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October 28, 2011

BY HAND DELIVERY AND E-FILING

Mark D. Marini, Secretary
Department of Public Utilities
One South Station, 5th Floor
Boston, MA 02110

Re: Cape Light Compact, D.P.U. 11-116
Proposed 2012 Mid-Term Modifications

Dear Secretary Marini:

On behalf of the Cape Light Compact ("Compact"), please find the Compact's mid-term modification ("MTM") filing for effect in calendar year 2012 ("2012 MTMs"), which is submitted pursuant to the Compact's Three-Year Energy Efficiency Plan; § 3.8 of the Department's Revised Energy Efficiency Guidelines ("Guidelines"); the rulemaking Orders of the Department in D.P.U. 08-50-A and in D.P.U. 08-50-B; and the Department's Order on *Electric Three-Year Energy Efficiency Plans-2010-2012*, D.P.U. 09-116 through D.P.U. 09-120 (2010) ("Electric Order"). Included with today's filing are the following materials:

(1) The Compact's Petition for Approval of Mid-Term Modifications, with supporting exhibits:

- ► Exhibit A: Executive Summary
- ► Exhibit B: Compact-Specific Significant Mid-Term Modifications

  Attachment 1: Trigger and Annual Variance Table
- ► Exhibit C: Evaluation, Monitoring, and Verification ("EM&V")
- ► Exhibit D: Performance Incentives (not applicable to the Compact)
- ► Exhibit E: Pilots

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- ► Exhibit F: Cost-Effectiveness

  Attachment 1: BCR Screening Models (*see* CD-ROM)
- ► Exhibit G: Updated 08-50 Tables
- ► Exhibit H: Technical Reference Manual
- ► Exhibit I: Appendices, including:

  Appendix 1: Compact-Specific Notification of Annual Variance

  Appendix 2: Benefits Summary Table

  Appendix 3: MTM Materials Provided to Council in advance of October 11, 2011 Meeting

  Appendix 4: Traditional Bill Impact Analyses

  Appendix 5: Evaluation Studies

(2) Affidavit of Kevin F. Galligan, Energy Efficiency Program Manager

The Compact has worked diligently and collaboratively with its fellow Program Administrators, the Energy Efficiency Advisory Council ("Council"), the Council's consultants, the Attorney General, and other interested stakeholders in the preparation of this filing, which is the Compact's second MTM filing. Before seeking Department approval of this filing, pursuant to §§ 3.8.3 and 3.8.4 of the Guidelines, the Program Administrators, including the Compact, provided information about their proposed 2012 MTMs to the Council for its review in advance of the Council's October 11, 2011 meeting. Since the Council's October meeting, the Program Administrators have obtained informal feedback from the Council and have been working with the Council to respond to that feedback and make any adjustments necessary to their MTM proposals. The Council is continuing to review the MTMs presented by the Compact and its fellow Program Administrators, but has not yet taken any definitive action with respect thereto.

The Compact notes that the filing is limited in scope to significant modifications, as required by Section 3.8 of the Guidelines, as well as those materials specifically required in the Electric Order. Any other change in budgets, savings goals, or incentives that is noted in the enclosed filing, but which does not meet the modification criteria set forth in Section 3.8.2 of the Guidelines, is included solely for informational purposes, and does not constitute a request for approval from the Department. For the Department's convenience, the Program Administrators will submit to the Department a statewide roll-up of the 08-50 tables of all Program Administrators for informational purposes in early November.

In developing their 2012 MTM filings, the Program Administrators, including the Compact, worked proactively and collaboratively with the Low-Income Weatherization and Fuel Assistance Network, Massachusetts Energy Directors Association, the Low-Income Energy Affordability Network (prior three entities, "LEAN"). LEAN, which is charged with implementing residential energy efficiency and related education programs to low-income customers under the Act, has stated that it is generally supportive of the 2012 MTM filings. Nevertheless, it is the understanding of the Program Administrators that LEAN is reserving its right to raise concerns about the Residential and Low-Income Non-Energy Impacts (NEI) Evaluation and Avoided Energy Supply Costs in New England: 2011 Report as necessary.

The $100 filing fee is enclosed. Should you have any questions with respect to today's filing, please do not hesitate to contact me.

Very truly yours,

Jo Ann Bodemer

JAB/drb
Enclosures

cc: Jeffrey M. Leupold, Esq., Hearing Officer (via email and hand delivery 3 copies)
Steven Venezia, Esq., DOER (via email and first class mail)
Danielle Rathbun, Esq., Office of the AG (via email and first class mail)
Jerrold Oppenheim, Esq., LEAN (via email and first class mail)
EEAC Consultants (via email only)
EEAC Councilors (via email only)
Margaret T. Downey, CLC (via email and first class mail)
Kevin F. Galligan, CLC (via email only)
Jennifer Kallay, Synapse Energy Economics (via email only)
(Bulk documents provided solely to Secretary Marini)

COMMONWEALTH OF MASSACHUSETTS

DEPARTMENT OF PUBLIC UTILITIES

CAPE LIGHT COMPACT	))))	D.P.U. 11-116

PETITION FOR APPROVAL OF MID-TERM MODIFICATIONS TO THREE-YEAR ENERGY EFFICIENCY PLAN FOR THE 2012 PLAN YEAR

The Cape Light Compact (the "Compact") respectfully requests approval from the Department of Public Utilities ("Department") pursuant to § 3.8 of the Department's Revised Energy Efficiency Guidelines ("Guidelines") and the Department's Order on *Electric Three-Year Energy Efficiency Plans-2010-2012*, D.P.U. 09-116 through D.P.U. 09-120 (2010) (collectively, "Electric Order"), of certain mid-term modifications ("MTMs") to the Compact's Three-Year Energy Efficiency Plan ("Plan") for effect in calendar year 2012 ("2012 MTMs"). In support of this Petition, the Compact states the following:

1. Petitioner the Cape Light Compact (the "Compact") is a municipal aggregator pursuant to G.L. c. 164, §134 and consists of the twenty-one towns in Barnstable and Dukes Counties, as well as the two counties themselves.

2. It is organized through a formal Intergovernmental Agreement under G.L. c. 40, §4A. The Compact's Aggregation Plan was approved by the Department in D.T.E. 00-47 (August 10, 2000). The Compact maintains a business office within the Barnstable County

offices located at the Superior Courthouse at 3195 Main Street in Barnstable, Massachusetts, 02630.

3. The design, implementation, and cost recovery of the Compact's energy efficiency programs are subject to the jurisdiction of the Department under the provisions of G.L. c. 164 and Chapter 169 of the Acts of 2008, an Act Relative to Green Communities (the "Act").

4. The Guidelines, as well as the Department's Orders in Investigation into Updating Energy Efficiency Guidelines Consistent with an Act Relative to Green Communities, D.P.U. 08-50-A (2009), and Energy Efficiency Guidelines, D.P.U. 08-50-B (2009), allow the Commonwealth's electric and gas distribution companies and municipal aggregators (together, "Program Administrators") to propose, for review and approval by the Department, "significant" MTMs to approved energy-efficiency plans. Guidelines at § 3.8.1.[1] Any such request must be accompanied by "(a) sufficient justification for why the proposed modification is appropriate; and (b) the results of the [Energy Efficiency Advisory] Council's review of the proposed modification." Guidelines at § 3.8.4.

5. In seeking MTMs, the Department has stated that a proposed change must exceed an applicable 20 percent threshold at the program level over the full three-year term of the Plan in order to require an MTM. In Cape Light Compact, D.P.U. 10-106, at 8-9 (2011), the Department clarified § 3.8 of its Guidelines with respect to whether the 20 percent threshold that triggers an MTM filing applies to a program's annual or three-year budget. Noting that the

[1] The Guidelines state that "[a] modification is deemed to be significant if it would result in (a) the addition of a new Energy Efficiency Program or the termination of an existing Energy Efficiency Program; (b) a change in an Energy Efficiency Program budget of greater than 20 percent; (c) an Energy Efficiency Program modification that leads to an adjustment in savings goals that is greater than 20 percent; or (d) an Energy Efficiency Program modification that leads to a change in performance incentives of greater than 20 percent." Guidelines at § 3.8.2.

Act established a three-year cycle for budgeting, planning, and regulatory review of energy-efficiency programs, the Department found that, pursuant to § 3.8.2 of the Guidelines, "Program Administrators are required to seek Department approval for a program budget modification that is *20 percent greater than the program's three-year budget*." D.P.U. 10-106, at 8-9 (emphasis added).

6. In addition, consistent with the procedure for filing an MTM proposal, the Department has directed the Program Administrators to provide updates for review and approval with respect to: (1) evaluation, measurement and verification ("EM&V") studies; (2) performance incentives; (3) pilot program budgets; and (4) if necessary, savings goals and budget modifications reflecting actual outside funding levels obtained. Electric Order, at 142 (2010); *Gas Three-Year Energy Efficiency Plans-2010-2012*, D.P.U. 09-121 through D.P.U. 09-128 at 134-135 ("Gas Order").

7. Under the Guidelines and Orders, the Program Administrators retain discretion to make changes to their programs, including budgetary adjustments, provided that such changes do not trigger an MTM pursuant to the requirements in § 3.8.2 of the Guidelines. See D.P.U. 08-50-A at 64.[2] Notwithstanding this discretion, the Program Administrators have been providing notice to the Energy Efficiency Advisory Council ("Council") and the Department in their MTM filings of discretionary adjustments to certain aspects of the approved Three-Year Energy Efficiency Plans in order to make them as transparent as possible to key stakeholders. Notice of these adjustments is for informational purposes only. These adjustments do not require any action on the part of the Department.

[2] The Department recently reiterated this discretion, in D.P.U. 10-106, at 7-8, when it stated that "the Three-Year Plan review process should move away from routine mid-term and mid-year program modifications."

8. The Compact filed its first request for MTMs on October 29, 2010, in D.P.U. 10-147.[3] As requested by the Department, on the same date, all of the Program Administrators also filed updates to their EM&V plans and performance incentives,[4] and the electric Program Administrators filed pilot program budgets, all as part of the Program Administrators' proposed MTM filings. The Compact also provided, for informational purposes only, notice of certain adjustments to the goals for 2011.

9. On April 15, 2011, following comprehensive negotiations, the Program Administrators, and the Department of Energy Resources, Environment Northeast and the Low-Income Weatherization and Fuel Assistance Network, Massachusetts Energy Directors Association, and the Low-Income Energy Affordability Network jointly filed for approval with the Department a Memorandum of Agreement intended to resolve all issues among the signatories related to the respective requests for MTMs to each Program Administrator's Three-Year Energy Efficiency Plan for the calendar year 2011.

10. In this 2012 MTM filing, the Compact asks the Department to review and approve those revisions and enhancements to the Plan that are "significant" as contemplated by the Department in § 3.8.2 of the Guidelines and its orders interpreting the Guidelines. The Compact also provides sufficient justification herein and in the supporting materials showing that its proposal is appropriate. In addition, as part of this filing and consistent with the Department's Electric Order at 142-43, the Compact provides updates for Department review and approval with respect to: (1) EM&V studies; and (2) pilot program budgets. Finally, as

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[3] On August 13, 2010, the Compact filed a petition seeking mid-year revisions to its three-year plan for the 2010 plan year. Its petition was docketed as D.P.U. 10-106, with the Department's Order issued on January 10, 2011.

[4] As a municipal aggregator, and public entity, the Compact does not participate in performance incentives.

referenced above, the Compact is providing notice, for informational purposes only, of certain Plan changes that do not rise to the level of MTMs and that do not require any Department action.

11. Before seeking Department approval of this filing, pursuant to §§ 3.8.3 and 3.8.4 of the Guidelines, the Compact and the other Program Administrators provided information about their proposed 2012 MTMs to the Council for its review. Following a series of informal meetings and discussions with the Council, the Program Administrators provided 2012 MTM information to the Council in advance of the Council's October 11, 2011 meeting.[5] At that Council meeting, the Program Administrators made written and oral presentations with respect to their 2012 MTMs and responded to questions from individual Councilors. While the Council did not take definitive action on the MTM proposals as presented, the Program Administrators anticipate that the Council will act on the MTM proposals at its next meeting, which is currently scheduled to be held on November 8, 2011. The Compact will keep the Department fully apprised of any definitive Council actions or resolutions with respect to its 2012 MTM proposals. Since the Council's October meeting, the Program Administrators have obtained informal feedback from the Council and have been working diligently and collaboratively with the Council to respond to that feedback and make any adjustments necessary to their MTM proposals.

12. In accordance with the Guidelines and the Electric Order, the Compact submits this Petition requesting approval of its proposed 2012 MTMs and in support of its request provides the following:

A. An Executive Summary, as set forth in Exhibit A;

[5] Individual MTM materials submitted to the Council are included as Exhibit I, Appendix 3 to this filing.

B. The Compact's proposed MTMs to its budgets and savings goals for the 2012 energy efficiency efforts, as modified from those originally set forth in the Plan as approved in the Electric Order, as set forth in Exhibit B;

C. The statewide EM&V Plan for calendar year 2012, as set forth in Exhibit C;

D. Performance Incentives (not applicable to the Compact);

E. The Compact's 2012 pilot program efforts, as detailed in Exhibit E;

F. A narrative discussion demonstrating the cost-effectiveness of the Compact's proposal, including the related benefit-cost ratio screening models, all as set forth in Exhibit F;

G. The Compact's Updated 08-50 Tables, as set forth in Exhibit G; and

H. The Technical Reference Manual, as set forth in Exhibit H.

13. In further support of the requests made in this filing, the Compact is submitting Appendices, attached as Exhibit I, containing detailed supporting information, including:

Appendix 1: Program Administrator-Specific Notifications of Annual Variance

Appendix 2: Benefits Summary Table

Appendix 3: MTM Materials Submitted to the Council Prior to October 11, 2011 Meeting

Appendix 4: Traditional Bill Impact Analyses

Appendix 5: Evaluation Studies Finalized Following Submission of 2010 Annual Reports

14. If approved, the Compact's proposed 2012 MTMs would provide for a total 2012 budget decrease of $13,983,297 and a total 2012 savings decrease of 25,024 MWh, as compared to the amounts originally approved by the Department in the Compact's Three-Year Energy Efficiency Plan (2010-2012) (D.P.U. 09-119) for Plan Year 2012.

15. The Compact's programs, with such modifications as described herein, would continue to be cost-effective if all modifications were approved. See Exhs. F and G.

16. Consistent with the Department's request last year, the Compact provides traditional bill impacts resulting from the total proposed budget change in Exhibit I, Appendix 4. These bill impacts for residential and low-income customers indicate the monthly change in dollars and percentage the customers would experience when compared to the amounts originally approved by the Department in the Compact's Three-Year Energy Efficiency Plan (2010-2012) (D.P.U. 09-119) for Plan Year 2012.

17. This Petition is consistent with the statutory mandate that the Program Administrators pursue "the acquisition of all available energy efficiency." G.L. c. 25, §21(b).

WHEREFORE, the Compact, respectfully requests that the Department:

a) approve the Compact's proposed modifications to its budget and savings goals as set forth in Exhibit B;

b) approve the Compact's 2012 EM&V efforts as set forth in Exhibit C;

c) approve the Compact's 2012 pilot program efforts as set forth in Exhibit E;

d) determine that the Compact's proposed 2012 energy efficiency effort is cost-effective as set forth in Exhibits F and G; and

e) provide such other and further relief as may be necessary or appropriate.

Respectfully submitted by,

CAPE LIGHT COMPACT

By its attorneys,

Jeffrey M. Bernstein, Esq.
Jo Ann Bodemer, Esq.
BCK Law, P.C.
One Gateway Center, Suite 809
Newton, Massachusetts 02458
Telephone: (617) 244-9500

Dated: October 28, 2011

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COMMONWEALTH OF MASSACHUSETTS

DEPARTMENT OF PUBLIC UTILITIES

CAPE LIGHT COMPACT	))))	D.P.U. 11-116

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing documents upon all parties of record in this proceeding in accordance with the requirements of 220 CMR 1.05(1) (Department's Rules of Practice and Procedure).

Dated at Newton, Massachusetts this 28th day of October, 2011.

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EXHIBIT A

Executive Summary

EXECUTIVE SUMMARY

A. Overview

The gas and electric distribution companies and municipal aggregators (together "Program Administrators") are seeking approval from the Department of Public Utilities ("Department") of certain MTMs ("MTMs") to each of their Three-Year Energy Efficiency Plans ("Plans") for effect in the calendar year 2012 ("2012 MTMs"). The 2012 MTMs are the Program Administrators' second request for MTMs pursuant to § 3.8 of the Department's Energy Efficiency Guidelines ("Guidelines"), as revised in Energy Efficiency Guidelines, D.P.U. 08-50-B (2009), and the Department's Orders on Gas Three-Year Energy Efficiency Plans-2010-2012, D.P.U. 09-121 through D.P.U. 09-128 (2010) ("Gas Order") and Electric Three-Year Energy Efficiency Plans-2010-2012, D.P.U. 09-116 through D.P.U. 09-120, at 142 (2010) ("Electric Order").[1] On October 29, 2010, the Program Administrators filed their first proposed MTMs to their individual Plans for effect in the calendar year 2011 ("2011 MTMs"). Subsequently, the Program Administrators and key stakeholders negotiated a Memorandum of Agreement ("MOA") resolving all issues among the signatories related to the MTMs for calendar year 2011, which was filed for approval with the Department on April 15, 2011.

In their 2012 MTM filings, the Program Administrators seek Department approval of those revisions and enhancements to the Plan that are "significant" as contemplated by the Department in § 3.8.2 of the Guidelines and its Orders interpreting the Guidelines. In addition, as part of the 2012 MTM filings, the Program Administrators provide updates for Department

[1] The Gas Order and Electric Order were approved by the Department on January 28, 2010.

review and approval with respect to: (1) EM&V studies; (2) performance incentives;[2] and (3) pilot program budgets, consistent with the Department's Gas Order at 134-135 and Electric Order at 142-143 (together, "Orders"). Finally, as part of the 2012 MTM filings, the Program Administrators provide notice, for informational purposes only, of certain changes to the Plans that do not rise to the level of a MTM and thus do not require any Department action.

B. Approval of Three-Year Plans

The Program Administrators have been statutorily charged with developing Plans that "provide for the acquisition of all available energy efficiency and demand reduction resources that are cost effective or less expensive than supply." G.L. c. 25, § 21(b)(1). In developing the Plans for 2010-2012, the Program Administrators engaged in a collaborative, iterative process, producing multiple draft versions of the Plans and considering the comments of the Energy Efficiency Advisory Council ("Council") and other interested stakeholders. On October 30, 2009, the Program Administrators filed their individual Plans with the Department. Following a discovery period and hearings, the Program Administrators and interested parties submitted briefs to the Department.

On January 28, 2010, the Department issued Orders on the Plans, approving them subject to limited specified exceptions and directives. Electric Order; Gas Order. The Department is required to determine the cost-effectiveness of the individual Plans on an annual basis. Id. § 21(d)(2). To fulfill this oversight requirement, the Department requires the Program Administrators to file Annual Reports on their energy efficiency activities. D.P.U. 08-50, at 38 (2008); D.P.U. 08-50-C, at 4 (2011).[3] The Program Administrators are also statutorily required

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2 As a municipal aggregator and public entity, the Compact does not participate in performance incentives. Any discussion, herein, does not apply to the Compact.

3 The Program Administrators filed their 2010 Annual Report with the Department on August 15, 2011.

to provide quarterly reports to the Council and the Council is charged with providing an annual report to the Department. G.L. c. 25, § 22(d).[4,5]

C. MTM Requirements from Guidelines

In Investigation into Updating its Energy Efficiency Guidelines Consistent with An Act Relative to Green Communities, D.P.U. 08-50-A (2009) and Energy Efficiency Guidelines, D.P.U. 08-50-B (2009), the Department directed the Program Administrators to seek Department approval for the following MTMs: "(1) the addition of a new program or the termination of an existing program; (2) a change in a program budget of greater than 20 percent; (3) a program modification that leads to an adjustment in savings goals that is greater than 20 percent; or (4) a program modification that leads to a change in performance incentives of greater than 20 percent." D.P.U. 08-50-A at 64; Guidelines at § 3.8.2. Under the Guidelines, these are considered "significant" MTMs that trigger Department review and approval. Guidelines at § 3.8.1, § 3.8.2. Any such request must be accompanied by "(a) sufficient justification for why the proposed modification is appropriate; and (b) the results of the Council's review of the proposed modification." Guidelines at § 3.8.4; see also D.P.U. 08-50-A at 64. In establishing these standards, the Department "sought to balance the need for Program Administrators to make improvements to energy efficiency programs during the course of the Three-Year Plans, with the need for adequate regulatory review and stakeholder input of significant changes to the Program Administrators' planning assumptions and parameters." Electric Order at 134; Gas Order at 125.

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4 Pursuant to the Orders, the Program Administrators are also required to provide a copy of their quarterly reports to the Department for informational purposes.

5 The Program Administrators' third quarter Quarterly Report includes current updates on program implementation and enhancements, such as program design enhancements, new delivery strategies/initiatives, and community mobilization initiatives in the field. The Program Administrators filed Part 1 of the Quarterly Report on October 6, 2011 and will file Part 2 on November 2, 2011.

In their 2012 MTMs filings, the Program Administrators have proposed MTMs based on 20 percent variances for review and approval only when there is a change in budget, savings goals, or performance incentives of greater than 20 percent at the program level over the full three-year term of the Plans. In Cape Light Compact, D.P.U. 10-106, at 8-9 (2011), the Department clarified that Program Administrators are required to seek Department approval only for a program budget modification that is 20 percent greater than the program's three-year budget. D.P.U. 10-106, at 8-9. In addition, in their 2012 MTMs filings, the Program Administrators have proposed MTMs for any instance where a program is being added or subtracted, pursuant to § 3.8.2 of the Guidelines.

D. Supplemental Filing Requirements from Orders

The Department has directed the Program Administrators to file, consistent with the procedure for filing a MTM proposal, updates for review and approval with respect to: (1) EM&V studies; (2) performance incentives; and (3) pilot program budgets (2011 and 2012 for electric; 2012 only for gas). See Electric Order at 142; Gas Order at 134-135. Accordingly, as part of the 2012 MTM filing, the Program Administrators provide for Department review and approval updates for those three categories, consistent with the Department's Gas Order at 134-135; Electric Order at 142-143.

E. Notice of Discretionary Program Changes

Under the Guidelines and Orders, the Program Administrators retain discretion to make changes to their programs, including budgetary adjustments, provided that such changes do not trigger an MTM pursuant to the requirements in § 3.8.2 of the Guidelines. See D.P.U. 08-50-A at 64.[6] Notwithstanding this discretion, the Program Administrators have been providing notice

[6] The Department recently reiterated this discretion, in D.P.U. 10-106, at 7-8, when it stated that "the Three-Year Plan review process should move away from routine mid-term and mid-year program modifications."

to the Council and the Department in their MTM filings of discretionary adjustments to certain aspects of the approved Plans in order to make them as transparent as possible to key stakeholders. Notice of these adjustments is for informational purposes only. These adjustments do not require any action on the part of the Department.

