionnaire.

4) Approximate number of company employees located in Massachusetts:

Greater than 50.

5) Building ownership:

Owned.

13) Annual electric costs as a percent of annual operating expenses:

Between five and one percent.

15) Annual natural gas costs as a percent of annual operating expenses:

Between five and one percent.

16) When purchasing new equipment, does your company consider the efficiency with which that equipment consumes energy?

Yes. We look for Energy Star equipment, and consider the lifecycle costs.

17) If the answer to question 16 is yes, what criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facility?

Payback period; Energy bill savings; Other.

18) Prior to being contacted for this interview, were you aware of the energy efficiency programs offered by your electric and gas utilities?

Yes.

20) Has your company ever participated in the energy efficiency programs offered by your electric or gas utility?

Yes, within the past three years.

21) If your company has participated in the energy efficiency programs offered by your electric and gas utilities within the past three years:

Please name one or two things about the program that worked well for your company:

Product cost after the incentives.

Please name one or two things about the program that did not work well for your company:

Timing is always an issue, along with communications along the way.

22) Based on your current knowledge of the efficiency programs offered by your electric and gas utilities, does your company plan to participate in these programs within the next three years?

Yes.

Predetermined Interview Questions

1. How important are energy costs to your company?

It is a medium priority for company as a whole. It is a top priority for the division in which the interviewee works. This division has formalized GHG emissions reduction goals recently and backed out specific kWh and therm reductions that need to be met in order to accomplish the GHG emissions reduction goal.

2. Please describe the decision-making process that your company undertakes to decide whether to implement an energy efficiency measure.

The division in which the interviewee works is very active in planning for equipment upgrades. The division generates a list of ideas that are converted into capital expenditure projects which is then shared with and considered by the company. The interviewee is typically well integrated in the process and is aware of equipment upgrades that the company needs to make and the timeframe of those upgrades. As long as there is enough advance notice, the interviewee is in a good position to recommend whether more efficient equipment should be considered when making these upgrades. However, the interviewee is not the only decision maker and energy efficiency and environmental footprint are not the only priorities. For example, if new products (such as bed linens) and services for customers are required, these usually take precedence over other capital expenditures.

In the event of an equipment failure, there isn't always time for consideration and coordination of energy efficiency. Past experience seems to stop the company from reaching out to its utility in the event of an equipment failure, as the interviewee indicated that the response has not been as timely as is required. For example, rooftop HVAC units had to be replaced without due diligence on efficiency due to the timeframe involved.

3. What criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facilities?

In addition to payback period and energy bill savings, the company is conscious of its environmental footprint and has goals to reduce its footprint. However, the need to provide top quality products and services, which is a priority, also interferes with the goal of energy efficiency. For example, some energy efficiency products are lower quality than conventional products or do not meet the needs of the company's customers.

4. Please explain why the company chose to participate in the Massachusetts energy efficiency programs.

Their efforts on energy efficiency are important marketing and reputational/branding tools that the company leverages in differentiating itself from other players in the market.

5. How well did the representative of the energy efficiency program administrator understand your company's interests and needs?

The utilities are not consistent in how they connect with customers. Some utilities are more proactive than others in terms of reaching out to the company. The interviewee's primary critique is that the utility does not make enough effort to speak the company's language. The company has made some effort to get up to speed on the utilities terminology, but it has taken special time and effort. The language is overly technical and very specific to the utilities process. Also, if the company asks the utility a general question it is frequently directed to fill out an application before it can get this question answered. As it is too early in the process for an application to be submitted, the discussion usually stops there and efficiency opportunities are not captured.

Also, the utilities are not the only entity the company has had contact with. There are third party implementation vendors and lighting distributors as well. For example, an LED distributor recently came to one or more of the properties, did a walk through, and installed free LEDs through the utility upstream buy down initiative.

6. Did your company decide not to implement any efficiency measures that were offered through the energy efficiency programs?

Yes, there have been cases where this has occurred. The utility did a walk through and suggested upgrades to walk-in refrigerators and freezers and additional areas where occupancy sensors could be effective. Some of these recommendations have not been implemented to date due to the need to focus on other equipment upgrades and other capital expenditure priorities.

7. Do you plan to participate in Massachusetts energy efficiency programs in the next three years?

Yes, the customer needs to replace some equipment and energy efficiency will be a consideration.

8. To what extent do budget limitations pose a barrier to your company's participation in energy efficiency programs?

The impact of budget limitations on participation differs by company property. However, energy efficient equipment has been installed in the past without utility incentives, when coordination with the utility was not possible, indicating that budget is not a key barrier. Also, generally, budget has been made available for participation since a core goal of the company is to reduce its environmental footprint.

9. To what extent do financing limitations pose a barrier to your company's participation in energy efficiency programs?

The company generally does not finance energy efficiency investments. The company prefers to pay off the costs upfront.

10. In general, how does the current state of the economy affect your interest and ability to participate in the energy efficiency programs?

Like any company, reductions to the capital budget tend to put the company focus on upgrades that are deemed absolute necessities. Currently, there is more money in the bank and more of an opportunity to get things done. In general though, the economy is not a major driver. The company does these projects because they are great business opportunities.

Barriers to Participation

A. Financial limits

Not really.

B. Economic downturn

Not really.

C. Customer awareness and marketing

Yes. It sounds like more opportunity to integrate utility- and company-initiated ideas would be beneficial to both parties.

D. Program design and administration

Yes. More targeted discussions of program offerings tailored to the industry would be more productive.

E. Corporate review and approval process

No. The company has integrated energy efficiency into its corporate goals and prioritization process for equipment upgrades.

F. Timing of program administrators

Yes. Not able to serve company in a timely manner in the event of a major equipment failure. This is compounded by the fact that company impressions from past interactions limit the company's interest in reaching out to the utility at the time of the failure.

G. Company distrust of new technologies

No.

H. Company convinced it has done all it can.

No. The company views its commitment to energy efficiency as a long term effort.

I. Others

Other Comments

The division that the interviewee has worked for was started in 1991. The company has a long history of staying ahead of green opportunities.

Survey of Commercial and Industrial Customer Perspectives of Massachusetts Energy Efficiency Programs

Interview Notes

Region: Boston

Industry: Office

Person(s) Interviewed: Property Owner

Interview Number: 9

Key Questionnaire Responses

Note: question numbers correspond to the order in which questions are asked in the questionnaire.

4) Approximate number of company employees located in Massachusetts:

n/a

5) Building ownership:

Owned.

13) Annual electric costs as a percent of annual operating expenses:

n/a

15) Annual natural gas costs as a percent of annual operating expenses:

n/a

16) When purchasing new equipment, does your company consider the efficiency with which that equipment consumes energy?

Yes.

17) If the answer to question 16 is yes, what criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facility?

n/a

18) Prior to being contacted for this interview, were you aware of the energy efficiency programs offered by your electric and gas utilities?

Yes.

20) Has your company ever participated in the energy efficiency programs offered by your electric or gas utility?

Yes – through two different third party companies.

21) If your company has participated in the energy efficiency programs offered by your electric and gas utilities within the past three years:

Please name one or two things about the program that worked well for your company:

Please name one or two things about the program that did not work well for your company:

The subcontractors did not clean up the old lighting fixtures once the new ones were installed.

22) Based on your current knowledge of the efficiency programs offered by your electric and gas utilities, does your company plan to participate in these programs within the next three years?

Yes.

Predetermined Interview Questions

1. How important are energy costs to your company?

Energy is a huge cost to this condo property owner and manager. Forty-two percent of the condo's fees are for utilities. The person interviewed disagrees with the mindset that energy costs are fixed and are therefore not controllable. He takes efficiency very seriously and is very involved in efficiency projects.

2. Please describe the decision-making process that your company undertakes to decide whether to implement an energy efficiency measure.

The person interviewed is the final gate keeper for decision making. There is also a board of trustees.

3. What criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facilities?

A three year payback is required for any capital investment.

4. Please explain why the company chose to participate in the Massachusetts energy efficiency programs.

The bill savings and free lighting. The person interviewed also received risk management savings in that higher efficiency lighting reduces the risk of fires, which resulted in insurance savings.

More generally, the person interviewed indicated that people participate in efficiency programs not just for the savings, but for other reasons including health improvements and marketing ability.

5. How well did the representative of the energy efficiency program administrator understand your company's interests and needs?

The person interviewed had very little contact with his utility. He has called 1-800 numbers on his bills to participate in the utility programs, but found the people he dealt with under sophisticated and not action oriented, and considered the process useless and endless. He called 2 or 3 times over the course of 5 to 6 weeks before he reached out to the two third party companies. He was pleased with one of the third party companies because he found that the things got done and people quickly put him in touch with the right people.

6. Did your company decide not to implement any efficiency measures that were offered through the energy efficiency programs?

n/a

7. Do you plan to participate in Massachusetts energy efficiency programs in the next three years?

Yes, plenty of buildings that still need to be upgraded.

8. To what extent do budget limitations pose a barrier to your company's participation in energy efficiency programs?

None, so long as incentives continue to reduce costs and provide free upgrades.

9. To what extent do financing limitations pose a barrier to your company's participation in energy efficiency programs?

The person interviewed was not aware of condo owners taking up the financing or loan options, as he had not heard a lot of buzz about the options. He thinks that the offerings should be better marketed through contractors that are working with small and medium sized businesses.

10. In general, how does the current state of the economy affect your interest and ability to participate in the energy efficiency programs?

The person interviewed felt that the economy can affect efficiency both positively and negatively. A down economy can make people fearful, as well as more cognizant of their costs. People are more sympathetic to savings opportunities in a down economy.

Barriers to Participation

A. Financial limits

Upfront costs are a huge barrier to participation, which is why financing is key component of efficiency programs.

B. Economic downturn

Not specifically for this Company, although the person interviewed felt that the economy can both increase and decrease savings potential.

C. Customer awareness and marketing

The person interviewed thought that information about the programs needs to get out there as knowledge is the number one barrier. Information needs to be better presented for the lay person who doesn't have the time to research efficiency opportunities.

D. Program design and administration

The person interviewed felt that certain measures that save substantial amounts of energy should be included in the programs (elevator equipment, for example).

E. Corporate review and approval process

F. Timing of program administrators

G. Company distrust of new technologies

H. Company convinced it has done all it can.

I. Others

Survey of Commercial and Industrial Customer Perspectives of Massachusetts Energy Efficiency Programs

Interview Notes

Region: Central Massachusetts

Industry: Heavy Industry

Person(s) Interviewed: Purchasing and Energy Procurement; Engineering Manager; Facilities Manager; Finance Manager

Interview Number: 10

Key Questionnaire Responses

Note: question numbers correspond to the order in which questions are asked in the questionnaire.

4) Approximate number of company employees located in Massachusetts:

Greater than 50.

5) Building ownership:

Owned.

13) Annual electric costs as a percent of annual operating expenses:

Between five and one percent.

15) Annual natural gas costs as a percent of annual operating expenses:

Between five and one percent.

16) When purchasing new equipment, does your company consider the efficiency with which that equipment consumes energy?

Yes, energy efficiency is one of many criteria.

17) If the answer to question 16 is yes, what criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facility?

Internal rate of return; Payback period; Benefit-cost ratio; Energy bill savings.

18) Prior to being contacted for this interview, were you aware of the energy efficiency programs offered by your electric and gas utilities?

Yes.

20) Has your company ever participated in the energy efficiency programs offered by your electric or gas utility?

Yes, within the past three years, and prior to the past three years.

21) If your company has participated in the energy efficiency programs offered by your electric and gas utilities within the past three years:

Please name one or two things about the program that worked well for your company:

We were able to cost justify the project with the help of EEI funds.

Please name one or two things about the program that did not work well for your company:

We did not have enough energy savings projects to recoup our contribution.

22) Based on your current knowledge of the efficiency programs offered by your electric and gas utilities, does your company plan to participate in these programs within the next three years?

Maybe. Yes - we would like to so that we get our contribution back, this will be dependent upon capital spend money available.

Predetermined Interview Questions

1. How important are energy costs to your company?

Very important. If energy costs go up too much, then their facilities will be moved to other states or countries.

2. Please describe the decision-making process that your company undertakes to decide whether to implement an energy efficiency measure.

NA.

3. What criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facilities?

IRR and payback periods. Payback must be less than 3 or 4 years.

4. Please explain why the company chose to participate in the Massachusetts energy efficiency programs.

Lower their costs.

5. How well did the representative of the energy efficiency program administrator understand your company's interests and needs?

The electric company representative is very engaged, and provides the technical support that they need. They are available to help when called upon. The electric company representative would give them an audit if they asked for it. The last time the electric company offered an audit was about two years ago.

The gas company does not reach out to them much on efficiency issues. The gas company representative is more of an account rep for billing than for efficiency. They met with the gas company representative about two years ago, but have not seen him since. The challenge is finding the right projects for EE improvements. The gas EE presentation was limited to space heating.

6. Did your company decide not to implement any efficiency measures that were offered through the energy efficiency programs?

They typically implement all that is eligible for financial support.

7. Do you plan to participate in Massachusetts energy efficiency programs in the next three years?

Maybe. If they can find more efficiency measures to implement.

They would like the utilities to open up the criteria for what qualifies for the EE programs; e.g., they would like to get rebates for changing out windows.

8. To what extent do budget limitations pose a barrier to your company's participation in energy efficiency programs?

NA

9. To what extent do financing limitations pose a barrier to your company's participation in energy efficiency programs?

Capital is tight in their company, but they are able to come up with enough to combine with what the utilities offer.

10. In general, how does the current state of the economy affect your interest and ability to participate in the energy efficiency programs?

This is not so much of a factor. However, if they do not remain economical and cost-effective, then their owners would re-locate them to other states or even other countries.

Barriers to Participation

A. Financial limits

No.

B. Economic downturn

Not really.

C. Customer awareness and marketing

This is only a barrier in that the customer is convinced that they do not have a lot of efficiency opportunities left.

D. Program design and administration

No.

E. Corporate review and approval process

No.

F. Company distrust of new technologies

Maybe.

G. Company convinced it has done all it can.

Yes.

H. Others

Not in contact with the gas company much.

Other Comments

This company is well aware of the benefits of energy efficiency investments, and does not seem to have any clear internal barriers to participating in the programs and adopting EE measures.

The biggest hurdle for them is finding new EE opportunities. They believe that they have already picked the low-hanging fruit, and there is not much more to pick.

They have gas-fired kilns that use a lot of gas. They are not planning to replace the kilns soon, but when they do they will call the gas company for financial support to buy smaller, more efficient kilns. There may be an opportunity to install more efficient burners.

They have some roof-top heating elements. Their plan is to wait until the elements die, and then get a rebate for efficient equipment from the gas company. If the rebates were higher, e.g., 80% or more, then they would replace the equipment before it dies.

One example of how the electric company really helped them out: At the end of one year the company called to tell them that they had a lot of money to spend by the end of the year. The electric company identified air leaks and sealed them up, all for free. The customer would welcome more of this on a regular basis.

However, based on this experience the customer believes that the company has too much EE money; and that they should either collect less from all customers or they should offer better deals to EE participants. "The utilities do not know what to do with all of the money that they have."

When asked how the utilities can serve them better, the response was that they would better served if they could fund the efficiency projects themselves, without putting their money into the EE funds.

They mentioned many times that they pay much more into the EE funds than they get out in rebates, and they are not happy about this. They think it makes no sense to pay more money into the fund each year than what they get back in rebates. They do not have enough EE projects to use up all the funds they put in.

They would like the electric and gas companies to be more creative with their funding options, e.g., to offer an industrial customer EE opt-out option.

They believe that the large customers subsidize the EE programs for the small and residential customers.

They believe that the utilities "mismanage" the EE funds. They did not provide specific anecdotal evidence of this belief. It was based on the view that as regulated companies the utilities do not have the competitive pressure to help them manage the programs well. They also have a guaranteed rate of return, which reduces the incentive for good management.

Survey of Commercial and Industrial Customer Perspectives of Massachusetts Energy Efficiency Programs

Interview Notes

Region: Western Massachusetts

Industry: Office

Person(s) Interviewed: Electrical Manager

Interview Number: 11

Key Questionnaire Responses

Note: question numbers correspond to the order in which questions are asked in the questionnaire.

4) Approximate number of company employees located in Massachusetts:

Greater than 50.

5) Building ownership:

Owned.

13) Annual electric costs as a percent of annual operating expenses:

Not indicated.

15) Annual natural gas costs as a percent of annual operating expenses:

Not indicated.

16) When purchasing new equipment, does your company consider the efficiency with which that equipment consumes energy?

Yes.

17) If the answer to question 16 is yes, what criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facility?

Internal rate of return; Payback period; Energy bill savings.

18) Prior to being contacted for this interview, were you aware of the energy efficiency programs offered by your electric and gas utilities?

Yes.

20) Has your company ever participated in the energy efficiency programs offered by your electric or gas utility?

Yes.

21) If your company has participated in the energy efficiency programs offered by your electric and gas utilities within the past three years:

Please name one or two things about the program that worked well for your company:

No comment.

Please name one or two things about the program that did not work well for your company:

No comment.

22) Based on your current knowledge of the efficiency programs offered by your electric and gas utilities, does your company plan to participate in these programs within the next three years?

Maybe.

Predetermined Interview Questions

1. How important are energy costs to your company?

Very important. They look at them every month. The production director, facility operators and electrical manager determine this priority.

2. Please describe the decision-making process that your company undertakes to decide whether to implement an energy efficiency measure.

The electric program administrator has been in frequent contact with the company (6-7 times a year) and had 4-5 audits conducted in the past 17 years. The electrical manager and operations director review these audits and use payback as the key criteria to establish if they will move forward. The company requires a payback of 1.5 years or less to proceed with a payback of 1.0 being a 'no brainer'. This is established at the corporate level. If energy efficiency were to be implemented, the publisher would need to approve it. The company has not moved forward on any of the opportunities identified in the audits due to the fact that the payback requirement was not met, not even on lighting measures (which showed a 20 month payback).

The company's perception is that the natural gas program administrator has not been active in the market. The natural gas program administrator has never contacted the company to pursue efficiency. Natural gas energy efficiency opportunities have never been examined by the company.

A third party has been in touch with the company and made a proposal regarding efficiency which the company has also not acted on. They proposed a plan whereby the company would pay for the upfront costs using the savings, but the company did not act on this proposal.

3. What criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facilities?

Payback period primarily. The interviewee believes that the company uses stingy criteria to evaluate efficiency opportunities but does not seem to be in a position to change it. Also, the interviewee feels that the building that he is in charge of is probably not the most inefficient facility that the company owns and operates, which could be making it harder to get improvements done at this building. The money could be better spent at other buildings.

4. Please explain why the company chose to participate in the Massachusetts energy efficiency programs.

The company's most recent audit was conducted on lighting and air compressor opportunities in 2008. The payback requirement was not met so no action was taken but limited improvements to the air system were made afterwards.

5. How well did the representative of the energy efficiency program administrator understand your company's interests and needs?

Well. She keeps them up to date as to the opportunities and is frequently in contact with them regarding the low hanging fruit that they should be addressing. The interviewee feels that the company is wasting her time and has said this to her, but she has assured them that this effort is not a waste of her time.

6. Did your company decide not to implement any efficiency measures that were offered through the energy efficiency programs?

Yes. The payback requirement was not met. Also, the building is undergoing some changes to usage (i.e., changes in occupied space vs. unoccupied space), which is an additional barrier to moving forward.

7. Do you plan to participate in Massachusetts energy efficiency programs in the next three years?

Possibly. There is one opportunity that the interviewee is looking at now. Since the interviewee did not seem to have reviewed the proposal, he was not in a position to speak about it in more detail. If the payback is there, then the interviewee will look to see if the capital is there to move forward. This could occur within the first half of 2012.

8. To what extent do budget limitations pose a barrier to your company's participation in energy efficiency programs?

None. If the payback is there, the company will move forward.

9. To what extent do financing limitations pose a barrier to your company's participation in energy efficiency programs?

None. Financing has not been considered in the past and all costs would have been paid upfront. However, there is some new management now so this might change.

10. In general, how does the current state of the economy affect your interest and ability to participate in the energy efficiency programs?

The bottom line is being watched month to month. If there is money available, it's there to use. But, the economy, especially being in the newspaper business, has made it a lot more difficult.

The interviewee has authorized Synapse to quote him on the statements made in response to this question, including: "[We are] definitely dotting our I's and crossing our T's on everything we do – everything."

Barriers to Participation

A. Financial limits

Not really.

B. Economic downturn

Yes.

C. Customer awareness and marketing

For electric, no. for gas, yes.

D. Program design and administration

No.

E. Corporate review and approval process

Yes, specifically the company's payback criteria in order to get approval.

F. Timing of program administrators

No.

G. Company distrust of new technologies

No.

H. Company convinced it has done all it can.

No.

I. Others

Other Comments

Survey of Commercial and Industrial Customer Perspectives of Massachusetts Energy Efficiency Programs

Interview Notes

Region: Boston

Industry: Office

Person(s) Interviewed: Global Director of Facilities & Engineering

Interview Number: 12

Key Questionnaire Responses

Note: question numbers correspond to the order in which questions are asked in the questionnaire.

4) Approximate number of company employees located in Massachusetts:

Greater than 50.

5) Building ownership:

Owned.

13) Annual electric costs as a percent of annual operating expenses:

Between twenty and ten percent.

15) Annual natural gas costs as a percent of annual operating expenses:

Between twenty and ten percent.

16) When purchasing new equipment, does your company consider the efficiency with which that equipment consumes energy?

Yes.

17) If the answer to question 16 is yes, what criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facility?

Internal rate of return; Payback period.

18) Prior to being contacted for this interview, were you aware of the energy efficiency programs offered by your electric and gas utilities?

Yes.

20) Has your company ever participated in the energy efficiency programs offered by your electric or gas utility?

Yes, within the past three years and yes, prior to the past three years.

21) If your company has participated in the energy efficiency programs offered by your electric and gas utilities within the past three years:

Please name one or two things about the program that worked well for your company:

Decreased payback period

Please name one or two things about the program that did not work well for your company:

Minimal programs for municipality.

22) Based on your current knowledge of the efficiency programs offered by your electric and gas utilities, does your company plan to participate in these programs within the next three years?

Yes.

Predetermined Interview Questions

1. How important are energy costs to your company?

It is important. They are a for profit company, so any reduction in energy costs improves their bottom line.

2. Please describe the decision-making process that your company undertakes to decide whether to implement an energy efficiency measure.

Business unit leaders submit capital improvement proposals to an executive committee comprised of the CEO, CFO and VPs of the various business units (6-7 members total). This committee determines which projects get approved based on each proposals impact to the bottom line. There is no mandate on EE – it is weighted using the same considerations as other projects such as expanding operations, etc. The metric for approval of these projects is simple payback. The threshold for approval is 4 years or less. Anything with a payback of 3 years or less will likely be approved. Anything with a payback of 3-4 years will be considered, but may not get approved, depending on what other projects are on the table for a given year.

After projects are approved, there is a kick off meeting with the site leaders and facility managers. These folks would have been involved in the proposal upfront, so they are already very knowledgeable about the project and supportive of it. Early buy in from these folks is critical for scientific reasons – there are risks in this industry to savings energy such as risks to equipment, products and experiments conducted in laboratories that, if compromised, could hurt the bottom line. Also, a procurement specialist is included in discussions to ensure the equipment is being procured at the best price.

Each year, this interviewee submits 2-3 significant energy savings proposals. His hit rate is one for every three proposals submitted.

3. What criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facilities?

Mid-sized projects are based on payback. Larger projects (i.e., over $100M) require lifecycle cost analysis and other analyses and may be approved even with a payback that is longer than 4 years.

4. Please explain why the company chose to participate in the Massachusetts energy efficiency programs.

Simple economics – to reduce cost.

The interviewee would like to note that not all equipment offered improves operations. Some technologies make operations more complex and therefore expensive. For example, the company looked at a centralized boiler plant vs. distributed gas fired furnaces. The company found that MA regulations require more expensive staff and extra dedicated staff for a centralized boiler plant, offsetting the energy savings that could have been realized. The interviewee states that one fault of the programs is that they don't account for the full operations impacts over the life of the system including any changes in staff costs required to run the equipment.

5. How well did the representative of the energy efficiency program administrator understand your company's interests and needs?

Neither the municipal electric utilities nor the gas companies have reached out to this company. The company has reached out to the appropriate administrators at various times to determine what incentives were available for specific projects.

At one location, the company has leveraged the amount offered annually for electric upgrades for many years. However, this only allows a small bit of lighting renovations to occur in a given year. The gas opportunities have been mostly tapped out using the amount available annually in incentives, which the company has leveraged 2 or 3 times. The company would renovate their entire campus if more electric incentives were available. They have an air handler that is 50 years old and a lot of lighting. This is a big space.

At another location, the company has not applied any rebates. The company looked at a cogeneration plant for this location, but abandoned the project after the site was temporarily closed. If the site comes back online, they would revisit efficiency opportunities.