F. Description of 2012 MTM Filing

1. 2012 Modifications- Budget, Savings, Performance Incentives

The Compact's 2012 MTMs, which are proposed pursuant to § 3.8.2 of the Guidelines, are set forth in Exhibit B. In order to achieve the greatest level of accuracy possible, the Program Administrators determined whether a particular change triggered the 20 percent threshold necessary for a proposed MTM based upon the best available data as to actual performance. Specifically, the Program Administrators used the following data to compute the 20 percent variances: (a) 2010 evaluated results as submitted to the Department in each Program Administrator's 2010 Annual Report; (b) 2011 values as set forth in each Program Administrator's 2011 MTMs; (c) and the 2012 values as proposed herein. The Program Administrators have used the following data as the planned values in their calculations: (a) 2010 values set forth in the Plan (or as approved in a 2010 mid-year modification, if applicable); (b) 2011 values as set forth in each Program Administrator's 2011 MTMs; and (c) the 2012 values set forth in the Plan. These values used to calculate the 20 percent variances represent the most accurate analysis to date, including evaluation results that have had a significant effect on claimed savings, particularly for gas Program Administrators.

Applying the principles set forth herein, in this filing, the Compact proposes certain limited MTMs to its budgets and savings goals for 2012, which require Department approval. Exhibit B, Attachment 1 describes these "triggering" modifications for which the Compact seeks Department approval, as well as a brief narrative of the factors driving those changes.

As set forth in Exhibit B, the Compact proposes adjustments to the following programs:

- Residential New Construction & Major Renovation (33% increase in budget, 46% increase in savings)
- Residential Cooling & Heating Equipment (22% decrease in budget, 25% decrease in savings)
- Multi-Family Retrofit (66% decrease in budget, 64% decrease in savings)
- ENERGY STAR Lighting (26% decrease in budget, 29% decrease in savings)
- Low-Income Residential New Construction & Major Renovation (36% increase in budget, 40% increase in savings)
- Low-Income Retrofit (33% decrease in savings)
- C&I New Construction and Major Renovation (32% decrease in savings)
- C&I Small Retrofit (52% decrease in budget, 51% decrease in savings)

2. Program Consolidation and Addition/Subtraction of Programs

The Program Administrators have proposed a consolidation of the low-income single family retrofit and low-income multi-family retrofit programs in order to form one low-income retrofit program. This combined program has been proposed in order to provide greater flexibility to address market circumstances and demands for program services in the field by low-income customers, to help ensure robust overall program cost-effectiveness, and to potentially provide opportunities for administrative efficiencies over time. Additionally, this consolidation is expected to provide in-the-field experience with programs that have separate initiatives operating within a single program, which is an approach the Program Administrators are exploring in advance of the next three-year plan.

In addition to the Low-Income Retrofit consolidation, and as set forth in Exhibit B, the Compact proposes the subtraction of the following pilot programs:

- Home Automation Pilot
- Heat Pump Water Heater Pilot

3. Outside Funding

The Plans approved by the Department included savings goals and budgets that were contingently predicated on certain planning assumptions with respect to the acquisition of outside funding. Specifically, the electric Program Administrators projected that they would secure $100 million and $200 million for 2011 and 2012, respectively, on a statewide basis; the gas Program Administrators projected that they would secure $20 million and $40 million for 2011 and 2012, respectively, on a statewide basis. The Program Administrators, however, recognized that the scope of available funding for those years could not be ascertained until they had explored potential funding sources fully. For planning purposes, the Program Administrators assumed that sixty percent (60%) of these dollars would be available in the form of funds/grants that would directly off-set program costs, similar to Forward Capacity Market (“FCM”) and Regional Greenhouse Gas Initiative (“RGGI”) funds, with the other forty percent (40%) of these dollars forming a loan or similar pool that would provide capital to customers, which would be repaid through on-bill or other mechanisms. Outside funding at the levels set forth in the original assumptions in the Plans has not materialized (largely due to the lack of any new Federal energy efficiency funding or greenhouse gas/cap and trade legislation).

Despite outside funding levels not reaching the very ambitious levels set forth in the Plans, the Program Administrators have not proposed to reduce portfolio savings goals for 2012 based on outside funding levels. In addition, the Compact has not increased its 2012 portfolio budget in any material manner. At a portfolio level, the Compact’s planned 2012 savings and budgets approved in the Plan were 48,597 MWh and $32,297,216 respectively; in today’s MTM filings, these values are 23,573 MWh and $18,313,920. The Compact's updated savings goals and budgets are reflected in the updated D.P.U. 08-50 tables included in Exhibit G.[7]

4. EM&V

Working collaboratively and with the Council, the Program Administrators are continuing to undertake extensive EM&V efforts designed to ensure accuracy and accountability in program planning and implementation. In accordance with the Department's directive (see Electric Order at 132, Gas Order at 122), Exhibit C sets forth a statewide update on EM&V efforts for 2012, including new initiatives planned for 2012 that have been collaboratively developed by the Program Administrators. The Program Administrators will continue to review the EM&V plan throughout the program year, adding additional studies when and if deemed necessary by the Program Administrators, working with the Council.

5. Performance Incentives

Pursuant to the Orders, the Department approved the proposed incentive pool allocation for 2010 but directed the Program Administrators to develop a revised method of allocating the statewide performance incentive pool among the various Program Administrators for the 2011 and 2012 program years. See Electric Order at 115, Gas Order at 114. In Exhibit D, the Program Administrators propose such a revised allocation model, which was developed collaboratively by the Program Administrators and the Council for 2011 and updated for 2012. The proposed model has been structured to improve the distribution of incentives among the three components - savings, value, and performance metrics - so that the Program

[7] In its Orders, the Department approved the Compact's bill impacts analysis for both of the budget scenarios presented, with full outside funding and without such funding. For informational purposes, the Compact provides traditional bill impacts resulting from the total proposed budget change in Appendix 4. These bill impacts for residential and low-income customers indicate the monthly change in dollars and percentage the customers could experience when compared to the amounts originally approved for 2012 in connection with the Department's approval of the Plan.

Administrators' incentives are aligned more closely and so that the Program Administrators' individual target component ratios are closer to the statewide average. This model eliminates the potential for anomalies in the performance metric component, while retaining the common payout rates for the savings and value mechanism that were approved by the Department.

Additionally, the Program Administrators have developed revised performance metrics in collaboration with the Council. These metrics are based on certain 2010 performance metrics, as well as metrics submitted to the Department in conjunction with the MOA proposed to resolve the 2011 MTMs.

6. Pilot Program Budgets

Pursuant to the Department's directive, the Compact is requesting approval of adjustments to its six pilot programs and associated budgets for 2012. See Electric Order at 142/Gas Order at 134-135. Exhibit E describes the Compact's pilot programs and related budgets for 2012.

7. Cost-Effectiveness

Consistent with the statutory mandate that the Plans "provide for the acquisition all available energy efficiency and demand reduction resources that are cost-effective or less expensive than supply" see G.L. c. 25, § 21(b)(1), the Council and the Department are each tasked with periodically reviewing and ensuring the continuing cost-effectiveness of programs. See G.L. c. 25, § 21(b)(3). In connection with the 2012 MTM filings, the Program Administrators provide updated benefit-cost ratios ("BCR") through program screening analysis that reflect the continuing cost-effectiveness of each Program Administrator's programs. See Exhibit F, Att. 1. BCR screening was conducted in accordance with the Total Resource Cost test, which has been reviewed and approved by the Department. Electric Order at 48; Gas Order at 47; D.P.U. 08-50-A at 14. Information regarding program cost-effectiveness is set forth in Exhibit F.

8. D.P.U. 08-50 Tables

In Exhibit G, the Program Administrators provide updated D.P.U. 08-50 Tables reflecting updated savings goals and budgets for 2012 incorporating the results of the Program Administrators' extensive EM&V efforts, the assumptions of the Technical Reference Manual-2012 Plan Version ("TRM"), anticipated program enhancements, and in-the-field experience, as well as actual levels of outside funding. Discount and inflation rates have been updated in compliance with the Department's Order in D.P.U. 08-50-A and the Guidelines at § 3.4.6. Evaluation studies reflected in the D.P.U. 08-50 Tables that were finalized following the 2010 Annual Reports are provided in Exhibit I, Appendix 5.

9. Technical Reference Manual

Today's filing includes a complete version of the statewide TRM updated for 2012. See Exhibit H. This collaboratively developed document provides detailed information, at a measure level, for all prescriptive measures installed by the Program Administrators, and the savings assumptions the Program Administrators plan to use when planning and reporting savings as a result of the implementation of energy efficiency programs. The TRM will be updated and refined over time to reflect new EM&V results, the addition of new measures, and the best data available.

10. Notice of Discretionary Program Changes

In Exhibit I, Appendix 1, in the spirit of cooperation and transparency, the Program Administrators provide notice for informational purposes of certain discretionary adjustments to the Plans that do not meet the Guidelines threshold for MTMs. These notices include any program-level budget, savings, or performance incentives variances that exceed 20 percent on an annual basis. In addition, the Program Administrators provide notice of any change involving an annual budget increase at the sector level of 15 percent for C&I programs or 20 percent for Residential and Low-Income programs. While not required, this sector-level notification is being provided in order to address any bill impact concerns, due to the fact that cost recovery mechanisms operate at the sector level. Lastly, the Program Administrators provide information regarding material program design changes that involve certain initiatives within programs, but do not fundamentally change the program. None of these adjustments rise to the level of MTMs, and therefore no Department action is required with respect to the materials provided in Exhibit 1, Appendix 1.

11. Meeting with Council

Following a series of informal meetings and discussions with the Council, the Program Administrators, pursuant to §§ 3.8.3 and 3.8.4 of the Guidelines, provided information relating to their proposed 2012 MTMs to the Council for review in advance of the Council's October 11, 2011 meeting. Compact-specific MTM materials submitted to the Council are included as Exhibit I, Appendix 3 to this filing. At that Council meeting, the Program Administrators made written and oral presentations with respect to their 2012 MTMs and responded to questions from individual Councilors. While the Council did not take definitive action on the MTM proposals as presented, the Program Administrators anticipate that the Council will act on the MTM proposals at its next meeting, which is currently scheduled to be held on November 8, 2011. The Program Administrators will keep the Department fully apprised of any definitive Council actions or resolutions with respect to their 2012 MTM proposals. Since the Council's October meeting, the Program Administrators have obtained informal feedback from the Council and have been working diligently and collaboratively with the Council to respond to that feedback and make any adjustments necessary to their MTM proposals.

12. Conclusion

The Program Administrators are successfully delivering energy savings efficiently and effectively at a scale that is unprecedented. In contemplating adjustments to their Plans for 2012, the Program Administrators sought to identify program improvements that will help to achieve the ambitious savings goals for 2012, that are based upon compelling in-the-field experience and that consider the very difficult economic climate in the Commonwealth, particularly in certain service territories. The proposed 2012 MTMs are consistent with the Guidelines and Department precedent, and will enable significant enhancements and adjustments to the Program Administrators' existing energy efficiency efforts, which have been cited as national models of excellence. Allowing the Program Administrators' proposed 2012 MTMs will permit the Program Administrators to continue providing results that benefit the environment, the economy and end-use customers.

T:\Clients\BCY\EEP\EEP Implementation\2010 - 2012 EEP Filing\2012 MTM Filing (DPU 11-116)\Exhibit A Executive Summary with Compact Summary.doc

<u>Attachment 1</u>
to

Exhibit B

<u>Trigger Table</u>

CAPE LIGHT COMPACT, 2012 MID-TERM MODIFICATIONS, OCTOBER 28, 2011

SAVINGS (Annual MWhs)

Program	2010 Actuals [1]	2011 MTM [3]	2012 Proposed Goal [4]	Proposed Goal 2010-2012 [6]	2010 MYR [2]	2011 MTM [3]	2012 Filed Goal [5]	Filed Goal 2010-2012 [7]	Annual % Difference [8]	3 Year % Difference [9]	MTM Trigger on Savings [10]
Residential	**8,372**	**19,364**	**13,315**	**41,051**	**10,179**	**19,364**	**23,888**	**53,432**	**-44.3%**	**-23.2%**	
Residential New Construction & Major Renovation	333	287	610	1,229	271	287	283	841	115.5%	46.2%	**MTM TRIGGER**
Residential Cooling & Heating Equipment	305	585	363	1,253	374	585	701	1,660	-48.2%	-24.5%	**MTM TRIGGER**
Multi-Family Retrofit	70	783	-	853	609	783	971	2,363	-100.0%	-63.9%	**MTM TRIGGER**
MassSAVE	3,917	5,244	4,591	13,752	4,063	5,244	6,423	15,731	-28.5%	-12.6%	
Behavior/Feedback Program	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
ENERGY STAR Lighting	2,844	11,220	6,551	20,616	4,199	11,220	13,571	28,990	-51.7%	-28.9%	**MTM TRIGGER**
ENERGY STAR Appliances	903	1,245	1,200	3,348.13	663	1,245	1,939	3,847	-38.1%	-13.0%	
Low Income	**628**	**2,250**	**1,413**	**4,291**	**1,416**	**2,250**	**2,669**	**6,335**	**-47.1%**	**-32.3%**	
Low-Income Residential New Construction	41	14	-	55	11	14	15	39	-100.0%	39.8%	**MTM TRIGGER**
Low-Income Retrofit [11]	587	2,236	1,413	4,236	1,405	2,236	2,654	6,295	-46.8%	-32.7%	**MTM TRIGGER**
C&I	**6,378**	**17,612**	**8,846**	**32,835**	**14,730**	**17,612**	**22,040**	**54,381**	**-59.9%**	**-39.6%**	
C&I New Construction and Major Renovation	407	3,841	3,732	7,980	2,917	3,841	4,960	11,717	-24.8%	-31.9%	**MTM TRIGGER**
C&I Large Retrofit	1,623	1,923	4,982	8,529	4,769	1,923	2,596	9,289	91.9%	-8.2%	
C&I Small Retrofit	4,347	11,848	132	16,326	7,044	11,848	14,484	33,375	-99.1%	-51.1%	**MTM TRIGGER**
Total Portfolio	**15,378**	**39,226**	**23,573**	**78,177**	**26,325**	**39,226**	**48,597**	**114,148**	**-51.5%**	**-31.5%**	

Notes:
1. As filed in the Cape Light Compact's 2010 Energy Efficiency Annual Report, D.P.U. 11-68
2. As filed in the Cape Light Compact's 2010 Mid-Year Revisions Filing Approved at D.P.U 10-106
3. As this filing assumes approval of the 2011 Mid-Term Modifications, this data is as filed in the Cape Light Compact's 2011 Mid-Term Modifications Filing, D.P.U. 10-147
4. Proposed 2012 changes presented in this filing, representing additional budget requirements for 2012, taking into account 2011 estimated carryover
5. As filed in the Cape Light Compact's 2010-2012 Three-Year Plan Filing, D.P.U. 09-119, as amended in the 2010 Mid-Year Revisions Filing, as Approved at D.P.U. 10-106, and amended in the 2011 Mid-Term Modifications Filing, D.P.U. 10-147 in Exhibit F, page 2 of 4, as this filing assumes approval of the 2011 Mid-Term Modifications filing.
6. 2010 Actuals, 2011 MTM and 2012 Proposed Goal
7. 2010 Appvd Mid-Year Revisions (D.P.U. 10-106), 2011 MTM (D.P.U. 10-147) and 2012 Goal
8. Annual % Difference = (2012 Proposed Goal - 2012 Filed Goal)/2012 Filed Goal
9. 3 Year % Difference = (Proposed Goal 2010-2012 - Filed Goal 2010-2012)/Filed Goal 2010-2012
10. Indicates if the 3 Year % Difference is greater than or equal to +/- 20% at the program level
11. Combined Low-Income 1 to 4 Family Retrofit and Low-Income MultiFamily Retrofit

CAPE LIGHT COMPACT, 2012 MID-TERM MODIFICATIONS, OCTOBER 28, 2011

BUDGET (PA Costs $)

Program	2010 Actuals [1]	2011 MTM [3]	2012 Proposed Goal [4]	Proposed Goal 2010-2012 [6]	2010 MYR [2]	2011 MTM [3]	2012 Filed Goal [5]	Filed Goal 2010-2012 [7]	Annual % Difference [8]	3 Year % Difference [9]	MTM Trigger on Savings [10]
Residential	**$ 6,388,566**	**$ 12,386,208**	**$ 11,163,540**	**$ 29,938,315**	**$ 9,449,462**	**$ 12,386,208**	**$ 15,306,769**	**$ 37,142,439**	**-27.1%**	**-19.4%**	
Residential New Construction & Major Renovation	$ 525,503	$ 235,663	$ 390,055	$ 1,151,222	$ 380,019	$ 235,663	$ 251,010	$ 866,692	55.4%	32.8%	**MTM TRIGGER**
Residential Cooling & Heating Equipment	$ 522,990	$ 890,256	$ 714,541	$ 2,127,787	$ 640,525	$ 890,256	$ 1,186,949	$ 2,717,730	-39.8%	-21.7%	**MTM TRIGGER**
Multi-Family Retrofit	$ 37,519	$ 521,038	$ -	$ 558,557	$ 443,571	$ 521,038	$ 681,917	$ 1,646,526	-100.0%	-66.1%	**MTM TRIGGER**
MassSAVE	$ 3,626,015	$ 7,408,109	$ 7,816,026	$ 18,850,149	$ 5,516,024	$ 7,408,109	$ 9,394,107	$ 22,318,240	-16.8%	-15.5%	
Behavior/Feedback Program	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
ENERGY STAR Lighting	$ 817,217	$ 2,018,330	$ 1,211,282	$ 4,046,829	$ 1,159,453	$ 2,018,330	$ 2,300,966	$ 5,478,749	-47.4%	-26.1%	**MTM TRIGGER**
ENERGY STAR Appliances	$ 386,404	$ 358,766	$ 396,326	$ 1,141,496	$ 253,545	$ 358,766	$ 564,411	$ 1,176,721	-29.8%	-3.0%	
Residential Education Program	$ 60,812	$ 195,000	$ 105,000	$ 360,812	$ 186,000	$ 195,000	$ 205,000	$ 586,000	-48.8%	-38.4%	
Workforce Development	$ 3,309	$ 15,000	$ 15,000	$ 33,309	$ 15,000	$ 15,000	$ 15,000	$ 45,000	0.0%	-26.0%	
Heat Loan Program	$ 120,133	$ 45,000	$ 110,000	$ 275,133	$ 30,000	$ 45,000	$ 60,000	$ 135,000	83.3%	103.8%	
R&D and Demonstration	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
Deep Energy Retrofit	$ 26,659	$ 80,000	$ -	$ 106,659	$ 83,333	$ 80,000	$ -	$ 163,333	0.0%	-34.7%	**MTM TRIGGER**
Behavior/Feedback Pilot	$ 74,496	$ 161,667	$ 176,486	$ 412,649	$ 233,333	$ 161,667	$ -	$ 395,000	0.0%	4.5%	
Residential New Construction - Major Renovation Statewide Pilot	$ 43,992	$ 278,452	$ -	$ 322,444	$ 257,547	$ 278,452	$ 308,752	$ 844,751	-100.0%	-61.8%	**MTM TRIGGER**
Residential New Construction - Multi Family (4-8 story) Statewide Pilot	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
Residential New Construction - Lighting Design Statewide Pilot	$ 11,264	$ 22,222	$ -	$ 33,486	$ 22,222	$ 22,222	$ 22,222	$ 66,667	-100.0%	-49.8%	**MTM TRIGGER**
Residential New Construction - V3 Energy Star Homes Statewide Pilot	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.0%	0.0%	
Heat Pump Water Heater Pilot	$ 9,022	$ 11,111	$ -	$ 20,133	$ 11,111	$ 11,111	$ 11,111	$ 33,333	-100.0%	-39.6%	**MTM TRIGGER**
Residential Technical Development	$ 12,611	$ 20,000	$ 20,000	$ 52,611	$ 20,000	$ 20,000	$ 20,000	$ 60,000	0.0%	-12.3%	
Hot Roofs	$ -	$ 9,000	$ 15,000	$ 24,000	$ 3,000	$ 9,000	$ 15,000	$ 27,000	0.0%	-11.1%	
Home Automation Pilot	$ -	$ 25,000	$ -	$ 25,000	$ 10,800	$ 25,000	$ 25,000	$ 60,800	-100.0%	-58.9%	**MTM TRIGGER**
Community Based Pilot	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
Statewide Marketing & Education	$ 39,970	$ 50,000	$ 90,000	$ 179,970	$ 50,000	$ 50,000	$ 50,000	$ 150,000	80.0%	20.0%	
EEAC Consultants	$ -	$ -	$ -	$ -	$ 93,555	$ -	$ 152,000	$ 245,555	-100.0%	-100.0%	
DOER Assessment	$ 46,639	$ 28,505	$ 89,134	$ 164,277	$ 28,456	$ 28,505	$ 28,557	$ 85,517	212.1%	92.1%	
Sponsorships & Subscriptions	$ 24,010	$ 13,090	$ 14,691	$ 51,791	$ 11,967	$ 13,090	$ 14,768	$ 39,825	-0.5%	30.0%	
Low Income	**$ 1,826,691**	**$ 2,854,274**	**$ 3,145,453**	**$ 7,826,419**	**$ 2,088,750**	**$ 2,854,274**	**$ 3,755,545**	**$ 8,698,569**	**-16.2%**	**-10.0%**	
Low-Income Residential New Construction	$ 100,180	$ 33,772	$ -	$ 133,952	$ 28,666	$ 33,772	$ 36,301	$ 98,739	-100.0%	35.7%	**MTM TRIGGER**
Low-Income Retrofit [11]	$ 1,704,413	$ 2,791,728	$ 3,027,265	$ 7,523,406	$ 2,033,309	$ 2,791,728	$ 3,687,470	$ 8,512,508	-17.9%	-11.6%	
Statewide Marketing & Education	NA	NA	$ 15,000	$ 15,000	NA	NA	NA	NA	NA	NA	
Low-Income Energy Affordability Network Funding	$ 11,790	$ 24,000	$ 80,000	$ 115,790	$ 22,000	$ 24,000	$ 27,000	$ 73,000	196.3%	58.6%	
DOER Assessment	$ 10,309	$ 4,774	$ 23,188	$ 38,271	$ 4,774	$ 4,774	$ 4,774	$ 14,322	385.7%	167.2%	
C&I	**$ 5,315,961**	**$ 9,659,199**	**$ 4,004,926**	**$ 18,980,086**	**$ 7,098,577**	**$ 9,659,199**	**$ 13,181,769**	**$ 29,939,546**	**-69.6%**	**-36.6%**	
C&I New Construction and Major Renovation	$ 729,220	$ 1,287,876	$ 1,457,124	$ 3,474,220	$ 905,004	$ 1,287,876	$ 1,755,174	$ 3,948,054	-17.0%	-12.0%	
C&I New Construction and Major Renovation - Government	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
C&I Large Retrofit	$ 1,575,123	$ 941,260	$ 2,307,088	$ 4,823,470	$ 1,807,995	$ 941,260	$ 1,331,718	$ 4,080,972	73.2%	18.2%	
Large C&I Retrofit - Government	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
C&I Small Retrofit	$ 2,972,638	$ 7,403,822	$ 107,728	$ 10,484,187	$ 4,289,871	$ 7,403,822	$ 9,936,866	$ 21,630,559	-98.9%	-51.5%	**MTM TRIGGER**
C&I Small Retrofit - Government	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
Community based Pilot	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
Statewide Marketing & Education	NA	NA	$ 46,000	$ 46,000	NA	NA	NA	NA	NA	NA	
EEAC Consultants	$ -	$ -	$ -	$ -	$ 70,295	$ -	$ 130,500	$ 200,795	-100.0%	-100.0%	
DOER Assessment	$ 35,036	$ 15,331	$ 74,678	$ 125,045	$ 15,380	$ 15,331	$ 15,279	$ 45,991	388.8%	171.9%	
Sponsorships & Subscriptions	$ 3,945	$ 10,910	$ 12,309	$ 27,164	$ 10,033	$ 10,910	$ 12,232	$ 33,175	0.6%	-18.1%	
Total Portfolio	**$ 13,531,218**	**$ 24,899,682**	**$ 18,313,920**	**$ 56,744,820**	**$ 18,636,789**	**$ 24,899,682**	**$ 32,244,083**	**$ 75,780,554**	**-43.2%**	**-25.1%**	

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CAPE LIGHT COMPACT, 2012 MID-TERM MODIFICATIONS, OCTOBER 28, 2011

PERFORMANCE INCENTIVES

The Cape Light Compact does not have performance incentives, therefore this is not applicable to the Cape Light Compact.

EXHIBIT B

Significant Mid-Term Modifications

I. KEY ASSUMPTIONS

1) Current benefit/cost analysis incorporates updated avoided costs from the recently completed study "Utilizing Avoided Energy Supply Costs in New England: 2011 Report (July 21, 2011, Amended August 11, 2011)", available at http://www.synapse-energy.com/Downloads/SynapseReport.2011-07.AESC.AESC-Study-2011.11-014.pdf ("2011 Avoided Cost Study"). The screening models reflect the following tables from the 2011 Avoided Cost Study: the Massachusetts tables set forth in Appendix B for electric PAs, and the Northern and Central New England tables set forth in Appendix D for gas PAs.

2) Proposed 2012 savings reflect recent program experience, anticipated program enhancements, and recent EM&V results as set forth in the updated Massachusetts Technical Reference Manual- 2012 Planned Version ("TRM") (including, but not limited to, the Residential and Low-Income Non-Energy Impacts study). The TRM is available on the consultants' SharePoint site.

3) Discount and inflation rates have been updated in compliance with the D.P.U. 08-50 Order and the Energy Efficiency Guidelines.

4) 2012 budgets take into account preliminary 2011 projected carryover.

5) Performance incentives do not apply to the Cape Light Compact.

II. MID TERM MODIFICATIONS[1]

A. ADDED/TERMINATED OR ENHANCED PROGRAMS/PILOTS
1. Home Automation Pilot (Terminated): As stated in its 2010 Annual Report, the Cape Light Compact did not sign a contract with an implementation partner in 2010, as the available partners did not have technologies that met the pilot requirements. While additional attempts were made to find and work with a partner in 2011, there continued to be an issue finding a partner that had a technology that would work within the pilot's parameters. At this time, as a partner has not been identified, the Cape Light Compact does not anticipate the need for any budget for this pilot in 2012.
2. Heat Pump Water Heater Pilot (Terminated): Based on favorable evaluation results to date, no funding in 2012 for this pilot is planned, as this pilot will move to become a measure within programs.
3. As further described below (please see Item #5 of the Notification section) the Cape Light Compact with other PAs have continued to make enhancements to their programs, including: the launch of the Upstream C&I Lighting Initiative and the Codes and Standards (C&S) Initiative. In addition, the PA's statewide residential program enhancements planned for 2012 do not require an MTM filing.
4. The Cape Light Compact, in coordination with all electric and gas PAs on a statewide basis, is proposing to consolidate its low-income single family retrofit and low-income multifamily retrofit programs into one low-income retrofit program. This consolidation has a number of benefits including: 1) providing greater flexibility to address market circumstances and demands for program services in the field by low-income customers; 2) helping ensure robust overall program cost-effectiveness; 3) providing in-the-field experience with operating a consolidated program in the low-income sector (similar to the C&I model where separate initiatives are grouped under a single program) which is an approach that will be explored for the next three year plan; and 4) potentially providing opportunities for administrative efficiencies over time. The Compact notes that it would continue to track expenses and participation for both its single family and multi-family low income initiatives in order to maintain transparent reporting and would not change contractual arrangements with service providers for these initiatives as a result of this consolidation. The PAs have had initial discussions with LEAN with respect to this consolidation and LEAN has indicated that such an approach could yield benefits.

[1] Twenty percent variations are calculated as the new three-year plan minus the original three-year plan as modified by mid-year-revisions and mid-term modifications divided by original three-year plan as modified by mid-year-revisions and mid-term modifications, as expressed by this formula: ((2010 Actuals + 2011 Plan MTM + 2012 Plan MTM) – (2010 Plan MYR + 2011 Plan MTM + 2012 Plan)) / (2010 Plan MYR + 2011 Plan MTM + 2012 Plan).

B. BUDGET CHANGE OF +/-20% OR MORE OVER THREE YEAR PERIOD AT PROGRAM/PILOT LEVEL
1. Residential New Construction & Major Renovation, 33% increase: Based on projects that have applied for participation and actuals thus far, the Cape Light Compact will have a change of budget by more than +20%. This is the result of one large unexpected project with 39 units that began in 2011, as well as past participation in the Green Affordable Homes Program that was referenced in the 2010 Annual Report.
2. Residential Cooling & Heating Equipment, 22% decrease: This program has experienced a significant ramp up in budget since the Cape Light Compact reintroduced it in 2009. However, based on experience in 2010 and YTD actuals for 2011, participation levels cannot support an additional ramp up of program budget as originally planned for 2012.
3. Multi-Family Retrofit, 66% decrease: As stated in its 2010 Annual Report, the Cape Light Compact does not have many traditionally defined Residential Multi-Family customers in its territory (for example, high rises and apartment complexes). Further, the new program design, finalized after plan approval, now precludes the Cape Light Compact from serving gas customers. As a result, the Cape Light Compact does not anticipate enough participation to substantiate significant budget increases beyond spending in 2010.
4. ENERGY STAR Lighting, 26% decrease: As stated in its 2010 Annual Report, this program started off slowly but has progressed at a good pace. However, due to a change in measure mix, available shelf space, 2010 actuals and YTD actuals for 2011, anticipated participation levels cannot support the additional ramp up as originally planned for 2012.
5. Deep Energy Retrofit, 35% decrease: Planned budgets for 2010 were not fully spent, which has resulted in a significant offset of the three-year budget need.
6. Residential New Construction - Major Renovation Statewide Pilot, 62% decrease: As stated in its 2010 Annual Report, the renovation and new construction markets for new, efficient additions are significantly smaller than expected, which is greatly impacting participation. As a result, the Cape Light Compact does not expect enough participants to substantiate additional budget increases beyond the carryover of 2011 funds into 2012.
7. Residential New Construction – Lighting Design Statewide Pilot, 50% decrease: Based on expected carryover of funds from plan year 2011, the necessary budget to continue the pilot in 2012 will be minimal.
8. Low-Income Residential New Construction, 36% increase: The 2010 planned budget was exceeded due to the Green Affordable Homes grant, which resulted in a significant increase in the three-year budget need.
9. C&I Small Retrofit, 52% decrease: As stated in its 2010 Annual Report, this program did not spend its budget in 2010 because there were fewer participants and a lower cost per participant than anticipated. The Cape Light Compact expects this trend to continue. Therefore, the Cape Light Compact cannot support the ramp up in budget as originally planned for in 2012.

C. SAVINGS GOAL ADJUSTMENT OF 20% OR MORE OVER THREE-YEAR PERIOD AT PROGRAM LEVEL
1. Residential New Construction & Major Renovation, 46% increase: Based on current projects and actuals thus far, the Cape Light Compact will have a change of savings by more than +20%. This is the result of one large unexpected project with 39 units that began in 2011, as well as past participation in the Green Affordable Homes Program that was referenced in the 2010 Annual Report.
2. Residential Cooling & Heating Equipment, 25% decrease: This program has experienced a significant ramp up in savings since the Cape Light Compact reintroduced it in 2009. However, based on experience in 2010 and YTD actuals for 2011, participation levels cannot support an additional ramp up of program savings as originally planned for in2012.
3. Multi-Family Retrofit, 64% decrease: As stated in its 2010 Annual Report, the Cape Light Compact does not have many traditionally defined Residential Multi-Family customers in its territory (for example, high rises and apartment complexes). Further, the new program design, finalized after plan approval, now precludes the Cape Light Compact from serving gas customers. As a result, the Cape Light Compact does not anticipate enough participation to substantiate significant increases beyond savings in 2010.
4. ENERGY STAR Lighting, 29% decrease: As stated in its 2010 Annual Report, this program started off slowly but has progressed at a good pace. However, due to a change in measure mix, available shelf space, 2010 actuals and YTD actuals for 2011, anticipated participation levels cannot support the additional ramp up as originally planned for in 2012.
5. Low-Income Residential New Construction, 40% increase: The 2010 planned budget was exceeded due to the Green Affordable Homes grant, which resulted in a significant increase in the three-year budget need.
6. Low-Income Retrofit, 33% decrease: Both Low-Income 1 to 4 Family Retrofit and Low-Income MultiFamily Retrofit programs are contributing to the need for revised savings goals. As stated in its 2010 Annual Report, in order to better service the Low Income Multi-Family program, the implementation vendor hired a Multi-Family assessor in 2010 that has recently become fully operational. However, several challenges still exist, including program design changes that now preclude the Cape Light Compact from serving gas customers. Also, as stated in its 2010 Annual Report, there were understated savings for Low Income 1 to 4 Family due to the continued use of a deemed savings value for weatherization. As a result, the Cape Light Compact plans to increase savings beyond levels in 2010, but cannot support the ramp up in savings as originally planned for in 2012.
7. C&I New Construction and Major Renovation, 32% decrease: As stated in its 2010 Annual Report, the current economic climate makes it especially difficult to plan for C&I New Construction and Major Renovation projects. While the Cape Cod and Martha's Vineyard new construction industry is holding steady with many new starts in progress, some project scopes were scaled back between planning and implementation phases in 2010, and that pattern, so far, exists in 2011. As a result, the Cape Light Compact cannot support a significant ramp up of savings beyond the planned savings for 2011.

C. SAVINGS GOAL ADJUSTMENT OF 20% OR MORE OVER THREE-YEAR PERIOD AT PROGRAM LEVEL (CONT'D)
8. C&I Small Retrofit, 51% decrease: As stated in its 2010 Annual Report, this program did not achieve savings goals in 2010 because there were fewer participants and the cost to achieve the savings was higher than projected. The Cape Light Compact expects this trend to continue. Therefore, the Cape Light Compact cannot support the ramp up in savings as originally planned for in 2012.

D. PERFORMANCE INCENTIVE CHANGE OF 20% OR MORE OVER THREE-YEAR PERIOD BASED ON PROGRAM MODIFICATION
Not Applicable

EXHIBIT C

Evaluation, Measurement, and Verification

Introduction

In accordance with the EM&V resolution agreed to on September 8, 2009, statewide evaluation efforts have been divided into multiple research areas. As presented in Table 1, each research area has contracted with an independent evaluation team that is responsible for the completion of all agreed upon evaluation efforts within its research area.

Table 1: Statewide Research Area & Evaluation Contractor

RESEARCH AREA	LEAD EVALUATION CONTRACTOR
Residential Lighting & Appliances	Nexus Market Research
Residential Retrofit & Low Income	Cadmus
Residential New Construction	Nexus Market Research
Non-Residential Small Business	Cadmus
Large Commercial & Industrial	KEMA
Special & Cross-Cutting	Tetra Tech & Opinion Dynamics (2 contracts)

Current and Planned Research

Table 2 details the studies in each of the six research areas that (1) have been completed since the filing of the 2010 Annual Reports on August 15, 2011, (2) are underway but not yet complete, or (3) are expected to commence in 2011 or early 2012. Using this numbering system, the status of each study is noted in the last column. Some of the descriptions have expected completion dates, and some of the studies that recently kicked off currently do not have expected completion dates listed in this draft.

This table includes only those studies that have been already been planned; additional evaluation may be planned throughout 2012. In addition, these studies and schedules are tentative and subject to change based, among other things, on the results of in-progress evaluation studies.

Table 2: Current and Planned EM&V Research

STUDY	DESCRIPTION	EXPECTED START DATE/STATUS
Residential New Construction		
Phase II: Baseline Study/Code Compliance Assessment	Underway, three quarters of the way through the field work, draft report due December 31, 2011	Currently ongoing Status: (2)
Major Renovation Pilot	Waiting for more completions, draft report due January 31, 2012.	Currently ongoing Status: (2)
Homebuyer Survey	Surveys complete, analysis underway, final report due December 31, 2011	Currently ongoing Status: (2)
Assessment of New Technologies	Initial memo completed August 29, 2011. Subsequent research will be performed on a quarterly basis if Program Managers identify additional technologies of interest.	Currently ongoing Status: (2)
Builder Focus Groups	Complete, final report due September 30, 2011.	Final stages Status: (1)
Residential Retrofit & Low Income		
Impact Evaluation of the Home Energy Services program	The goal of this study is to review and quantify savings assumptions used by the PAs and determine the best value or calculation to enable PAs to have consistent assumptions statewide. This program includes Mass Save and the gas weatherization program.	March 2011 Status: (2)
Market Research of the Home Energy Services program (to support the Residential Performance Metric #2 – Threshold)	Scope to be discussed. A market research plan will be developed and conducted to explore the potential of leveraging existing market opportunities within this program.	Late fall 2011 Status: (3)
Potential Study of the Multifamily Program	The goal of the evaluation is to provide a descriptive, cross-sectional assessment of the market size and characteristics of multi-family buildings within the state. Site visits to support the effort were completed in late August 2011.	August 2010 Status: (2)

STUDY	DESCRIPTION	EXPECTED START DATE/STATUS
Process and Impact evaluation of Multifamily Program	The goal of this research is to assess program processes and identify similarities and differences between the perspectives and assumptions of program staff, trade allies, and customers regarding the goals, design, and implementation of the program. Additionally, an impact evaluation will be performed to review and quantify savings assumptions and impact factors used by the PAs and determine the best value or calculation to enable PAs to have consistent assumptions statewide.	March 2011 Status: (2)
Net-to-Gross study on Residential Cooling & Heating Equipment (Cool Smart)	The goal of this study is to perform a free ridership and spillover study to assess the true impacts to this program.	Fall 2011 Status: (3)
Process and Impact evaluation of Low Income program	The goal of this research is to do some follow up analysis from the process work already completed, and to assess program processes and identify similarities and differences between the perspectives and assumptions of program staff, trade allies, and customers regarding the goals, design, and implementation of the program. Additionally, an impact evaluation will be performed to review and quantify savings assumptions used by the PAs and determine the best value or calculation to enable PAs to have consistent assumptions statewide.	March 2011 Status: (2)
Process and Impact Evaluation of Home Energy Services Bundled Measure Pilot	The goal is to assess customers' perceptions of packaged measures and their effect on decision making process and an analysis of the acceptance rate for packaged measures. In addition we want to estimate aggregated savings; compare with non- bundled participants for estimate of interactive effects by PA and statewide. This analysis will assist PAs in determining whether this pilot could potentially be a program offering.	September 2011 Status: (2)

STUDY	DESCRIPTION	EXPECTED START DATE/STATUS
Coincident Factor Study	The goal of this study is update the Quantec model currently used to calculate coincident factors utilized in the cost effectiveness model. This study will provide 8760 load shapes and will include a variety of measures; all PAs will be able to utilize this study for determining accurate coincident factors.	September 2011 Status: (2)
NTG study of the High Efficiency Heating Equipment (HEHE) program.	This goal of this NTG study is to obtain spillover for this program.	August 2011 Status: (2)
Process and Impact Evaluation of the Solar Thermal Domestic Hot Water Pilot	The goal of this evaluation is to obtain customer/contractor perceptions of the pilot in addition to obtaining actual savings associated with this measure and to recommend whether the pilot could potentially be offered as a program measure.	June 2011 Status: (2)
Process and Impact Evaluation of the WI FI Thermostat Pilot	The goal of this evaluation will assist in understanding the energy impacts attributable to the pilot, as well as to determine potential ways to improve the program offering should it expand beyond the pilot phase.	June 2011 Status: (2)
Electronically Commutated Motor (ECM) Circulator Pump pilot program.	The goal of this evaluation is to determine the energy savings potential of replacing split phase motors in residential boiler pumps with high-efficiency ECMs. In addition to assessing energy savings, the study aims to test the reliability of single and multiple pump installations.	June 2011 Status: (2)
Impact Evaluation of the Brushless Fan Motor (BFM)	This study seeks to identify savings associated with the BFM retrofits in residential HVAC applications. Anticipated completion of this study is October 2011.	August 2010 Status: (2)
Impact of Gas Training	Scope has not yet been determined.	TBD Status: (3)
Residential Lighting & Appliances		
Market assessment on lighting measures	Assess the changing and evolving lighting marketplace	Fall/winter 2011 Status: (3)

STUDY	DESCRIPTION	EXPECTED START DATE/STATUS
Shelf stocking survey of MA retailers	Understanding retailers stocking of efficient lighting equipment	Fall 2011 Status: (3)
Lighting on-site saturation study	Understanding lighting and products market	Fall/winter 2011 Status: (3)
Baseline study for lighting based on EISA	Guiding principles and measurement of baseline based on new CFL efficiency standards	October 2011 Status: (3)
Consumer electronic exploratory evaluation	Still under discussion	TBD Status: (3)
Non-Residential Small Business		
Integrated Program Process Evaluations	1. Effectiveness of DI program in serving 200-300kW customers 2. Focused study of incentive and financing options to motivate program participation Scope currently under discussion.	Fall 2011 Status: (3)
Lighting Fixture Summer Metering Impact Evaluation	Additional metering for a subset of Non-Controls Lighting Fixture Impact study sites with uncertain seasonal operating hours	July 2011 Status: (2)
Lighting Controls Impact Evaluation	Pre/Post metering impact evaluation of 2011 program participant sites with lighting control measures	January 2011 Status: (2)
Large Commercial & Industrial		
Process Evaluation of the Large Commercial and Industrial Energy Efficiency Programs	Examination of efficiency of current practices. Suggested topics for study span gas and electric integration to similarities and differences of PA tracking systems.	September 2011 Status: (2)
New Construction Baseline Code Compliance Study	On-site interviewing of EE customers, property owners, etc to gauge program effects on adoption. Also on-site interviewing of non-EE customers to determine actual baseline efficiencies.	September 2011 Status: (2)
Custom Electric Measures Impact Evaluations (Lighting, Process, Compressed Air)	Determination of PA specific and statewide realization rates. Lighting involves a 12 month logger study and lighting is the first stage of a two year custom electric evaluation to be followed by refrigeration and motors.	September 2011 Status: (2)

STUDY	DESCRIPTION	EXPECTED START DATE/STATUS
Prescriptive Gas Measures Impact Evaluation	On-site monitoring of furnaces, conventional boilers, and infrared heaters. Possible inclusion of condensing boilers.	September 2011 Status: (2)
Custom Gas Measures Impact Evaluation	Continuation of 2010 study examining custom measures. Determination of PA specific and statewide realization rates.	September 2011 Status: (2)
Prescriptive Measure Impact Evaluation (VSDs)	Determination of PA specific and statewide realization rates. VSD involves pre and post VSD installation metering.	Ongoing Status: (2)
Prescriptive Measure Impact Evaluation (Lighting)	Determination of PA specific and statewide realization rates. Lighting involves a 12 month logger study.	September 2011 Status: (2)
CHP Impact Evaluation	Determination of PA specific and statewide realization rates. All CHP installations currently being metered and evaluated for therms and kWh.	Ongoing Status: (2)
Potential Study to assess the mid-sized C&I customers	Scope not yet determined but this study would focus on understanding mid-sized non-residential customers (300-750 kW, including both electric and gas potential), without duplicating ongoing assessment work.	TBD Status: (3)
Special & Cross Cutting		
Phase II: Behavioral Pilots	Tasks include impact analysis of NSTAR's OPower program, impact analysis of the WMECO Efficiency 2.0 program, Effective Useful Life of National Grid's impact findings, and initiating a baseline survey for CLC Tendril pilot.	June 2011 Status: (2)
Phase II: Community Based Pilots	Phase II of 2011 research includes participant interviews, participation analysis and a possible costs/savings assessment. The form and extent of the cost/savings assessment is currently under discussion.	September 2011 Status: (2)
Phase II: Umbrella Marketing	Evaluate the framework, reach and effectiveness of the statewide marketing campaign, and provide actionable recommendations to inform ongoing program design and implementation.	February 2011 Status: (2)

STUDY	DESCRIPTION	EXPECTED START DATE/STATUS
C&I Gas Net-to-Gross Study 2010 Projects	Quantify the Net-to-Gross impact factors for 2010 C&I projects. Study was completed in late August 2011.	April 2011 Status: (1)
C&I Gas Net-to-Gross Study 2011 Projects	Quantify the Net-to-Gross impact factors for 2011 C&I projects.	TBD – Early 2012 Status: (3)
Non-Energy Impacts 2011 – Residential & Low Income	Quantify the Non-Energy Impacts of the Residential & Low-Income programs. Study was completed in late August 2011.	June 2010 Status: (1)
Non-Energy Impacts 2011 - C&I: non-Custom	Quantify the Non-Energy Impacts of prescriptive C&I measures.	Fall 2011 Status: (3)
Non-Energy Impacts 2011 – Deep Energy Retrofit	This study is TBD based on planned pilot redesign	TBD Status: (3)
Additional study conducted by New England Clean Energy Council		
Job Creation Study	Study to quantify job creation by sector, resulting from the implementation of the Three Year Plans. Build on previous work conducted.	Winter 2011 Status: (3)

<u>EXHIBIT D</u>

<u>Performance Incentives</u>

As a municipal aggregator and public entity, the Cape Light Compact does not participate in performance incentives.