The company has received one off rebates for specific equipment only; no technical support, audits or assessments have been provided by the PA.

Most of the company's energy efficiency activity has been in new construction, for which the company received no rebates. The company estimates they have achieved low savings to date for renovations/retrofits of existing equipment and space.

6. Did your company decide not to implement any efficiency measures that were offered through the energy efficiency programs?

No efficiency measures have been proactively offered. Of the measures the company has identified, all that were approved as economically sound were implemented.

7. Do you plan to participate in Massachusetts energy efficiency programs in the next three years?

The company could continue to replace lighting fixtures for the next 10 years using the incentive amount available annually to one of its locations.

The company anticipates participating in other ways too, but no projects have been proposed or approved for this timeframe yet. In Sept/Oct before the year in which measures would be implemented, proposals are submitted. In December, the capital funds that are available are known and allocated. There are at least three projects approved and in process for 2012, but none are in Massachusetts.

8. To what extent do budget limitations pose a barrier to your company's participation in energy efficiency programs?

If the payback is there, budget is likely not an issue.

9. To what extent do financing limitations pose a barrier to your company's participation in energy efficiency programs?

The company generates a lot of cash, so financing has not been considered. If the project were large enough, the company would consider a shared savings approach through a third party.

10. In general, how does the current state of the economy affect your interest and ability to participate in the energy efficiency programs?

[He can be quoted if it is anonymous, meaning Synapse cannot attribute this quote to the company or the interviewee]

"What it has caused is, it has caused us to want to spend less capital, spend less money to increase shareholder returns. So don't spend any money and maintain your existing clients and improve profitability at the same time somehow.

We are a public company and the impact of that cannot really be understated. We have to present numbers to shareholders quarterly, on a quarterly basis, and the big grand finale at the end of the year. And you know they are not so much concerned with, you know did you reduce your energy consumption. They are looking at the amount of impact you made in that quarter and that year on the profitability so in some cases we will even though you have something that pays for itself in 3 years, if the savings isn't going to be realized until year 4, then the climate might not be right with the downturn to implement all of the measures that we come up with."

The straight answer to the question is that economic downturns do slow down energy efficiency initiatives.

Barriers to Participation

A. Financial limits

Yes

B. Economic downturn

Yes

C. Customer awareness and marketing

Possibly – it is not clear whether increased communication from the PA to the company would result in more/deeper projects

D. Program design and administration

No

E. Corporate review and approval process

Yes, specifically competition with other projects on payback

F. Timing of program administrators

Yes, outreach should coincide with planning cycle

G. Company distrust of new technologies

Yes, somewhat. The company is wary that the full operational costs are often not represented correctly.

H. Company convinced it has done all it can.

No

I. Others

Other Comments

The interviewee stated that the biggest benefit of these programs has been to impact product development and manufacturing, that results in reduced cost of leading technologies. Provided one example of VFDs where cost was $50,000 and now is $5,000 due to program promotion/acceleration of this technology.

Survey of Commercial and Industrial Customer Perspectives of Massachusetts Energy Efficiency Programs

Interview Notes

Region: Central Massachusetts

Industry: Healthcare

Person(s) Interviewed: Facilities

Interview Number: 13

Key Questionnaire Responses

Note: question numbers correspond to the order in which questions are asked in the questionnaire.

4) Approximate number of company employees located in Massachusetts:

Greater than 50.

5) Building ownership:

Owned.

13) Annual electric costs as a percent of annual operating expenses:

Twenty percent or great.

15) Annual natural gas costs as a percent of annual operating expenses:

Between twenty and ten percent.

16) When purchasing new equipment, does your company consider the efficiency with which that equipment consumes energy?

Yes.

17) If the answer to question 16 is yes, what criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facility?

Internal rate of return; Payback period.

18) Prior to being contacted for this interview, were you aware of the energy efficiency programs offered by your electric and gas utilities?

Yes.

20) Has your company ever participated in the energy efficiency programs offered by your electric or gas utility?

Yes, within the past three years and prior to the past three years.

21) If your company has participated in the energy efficiency programs offered by your electric and gas utilities within the past three years:

Please name one or two things about the program that worked well for your company:

The reduction in energy consumption and the rebate check.

Please name one or two things about the program that did not work well for your company:

The paperwork required.

22) Based on your current knowledge of the efficiency programs offered by your electric and gas utilities, does your company plan to participate in these programs within the next three years?

Yes.

Predetermined Interview Questions

1. How important are energy costs to your company?

Energy costs are extremely important. The customer spends a large amount of its budget on electric and natural gas use.

2. Please describe the decision-making process that your company undertakes to decide whether to implement an energy efficiency measure.

If the measure has no cost, then it's implemented. If costs are required, the project needs to be approved by the capital planning department. The approval process can take a few weeks to a month depending on the numbers. It could take up to 6 months to implement a project after it has been approved. Combined with budget limitations, internal approval of a project is the customer's biggest barriers to efficiency participation. Efficiency projects are often turned down in favor of other projects more germane to the customer's core business.

Sometimes the person interviewed will try to work around the capital approval process. When equipment fails it becomes an emergency capital replacement project. The person interviewed is aware of equipment that could be perceived as an emergency replacement, and does the homework to find out what would be the most efficient replacement. Once the equipment fails, capital approval is received for the most efficient equipment. The customer pursues the utility rebate after the fact.

3. What criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facilities?

Return on investment is considered during the capital planning process. Capital approval usually requires a 2 year or less payback period. Whenever the customer replaces equipment they always look for the most efficient model.

4. Please explain why the company chose to participate in the Massachusetts energy efficiency programs.

The customer primarily participates for the bill/budget savings. The customer regularly installs or replaces lighting and HVAC related measures. The person interviewed is obligated to maintain a budget, the more energy efficient equipment that can be installed and automated cost controls, than the budget can be maintained better. By reducing the operational budget, the customer can spend more on other projects, both efficiency related and other facilities management projects.

5. How well did the representative of the energy efficiency program administrator understand your company's interests and needs?

The utility understands the customer very well. The customer has had no issues. The utility has been helpful and supportive and keeps the person interviewed well informed.

If the utility has something new to offer they will contact the customer. If the customer has an efficiency project it wants to do, then the person interviewed will contact the utility. The paperwork doesn't usually take that long, and it's not that bad of a process. The availability of money is beneficial because the customer has been paying into the state efficiency funds for years. The turnaround is pretty quick. The documentation isn't that hard to fill out; relatively straight forward.

6. Did your company decide not to implement any efficiency measures that were offered through the energy efficiency programs?

Only if the project does not receive capital approval internally.

7. Do you plan to participate in Massachusetts energy efficiency programs in the next three years?

The customer would like to participate going forward. No barriers from utility side. Only barrier would be getting capital approval.

8. To what extent do budget limitations pose a barrier to your company's participation in energy efficiency programs?

There is only a certain number of dollars that can go around. If a capital investment project is proposed that is more in line with the customer's core business, that project will likely receive funding over the efficiency project. Efficiency projects are often turned down because of the limited capital available. Have to spend dollars wisely to keep customer up-to-date on current technology.

9. To what extent do financing limitations pose a barrier to your company's participation in energy efficiency programs?

n/a

10. In general, how does the current state of the economy affect your interest and ability to participate in the energy efficiency programs?

The economic environment is causing the customer to require payback periods less than 2 years, which is the customer's normal payback standard.

The customer is in the healthcare industry, and is concerned about the effect of the political environment on its budget and planning. Specifically the customer is concerned about the reimbursements they will receive from Medicare or Patrick-care, Obamacare or whatever the next president will offer. The customer has concerns as to the amount of dollars that will be available for operations, expansion or new programs, and are getting much more frugal with money.

The customer has seen a reduction in inpatients and elective healthcare services that would normally generate revenue, which the person interviewed attributes to the economy and lack of spending. Elective surgeries such as cosmetic surgeries are not taking place. This could change once the economy gets better. Notably, pregnancies are down from previous years, which also decreases future projections of revenue. This is because if a baby is delivered at the customer's facilities, ultimately the baby is likely to become a user of the facilities due to the history and familiarity.

The customer has also seen an increase in emergency care services, especially for uninsured patients. If someone is out of a job and has used up any health benefits they may have, then they become uninsured and use emergency care as they would normally use a primary care provider. Because they are uninsured, the customer essentially gives away the medical services for free and is not likely to be reimbursed by the insurance company. The person interviewed thinks this will change as soon as unemployment decreases to 4-6 percent.

Barriers to Participation

A. Financial limits

Yes. Capital is tight and efficiency competes against projects that are more closely related to the customer's core business.

B. Economic downturn

Definitely.

C. Customer awareness and marketing

no

D. Program design and administration

no

E. Corporate review and approval process

Yes. Largest barrier for the customer.

F. Timing of program administrators

no

G. Customer distrust of new technologies

no

H. Customer convinced it has done all it can.

no

I. Others

Other Comments

Survey of Commercial and Industrial Customer Perspectives of Massachusetts Energy Efficiency Programs

Interview Notes

Region: Boston

Industry: Schools & Colleges

Person(s) Interviewed: n/a

Interview Number: 14

Key Questionnaire Responses

The Company did not provide the questionnaire.

Predetermined Interview Questions

1. How important are energy costs to your company?

Very important.

2. Please describe the decision-making process that your company undertakes to decide whether to implement an energy efficiency measure.

n/a

3. What criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facilities?

n/a

4. Please explain why the company chose to participate in the Massachusetts energy efficiency programs.

5. How well did the representative of the energy efficiency program administrator understand your company's interests and needs?

6. Did your company decide not to implement any efficiency measures that were offered through the energy efficiency programs?

n/a

7. Do you plan to participate in Massachusetts energy efficiency programs in the next three years?

Yes.

8. To what extent do budget limitations pose a barrier to your company's participation in energy efficiency programs?

9. To what extent do financing limitations pose a barrier to your company's participation in energy efficiency programs?

10. In general, how does the current state of the economy affect your interest and ability to participate in the energy efficiency programs?

For three years put little money into efficiency. Competing for funds in a bunch of other areas and efficiency is not a high priority for the Company. Anything that supports the main goal of the Company will receive funding before conservation. The Company recently received approval for an efficiency project, but for three years the Company didn't do anything.

Barriers to Participation

A. Financial limits

B. Economic downturn

Previously, yes. Uncertain going forward.

C. Customer awareness and marketing

D. Program design and administration

The real money seems to be on the retrofit side. It's much harder to get money on the new construction side than on the retrofit side and there is only a certain amount of that that you can do.

E. Corporate review and approval process

F. Timing of program administrators

G. Company distrust of new technologies

H. Company convinced it has done all it can.

I. Others

Large companies should be allowed to retain the amount they pay into state efficiency programs and use that money within their company only for efficiency purposes. On the gas side, companies don't pay into program and don't participate in programs and seems to work well. Companies don't get nearly as much money out of the program on the electric side as they put into it. It would be helpful if companies could retain the money. If there was a cap on the amount that could be used in total, perhaps the amount spent can't be greater than funds normally paid into the utility programs, it could be a reasonable constraint. Company feels forced to leave money on the table; money that could be used towards conservation.

On a universal basis, if a company can help the utilities meet their savings goals, there should be a simple reward that applies to everyone, perhaps a universal ratio of incentive dollars per savings achieved. Could get more people to jump on board because it's a simpler approach to participation. If a project has real savings but is too complicated like a behavioral based program, then it won't get done because it doesn't fit into the utilities programs. This could open up funding to more people.

Companies that have done all the low hanging fruit could receive higher incentives for the harder, more complicated projects. They need to be incented to do more, and meeting paybacks is difficult with more complex projects. The incentive could be based on a scale of previous projects, where the more you've done the more incentive you receive for a future project. Could be a difficult program to manage however.

There should be better transparency on the amount the utilities spend and save relative to the amounts they planned for.

Other Comments

Survey of Commercial and Industrial Customer Perspectives of Massachusetts Energy Efficiency Programs

Interview Notes

Region: Boston

Industry: Schools & Colleges

Person(s) Interviewed: Associate Director of Energy Supply and Utility Administration

Interview Number: 15

Key Questionnaire Responses

Note: question numbers correspond to the order in which questions are asked in the questionnaire.

4) Approximate number of company employees located in Massachusetts:

Greater than 50.

5) Building ownership:

Owned.

13) Annual electric costs as a percent of annual operating expenses:

Between five and one percent.

15) Annual natural gas costs as a percent of annual operating expenses:

Between five and one percent.

16) When purchasing new equipment, does your company consider the efficiency with which that equipment consumes energy?

Yes.

17) If the answer to question 16 is yes, what criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facility?

Internal rate of return; Payback period; Energy bill savings.

18) Prior to being contacted for this interview, were you aware of the energy efficiency programs offered by your electric and gas utilities?

Yes.

20) Has your company ever participated in the energy efficiency programs offered by your electric or gas utility?

Yes, within the past three years.

21) If your company has participated in the energy efficiency programs offered by your electric and gas utilities within the past three years:

Please name one or two things about the program that worked well for your company:

The rebates and technical assistance.

Please name one or two things about the program that did not work well for your company:

The process is not well defined. There is too much turn over in personnel. Utilities should not keep 100% of the FCM credit.

22) Based on your current knowledge of the efficiency programs offered by your electric and gas utilities, does your company plan to participate in these programs within the next three years?

Yes.

Predetermined Interview Questions

1. How important are energy costs to your company?

Very important.

2. Please describe the decision-making process that your company undertakes to decide whether to implement an energy efficiency measure.

n/a

3. What criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facilities?

n/a

4. Please explain why the company chose to participate in the Massachusetts energy efficiency programs.

5. How well did the representative of the energy efficiency program administrator understand your company's interests and needs?

The utilities are not very up to speed on new thing. It can take a long time for the them to come to grips with some of the possibilities of new products or projects. The person interviewed finds it very frustrating that behavioral programs are not well incorporated into utility programs. The utilities say they want to do behavioral things but there is really no reward for it. The customer has brought very clear behavioral programs to the utilities but it's been difficult to get anything going.

The utilities are not proactive enough on informing companies on how best to use money for efficiency and how can the utilities help in efficiency projects.

Utilities don't treat the customer like it knows anything. Most large companies are pretty sophisticated. It would be nice if the utilities treated them with that sophistication and understood that they're not babes in the woods.

6. Did your company decide not to implement any efficiency measures that were offered through the energy efficiency programs?

n/a

7. Do you plan to participate in Massachusetts energy efficiency programs in the next three years?

Yes.

8. To what extent do budget limitations pose a barrier to your company's participation in energy efficiency programs?

The person interviewed feels that utilities should cover more of the technical support costs.

9. To what extent do financing limitations pose a barrier to your company's participation in energy efficiency programs?

n/a

10. In general, how does the current state of the economy affect your interest and ability to participate in the energy efficiency programs?

It is important that there is enough money to support more efficient option all the time. If money is available, companies will do efficiency projects, but they have to be made aware that the money is available, and there has to be enough money so that it's worthwhile and won't take too much out of the customer's budget to participate.

Barriers to Participation

A. Financial limits

B. Economic downturn

C. Customer awareness and marketing

D. Program design and administration

Yes. The utilities are slow to adopt new projects or savings opportunities, and are not proactive enough in assisting companies in recognizing projects.

The person interviewed feels that utilities should cover more of the technical support costs.

E. Corporate review and approval process

F. Timing of program administrators

G. Customer distrust of new technologies

H. Customer convinced it has done all it can.

I. Others

Utilities don't treat the customer like it knows anything. Most large companies are pretty sophisticated. It would be nice if the utilities treated them with that sophistication and understood that they're not babes in the woods.

Other Comments

The customer strongly recommends the right to opt-out of efficiency programs. Large companies should be allowed to retain the amount they pay into state efficiency programs and use that money within their company only for efficiency purposes. MOUs help but do not address the problem. The customer would spend a lot on efficiency even if it didn't feel compelled to get the money back out of the programs that it put into it. Make it so that the customer gets to keep more of its money to spend on electricity savings.

Larger companies would benefit from FCM credits, and the person interviewed feels that the utility is stealing that money.

Survey of Commercial and Industrial Customer Perspectives of Massachusetts Energy Efficiency Programs

Interview Notes

Region: Boston

Industry: Healthcare

Person(s) Interviewed: Utilities Manager

Interview Number: 16

Key Questionnaire Responses

The Company did not provide the questionnaire.

Predetermined Interview Questions

1. How important are energy costs to your company?

Very important.

2. Please describe the decision-making process that your company undertakes to decide whether to implement an energy efficiency measure.

n/a

3. What criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facilities?

n/a

4. Please explain why the company chose to participate in the Massachusetts energy efficiency programs.

5. How well did the representative of the energy efficiency program administrator understand your company's interests and needs?

6. Did your company decide not to implement any efficiency measures that were offered through the energy efficiency programs?

n/a

7. Do you plan to participate in Massachusetts energy efficiency programs in the next three years?

Yes.

8. To what extent do budget limitations pose a barrier to your company's participation in energy efficiency programs?

When dealing with budget issues, money does not go to efficiency. Even easy projects with a 6 month payback can take time to convince management to participate.

9. To what extent do financing limitations pose a barrier to your company's participation in energy efficiency programs?

n/a

10. In general, how does the current state of the economy affect your interest and ability to participate in the energy efficiency programs?

Barriers to Participation

A. Financial limits

B. Economic downturn

C. Customer awareness and marketing

D. Program design and administration

The person interviewed recommended that the utilities should divide the amount of funding available by their MW or kWh goals as a way of allocating incentive dollars. Reward each kWh saved in the same way. Sometimes utilities can't fund a project because it doesn't meet the program requirements. If a company can't do a project with the utility's funding, it would be hard to convince that company to do any more efficiency if they were already turned down by the utility. If a company can prove that a project saved energy they should be rewarded with the incentive. Large companies should have incentives for being aggressive as it's getting harder and harder to find efficiency projects.

MOUs are not blind to other project requirements. It can be difficult and time consuming to document costs, such as behavioral or automation costs, although the savings can be well documented. If you can document savings clearly with the M&V protocols that utilities establish, then that should be the rule, not anything else involved in the project. If the Company saves an amount of kWh that meets the utilities' goals for the savings for that amount of money, then that money should just be paid out to the Company to make it easier. Buy the kWh the Company is saving, regardless of the cost to implement the efficiency savings. Requires a rigid way of documenting and measuring savings.

The person interviewed feels that utilities should cover more of the technical support costs.

E. Corporate review and approval process

F. Timing of program administrators

G. Company distrust of new technologies

H. Company convinced it has done all it can.

I. Others

Large companies should be allowed to retain the amount they pay into state efficiency programs and use that money within their company only for efficiency purposes. Companies can pay millions into the state efficiency funds without getting close to that back. Utilities should make it easier for companies to access that money. If businesses could keep the amount they pay into the state efficiency funds, they could avoid having to raise additional capital for efficiency projects. That would be the fairest way, people would look for projects, and projects would move faster.

Over the past 4 or 5 years, the Company has been pretty aggressive with energy conservation, and the person interviewed thinks they received back about 10% to 20% of what they put in, and they have been aggressive. Wondering where the other 80% of money is going and how it's being distributed. Not sure if what that 80% is used for offsets the savings that the Company would get if it had been allowed to use it for efficiency.

The low-hanging fruit is gone. As you get into more complex projects, payback and costs change dramatically.

There are rules in place that don't allow utilities to give money for certain projects. The regulators don't allow them to do certain things. The project has to meet certain metrics according to the regulator. Needs to be a policy change that makes the utility want to give you the money for efficiency projects.

The person interviewed does not like that FCM payments are not returned to the Company.

Other Comments

Survey of Commercial and Industrial Customer Perspectives of Massachusetts Energy Efficiency Programs

Interview Notes

Region: Boston

Industry: Schools & Colleges

Person(s) Interviewed: Energy Manager

Interview Number: 17

Key Questionnaire Responses

The Company did not provide the questionnaire.

Predetermined Interview Questions

1. How important are energy costs to your company?

Very important.

2. Please describe the decision-making process that your company undertakes to decide whether to implement an energy efficiency measure.

n/a

3. What criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facilities?

n/a

4. Please explain why the company chose to participate in the Massachusetts energy efficiency programs.

5. How well did the representative of the energy efficiency program administrator understand your company's interests and needs?

6. Did your company decide not to implement any efficiency measures that were offered through the energy efficiency programs?

n/a

7. Do you plan to participate in Massachusetts energy efficiency programs in the next three years?

Yes.

8. To what extent do budget limitations pose a barrier to your company's participation in energy efficiency programs?

9. To what extent do financing limitations pose a barrier to your company's participation in energy efficiency programs?

n/a

10. In general, how does the current state of the economy affect your interest and ability to participate in the energy efficiency programs?

The Company had a lot of new construction projects stopped because of the economic downturn, and so any efficiency associated with those projects obviously isn't happening anymore. Digging into existing facilities is more difficult, but the only place to spend money on efficiency at the moment. Such projects would probably have a better efficiency outcome though.

Barriers to Participation

A. Financial limits

B. Economic downturn

Yes. Less new construction.

C. Customer awareness and marketing

D. Program design and administration

New construction side is a tremendous amount of effort to try to coordinate the utility programs with the construction process and not get in the way of it. The reward in the end is not huge so you have to wonder if it was worth it

Anything that simplifies the process breaks down a barrier.

The person interviewed would like outside lighting to be incented more by the utilities. Outside lighting reductions don't work well in the utilities formulas because it's off peak load.

E. Corporate review and approval process

F. Timing of program administrators

Utilities have problems with scale. When the Company is ready to roll out a project and when the utility is ready to roll out a project it's not necessarily the same time. The utilities can't always be there to support a project and the Company needs to move forward with the project, so opportunities are missed. It doesn't always happen in the same timeframe that the programs are working within.

G. Company distrust of new technologies

H. Company convinced it has done all it can.

I. Others

Large companies should be allowed to retain the amount they pay into state efficiency programs and use that money within their company only for efficiency purposes. Company feels forced to leave money on the table because the Company has already done the easy stuff that the rebate programs are designed around. The Company has changed its light bulbs multiple times, but the next level of work is much more complex. If the Company could keep its efficiency money in house, it would be easy for the Company to make a commitment to only spending that money on efficiency projects.

Other Comments

Survey of Commercial and Industrial Customer Perspectives of Massachusetts Energy Efficiency Programs

Interview Notes

Region: Western Massachusetts

Industry: Heavy Industry

Person(s) Interviewed: Plant Superintendent

Interview Number: 18

Key Questionnaire Responses

Note: question numbers correspond to the order in which questions are asked in the questionnaire.

4) Approximate number of company employees located in Massachusetts:

20 to 50.

5) Building ownership:

Owned.

13) Annual electric costs as a percent of annual operating expenses:

Between five and one percent.

15) Annual natural gas costs as a percent of annual operating expenses:

One percent or less.

16) When purchasing new equipment, does your company consider the efficiency with which that equipment consumes energy?

n/a

17) If the answer to question 16 is yes, what criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facility?

The company has not specified criteria regarding efficiency measures.

18) Prior to being contacted for this interview, were you aware of the energy efficiency programs offered by your electric and gas utilities?

Yes,

20) Has your company ever participated in the energy efficiency programs offered by your electric or gas utility?

Yes, prior to the past three years.

21) If your company has participated in the energy efficiency programs offered by your electric and gas utilities within the past three years:

Please name one or two things about the program that worked well for your company:

We received money from {utility} for purchasing new energy efficient light fixtures

Please name one or two things about the program that did not work well for your company:

n/a

22) Based on your current knowledge of the efficiency programs offered by your electric and gas utilities, does your company plan to participate in these programs within the next three years?

Yes.

Predetermined Interview Questions

1. How important are energy costs to your company?

Very important.

2. Please describe the decision-making process that your company undertakes to decide whether to implement an energy efficiency measure.

The customer was recently purchased by a different parent company, and is still working through the new capital approval process. For projects that are large than $10,000, capital expenditure approval is required from the new parent company. The approval process takes about 8 to 10 weeks. Anything less than $10,000 the customer does not need capital approval.

3. What criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facilities?

The customer looks for a 2 to 2.5 year payback.

4. Please explain why the company chose to participate in the Massachusetts energy efficiency programs.

The customer primarily participates as a way to save money and to make the process simpler. The customer couldn't have done efficiency projects without the rebates offered by its utility.

Anytime equipment needs to be replaced, the customer looks for a more efficient model with newest technology available.

5. How well did the representative of the energy efficiency program administrator understand your company's interests and needs?

The utility company is easy to work with but could be more helpful. "They don't make the process as easy as they could." The customer first learned of efficiency opportunities through contractors that knew about the programs and not from the utility company. The customer heard of efficiency opportunities from three other sources before the utility called the person interviewed to say that they will pay him to change the lights.

The customer would prefer that the utility contact them directly, especially given the amount they pay into the state efficiency funds. "They send me a bill every month, you'd think they'd put on the bottom 'Hey you could save some money if you did this.' But with all those taxes and fees on the back there's probably no room on the same piece of paper."

The utility should "have someone come out to you facility and show you the potential you could have. To me it's pretty much a no brainer: they have endless amounts of money because all they have to do is raise the rate a penny and they pick up a half a million dollars a year. How simple is it to go out and see who's using the most electricity and say "Hey you guys are using a lot of electricity. Why don't we see if we can give you guys some help? Let's come into your place look around and see what we can do to save you money."

The person interviewed is attending a seminar hosted by its utility to learn more about efficiency opportunities.

The utility provided an audit and recommended lighting upgrades, including upgrades for more efficient exit signs. The person interviewed did homework on pricing for lighting contractors and then went to the utility for the rebate. Contractors charge different rates for bulbs and installations, so the person interviewed shopped around for the best rate from a contractors. The customer also had an audit for its air compressor system.

6. Did your company decide not to implement any efficiency measures that were offered through the energy efficiency programs?

7. Do you plan to participate in Massachusetts energy efficiency programs in the next three years?

Yes. The customer planned to undergo a lighting upgrade last year, but the project was stalled because of the corporate restructuring and new ownership (see question 2). The project was approved by the last parent company, so the person interviewed doesn't see why the project would not receive approval from the new parent company, especially because the new company has a more "green" focus.

The customer also plans to participate so that it can upgrade aging equipment, and so that the customer can be more cost-efficient. The person interviewed has been looking into such projects.

8. To what extent do budget limitations pose a barrier to your company's participation in energy efficiency programs?

At the moment the person interviewed does not see budgets posing a barrier, although with the new ownership it is uncertain.

9. To what extent do financing limitations pose a barrier to your company's participation in energy efficiency programs?

10. In general, how does the current state of the economy affect your interest and ability to participate in the energy efficiency programs?

The previous parent company had troubles with the economy, and the person interviewed is uncertain about the new parent company. "The economy itself is not good. We're extremely slow right now. I'm laying people off tomorrow because there isn't enough work for them. There's no sense bringing them in and turning the lights on if I can't make enough money to pay for it."

Energy efficiency is seen as an opportunity to save money, so long as the payback is high, such as lighting. "When times are slow you have to cut back spending every place you can. Spending a few dollars to put in new light fixtures which is going to save us thousands of dollars over the long run makes sense to do it. It helps the environment and it helps your costs. It's a no brainer."

The customer changed its lighting in the 1990s when the economy was affecting the customer's business and it had to stay competitive. The customer is changing out its lighting again to remain competitive still.

About three years ago the customer condensed its operations into half of its building facilities and the other half is vacant. This does not eliminate processes or production potential. This was done solely to save on utilities. The customer has shut down the water to that side of the building except for sprinklers, turned off the lights, and keeps the heat down to a minimum so the pipes don't freezing. The customer has tried to rent out the other half of its facilities but has not been successful.

Barriers to Participation

A. Customer Barriers

a. Financial limits

b. Budget limits

Potentially – depends on new corporate structure.

c. Economic downturn

Yes. customer has been downsizing but efficiency is seen as something that can help with the down economy.

d. Corporate review and approval process

Potentially, but unlikely.

e. customer distrust of new technologies

f. customer convinced it has done all it can

No.

B. Program Design & Administration Barriers

a. Insufficient incentives

No – the more the better.

b. Insufficient marketing and outreach

Strong yes. The customer would like for the utility to be much more proactive about identifying and promoting efficiency.

c. Transaction costs

d. Responsiveness and timing

Not really.

e. Limited measures offered

No.

f. Policy Issues (Opt out of SBC)

Yes – "I'll never figure out any of these utilities' billing. When I have to pay more for electricity to come here than I actually use, it makes no sense to me. There's more taxes on these damn things."

g. Other (note)

Other Comments

Survey of Commercial and Industrial Customer Perspectives of Massachusetts Energy Efficiency Programs

Interview Notes

Region: Central Massachusetts

Industry: Retail

Person(s) Interviewed: Manager of Utility and Energy Services

Interview Number: 19

Key Questionnaire Responses

Note: question numbers correspond to the order in which questions are asked in the questionnaire.

4) Approximate number of company employees located in Massachusetts:

Greater than 50.

5) Building ownership:

Leased.

13) Annual electric costs as a percent of annual operating expenses:

One percent or less.

15) Annual natural gas costs as a percent of annual operating expenses:

Between one and five percent.

16) When purchasing new equipment, does your company consider the efficiency with which that equipment consumes energy?

Yes.

17) If the answer to question 16 is yes, what criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facility?

Internal rate of return; Payback period; Other.

18) Prior to being contacted for this interview, were you aware of the energy efficiency programs offered by your electric and gas utilities?

Yes.

20) Has your company ever participated in the energy efficiency programs offered by your electric or gas utility?

Yes, within the past three years.

Yes, prior to the past three years.

21) If your company has participated in the energy efficiency programs offered by your electric and gas utilities within the past three years:

Please name one or two things about the program that worked well for your company:

We like the concept of the Upstream Program. It shows that the utilities are trying to help their customers get incentive dollars without having to submit a lot of paperwork.

Please name one or two things about the program that did not work well for your company:

There is little or no flexibility reemerging technologies and the DLC list that many of the utilities use to determine of the product qualifies for rebates. There should be some flexibility that allows the utility or the vendor to get the product approved for a rebate when there is a minor difference such as color temperature.

Finally, the company has changed the way our stores are constructed. We have gone from actually owning the building to "build to suit." The developer ultimately owns the building but is buying the energy efficient equipment according to the company's specifications. With these types of projects, it is very difficult to get the necessary documentation (such as invoices) from the developer to show the utility what is actually installed. Since build to suit projects are becoming more common the utilities need to come up with a better system to make it easier to get incentive dollars.

22) Based on your current knowledge of the efficiency programs offered by your electric and gas utilities, does your company plan to participate in these programs within the next three years?

Yes.

Predetermined Interview Questions

1. How important are energy costs to your company?

Very important. They have a staff of four full-time people managing energy costs; for 200 stores, including some office buildings.

They build six to twelve new stores per year.

2. Please describe the decision-making process that your company undertakes to decide whether to implement an energy efficiency measure.

The energy management team oversees all the procurement and energy needs. "If they can find an EE measure, they will adopt it."

3. What criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facilities?

They are always looking for ways to reduce their energy bills.

Their decision-making process on how deep to go has evolved over the past five years. It used to be that they would focus on lighting, and it would need a payback period of two years or less. Now with LEDs with long lives and O&M savings they have stretched out the payback period. They have seen their light O&M bills drop significantly with LEDs.

For deeper retrofits, beyond lighting, they might adopt measures with paybacks of longer than two years.

Their standard lease for new buildings is 20 years, it used to be six years. This is very long for a retailer. This long-term perspective carries over to their EE investment perspective.

4. Please explain why the company chose to participate in the Massachusetts energy efficiency programs.

Not asked.

5. How well did the representative of the energy efficiency program administrator understand your company's interests and needs?

They have had mixed experience. "It all comes down to the personnel."

One of the electric companies used to be really good. Now they have been less responsive with new personnel.

Another one of the electric companies used to be "horrendous," but have recently been much better.

The PAs should be more pro-active in helping with the paperwork.

In general, the PAs have been more supportive in the past; where the applications were filled out in advance and they (the customer) "just had to sign the forms."

If they only have one account rep, then that rep is likely to be a bottleneck to the process.

6. Did your company decide not to implement any efficiency measures that were offered through the energy efficiency programs?

No, they have the opposite problem. They would like to get rebates for efficiency measures that are not offered by the programs.

7. Do you plan to participate in Massachusetts energy efficiency programs in the next three years?

Yes, they want to get as much financial support as they can get. They want to get refunds that are closed to the amount of money that they contribute to the efficiency programs.

8. To what extent do budget limitations pose a barrier to your company's participation in energy efficiency programs?

This is not a limitation for them.

9. To what extent do financing limitations pose a barrier to your company's participation in energy efficiency programs?

This is not a barrier for them.

10. In general, how does the current state of the economy affect your interest and ability to participate in the energy efficiency programs?

This was never mentioned as a barrier for them.

Barriers to Participation

A. Customer Barriers

a. Financial limits

No.

b. Budget limits

No.

c. Economic downturn

No.

d. Corporate review and approval process

No.

e. Company distrust of new technologies

No.

f. Company convinced it has done all it can

No.

B. Program Design & Administration Barriers

a. Insufficient incentives

Yes. They would like to see incentives available for a much broader range of efficiency measures.

b. Insufficient marketing and outreach

Yes. They would prefer more pro-active engagement from the PAs.

They do not hear much from gas companies and do very little gas efficiency.

c. Transaction costs

Yes. Paperwork and invoices. One of the biggest barriers.

d. Responsiveness and timing

Yes. One of the biggest barriers.

e. Limited measures offered

Yes. The PAs should be more on top of emerging technologies.

f. Policy Issues (Opt out of SBC)

Mentioned briefly.

g. Other (note)

The DLC list is too confining, cumbersome and slow. See below.

Other Comments

The three biggest issues for this company are (1) the programs do not sufficiently support emerging technologies, (2) the application process is too cumbersome and should be streamlined, and (3) the new building program requires a new application for each new building even though the build many that are exactly alike.

This company has several stories of how the programs were too slow and burdensome in approving new technologies – technologies that were clearly highly energy efficient. They are especially frustrated with the Design Lights Consortium (DLC) list, and the time it takes to get new products on the list.

- When they moved to a new building they had an immediate need for new LED floodlights. They put a lot of work into finding the right fixture, but the one they needed was not on the DLC list, due to the color temperature.
- They also needed 3,500 LEDs to go from 50W to 9W, but they were not on the DLC list because they were not directional.
- They gave a manufacturer a set of specs for a specific LED lights, they got what they wanted, a great design, but it took six to twelve months to get it approved for rebates.
- The products change every month, but it takes much longer for the DLC list to be updated to reflect new products.
- In the time it takes a manufacturer to get on the DLC their product can be out of date. Three-quarters of measures on the DLC is out of date and no longer available.
- One of the specs on the DLC was in error.
- DLC is a regional / national list – the MA program administrators could go beyond what is on the list, but they do not.
- They have seen a similar problem with upstream measures.

They are trying to be more progressive and pro-active, but they feel like they “get slapped” by the programs.

They put in lots of LED in their parking lots and expected to get paid $40k, according to the program offerings, but were only paid $20k.

They make energy efficiency decisions for their entire chain, which extends well beyond Massachusetts. They make decisions about what to purchase regardless of whether they will be getting rebates. They also did a lot of lighting upgrades to their office building without any rebates.

- However, they can do more efficiency investments with the funds provided by the rebates.
- Also, there often is a lot of deeper efficiency measures that they could adopt but that they do not adopt because of the paperwork necessary for the rebates.

They build a lot of new buildings, and they are all alike; cookie-cutter. But every time they want to get rebates from the new construction program they have to re-apply from scratch. They often don’t bother. Also, they typically lease the buildings and pay the energy bills. They don’t bother to apply for the NC program because of the paperwork, and because they have to chase the builder down for all the invoices. It is not worth it. They do not know if the builder goes after the NC program rebates.

Their experiences in New York and New Jersey have been even worse, because those programs are run by the government.

In general they applaud what the states are doing on energy efficiency, and want to be a part of it.

They are investing in a lot of roof-top PV. However, all of it is through PPAs with private companies; they just get a bill reduction. None of this is through the energy efficiency programs.

Survey of Commercial and Industrial Customer Perspectives of Massachusetts Energy Efficiency Programs

Interview Notes

Region: Central Massachusetts

Industry: Office

Person(s) Interviewed: Project Manager

Interview Number: 20

Key Questionnaire Responses

Note: question numbers correspond to the order in which questions are asked in the questionnaire.

4) Approximate number of company employees located in Massachusetts:

Not provided.

5) Building ownership:

Owned.

13) Annual electric costs as a percent of annual operating expenses:

Not provided.

15) Annual natural gas costs as a percent of annual operating expenses:

Not provided.

16) When purchasing new equipment, does your company consider the efficiency with which that equipment consumes energy?

Yes.

17) If the answer to question 16 is yes, what criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facility?

Internal rate of return, payback period, benefit-cost ratio, energy bill savings, but mostly whether the incentives are there and energy bill savings.

18) Prior to being contacted for this interview, were you aware of the energy efficiency programs offered by your electric and gas utilities?

Yes.

20) Has your company ever participated in the energy efficiency programs offered by your electric or gas utility?

Yes, within the past three years and yes, prior to the past three years.

21) If your company has participated in the energy efficiency programs offered by your electric and gas utilities within the past three years:

Please name one or two things about the program that worked well for your company:

Not provided.

Please name one or two things about the program that did not work well for your company:

Not provided.

22) Based on your current knowledge of the efficiency programs offered by your electric and gas utilities, does your company plan to participate in these programs within the next three years?

Yes.

Predetermined Interview Questions

1. How important are energy costs to your company?

Very important. They are a small company, so energy expenditures immediately affect expenses. They are always looking to streamline manpower and energy.

2. Please describe the decision-making process that your company undertakes to decide whether to implement an energy efficiency measure.

When new tenants trigger a retrofit, or a tenant space opens up and allows for upgrades, the company typically contacts the utility with ideas and to see if there are incentives for those projects. If so, the interviewee discusses the opportunity with the property manager and they make the decision.

3. What criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facilities?

The company does not have a threshold for savings or payback. They evaluate the merits of energy efficiency project by project and implement energy efficiency as it makes sense.

4. Please explain why the company chose to participate in the Massachusetts energy efficiency programs.

The company trusts the utilities guidance on energy efficiency products and services.

5. How well did the representative of the energy efficiency program administrator understand your company's interests and needs?

The company's relationship with their gas provider is new, but they were very satisfied with the process. They recently converted from oil to gas and received incentives towards a new gas boiler. They said their rep was excellent and eager to help.

The company's relationship with their electric provider has been ongoing for at least 7 years. They have been happy with the relationship until recently. Recently, they have been experiencing an issue that is straining this relationship. The electric provider has hired a third party as a go between the company and electric provider. This third party is responsible for assisting with the application process and answering the company's questions. The company does not trust this third party as they suspect there is some incentive involved for the third party and also is concerned that this duplication of effort is costing additional money that is being charged to ratepayers, including themselves.

6. Did your company decide not to implement any efficiency measures that were offered through the energy efficiency programs?

No. The electric provider did a technical assessment of the building and did not recommend anything outside of lighting to the company. They have cooling towers and HVAC systems. The company has mostly focused on lighting opportunities and has been transitioning to new lighting over the past 10-13 years. Their building was built in the late 1800s and is on the historical registrar which limits opportunities somewhat. They are interested in doing window replacements, but there isn't currently an incentive for this so they probably won't get done.

7. Do you plan to participate in Massachusetts energy efficiency programs in the next three years?

Yes, every step the company takes affects long run expenses. Even though they must do this in a phased approach, eventually they will get to it all.

8. To what extent do budget limitations pose a barrier to your company's participation in energy efficiency programs?

Tenant fit outs, when expensive, compete with dollars for EE. But usually, they have enough capital to do what needs to get done. Fortunately they have remained busy/full. However, this takes away from their ability to do as much EE as they could be doing. They evaluate opportunities on a year by year basis.

9. To what extent do financing limitations pose a barrier to your company's participation in energy efficiency programs?

They haven't financed any projects to date. They typically have the cash on hand to cover it. However, they would consider financing if they find cost effective savings.

10. In general, how does the current state of the economy affect your interest and ability to participate in the energy efficiency programs?

[the interviewee has granted Synapse permission to quote her]

"With this economy a lot of businesses have a hard time."

"Because we have tenants that have a difficult time, which means they have a difficult time paying the rent and so forth, it does somewhat affect us. Without the income it is hard to carry the expense side of the building, so at times you find, when things are bad, you are taking care of the most necessary and not doing as many improvements as you would like to. We've been fortunate enough where our tenant base has not been as bad as it could be. We have a lot of state tenants in our building, because they are large and here for large periods of time it helps out our expenses, our income so that when the smaller tenants because all of the spaces are rented to different businesses."

They found that mortgage brokers and attorneys specifically went through hard times, and it impacted the company.

Barriers to Participation

A. Financial limits

No

B. Economic downturn

Not really

C. Customer awareness and marketing

Yes, to the extent that there are other opportunities other than lighting that could be addressed.

D. Program design and administration

No

E. Corporate review and approval process

No

F. Timing of program administrators

No

G. Company distrust of new technologies

No

H. Company convinced it has done all it can.

Partly. The company knows it has more to do, but does not seem to be aware that they could be going much deeper than they are today.

I. Others

Other Comments

The company has saved 5% of its energy costs by implementing efficiency measures until this year. They expect greater savings moving forward from their oil to gas conversion project.

The company met with a company recently to set up sustainability goals but no action has been taken at this time. The company considers itself to be very environmentally conscious (i.e., they recycle lighting, electronics).

Survey of Commercial and Industrial Customer Perspectives of Massachusetts Energy Efficiency Programs

Interview Notes

Region: Boston

Industry: Healthcare

Person(s) Interviewed: VP Property Management

Interview Number: 21

Key Questionnaire Responses

Note: question numbers correspond to the order in which questions are asked in the questionnaire.

4) Approximate number of company employees located in Massachusetts:

Greater than 50.

5) Building ownership:

Leased.

13) Annual electric costs as a percent of annual operating expenses:

Twenty percent or greater.

15) Annual natural gas costs as a percent of annual operating expenses:

Between ten and five percent.

16) When purchasing new equipment, does your company consider the efficiency with which that equipment consumes energy?

Yes.

17) If the answer to question 16 is yes, what criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facility?

Payback period and energy bill savings.

18) Prior to being contacted for this interview, were you aware of the energy efficiency programs offered by your electric and gas utilities?

Yes.

20) Has your company ever participated in the energy efficiency programs offered by your electric or gas utility?

Yes, within the past three years.

21) If your company has participated in the energy efficiency programs offered by your electric and gas utilities within the past three years:

Please name one or two things about the program that worked well for your company:

No cash upfront, the ability to pay through savings.

Please name one or two things about the program that did not work well for your company:

Not indicated.

22) Based on your current knowledge of the efficiency programs offered by your electric and gas utilities, does your company plan to participate in these programs within the next three years?

Maybe.

Predetermined Interview Questions

1. How important are energy costs to your company?

High importance. The fact that all buildings in MA are leased has not raised any limitations as all parties benefit from efficiency; the company is responsible for all utility costs and the building owners also see the benefit of having new equipment and more efficient equipment.

2. Please describe the decision-making process that your company undertakes to decide whether to implement an energy efficiency measure.

The interviewee drives the process. He makes a proposal to the CFO including capital costs, payback analysis, and what rebates are available. If the capital and payback are there the interviewee gets approval. The company will only consider projects with a payback of three years or less. Energy efficiency competes with patient care and other infrastructure upgrades for capital. Once approval is given, the interviewee manages the process by working with maintenance directors on site and hiring contractors to do the work.

Over the past 5 years, the interviewee has upgraded 10 facilities and done 1-2 projects per year. The projects they have pursued include lighting upgrades, boiler replacements, domestic hot water, kitchen appliances, and cogeneration.

3. What criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facilities?

A payback period of 3 years or less is the primary criteria.

4. Please explain why the company chose to participate in the Massachusetts energy efficiency programs.

Reduced costs. Utility costs come directly out of the bottom line.

5. How well did the representative of the energy efficiency program administrator understand your company's interests and needs?

The program administrators do reach out, but the company generally drives the process.

The interviewee feels that the program administrators don't understand health care at all. An assessment was conducted that 1) identified projects that had already been implemented 2) identified measures that are not able to be implemented in a healthcare environment (i.e., occupancy sensors and programmable thermostats with set back) and 3) did not identify opportunities that the company was interested in (the assessment focused entirely on short term quick fixes and ignored projects with larger capital outlays). They look at lighting in healthcare the same as for an office building which doesn't work.

The company believes the ideal program would be a no capital outlay, pay as you save program and wants the utility to offer this. They feel that 100% of customers would participate if this program were available. A third party company has approached the company with proposals of this nature, but the company finds that ESCOs are too focused on energy management systems for lighting and space heating and cooling that don't work well for healthcare. Also, the company is required by EPA to have a certain number of air changes, which limit opportunities for air sealing improvements.

6. Did your company decide not to implement any efficiency measures that were offered through the energy efficiency programs?

The company did not implement the recommended measures from the assessment, but has implemented measures that it has identified on its own.

7. Do you plan to participate in Massachusetts energy efficiency programs in the next three years?

Maybe. Future opportunities include more boiler replacements, domestic hot water opportunities, and rooftop unit retrofits. However, the company's capital is constrained by government action which is difficult to plan for.

8. To what extent do budget limitations pose a barrier to your company's participation in energy efficiency programs?

This is a key issue for health care. Revenue streams are restricted (i.e., Medicare/Medicaid) and at the whim of the government. The rate cuts have impacted them greatly. The company has a forward looking 5 year capital plan that is reviewed on an annual basis.

9. To what extent do financing limitations pose a barrier to your company's participation in energy efficiency programs?

They have looked at financing both in terms of leasing equipment and financing equipment replacement, but the interest rates were too high (i.e., 8-9%) to bring the payback to below three years. They would do much more if there was low interest financing with an interest rate of 2-4%. They feel that if a well-designed financing program were available that many customers would take advantage of it.

"If there was a program out there that had low interest for some of these capital projects I'm willing to bet you more and more people would take advantage of it because it makes a lot of sense and not just in my industry but in a lot of industries. This equipment is expensive."

For example, the company looked at cogeneration which met the 2-3 year payback requirement, but required a $1M capital outlay that they couldn't afford. The financing pushed the payback out of their comfort zone.

10. In general, how does the current state of the economy affect your interest and ability to participate in the energy efficiency programs?

[interviewee has granted Synapse permission to quote him on this]

"It has dramatically hurt us. The rate cuts on Medicaid and Medicare have really put a strain on our revenue. You put a strain on the revenue, you can't turn around and take that revenue and put it into what some would deem discretionary projects. You know, we like to replace things before they break at the end of their expected useful life. But that's a luxury, not a necessity. So, you know, we end up having to replace when we have to replace and then a lot of times you just don't have the time to go through the process of seeking out energy rebates, you got to try to do it after the fact. And, after the fact you are not always successful."

Barriers to Participation

A. Financial limits

Yes.

B. Economic downturn

Yes.

C. Customer awareness and marketing

No.

D. Program design and administration

No.

E. Corporate review and approval process

No.

F. Timing of program administrators

No.

G. Company distrust of new technologies

No.

H. Company convinced it has done all it can.

No.

I. Others

Other Comments

The company has seen its utility cost decrease 40% over the past 3 years due to a combination of a unique natural gas commodity purchasing arrangement with an energy supply company, energy efficiency, and a reduction in heating and cooling degree days. The company estimates that 5% of this reduction is due to its efforts on energy efficiency.

Survey of Commercial and Industrial Customer Perspectives of Massachusetts Energy Efficiency Programs

Interview Notes

Region: Western Massachusetts

Industry: Heavy Industry

Person(s) Interviewed: President

Interview Number: 22

Key Questionnaire Responses

Note: question numbers correspond to the order in which questions are asked in the questionnaire.

This company did not complete a questionnaire. The information below was obtained through the interview.

4) Approximate number of company employees located in Massachusetts:

NA.

5) Building ownership:

NA.

13) Annual electric costs as a percent of annual operating expenses:

Between one and ten percent.

15) Annual natural gas costs as a percent of annual operating expenses:

Between one and five percent.

16) When purchasing new equipment, does your company consider the efficiency with which that equipment consumes energy?

Yes. It is an important issue.

17) If the answer to question 16 is yes, what criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facility?

The capital costs required and the project ROI relative to other uses of that capital.

18) Prior to being contacted for this interview, were you aware of the energy efficiency programs offered by your electric and gas utilities?

Yes.

20) Has your company ever participated in the energy efficiency programs offered by your electric or gas utility?

Yes, within the past three years.

Yes, prior to the past three years.

21) If your company has participated in the energy efficiency programs offered by your electric and gas utilities within the past three years:

Please name one or two things about the program that worked well for your company:

NA

Please name one or two things about the program that did not work well for your company:

NA

22) Based on your current knowledge of the efficiency programs offered by your electric and gas utilities, does your company plan to participate in these programs within the next three years?

Yes.

Predetermined Interview Questions

1. How important are energy costs to your company?

Very important.

2. Please describe the decision-making process that your company undertakes to decide whether to implement an energy efficiency measure.

She makes the decisions, and has wide latitude to undertake EE investments.

3. What criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facilities?

Based on the use of capital, and project ROI. They do not have a problem getting access to capital, because of the size and nature of their company. However, competition for capital is the big question for them – if they can get a better ROI on a different capital project, they will forgo the EE project.