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EXHIBIT E

Pilots

Exhibit E

Pilots

The information set forth in this Exhibit E represents the Compact's adjustments to its energy efficiency pilots. The Compact's Three-Year plan provided for six pilots[1] as follows: Deep Energy Retrofit, Behavior Feedback Pilot, Residential New Construction- Major Renovation Statewide Pilot, Residential New Construction- Lighting Design Statewide Pilot, Heat Pump Water Heater Pilot and a Home Automation Pilot.

The Compact did not seek prior EEAC approval of its 2012 pilot budget adjustments. Since approval of the Compact's 2012 MTM will result in its pilot budget for Plan Year 2012 to drop below the 1% of budget threshold, EEAC approval is not required.

Specifically, as noted on Exhibit B, Attachment 1, the only pilot the Compact is allocating 2012 budget ($176, 486) is for the Behavior/Feedback Pilot.

The following summarizes the Compact's 2012 MTM for pilots:

For Department's Approval:

1. Heat Pump Water Heater Pilot- terminated (see Exhibit B);
2. Home Automation Pilot- terminated (see Exhibit B);
3. Deep Energy Retrofit – 35% budget decrease due to carryover (see Exhibit B)
4. Residential New Construction – Major Renovation Statewide Pilot – 62% budget decrease due to carryover (see Exhibit B) and;
5. Residential New Construction- Lighting Design Statewide Pilot- 50% budget decrease due to carryover (see Exhibit B).

For Informational Purposes

6. Behavior Feedback Pilot- 4.5% increase to the three year approved budget.

[1] Due to the demographics of its service territory, the Compact's three-year plan did not contain any budget allocation for the Residential New Construction – Multi Family (4-8 story) Statewide Pilot and the Residential New Construction-V3 Energy Star Homes Statewide Pilot.

EXHIBIT F

Cost-Effectiveness

EXHIBIT F

Cost-Effectiveness

The Program Administrators have updated the cost-effectiveness screening associated with the energy efficiency programs and services they plan to administer in 2012 using the Total Resource Cost ("TRC") test, consistent with Department's directive in D.P.U. 08-50-A (confirming the Department's long-standing policy established in D.T.E. 98-100 (2000)). Additionally, as directed by the Department in the 2009 energy efficiency plan dockets, the Program Administrators included pre-tax performance incentives in their cost-effectiveness analyses for 2012. Unless otherwise stated below, all Compact programs continue to be cost-effective based on these analyses, consistent with the statutory mandate that the Plans "provide for the acquisition of all available energy efficiency and demand reduction resources that are cost-effective or less expensive than supply." G.L. c. 25, §21(b)(1).

The TRC test produces and examines the overall benefit-cost ratio of the energy efficiency programs. It compares the present value of future system and other customer savings to the total of the expenditures and customer costs necessary to implement the programs. Programs usually consist of numerous measures. The benefit for a measure is the net present value of the avoided costs (*i.e.*, value of the savings) associated with the net savings of the measure over the life of that measure. The net savings reflect findings from evaluation studies. The measure life is based on the technical life of the measure modified to reflect expected measure persistence. The TRC test is conducted at a program and sector level, building on the measure-level analysis.

The assumptions used by the Program Administrators in the benefit cost analyses undertaken for the 2012 mid-term modification filings are consistent with the analyses reviewed and approved in the Plan. Updates have been made where applicable to reflect recently finalized impact evaluations, the 2011 Avoided Cost Study, as well as updates based on the finalized TRM.

Please refer to the screening models, which have been filed in CD-Rom format as Exhibit F, Attachment 1. For more detailed information on the cost-effectiveness of the Compact's portfolio of program offerings, please refer to the updated D.P.U. 08-50 tables as set forth in Exhibit G.

T:\Clients\BCY\EEP\EEP Implementation\2010 - 2012 EEP Filing\2012 MTM Filing (DPU 11-116)\Exhibit F Cost Effectiveness write-up MTM 2012 v.3 Final.doc

<u>EXHIBIT G</u>

<u>Updated 08-50 Tables</u>

IV.B. Electric PA Funding Sources

1. Summary Table

Allocation of Funding Sources, 2010							
Sector	**SBC (1)**	**FCM (2)**	**RGGI (3)**	**Other (4)**	**Carryover (5)**	**EERF (6)**	**TOTAL**
Residential	$2,644,835	$255,895	$1,169,485	$0	$261,833	$6,126,905	**$10,458,953**
% of Residential	25%	2%	11%	0%	3%	59%	**100%**
Low Income	$114,833	$11,110	$50,776	$0	$12,425	$43,830	**$232,975**
% of Low Income	49%	5%	22%	0%	5%	19%	**100%**
Commercial & Industrial	$2,217,235	$214,524	$980,410	$836,700	$132,802	$3,563,190	**$7,944,861**
% of Commercial & Industrial	28%	3%	12%	11%	2%	45%	**100%**
TOTAL	**$4,976,904**	**$481,529**	**$2,200,671**	**$836,700**	**$407,060**	**$9,733,925**	**$18,636,789**
% of Total	**27%**	**3%**	**12%**	**4%**	**2%**	**52%**	**100%**

Allocation of Funding Sources, 2011							
Sector	**SBC (1)**	**FCM (2)**	**RGGI (3)**	**Other (4)**	**Carryover (5)**	**EERF (6)**	**TOTAL**
Residential	$2,653,181	$336,236	$1,193,064	$1,340,539	n/a	$8,259,551	**$13,782,571**
% of Residential	19%	2%	9%	10%	n/a	60%	**100%**
Low Income	$112,763	$14,290	$50,706	$56,974	n/a	$59,347	**$294,081**
% of Low Income	38%	5%	17%	19%	n/a	20%	**100%**
Commercial & Industrial	$2,211,355	$280,243	$994,387	$1,117,303	n/a	$6,219,742	**$10,823,030**
% of Commercial & Industrial	20%	3%	9%	10%	n/a	57%	**100%**
TOTAL	**$4,977,299**	**$630,769**	**$2,238,158**	**$2,514,817**	**n/a**	**$14,538,640**	**$24,899,683**
% of Total	**20%**	**3%**	**9%**	**10%**	**n/a**	**58%**	**100%**

Allocation of Funding Sources, 2012							
Sector	**SBC (1)**	**FCM (2)**	**RGGI (3)**	**Other (4)**	**Carryover (5)**	**EERF (6)**	**TOTAL**
Residential	$2,650,267	$389,986	$895,717	$2,690,227	n/a	$6,073,402	**$12,699,598**
% of Residential	21%	3%	7%	21%	n/a	48%	**100%**
Low Income	$109,450	$16,106	$36,991	$111,101	n/a	$63,436	**$337,084**
% of Low Income	32%	5%	11%	33%	n/a	19%	**100%**
Commercial & Industrial	$2,195,206	$323,024	$741,919	$2,228,305	n/a	($211,217)	**$5,277,238**
% of Commercial & Industrial	42%	6%	14%	42%	n/a	-4%	**100%**
TOTAL	**$4,954,923**	**$729,115**	**$1,674,627**	**$5,029,633**	**n/a**	**$5,925,621**	**$18,313,920**
% of Total	**27%**	**4%**	**9%**	**27%**	**n/a**	**32%**	**100%**

Allocation of Funding Sources, 2010-2012							
Sector	**SBC (1)**	**FCM (2)**	**RGGI (3)**	**Other (4)**	**Carryover (5)**	**EERF (6)**	**TOTAL**
Residential	$7,948,283	$982,117	$3,258,266	$4,030,766	$261,833	$20,459,859	**$36,941,123**
% of Residential	22%	3%	9%	11%	1%	55%	**100%**
Low Income	$337,046	$41,506	$138,474	$168,075	$12,425	$166,613	**$864,139**
% of Low Income	39%	5%	16%	19%	1%	19%	**100%**
Commercial & Industrial	$6,623,796	$817,791	$2,716,716	$4,182,309	$132,802	$9,571,714	**$24,045,128**
% of Commercial & Industrial	28%	3%	11%	17%	1%	40%	**100%**
TOTAL	**$14,909,126**	**$1,841,414**	**$6,113,456**	**$8,381,150**	**$407,060**	**$30,198,185**	**$61,850,391**
% of Total	**24%**	**3%**	**10%**	**14%**	**1%**	**49%**	**100%**

Notes:

(1) See Table IV.B.3.1
(2) See Table IV.B.3.2
(3) See Table IV.B.3.3
(4) See Table IV.B.3.4
(5) See Table IV.B.3.5
(6) See Table IV.B.3.6

IV.B. Electric PA Funding Sources
3.1. System Benefit Charge Funds

SBC Funds, 2010						
Sector	**kWh Sales**	**Energy Efficiency Charge**	**Collections**	**% Collections of Total**	**Allocation**	**% Allocation of Total**
Residential (1)	1,057,934,150	0.0025	$2,644,835	53.1%	$2,644,835	53.1%
Low Income (2)	45,933,192	0.0025	$114,833	2.3%	$114,833	2.3%
Commercial & Industrial (3)	886,894,069	0.0025	$2,217,235	44.6%	$2,217,235	44.6%
TOTAL	1,990,761,411		$4,976,904	100%	$4,976,904	100%

SBC Collections, 2011						
Sector	**kWh Sales**	**Energy Efficiency Charge**	**Collections**	**% Collections of Total**	**Allocation**	**% Allocation of Total**
Residential (1)	1,061,272,398	0.0025	$2,653,181	53.3%	$2,653,181	53.3%
Low Income (2)	45,105,200	0.0025	$112,763	2.3%	$112,763	2.3%
Commercial & Industrial (3)	884,541,932	0.0025	$2,211,355	44.4%	$2,211,355	44.4%
TOTAL	1,990,919,529		$4,977,299	100%	$4,977,299	100%

SBC Collections, 2012						
Sector	**kWh Sales**	**Energy Efficiency Charge**	**Collections**	**% Collections of Total**	**Allocation**	**% Allocation of Total**
Residential (1)	1,060,106,607	0.0025	$2,650,267	53.5%	$2,650,267	53.5%
Low Income (2)	43,780,128	0.0025	$109,450	2.2%	$109,450	2.2%
Commercial & Industrial (3)	878,082,566	0.0025	$2,195,206	44.3%	$2,195,206	44.3%
TOTAL	1,981,969,302		$4,954,923	100%	$4,954,923	100%

SBC Collections, 2010-2012						
Sector	**kWh Sales**	**Energy Efficiency Charge**	**Collections**	**% Collections of Total**	**Allocation**	**% Allocation of Total**
Residential (1)	3,179,313,155	0.0025	$7,948,283	53.3%	$7,948,283	53.3%
Low Income (2)	134,818,520	0.0025	$337,046	2.3%	$337,046	2.3%
Commercial & Industrial (3)	2,649,518,567	0.0025	$6,623,796	44.4%	$6,623,796	44.4%
TOTAL	5,963,650,242		$14,909,126	100%	$14,909,126	100%

Notes:
(1) kWh Sales is the sum of sales from the following rate classes: R1RESIDENTIAL, R1RESSEASONAL, R3RESHTG, R5WTRHTG, and R6RESTOU.
(2) kWh Sales is the sum of sales from the following rate classes: R2RESASST, R2RESASSTSEA, and R4RESASSTHTG.
(3) kWh Sales is the sum of sales from the following rate classes: CONSTBYSERV, CONTRANSM, G1GENERAL, G2MEDGENTOU, G3LGGENTOU, G5COMMSPHTG, G6ELECTSCH, G7GENSEATOU, G7GENTOU, GENSEASONAL, S1ST/AREALTG and S2CUSTOWNSTLTG.

IV.B. Electric PA Funding Sources
3.2. Forward Capacity Market Proceeds

Forward Capacity Market Revenue, 2010

Portfolio	Nov. 2009			Dec. 2009			Jan. 2010			Feb. 2010		
	kW	FCM Transition Price	Revenue	kW	FCM Transition Price	Revenue	kW	FCM Transition Price	Revenue	kW	FCM Transition Price	Revenue
	6,986	$4.10	$28,641	7,171	$4.10	$29,401	7,356	$4.10	$30,160	7,541	$4.10	$30,919

Portfolio	Mar. 2010			Apr. 2010			May 2010			June 2010 - Dec 2010 (1)			TOTAL 2010 Revenue
	kW	FCM Transition Price	Revenue	kW	FCM Transition Price	Revenue	kW	FCM Transition Price	Revenue	kW	FCM Clearing Price	Revenue	
	7,726	$4.10	$31,678	7,912	$4.10	$32,437	8,097	$4.10	$33,196	11,258	$4.10	$323,139	$481,529

Forward Capacity Market Revenue, 2011

Portfolio	Jan 2010 - May 2011 (1)			June 2011 - Dec 2011 (1)			TOTAL 2011 Revenue
	kW	FCM Clearing Price	Revenue	kW	FCM Clearing Price	Revenue	
	11,258	$4.10	$230,814	13,057	$4.38	$399,956	$630,769

Forward Capacity Market Revenue, 2012

Portfolio	Jan 2011 - May 2012 (1)			June 2012 - Dec 2012 (1)			TOTAL 2012 Revenue
	kW	FCM Clearing Price	Revenue	kW	FCM Clearing Price	Revenue	
	13,057	$4.38	$285,683	15,162	$4.18	$443,432	$729,115

(1) The Cape Light Comapct expects to receive FCM funds every month during the program year.

Allocation of 2010-2012 FCM Revenue

Sector	2010		2011		2012		TOTAL	
	FCM Revenue	% of Total FCM Revenue (2)	FCM Revenue	% of Total FCM Revenue (2)	FCM Revenue	% of Total FCM Revenue (2)	FCM Revenue	% of Total FCM Revenue (2)
Residential	$255,895	53.1%	$336,236	53.3%	$389,986	53.5%	$982,117	53.3%
Low Income	$11,110	2.3%	$14,290	2.3%	$16,106	2.2%	$41,506	2.3%
C&I	$214,524	44.6%	$280,243	44.4%	$323,024	44.3%	$817,791	44.4%
TOTAL	$481,529	100.0%	$630,769	100.0%	$729,115	100.0%	$1,841,414	100.0%

Notes:
(2) Revenue is allocated across customer sector based on percentage allocation of kWh sales. See Table IV.B.3.1

IV.B. Electric PA Funding Sources

3.3. RGGI Proceeds

Regional Greenhouse Gas Initiative Proceeds, 2010 (1)

Auction Projections	Auction 1 (2)		Auction 2 (2)		Auction 3 (2)		Auction 4 (2)		TOTAL
	Compliance Period 1 (3)	Compliance Period 2 (3)	Compliance Period 1 (3)	Compliance Period 2 (3)	Compliance Period 1 (3)	Compliance Period 2 (3)	Compliance Period 1 (3)	Compliance Period 2 (3)	
MA Proceeds (4)									
MA Allowances Sold	6,578,405	328,921	6,578,405	328,921	6,578,405	328,921	6,578,405	328,921	
Auction Clearing Price	$2.38	$1.90	$2.39	$1.90	$2.41	$1.90	$2.42	$1.90	
Total Proceeds to MA	$15,656,604	$624,950	$15,722,388	$624,950	$15,853,956	$624,950	$15,919,740	$624,950	$65,652,488
Proceeds to MA EE Plan (4)									
Percent of MA Funds to EE Plans (e.g., >=80%)	80%	80%	80%	80%	80%	80%	80%	80%	
Total $ to MA Energy Efficiency Plans	$12,525,283	$499,960	$12,577,910	$499,960	$12,683,165	$499,960	$12,735,792	$499,960	$52,521,990
Allocation to PA									
Total MA kWh (4)									
PA kWh									
% PA kWh of State	4.19%	4.19%	4.19%	4.19%	4.19%	4.19%	4.19%	4.19%	
TOTAL $ to PA	**$524,809**	**$20,948**	**$527,014**	**$20,948**	**$531,425**	**$20,948**	**$533,630**	**$20,948**	**$2,200,671**

Regional Greenhouse Gas Initiative Proceeds, 2011 (1)

Auction Projections	Auction 1 (2)		Auction 2 (2)		Auction 3 (2)		Auction 4 (2)		TOTAL
	Compliance Period 1 (3)	Compliance Period 2 (3)	Compliance Period 1 (3)	Compliance Period 2 (3)	Compliance Period 1 (3)	Compliance Period 2 (3)	Compliance Period 1 (3)	Compliance Period 2 (3)	
MA Proceeds (4)									
MA Allowances Sold	6,578,405	328,921	6,578,405	328,921	6,578,405	328,921	6,578,405	328,921	
Auction Clearing Price	$2.42	$1.90	$2.43	$1.90	$2.45	$1.90	$2.47	$1.90	
Total Proceeds to MA	$15,919,740	$624,950	$15,985,524	$624,950	$16,117,092	$624,950	$16,248,660	$624,950	$66,770,816
Proceeds to MA EE Plan (4)									
Percent of MA Funds to EE Plans (e.g., >=80%)	80%	80%	80%	80%	80%	80%	80%	80%	
Total $ to MA Energy Efficiency Plans	$12,735,792	$499,960	$12,788,419	$499,960	$12,893,674	$499,960	$12,998,928	$499,960	$53,416,653
Allocation to PA									
Total MA kWh (4)									
PA kWh									
% PA kWh of State	4.19%	4.19%	4.19%	4.19%	4.19%	4.19%	4.19%	4.19%	
TOTAL $ to PA	**$533,630**	**$20,948**	**$535,835**	**$20,948**	**$540,245**	**$20,948**	**$544,655**	**$20,948**	**$2,238,158**

Regional Greenhouse Gas Initiative Proceeds, 2012 (1)

Auction Projections	Auction 1 (2)		Auction 2 (2)		Auction 3 (2)		Auction 4 (2)		TOTAL
	Compliance Period 1 (3)	Compliance Period 2 (3)	Compliance Period 1 (3)	Compliance Period 2 (3)	Compliance Period 1 (3)	Compliance Period 2 (3)	Compliance Period 1 (3)	Compliance Period 2 (3)	
MA Proceeds (4)									
MA Allowances Sold	6,249,485	320,697	6,249,485	320,697	6,249,485	320,697	6,249,485	320,697	
Auction Clearing Price	$1.90	$1.92	$1.90	$1.92	$1.90	$1.92	$1.90	$1.92	
Total Proceeds to MA	$11,874,022	$615,738	$11,874,022	$615,738	$11,874,022	$615,738	$11,874,022	$615,738	$49,959,039
Proceeds to MA EE Plan (4)									
Percent of MA Funds to EE Plans (e.g., >=80%)	80%	80%	80%	80%	80%	80%	80%	80%	
Total $ to MA Energy Efficiency Plans	$9,499,217	$492,591	$9,499,217	$492,591	$9,499,217	$492,591	$9,499,217	$492,591	$39,967,231
Allocation to PA									
Total MA kWh (4)									
PA kWh									
% PA kWh of State	4.19%	4.19%	4.19%	4.19%	4.19%	4.19%	4.19%	4.19%	
TOTAL $ to PA	**$398,017**	**$20,640**	**$398,017**	**$20,640**	**$398,017**	**$20,640**	**$398,017**	**$20,640**	**$1,674,627**

Notes:

(1) Include auctions in which proceeds will be applied for the applicable program year.
(2) The actual date of each auction shall be included and shall be uniform across all PAs.
(3) The dates of each compliance period shall be included and shall be uniform across all PAs.
(4) Information included in sections "MA Proceeds" and "Proceeds to MA EE Plan" and in line "Total MA kWh" shall be uniform across all electric PAs.

Allocation of RGGI Proceeds

Sector (5)	2010		2011		2012		TOTAL	
	RGGI Funds	% of Total RGGI Funds	RGGI Funds	% of Total RGGI Funds	RGGI Funds	% of Total RGGI Funds	RGGI Funds	% of Total RGGI Funds
Residential	$1,169,485	53.1%	$1,193,064	53.3%	$895,717	53.5%	$3,258,266	53.3%
Low Income	$50,776	2.3%	$50,706	2.3%	$36,991	2.2%	$138,474	2.3%
Commercial & Industrial	$980,410	44.6%	$994,387	44.4%	$741,919	44.3%	$2,716,716	44.4%
TOTAL	$2,200,671	100.0%	$2,238,158	100.0%	$1,674,627	100.0%	$6,113,456	100.0%

Notes:

(5) Revenue is allocated across customer sector based on percentage allocation of total kWh sales. See Table IV.B.3.1
(6) Distribution of Allowances. Compliance Period 1: 16.67% for 2009, then 25% thereafter. Allowances for 2012 are short by 5% used in 2009.
Compliance Period 2: 5% from future control period two years, i.e. 5% from 2012 for 2009. The same for the period 2013 for 2010, 2014 for 2011 and 2015 for 2012.
Allowances for 2015 year are decreased by 2.5% in line with RGGI design.
(7) Compliance Period 1 prices: Quoted Nymex prices (July 6, 09) till 2011. Period 2: Current 2012 auction price ($2.06) grown by yearly CPI inflation.
Period 3: 2012 Compliance Period 2 prices grown by inflation till 2015, increased by 2.5% then decreased by inflation until 2012.

IV.B. Electric PA Funding Sources
3.4. Other Funding Sources

Other Funding Sources, 2010		
Other Funding Sources Available	**Description**	**Funding Amount**
Energy Efficiency Block Grant	Block grant	$736,700
Outside Funding		$0
USDA Grant	Available to Small C&I projects only	$100,000
TOTAL		$836,700

Other Funding Sources, 2011 (1)		
Other Funding Sources Available	**Description**	**Funding Amount**
Energy Efficiency Block Grant	Block grant	$0
Outside Funding	CLC portion of estimated $100 million	$2,514,817
USDA		$0
TOTAL		$2,514,817

Other Funding Sources, 2012 (2)		
Other Funding Sources Available	**Description**	**Funding Amount**
Energy Efficiency Block Grant	Block grant	$0
Outside Funding	CLC portion of estimated $200 million	$5,029,633
USDA		$0
TOTAL		$5,029,633

Other Funding Sources, 2010-2012 (1)		
Other Funding Sources Available	**Description**	**Funding Amount**
Energy Efficiency Block Grant	Block grant	$736,700
Outside Funding	CLC portion of estimated $300 million	$7,544,450
USDA		$100,000
TOTAL		$8,381,150

Notes:

(1) CLC "Other" funding include two one-year grants: Energy Efficiency Block Grant and USDA Grant. Additional funding of $100 and $200 million assumed to be allocated across PA's in 2011 and 2012 respectively

IV.B. Electric PA Funding Sources
3.5. Carryover

Carryover Information (1)							
Sector	2009 Plan (2)		2009 Actual (3)		2009 Carryover (Not Inc. Interest)	2009 Carryover Interest (4)	TOTAL 2009 Carryover
	Collections	Budget	Collections	Expenditures			
Residential	$2,387,879	$4,625,647	n/a	n/a	n/a	n/a	$261,833
Low Income	$637,089	$1,532,176	n/a	n/a	n/a	n/a	$12,425
Commercial & Industrial	$2,112,850	$3,909,811	n/a	n/a	n/a	n/a	$132,802
TOTAL	$5,137,818	$10,067,635	$9,383,438	$8,977,393	$406,045	$1,015	$407,060

Notes:
(1) Includes all sources/factors for collections, budget and expenditures for CLC, based on the EERF compliance filing effective 7/1/2010
(2) This information provided for comparative and informational purposes only.
(3) Interest subject to Department Public Utilities approval

IV.B. Electric PA Funding Sources
3.6. EERF

Calculation of Energy Efficiency Reconciliation Factor Funds, 2010 (1)							
Sector	**Total Budget (2)**	**Lost Base Revenue (3)**	**SBC + FCM + RGGI + Other Funds + Carryover**	**EERF Funding Required (4)**	**% of Total Company kWh (5)**	**Low Income Allocation (6)**	**EERF Funding Allocation (7)**
Residential	$9,449,462	n/a	$4,332,049	$5,117,413	53.1%	$1,009,492	$6,126,905
Low Income	$2,088,750	n/a	$189,145	$1,899,605	2.3%	$43,830	$43,830
Commercial & Industrial	$7,098,577	n/a	$4,381,671	$2,716,906	44.6%	$846,283	$3,563,190
TOTAL	$18,636,789	$0	$8,902,864	$9,733,925	100.0%	$1,899,605	$9,733,925

Calculation of Energy Efficiency Reconciliation Factor Funds, 2011 (1)							
Sector	**Total Budget (2)**	**Lost Base Revenue (3)**	**SBC + FCM + RGGI + Other Funds**	**EERF Funding Required (4)**	**% of Total Company kWh (5)**	**Low Income Allocation (6)**	**EERF Funding Allocation (7)**
Residential	$12,386,208	n/a	$5,523,020	$6,863,188	53.3%	$1,396,363	$8,259,551
Low Income	$2,854,275	n/a	$234,734	$2,619,541	2.3%	$59,347	$59,347
Commercial & Industrial	$9,659,199	n/a	$4,603,289	$5,055,911	44.4%	$1,163,831	$6,219,742
TOTAL	$24,899,683	$0	$10,361,043	$14,538,640	100.0%	$2,619,541	$14,538,640

Calculation of Energy Efficiency Reconciliation Factor Funds, 2012 (1)							
Sector	**Total Budget (2)**	**Lost Base Revenue (3)**	**SBC + FCM + RGGI + Other Funds**	**EERF Funding Required (4)**	**% of Total Company kWh (5)**	**Low Income Allocation (6)**	**EERF Funding Allocation (7)**
Residential	$11,163,540	n/a	$6,626,196	$4,537,344	53.5%	$1,536,058	$6,073,402
Low Income	$3,145,453	n/a	$273,648	$2,871,805	2.2%	$63,435.90	$63,436
Commercial & Industrial	$4,004,926	n/a	$5,488,455	($1,483,529)	44.3%	$1,272,311	($211,217)
TOTAL	$18,313,920	$0	$12,388,298	$5,925,621	100.0%	$2,871,805	$5,925,621

Calculation of Energy Efficiency Reconciliation Factor Funds, 2010-2012 (1)							
Sector	**Total Budget (2)**	**Lost Base Revenue (3)**	**SBC + FCM + RGGI + Other Funds**	**EERF Funding Required (4)**	**% of Total Company kWh (5)**	**Low Income Allocation (6)**	**EERF Funding Allocation (7)**
Residential	$32,999,211	n/a	$16,481,265	$16,517,946	53.3%	$3,941,912	$20,459,859
Low Income	$8,088,478	n/a	$697,527	$7,390,951	2.3%	$166,613	$166,613
Commercial & Industrial	$20,762,703	n/a	$14,473,414	$6,289,289	44.4%	$3,282,426	$9,571,714
TOTAL	$61,850,391	$0	$31,652,206	$30,198,185	100.0%	$7,390,951	$30,198,185

Notes:
(1) See Section IV.I.2 Calculation of EERF and V.E. Energy Efficiency Reconciliation Factor for more information
(2) Budget - See Budget Summary Table IV.C.1.
(3) LBR - See LBR Calculation Table IV.G.1.
(4) EERF Revenue Required = (Total Budget + LBR) - (SBC + FCM + RGGI + Other Funds + Carryover Funds)
(5) See Elec - SBC Table IV.B. 3.1
(6) Column F x Low Income EERF Funding Required
(7) Residetial = EERF Funding Required for Residential + Low Income Allocation for Residential; Low Income = Low Income Allocation; Commercial & Industrial = EERF Funding Required for C&I + Low Income Allocation for C&I

IV.C. Electric PA Budgets
1. Summary Table

Program Administrator Budget, 2010 (1) (6)									
Program	PA Costs (1)						Lost Base Revenue (2)	Performance Incentive (3)	TOTAL PA Budget (4)
	Program Planning and Administration	Marketing and Advertising	Participant Incentive	Sales, Technical Assistance & Training	Evaluation and Market Research	Total PA Costs			
Residential (total)	$463,219	$436,209	$6,616,872	$1,386,348	$546,814	$9,449,462	$0	$0	$9,449,462
Residential New Construction & Major Renovation	12,301	2,815	267,214	88,008	9,680	380,019			380,019
Residential Cooling & Heating Equipment	20,731	4,744	450,325	96,812	67,912	640,525			640,525
Multi-Family Retrofit	12,722	2,911	276,343	76,453	75,142	443,571			443,571
MassSAVE	238,857	43,218	4,102,410	846,458	285,081	5,516,024			5,516,024
Behavior/Feedback Program	n/a	n/a	n/a	n/a	n/a	0			0
ENERGY STAR Lighting	36,570	120,061	794,385	167,283	41,155	1,159,453			1,159,453
ENERGY STAR Appliances	8,059	26,459	175,070	36,867	7,089	253,545			253,545
Residential Education Program	0	186,000	0	0	0	186,000			186,000
Workforce Development	0	0	0	15,000	0	15,000			15,000
HEAT Loan Program	0	0	0	30,000	0	30,000			30,000
R&D Demonstration	n/a	n/a	n/a	n/a	n/a	0			0
Deep Energy Retrofit	0	0	60,000	0	23,333	83,333			83,333
Behavior/Feedback Pilot	0	0	225,000	0	8,333	233,333			233,333
Residential New Construction & Major Renovation - Maj	0	0	220,425	11,367	25,755	257,547			257,547
Residential New Construction Multi Family (4-8 story) st	0	0	0	0	0	0			0
Residential New Construction Lighting Design statewide	0	0	10,000	10,000	2,222	22,222			
Residential New Construction V3 Energy Star Homes st	0	0	0	0	0	0			0
Heat Pump Water Heater Pilot	0	0	2,800	7,200	1,111	11,111			11,111
Residential Technical Development	0	0	20,000	0	0	20,000			20,000
Hot Roofs	0	0	3,000	0	0	3,000			3,000
Home Automation	0	0	9,900	900	0	10,800			10,800
Community Based Pilot	n/a	n/a	n/a	n/a	n/a	0			0
Statewide Marketing & Education	0	50,000	0	0	0	50,000			50,000
EEAC Consultants	93,555	0	0	0	0	93,555			93,555
DOER Assessment	28,456	0	0	0	0	28,456			28,456
Sponsorships & Subscriptions	11,967	0	0	0	0	11,967			
Low Income (total)	$77,438	$24,878	$1,411,137	$491,104	$84,191	$2,088,750	$0	$0	$2,088,750
Low-Income Residential New Construction	705	161	13,060	14,326	414	28,666			28,666
Low-Income Retrofit	71,959	16,467	1,398,077	463,029	83,777	2,033,309			2,033,309
Statewide Marketing & Education	0	0	0	0	0	0			0
Low-Income Energy Affordability Network Funding	0	8,250	0	13,750	0	22,000			22,000
DOER Assessment	4,774	0	0	0	0	4,774			4,774
Commercial & Industrial (total)	$329,803	$53,570	$5,632,501	$962,949	$119,754	$7,098,577	$0	$0	$7,098,577
C&I New Construction and Major Renovation	33,008	7,554	694,197	130,935	39,310	905,004			905,004
C&I New Construction and Major Renovation - Governm	n/a	n/a	n/a	n/a	n/a	0			0
C&I Large Retrofit	23,505	5,379	1,665,555	93,240	20,316	1,807,995			1,807,995
Large C&I Retrofit - Government	n/a	n/a	n/a	n/a	n/a	0			0
C&I Small Retrofit	177,582	40,638	3,272,749	738,774	60,128	4,289,871			4,289,871
C&I Small Retrofit - Government	n/a	n/a	n/a	n/a	n/a	0			0
Community Based Pilot	n/a	n/a	n/a	n/a	n/a	0			0
Statewide Marketing & Education	0	0	0	0	0	0			0
EEAC Consultants	70,295	0	0	0	0	70,295			70,295
DOER Assessment	15,380	0	0	0	0	15,380			15,380
Sponsorships & Subscriptions	10,033	0	0	0	0	10,033			10,033
GRAND TOTAL	**$870,460**	**$514,657**	**$13,660,510**	**$2,840,402**	**$750,760**	**$18,636,789**	**$0**	**$0**	**$18,636,789**

IV.C. Electric PA Budgets
1. Summary Table

Program Administrator Budget, 2011 (1) (7)										
Program	PA Costs (1)						Lost Base Revenue (2)	Performance Incentive (3)	TOTAL PA Budget (4)
	Program Planning and Administration	Marketing and Advertising	Participant Incentive	Sales, Technical Assistance & Training	Evaluation and Market Research	Total PA Costs			
Residential (total)	$413,619	$462,052	$9,343,005	$1,533,376	$634,156	$12,386,208	$0	$0	$12,386,208
Residential New Construction & Major Renovation	5,213	1,307	142,980	79,097	7,065	235,663			235,663
Residential Cooling & Heating Equipment	25,592	6,417	701,900	95,402	60,945	890,256			890,256
Multi-Family Retrofit	12,556	3,148	344,355	92,462	68,517	521,038			521,038
MassSAVE	261,273	52,975	5,794,440	956,206	343,215	7,408,109			7,408,109
Behavior/Feedback Program	n/a	n/a	n/a	n/a	n/a	0			0
ENERGY STAR Lighting	57,071	129,744	1,565,250	177,114	89,151	2,018,330			2,018,330
ENERGY STAR Appliances	10,320	23,461	283,040	32,027	9,917	358,766			358,766
Residential Education Program	0	195,000	0	0	0	195,000			195,000
Workforce Development	0	0	0	15,000	0	15,000			15,000
HEAT Loan Program	0	0	0	45,000	0	45,000			45,000
R&D Demonstration	n/a	n/a	n/a	n/a	n/a	0			0
Deep Energy Retrofit	0	0	72,000	0	8,000	80,000			80,000
Behavior/Feedback Pilot	0	0	145,500	0	16,167	161,667			161,667
Residential New Construction & Major Renovation - Maj	0	0	239,240	11,367	27,845	278,452			278,452
Residential New Construction Multi Family (4-8 story) sta	0	0	0	0	0	0			0
Residential New Construction Lighting Design statewide	0	0	10,000	10,000	2,222	22,222			22,222
Residential New Construction V3 Energy Star Homes sta	0	0	0	0	0	0			0
Heat Pump Water Heater Pilot	0	0	2,800	7,200	1,111	11,111			11,111
Residential Technical Development	0	0	20,000	0	0	20,000			20,000
Hot Roofs	0	0	9,000	0	0	9,000			9,000
Home Automation	0	0	12,500	12,500	0	25,000			25,000
Community Based Pilot	n/a	n/a	n/a	n/a	n/a	0			0
Statewide Marketing & Education	0	50,000	0	0	0	50,000			50,000
EEAC Consultants (5)	0	0	0	0	0	0			0
DOER Assessment	28,505	0	0	0	0	28,505			28,505
Sponsorships & Subscriptions	13,090	0	0	0	0	13,090			13,090
Low Income (total)	$88,350	$29,956	$1,958,648	$662,273	$115,048	$2,854,275	$0	$0	$2,854,275
Low-Income Residential New Construction	777	195	17,360	14,927	513	33,772			33,772
Low-Income Retrofit	82,799	20,761	1,941,288	632,346	114,535	2,791,729			2,791,729
Statewide Marketing & Education	0	0	0	0	0	0			0
Low-Income Energy Affordability Network Funding	0	9,000	0	15,000	0	24,000			24,000
DOER Assessment	4,774	0	0	0	0	4,774			4,774
Commercial & Industrial (total)	$294,641	$67,299	$7,858,999	$1,183,830	$254,431	$9,659,199	$0	$0	$9,659,199
C&I New Construction and Major Renovation	35,471	8,894	1,038,613	$ 150,609	54,290	1,287,876			1,287,876
C&I New Construction and Major Renovation - Governm	n/a	n/a	n/a	n/a	n/a	0			0
C&I Large Retrofit	26,022	6,525	761,939	$ 110,488	36,286	941,260			941,260
Large C&I Retrofit - Government	n/a	n/a	n/a	n/a	n/a	0			0
C&I Small Retrofit	206,907	51,880	6,058,447	$ 922,733	163,855	7,403,822			7,403,822
C&I Small Retrofit - Government	n/a	n/a	n/a	n/a	n/a	0			0
Community Based Pilot	n/a	n/a	n/a	n/a	n/a	0			0
Statewide Marketing & Education	0	0	0	0	0	0			0
EEAC Consultants (5)	0	0	0	0	0	0			0
DOER Assessment	15,331	0	0	0	0	15,331			15,331
Sponsorships & Subscriptions	10,910	0	0	0	0	10,910			10,910
GRAND TOTAL	**$796,610**	**$559,307**	**$19,160,652**	**$3,379,479**	**$1,003,634**	**$24,899,683**	**$0**	**$0**	**$24,899,683**

IV.C. Electric PA Budgets
1. Summary Table

Program Administrator Budget, 2012 (1) (8)

Program	PA Costs (1): Program Planning and Administration	Marketing and Advertising	Participant Incentive	Sales, Technical Assistance & Training	Evaluation and Market Research	Total PA Costs	Lost Base Revenue (2)	Performance Incentive (3)	TOTAL PA Budget (4)
Residential (total)	$538,044	$453,724	$8,914,735	$807,067	$449,970	$11,163,540	$0	$0	$11,163,540
Residential New Construction & Major Renovation	13,715	17,173	260,500	89,695	8,972	390,055	[redacted]		390,055
Residential Cooling & Heating Equipment	29,569	18,886	561,650	86,198	18,237	714,541	[redacted]		714,541
Multi-Family Retrofit	0	0	0	0	0	0	[redacted]		0
MassSAVE	327,685	110,029	6,697,373	314,776	366,162	7,816,026	[redacted]		7,816,026
Behavior/Feedback Program	n/a	n/a	n/a	n/a	n/a	0	[redacted]		0
ENERGY STAR Lighting	48,383	70,637	919,000	141,129	32,133	1,211,282	[redacted]		1,211,282
ENERGY STAR Appliances	14,866	41,999	282,375	50,269	6,816	396,326	[redacted]		396,326
Residential Education Program	0	105,000	0	0	0	105,000	[redacted]		105,000
Workforce Development	0	0	0	15,000	0	15,000	[redacted]		15,000
HEAT Loan Program	0	0	0	110,000	0	110,000	[redacted]		110,000
R&D Demonstration	n/a	n/a	n/a	n/a	n/a	0	[redacted]		0
Deep Energy Retrofit	0	0	0	0	0	0	[redacted]		0
Behavior/Feedback Pilot	0	0	158,837	0	17,649	176,486	[redacted]		176,486
Residential New Construction & Major Renovation - Maj	0	0	0	0	0	0	[redacted]		0
Residential New Construction Multi Family (4-8 story) sta	0	0	0	0	0	0	[redacted]		0
Residential New Construction Lighting Design statewide	0	0	0	0	0	0	[redacted]		0
Residential New Construction V3 Energy Star Homes sta	0	0	0	0	0	0	[redacted]		0
Heat Pump Water Heater Pilot	0	0	0	0	0	0	[redacted]		0
Residential Technical Development	0	0	20,000	0	0	20,000	[redacted]		20,000
Hot Roofs	0	0	15,000	0	0	15,000	[redacted]		15,000
Home Automation	0	0	0	0	0	0	[redacted]		0
Community Based Pilot	n/a	n/a	n/a	n/a	n/a	0	[redacted]		0
Statewide Marketing & Education	0	90,000	0	0	0	90,000	[redacted]		90,000
EEAC Consultants	0	0	0	0	0	0	[redacted]		0
DOER Assessment	89,134	0	0	0	0	89,134	[redacted]		89,134
Sponsorships & Subscriptions	14,691	0	0	0	0	14,691	[redacted]		
Low Income (total)	$133,313	$48,720	$2,302,348	$534,287	$126,784	$3,145,453	$0	$0	$3,145,453
Low-Income Residential New Construction	0	0	0	0	0	0	[redacted]		0
Low-Income Retrofit	110,125	3,720	2,302,348	484,287	126,784	3,027,265	[redacted]		3,027,265
Statewide Marketing & Education	0	15,000	0	0	0	15,000	[redacted]		
Low-Income Energy Affordability Network Funding	0	30,000	0	50,000	0	80,000	[redacted]		80,000
DOER Assessment	23,188	0	0	0	0	23,188	[redacted]		23,188
Commercial & Industrial (total)	$441,651	$57,980	$2,818,372	$525,496	$161,427	$4,004,926	$0	$0	$4,004,926
C&I New Construction and Major Renovation	125,887	4,252	1,000,372	267,003	59,610	1,457,124	[redacted]		1,457,124
C&I New Construction and Major Renovation - Governm	n/a	n/a	n/a	n/a	n/a	0	[redacted]		0
C&I Large Retrofit	218,962	7,396	1,740,000	241,165	99,565	2,307,088	[redacted]		2,307,088
Large C&I Retrofit - Government	n/a	n/a	n/a	n/a	n/a	0	[redacted]		0
C&I Small Retrofit	9,816	332	78,000	17,328	2,252	107,728	[redacted]		107,728
C&I Small Retrofit - Government	n/a	n/a	n/a	n/a	n/a	0	[redacted]		0
Community Based Pilot	n/a	n/a	n/a	n/a	n/a	0	[redacted]		0
Statewide Marketing & Education	0	46,000	0	0	0	46,000	[redacted]		46,000
EEAC Consultants	0	0	0	0	0	0	[redacted]		0
DOER Assessment	74,678	0	0	0	0	74,678	[redacted]		74,678
Sponsorships & Subscriptions	12,309	0	0	0	0	12,309	[redacted]		12,309
GRAND TOTAL	**$1,113,009**	**$560,424**	**$14,035,455**	**$1,866,850**	**$738,181**	**$18,313,920**	**$0**	**$0**	**$18,313,920**

IV.C. Electric PA Budgets
1. Summary Table

Program Administrator Budget, 2010-2012 (1)										
Program	PA Costs (1)						Lost Base Revenue (2)	Performance Incentive (3)	TOTAL PA Budget (4)
	Program Planning and Administration	Marketing and Advertising	Participant Incentive	Sales, Technical Assistance & Training	Evaluation and Market Research	Total PA Costs			
Residential (total)	$1,414,883	$1,351,985	$24,874,613	$3,726,791	$1,630,940	$32,999,211	$0	$0	$32,999,211
Residential New Construction & Major Renovation	31,229	21,295	670,694	256,801	25,718	1,005,737		0	1,005,737
Residential Cooling & Heating Equipment	75,893	30,047	1,713,875	278,412	147,094	2,245,322		0	2,245,322
Multi-Family Retrofit	25,277	6,059	620,698	168,916	143,659	964,609		0	964,609
MassSAVE	827,815	206,222	16,594,223	2,117,439	994,459	20,740,159		0	20,740,159
Behavior/Feedback Program	n/a	n/a	n/a	n/a	n/a	0		0	0
ENERGY STAR Lighting	142,024	320,441	3,278,635	485,526	162,439	4,389,065		0	4,389,065
ENERGY STAR Appliances	33,246	91,920	740,485	119,163	23,823	1,008,636		0	1,008,636
Residential Education Program	0	486,000	0	0	0	486,000		0	486,000
Workforce Development	0	0	0	45,000	0	45,000		0	45,000
HEAT Loan Program	0	0	0	185,000	0	185,000		0	185,000
R&D Demonstration	n/a	n/a	n/a	n/a	n/a	0		0	0
Deep Energy Retrofit	0	0	132,000	0	31,333	163,333		0	163,333
Behavior/Feedback Pilot	0	0	529,337	0	42,148	571,486		0	571,486
Residential New Construction & Major Renovation - Maj	0	0	459,665	22,734	53,600	535,999		0	535,999
Residential New Construction Multi Family (4-8 story) sta	0	0	0	0	0	0		0	0
Residential New Construction Lighting Design statewide	0	0	20,000	20,000	4,444	44,444		0	44,444
Residential New Construction V3 Energy Star Homes sta	0	0	0	0	0	0		0	0
Heat Pump Water Heater Pilot	0	0	5,600	14,400	2,222	22,222		0	22,222
Residential Technical Development	0	0	60,000	0	0	60,000		0	60,000
Hot Roofs	0	0	27,000	0	0	27,000		0	27,000
Home Automation	0	0	22,400	13,400	0	35,800		0	35,800
Community Based Pilot	n/a	n/a	n/a	n/a	n/a	0		0	0
Statewide Marketing & Education	0	190,000	0	0	0	190,000		0	190,000
EEAC Consultants	93,555	0	0	0	0	93,555		0	93,555
DOER Assessment	146,095	0	0	0	0	146,095		0	146,095
Sponsorships & Subscriptions	39,749	0	0	0	0	39,749		0	39,749
Low Income (total)	$299,101	$103,554	$5,672,134	$1,687,665	$326,023	$8,088,478	$0	$0	$8,088,478
Low-Income Residential New Construction	1,483	356	30,420	29,253	927	62,438		0	62,438
Low-Income Retrofit	264,883	40,948	5,641,714	1,579,662	325,096	7,852,303		0	7,852,303
Statewide Marketing & Education	0	15,000	0	0	0	15,000		0	15,000
Low-Income Energy Affordability Network Funding	0	47,250	0	78,750	0	126,000		0	126,000
DOER Assessment	32,736	0	0	0	0	32,736		0	32,736
Commercial & Industrial (total)	$1,066,094	$178,850	$16,309,872	$2,672,275	$535,612	$20,762,703	$0	$0	$20,762,703
C&I New Construction and Major Renovation	194,365	20,700	2,733,182	548,547	153,210	3,650,004		0	3,650,004
C&I New Construction and Major Renovation - Governm	n/a	n/a	n/a	n/a	n/a	0		0	0
C&I Large Retrofit	268,489	19,300	4,167,494	444,893	156,166	5,056,342		0	5,056,342
Large C&I Retrofit - Government	n/a	n/a	n/a	n/a	n/a	0		0	0
C&I Small Retrofit	394,304	92,850	9,409,196	1,678,835	226,235	11,801,420		0	11,801,420
C&I Small Retrofit - Government	n/a	n/a	n/a	n/a	n/a	0		0	0
Community Based Pilot	n/a	n/a	n/a	n/a	n/a	0		0	0
Statewide Marketing & Education	0	46,000	0	0	0	46,000		0	46,000
EEAC Consultants	70,295	0	0	0	0	70,295		0	70,295
DOER Assessment	105,389	0	0	0	0	105,389		0	105,389
Sponsorships & Subscriptions	33,251	0	0	0	0	33,251		0	33,251
GRAND TOTAL	**$2,780,079**	**$1,634,389**	**$46,856,618**	**$8,086,731**	**$2,492,575**	**$61,850,391**	**$0**	**$0**	**$61,850,391**