They have competing capital projects, some with great ROIs.

They use a payback criterion of three to five years for EE projects. However, their own projects have much shorter payback periods.

4. Please explain why the company chose to participate in the Massachusetts energy efficiency programs.

Reduce energy costs.

5. How well did the representative of the energy efficiency program administrator understand your company's interests and needs?

The electric company account manager does fairly well. However, it seems like the problem occurs "behind" them, i.e., they do not have enough support from the rest of the electric company.

They see very little of the gas company account representatives.

6. Did your company decide not to implement any efficiency measures that were offered through the energy efficiency programs?

Yes, due to competition for capital for other projects.

7. Do you plan to participate in Massachusetts energy efficiency programs in the next three years?

Yes. They want to do more projects, but the program administrators need to make it easier with more real-time commitments to projects and higher funding levels to help address the competition for capital.

8. To what extent do budget limitations pose a barrier to your company's participation in energy efficiency programs?

Not really. The issue is competition for capital.

9. To what extent do financing limitations pose a barrier to your company's participation in energy efficiency programs?

Again, the primary barrier for them is competition for capital. They have no shortage of capital opportunities that compete for the capital that is required for the EE projects.

10. In general, how does the current state of the economy affect your interest and ability to participate in the energy efficiency programs?

The economy is not an issue for them.

Barriers to Participation

A. Customer Barriers

a. Financial limits

Yes, in terms of competition for capital

b. Budget limits

No.

c. Economic downturn

No.

d. Corporate review and approval process

No.

e. Company distrust of new technologies

No.

f. Company convinced it has done all it can

No.

B. Program Design & Administration Barriers

a. Insufficient incentives

Yes. This is an important issue as it would address the competition for capital.

b. Insufficient marketing and outreach

No for electric program administrators. Yes for gas program administrators.

c. Transaction costs

Yes.

d. Responsiveness and timing

Yes.

e. Limited measures offered

No.

f. Policy Issues (Opt out of SBC)

Yes. They believe they should be able to opt-out and use the money more efficiently on their own EE.

g. Other (note)

Other Comments

They could utilize the EE programs much more.

They have done many projects and never seem to get the full 50 percent of rebates. It always turns out to be less.

They are not provided with good information, for example regarding payback periods.

They see energy as a whole; electric, gas, oil, etc. They did a study of a CHP project. The payback period turned out to be seven years, even with the incentive from the program. They were uncertain that they would actually get the incentive, which turned them off. They chose to replace the oil boiler with gas, but not to install CHP.

There is too much paperwork. It took them over two years to get a rebate for an EE project, primarily because of the need for data and measurements.

The programs should be less bureaucratic. Contracts must go through legal review with the customer's legal team. This slows things down on their end.

Their gas company has been terrible in outreach. They have not heard from them at all, even though they have lots of gas end-uses.

There is inefficiency in the communication with the account reps. There needs to be more information up front.

The amount of the incentive offered by the program administrators must be clear up front, and the program administrators must follow through and make the payments offered.

Participating customers should get a portion of the shareholder incentives that the program administrators get.

Survey of Commercial and Industrial Customer Perspectives of Massachusetts Energy Efficiency Programs

Interview Notes

Region: Western Massachusetts

Industry: Heavy Industry

Person(s) Interviewed: Manager of Environmental Affairs

Interview Number: 23

Key Questionnaire Responses

Note: question numbers correspond to the order in which questions are asked in the questionnaire.

This company did not complete a questionnaire. The information below was obtained through the interview.

4) Approximate number of company employees located in Massachusetts:

Greater than 50. They also have facilities globally.

5) Building ownership:

NA.

13) Annual electric costs as a percent of annual operating expenses:

Between one and ten percent.

15) Annual natural gas costs as a percent of annual operating expenses:

Between one and five percent.

16) When purchasing new equipment, does your company consider the efficiency with which that equipment consumes energy?

Yes. It is an important issue.

17) If the answer to question 16 is yes, what criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facility?

The capital costs required and the project ROI relative to other uses of that capital.

18) Prior to being contacted for this interview, were you aware of the energy efficiency programs offered by your electric and gas utilities?

Yes.

20) Has your company ever participated in the energy efficiency programs offered by your electric or gas utility?

Yes, within the past three years.

Yes, prior to the past three years.

21) If your company has participated in the energy efficiency programs offered by your electric and gas utilities within the past three years:

Please name one or two things about the program that worked well for your company:

NA

Please name one or two things about the program that did not work well for your company:

NA

22) Based on your current knowledge of the efficiency programs offered by your electric and gas utilities, does your company plan to participate in these programs within the next three years?

Yes.

Predetermined Interview Questions

1. How important are energy costs to your company?

Very important.

2. Please describe the decision-making process that your company undertakes to decide whether to implement an energy efficiency measure.

They have wide latitude to undertake EE investments. See below.

However, their finance executives take a macro view to all this. They want to see the bills going down, but they continue to go up despite their EE investments. While it is true that they are better off with the EE, this is still a very big issue at the corporate executive level. They need to see the data to convince them that EE makes sense for them.

3. What criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facilities?

Based on the use of capital, and project ROI. They do not have a problem getting access to capital, because of the size and nature of their company. However, competition for capital is the big question for them – if they can get a better ROI on a different capital project, they will forgo the EE project.

They have many competing capital projects, some with great ROIs.

They see environmental benefits of the EE programs, but they are small. It is better to show a reduced environmental footprint from their own operations.

They do want to be good corporate citizens, but they can only do so many “feel good” projects.

4. Please explain why the company chose to participate in the Massachusetts energy efficiency programs.

Reduce energy costs.

5. How well did the representative of the energy efficiency program administrator understand your company’s interests and needs?

They see very little of the gas company account representatives.

6. Did your company decide not to implement any efficiency measures that were offered through the energy efficiency programs?

Yes, due to competition for capital for other projects.

7. Do you plan to participate in Massachusetts energy efficiency programs in the next three years?

Yes. They want to do more projects, but the program administrators need to make it easier with more real-time commitments to projects and higher funding levels to help address the competition for capital.

8. To what extent do budget limitations pose a barrier to your company's participation in energy efficiency programs?

Not really. The issue is competition for capital.

9. To what extent do financing limitations pose a barrier to your company's participation in energy efficiency programs?

Again, the primary barrier for them is competition for capital. They have no shortage of capital opportunities that compete for the capital that is required for the EE projects.

10. In general, how does the current state of the economy affect your interest and ability to participate in the energy efficiency programs?

The economy is not an issue for them.

Barriers to Participation

A. Customer Barriers

a. Financial limits

Yes, in terms of competition for capital

b. Budget limits

No.

c. Economic downturn

No.

d. Corporate review and approval process

Limited.

e. Company distrust of new technologies

No.

f. Company convinced it has done all it can

No.

B. Program Design & Administration Barriers

a. Insufficient incentives

Yes. This is an important issue as it would address the competition for capital.

b. Insufficient marketing and outreach

No for electric program administrators. Yes for gas program administrators.

c. Transaction costs

Yes.

d. Responsiveness and timing

Yes.

e. Limited measures offered

No.

f. Policy Issues (Opt out of SBC)

Yes. They believe they should be able to opt-out and use the money more efficiently on their own EE.

g. Other (note)

Other Comments

None.

Survey of Commercial and Industrial Customer Perspectives of Massachusetts Energy Efficiency Programs

Interview Notes

Region: Western Massachusetts

Industry: Heavy Industry

Person(s) Interviewed: Manager of Engineering

Interview Number: 24

Key Questionnaire Responses

Note: question numbers correspond to the order in which questions are asked in the questionnaire.

This company did not complete a questionnaire. The information below was obtained through the interview.

4) Approximate number of company employees located in Massachusetts:

Greater than 50. They also have facilities globally.

5) Building ownership:

NA.

13) Annual electric costs as a percent of annual operating expenses:

Between one and ten percent.

15) Annual natural gas costs as a percent of annual operating expenses:

Between one and five percent.

16) When purchasing new equipment, does your company consider the efficiency with which that equipment consumes energy?

Yes. It is an important issue.

17) If the answer to question 16 is yes, what criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facility?

The capital costs required and the project ROI relative to other uses of that capital.

18) Prior to being contacted for this interview, were you aware of the energy efficiency programs offered by your electric and gas utilities?

Yes.

20) Has your company ever participated in the energy efficiency programs offered by your electric or gas utility?

Yes, within the past three years.

Yes, prior to the past three years.

21) If your company has participated in the energy efficiency programs offered by your electric and gas utilities within the past three years:

Please name one or two things about the program that worked well for your company:

NA

Please name one or two things about the program that did not work well for your company:

NA

22) Based on your current knowledge of the efficiency programs offered by your electric and gas utilities, does your company plan to participate in these programs within the next three years?

Yes.

Predetermined Interview Questions

1. How important are energy costs to your company?

Very important.

2. Please describe the decision-making process that your company undertakes to decide whether to implement an energy efficiency measure.

They have wide latitude to undertake EE investments. See below.

However, their finance executives take a macro view to all this. They want to see the bills going down, but they continue to go up despite their EE investments. While it is true that they are better off with the EE, this is still a very big issue at the corporate executive level.

3. What criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facilities?

Based on the use of capital, and project ROI. They do not have a problem getting access to capital, because of the size and nature of their company. However, competition for capital is the big question for them – if they can get a better ROI on a different capital project, they will forgo the EE project.

They have competing capital projects all over the world, some with great ROIs.

4. Please explain why the company chose to participate in the Massachusetts energy efficiency programs.

Reduce energy costs.

5. How well did the representative of the energy efficiency program administrator understand your company's interests and needs?

They have had great experience with the electric company representative.

They see very little of the gas company account representatives.

6. Did your company decide not to implement any efficiency measures that were offered through the energy efficiency programs?

Yes, due to competition for capital for other projects.

7. Do you plan to participate in Massachusetts energy efficiency programs in the next three years?

Yes. They want to do more projects, but the program administrators need to make it easier with more real-time commitments to projects and higher funding levels to help address the competition for capital.

8. To what extent do budget limitations pose a barrier to your company's participation in energy efficiency programs?

Not really. The issue is competition for capital.

9. To what extent do financing limitations pose a barrier to your company's participation in energy efficiency programs?

Again, the primary barrier for them is competition for capital. They have no shortage of capital opportunities that compete for the capital that is required for the EE projects.

10. In general, how does the current state of the economy affect your interest and ability to participate in the energy efficiency programs?

The economy is not an issue for them.

Barriers to Participation

A. Customer Barriers

   a. Financial limits

Yes, in terms of competition for capital

   b. Budget limits

No.

   c. Economic downturn

No.

   d. Corporate review and approval process

Limited.

   e. Company distrust of new technologies

No.

   f. Company convinced it has done all it can

No.

B. Program Design & Administration Barriers

   a. Insufficient incentives

Yes. This is an important issue as it would address the competition for capital.

   b. Insufficient marketing and outreach

No for electric program administrators. Yes for gas program administrators.

c. Transaction costs

Yes.

d. Responsiveness and timing

Yes.

e. Limited measures offered

No.

f. Policy Issues (Opt out of SBC)

Yes. They believe they should be able to opt-out and use the money more efficiently on their own EE.

g. Other (note)

Other Comments

They were only able to recover ten to twenty percent of the incremental costs of some EE projects.

The program administrator offered a "crash" replacement program that they liked. If you fit in to their standard programs designs, they work great. Otherwise, they do not fit your needs well.

The program administrators do not offer a program to improve power factor, or for induction motors.

The program administrators should plan their expenditures better so that they spend it all in time, and are not left at the end of the year with unspent funds.

The amount of the incentive offered by the program administrators must be clear up front, and the program administrators must follow through and make the payments offered.

Survey of Commercial and Industrial Customer Perspectives of Massachusetts Energy Efficiency Programs

Interview Notes

Region: Western Massachusetts

Industry: Heavy Industry

Person(s) Interviewed: Director of Procurement Operations, Americas

Interview Number: 25

Key Questionnaire Responses

Note: question numbers correspond to the order in which questions are asked in the questionnaire.

This company did not complete a questionnaire. The information below was obtained through the interview.

4) Approximate number of company employees located in Massachusetts:

Greater than 50. They also have facilities globally.

5) Building ownership:

NA.

13) Annual electric costs as a percent of annual operating expenses:

Between one and ten percent.

15) Annual natural gas costs as a percent of annual operating expenses:

Between one and five percent.

16) When purchasing new equipment, does your company consider the efficiency with which that equipment consumes energy?

Yes. It is an important issue.

17) If the answer to question 16 is yes, what criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facility?

The capital costs required and the project ROI relative to other uses of that capital.

18) Prior to being contacted for this interview, were you aware of the energy efficiency programs offered by your electric and gas utilities?

Yes.

20) Has your company ever participated in the energy efficiency programs offered by your electric or gas utility?

Yes, within the past three years.

Yes, prior to the past three years.

21) If your company has participated in the energy efficiency programs offered by your electric and gas utilities within the past three years:

Please name one or two things about the program that worked well for your company:

NA

Please name one or two things about the program that did not work well for your company:

NA

22) Based on your current knowledge of the efficiency programs offered by your electric and gas utilities, does your company plan to participate in these programs within the next three years?

Yes.

Predetermined Interview Questions

1. How important are energy costs to your company?

Very important.

2. Please describe the decision-making process that your company undertakes to decide whether to implement an energy efficiency measure.

They have wide latitude to undertake EE investments. See below.

However, their finance executives take a macro view to all this. They want to see the bills going down, but they continue to go up despite their EE investments. While it is true that they are better off with the EE, this is still a very big issue at the corporate executive level. They need to see the data to convince them that EE makes sense for them.

3. What criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facilities?

Based on the use of capital, and project ROI. They do not have a problem getting access to capital, because of the size and nature of their company. However, competition for capital is the big question for them – if they can get a better ROI on a different capital project, they will forgo the EE project.

They have competing capital projects all over the world, some with great ROIs.

4. Please explain why the company chose to participate in the Massachusetts energy efficiency programs.

Reduce energy costs.

5. How well did the representative of the energy efficiency program administrator understand your company's interests and needs?

They see very little of the gas company account representatives.

6. Did your company decide not to implement any efficiency measures that were offered through the energy efficiency programs?

Yes, due to competition for capital for other projects.

7. Do you plan to participate in Massachusetts energy efficiency programs in the next three years?

Yes. They want to do more projects, but the program administrators need to make it easier with more real-time commitments to projects and higher funding levels to help address the competition for capital.

8. To what extent do budget limitations pose a barrier to your company's participation in energy efficiency programs?

Not really. The issue is competition for capital.

9. To what extent do financing limitations pose a barrier to your company's participation in energy efficiency programs?

Again, the primary barrier for them is competition for capital. They have no shortage of capital opportunities that compete for the capital that is required for the EE projects.

10. In general, how does the current state of the economy affect your interest and ability to participate in the energy efficiency programs?

The economy is not an issue for them.

Barriers to Participation

A. Customer Barriers

   a. Financial limits

Yes, in terms of competition for capital

   b. Budget limits

No.

   c. Economic downturn

No.

   d. Corporate review and approval process

Limited.

   e. Company distrust of new technologies

No.

   f. Company convinced it has done all it can

No.

B. Program Design & Administration Barriers

   a. Insufficient incentives

Yes. This is an important issue as it would address the competition for capital.

   b. Insufficient marketing and outreach

No for electric program administrators. Yes for gas program administrators.

   c. Transaction costs

Yes.

d. Responsiveness and timing

Yes.

e. Limited measures offered

No.

f. Policy Issues (Opt out of SBC)

Yes. They believe they should be able to opt-out and use the money more efficiently on their own EE.

g. Other (note)

Other Comments

They have done a lot of efficiency projects already, including lighting, steam process and CFDs.

They believe that the program administrators are not efficient; they spend 35% of the program fund on administration and profit. The customer could be more efficient with that money.

It feels to them like they are paying for the efficiency twice, first through their bills and second with the resources and money that they have to invest to participate in the programs.

The programs should be less bureaucratic. Contracts must go through legal review with the customer's legal team. This slows things down on their end.

There is inefficiency in the communication with the account reps. There needs to be more information up front.

The amount of the incentive offered by the program administrators must be clear up front, and the program administrators must follow through and make the payments offered.

Participating customers should get a portion of the shareholder incentives that the program administrators get.

Survey of Commercial and Industrial Customer Perspectives of Massachusetts Energy Efficiency Programs

Interview Notes

Region: Bristol County

Industry: Retail

Person(s) Interviewed: Controller

Interview Number: 26

Key Questionnaire Responses

Note: question numbers correspond to the order in which questions are asked in the questionnaire.

4) Approximate number of company employees located in Massachusetts:

Greater than 50.

5) Building ownership:

Owned.

13) Annual electric costs as a percent of annual operating expenses:

Between five and one percent.

15) Annual natural gas costs as a percent of annual operating expenses:

One percent or less.

16) When purchasing new equipment, does your company consider the efficiency with which that equipment consumes energy?

Yes.

17) If the answer to question 16 is yes, what criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facility?

Internal rate of return, payback period and energy bill savings.

18) Prior to being contacted for this interview, were you aware of the energy efficiency programs offered by your electric and gas utilities?

No.

20) Has your company ever participated in the energy efficiency programs offered by your electric or gas utility?

Yes, within the past three years.

21) If your company has participated in the energy efficiency programs offered by your electric and gas utilities within the past three years:

Please name one or two things about the program that worked well for your company:

Payback made the jump to gas financially attainable.

Please name one or two things about the program that did not work well for your company:

Slow turnaround on the payback of the rebate due to computer issues at the agency. Could not get a confirmation that the application was received.

22) Based on your current knowledge of the efficiency programs offered by your electric and gas utilities, does your company plan to participate in these programs within the next three years?

Maybe.

Predetermined Interview Questions

1. How important are energy costs to your company?

They are very important. Energy costs are a regular topic of conversation at the senior team level.

2. Please describe the decision-making process that your company undertakes to decide whether to implement an energy efficiency measure.

The building maintenance manager is in charge of making a request at the time that a piece of equipment needs replacing. The controller helps to evaluate the incentives available and the payback.

3. What criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facilities?

They are looking for a 3-5 year payback. Also mentioned that environmental cost avoidance (as in the case with inspection costs that motivated their recent switch from oil to gas boilers) plays a role.

4. Please explain why the company chose to participate in the Massachusetts energy efficiency programs.

Reduced and avoided costs.

5. How well did the representative of the energy efficiency program administrator understand your company's interests and needs?

Not really applicable. The Company has a municipal electric utility, a new relationship with its gas utility and is working on a solar project with a third party. However, the company indicated that the incentive program allowed them to really jump at the opportunity to convert from oil to gas. The gas program administrator did a presentation for the company which kicked off the process. They also provided a technical efficiency analysis and explained the operation of the new technology.

6. Did your company decide not to implement any efficiency measures that were offered through the energy efficiency programs?

No.

7. Do you plan to participate in Massachusetts energy efficiency programs in the next three years?

Maybe. They have a 30 year old building and 4 AC units with compressors that need replacing. They also need to replace all lighting due to recent legislation and need to look at other options. Lastly, they are also hoping to get a federal credit for a solar installation.

8. To what extent do budget limitations pose a barrier to your company's participation in energy efficiency programs?

They don't really feel constrained by budget.

9. To what extent do financing limitations pose a barrier to your company's participation in energy efficiency programs?

They are not aware of any financing available, but would absolutely take advantage of financing if it were available. They would need to see a 5-6% interest rate to pursue financing.

10. In general, how does the current state of the economy affect your interest and ability to participate in the energy efficiency programs?

They had one tough year where they had to right size their staff, but other than that they haven't really been too constrained that they couldn't move forward with energy efficiency projects when they wanted to.

Barriers to Participation

A. Customer Barriers

   a. Financial limits

      Yes.

   b. Budget limits

      No.

   c. Economic downturn

      No.

   d. Corporate review and approval process

      No.

   e. Company distrust of new technologies

      No.

   f. Company convinced it has done all it can

      No.

B. Program Design & Administration Barriers

   a. Insufficient incentives

      Yes, in that they have a municipal electric utility.

   b. Insufficient marketing and outreach

      No.

   c. Transaction costs

No.

d. Responsiveness and timing

No.

e. Limited measures offered

No.

f. Programs not tailored to customer's unique needs

No.

g. Policy Issues (Opt out of SBC)

Yes, in that they have a municipal electric utility.

h. Other (note)

Other Comments

Overall, the interviewee was very unclear as to the distinction between the incentives offered by the program administrators vs. other third parties vs. federal tax credits, etc. The interviewee considered them all one in the same and seemed willing to work with any party that could provide an incentive.

The interviewee was also not that knowledgeable about the overall process and relationship between the program administrator and company. Was not aware whether a technical assessment has been completed or not. The building maintenance manager would likely have been a better person to talk with about this.

They expected to save 30% of energy costs with their oil to gas conversion. Even with the mild winter, it has been more than that so far.

Survey of Commercial and Industrial Customer Perspectives of Massachusetts Energy Efficiency Programs

Interview Notes

Region: Central Massachusetts

Industry: Restaurant & Lodging

Person(s) Interviewed: CFO

Interview Number: 27

Key Questionnaire Responses

Note: question numbers correspond to the order in which questions are asked in the questionnaire.

4) Approximate number of company employees located in Massachusetts:

Greater than 50.

5) Building ownership:

Owned.

13) Annual electric costs as a percent of annual operating expenses:

One percent or less.

15) Annual natural gas costs as a percent of annual operating expenses:

One percent or less

16) When purchasing new equipment, does your company consider the efficiency with which that equipment consumes energy?

Yes.

17) If the answer to question 16 is yes, what criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facility?

Payback period; Energy bill savings.

18) Prior to being contacted for this interview, were you aware of the energy efficiency programs offered by your electric and gas utilities?

Yes.

20) Has your company ever participated in the energy efficiency programs offered by your electric or gas utility?

Yes, within the past three years and prior to the past three years.

21) If your company has participated in the energy efficiency programs offered by your electric and gas utilities within the past three years:

Please name one or two things about the program that worked well for your company:

Simplicity of paperwork, ease of financing cost.

Please name one or two things about the program that did not work well for your company:

Identifying qualified light bulbs that suit our design.

22) Based on your current knowledge of the efficiency programs offered by your electric and gas utilities, does your company plan to participate in these programs within the next three years?

Yes

Predetermined Interview Questions

1. How important are energy costs to your company?

Very important.

2. Please describe the decision-making process that your company undertakes to decide whether to implement an energy efficiency measure.

The approval process can be a little bit long and cumbersome. The CFO does the initial investigation of the possibilities and then presents it to the ownership who then weighs it with other factors, such as payback and initial cost of the program and how seamlessly it will integrate into their existing environment.

3. What criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facilities?

“We see what’s available for energy savings solutions. We see what’s involved with the expense of making any changes. We also like to know if it’s going to give us similar results to what we’re seeing without the efficiency, in terms of lighting quality and refrigeration performance. Then look to see payback period. Then we typically do a trial on a smaller scale then do a full scale installation.”

4. Please explain why the company chose to participate in the Massachusetts energy efficiency programs.

Primarily for financial reasons and trying to increase the bottom line and save as much money as possible. The person interviewed is always looking for things that would achieve those goals but not require a lot of hands on, constant working at a project. For instance, it’s easier to change a light bulb that’s going to payback for five plus years and not have to worry about it, just get it done and enjoy the savings. The customer is always looking for new options that might save it some energy and some money.

5. How well did the representative of the energy efficiency program administrator understand your company’s interests and needs?

Some lighting upgrades received pushback from the ownership, particularly because the color and brightness of the light was not quite right so it was changing the aesthetics of the building. The company was ultimately able to find some products that were qualified with the rebate program as well as provided the correct quality of light.

The company participates regularly, and sometimes the company will be interested in projects that it brings to the utility and other times the utility will approach the company with projects.

Generally speaking the process goes smoothly and there is not an excessive amount of paperwork.

6. Did your company decide not to implement any efficiency measures that were offered through the energy efficiency programs?

n/a

7. Do you plan to participate in Massachusetts energy efficiency programs in the next three years?

Yes.

8. To what extent do budget limitations pose a barrier to your company's participation in energy efficiency programs?

No.

9. To what extent do financing limitations pose a barrier to your company's participation in energy efficiency programs?

The company has financed efficiency. The process was very easy. They installed some refrigeration controls and the cost of that installation was spread out over one year and was added to the utility bill so it wasn't a large initial outlay of money. As the savings were coming in the customer was paying for the expense of doing it and that made it a lot easier. This definitely helped overcome upfront costs.

10. In general, how does the current state of the economy affect your interest and ability to participate in the energy efficiency programs?