Notes:

(1) All parties would refer to common definitions (in Appendix I) for allocation of costs.
(2) Lost Base Revenues are not applicable to The Cape Light Compact.
(3) Shareholder Performance Incentives are not applicable to The Cape Light Compact.
(4) The Total PA Budget is the sum of Total TRC Costs and LBR.
(5) EEAC Consultant fees on the electric side do not get paid out of the PA's budgets, but are instead paid by the DOER out of the RGGI proceeds.
(6) As filed in the Cape Light Compact's 2010 Mid-Year Revisions Filing, D.P.U 10-106, in 2010$
(7) As this filing assumes approval of the 2011 Mid-Term Modifications, this data is as filed in the Cape Light Compact's 2011 Mid-Term Modifications Filing, D.P.U. 10-147, in 2011$
(8) Proposed 2012 changes presented in this filing, representing additional budget requirements for 2012, taking into account 2011 estimated carryover, in 2012$

IV.C Electric PA Budgets

2.2 PA Cost Comparison Table - Three Year Plan vs. Previous Years

Residential Programs

PA Cost Category	2007 (1)		2008 (2)		2009 (3)		2010 (4)		2011 (5)		2012 (6)	
	$	%	$	%	$	%	$	%	$	%	$	%
Program Planning and Administration	$183,921	9%	$271,820	11%	$334,283	8%	$459,486	7%	$413,619	3%	$538,044	5%
Marketing and Advertising	$79,832	4%	$103,264	4%	$115,625	3%	$446,088	7%	$462,052	4%	$453,724	4%
Participant Incentive	$913,873	45%	$1,262,769	51%	$2,131,605	54%	$4,499,624	70%	$9,343,005	75%	$8,914,735	80%
Sales, Technical Assistance & Training	$723,447	36%	$786,519	32%	$1,302,913	33%	$737,653	12%	$1,533,376	12%	$807,067	7%
Evaluation and Market Research	$110,415	5%	$53,795	2%	$77,890	2%	$245,715	4%	$634,156	5%	$449,970	4%
Performance Incentive	$0	0%	$0	0%	$0	0%	$0	0%	$0	0%	$0	0%
TOTAL	**$2,011,488**	**100%**	**$2,478,166**	**100%**	**$3,962,316**	**100%**	**$6,388,566**	**100%**	**$12,386,208**	**100%**	**$11,163,540**	**100%**

Low Income Programs

PA Cost Category	2007 (1)		2008 (2)		2009 (3)		2010 (4)		2011 (5)		2012 (6)	
	$	%	$	%	$	%	$	%	$	%	$	%
Program Planning and Administration	$71,924	11%	$102,693	14%	$82,709	8%	$111,114	6%	$88,350	3%	$133,313	4%
Marketing and Advertising	$25,815	4%	$30,066	4%	$33,880	3%	$51,184	3%	$29,956	1%	$48,720	2%
Participant Incentive	$372,030	59%	$435,363	58%	$636,046	64%	$1,388,933	76%	$1,958,648	72%	$2,302,348	73%
Sales, Technical Assistance & Training	$157,426	25%	$161,300	22%	$222,517	22%	$256,575	14%	$662,273	24%	$534,287	17%
Evaluation and Market Research	$0	0%	$15,663	2%	$19,272	2%	$18,885	1%		0%	$126,784	4%
Performance Incentive	$0	0%	$0	0%	$0	0%	$0	0%	$0	0%	$0	0%
TOTAL	**$627,195**	**100%**	**$745,085**	**100%**	**$994,424**	**100%**	**$1,826,691**	**100%**	**$2,739,227**	**100%**	**$3,145,453**	**100%**

Commercial & Industrial Programs

PA Cost Category	2007 (1)		2008 (2)		2009 (3)		2010 (4)		2011 (5)		2012 (6)	
	$	%	$	%	$	%	$	%	$	%	$	%
Program Planning and Administration	$207,660	9%	$225,215	10%	$332,768	8%	$306,999	6%	$294,641	3%	$441,651	11%
Marketing and Advertising	$101,020	4%	$95,361	4%	$115,102	3%	$156,897	3%	$67,299	1%	$57,980	1%
Participant Incentive	$1,774,260	74%	$1,552,336	69%	$2,835,638	72%	$4,267,166	80%	$7,858,999	81%	$2,818,372	70%
Sales, Technical Assistance & Training	$297,613	12%	$340,122	15%	$583,322	15%	$499,832	9%	$1,183,830	12%	$525,496	13%
Evaluation and Market Research	$28,854	1%	$49,678	2%	$77,537	2%	$85,068	2%	$254,431	3%	$161,427	4%
Performance Incentive	$0	0%	$0	0%	$0	0%	$0	0%	$0	0%	$0	0%
TOTAL	**$2,409,406**	**100%**	**$2,262,712**	**100%**	**$3,944,366**	**100%**	**$5,315,961**	**100%**	**$9,659,199**	**100%**	**$4,004,926**	**100%**

Total Programs

PA Cost Category	2007 (1)		2008 (2)		2009 (3)		2010 (4)		2011 (5)		2012 (6)	
	$	%	$	%	$	%	$	%	$	%	$	%
Program Planning and Administration	$463,505	9%	$599,728	11%	$749,760	8%	$877,598	6%	$796,610	3%	$1,113,009	6%
Marketing and Advertising	$206,667	4%	$228,690	4%	$264,607	3%	$654,169	5%	$559,307	2%	$560,424	3%
Participant Incentive	$3,060,164	61%	$3,250,468	59%	$5,603,290	63%	$10,155,723	75%	$19,160,652	77%	$14,035,455	77%
Sales, Technical Assistance & Training	$1,178,485	23%	$1,287,940	23%	$2,108,752	24%	$1,494,060	11%	$3,379,479	14%	$1,866,850	10%
Evaluation and Market Research	$139,269	3%	$119,135	2%	$174,698	2%	$349,667	3%	$888,586	4%	$738,181	4%
Performance Incentive	$0	0%	$0	0%	$0	0%	$0	0%	$0	0%	$0	0%
TOTAL	**$5,048,090**	**100%**	**$5,485,962**	**100%**	**$8,901,106**	**100%**	**$13,531,218**	**100%**	**$24,784,635**	**100%**	**$18,313,920**	**100%**

Notes:

(1) Actual values from the Cape Light Compact's 2007 Annual Report D.P.U. 09-68, in 2007$.

(2) Actual values from the Cape Light Compact's 2008 Annual Report D.P.U. 09-69, in 2008$.

(3) Actual values from the Cape Light Compact's 2009 Annual Report D.P.U. 10-97, in 2009$.

(4) Actual values from the Cape Light Compact's 2010 Annual Report D.P.U. 11-68, in 2010$.

(5) As this filing assumes approval of the 2011 Mid-Term Modifications, this data is as filed in the Cape Light Compact's 2011 Mid-Term Modifications Filing, D.P.U. 10-147, in 2011$.

(6) Proposed 2012 changes presented in this filing, representing additional budget requirements for 2012, taking into account 2011 estimated carryover, in 2012$.

IV.D. Cost Effectiveness

1. Summary Table

Total Resource Cost Test, 2010				
Customer Sector	**B/C Ratio**	**Net Benefits**	**Benefits**	**Costs**
Residential	**3.24**	**$24,079,949**	**$34,831,733**	**$10,751,784**
Residential New Construction & Major Renovation	2.19	587,311	$1,079,130	$491,819
Residential Cooling & Heating Equipment	1.68	456,431	$1,131,262	$674,832
Multi-Family Retrofit	4.06	1,447,741	$1,920,590	$472,849
MassSAVE	4.00	19,012,063	$25,346,901	$6,334,839
Behavior/Feedback Program	n/a	n/a	n/a	$0
ENERGY STAR Lighting	3.26	3,164,620	$4,566,401	$1,401,781
ENERGY STAR Appliances	2.47	468,109	$787,448	$319,340
Residential Education Program	n/a	n/a	n/a	$186,000
Workforce Development	n/a	n/a	n/a	$15,000
HEAT Loan Program	n/a	n/a	n/a	$30,000
R&D Demonstration	n/a	n/a	n/a	$0
Deep Energy Retrofit	n/a	n/a	n/a	$83,333
Behavior/Feedback Pilot	n/a	n/a	n/a	$233,333
Residential New Construction & Major Renovation - Major Renovation	n/a	n/a	n/a	$257,547
Residential New Construction Multi Family (4-8 story) statewide pilot	n/a	n/a	n/a	$0
Residential New Construction Lighting Design statewide pilot	n/a	n/a	n/a	$22,222
Residential New Construction V3 Energy Star Homes statewide pilot	n/a	n/a	n/a	$0
Heat Pump Water Heater Pilot	n/a	n/a	n/a	$11,111
Residential Technical Development	n/a	n/a	n/a	$20,000
Hot Roofs	n/a	n/a	n/a	$3,000
Home Automation	n/a	n/a	n/a	$10,800
Community Based Pilot	n/a	n/a	n/a	$0
Statewide Marketing & Education	n/a	n/a	n/a	$50,000
EEAC Consultants	n/a	n/a	n/a	$93,555
DOER Assessment	n/a	n/a	n/a	$28,456
Sponsorships & Subscriptions	n/a	n/a	n/a	$11,967
Low Income	**2.83**	**$3,832,391**	**$5,921,141**	**$2,088,750**
Low-Income Residential New Construction	0.96	-1,207	$27,459	$28,666
Low-Income Retrofit	2.90	3,860,372	$5,893,681	$2,033,309
Statewide Marketing & Education	n/a	n/a	n/a	$0
Low-Income Energy Affordability Network Funding	n/a	n/a	n/a	$22,000
DOER Assessment	n/a	n/a	n/a	$4,774
Commercial & Industrial	**3.33**	**$19,481,283**	**$27,855,987**	**$8,374,704**
C&I New Construction and Major Renovation	5.50	5,406,669	$6,608,366	$1,201,698
C&I New Construction and Major Renovation - Government	n/a	n/a	n/a	$0
C&I Large Retrofit	3.94	6,745,181	$9,035,693	$2,290,512
Large C&I Retrofit - Government	n/a	n/a	n/a	$0
C&I Small Retrofit	2.55	7,425,141	$12,211,928	$4,786,787
C&I Small Retrofit - Government	n/a	n/a	n/a	$0
Community Based Pilot	n/a	n/a	n/a	$0
Statewide Marketing & Education	n/a	n/a	n/a	$0
EEAC Consultants	n/a	n/a	n/a	$70,295
DOER Assessment	n/a	n/a	n/a	$15,380
Sponsorships & Subscriptions	n/a	n/a	n/a	$10,033
GRAND TOTAL	**3.23**	**$47,393,623**	**$68,608,861**	**$21,215,238**

IV.D. Cost Effectiveness

1. Summary Table

Total Resource Cost Test, 2011				
Sector	**B/C Ratio**	**Net Benefits**	**Benefits**	**Costs**
Residential	**3.89**	**$42,798,641**	**$57,600,761**	**$14,802,121**
Residential New Construction & Major Renovation	2.63	575,455	$928,618	$353,163
Residential Cooling & Heating Equipment	1.85	852,041	$1,852,339	$1,000,298
Multi-Family Retrofit	5.07	2,284,225	$2,845,701	$561,476
MassSAVE	4.39	30,087,937	$38,952,913	$8,864,976
Behavior/Feedback Program	n/a	n/a	n/a	$0
ENERGY STAR Lighting	4.49	9,107,776	$11,717,686	$2,609,910
ENERGY STAR Appliances	2.84	845,253	$1,303,504	$458,251
Residential Education Program	n/a	n/a	n/a	$195,000
Workforce Development	n/a	n/a	n/a	$15,000
HEAT Loan Program	n/a	n/a	n/a	$45,000
R&D Demonstration	n/a	n/a	n/a	$0
Deep Energy Retrofit	n/a	n/a	n/a	$80,000
Behavior/Feedback Pilot	n/a	n/a	n/a	$161,667
Residential New Construction & Major Renovation - Major Renovation	n/a	n/a	n/a	$278,452
Residential New Construction Multi Family (4-8 story) statewide pilot	n/a	n/a	n/a	$0
Residential New Construction Lighting Design statewide pilot	n/a	n/a	n/a	$22,222
Residential New Construction V3 Energy Star Homes statewide pilot	n/a	n/a	n/a	$0
Heat Pump Water Heater Pilot	n/a	n/a	n/a	$11,111
Residential Technical Development	n/a	n/a	n/a	$20,000
Hot Roofs	n/a	n/a	n/a	$9,000
Home Automation	n/a	n/a	n/a	$25,000
Community Based Pilot	n/a	n/a	n/a	$0
Statewide Marketing & Education	n/a	n/a	n/a	$50,000
EEAC Consultants	n/a	n/a	n/a	$0
DOER Assessment	n/a	n/a	n/a	$28,505
Sponsorships & Subscriptions	n/a	n/a	n/a	$13,090
Low Income	**3.54**	**$7,243,737**	**$10,098,012**	**$2,854,275**
Low-Income Residential New Construction	1.33	11,216	$44,988	$33,772
Low-Income Retrofit	3.60	7,261,294	$10,053,023	$2,791,729
Statewide Marketing & Education	n/a	n/a	n/a	$0
Low-Income Energy Affordability Network Funding	n/a	n/a	n/a	$24,000
DOER Assessment	n/a	n/a	n/a	$4,774
Commercial & Industrial	**3.02**	**$22,585,221**	**$33,764,352**	**$11,179,131**
C&I New Construction and Major Renovation	5.39	7,443,018	$9,138,214	$1,695,196
C&I New Construction and Major Renovation - Government	n/a	n/a	n/a	$0
C&I Large Retrofit	3.33	2,653,203	$3,791,075	$1,137,872
Large C&I Retrofit - Government	n/a	n/a	n/a	$0
C&I Small Retrofit	2.50	12,515,241	$20,835,063	$8,319,822
C&I Small Retrofit - Government	n/a	n/a	n/a	$0
Community Based Pilot	n/a	n/a	n/a	$0
Statewide Marketing & Education	n/a	n/a	n/a	$0
EEAC Consultants	n/a	n/a	n/a	$0
DOER Assessment	n/a	n/a	n/a	$15,331
Sponsorships & Subscriptions	n/a	n/a	n/a	$10,910
GRAND TOTAL	**3.52**	**$72,627,598**	**$101,463,125**	**$28,835,527**

IV.D. Cost Effectiveness

1. Summary Table

Total Resource Cost Test, 2012				
Sector	**B/C Ratio**	**Net Benefits**	**Benefits**	**Costs**
Residential	**5.71**	**$67,012,151**	**$81,244,610**	**$14,232,459**
Residential New Construction & Major Renovation	3.05	1,133,612	$1,686,167	$552,555
Residential Cooling & Heating Equipment	3.93	2,554,823	$3,427,250	$872,427
Multi-Family Retrofit	0.00	0	$0	$0
MassSAVE	6.52	58,264,644	$68,811,551	$10,546,908
Behavior/Feedback Program	n/a	n/a	n/a	$0
ENERGY STAR Lighting	4.99	4,827,395	$6,038,677	$1,211,282
ENERGY STAR Appliances	3.09	866,989	$1,280,964	$413,976
Residential Education Program	n/a	n/a	n/a	$105,000
Workforce Development	n/a	n/a	n/a	$15,000
HEAT Loan Program	n/a	n/a	n/a	$110,000
R&D Demonstration	n/a	n/a	n/a	$0
Deep Energy Retrofit	n/a	n/a	n/a	$0
Behavior/Feedback Pilot	n/a	n/a	n/a	$176,486
Residential New Construction & Major Renovation - Major Renovatior	n/a	n/a	n/a	$0
Residential New Construction Multi Family (4-8 story) statewide pilot	n/a	n/a	n/a	$0
Residential New Construction Lighting Design statewide pilot	n/a	n/a	n/a	$0
Residential New Construction V3 Energy Star Homes statewide pilot	n/a	n/a	n/a	$0
Heat Pump Water Heater Pilot	n/a	n/a	n/a	$0
Residential Technical Development	n/a	n/a	n/a	$20,000
Hot Roofs	n/a	n/a	n/a	$15,000
Home Automation	n/a	n/a	n/a	$0
Community Based Pilot	n/a	n/a	n/a	$0
Statewide Marketing & Education	n/a	n/a	n/a	$90,000
EEAC Consultants	n/a	n/a	n/a	$0
DOER Assessment	n/a	n/a	n/a	$89,134
Sponsorships & Subscriptions	n/a	n/a	n/a	$14,691
Low Income	**3.03**	**$6,400,983**	**$9,546,436**	**$3,145,453**
Low-Income Residential New Construction	0.00	0	$0	$0
Low-Income Retrofit	3.15	6,519,171	$9,546,436	$3,027,265
Statewide Marketing & Education	n/a	n/a	n/a	$15,000
Low-Income Energy Affordability Network Funding	n/a	n/a	n/a	$80,000
DOER Assessment	n/a	n/a	n/a	$23,188
Commercial & Industrial	**3.80**	**$13,467,187**	**$18,271,687**	**$4,804,500**
C&I New Construction and Major Renovation	4.28	5,171,565	$6,747,151	$1,575,586
C&I New Construction and Major Renovation - Government	n/a	n/a	n/a	$0
C&I Large Retrofit	3.79	8,293,556	$11,269,587	$2,976,031
Large C&I Retrofit - Government	n/a	n/a	n/a	$0
C&I Small Retrofit	2.13	135,053	$254,949	$119,896
C&I Small Retrofit - Government	n/a	n/a	n/a	$0
Community Based Pilot	n/a	n/a	n/a	$0
Statewide Marketing & Education	n/a	n/a	n/a	$46,000
EEAC Consultants	n/a	n/a	n/a	$0
DOER Assessment	n/a	n/a	n/a	$74,678
Sponsorships & Subscriptions	n/a	n/a	n/a	$12,309
GRAND TOTAL	**4.92**	**$86,880,321**	**$109,062,733**	**$22,182,412**

IV.D. Cost Effectiveness

1. Summary Table

Total Resource Cost Test, 2010-2012				
Sector	**B/C Ratio**	**Net Benefits**	**Benefits**	**Costs**
Residential	**4.37**	**$133,890,741**	**$173,677,104**	**$39,786,363**
Residential New Construction & Major Renovation	2.64	2,296,378	3,693,915	1,397,537
Residential Cooling & Heating Equipment	2.52	3,863,295	6,410,852	2,547,557
Multi-Family Retrofit	4.61	3,731,965	4,766,290	1,034,325
MassSAVE	5.17	107,364,643	133,111,366	25,746,723
Behavior/Feedback Program	n/a	n/a	n/a	0
ENERGY STAR Lighting	4.27	17,099,792	22,322,765	5,222,973
ENERGY STAR Appliances	2.83	2,180,350	3,371,916	1,191,566
Residential Education Program	n/a	n/a	n/a	486,000
Workforce Development	n/a	n/a	n/a	45,000
HEAT Loan Program	n/a	n/a	n/a	185,000
R&D Demonstration	n/a	n/a	n/a	0
Deep Energy Retrofit	n/a	n/a	n/a	163,333
Behavior/Feedback Pilot	n/a	n/a	n/a	571,486
Residential New Construction & Major Renovation - Major Renovation	n/a	n/a	n/a	535,999
Residential New Construction Multi Family (4-8 story) statewide pilot	n/a	n/a	n/a	0
Residential New Construction Lighting Design statewide pilot	n/a	n/a	n/a	44,444
Residential New Construction V3 Energy Star Homes statewide pilot	n/a	n/a	n/a	0
Heat Pump Water Heater Pilot	n/a	n/a	n/a	22,222
Residential Technical Development	n/a	n/a	n/a	60,000
Hot Roofs	n/a	n/a	n/a	27,000
Home Automation	n/a	n/a	n/a	35,800
Community Based Pilot	n/a	n/a	n/a	0
Statewide Marketing & Education	n/a	n/a	n/a	190,000
EEAC Consultants	n/a	n/a	n/a	93,555
DOER Assessment	n/a	n/a	n/a	146,095
Sponsorships & Subscriptions	n/a	n/a	n/a	39,749
Low Income	**3.16**	**$17,477,111**	**$25,565,589**	**$8,088,478**
Low-Income Residential New Construction	1.16	10,009	72,448	62,438
Low-Income Retrofit	3.25	17,640,838	25,493,141	7,852,303
Statewide Marketing & Education	n/a	n/a	n/a	15,000
Low-Income Energy Affordability Network Funding	n/a	n/a	n/a	126,000
DOER Assessment	n/a	n/a	n/a	32,736
Commercial & Industrial	**3.28**	**$55,533,691**	**$79,892,026**	**$24,358,335**
C&I New Construction and Major Renovation	5.03	18,021,251	22,493,732	4,472,480
C&I New Construction and Major Renovation - Government	n/a	n/a	n/a	0
C&I Large Retrofit	3.76	17,691,940	24,096,354	6,404,415
Large C&I Retrofit - Government	n/a	n/a	n/a	0
C&I Small Retrofit	2.52	20,075,435	33,301,940	13,226,505
C&I Small Retrofit - Government	n/a	n/a	n/a	0
Community Based Pilot	n/a	n/a	n/a	0
Statewide Marketing & Education	n/a	n/a	n/a	46,000
EEAC Consultants	n/a	n/a	n/a	70,295
DOER Assessment	n/a	n/a	n/a	105,389
Sponsorships & Subscriptions	n/a	n/a	n/a	33,251
GRAND TOTAL	**3.86**	**$206,901,542**	**$279,134,718**	**$72,233,176**

IV.D. Cost Effectiveness
2.1. Cost Summary Table

2010				
Programs	PA Costs		Participant Costs	Total TRC Test Costs
	Program Costs (1)	Performance Incentive (2)		
Residential (total)	**$9,449,462**	**$0**	**$1,302,322**	**$10,751,784**
Residential New Construction & Major Ren	380,019	0	111,800	491,819
Residential Cooling & Heating Equipment	640,525	0	34,307	674,832
Multi-Family Retrofit	443,571	0	29,278	472,849
MassSAVE	5,516,024	0	818,814	6,334,839
Behavior/Feedback Program	n/a	n/a	n/a	0
ENERGY STAR Lighting	1,159,453	0	242,328	1,401,781
ENERGY STAR Appliances	253,545	0	65,795	319,340
Residential Education Program	186,000	0	0	186,000
Workforce Development	15,000	0	0	15,000
Heat Loan Program	30,000	0	0	30,000
R&D Demonstration	n/a	n/a	n/a	0
Deep Energy Retrofit	83,333	0	0	83,333
Behavior/Feedback Pilot	233,333	0	0	233,333
Residential New Construction & Major Ren	257,547	0	0	257,547
Residential New Construction Multi Family	0	0	0	0
Residential New Construction Lighting Des	22,222	0	0	22,222
Residential New Construction V3 Energy S	0	0	0	0
Heat Pump Water Heater Pilot	11,111	0	0	11,111
Residential Technical Development	20,000	0	0	20,000
Hot Roofs	3,000	0	0	3,000
Home Automation	10,800	0	0	10,800
Community-Based Outreach Pilot	n/a	n/a	n/a	0
Statewide Marketing & Education	50,000	0	0	50,000
EEAC Consultants	93,555	0	0	93,555
DOER Assessment	28,456	0	0	28,456
Sponsorships & Subscriptions	11,967	0	0	11,967
Low Income (total)	**$2,088,750**	**$0**	**$0**	**$2,088,750**
Low-Income Residential New Construction	28,666	0	0	28,666
Low-Income Retrofit	2,033,309	0	0	2,033,309
Statewide Marketing & Education	0	0	0	0
Low-Income Energy Affordability Network F	22,000	0	0	22,000
DOER Assessment	4,774	0	0	4,774
Commercial & Industrial (total)	**$7,098,577**	**$0**	**$1,276,127**	**$8,374,704**
C&I New Construction and Major Renovati	905,004	0	296,694	1,201,698
C&I New Construction and Major Renovati	n/a	n/a	n/a	0
C&I Large Retrofit	1,807,995	0	482,517	2,290,512
Large C&I Retrofit - Government	n/a	n/a	n/a	0
C&I Small Retrofit	4,289,871	0	496,916	4,786,787
C&I Small Retrofit - Government	n/a	n/a	n/a	0
Community-Based Outreach Pilot	n/a	n/a	n/a	0
Statewide Marketing & Education	0	0	0	0
EEAC Consultants	70,295	0	0	70,295
DOER Assessment	15,380	0	0	15,380
Sponsorships & Subscriptions	10,033	0	0	10,033
GRAND TOTAL	**$18,636,789**	**$0**	**$2,578,449**	**$21,215,238**

IV.D. Cost Effectiveness
2.1. Cost Summary Table

2011				
Programs	PA Costs		Participant Costs	Total TRC Test Costs
	Program Costs (1)	Performance Incentive (2)		
Residential (total)	**$12,386,208**	**$0**	**$2,415,912**	**$14,802,121**
Residential New Construction & Major Ren	235,663	0	117,500	353,163
Residential Cooling & Heating Equipment	890,256	0	110,041	1,000,298
Multi-Family Retrofit	521,038	0	40,438	561,476
MassSAVE	7,408,109	0	1,456,868	8,864,976
Behavior/Feedback Program	n/a	n/a	n/a	0
ENERGY STAR Lighting	2,018,330	0	591,580	2,609,910
ENERGY STAR Appliances	358,766	0	99,485	458,251
Residential Education Program	195,000	0	0	195,000
Workforce Development	15,000	0	0	15,000
Heat Loan Program	45,000	0	0	45,000
R&D Demonstration	n/a	n/a	n/a	0
Deep Energy Retrofit	80,000	0	0	80,000
Behavior/Feedback Pilot	161,667	0	0	161,667
Residential New Construction & Major Ren	278,452	0	0	278,452
Residential New Construction Multi Family	0	0	0	0
Residential New Construction Lighting Des	22,222	0	0	22,222
Residential New Construction V3 Energy S	0	0	0	0
Heat Pump Water Heater Pilot	11,111	0	0	11,111
Residential Technical Development	20,000	0	0	20,000
Hot Roofs	9,000	0	0	9,000
Home Automation	25,000	0	0	25,000
Community-Based Outreach Pilot	n/a	n/a	n/a	0
Statewide Marketing & Education	50,000	0	0	50,000
EEAC Consultants	0	0	0	0
DOER Assessment	28,505	0	0	28,505
Sponsorships & Subscriptions	13,090	0	0	13,090
Low Income (total)	**$2,854,275**	**$0**	**$0**	**$2,854,275**
Low-Income Residential New Construction	33,772	0	0	33,772
Low-Income Retrofit	2,791,729	0	0	2,791,729
Statewide Marketing & Education	0	0	0	0
Low-Income Energy Affordability Network F	24,000	0	0	24,000
DOER Assessment	4,774	0	0	4,774
Commercial & Industrial (total)	**$9,659,199**	**$0**	**$1,519,932**	**$11,179,131**
C&I New Construction and Major Renovatio	1,287,876	0	407,320	1,695,196
C&I New Construction and Major Renovatio	n/a	n/a	n/a	0
C&I Large Retrofit	941,260	0	196,612	1,137,872
Large C&I Retrofit - Government	n/a	n/a	n/a	0
C&I Small Retrofit	7,403,822	0	916,000	8,319,822
C&I Small Retrofit - Government	n/a	n/a	n/a	0
Community-Based Outreach Pilot	n/a	n/a	n/a	0
Statewide Marketing & Education	0	0	0	0
EEAC Consultants	0	0	0	0
DOER Assessment	15,331	0	0	15,331
Sponsorships & Subscriptions	10,910	0	0	10,910
GRAND TOTAL	**$24,899,683**	**$0**	**$3,935,844**	**$28,835,527**

IV.D. Cost Effectiveness

2.1. Cost Summary Table

2012				
Programs	PA Costs		Participant Costs	Total TRC Test Costs
	Program Costs (1)	Performance Incentive (2)		
Residential (total)	**$11,163,540**	**$0**	**$3,068,919**	**$14,232,459**
Residential New Construction & Major Ren	390,055	0	162,500	552,555
Residential Cooling & Heating Equipment	714,541	0	157,887	872,427
Multi-Family Retrofit	0	0	0	0
MassSAVE	7,816,026	0	2,730,882	10,546,908
Behavior/Feedback Program	n/a	n/a	n/a	0
ENERGY STAR Lighting	1,211,282	0	0	1,211,282
ENERGY STAR Appliances	396,326	0	17,650	413,976
Residential Education Program	105,000	0	0	105,000
Workforce Development	15,000	0	0	15,000
Heat Loan Program	110,000	0	0	110,000
R&D Demonstration	n/a	n/a	n/a	0
Deep Energy Retrofit	0	0	0	0
Behavior/Feedback Pilot	176,486	0	0	176,486
Residential New Construction & Major Ren	0	0	0	0
Residential New Construction Multi Family	0	0	0	0
Residential New Construction Lighting Des	0	0	0	0
Residential New Construction V3 Energy S	0	0	0	0
Heat Pump Water Heater Pilot	0	0	0	0
Residential Technical Development	20,000	0	0	20,000
Hot Roofs	15,000	0	0	15,000
Home Automation	0	0	0	0
Community-Based Outreach Pilot	n/a	n/a	n/a	0
Statewide Marketing & Education	90,000	0	0	90,000
EEAC Consultants	0	0	0	0
DOER Assessment	89,134	0	0	89,134
Sponsorships & Subscriptions	14,691	0	0	14,691
Low Income (total)	**$3,145,453**	**$0**	**$0**	**$3,145,453**
Low-Income Residential New Construction	0	0	0	0
Low-Income Retrofit	3,027,265	0	0	3,027,265
Statewide Marketing & Education	15,000	0	0	15,000
Low-Income Energy Affordability Network F	80,000	0	0	80,000
DOER Assessment	23,188	0	0	23,188
Commercial & Industrial (total)	**$4,004,926**	**$0**	**$799,574**	**$4,804,500**
C&I New Construction and Major Renovatio	1,457,124	0	118,462	1,575,586
C&I New Construction and Major Renovatio	n/a	n/a	n/a	0
C&I Large Retrofit	2,307,088	0	668,943	2,976,031
Large C&I Retrofit - Government	n/a	n/a	n/a	0
C&I Small Retrofit	107,728	0	12,169	119,896
C&I Small Retrofit - Government	n/a	n/a	n/a	0
Community-Based Outreach Pilot	n/a	n/a	n/a	0
Statewide Marketing & Education	46,000	0	0	46,000
EEAC Consultants	0	0	0	0
DOER Assessment	74,678	0	0	74,678
Sponsorships & Subscriptions	12,309	0	0	12,309
GRAND TOTAL	**$18,313,920**	**$0**	**$3,868,492**	**$22,182,412**

IV.D. Cost Effectiveness
2.1. Cost Summary Table

2010-2012				
Programs	PA Costs		Participant Costs	Total TRC Test Costs
	Program Costs (1)	Performance Incentive (2)		
Residential (total)	**$32,999,211**	**$0**	**$6,787,152**	**$39,786,363**
Residential New Construction & Major Ren	1,005,737	0	391,800	1,397,537
Residential Cooling & Heating Equipment	2,245,322	0	302,235	2,547,557
Multi-Family Retrofit	964,609	0	69,716	1,034,325
MassSAVE	20,740,159	0	5,006,564	25,746,723
Behavior/Feedback Program	n/a	n/a	n/a	0
ENERGY STAR Lighting	4,389,065	0	833,908	5,222,973
ENERGY STAR Appliances	1,008,636	0	182,930	1,191,566
Residential Education Program	486,000	0	0	486,000
Workforce Development	45,000	0	0	45,000
Heat Loan Program	185,000	0	0	185,000
R&D Demonstration	n/a	n/a	n/a	0
Deep Energy Retrofit	163,333	0	0	163,333
Behavior/Feedback Pilot	571,486	0	0	571,486
Residential New Construction & Major Ren	535,999	0	0	535,999
Residential New Construction Multi Family	0	0	0	0
Residential New Construction Lighting Des	44,444	0	0	44,444
Residential New Construction V3 Energy S	0	0	0	0
Heat Pump Water Heater Pilot	22,222	0	0	22,222
Residential Technical Development	60,000	0	0	60,000
Hot Roofs	27,000	0	0	27,000
Home Automation	35,800	0	0	35,800
Community-Based Outreach Pilot	n/a	n/a	n/a	0
Statewide Marketing & Education	190,000	0	0	190,000
EEAC Consultants	93,555	0	0	93,555
DOER Assessment	146,095	0	0	146,095
Sponsorships & Subscriptions	39,749	0	0	39,749
Low Income (total)	**$8,088,478**	**$0**	**$0**	**$8,088,478**
Low-Income Residential New Construction	62,438	0	0	62,438
Low-Income Retrofit	7,852,303	0	0	7,852,303
Statewide Marketing & Education	15,000	0	0	15,000
Low-Income Energy Affordability Network F	126,000	0	0	126,000
DOER Assessment	32,736	0	0	32,736
Commercial & Industrial (total)	**$20,762,703**	**$0**	**$3,595,633**	**$24,358,335**
C&I New Construction and Major Renovatio	3,650,004	0	822,476	4,472,480
C&I New Construction and Major Renovatio	n/a	n/a	n/a	0
C&I Large Retrofit	5,056,342	0	1,348,072	6,404,415
Large C&I Retrofit - Government	n/a	n/a	n/a	0
C&I Small Retrofit	11,801,420	0	1,425,084	13,226,505
C&I Small Retrofit - Government	n/a	n/a	n/a	0
Community-Based Outreach Pilot	n/a	n/a	n/a	0
Statewide Marketing & Education	46,000	0	0	46,000
EEAC Consultants	70,295	0	0	70,295
DOER Assessment	105,389	0	0	105,389
Sponsorships & Subscriptions	33,251	0	0	33,251
GRAND TOTAL	**$61,850,391**	**$0**	**$10,382,785**	**$72,233,176**

Notes:

(1) Program Costs include Program Planning and Administration, Marketing and Advertising, Program Incentive, Sales, Technical Assistance & Training, Evaluation and Market Research (See Table IV.C.1, Budget Summary)

(2) Performance Incentives are not applicable to The Cape Light Compact.

IV.D Cost Effectiveness
2.3 Cost Comparison Table - Three-Year Plan vs. Previous Years

Historical Cost Comparison												
Programs	**2007 (1)**		**2008 (2)**		**2009 (3)**		**2010 (4)**		**2011 (5)**		**2012(6)**	
	$	**%**	**$**	**%**	**$**	**%**	**$**	**%**	**$**	**%**	**$**	**%**
Residential	**2,301,072**	**100%**	**2,876,281**	**100%**	**4,481,734**	**100%**	**7,186,647**	**100%**	**14,802,121**	**100%**	**14,232,459**	**100%**
PA Costs	2,011,488	87%	2,478,166	86%	3,962,316	88%	6,388,566	89%	12,386,208	84%	11,163,540	78%
Participant Cost	289,583	13%	398,116	14%	519,417	12%	798,081	11%	2,415,912	16%	3,068,919	22%
Low Income	**627,195**	**100%**	**745,085**	**100%**	**994,424**	**100%**	**1,828,369**	**100%**	**2,854,275**	**100%**	**3,145,453**	**100%**
PA Costs	627,195	100%	745,085	100%	994,424	100%	1,826,691	100%	2,854,275	100%	3,145,453	100%
Participant Cost	0	0%	0	0%	0	0%	1,678	0%	0	0%	0	0%
Commercial & Industrial	**2,928,385**	**100%**	**2,789,873**	**100%**	**5,112,881**	**100%**	**5,983,719**	**100%**	**11,179,131**	**100%**	**4,804,500**	**100%**
PA Costs	2,409,406	82%	2,262,712	81%	3,944,366	77%	5,315,961	89%	9,659,199	86%	4,004,926	83%
Participant Cost	518,978	18%	527,162	19%	1,168,515	23%	667,758	11%	1,519,932	14%	799,574	17%
TOTAL	**5,856,651**	**100%**	**6,411,240**	**100%**	**10,589,038**	**100%**	**14,998,735**	**100%**	**28,835,527**	**100%**	**22,182,412**	**100%**
PA Costs	**5,048,090**	**86%**	**5,485,962**	**86%**	**8,901,106**	**84%**	**13,531,218**	**90%**	**24,899,683**	**86%**	**18,313,920**	**83%**
Participant Cost	**808,562**	**14%**	**925,278**	**14%**	**1,687,932**	**16%**	**1,467,517**	**10%**	**3,935,844**	**14%**	**3,868,492**	**17%**

Notes:
(1) Actual values from the Cape Light Compact's 2007 Annual Report D.P.U. 09-68, in 2007$.
(2) Actual values from the Cape Light Compact's 2008 Annual Report D.P.U. 09-69, in 2008$.
(3) Actual values from the Cape Light Compact's 2009 Annual Report D.P.U. 10-97, in 2009$.
(4) Actual values from the Cape Light Compact's 2010 Annual Report D.P.U. 11-68, in 2010$.
(5) As this filing assumes approval of the 2011 Mid-Term Modifications, this data is as filed in the Cape Light Compact's 2011 Mid-Term Modifications Filing, D.P.U. 10-147, in 2011$.
(6) Proposed 2012 changes presented in this filing, representing additional budget requirements for 2012, taking into account 2011 estimated carryover, in 2012$.

IV.D Cost Effectiveness

3.1.i. Benefits Summary Table

Program	Electric Benefits, 2010 ($) (3)											
	Capacity						Energy					
	Generation		Trans.	Distrib.	DRIPE	TOTAL	Winter		Summer		DRIPE	TOTAL
	Summer	Winter					Peak	Off Peak	Peak	Off Peak		
Residential (total)	$1,449,381	$0	$587,336	$2,913,398	$405,188	$5,355,303	$2,224,852	$2,345,459	$1,920,651	$1,378,743	$2,576,599	$10,446,304
Residential New Construction & Major Renovation	$37,713	$0	$13,621	$67,563	$8,550	127,447	$56,949	$55,621	$55,700	$35,837	$70,963	275,071
Residential Cooling & Heating Equipment	$129,954	$0	$64,392	$319,407	$43,258	557,011	$287,116	$98,529	$144,472	$45,847	$125,959	701,923
Multi-Family Retrofit	$25,959	$0	$10,330	$51,240	$7,467	94,996	$110,112	$128,610	$54,889	$61,653	$120,753	476,018
MassSAVE	$1,095,461	$0	$421,845	$2,092,504	$249,956	3,859,766	$806,344	$944,071	$1,163,959	$694,693	$1,020,514	4,629,582
Behavior/Feedback Program	n/a	n/a	n/a	n/a	n/a	0	n/a	n/a	n/a	n/a	n/a	0
ENERGY STAR Lighting	$122,070	$0	$57,709	$286,256	$74,100	540,135	$837,479	$971,170	$414,697	$462,972	$1,065,891	3,752,210
ENERGY STAR Appliances	$38,225	$0	$19,440	$96,427	$21,857	175,948	$126,851	$147,458	$86,933	$77,740	$172,518	611,500
Residential Education Program	n/a	n/a	n/a	n/a	n/a	0	n/a	n/a	n/a	n/a	n/a	0
Workforce Development	n/a	n/a	n/a	n/a	n/a	0	n/a	n/a	n/a	n/a	n/a	0
Heat Loan Program	n/a	n/a	n/a	n/a	n/a	0	n/a	n/a	n/a	n/a	n/a	0
R&D Demonstration	n/a	n/a	n/a	n/a	n/a	0	n/a	n/a	n/a	n/a	n/a	0
Deep Energy Retrofit	n/a	n/a	n/a	n/a	n/a	0	n/a	n/a	n/a	n/a	n/a	0
Behavior/Feedback Pilot	n/a	n/a	n/a	n/a	n/a	0	n/a	n/a	n/a	n/a	n/a	0
Low Income (total)	$58,313	$0	$28,850	$143,107	$25,839	$256,108	$404,869	$476,022	$200,781	$227,753	$387,809	$1,697,233
Low-Income Residential New Construction	$979	$0	$364	$1,804	$241	3,388	$2,505	$2,920		$1,392	$3,006	9,822
Low-Income Retrofit	$57,333	$0	$28,486	$141,303	$25,598	252,720	$402,365	$473,102	$200,781	$226,362	$384,803	1,687,412
C&I (total)	$1,376,081	$0	$766,036	$3,799,816	$639,845	$6,581,779	$7,346,237	$2,503,904	$4,709,125	$1,481,967	$4,767,116	$20,808,349
C&I New Construction and Major Renovation	$304,004	$0	$166,961	$828,190	$123,318	1,422,473	$1,722,958	$430,550	$1,250,888	$286,601	$975,050	4,666,047
C&I New Construction and Major Renovation - Gov	n/a	n/a	n/a	n/a	n/a	0	n/a	n/a	n/a	n/a	n/a	0
C&I Large Retrofit	$494,982	$0	$276,871	$1,373,383	$238,542	2,383,778	$2,262,497	$783,611	$1,580,420	$509,809	$1,548,967	6,685,305
Large C&I Retrofit - Government	n/a	n/a	n/a	n/a	n/a	0	n/a	n/a	n/a	n/a	n/a	0
C&I Small Retrofit	$577,095	$0	$322,203	$1,598,244	$277,985	2,775,528	$3,360,783	$1,289,743	$1,877,817	$685,556	$2,243,099	9,456,998
C&I Small Retrofit - Government	n/a	n/a	n/a	n/a	n/a	0	n/a	n/a	n/a	n/a	n/a	0
GRAND TOTAL	$2,883,774	$0	$1,382,221	$6,856,321	$1,070,872	$12,193,189	$9,975,959	$5,325,384	$6,830,556	$3,088,463	$7,731,524	$32,951,887

Program	Electric Benefits, 2011 ($) (4)											
	Capacity						Energy					
	Generation		Trans.	Distrib.	DRIPE	TOTAL	Winter		Summer		DRIPE	TOTAL
	Summer	Winter					Peak	Off Peak	Peak	Off Peak		
Residential (total)	$2,275,523	$0	$951,733	$4,720,944	$1,120,292	$9,068,491	$4,190,740	$4,640,180	$3,423,538	$2,621,555	$4,312,348	$19,188,360
Residential New Construction & Major Renovation	$22,256	$0	$8,505	$42,190	$10,485	83,436	$68,104	$80,316	$51,525	$44,022	$65,710	309,677
Residential Cooling & Heating Equipment	$201,100	$0	$101,282	$502,394	$109,479	914,255	$376,446	$158,080	$301,208	$96,029	$167,355	1,099,119
Multi-Family Retrofit	$99,168	$0	$38,835	$192,634	$39,984	370,620	$159,543	$188,309	$79,732	$90,049	$143,806	661,439
MassSAVE	$1,667,737	$0	$634,909	$3,149,378	$596,522	6,048,546	$1,154,160	$1,365,790	$1,737,787	$1,024,763	$1,169,464	6,451,964
Behavior/Feedback Program	n/a	n/a	n/a	n/a	n/a	0	n/a	n/a	n/a	n/a	n/a	0
ENERGY STAR Lighting	$246,130	$0	$144,280	$715,679	$315,452	1,421,541	$2,204,334	$2,580,496	$1,092,395	$1,224,913	$2,490,611	9,592,751
ENERGY STAR Appliances	$39,132	$0	$23,923	$118,668	$48,370	230,093	$228,152	$267,189	$160,890	$141,779	$275,400	1,073,411
Residential Education Program	n/a	n/a	n/a	n/a	n/a	0	n/a	n/a	n/a	n/a	n/a	0
Workforce Development	n/a	n/a	n/a	n/a	n/a	0	n/a	n/a	n/a	n/a	n/a	0
Heat Loan Program	n/a	n/a	n/a	n/a	n/a	0	n/a	n/a	n/a	n/a	n/a	0
R&D Demonstration	n/a	n/a	n/a	n/a	n/a	0	n/a	n/a	n/a	n/a	n/a	0
Deep Energy Retrofit	n/a	n/a	n/a	n/a	n/a	0	n/a	n/a	n/a	n/a	n/a	0
Behavior/Feedback Pilot	n/a	n/a	n/a	n/a	n/a	0	n/a	n/a	n/a	n/a	n/a	0
Low Income (total)	$76,785	$0	$41,893	$207,804	$62,490	$388,972	$607,363	$718,957	$304,300	$343,376	$505,972	$2,479,968
Low-Income Residential New Construction	$2,579	$0	$912	$4,523	$903	8,917	$2,508	$2,935	$2,333	$1,740	$3,092	12,608
Low-Income Retrofit	$74,205	$0	$40,981	$203,281	$61,587	380,055	$604,855	$716,021	$301,967	$341,636	$502,881	2,467,361
C&I (total)	$1,443,500	$0	$911,274	$4,520,251	$1,191,116	$8,066,142	$9,390,790	$3,245,065	$5,765,246	$1,836,512	$4,887,227	$25,124,841
C&I New Construction and Major Renovation	$392,399	$0	$236,653	$1,173,883	$271,489	2,074,425	$2,497,966	$621,034	$1,761,754	$404,431	$1,099,886	6,385,071
C&I New Construction and Major Renovation - Gov	n/a	n/a	n/a	n/a	n/a	0	n/a	n/a	n/a	n/a	n/a	0
C&I Large Retrofit	$183,733	$0	$117,403	$582,360	$160,193	1,043,689	$1,000,960	$342,558	$660,860	$213,034	$536,360	2,753,771
Large C&I Retrofit - Government	n/a	n/a	n/a	n/a	n/a	0	n/a	n/a	n/a	n/a	n/a	0
C&I Small Retrofit	$867,368	$0	$557,219	$2,764,008	$759,434	4,948,028	$5,891,864	$2,281,473	$3,342,632	$1,219,048	$3,250,981	15,985,998
C&I Small Retrofit - Government	n/a	n/a	n/a	n/a	n/a	0	n/a	n/a	n/a	n/a	n/a	0
GRAND TOTAL	$3,795,808	$0	$1,904,900	$9,448,999	$2,373,898	$17,523,605	$14,188,892	$8,604,201	$9,493,085	$4,801,444	$9,705,547	$46,793,170