If business levels were higher, there would be more cash available to spend on efficiency. The company is not suffering in the economy and is doing fairly well all things considered. It hasn't been a major factor. It's actually probably encouraged the customer to be more careful in how it spends its money. Investing in efficiency is a little more on the forefront because of the down economy. Profits are not as easy to come by, it makes the customer more careful without expenses. If there are ways the customer were able to save on its utility bills without too much of an investment then obviously the customer would be more likely to pursue some of those efficiency measures to capture some more money. Rather than spending it on utilities the customer can enjoy those profits instead.

Barriers to Participation

A. Customer Barriers

   a. Financial limits

   b. Budget limits

   c. Economic downturn

   d. Corporate review and approval process

   e. Company distrust of new technologies

   f. Company convinced it has done all it can

Still some more opportunities. Some of them are bigger investments in terms of HVAC so the customer is slower to make decisions because the existing equipment is working and functional, and doesn't necessarily know if it makes sense to replace it. It's easier to replace something when it needs to be replaced rather than when it's still working.

B. Program Design & Administration Barriers

a. Insufficient incentives

Incentives are generally adequately set. It would be nice if they were even greater to minimize or eliminate the initial investment and decrease the payback period. Accelerate the savings.

b. Insufficient marketing and outreach

Utility is very helpful in identifying projects.

c. Transaction costs

It's absolutely worth taking the time to participate. Participating does eat into my available time to work on other projects, but the benefits are great enough that it's worthwhile. That's also why the person interviewed likes projects that generate the benefit but don't require a lot of maintenance along the way. Once the measure has been put in place it runs itself rather than requiring maintenance and continually eating up my time. Set it and forget it.

It takes up more time in terms of researching the models that are available and see what kind of incentives they qualify for. Certainly it'd be a lot easier to call someone up and say I need a new piece of equipment and just take what they give you. You do have to weigh some other issues, so it does take extra time.

d. Responsiveness and timing

There have been some instances when equipment needed to be replaced quickly. At that time the customer was looking for the more energy efficient model to see if they qualified for any rebates.

e. Limited measures offered

The color quality and brightness of the light and availability of the light bulbs. The Company wasn't able to buy a light bulb off a shelf. They had to special order them because the one that was on the approved list for rebates was not readily available. The company had to find a light that was qualified for a rebate and then test the aesthetics of it in its building. The special order took many weeks to a couple months to arrive. It would have been easier to purchase the light bulb that was more readily available. The bulb the company ultimately ended up buying was more expensive, so the initial cost of the program was greater than if they had been able to use the light bulbs that were more readily available. However the rebates offered through the program administrator made the overall cost less than the initial bulbs.

f. Policy Issues (Opt out of SBC)

g. Other (note)

Other Comments

Survey of Commercial and Industrial Customer Perspectives of Massachusetts Energy Efficiency Programs

Interview Notes

Region: Boston

Industry: Office

Person(s) Interviewed: Sustainability Practice Leader

Interview Number: 28

Key Questionnaire Responses

Note: question numbers correspond to the order in which questions are asked in the questionnaire.

4) Approximate number of company employees located in Massachusetts:

Greater than 50.

5) Building ownership:

Leased.

13) Annual electric costs as a percent of annual operating expenses:

One percent or less.

15) Annual natural gas costs as a percent of annual operating expenses:

One percent or less.

16) When purchasing new equipment, does your company consider the efficiency with which that equipment consumes energy?

Yes.

17) If the answer to question 16 is yes, what criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facility?

We look for Energy Star or equivalent where appropriate.

18) Prior to being contacted for this interview, were you aware of the energy efficiency programs offered by your electric and gas utilities?

No.

20) Has your company ever participated in the energy efficiency programs offered by your electric or gas utility?

No.

21) If your company has participated in the energy efficiency programs offered by your electric and gas utilities within the past three years:

Please name one or two things about the program that worked well for your company:

n/a

Please name one or two things about the program that did not work well for your company:

n/a

22) Based on your current knowledge of the efficiency programs offered by your electric and gas utilities, does your company plan to participate in these programs within the next three years?

No. We will probably be relocating our office within this amount of time, so there is no financial incentive to do such

Predetermined Interview Questions

1. How important are energy costs to your company?

The person interviewed wished they were more important. The customer is looking to save money and energy but it's actually not a huge priority right now, just because the customer is not documenting it or sub-metering it. A lot of that has to do with the fact that the customer is a tenant in a building that's not being sub-metered. It's a huge priority whenever the person interviewed makes it a priority, but it's not something that is brought up before the building's board.

It would be great if they were sub-metered and would likely help their ability to participate. The company is an office tenant in a building set up for retail. There is one meter for the entire building with six floors. The overall energy consumption of the building is divided up to each tenant by square footage, not based off usage. The first floor is going to use more energy because they're retail establishments with restaurants and kitchens, which use more energy than an office. The company realizes that it is probably paying for a lot of the electrical use of its neighbors. It would definitely be in the company's interest to have more energy focus, but it's the virtue of the building and the way that it was set up. The company was not even aware that this was the billing arrangement until about 2 years ago when the person interviewed looked into it. Now as the company considers new office spaces, sub-metering is a huge consideration.

If the company were to install efficient equipment, they would only see a very small bill reduction, and wouldn't be able to calculate the return on investment.

The company does not discourage employees if they request new plug loads (i.e., new computers or a space heater). As they need energy, it is freely given.

2. Please describe the decision-making process that your company undertakes to decide whether to implement an energy efficiency measure.

When the company first moved to its current office space, efficiency was a huge priority. The company has high efficiency lighting. The company is considering moving within the next few years, so there is no incentive to do any efficient upgrades, no matter how slight they might be. The ability to sub-meter and energy efficiency is something that is being considered by the company for their next office space.

3. What criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facilities?

4. Please explain why the company chose to participate in the Massachusetts energy efficiency programs.

Over time the company has done lighting and retrofitted its space to be efficient. The person interviewed did not know if the company had taken advantage of utility rebates or incentives because it was before his time at the company.

A year and a half ago the company had an energy audit. The person who conducted the audit was only able to find a couple hundred dollars' worth of efficiency measures. A lot of it had to do with getting read of redundant lighting and adding motion sensors. He said they had the top of the line efficiency fixtures, and couldn't go any lower and justify the costs. The company only focused on lighting measures, as their lease is very clear that they cannot alter base building features such as HVAC systems. If the company were to upgrade base building equipment, their lease stipulates that they are required to re-retrofit back to the previous equipment. The company has no incentive to upgrade such equipment.

The company is an architectural firm and often works with its clients to engage in efficiency and tries to help its clients utilize efficiency rebates and incentives in various states.

5. How well did the representative of the energy efficiency program administrator understand your company's interests and needs?

The person interviewed is not in regular contact with its utility.

6. Did your company decide not to implement any efficiency measures that were offered through the energy efficiency programs?

The company would like to install occupancy sensors but cannot justify the costs. There is pushback to install anything if the company may vacate within the year, primarily due to rental prices in the area.

7. Do you plan to participate in Massachusetts energy efficiency programs in the next three years?

8. To what extent do budget limitations pose a barrier to your company's participation in energy efficiency programs?

The customer does not see budgets being an issue. Obviously no one wants to over pay for anything and everyone wants to get the most for their money. As long as you can demonstrate an ROI of about 3 to 5 years on any item, that's usually a no-brainer. The customer works with clients that have tight budget concerns, but the customer usually likes to demonstrate the benefits of each measure, and would consider a payback up to 8 years if it was worth it. It's not so much about the budget as it is about the payback. HVAC tends to be within the 10, 12, or 15 year payback range, so those tend to be a little more difficult, especially as a tenant when leases are about 10 years.

The best situation would be if the customer could find a building to occupy as it was being built, and then work with the owner to configure the building to their needs. It would be difficult to find that and negotiate such a situation.

9. To what extent do financing limitations pose a barrier to your company's participation in energy efficiency programs?

10. In general, how does the current state of the economy affect your interest and ability to participate in the energy efficiency programs?

Because of the economy, the customer's employee base has shrunk to about a third of what it was before the economic downturn. The customer is in the architectural industry, and architecture and new construction have been hit pretty hard by the economy. Over the years the customer has gotten leaner and leaner and leaner. The customer used to occupy two floors of the building, and now occupies one floor and is a third of the size it used to be. There's just not a lot of work out there. Everyone is afraid of taking risk and competition for architectural projects is fiercer than in previous years. There's definitely a difference in the market.

The economy is a huge part of the company's decision to move. Rent prices are high and the company wants to remain profitable. Business was better last year than it was before, but because it hasn't been what it was a few years ago. The company has to sincerely look at its overhead to see if it can be reduced and see if there are benefits to moving. Energy is part of the overhead, and the ability be responsible about how you use a resource like energy and not using it at will like the company currently does.

Barriers to Participation

A. Customer Barriers

   a. Financial limits

The incentives continually change, making it difficult to stay on top of them.

   b. Budget limits
   c. Economic downturn
   d. Corporate review and approval process
   e. Company distrust of new technologies
   f. Company convinced it has done all it can

B. Program Design & Administration Barriers

   a. Insufficient incentives
   b. Insufficient marketing and outreach

Awareness only goes so far as you're willing to look. The customer wasn't aware of efficiency opportunities through the program administrators until another employee asked about it. Once the customer was aware of the opportunities, it continues to look for rebates for its clients. It's hard to be in the know. The person interviewed did the research on the program administrators programs.

The customer noted a trend with its national clients that, in new construction, owners and companies in the construction industry are learning to look to the utility early in the design process to access rebates. There is also a benefit to the utility knowing that a new hospital or other building is going to be joining the electricity grid. The energy provider needs to be part of the design team.

As long as you know who the provider is, it's pretty easy to go out and look up the incentives yourself. If there were campaigns or commercials or something to get the general public more aware, that would help. However, these programs have become more common place, so keep up the good work.

c. Transaction costs

d. Responsiveness and timing

e. Limited measures offered

f. Policy Issues (Opt out of SBC)

g. Other (note)

Other Comments

The customer spoke of a situation where it helped a company in Massachusetts receive one of the biggest efficiency packages provided by a program administrator because other customers were not taking advantage of the incentives and the program administrator needed to spend the money. The company was exquisitely happy.

Education of the clients is a big barrier. A new build, or a tenant situation also create barriers and unique situations. Sub-metering would be a great way to overcome the tenant-owner barrier. Sub-metering can quickly identify inefficiencies and problems, thereby quickly resolving the problems and identifying opportunities for efficiency. The customer would have more leverage to make the argument to participate if they were sub-metered. Also, the customer doesn't use that much energy to begin with.

Survey of Commercial and Industrial Customer Perspectives of Massachusetts Energy Efficiency Programs

Interview Notes

Region: Boston

Industry: Office

Person(s) Interviewed: n/a

Interview Number: 29

Key Questionnaire Responses

The customer did not provide the questionnaire.

Predetermined Interview Questions

1. How important are energy costs to your company?

Very important. With the size of the facility, it's a considerable investment each year.

2. Please describe the decision-making process that your company undertakes to decide whether to implement an energy efficiency measure.

The customer has to do a cost analysis and determine the return on investment and have that approved. The approval is based on the dollar costs and what the payback is based against the term of the customer's lease. If the payback is 2 years, and the lease extends out five years, than it makes sense to go ahead with the efficiency project.

The process can take time; depends on the dollars spend. If it's hundreds of thousands of dollars, it has to go through a couple levels and can take from 2 weeks to 10 weeks.

Efficiency projects are generally straight forward and received very well.

3. What criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facilities?

The customer has to do a cost analysis and determine the return on investment. Anything with a payback under 2 years is a no brainer; it's pretty attractive.

4. Please explain why the company chose to participate in the Massachusetts energy efficiency programs.

The customer did a complete re-lamping and rebalancing in a number of buildings, and installed occupancy lighting sensors and controls in all restrooms, copy/fax, and kitchen areas in all buildings.

The company knew of the local incentives and worked with an energy consultant that helped shape the program and what the company wanted to do to get the process streamlined through the utility. The company brought in the energy consultants to help out with the process. The company explained to them what they were looking for: they wanted to get a grasp on what the incentives were for the programs. The consultants helped them from start to finish doing the reporting back to the utility on the fixtures installed, any other controls, what the kWh saved were. They did it from top to bottom:

proceed the paper work, did all the calculations in terms of what the utility was looking for in order to make it a smoother process.

Hiring the consultant was something that just made sense to the customer, knowing that, by working through the consultants, they would handle all the applications and processing and calculations. It just made sense to give the company time to focus on what they were doing day to day but also to give leverage to make sure they were capitalizing on the programs to the best of the customer's ability. It was well worth the investment in time having the consultants. The customer was able to achieve the maximum benefits and rebate.

The customer does receive frequent updates from its utility on what efficiency incentives are available.

5. How well did the representative of the energy efficiency program administrator understand your company's interests and needs?

Yes. In the past few years, it's become more evident that they're doing a much better job in announcing and pushing these programs out. The person interviewed receives information from its local utility on different types of products that are available for rebates; everything from variable speed frequency drives to lighting packages.

6. Did your company decide not to implement any efficiency measures that were offered through the energy efficiency programs?

Yes. At the time of participation, the customer was also looking at ultra HVAC implementation (retrofits and change outs) throughout all the customer's buildings. At the time, there wasn't enough interest in that with the payback at about 6 years, the age of the equipment (too young to benefit from the program) and the dollar amount to do the project.

7. Do you plan to participate in Massachusetts energy efficiency programs in the next three years?

Yes. The customer feels that, with the ever changing lighting and energy field, they would probably be at the point within the next three years to start considering other options to take advantage of the programs.

A lot of the customer's ability to participate in the future is based on where the customer is (a sole tenant in a multi building facility), and based on the customer's lease. If the customer renews in the next couple years, there would be a lot of changing and work within the facilities to take advantage of some programs.

8. To what extent do budget limitations pose a barrier to your company's participation in energy efficiency programs?

Any budget limitations would be based on the terms of the lease and the return on investment.

9. To what extent do financing limitations pose a barrier to your company's participation in energy efficiency programs?

The customer has never really looked into the financing option. Actually, when the customer did the lighting retrofit there was a finance option, but they thought it was better to purchase outright and use the savings on maintenance and cost of the utility to get a return. The upfront cost was not an issue. If the upfront costs come into the millions of dollars, then there might be options there.

10. In general, how does the current state of the economy affect your interest and ability to participate in the energy efficiency programs?

The current state of the economy when the customer was doing the lighting retrofit had a positive effect on the customer. Companies were in that cut back mode looking to save anything they can. Sometimes you do have to spend to save so it made sense in the long term to the customer. Sometimes when the economy is down, but if you can put out a structure to show savings over a course of time, those things get approved quickly.

The customer made it through the economy alright. The company provides information for the financial markets, so when the stock market was down it hurt everybody. There were tough times when the reigns were pulled back on spending, but if you were showing a good turn around and considerable savings, that was considered money well spent.

Barriers to Participation

A. Customer Barriers

  a. Financial limits

No, unless upfront costs get in the millions.

  b. Budget limits

No, so long as payback is shorter than the building's lease.

  c. Economic downturn

No. Economy had a positive effect on the customer's energy use.

  d. Corporate review and approval process

No so long as there is a short payback and does not conflict with the customer's lease.

  e. customer distrust of new technologies

n/a

  f. customer convinced it has done all it can

No, would like to do more HVAC.

B. Program Design & Administration Barriers

  a. Insufficient incentives

Thought the incentives were very good this last time around. It was very nice. It was incomparable to what the cost savings were in utility charges, too. Those two combined worked out really well.

Overtime, the person interviewed would expect the incentives to get more attractive as government regulations put them in that corner to offer these programs. It seems that in the past couple years there's been a big push on being environmentally friendly and reducing energy costs. Obviously the utilities have a responsibility to provide to their customers options. Over the next couple years you're going to see that grow and grow and their programs will probably become more attractive to some people that thought they weren't attractive. For the customer right now, they are very attractive and it worked out well.

b. Insufficient marketing and outreach

No. customer thought they were well informed.

c. Transaction costs

Potentially. The customer needed to hire an energy consultant to make sure they were taking full advantage of the efficiency programs.

d. Responsiveness and timing

n/a

e. Limited measures offered

Everything was fine. Fit the customer's needs at the time.

Lighting and HVAC are large portions of utility costs. If could get over hurdles and make HVAC systems more attractive that would be something that the customer would be interested in pursuing.

f. Programs not tailored to customer's unique needs

g. Policy Issues (Opt out of SBC)

h. Other (note)

Other Comments

Survey of Commercial and Industrial Customer Perspectives of Massachusetts Energy Efficiency Programs

Interview Notes

Region: Boston

Industry: Heavy Industry

Person(s) Interviewed: Controller

Interview Number: 30

Key Questionnaire Responses

Note: question numbers correspond to the order in which questions are asked in the questionnaire.

4) Approximate number of company employees located in Massachusetts:

Greater than 50.

5) Building ownership:

Owned.

13) Annual electric costs as a percent of annual operating expenses:

Between five and one percent.

15) Annual natural gas costs as a percent of annual operating expenses:

n/a

16) When purchasing new equipment, does your company consider the efficiency with which that equipment consumes energy?

Yes.

17) If the answer to question 16 is yes, what criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facility?

Payback period; Benefit-cost ratio; Energy bill savings.

18) Prior to being contacted for this interview, were you aware of the energy efficiency programs offered by your electric and gas utilities?

No.

20) Has your company ever participated in the energy efficiency programs offered by your electric or gas utility?

No.

21) If your company has participated in the energy efficiency programs offered by your electric and gas utilities within the past three years:

Please name one or two things about the program that worked well for your company:

n/a

Please name one or two things about the program that did not work well for your company:

n/a

22) Based on your current knowledge of the efficiency programs offered by your electric and gas utilities, does your company plan to participate in these programs within the next three years?

Maybe.

Predetermined Interview Questions

1. How important are energy costs to your company?

Very important.

2. Please describe the decision-making process that your company undertakes to decide whether to implement an energy efficiency measure.

The approval process varies based on the dollar volume being discussed. If it's a relatively inexpensive measure or the payback is very quick then it becomes a no brainer and the decision process is relatively quick. As the dollar amount gets bigger and the payback gets longer, more discussions happen, more analysis is need, therefore the decision making process gets expanded out.

3. What criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facilities?

The company looks at how much it is going to cost. Cash flow for the company right now is definitely a challenge and something that is managed very closely. Before implementing any type of policy or change they need to make sure they have a way to pay for it and analyze what the benefit is going to be. The company looks at the break even, how long it is going to take to pay it back, and the cost-benefit.

The company looks for a payback before 18 months. That's the latest they would want to go.

4. Please explain why the company chose to participate in the Massachusetts energy efficiency programs.

5. How well did the representative of the energy efficiency program administrator understand your company's interests and needs?

The company is not in regular contact with its utility. If they company has a problem, the utility tries to address it as best they can.

The company has not been very proactive in trying to look for cost saving measures, and the program administrators have not been very proactive in trying to assist the customer in cost saving. The company would be receptive if the utility were to reach out to them.

6. Did your company decide not to implement any efficiency measures that were offered through the energy efficiency programs?

n/a

7. Do you plan to participate in Massachusetts energy efficiency programs in the next three years?

It would depend on the cost, but would definitely be something the company would entertain. The company is not actively looking for opportunities, but if opportunities were brought to the company's attention, then they would consider them.

8. To what extent do budget limitations pose a barrier to your company's participation in energy efficiency programs?

Budgets would definitely play a major role in the company's ability to participate.

9. To what extent do financing limitations pose a barrier to your company's participation in energy efficiency programs?

Would depend on the dollar amount and the payback. The company wouldn't be opposed to that option if it made sense and within the 18 month break event that they're looking for.

10. In general, how does the current state of the economy affect your interest and ability to participate in the energy efficiency programs?

Significantly. The customer is a manufacturing company. The last recession had an impact on its business. It does seem to be picking up and moving in the right direction, but the economic climate and conditions definitely play in the customer's decision making.

Capital is not tighter because of the economy. Their bank has told the company that they have mandates form corporate to lend as much as possible, so capital is not a major issue at this point.

Business is slow, margins are tighter, a lot more price shopping is taking place. The company is making less money on its bottom line because of all that.

Because of the economy the company has cut back and is wearing more hats so there is less time to devote to efficiency.

Efficiency viewed favorably at the company and as a way to cut costs.

Barriers to Participation

A. Customer Barriers

   a. Financial limits

   b. Budget limits

Yes. Capital is a big barrier.

   c. Economic downturn

Yes. The company has less time to devote to efficiency and profit margins are tighter.

   d. Corporate review and approval process

Yes – 18 month payback.

   e. Company distrust of new technologies

f. Company convinced it has done all it can

B. Program Design & Administration Barriers

a. Insufficient incentives

b. Insufficient marketing and outreach

Yes. The company has only a general understanding of the programs and has not been given much information by its utility on the programs.

c. Transaction costs

Yes. The company does not have time to devote to efficiency participation. The easier the process is the more likely the company is to participate.

d. Responsiveness and timing

e. Limited measures offered

f. Policy Issues (Opt out of SBC)

g. Other (note)

Other Comments

Survey of Commercial and Industrial Customer Perspectives of Massachusetts Energy Efficiency Programs

Interview Notes

Region: Western Massachusetts

Industry: Heavy Industry

Person(s) Interviewed: Purchasing; Plant Manager

Interview Number: 31

Key Questionnaire Responses

Note: question numbers correspond to the order in which questions are asked in the questionnaire.

4) Approximate number of company employees located in Massachusetts:

Greater than 50.

5) Building ownership:

Owned.

13) Annual electric costs as a percent of annual operating expenses:

Between ten and five percent.

15) Annual natural gas costs as a percent of annual operating expenses:

n/a (uses propane)

16) When purchasing new equipment, does your company consider the efficiency with which that equipment consumes energy?

Yes.

17) If the answer to question 16 is yes, what criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facility?

Payback period; Energy bill savings.

18) Prior to being contacted for this interview, were you aware of the energy efficiency programs offered by your electric and gas utilities?

Yes.

20) Has your company ever participated in the energy efficiency programs offered by your electric or gas utility?

No (10 years ago)

21) If your company has participated in the energy efficiency programs offered by your electric and gas utilities within the past three years:

Please name one or two things about the program that worked well for your company:

n/a

Please name one or two things about the program that did not work well for your company:

n/a

22) Based on your current knowledge of the efficiency programs offered by your electric and gas utilities, does your company plan to participate in these programs within the next three years?

Yes.

Predetermined Interview Questions

1. How important are energy costs to your company?

Very important.

2. Please describe the decision-making process that your company undertakes to decide whether to implement an energy efficiency measure.

The customer has an audit conducted to identify areas for energy improvement. From there the customer does the repairs or implement what they have to do.

The Finance Manager/Vice President is in charge of energy approvals. He goes through proposals thoroughly before giving approval. The person interviewed was not aware of the Finance Manager/Vice President turning down efficiency projects. His review of efficiency projects is usually pretty quick.

3. What criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facilities?

The customer is always looking for some kind of a payback period anytime they look to invest in something. The customer generally looks for a quick payback, anywhere from 2 to 7 years. When buying a new machine, the customer is always looking at how long is it going to take to get the payback on it as well as what are they going to save on their energy bill compared to the last machine. The customer is always trying to go a little more energy efficient. A lot of new machines you can't really be more efficient with. The customer looks at machines that will allow them to increase their productivity and at that point, they're not looking at the efficiency as much. The customer needs equipment that will do the job that needs to be done. The customer needs to get what it's got to have to run the product. If they can combine it with energy efficiency they will.

Equipment planning is done pretty well in advance of whether a machine is likely to fail. Machines usually stay around for 10 to 15 years or more. There are plenty of warning signs that they will need to start shopping for new machines, and don't usually need to replace equipment on an emergency basis.

4. Please explain why the company chose to participate in the Massachusetts energy efficiency programs.

The customer is aware that rebates and incentives are available through its utility. About 10 years ago the customer completed a lighting upgrade through its utility. The customer also had a new furnace installed, which could possibly have a rebate available for it.

Within the past few months, the customer had an audit completed by the University of Massachusetts' Department of Mechanical and Industrial Engineering. The UMass Department approached the customer and offered to do the free audit. They walked around and identified where the customer was losing or wasting energy, mostly around fixing air leaks and compressors, meaning that the compressors were running more than they should be. Air leaks had the shortest payback. Because of the audit, the customer made adjustments to its air compressor systems.

The UMass Department gave a list of everything they found, along with recommendations for repairs and calculated paybacks with the savings they would receive and what the customer was losing. Some repairs were identified but did not have a payback associated with it. The customer then did the upgrades on their own based on the recommendations in the report. The UMass Department did not identify rebates or incentives in their report. Most of the things identified by the UMass Department were not available to be incented by the utility programs. There may have been a few things that were eligible, but the customer did not look into it.

There's a lot of stuff out there that you can get for free. To pay someone to come in and do the same type of evaluations doesn't work well for the customer. The customer doesn't like to pay people to come in and do evaluations. A bunch of people have been offering to do free audits. It seems to come in spurts. Right now everybody's calling about it. The UMass Department was different because the Finance Manager/Vice President told the person interviewed to get them into the building to do the audit.

5. How well did the representative of the energy efficiency program administrator understand your company's interests and needs?

The persons interviewed were not sure if their utility had reached out to the customer regarding efficiency measures. The utility may have contacted someone else at the customer.

The customer is not in regular contact with its utility unless there is a power outage. When asked whether the customer would prefer to be in more regular contact with its utility, the person interviewed questioned what benefit that would bring. There's been no real problems.

The customer gets people calling all the time about different types of efficiencies, primarily third party suppliers trying to bid on the next energy supply contract when its current contract expires.

6. Did your company decide not to implement any efficiency measures that were offered through the energy efficiency programs?

7. Do you plan to participate in Massachusetts energy efficiency programs in the next three years?

Yes. No specific plans yet. Once the Finance Manager/Vice President makes a decision to move forward, which should be soon, the customer will move forward with efficiency projects. There's no other barriers to participation other than the Finance Manager/Vice President making the call to say let's do it.

The main motivating factor to participate in the next few years is to reduce energy costs and make things more efficient, and to make everything greener. The Finance Manager/Vice President is figuring out it's a good time to get going on some efficiency projects again and they have some good opportunities and a good window coming up. He had some time freed up after the end of the year was finished, and wants to take another look at energy use around the customer and cost savings and improvements. He's big on trying to get his arms around the heat loss in the building.

8. To what extent do budget limitations pose a barrier to your company's participation in energy efficiency programs?

No budget or capital barriers. The customer is not just going to spend money on efficiency just for the sake of saying they're spending money on efficiency if it's not going to give any payback.

9. To what extent do financing limitations pose a barrier to your company's participation in energy efficiency programs?

No, finance is not a problem.

10. In general, how does the current state of the economy affect your interest and ability to participate in the energy efficiency programs?

The biggest effect was in 2008. The customer had a substantial layoff and business just dropped off because people weren't ordering products. Since 2008, the customer has been steadily climbing back to where they were.

Going forward, as long as the economy is going pretty well it's not likely to pose a barrier to participation. If it crashed again like it did back then, than that will have an effect. The customer would be on locked down and wouldn't be allowed to spend extra money on anything. Going along now, it should be business as usual.

Barriers to Participation

A. Customer Barriers

   a. Financial limits

No.

   b. Budget limits

No, so long as decent payback.

   c. Economic downturn

No.

   d. Corporate review and approval process

Yes. The Finance Manager/Vice President seems to control the direction of efficiency projects.

   e. customer distrust of new technologies

n/a

   f. customer convinced it has done all it can

There are always opportunities to do more efficiency.

B. Program Design & Administration Barriers

a. Insufficient incentives

b. Insufficient marketing and outreach

Possibly. The customer is not in regular contact with its utility, and was just aware that incentive programs are available.

c. Transaction costs

Time is the only barrier identified by the person interviewed. The customer is very busy so it’s just a matter of finding the time to looking into everything and get it going.

d. Responsiveness and timing

e. Limited measures offered

Potentially. Air compressors seemed to be an area of improvement that were not incentivized through the program.

f. Programs not tailored to customer’s unique needs

Customer is not unique. Big old steel building with high ceiling, big windows, concrete floors.

g. Policy Issues (Opt out of SBC)

h. Other (note)

Other Comments

Survey of Commercial and Industrial Customer Perspectives of Massachusetts Energy Efficiency Programs

Interview Notes

Region: Boston

Industry: Heavy Industry

Person(s) Interviewed: VP of Finance

Interview Number: 32

Key Questionnaire Responses

Note: question numbers correspond to the order in which questions are asked in the questionnaire.

4) Approximate number of company employees located in Massachusetts:

Greater than 50.

5) Building ownership:

Owned.

13) Annual electric costs as a percent of annual operating expenses:

Between five and one percent.

15) Annual natural gas costs as a percent of annual operating expenses:

Between ten and five percent.

16) When purchasing new equipment, does your company consider the efficiency with which that equipment consumes energy?

Yes.

17) If the answer to question 16 is yes, what criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facility?

Internal rate of return; Payback period; Benefit-cost ratio; Energy bill savings.

18) Prior to being contacted for this interview, were you aware of the energy efficiency programs offered by your electric and gas utilities?

Yes.

20) Has your company ever participated in the energy efficiency programs offered by your electric or gas utility?

Yes, both within the past three years and prior to the past three years.

21) If your company has participated in the energy efficiency programs offered by your electric and gas utilities within the past three years:

Please name one or two things about the program that worked well for your company:

n/a

Please name one or two things about the program that did not work well for your company:

n/a

22) Based on your current knowledge of the efficiency programs offered by your electric and gas utilities, does your company plan to participate in these programs within the next three years?

Maybe.

Predetermined Interview Questions

1. How important are energy costs to your company?

Quite important. The customer pays a nice piece of change each month for electricity and natural gas. They keep an eye on it and contract out for gas and electricity so that they can fix the cost for a period of time and do their costing for other materials.

Energy costs are typically a low priority until the contract is up. The company usually signs up for a one or two year contract. As it's time to renew, it starts picking up the pace and then the customer is able to put it behind them knowing that they're locked in and can move on from there. It's certainly an important piece, but it's not like they're buying on a daily or monthly basis.

When buying the contract, the customer gets an estimate of how much they expect to use for electricity or gas, based on how they expect their business to do over the year.

2. Please describe the decision-making process that your company undertakes to decide whether to implement an energy efficiency measure.

The customer certainly looks to see if new equipment is going to be energy efficient. On the other hand, there may not be too many choices for the type of industrial equipment that is needed to get the job done. It's going to take whatever amount of horse power or gas it's going to take. They look to see what the operating costs will be like but they also look to see how well the equipment will perform.

The President, the VP of Manufacturing, and the VP of Finance (the person interviewed) get together and look around to see how buying new equipment would affect the company. "It's like getting a razor for free but having to spend an awful lot of money for the blades. Electricity is the same way. If the equipment is inexpensive but it's going to cost a lot to power it, you may look for something else. In other cases, we don't have a much of a choice. If it's a unique piece of equipment, then that's pretty much all we can buy." Energy is part of the decision making process but it's not the only factor.

3. What criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facilities?

If it's a payback of many many years, it's probably not going to happen. If the payback is less than a year, it's probably going to happen. Less than a 1 year payback is pretty self-explanatory unless it's going to disrupt production. Changing lights is not going to shut your facility down. There's no real rule in place on the payback period, but it's been the customer's practice to go with a payback of less than a year, and it's not too difficult to sign off on such a project because you'll see the results real quickly. Once the payback is longer than a year, there are a number of different factors considered. What those factors are depends on the situation.

At the end it comes down to economics. The lighting upgrade (discussed below) was a no brainer. Anything with a long payback would probably be put on the back burner and probably wouldn't be acted on immediately.

4. Please explain why the company chose to participate in the Massachusetts energy efficiency programs.

A couple years back (probably not within the past 2 years) the customer had an energy audit conducted on its facilities. The company relighted with efficient lamps in its warehouse facility. The PA did the audit, showed the company what they could save and what it would cost them to do and it was basically a no brainer to the customer. With a payback period of less than a year the company went for it and had the warehouse re-lamped. The audit seemed very thorough to the customer. The customer had just installed some new equipment, which probably limited the extent of the opportunities in the audit. Any recommendation that could be made was positive to the company. The lighting was very easy. As far as some of the other things, it's more difficult to change motors. The company also took care of a compressor issue and a couple of smaller recommendations from the audit.

About every 5 years the company has an audit conducted. From time to time the customer does have measures identified in the audits taken care of to see what else they can do. The two buildings that the customer used to occupy were audited.

The company doesn't know what it will be like the next time around, because you get to a certain point when you get the low-hanging fruit and after that it gets more difficult. Payback becomes a strong consideration.

They also participated in demand response programs.

5. How well did the representative of the energy efficiency program administrator understand your company's interests and needs?

The person interviewed believes that the PA approached the customer to conduct the audit, although was not entirely sure. When the "utility" approached the customer about demand response programs, the person interviewed believed that that is when they were made aware of efficiency programs.

The customer had not done any specific research ahead of time to assess rebates or opportunities. When the customer was contacted for the interview, it reminded them to see what new opportunities are available. The customer acknowledged that natural gas is low now, but will go up in time, and so is considering adjusting its supply contract.

The customer was not aware of whether it had been contacted by its gas utility.

6. Did your company decide not to implement any efficiency measures that were offered through the energy efficiency programs?

The person interviewed could not remember if recommendations were made on some of the bigger equipment and motors. Because a lot of equipment was new, there was not a lot that could be addressed for bigger pieces of equipment in the audit. The company did most or all of the measures and recommendations that were worthwhile. The customer did not adopt any recommendations because it didn't believe in them; there weren't any measures that made sense to some people but didn't make sense to others. There may have been some measure that the customer may want to consider at some point.

7. Do you plan to participate in Massachusetts energy efficiency programs in the next three years?

The customer said "maybe" because they couldn't respond yes or no. They probably could have said yes, but didn't want to be definitive about it. With energy costs relatively low, it's not the number one priority. Right now the customer is looking to make more sales and get more business.

If the customer could be pointed in the right direction as far as who to contact, the person will certainly take notes and see what they can do. At some point the company will look to see what they can do, but at the moment it's not on their radar. The person interviewed asked whether they should be contacting the EEAC for information on program participation. They were directed to contact their utility/PA, and they said they would at some point. Anything that could be done in the short term or kept in mind for down the road about something they haven't thought about would help the customer.

8. To what extent do budget limitations pose a barrier to your company's participation in energy efficiency programs?

There might be some budget limitations, but without knowing what the projects might be, the person interviewed could not say. There are always budget limitations for something. The company looks at the cost of most projects, but also evaluates what benefit it will give them. There is no fixed dollar limit as to what can or cannot be spent. It's more a matter of what makes sense. The customer has a parent company that supports them well. In 2004 the parent company leant the customer some money for a project, and at the time no one else would have leant funds to the customer. The loan is now paid back. If they can justify the expense, they can usually get the money.

9. To what extent do financing limitations pose a barrier to your company's participation in energy efficiency programs?

No. The customer goes through its parent company (the customer is a subsidiary of a privately held company). The parent company mostly leaves the customer alone except for money matters and insurance matters. Everyone has a limit somewhere, but financing has never been a concern of the customer.

10. In general, how does the current state of the economy affect your interest and ability to participate in the energy efficiency programs?

With the economy the way it is right now the customer is more interested in making sales. With gas prices the way they are, efficiency is not something that is foremost in the customer's mind. Usually you take care of these things when it's too late. If gas prices started to rise, it would peak the customer's interest in efficiency.

The customer certainly felt the downturn in the economy. They felt it like everyone else did. The company works in an industry that is mostly based on new construction or capital investment activities. When the economy took a down turn and companies stopped new construction or refurbishing projects, the customer felt the decrease in business. The customer's business is slowly picking up again as the business it depends on start to pick up again. Historically, the customer's business slows down after the slowdown because contracts are already in place. They also pick up after other businesses pick up because their one of the last considerations in a new construction project. They follow the economic curve but are always a little later than other businesses.

The nice thing is, that with the customer's parent company, they do not feel that the economy would affect the customer's ability to participate in efficiency programs going forward. The parent company has allowed the customer to take advantage of economic dips from time to time depending on what it is. Once, the company bought equipment when it wasn't the best time to be equipment if you were going to go to a bank. The company was able to get good pricing from a manufacturing company because they were looking for business, and the customer was able to negotiate a low price with the help of its parent company.

Barriers to Participation

A. Customer Barriers

a. Financial limits

No.

b. Budget limits

Maybe, likely not.

c. Economic downturn

Could be a barrier, but person interviewed does not think so.

d. Corporate review and approval process

No.

e. Company distrust of new technologies

f. Company convinced it has done all it can

Maybe. Right now, the customer has done several improvements. That's not to say that there isn't the next generation of motors ore equipment that isn't going to be coming down the pike that might be worthwhile. The majority of the customer's equipment is new and they had the lighting taken care of. Sometime down the line when it's time to replace equipment the customer will look into efficient options.

B. Program Design & Administration Barriers

a. Insufficient incentives

No.

b. Insufficient marketing and outreach

The power companies are doing what they can do and it's up to the customer to take advantage of them and seek them out further. The customer has to help themselves.

There's always that friendly reminder that could come across and wouldn't hurt to jog the company's memory to participate in programs. The customer is well aware of the programs offered. If the customer was not aware, then they would suggest that the utilities need to do a better job of outreach. Because the customer is aware, it's on them to see what they can do.

c. Transaction costs

The person interviewed did not remember any significant paperwork involved with the energy audit the customer conducted. There was more paperwork for demand response. It was all within the regular course of business and was not a real problem.

d. Responsiveness and timing

The customer does not have the time to devote to participation, and is more concerned with business and sales than efficiency.

e. Limited measures offered

No.

f. Programs not tailored to customer's unique needs

No.

g. Policy Issues (Opt out of SBC)

No. Customer needs to help itself.

h. Other (note)

Other Comments

Probably not a lot of things would prevent the customer from at least talking to the PAs.

Survey of Commercial and Industrial Customer Perspectives of Massachusetts Energy Efficiency Programs

Interview Notes

Region: Western Mass

Industry: Office

Person(s) Interviewed: Senior Property Manager

Interview Number: 33

Key Questionnaire Responses

Note: question numbers correspond to the order in which questions are asked in the questionnaire.

4) Approximate number of company employees located in Massachusetts:

1 to 4.

5) Building ownership:

Owned.

13) Annual electric costs as a percent of annual operating expenses:

Between ten and five percent.

15) Annual natural gas costs as a percent of annual operating expenses:

Between ten and five percent.

16) When purchasing new equipment, does your company consider the efficiency with which that equipment consumes energy?

Yes.

17) If the answer to question 16 is yes, what criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facility?

Internal rate of return; Payback period; Benefit-cot ratio; Energy bill savings.

18) Prior to being contacted for this interview, were you aware of the energy efficiency programs offered by your electric and gas utilities?

Yes.

20) Has your company ever participated in the energy efficiency programs offered by your electric or gas utility?

No.

21) If your company has participated in the energy efficiency programs offered by your electric and gas utilities within the past three years:

Please name one or two things about the program that worked well for your company:

n/a

Please name one or two things about the program that did not work well for your company:

n/a

22) Based on your current knowledge of the efficiency programs offered by your electric and gas utilities, does your company plan to participate in these programs within the next three years?

Yes.

Predetermined Interview Questions

1. How important are energy costs to your company?

Very important. A high priority is set for energy costs. The customer is a property management company that communicates this high priority to the building owners. The company looks at each building's usage and energy costs, and then looks for ways to reduce them.

2. Please describe the decision-making process that your company undertakes to decide whether to implement an energy efficiency measure.

The company has not installed energy using equipment in its building recently. The company looks to install new equipment only when it breaks down. The maintenance staff at the building will monitor equipment and notify the management company when it's at the end of its life. The maintenance staff calls a vendor to find new equipment, and then asks the management to fund the new equipment. The management company then considers payback and the equipment's usage, before bringing the proposal to the building owner for approval.

3. What criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facilities?

When looking to purchase new equipment, the customer looks at its energy savings, the payback period, and whether it will work or not for the building. The company looks for a 2 year payback.

4. Please explain why the company chose to participate in the Massachusetts energy efficiency programs.

The PA contacted the customer about efficiency programs. Prior to being contacted, the customer was not aware of the efficiency programs (later the person interviewed indicated that they are aware of the programs). The customer has been in discussions with its PA, and is expecting to have an audit to see what can be done. The audit looked into HVAC and lighting opportunities, and the customer just received the engineering report and is currently deciding how to proceed. Gas measures are being looked into as part of the audit process. The next step is to work with the PA to determine the incentives available for the recommendations in the engineering report. The company has not yet made investments in efficiency, but expects to address HVAC and lighting measures.

The building owners can see efficiency as a more expensive option at times. One building in particular is very old. There could be a lot of efficiency opportunities but the owner is hesitant because it could be a lot of upfront money. It's a huge building and to upgrade or replace the HVAC system will likely result in astronomical costs that would be too expensive to undertake in one year. The customer is considering a phased approach to spread the costs out over time. The PA is accommodating to the phased approach.

The company primarily conducted the audit to look for ways to save money. The company is also trying to be proactive and avoid not being able to participate because of equipment failure.

The company has replaced some converters and some pumps. Equipment does not need to be replaced often. The company tries to look for something that's energy efficient if it's going to be replaced. Sometimes trying to get equipment incented from the PAs doesn't work because the equipment needs to be replaced immediately. They don't have the time to go to the PA and request incentives. Everything has to be preapproved and that takes a while, and the customer doesn't have a while because they need it immediately.

5. How well did the representative of the energy efficiency program administrator understand your company's interests and needs?

Well. There is nothing the PA could have done differently to address the customer's needs. The customer is in regular contact with its utility. The customer finds them be very helpful. If the customer calls with a question, they give you an answer and if they don't have an answer, they call back quickly with someone who can answer the question.

The company keeps in contact with its gas PA, but not as often as its electric PA. The gas PA has not mentioned efficiency, whereas the electric PA is in regular discussions with the customer regarding efficiency.

6. Did your company decide not to implement any efficiency measures that were offered through the energy efficiency programs?

7. Do you plan to participate in Massachusetts energy efficiency programs in the next three years?

8. To what extent do budget limitations pose a barrier to your company's participation in energy efficiency programs?

There could be budget constraints; it all depends on what the bottom line is. The person interviewed does not think that efficiency projects would compete with other capital investments.

9. To what extent do financing limitations pose a barrier to your company's participation in energy efficiency programs?

No.

10. In general, how does the current state of the economy affect your interest and ability to participate in the energy efficiency programs?

The customer is lucky in that it has been preforming really well over the past couple years. The customer did not have much of an issue with the economy. The company's performance does not affect its views on efficiency. The company is hopeful that they will continue to perform well going forward.

Barriers to Participation

A. Customer Barriers

a. Financial limits

No.

b. Budget limits

Maybe.

c. Economic downturn

No.

d. Corporate review and approval process

Maybe. Owners determine what gets funding.

e. Company distrust of new technologies

No.

f. Company convinced it has done all it can

No.

B. Program Design & Administration Barriers

a. Insufficient incentives

No.

b. Insufficient marketing and outreach

Likely no.

c. Transaction costs

Yes. The process is taking a little while. There have been lags getting the engineering report.

d. Responsiveness and timing

Yes. When equipment breaks the customer needs it to be replaced immediately, and the programs are not responsive to that.

The customer has done minor efficiency upgrades in one building (even though the person interviewed stated earlier that they were unaware of the programs). The last time the person participated, they found the process much easier. They could submit to the PA receipts from efficiency equipment and related paperwork. Now, everything needs to be preapproved by the utility before the equipment can be purchased. While this adds an extra step to the participation process, the real issue is that if you need new equipment you need it now.

e. Limited measures offered

No.

f. Programs not tailored to customer's unique needs

No.

g. Policy Issues (Opt out of SBC)

No.

h. Other (note)

Other Comments

Survey of Commercial and Industrial Customer Perspectives of Massachusetts Energy Efficiency Programs

Interview Notes

Region: Western Massachusetts

Industry: Warehouses & Distribution

Person(s) Interviewed: Facilities & Systems Engineering

Interview Number: 34

Key Questionnaire Responses

Note: question numbers correspond to the order in which questions are asked in the questionnaire.

4) Approximate number of company employees located in Massachusetts:

20 to 50.

5) Building ownership:

Owned.

13) Annual electric costs as a percent of annual operating expenses:

Between ten and five percent.

15) Annual natural gas costs as a percent of annual operating expenses:

Between ten and five percent.

16) When purchasing new equipment, does your company consider the efficiency with which that equipment consumes energy?

Of course.

17) If the answer to question 16 is yes, what criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facility?

Payback period,

18) Prior to being contacted for this interview, were you aware of the energy efficiency programs offered by your electric and gas utilities?

Yes.

20) Has your company ever participated in the energy efficiency programs offered by your electric or gas utility?

No.

21) If your company has participated in the energy efficiency programs offered by your electric and gas utilities within the past three years:

Please name one or two things about the program that worked well for your company:

n/a

Please name one or two things about the program that did not work well for your company:

n/a

22) Based on your current knowledge of the efficiency programs offered by your electric and gas utilities, does your company plan to participate in these programs within the next three years?

Maybe.

Predetermined Interview Questions

1. How important are energy costs to your company?

Energy represents 10% of operating costs between gas and electric, so they're not trivial, but they're not the overriding piece of it. Energy is probably a medium priority for the customer. They've secured good electric rates and they have natural gas so that's working in their favor at this point in time. This priority is not officially set or communicated to employees.

2. Please describe the decision-making process that your company undertakes to decide whether to implement an energy efficiency measure.

The CFO considers projects and provides approval. He makes a fairly quick decision. He generally views efficiency favorably.

The company is in the process of replacing the roof over the summer, so any other projects are not likely to be approved in the near term.

3. What criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facilities?

If a project doesn't have a very quick 24 month payback, then it wouldn't be considered. A project within 24 months is more likely to be considered. The shorter the better, but it needs to be something that will provide real savings in the near term.

At one point the customer considered a co-generation facility, but with the low gas costs and electric rates, it had a 5 or 6 year payback, so it was not considered.

4. Please explain why the company chose to participate in the Massachusetts energy efficiency programs.

In 2006 and 2007 the company put on a major addition, adding about 40% capacity to the company's operations. At that time, the customer added about 140 horse power worth of electric motors. Since then, equipment alterations have only been to replace equipment. No substantial changes since 2007.

Energy efficiency is a consideration when replacing equipment, but it hasn't been given a lot of thought, or there have been expeditious swap outs. The system runs with relatively high efficient motors, some of which include VSDs. The company has considered adding more VSDs, but the physical constraints are daunting, so they haven't gone far with it. The customer has spoken with local vendors and its PA about efficiency opportunities. They got to the point where they understood what the cost would be, but weren't able to pull it off at that point in time and haven't been back to it. The cost and capital outlay and ability to do the install prevented the customer from pulling off the project. Physically the customer doesn't have the space in the electric room to add the gadgetry to add the VSDs and efficient equipment. The physical, practical aspects of the installations stood in the way. There are other things that come up that need attention all the time.

The cost with incentives was not the problem. The physical space prohibited the customer from being able to install more efficient equipment. The customer was presented with discounts or incentives that would largely cover the cost of the VSDs, but the customer wasn't convinced that they were going to be able to take advantage of them anyway. Most of the time the systems are running wide open. To turn the system back would potentially reduce the customer's ability to operate the system successfully with a lower electricity flows.

The customer has been contacted by both its gas and electric PA. The gas PA has been in touch with the customer and they installed high efficiency munchkin boilers in 2000. The electric PA worked with Applied Dynamics to determine the savings estimates.

The customer feels like it's done a lot in terms of savings and has done a lot of the low-hanging fruit. When the offices were built, they were state of the art in terms of lighting. There may be some savings achievable with more lighting.

5. How well did the representative of the energy efficiency program administrator understand your company's interests and needs?

The customer is in occasional contact with its utilities. The person interviewed attended a conference a few years ago organized by its gas PA where efficiency was a big topic. He felt like that was an indication that the PAs are reaching out to customers.

6. Did your company decide not to implement any efficiency measures that were offered through the energy efficiency programs?

n/a

7. Do you plan to participate in Massachusetts energy efficiency programs in the next three years?

Not likely.

8. To what extent do budget limitations pose a barrier to your company's participation in energy efficiency programs?

Budget limitations are always going to be a consideration. If a project doesn't have a very quick 24 month payback, then it wouldn't be considered.

There are other things that come up that need attention all the time.

9. To what extent do financing limitations pose a barrier to your company's participation in energy efficiency programs?

n/a

10. In general, how does the current state of the economy affect your interest and ability to participate in the energy efficiency programs?

The economy has had an effect on the company over the past few years. The company's employee base has remained fairly constant.

The economy has not had an impact on the customer's decision to participate in efficiency projects. The uncertainties have made the company more hesitant to invest in something that doesn't have a highly guaranteed returned. It's hard to create a compelling argument when you only have 10% of the operating costs going into energy.

Barriers to Participation

A. Customer Barriers

a. Customer's financial limitations

n/a

b. Customer's competition for capital

Yes. Other projects (such as a roofing project) compete for capital, and other things are always coming up.

c. Economic downturn

No.

d. Corporate review and approval process

No.

e. Company distrust of new technologies

The customer is concerned that reducing energy consumption may reduce production capability. This was an impediment to implementing efficiency but was not a stopper.

f. Company convinced it has done all it can

Maybe. The customer thinks there are opportunities out there, but doesn't feel like the savings are significant enough to prompt them to throw the man power at it. The customer thinks it has done all the low hanging fruit. Participating in an energy audit would probably be a great idea to have someone with a fresh set of eyes view the facility. The person interviewed had been there for 20 years and admitted he is probably jaundiced and may not see things that someone else from outside the facility would see things. The customer does not think they have huge savings to be had, maybe talking on the order of 5-10% of consumption at best, which is half or one percent of operating costs. There's just so much else going on, that it's not something the person interviewed can get their arms around. Having an energy audit might be useful to figure out what's going on.