IV.D Cost Effectiveness
3.1.i. Benefits Summary Table

Program	Electric Benefits, 2012 ($) (5)											
	Capacity						Energy					
	Generation		Trans.	Distrib.	DRIPE	TOTAL	Winter		Summer		DRIPE	TOTAL
	Summer	Winter					Peak	Off Peak	Peak	Off Peak		
Residential (total)	$1,124,750	$0	$606,875	$2,505,534	$1,146,224	$5,383,383	$2,376,212	$2,879,183	$3,070,222	$1,936,278	$3,059,393	$13,321,288
Residential New Construction & Major Renovation	$66,252	$0	$27,463	$113,382	$42,493	249,590	$130,345	$162,246	$122,684	$94,602	$138,538	648,416
Residential Cooling & Heating Equipment	$198,244	$0	$126,362	$521,698	$209,571	1,055,875	$137,095	$83,669	$97,798	$49,851	$104,574	472,986
Multi-Family Retrofit	$0	$0	$0	$0	$0	0	$0	$0	$0	$0	$0	0
MassSAVE	$649,950	$0	$295,630	$1,220,533	$648,169	2,814,282	$960,748	$1,194,238	$2,174,394	$1,088,383	$1,235,137	6,652,900
Behavior/Feedback Program	n/a	n/a	n/a	n/a	n/a	0	n/a	n/a	n/a	n/a	n/a	0
ENERGY STAR Lighting	$168,214	$0	$129,193	$533,384	$191,084	1,021,875	$947,759	$1,187,562	$556,290	$579,908	$1,320,420	4,591,939
ENERGY STAR Appliances	$42,090	$0	$28,227	$116,537	$54,907	241,761	$200,265	$251,467	$119,056	$123,534	$260,724	955,046
Residential Education Program	n/a	n/a	n/a	n/a	n/a	0	n/a	n/a	n/a	n/a	n/a	0
Workforce Development	n/a	n/a	n/a	n/a	n/a	0	n/a	n/a	n/a	n/a	n/a	0
Heat Loan Program	n/a	n/a	n/a	n/a	n/a	0	n/a	n/a	n/a	n/a	n/a	0
R&D Demonstration	n/a	n/a	n/a	n/a	n/a	0	n/a	n/a	n/a	n/a	n/a	0
Deep Energy Retrofit	n/a	n/a	n/a	n/a	n/a	0	n/a	n/a	n/a	n/a	n/a	0
Behavior/Feedback Pilot	n/a	n/a	n/a	n/a	n/a	0	n/a	n/a	n/a	n/a	n/a	0
Low Income (total)	$50,433	$0	$27,016	$111,540	$44,350	$233,340	$278,704	$348,121	$159,573	$170,885	$281,346	$1,238,629
Low-Income Residential New Construction	$0	$0	$0	$0	$0	0	$0	$0	$0	$0	$0	0
Low-Income Retrofit	$50,433	$0	$27,016	$111,540	$44,350	233,340	$278,704	$348,121	$159,573	$170,885	$281,346	1,238,629
C&I (total)	$1,462,335	$0	$820,435	$3,387,236	$1,873,582	$7,543,589	$3,525,774	$1,095,018	$2,784,334	$720,038	$2,710,324	$10,835,487
C&I New Construction and Major Renovation	$488,947	$0	$274,816	$1,134,601	$552,867	2,451,231	$1,473,617	$426,198	$1,110,635	$265,907	$1,099,487	4,375,843
C&I New Construction and Major Renovation - Gov	n/a	n/a	n/a	n/a	n/a	0	n/a	n/a	n/a	n/a	n/a	0
C&I Large Retrofit	$959,134	$0	$537,880	$2,220,681	$1,300,949	5,018,643	$2,000,857	$649,662	$1,634,782	$442,762	$1,570,792	6,298,856
Large C&I Retrofit - Government	n/a	n/a	n/a	n/a	n/a	0	n/a	n/a	n/a	n/a	n/a	0
C&I Small Retrofit	$14,254	$0	$7,740	$31,955	$19,766	73,716	$51,299	$19,158	$38,917	$11,369	$40,045	160,788
C&I Small Retrofit - Government	n/a	n/a	n/a	n/a	n/a	0	n/a	n/a	n/a	n/a	n/a	0
GRAND TOTAL	$2,637,518	$0	$1,454,327	$6,004,310	$3,064,156	$13,160,312	$6,180,690	$4,322,321	$6,014,129	$2,827,201	$6,051,063	$25,395,404

Program	Electric Benefits, 2010-2012 ($)											
	Capacity						Energy					
	Generation		Trans.	Distrib.	DRIPE	TOTAL	Winter		Summer		DRIPE	TOTAL
	Summer	Winter					Peak	Off Peak	Peak	Off Peak		
Residential (total)	$4,849,653	$0	$2,145,944	$10,139,876	$2,671,704	$19,807,177	$8,791,804	$9,864,821	$8,414,411	$5,936,576	$9,948,340	$42,955,953
Residential New Construction & Major Renovation	$126,221	$0	$49,589	$223,135	$61,528	460,473	$255,399	$298,183	$229,909	$174,462	$275,212	1,233,165
Residential Cooling & Heating Equipment	$529,298	$0	$292,036	$1,343,500	$362,308	2,527,142	$800,657	$340,278	$543,478	$191,727	$397,888	2,274,028
Multi-Family Retrofit	$125,127	$0	$49,165	$243,874	$47,451	465,616	$269,655	$316,919	$134,621	$151,702	$264,559	1,137,457
MassSAVE	$3,413,147	$0	$1,352,384	$6,462,416	$1,494,647	12,722,594	$2,921,252	$3,504,099	$5,076,140	$2,807,839	$3,425,116	17,734,446
Behavior/Feedback Program	n/a	n/a	n/a	n/a	n/a	0	n/a	n/a	n/a	n/a	n/a	0
ENERGY STAR Lighting	$536,414	$0	$331,181	$1,535,319	$580,636	2,983,551	$3,989,572	$4,739,229	$2,063,383	$2,267,793	$4,876,922	17,936,900
ENERGY STAR Appliances	$119,447	$0	$71,590	$331,632	$125,134	647,802	$555,268	$666,113	$366,880	$343,053	$708,643	2,639,957
Residential Education Program	n/a	n/a	n/a	n/a	n/a	0	n/a	n/a	n/a	n/a	n/a	0
Workforce Development	n/a	n/a	n/a	n/a	n/a	0	n/a	n/a	n/a	n/a	n/a	0
Heat Loan Program	n/a	n/a	n/a	n/a	n/a	0	n/a	n/a	n/a	n/a	n/a	0
R&D Demonstration	n/a	n/a	n/a	n/a	n/a	0	n/a	n/a	n/a	n/a	n/a	0
Deep Energy Retrofit	n/a	n/a	n/a	n/a	n/a	0	n/a	n/a	n/a	n/a	n/a	0
Behavior/Feedback Pilot	n/a	n/a	n/a	n/a	n/a	0	n/a	n/a	n/a	n/a	n/a	0
Low Income (total)	$185,531	$0	$97,759	$462,450	$132,679	$878,420	$1,290,936	$1,543,099	$664,654	$742,015	$1,175,127	$5,415,831
Low-Income Residential New Construction	$3,559	$0	$1,276	$6,327	$1,143	12,305	$5,013	$5,855	$2,333	$3,131	$6,098	22,430
Low-Income Retrofit	$181,972	$0	$96,484	$456,123	$131,536	866,115	$1,285,924	$1,537,245	$662,321	$738,883	$1,169,029	5,393,401
C&I (total)	$4,281,917	$0	$2,497,745	$11,707,304	$3,704,544	$22,191,510	$20,262,801	$6,843,986	$13,258,705	$4,038,517	$12,364,667	$56,768,676
C&I New Construction and Major Renovation	$1,185,350	$0	$678,430	$3,136,674	$947,675	5,948,129	$5,694,541	$1,477,782	$4,123,277	$956,939	$3,174,423	15,426,961
C&I New Construction and Major Renovation - Gov	n/a	n/a	n/a	n/a	n/a	0	n/a	n/a	n/a	n/a	n/a	0
C&I Large Retrofit	$1,637,849	$0	$932,154	$4,176,423	$1,699,683	8,446,110	$5,264,314	$1,775,832	$3,876,062	$1,165,605	$3,656,119	15,737,931
Large C&I Retrofit - Government	n/a	n/a	n/a	n/a	n/a	0	n/a	n/a	n/a	n/a	n/a	0
C&I Small Retrofit	$1,458,718	$0	$887,162	$4,394,207	$1,057,186	7,797,272	$9,303,946	$3,590,373	$5,259,367	$1,915,974	$5,534,125	25,603,784
C&I Small Retrofit - Government	n/a	n/a	n/a	n/a	n/a	0	n/a	n/a	n/a	n/a	n/a	0
GRAND TOTAL	$9,317,101	$0	$4,741,449	$22,309,630	$6,508,927	$42,877,107	$30,345,541	$18,251,907	$22,337,770	$10,717,108	$23,488,134	$105,140,460

Notes:
(1) See Table IV.D.3.2.i Savings Summary for information on the savings used to determine the benefits in these tables.
(2) See Table IV.D.3.3.i for the Avoided Cost Factors used to determine the benefits in these tables
(3) As filed in the Cape Light Compact's 2010 Mid-Year Revisions Filing, D.P.U 10-106, in 2010$
(4) As this filing assumes approval of the 2011 Mid-Term Modifications, this data is as filed in the Cape Light Compact's 2011 Mid-Term Modifications Filing, D.P.U. 10-147, in 2011$
(5) Proposed 2012 changes presented in this filing, representing additional budget requirements for 2012, taking into account 2011 estimated carryover, in 2012$

IV.D Cost Effectiveness
3.1.i. Benefits Summary Table

Program	Non-Electric Benefits, 2010 ($) (3)									TOTAL BENEFITS
	Resource Benefits									
	Avoided Natural Gas	No. 2 Distillate	No. 4 Fuel Oil	Propane	Wood	Water	Kerosene	Non- Resource Benefits (1)	TOTAL	
Residential (total)	$4,458,768	$12,072,408	$0	$1,892,765	$0	$134,972	$0	$471,213	$19,030,126	$34,831,733
Residential New Construction & Major Renovation	$122	$29,685	$0	$634,601	$0	$947	$0	$11,257	676,612	1,079,130
Residential Cooling & Heating Equipment	-$137,551	$0	$0	$0	$0	$0	$0	$9,879	-127,672	1,131,262
Multi-Family Retrofit	$346,300	$583,069	$0	$291,306	$0	$114,313	$0	$14,588	1,349,576	1,920,590
MassSAVE	$4,249,897	$11,459,653	$0	$966,858	$0	$19,713	$0	$161,433	16,857,554	25,346,901
Behavior/Feedback Program	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	0	0
ENERGY STAR Lighting	$0	$0	$0	$0	$0	$0	$0	$274,056	274,056	4,566,401
ENERGY STAR Appliances	$0	$0	$0	$0	$0	$0	$0	$0	0	787,448
Residential Education Program	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	0	0
Workforce Development	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	0	0
Heat Loan Program	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	0	0
R&D Demonstration	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	0	0
Deep Energy Retrofit	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	0	0
Behavior/Feedback Pilot	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	0	0
Low Income (total)	-$31,597	$1,092,388	$0	$10,249	$0	$159,433	$0	$2,737,325	$3,967,799	$5,921,141
Low-Income Residential New Construction	$21	$0	$0	$10,249	$0	$61	$0	$3,919	14,250	27,459
Low-Income Retrofit	-$31,618	$1,092,388	$0	$0	$0	$159,372	$0	$2,733,407	3,953,549	5,893,681
C&I (total)	-$839,476	$125,653	$0	$104,823	$0	$0	$0	$1,074,859	$465,860	$27,855,987
C&I New Construction and Major Renovation	$0	$0	$0	$0	$0	$0	$0	$519,847	519,847	6,608,366
C&I New Construction and Major Renovation - Gov	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	0	0
C&I Large Retrofit	-$41,828	$0	$0	$0	$0	$0	$0	$8,438	-33,390	9,035,693
Large C&I Retrofit - Government	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	0	0
C&I Small Retrofit	-$797,648	$125,653	$0	$104,823	$0	$0	$0	$546,574	-20,597	12,211,928
C&I Small Retrofit - Government	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	0	0
GRAND TOTAL	$3,587,695	$13,290,449	$0	$2,007,837	$0	$294,406	$0	$4,283,397	$23,463,784	$68,608,861

Program	Non-Electric Benefits, 2011 ($) (4)									TOTAL BENEFITS
	Resource Benefits									
	Avoided Natural Gas	No. 2 Distillate	No. 4 Fuel Oil	Propane	Wood	Water	Kerosene	Non- Resource Benefits (1)	TOTAL	
Residential (total)	$7,061,808	$18,859,818	$0	$2,240,404	$0	$144,623	$0	$1,037,256	$29,343,909	$57,600,761
Residential New Construction & Major Renovation	$156,073	$13,980	$0	$351,274	$0	$1,683	$0	$12,495	535,505	928,618
Residential Cooling & Heating Equipment	-$176,471	$0	$0	$0	$0	$0	$0	$15,436	-161,035	1,852,339
Multi-Family Retrofit	$485,868	$813,655	$0	$377,431	$0	$118,227	$0	$18,461	1,813,642	2,845,701
MassSAVE	$6,596,337	$18,032,183	$0	$1,511,699	$0	$24,713	$0	$287,471	26,452,403	38,952,913
Behavior/Feedback Program	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	0	0
ENERGY STAR Lighting	$0	$0	$0	$0	$0	$0	$0	$703,394	703,394	11,717,686
ENERGY STAR Appliances	$0	$0	$0	$0	$0	$0	$0	$0	0	1,303,504
Residential Education Program	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	0	0
Workforce Development	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	0	0
Heat Loan Program	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	0	0
R&D Demonstration	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	0	0
Deep Energy Retrofit	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	0	0
Behavior/Feedback Pilot	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	0	0
Low Income (total)	-$28,014	$1,156,219	$0	$5,676	$0	$189,452	$0	$5,905,739	$7,229,071	$10,098,012
Low-Income Residential New Construction	$16,297	$0	$0	$5,676	$0	$322	$0	$1,169	23,464	44,988
Low-Income Retrofit	-$44,310	$1,156,219	$0	$0	$0	$189,130	$0	$5,904,570	7,205,608	10,053,023
C&I (total)	-$1,402,806	$282,291	$0	$228,780	$0	$0	$0	$1,465,103	$573,369	$33,764,352
C&I New Construction and Major Renovation	$0	$0	$0	$0	$0	$0	$0	$678,718	678,718	9,138,214
C&I New Construction and Major Renovation - Gov	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	0	0
C&I Large Retrofit	-$17,753	$0	$0	$0	$0	$0	$0	$11,368	-6,385	3,791,075
Large C&I Retrofit - Government	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	0	0
C&I Small Retrofit	-$1,385,053	$282,291	$0	$228,780	$0	$0	$0	$775,017	-98,964	20,835,063
C&I Small Retrofit - Government	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	0	0
GRAND TOTAL	$5,630,989	$20,298,328	$0	$2,474,861	$0	$334,075	$0	$8,408,098	$37,146,350	$101,463,125

IV.D Cost Effectiveness
3.1.i. Benefits Summary Table

Program	Non-Electric Benefits, 2012 ($) (5)									TOTAL BENEFITS
	Resource Benefits							Non- Resource Benefits (1)	TOTAL	
	Avoided Natural Gas	No. 2 Distillate	No. 4 Fuel Oil	Propane	Wood	Water	Kerosene			
Residential (total)	$6,502,477	$29,527,912	$0	$3,683,015	$0	$67,659	$0	$22,758,875	$62,539,939	$81,244,610
Residential New Construction & Major Renovation	$95,344	$24,594	$0	$370,510	$0	$0	$0	$297,712	788,161	1,686,167
Residential Cooling & Heating Equipment	-$28,763	$95,170	$0	$815,182	$0	$0	$0	$1,016,800	1,898,389	3,427,250
Multi-Family Retrofit	$0	$0	$0	$0	$0	$0	$0	$0	0	0
MassSAVE	$6,435,896	$29,408,149	$0	$2,497,323	$0	$67,659	$0	$20,935,342	59,344,369	68,811,551
Behavior/Feedback Program	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	0	0
ENERGY STAR Lighting	$0	$0	$0	$0	$0	$0	$0	$424,863	424,863	6,038,677
ENERGY STAR Appliances	$0	$0	$0	$0	$0	$0	$0	$84,157	84,157	1,280,964
Residential Education Program	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	0	0
Workforce Development	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	0	0
Heat Loan Program	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	0	0
R&D Demonstration	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	0	0
Deep Energy Retrofit	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	0	0
Behavior/Feedback Pilot	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	0	0
Low Income (total)	$498,783	$1,749,470	$0	$484,006	$0	$81,448	$0	$5,260,759	$8,074,467	$9,546,436
Low-Income Residential New Construction	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
Low-Income Retrofit	$498,783	$1,749,470	$0	$484,006	$0	$81,448	$0	$5,260,759	$8,074,467	9,546,436
C&I (total)	-$159,068	$13,042	$0	$10,825	$0	$27,812	$0	$0	-$107,389	$18,271,687
C&I New Construction and Major Renovation	-$107,736	$0	$0	$0	$0	$27,812	$0	$0	-79,924	6,747,151
C&I New Construction and Major Renovation - Gov	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	0	0
C&I Large Retrofit	-$47,912	$0	$0	$0	$0	$0	$0	$0	-47,912	11,269,587
Large C&I Retrofit - Government	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	0	0
C&I Small Retrofit	-$3,421	$13,042	$0	$10,825	$0	$0	$0	$0	20,446	254,949
C&I Small Retrofit - Government	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	0	0
GRAND TOTAL	$6,842,192	$31,290,425	$0	$4,177,846	$0	$176,919	$0	$28,019,635	$70,507,017	$109,062,733

Program	Non-Electric Benefits, 2010-2012 ($)									TOTAL BENEFITS
	Resource Benefits							Non- Resource Benefits (1)	TOTAL	
	Avoided Natural Gas	No. 2 Distillate	No. 4 Fuel Oil	Propane	Wood	Water	Kerosene			
Residential (total)	$18,023,053	$60,460,138	$0	$7,816,185	$0	$347,254	$0	$24,267,345	$110,913,974	$173,677,104
Residential New Construction & Major Renovation	$251,540	$68,259	$0	$1,356,385	$0	$2,629	$0	$321,464	2,000,277	3,693,915
Residential Cooling & Heating Equipment	-$342,785	$95,170	$0	$815,182	$0	$0	$0	$1,042,115	1,609,682	6,410,852
Multi-Family Retrofit	$832,168	$1,396,724	$0	$668,737	$0	$232,540	$0	$33,049	3,163,218	4,766,290
MassSAVE	$17,282,130	$58,899,985	$0	$4,975,880	$0	$112,084	$0	$21,384,246	102,654,326	133,111,366
Behavior/Feedback Program	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	0	0
ENERGY STAR Lighting	$0	$0	$0	$0	$0	$0	$0	$1,402,314	1,402,314	22,322,765
ENERGY STAR Appliances	$0	$0	$0	$0	$0	$0	$0	$84,157	84,157	3,371,916
Residential Education Program	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	0	0
Workforce Development	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	0	0
Heat Loan Program	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	0	0
R&D Demonstration	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	0	0
Deep Energy Retrofit	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	0	0
Behavior/Feedback Pilot	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	0	0
Low Income (total)	$439,172	$3,998,077	$0	$499,931	$0	$430,334	$0	$13,903,823	$19,271,338	$25,565,589
Low-Income Residential New Construction	$16,317	$0	$0	$15,925	$0	$384	$0	$5,088	37,713	72,448
Low-Income Retrofit	$422,855	$3,998,077	$0	$484,006	$0	$429,950	$0	$13,898,736	19,233,624	25,493,141
C&I (total)	-$2,401,350	$420,986	$0	$344,428	$0	$27,812	$0	$2,539,962	$931,839	$79,892,026
C&I New Construction and Major Renovation	-$107,736	$0	$0	$0	$0	$27,812	$0	$1,198,565	1,118,641	22,493,732
C&I New Construction and Major Renovation - Gov	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	0	0
C&I Large Retrofit	-$107,492	$0	$0	$0	$0	$0	$0	$19,806	-87,687	24,096,354
Large C&I Retrofit - Government	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	0	0
C&I Small Retrofit	-$2,186,121	$420,986	$0	$344,428	$0	$0	$0	$1,321,592	-99,116	33,301,940
C&I Small Retrofit - Government	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	0	0
GRAND TOTAL	$16,060,876	$64,879,202	$0	$8,660,544	$0	$805,400	$0	$40,711,130	$131,117,151	$279,134,718

IV.D Cost Effectiveness
3.1.iii. Benefits Comparison Table - Three Year Plan vs. Previous Years

Total Benefits (1)						
Year by Sector	Electric Benefits		Non-Electric Benefits		TOTAL TRC Test Benefits	
	$	%	$	%	$	%
Residential (total)	**81,533,005**	**41%**	**119,304,523**	**59%**	**200,837,528**	**100%**
2007 (1)	8,530,622	64%	4,805,206	36%	13,335,828	100%
2008 (2)	5,522,217	51%	5,289,220	49%	10,811,437	100%
2009 (3)	10,158,754	55%	8,303,642	45%	$ 18,462,396	100%
2010 (4)	10,359,888	53%	9,022,607	47%	19,382,496	100%
2011 (5)	28,256,852	49%	29,343,909	51%	57,600,761	100%
2012 (6)	18,704,671	23%	62,539,939	77%	81,244,610	100%
Low Income (total)	**7,618,768**	**21%**	**28,116,670**	**79%**	**35,735,438**	**100%**
2007 (1