B. Program Design & Administration Barriers

a. Insufficient incentives

No.

b. Insufficient marketing and outreach

No.

c. Transaction costs

Yes. The customer believes it would take a lot of time and manpower to participate in the programs. About ten years ago, the customer tried to install lighting and in house staff would have needed to do the installation as part of the package of incentives offered by the PA. The measures would only be completely incented with an installation contribution by the customer. This makes it not free and not without commitment of resources on the customer's part.

Because of this, the customer figured that this time around would require similar time commitments. Justifying the time commitment to participate is a barrier for the customer.

d. Responsiveness and timing

n/a

e. Limited measures offered

Yes. The equipment the customer needed to be efficient could not fit into the space in the electrical room.

f. Programs not tailored to customer's unique needs

n/a

g. Policy Issues (Opt out of SBC)

h. Other (note)

Other Comments

The customer suggested that more effort or assistance in evaluating the achievable energy reductions and implementing the projects would help customers. The customer didn't have a firm sense of whether the energy savings were really achievable, and whether they could practically implement them. There was not a huge motivation to go the more efficient version. Even if the measures were free, there would still be system upsets that would go along with trying to install them and providing their piece of whatever the incentive was. A lot of businesses don't have someone dedicated to energy and conservation looking at these things. It would be better to have someone shepherd the project and evaluate whether the project would be feasible under the certain circumstances a customer has. That was a missing piece for the customer. They did speculate that they could periodically turn down the system, but they didn't do a system level analysis on the impact that would have on operations. They realized it was free, but the energy savings were like to be sporadic.

Having a better understanding of what's realistically achievable and having a compelling case for change stands in the way of executing projects. Everyone is supportive of the idea of conservation, and the company considers itself to be a sustainable company. Actually getting from there to executing concrete actions there is a process that the customer has not gone through yet in terms of pulling it off.

Someone to shepherd the project a little more: to introduce it to the company and go through the energy audit and stick with it as a mentor or contact would be useful to get the company to the point that they're confident that the energy savings are going to be significant enough that they impact the bottom line enough to warrant the investment. It's not like the PA just comes into your house, screws in a CFL, and walks away. You actually have to do something. You have to revise the operating strategy of the systems and that requires a lot of time and effort. Working with some to understand what its actually going to take would be useful.

Building a stronger case for the practicality and achievability of the conservation measures is something the customer would recommend would be useful for the programs.

The customer was curious to know how successful the programs have been to warrant Synapse conducting this study.

The customer suggested that the PAs revisit customers who were at one point interested in efficiency but did not follow through to see why they may have been put on hold. If he were trying to see why customers aren't participating in programs, that's where he would start asking questions. If there is a dead-letter file or are open applications where things never came through to fruition that could be a good area to explore and follow up.

Survey of Commercial and Industrial Customer Perspectives of Massachusetts Energy Efficiency Programs

Interview Notes

Region: Cape Cod

Industry: Healthcare

Person(s) Interviewed: Director of Engineering

Interview Number: 35

Key Questionnaire Responses

Note: question numbers correspond to the order in which questions are asked in the questionnaire.

4) Approximate number of company employees located in Massachusetts:

Greater than 50.

5) Building ownership:

Owned.

13) Annual electric costs as a percent of annual operating expenses:

Between five and one percent.

15) Annual natural gas costs as a percent of annual operating expenses:

One percent or less.

16) When purchasing new equipment, does your company consider the efficiency with which that equipment consumes energy?

Yes for the larger equipment. Smaller equipment depends on up front cost.

17) If the answer to question 16 is yes, what criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facility?

Internal rate of return; Payback period; Benefit-cost ratio; Energy bill savings; Other.

18) Prior to being contacted for this interview, were you aware of the energy efficiency programs offered by your electric and gas utilities?

Yes.

20) Has your company ever participated in the energy efficiency programs offered by your electric or gas utility?

Yes, within the past three years.

21) If your company has participated in the energy efficiency programs offered by your electric and gas utilities within the past three years:

Please name one or two things about the program that worked well for your company:

Having some one knowledgeable filling out the paper work.

Please name one or two things about the program that did not work well for your company:

On the electric side, the energy efficiency engineers were dreadfully slow. I need to produce and I can't be waiting on others. It certainly makes me wonder about the qualifications of the company that is being used for the engineering analysis.

22) Based on your current knowledge of the efficiency programs offered by your electric and gas utilities, does your company plan to participate in these programs within the next three years?

Yes.

Predetermined Interview Questions

1. How important are energy costs to your company?

Very important. Energy costs are a high to medium priority for the customer.

2. Please describe the decision-making process that your company undertakes to decide whether to implement an energy efficiency measure.

Efficiency or energy projects have to go through capital budgets.

Once equipment is about to reach the end of its useful life, that's when it will get approved. The company has an annual review process that starts in the spring and is approved by October for the following year. If a project has savings associated with it, it's an easier sell. This past year, the customer had a lighting project and new chillers approved. Originally the customer was supposed to receive incentives for the lighting projects but, as further discussed below, the customer no longer expects the incentives. The customer needs plans now for efficiency upgrades to start putting it through the system for approval for 2013.

There is a chain of review. The person interviewed comes up with a plan, submits it, then all the department managers review everyone's requests, sees which ones are the best, serve the needs of the patients and the facility, then it goes to corporate to see how much money they have to fund everything, they chop out a few more things, then a list of approved projects is provided in October for the following year.

3. What criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facilities?

When purchasing new equipment, the customer considers the implications to its electricity bills and knew it was going to be a significant cost. They didn't buy the equipment based on how much energy it used; they based it on the quality of treatment that is provided to their patients. The decision was made solely on what is the best product for their customers. They knew the equipment would use a lot of electricity, but that was not a consideration in which purchase they made. Patient care first; energy second, or not at all.

Patient care is number one for the customer. But on the other hand, you have to have a facility or else you can't have patient care. There's got to be compromise there. The organization is very good at trying to improve the quality of the facility. The engineering department probably gets more than half of the capital funds available for the plant, equipment, and building, which are big ticket items.

Management is generally receptive to efficiency projects. A lighting project did not pass the corporate review last year. They knew it was going to save money, but they didn't have the funds for it. This year, the project was approved. They do give efficiency serious consideration.

The dollar amount is also considered. The efficiency program incentives allow the person interviewed to ask for less funding from corporate, which makes it more likely to pass approval. Corporate does ask about the rebates and incentives offered through the program and needs a number. As discussed below, the person interviewed does not have an incentive number available for projects because the engineering study has not yet been provided to the customer, so projects have more trouble receiving corporate approval.

The customer looks for shorter paybacks. The CEO stated that the customer is not going to do any projects that have a payback greater than 3 years. But the person interviewed stated that there aren't that many projects with a payback period of less than 3 years out there. Five to seven years is more typical, but are not likely to get approved. When money is tight, they look for shorter paybacks. If there is any money left over at the end of year, then they look at longer paybacks.

However, the company recently purchased air conditioners, and the particular brand purchased by the customer was chosen for its energy efficiency.

4. Please explain why the company chose to participate in the Massachusetts energy efficiency programs.

The customer approached its PA to see if incentives could be received for the air conditioning equipment purchased. The PA also suggested that the customer complete an energy audit, which the customer allowed, but was mostly interested in the air conditioning incentives. The customer is working with, and still working with the PA, and are making "damn little progress and damn slow progress for rebates and stuff, and as far as I know I won't be getting a nickel. I put a lot of time and effort into it." The customer hasn't heard anything from the people that would be giving them the incentive, primarily because the engineering firm has not provided the engineering study.

The customer started the audit process in the middle of summer 2011, and as of March 2012, had not received the engineering study. The engineering company did a "preliminary audit: it was a couple of days of walking through the facility, but it wasn't a detailed study." That was the last the customer has seen or heard from the engineering company, unless the person interviewed calls them directly. When the customer calls, he's told the engineering company needs more information or that they're still looking into it, but nothing definitive. The customer is told that they need to figure out how much the old machines were using and compare that to how much the new machines are using, which doesn't seem that complicated to the person interviewed (who is an engineer). As far as the person interviewed is concerned, it's a waste of his time. "It doesn't take an awful lot of math to figure this stuff out. It doesn't take 9 months. So quite frankly, I'm not going to put my job in jeopardy to save my organization maybe a couple of dollars. It's not worth it."

He's called several times. The customer hasn't tried to call back the engineering company in months, and had no interest in talking to them at all anymore. The customer is unsure if the engineering company is overwhelmed and has too much going on, but the customer hears nothing. They usually have short conversations. They're either overwhelmed or under performers. Dealing with the PAs and engineering company has not been difficult; it's the lack of response that upsets the customer.

The PA isn't the problem, but they're at the mercy of the engineering firm they favor. The PA initially tried to help the customer deal with the engineering firm, but over the last several months the customer "threw up his hands and said to hell with it."

The customer doesn't know how much the air conditioners are going to be incented for, and is getting tired of waiting. The person interviewed thinks it would take another year before they will get the process completed, and has gone ahead with purchasing the ACs without waiting for the PAs. "Their response is poor, and that's being kind." The person interviewed "doesn't have a clue if we'll get a nickel back, or $1,000 back." The customer expected significant rebates when planning to buy the ACs, because its half a million dollars of equipment. The customer is annoyed that they still have not received the engineering study, and that any discussions have been verbal and there is nothing in writing to indicate the incentive amount.

All of the above information is specific to electric. The customer has been in conversations and had an audit with its gas PA but doesn't really have a lot of opportunities with gas measures just yet. The customer doesn't have any equipment that it would replace that would save copious amounts of gas. If the customer had the engineering study, they could at least see what the gas opportunities would be and could set aside capital dollars for it. The customer expects gas measures to be included in the engineering report. However, because of the lack of response from the engineering company, the customer is just going to go ahead with whatever gas measures that need to be done and won't consider the efficiency programs.

There could be small things that the customer does that could be incented through the programs, but the customer is not going to waste his time participating, unless his boss specifically tells him to participate. The person interviewed is just going to go ahead and buy the equipment. The person's time "is a hell of a lot more valuable than the service I'm getting from the people I'm dealing with."

"This is not unusual by the way. Thirty years ago we had programs similar to this, and I threw up my hands then, too. A $70,000 grant to do stuff cost me $200,000 of my time to get it done. So I said nope never again. But I tried it here, and it ain't working here any better than it did 30 years ago."

If the person interviewed is waiting on someone forever and ever and ever, that means he's not getting his job done. If he doesn't get his job done, he's going to have to work someplace else. He's not going to jeopardize his job for someone else's incompetence. Every month, the person interviewed sends status reports to management. Every month, the same projects are not going forward, which makes the person interviewed look bad.

5. How well did the representative of the energy efficiency program administrator understand your company's interests and needs?

6. Did your company decide not to implement any efficiency measures that were offered through the energy efficiency programs?

7. Do you plan to participate in Massachusetts energy efficiency programs in the next three years?

The person interviewed has to look at the incentives and programs or else he would be negligent at his job. But he does not plan to aggressively pursue them. He just doesn't have the time to be chasing after people. That's the bottom line. If his boss doesn't insist that he participate, then he's not going to bother. "What's $5,000? That's nothing for an organization of this size. It's a huge amount of effort."

8. To what extent do budget limitations pose a barrier to your company's participation in energy efficiency programs?

A lighting project did not pass the corporate review last year. They knew it was going to save money, but they didn't have the funds for it.

The new healthcare plan could affect how much money the customer has to put into the building.

The facility is allotted only so many dollars, which are determined by administration of the financing.

9. To what extent do financing limitations pose a barrier to your company's participation in energy efficiency programs?

10. In general, how does the current state of the economy affect your interest and ability to participate in the energy efficiency programs?

The economy will definitely affect efficiency as new healthcare policies take effect. "We give that very serious consideration because we're going to get reimbursed significantly less, which means we're not going to be able to replace aging equipment for new more efficient equipment. Those things are brought up at almost every meeting; we have to be prepared. Every healthcare organization is giving it serious consideration. We have to be able to pay the bills and take care of the patients. If the more efficient equipment has to wait because we don't have the funds, that's the way it is. The better care we give, the better reimbursement we get. We're going to go with the best possible medical equipment we can get to get the best possible outcomes we can get for the patient so we can get reimbursed for a higher rate." They expect to get millions of dollars less than they got before. It's a lot of money. "People are very weary, so they're going to keep money in their pocket so we can get through. If something breaks, then we'll fix it if we have a dollar in the bank." Management is trying to take care of things now while they have the money, and are preparing for the storm.

Barriers to Participation

A. Customer Barriers

   a. Customer's financial limitations

   b. Customer's competition for capital

Yes. A lighting project did not pass the corporate review last year. They knew it was going to save money, but they didn't have the funds for it.

   c. Economic downturn

Yes. Customer is definitely affected by the economy and healthcare policies.

d. Corporate review and approval process

No.

e. Company distrust of new technologies

No.

f. Company convinced it has done all it can

B. Program Design & Administration Barriers

a. Insufficient incentives

Maybe. The person interviewed seemed to think that participation would not save the customer much money, especially compared to the opportunity cost of the time required to participate.

b. Insufficient marketing and outreach

No. Customer was well aware of the programs.

c. Transaction costs

Not really. More the responsiveness and timing.

d. Responsiveness and timing

YES. The customer was very upset that the engineering company took so long to get back to them, and will likely not participate again because of it.

e. Limited measures offered

Not really.

f. Programs not tailored to customer's unique needs

Not really.

g. Policy Issues (Opt out of SBC)

No. Likes the SBC idea.

h. Other (note)

Other Comments

The programs should be changed to provide a faster response. It's not rocket science to figure out how much energy equipment uses or saves. "In a matter of days, I should have an answer as to how much the new equipment is going to cost, save, and be incented for. The money has been paid into the system, and if that's what it's for then I'll try to do my part." "I like the idea that we all put into this little kitty and have the opportunity to get some money back."

The PAs should make it easier to see how much the programs are going to benefit the customer. “Don’t make me wait 9 months to tell me nothing.” Make it simple for the customer and the engineering company. It’s not worth the effort.

The PAs seem to be on top of things and that worked well. They were clear and filled out all the appropriate stuff. Then it went over to the engineering firm and that’s where everything fell apart. The reps are in tune with the programs and what the customer wanted to do, but that’s where it stops.

Survey of Commercial and Industrial Customer Perspectives of Massachusetts Energy Efficiency Programs

Interview Notes

Region: Boston

Industry: Retail

Person(s) Interviewed: Regional Energy Manager

Interview Number: 36

Key Questionnaire Responses

Note: question numbers correspond to the order in which questions are asked in the questionnaire.

4) Approximate number of company employees located in Massachusetts:

Greater than 50.

5) Building ownership:

Owned.

13) Annual electric costs as a percent of annual operating expenses:

Not indicated.

15) Annual natural gas costs as a percent of annual operating expenses:

Not indicated.

16) When purchasing new equipment, does your company consider the efficiency with which that equipment consumes energy?

Yes.

17) If the answer to question 16 is yes, what criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facility?

Internal rate of return, payback period, benefit cost ratio, and energy bill savings.

18) Prior to being contacted for this interview, were you aware of the energy efficiency programs offered by your electric and gas utilities?

Yes.

20) Has your company ever participated in the energy efficiency programs offered by your electric or gas utility?

Yes, prior to the past three years.

21) If your company has participated in the energy efficiency programs offered by your electric and gas utilities within the past three years:

Please name one or two things about the program that worked well for your company:

Ease of filling out the applications.

Please name one or two things about the program that did not work well for your company:

The time to receive the incentive.

22) Based on your current knowledge of the efficiency programs offered by your electric and gas utilities, does your company plan to participate in these programs within the next three years?

Yes.

Predetermined Interview Questions

1. How important are energy costs to your company?

Very important; this priority is communicated from the top down.

2. Please describe the decision-making process that your company undertakes to decide whether to implement an energy efficiency measure.

When a store is about to be built or remodeled, the design managers sit down with the electric, HVAC, and refrigeration experts and determine what energy efficiency upgrades make sense for the space. As early as possible, the interviewee, who is the liaison between the utilities and the company on efficiency, reaches out to the appropriate utility to determine what incentives are available. The incentive is used to calculate ROI for the project. After reviewing the analysis provided by the design managers, the interviewee makes the call on whether to proceed with the measures. The interviewee takes into account her time and effort when determining the measures to proceed with. If a measure offers only a marginal return, but will take a lot of her time and effort, it may not be worth it. Also, she manages stores from Virginia to Maine and is responsible for efficiency across that entire territory.

3. What criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facilities?

The extent to which it can save the company money on their energy usage.

4. Please explain why the company chose to participate in the Massachusetts energy efficiency programs.

Reduced energy costs. The company does have a department in charge of sustainability, but these projects are not the responsibility of that department.

5. How well did the representative of the energy efficiency program administrator understand your company's interests and needs?

The electric program administrators are pretty good; the company has had good relationships with these folks. They have received rebates and incentives from the electric program administrators, but no audit or technical assessment has been conducted (the company has its own engineers to do this).

The company has not heard from the gas companies, though in talking with its electric program administrator, gas programs did come up once.

6. Did your company decide not to implement any efficiency measures that were offered through the energy efficiency programs?

The company drives the boat in terms of which efficiency measures to install. Most of the focus has been on lighting, HVAC and refrigeration, with the biggest savings coming in refrigeration measures.

7. Do you plan to participate in Massachusetts energy efficiency programs in the next three years?

They hope to but it depends on what they will be doing and the ROI of the projects.

8. To what extent do budget limitations pose a barrier to your company's participation in energy efficiency programs?

The interviewee cannot say. This is the responsibility of the design managers.

9. To what extent do financing limitations pose a barrier to your company's participation in energy efficiency programs?

Financing has not been used yet. The interviewee would have to look into this further with her director to determine whether the company would be interested in financing.

10. In general, how does the current state of the economy affect your interest and ability to participate in the energy efficiency programs?

It affects it. They have to make sure that revenues always offset the costs of any energy efficiency improvements they are making.

Barriers to Participation

A. Customer Barriers

   a. Customer's financial limitations

      Not sure.

   b. Customer's competition for capital

      Not sure.

   c. Economic downturn

      Yes.

   d. Corporate review and approval process

      Yes.

   e. Company distrust of new technologies

      No.

   f. Company convinced it has done all it can

      No.

B. Program Design & Administration Barriers

   a. Insufficient incentives

No.

b. Insufficient marketing and outreach

Yes, in that they have not heard about gas opportunities.

c. Transaction costs

Yes, in that this is factored into ROI.

d. Responsiveness and timing

Yes, must align with construction of new stores or remodeling of existing stores.

e. Limited measures offered

No.

f. Programs not tailored to customer's unique needs

No.

g. Policy Issues (Opt out of SBC)

No.

h. Other (note)

Other Comments

Survey of Commercial and Industrial Customer Perspectives of Massachusetts Energy Efficiency Programs

Interview Notes

Region: Western Massachusetts

Industry: Restaurants & Lodging

Person(s) Interviewed: General Manager

Interview Number: N/A: only provided questionnaire

Key Questionnaire Responses

Note: question numbers correspond to the order in which questions are asked in the questionnaire.

4) Approximate number of company employees located in Massachusetts:

Greater than 50.

5) Building ownership:

Owned.

13) Annual electric costs as a percent of annual operating expenses:

One percent or less.

15) Annual natural gas costs as a percent of annual operating expenses:

One percent or less.

16) When purchasing new equipment, does your company consider the efficiency with which that equipment consumes energy?

Yes.

17) If the answer to question 16 is yes, what criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facility?

Payback period; Energy bill savings.

18) Prior to being contacted for this interview, were you aware of the energy efficiency programs offered by your electric and gas utilities?

No.

20) Has your company ever participated in the energy efficiency programs offered by your electric or gas utility?

No.

21) If your company has participated in the energy efficiency programs offered by your electric and gas utilities within the past three years:

Please name one or two things about the program that worked well for your company:

Not aware of any.

Please name one or two things about the program that did not work well for your company:

22) Based on your current knowledge of the efficiency programs offered by your electric and gas utilities, does your company plan to participate in these programs within the next three years?

I have no information about any electric or gas efficiency programs.

Survey of Commercial and Industrial Customer Perspectives of Massachusetts Energy Efficiency Programs

Interview Notes

Region: Boston

Industry: Office

Person(s) Interviewed:

Interview Number: N/A: only provided questionnaire

Key Questionnaire Responses

Note: question numbers correspond to the order in which questions are asked in the questionnaire.

4) Approximate number of company employees located in Massachusetts:

Greater than 50.

5) Building ownership:

Owned.

13) Annual electric costs as a percent of annual operating expenses:

Twenty percent or greater.

15) Annual natural gas costs as a percent of annual operating expenses:

Between ten and five percent.

16) When purchasing new equipment, does your company consider the efficiency with which that equipment consumes energy?

Yes.

17) If the answer to question 16 is yes, what criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facility?

Benefit-cost ratio.

18) Prior to being contacted for this interview, were you aware of the energy efficiency programs offered by your electric and gas utilities?

Yes.

20) Has your company ever participated in the energy efficiency programs offered by your electric or gas utility?

Yes, within the past three years.

21) If your company has participated in the energy efficiency programs offered by your electric and gas utilities within the past three years:

Please name one or two things about the program that worked well for your company:

Enhanced modeling of building

Please name one or two things about the program that did not work well for your company:

Inclusion conditions tied to rebate.

22) Based on your current knowledge of the efficiency programs offered by your electric and gas utilities, does your company plan to participate in these programs within the next three years?

Maybe.

Survey of Commercial and Industrial Customer Perspectives of Massachusetts Energy Efficiency Programs

Interview Notes

Region: Central Massachusetts

Industry: Heavy Industry

Person(s) Interviewed: Plant Manager

Interview Number: N/A: only provided questionnaire

Key Questionnaire Responses

Note: question numbers correspond to the order in which questions are asked in the questionnaire.

4) Approximate number of company employees located in Massachusetts:

Greater than 50.

5) Building ownership:

Owned.

13) Annual electric costs as a percent of annual operating expenses:

One percent or less.

15) Annual natural gas costs as a percent of annual operating expenses:

One percent or less.

16) When purchasing new equipment, does your company consider the efficiency with which that equipment consumes energy?

Yes

17) If the answer to question 16 is yes, what criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facility?

Payback period; energy bill savings.

18) Prior to being contacted for this interview, were you aware of the energy efficiency programs offered by your electric and gas utilities?

Yes.

20) Has your company ever participated in the energy efficiency programs offered by your electric or gas utility?

Yes, prior to the past three years.

21) If your company has participated in the energy efficiency programs offered by your electric and gas utilities within the past three years:

Please name one or two things about the program that worked well for your company:

Please name one or two things about the program that did not work well for your company:

22) Based on your current knowledge of the efficiency programs offered by your electric and gas utilities, does your company plan to participate in these programs within the next three years?

Maybe.

Survey of Commercial and Industrial Customer Perspectives of Massachusetts Energy Efficiency Programs

Interview Notes

Region: Cape Cod

Industry: Heavy Industry

Person(s) Interviewed: Associate Manager, Facilities/Project Engineer

Interview Number: N/A: only provided questionnaire

Key Questionnaire Responses

Note: question numbers correspond to the order in which questions are asked in the questionnaire.

4) Approximate number of company employees located in Massachusetts:

Greater than 50.

5) Building ownership:

Owned.

13) Annual electric costs as a percent of annual operating expenses:

n/a

15) Annual natural gas costs as a percent of annual operating expenses:

n/a

16) When purchasing new equipment, does your company consider the efficiency with which that equipment consumes energy?

Yes.

17) If the answer to question 16 is yes, what criteria does your company use to determine whether to purchase equipment that is relatively energy efficient or to undertake energy efficiency improvements to your facility?

Internal rate of return; Payback period; Benefit-cost ratio; Energy bill savings.

18) Prior to being contacted for this interview, were you aware of the energy efficiency programs offered by your electric and gas utilities?

Yes.

20) Has your company ever participated in the energy efficiency programs offered by your electric or gas utility?

Yes, within the past three years.

21) If your company has participated in the energy efficiency programs offered by your electric and gas utilities within the past three years:

Please name one or two things about the program that worked well for your company:

Contractor was familiar with the reimbursement process and coordinated the majority of those activities.

Please name one or two things about the program that did not work well for your company:

n/a

22) Based on your current knowledge of the efficiency programs offered by your electric and gas utilities, does your company plan to participate in these programs within the next three years?

Maybe.

GREEN ENERGY COALITION INTERROGATORY #13

INTERROGATORY

Reference: Section 6.2.5, p. 102

Preamble:
Synapse recommends that "the Board consider requiring the utilities to develop metrics that focus on program cost-effectiveness."

Question:
If the utilities essentially have fixed budgets once their plans are approved, and if they do not maximize their shareholder incentive until they reach 150% of their goals, don't they already have a very strong incentive to maximize the cost-effectiveness of their programs (at least under the PAC Test) as long as the 100% targets or performance metrics are reasonably aggressive? If not, why not?

RESPONSE

No. A cost-effectiveness metric would ensure that the utilities keep costs low while achieving significant benefits. A fixed budget in and of itself does not encourage the utilities to minimize spending within that budget. Even if the 100% targets are reasonably aggressive, the current incentive structure primarily focuses on achievement of savings, and does not motivate the utilities to also save electricity, water, and the non-energy benefits included in the TRC Plus 15 percent adder.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

GREEN ENERGY COALITION INTERROGATORY #14

INTERROGATORY

Reference: Section 6.2

Question:
Given the types of performance metric proposed by the utilities, does Synapse have any opinion regarding the reasonableness of the specific proposed metric values or targets? If so, please explain.

RESPONSE

Synapse was tasked with reviewing the proposed DSM programs and commenting on the program design elements that could be modified or improved. Therefore, commenting on the reasonableness of the specific proposed metric values or targets is beyond the scope of our work.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

GREEN ENERGY COALITION INTERROGATORY #15

INTERROGATORY

Reference: Section 5.4.2

Question:
Regarding the utilities' prescriptive C&I rebate program:

a. Did Synapse attempt to benchmark the utilities' proposed participation rates and/or savings from any measures in the program against the performance of other leading jurisdictions? If so, what were the results?
b. Would Synapse agree that the utilities' proposed participation rates in the program - at least for many measures - are relatively low? If not, why not?
c. Did Synapse attempt to benchmark the utilities' proposed rebate/incentive levels against those of other leading jurisdictions? If so, what were the results?
d. Does Synapse have any basis for disagreeing with the statement that the utilities could acquire significant additional savings from this program if they either increased incentive levels, moved incentives "upstream", increased marketing efforts, and/or made other changes to program design or implementation?

RESPONSE

a. No. Benchmarking the utilities' proposed participation rates and/or savings from any measures in the program against the performance of other leading jurisdictions is beyond our scope of work.

b. See Exhibit M.Staff.GEC.15, part a.

c. No. Benchmarking the utilities' proposed rebate/incentive levels against those of other leading jurisdictions is beyond our scope of work.

d. Such strategies may increase energy savings. The magnitude of such impacts (e.g., whether significant or insignificant) depends on how well the proposed strategies are designed and implemented.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

ASSOCIATION OF POWER PRODUCERS OF ONTARIO INTERROGATORY #1

INTERROGATORY

Reference:

i. Evidence of Synapse page 1, 3, 4, 5
ii. Evidence of Synapse Section 6 Qualifications and Experience

Preamble:
APPrO would like to better understand Synapse's expertise and evidence as it relates to large volume customers.

Question:

a. Does Synapse have any experience with designing and implementing energy efficiency programs for large volume customers in the size range of Enbridge's Rate 125, and Union's T2 and Rate 100 customers? If so, please describe and provide examples.
b. More specifically, does Synapse have any experience with designing and implementing energy efficiency programs for large-scale gas-fired power generation customers (i.e. up to 1,000 MW)? If so please describe.
c. Synapse identifies a significant free-ridership issue for large commercial and industrial customers and recommends Board action in relation to free-ridership and spillover (leakage). Please provide any and all Synapse expertise relating to: (i) the identification of free-ridership, competitiveness, spill-over, efficacy and cost-effectiveness issues associated with DSM programs for large volume customers, and (ii) the design of any programs or measures to address the issues outlined in c)(i) above.

RESPONSE

a. Yes, Synapse has experience with designing and critiquing the design of energy efficiency programs for large volume customers.

   - Synapse assisted the U.S. Department of Energy in developing a set of resources (i.e., a toolkit) providing the necessary information, resources, frameworks for analysis, and case studies to facilitate the development and deployment of ratepayer-funded Superior Energy Performance (SEP) program offerings to large electric and gas customers. Integrating input from partner energy efficiency program administrators (PAs) with strategic energy management programs and/or programs targeting large customers, Synapse developed the SEP Filing Guide to provide PAs with guidance on the

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

information to include in their program plans, and the Cost-Effectiveness Screening Tool to look at the costs and benefits of a SEP offering.

- Synapse conducted a review of New Jersey Large Energy Users Coalition Request for mitigation of efficiency program surcharges, and provided key input into the design of New Jersey's SBC Credit program serving those customers.
- Synapse conducted a review of the New Jersey Clean Energy Program Pay for Performance program.
- Synapse conducted a survey and prepared a report for the Massachusetts Energy Efficiency Advisory Council on the barriers that large commercial and industrial customers face with regard to implementing energy efficiency.
- Synapse assisted the Arkansas Public Service Commission with developing initial rules for its Opt Out / Self Direct Option for Qualifying Non-Residential Customers (electric and gas).

b. No.

c. (i) and (ii). See Exhibit M.Staff.APPrO.1, part a., regarding the SEP toolkit, with respect to assessing the efficacy and cost-effectiveness of DSM programs for large volume customers.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

ASSOCIATION OF POWER PRODUCERS OF ONTARIO INTERROGATORY #2

INTERROGATORY

Reference: EB-2012-0337 Exhibit C2 Tab A page 5, Navigant states:

> In the US, large industrial customers such as power producers have the option of directly accessing inter-state pipeline system, and the vast majority of natural gas fired electric generators in the US are attached to the inter-state natural gas pipeline system. Where generators are connected to a distribution system, the natural gas distributors often negotiate separate contract rates for such customers to avoid economic by-pass. As a result, electric generators using natural gas as fuel are often not included in general industrial tariffs or subject to cost recovery mechanisms such as a DSM CRM.

Preamble:
APPrO would like to understand if Synapse's assessment of the accuracy Navigant's and its application to the Board's current DSM Framework as applied in this proceeding.

Question:

a. Does Synapse agree with Navigant above-noted statement? Please provide your response and supporting rationale.
b. Are there instances of economic bypass of the LDC by large volume customers that have occurred in Ontario? If so, was there a prudent economic rationale for doing so?

RESPONSE

a. Synapse is aware that electric generators using natural gas as fuel are often not subject to cost recovery mechanisms such as a DSM CRM in the U.S.

b. This question asks for information that is beyond the scope of Synapse's work. However, Synapse is not aware of whether there have been instances of economic bypass of the LDC by large volume customers in Ontario.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

ASSOCIATION OF POWER PRODUCERS OF ONTARIO INTERROGATORY #3

INTERROGATORY

Reference:

i. Synapse evidence
ii. EB-2012-0337 Transcript Volume 2 page 122 lines 10-15, extract from Union's oral argument:

> So on to my first issue, Union's position. Union freely acknowledges that power generation customers possess expertise to undertake energy efficiency programs on their own that result in natural gas savings. In Union's submission, this fact should not be seen as a matter of controversy in this proceeding.

Preamble:
APPrO would like to understand Synapse's and Board Staff's views on large volume customer (including power generator) incentives to self-implement energy efficiency programs.

Question:

a. Please provide an itemization of any and all incentives that large volume customers have to improve their overall operational efficiency and reduce fuel consumption outside of any utility sponsored DSM program.
b. Can you confirm that each of the following are valid reasons for large volume customers to directly undertake and invest in energy efficiency and conservation measures:
   i. Increasing profitability and/or lowering costs through direct savings from lower fuel consumption, purchase and demand requirements
   ii. Complying with strict contractual product off-take and sale provisions including:
      1. Heat rate requirements
      2. Production efficiencies
      3. Maintenance, engineering and industry best practice standards
      4. Prudent operating standards
      5. Management standards (including but not limited to ISO)
      6. Reporting requirements
      7. Green or other labeling requirements
      8. The treatment or limited pass through of fuel costs
      9. Avoiding border measures on higher emission export products (including but not limited to measures such as the First Jurisdictional Deliverer measures on electricity importers into Quebec and California)
   iii. Complying with legislative and regulatory requirements including:

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

1. General environmental regulations
2. Specific facility environmental approvals and permits
3. Emissions reporting and labeling requirements
4. Carbon pricing regimes taking various forms including tax, cap and trade, and/or reduced carbon or carbon neutral procurement requirements

iv. Enhancing competitiveness by lower production costs relative to competitors and imports

v. v. Complying with voluntary initiatives including:

1. Management performance and efficiency standards
2. Corporate social responsibility measures
3. Optimizing investment in, and potentially deferring, untimely infrastructure, replacement, operations and maintenance costs
4. Reporting and green labeling standards, including but not limited to the CDP Program[12] and various Eco-labeling initiatives
5. Customer outreach and education measures

c. Please provide any and all examples of direct large volume customer energy efficiency and conservation measures that Synapse has worked on or otherwise encountered.

d. Please provide your view on the relative cost effectiveness, efficiency, end-use customer impact, and investment in any and all of the measures outlined in (b) and (c) above, relative to paying a third party utility a rate-regulated amount to effect efficiency measure and programs across the applicable industrial rate.

RESPONSE

The response below is from Synapse, who authored the report (and not both Synapse and Board staff as requested in the interrogatory).

a. Refer to Exhibit M.Staff.APPrO.3, part b.

b. Yes, each of the listed items are valid reasons for large volume customers to directly undertake and invest in energy efficiency and conservation measures, except Synapse is not familiar with ii(9).

c. Synapse is generally familiar with a variety of measures, including but not limited to motors, CHP, compressors, pumps, lighting, air handling, process changes, and energy management systems.

[12] https://www.cdp.net/en-US/Pages/HomePage.aspx

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

d. A full response to this question would require extensive effort to compile, and is beyond the scope of Synapse's work. However, we note that even when factors that encourage large volume customers to undertake and invest in energy efficiency and conservation measures are present (such as those listed in part b of this question, and excluding intervention by a program administrator), the literature on this subject indicates that barriers to energy efficiency persist for the industrial sector, and not all viable measures are implemented. Please refer to Exhibit M.Staff.GEC.12. Our report for the Massachusetts Energy Efficiency Advisory Council (see Exhibit M.Staff.GEC.12, Attachment 1) found that one of the main reasons that large volume customers do not implement cost-effective energy efficiency measures is that they have limited access to capital or they prefer to invest their capital in their core area of business.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

ASSOCIATION OF POWER PRODUCERS OF ONTARIO INTERROGATORY #4

INTERROGATORY

Reference: i) Evidence of Synapse Section 9.3.2 pages 123-125

Preamble:
In Reference i) Synapse indicates that it is inherently difficult to estimate free ridership. APPrO would like to better understand the factors that influence free ridership and leakage (spillover) for DSM programs for large volume customers.

Question:

a. Please provide an itemization of any and all factors that can lead to free ridership and/or spillover for commercial or industrial customers.
b. Please advise whether each of the following factors would, if all other factors were held constant, tend to (a) increase the efficacy and effectiveness of direct energy efficiency and conservations measures of a large volume customer and/or (b) decrease free ridership and spillover among large volume customers in a DSM system:
    i. Large volume customer (LVC) has full time staff dedicated to the operation and maintenance of their facilities
    ii. LVC has employee incentive programs to seek out, report and improve the efficiency of their operations
    iii. LVC is subject to potential border measures reflecting emissions or energy efficiency
    iv. LVC has and facilitates a culture of conservation within the organization
    v. LVC operates in a highly competitive environment
    vi. LVC is required to comply with strict contractual product off-take and sale provisions pertaining to any or all of:
        1. Heat rate requirements
        2. Production efficiencies
        3. Maintenance, engineering and industry best practice standards
        4. Prudent operating standards
        5. Management standards (including but not limited to ISO)
        6. Reporting requirements
        7. Green or other labeling requirements
        8. The treatment or limited pass through of fuel costs
    vii. LVC is required to comply with legislative and regulatory requirements including:
        1. General environmental regulations
        2. Specific facility environmental approvals and permits
        3. Emissions reporting and labeling requirements

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

4. Carbon pricing regimes taking various forms including tax, cap and trade, and/or reduced carbon or carbon neutral procurement requirements

viii. LVC is complying with voluntary initiatives including:

1. Management performance and efficiency standards
2. Corporate social responsibility measures
3. Optimizing investment in, and potentially deferring, untimely infrastructure, replacement, operations and maintenance costs
4. Reporting and green labeling standards, including but not limited to the CDP Program2 and various Eco-labeling initiatives

ix. LVC is undertaking customer loyalty, outreach and education measures

RESPONSE

a. Any factor that results in a program participant implementing a program measure or practice even though they would have implemented that measure or practice in the absence of the program can lead to free-ridership. Any factor that results in reductions in consumption due to the presence of an energy efficiency program but beyond the program-related gross savings of the participants and without financial or technical assistance from the program can lead to spillover.

b. Synapse was tasked with reviewing the proposed DSM programs and commenting on the program design elements that could be modified or improved. Synapse did not review or analyze the factors identified above in our report. Therefore, the above question is beyond the scope of our work.

   However, in the spirit of providing complete information, we offer the following.

   In general, it is possible and potentially even probable that the above factors could lead to increases in the efficacy and effectiveness of direct energy efficiency and conservations measures of a large volume customer and/or decreases in free-ridership and spillover among large volume customers in a DSM system, all else being equal. However, without specific proposals that detail the design and implementation of such factors, it cannot be confirmed that such factors will definitively result in net efficiency increases.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

ASSOCIATION OF POWER PRODUCERS OF ONTARIO INTERROGATORY #5

INTERROGATORY

Reference: Evidence of Synapse page 84 Recommendation #1

> To ensure that recommended measures are implemented, Union should (a) collect the costs for the technical assistance from the customer if a customer does not implement the recommendations from the technical assistance, then Union should; (b) require execution of an agreement including customer energy savings commitments; and/or (c) require implementation of all recommended measures that meet certain conditions (e.g., a payback period of 1.5 years or less).

Preamble:
In the above reference Synapse recommends that Union collect the costs of providing technical assistance if the customer does not implement the recommendations from the technical assistance.

Question:

a. Please confirm that the customer is in the best position to make decisions related to the implementation of any particular energy efficiency measures based on the operating characteristics of its particular plant, the customer's cost of capital, contractual requirements, legislative and regulatory permits and approvals, and other factors that Union may not be privy to. If not, please explain.
b. Please confirm that providing technical assistance will not always result in a 'recommendation' to implement a particular energy savings measure.
c. Please advise whether the utility, in any of the programs cited on p. 83 and 84 assumes the financial, legal, or other liability of the LVC customer if the recommended energy savings measure results in prohibited changes to the operating characteristics of particular plant, restricted capital expenditure, a breach of a contractual requirement, a breach of a legislative or regulatory permit or approval.
d. Please provide evidence of the relative costs and effectiveness of a LVC customer: (i) contracting directly for an energy assessment and audit and (ii) engaging a gas utility to indirectly undertake an energy assessment and audit on its behalf.
e. Does Synapse believe that requiring the customer to enter into an agreement to access technical assistance which contains penalty provisions may actually be a disincentive for customers to request technical assistance?

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

RESPONSE

a. Please refer to Exhibit M.Staff.UNION.13. In general, the customer is most familiar with the specific factors referenced in this question. However, program administrators can provide value by, for example, providing information on new technology options, reviewing current processes and equipment from a new/external perspective, assisting with integrating new standards and energy management systems, etc.

b. Please refer to Exhibit M.Staff.UNION.13.

c. Synapse does not know whether the utility, in any of the programs cited on p. 83 and 84 assumes the financial, legal, or other liability of the LVC customer in any of the situations presented in this question. While Synapse believes that it is highly unlikely that a utility would accept the types of liability mentioned above, we believe that program administrators try to avoid creating liabilities when designing and implementing programs. Also, we note that a program administrator who routinely fails to consider these and other factors will have difficulty obtaining new participants in its DSM programs.

d. Synapse has not investigated this issue.

e. Some customers may see such provisions as a disincentive, but may for other customers provide motivation for implementing energy saving measures and reducing energy bills. Please refer to Exhibit M.Staff.UNION.13. Synapse did not intend to propose a specific mechanism to ensure that recommended measures are implemented, but rather meant that such a mechanism should be considered. However, Synapse suggests that if the technical assistance does not identify a recommendation for implementing cost effective energy conservation measures, then no penalty should be imposed.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

ASSOCIATION OF POWER PRODUCERS OF ONTARIO INTERROGATORY #6

INTERROGATORY

Reference:

i. Evidence of Synapse page 84 Recommendation #2

> It would be appropriate to at least conduct a process evaluation to examine the effectiveness of this offering and identify any modifications for offer training, specialized technical support, and audits by qualified Union Professional Engineers.

ii. Exhibit B.T3.Union.APPrO.4

Preamble:
In Reference i), Synapse recommends audits by Union professional engineering staff on the effectiveness of the offering. In Reference ii) Union notes that it is Union's professional engineering staff that will be delivering the services.

Question:

a. Is Synapse aware of any conflict of interest standards or avoidance measures that are applicable to the audit or the auditor(s)?
b. What are the potential impacts if the audit is conducted by either the same people that were, or the same department that was, responsible for delivering the DSM related services in the first place?

RESPONSE

a. No.

b. Synapse meant in this sentence that a process evaluation can identify areas for improvement in the process of conducting energy audits, which may be conducted by qualified Union Professional Engineers. This sentence did not mean to say that Union's Professional Engineers should evaluate Union's offerings. Rather, an independent third party should conduct the evaluation.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

ONTARIO SUSTAINABLE ENERGY ASSOCIATION INTERROGATORY #1

INTERROGATORY

Reference: L.OEBStaff.1, Section 3.1.2, Page 8-9

Question:
From your review on best practices in leading jurisdictions, how do combination (natural gas and electricity) utilities treat cost-effectiveness, such as avoided cost calculations and benefit cost ratios, for applications which affect both gas and electric consumption? For example, how is the cost-effectiveness of implementing ground source heat pumps which replace natural gas heating and electric air conditioning treated?

RESPONSE

Jurisdictions treat cost-effectiveness for gas and electric efficiency programs differently. Examples are provide below.

In Massachusetts, electric and gas efficiency measures are screened for cost-effectiveness separately, even if the program administrator serves both gas and electric customers. This is partly because the Department of Public Utilities reviews and approves energy efficiency programs budgets separately for each gas and electric utility as those costs are collected through separate rate tariffs at each utility. However, for measures such as lighting which save electricity but can result in a heating penalty if a customer's primary heating fuel is gas, oil, or propane. In such instances, the program administrator will claim the electricity savings and benefits, as well as the "negative" gas savings and benefits.

Conversely, Synapse is aware that program administrators in jurisdictions such as California and Wisconsin analyze both gas and electric measures together when conducting benefit-cost analyses.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

ONTARIO SUSTAINABLE ENERGY ASSOCIATION INTERROGATORY #2

INTERROGATORY

Reference: L.OEBStaff.1, Section 7.3, Page 108

Question:
Are there jurisdictions where single fuel utilities promote fuel switching? Please describe these programs.

RESPONSE

Synapse is not aware of many jurisdictions where fuel switching is currently promoted as part of ratepayer funded energy efficiency programs. We are aware of the following instances:

- Several jurisdictions promote solar hot water systems. See Exhibit M.Staff.OSEA.3.
- A few jurisdictions promote combined heat and power systems. See Exhibit M.Staff.OSEA.3 and Exhibit M.Staff.OSEA.4.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

ONTARIO SUSTAINABLE ENERGY ASSOCIATION INTERROGATORY #3

INTERROGATORY

Reference: L.OEBStaff.1, Section 7.3, Page 108

Question:
In jurisdictions where natural gas is on the margin for electricity generation, are more efficient generation modes, such as combined heat and power, credited with both fuel savings and considered DSM/CDM?

RESPONSE

To the best of our knowledge, it is not common to include combined heat and power (CHP) in energy efficiency programs. The only examples we are aware of are in Massachusetts and Rhode Island, where program administrators promote CHP as part of their electric energy efficiency programs. CHP is offered by electric program administrators because it could be viewed as a conflict of interest for natural gas utilities to promote CHP, considering that such a gas sponsored CHP program would increase natural gas sales using ratepayer funds committed to achieving energy savings. Similarly, a proposal to include CHP in a New Jersey gas utilities' energy efficiency program was not accepted partly because CHP was viewed as a load building program.

Please also see Exhibit M.Staff.OGVG.1.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

ONTARIO SUSTAINABLE ENERGY ASSOCIATION INTERROGATORY #4

INTERROGATORY

Reference: L.OEBStaff.1, Section 7.3, Page 108

Question:
Are there any utilities, gas or electric, using renewable energy (solar, solar thermal, solar voltaic, wind, bio gas, storage) for fuel switching away from natural gas or electricity use as part of their DSM/CDM program mix? Please provide the names of the utilities and a description of the DSM/CDM program.

RESPONSE

Yes, Synapse is aware of several electric and gas efficiency program administrators that promote solar hot water (SHW) heaters. See the following examples:

- Massachusetts's MassSave HEAT Loan program provides loans to solar hot water systems. For more information, see http://www.masssave.com/residential/offers/heat-loan-program
- SoCalGas provides offers a SWH program for residential and commercial customers. Residential systems can receive a rebate up to $4,366, and commercial systems can receive a rebate up to $800,000. . For more information, see http://www.socalgas.com/for-your-home/energy-savings/solar-water-heating/
- Hawaii Energy offers a residential SWH program which provides $1000 per participant. For more information, see https://hawaiienergy.com/for-homes/solar-water-heating
- Duke Energy's SunSEnse Solar Water Heating program provides $550 rebate for a residential SHW system. For more information, see https://www.progress-energy.com/florida/home/save-energy-money/energy-efficiency-improvements/sunsense/solar-water-heating.page?

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

ONTARIO SUSTAINABLE ENERGY ASSOCIATION INTERROGATORY #5

INTERROGATORY

Reference: L.OEBStaff.1, Section 7.3, Page 108

Question:
Are there any utilities pursuing performance based conservation such as Toronto and Region Conservation Authority's Sustainable Schools Program (see attached Sample Report)? If so, please provide information about the utilities and the programs.

RESPONSE

Synapse is aware of many residential home energy report programs (e.g. by OPower) that provide high level benchmarking similar to the Sustainable Schools Program mentioned above. For example, Opower has offered home energy report programs to over 70 utilities, most of which are in North America. For more information about Opower's program, see Opower. (2012). Successful Behavioral EE Programs. Available at: https://opower.com/uploads/files/BEE_Whitepaper.pdf. Some of the participating utilities are found at http://opower.com/customers.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

ONTARIO GREENHOUSE VEGETABLE GROWERS INTERROGATORY #1

INTERROGATORY

Reference: SYNAPSE REPORT, Section 7 Coordination Between Electric and Gas Programs

Question:
Please provide expert comments on the opportunity for gas and electric utilities to contribute to reduced electric costs, particularly in areas of transmission congestion, through programs facilitating Combined Heat and Power.

a. Please provide some jurisdictional examples of programs in Synapse experience

RESPONSE

Synapse was tasked with reviewing the proposed DSM programs and commenting on the program design elements that could be modified or improved. Synapse did not conduct a detailed review of the program screening for combined heat and power (CHP) measures from other jurisdictions. Therefore, this question is beyond the scope of our work.

Please also see Exhibit M.Staff.OSEA.3.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

LOW INCOME ENERGY NETWORK INTERROGATORY #1

INTERROGATORY

On which factors (local, provincial and best practice) is Synapse relying to conclude that:

a. Enbridge should offer a full scale program before piloting the low-income new construction offering?
b. Union Gas should offer a low-income new construction offering similar to that of Enbridge?
c. Union Gas should offer a full scale program before piloting its Low-Income Multi-Family offering?

RESPONSE

One best practice for ratepayer funded energy efficiency programs where all customers are contributing a portion of their bill to the energy efficiency programs is to provide efficiency savings to all types of customers in order to promote equity and to help achieve all cost-effective energy efficiency. As a result, we recommend that all core programs that serve key markets be present in each utilities energy efficiency program portfolio. Core programs include Low Income New Construction programs and Low Income Multi-Family programs.

We recognize that the terminology 'pilot' may mean different things to different stakeholders. The terminology is not as important as the key concepts. These two programs should be available to customers who want to participate in them. If they are new, they should be ramped up as quickly as possible. The programs should be evaluated on a frequent basis and program designs should be continually optimized as is done with all other programs.

a. Enbridge should, now and on an ongoing basis, offer rebates and incentives to builders and customers to incent them to build more efficient low income housing.

b. Union Gas should, now and on an ongoing basis, offer rebates and incentives to builders and customers to incent them to build more efficient low income housing.

c. Union Gas should, now and on an ongoing basis, offer rebates and incentives to building owners and inhabitants to incent them to retrofit low income multi-family housing.

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon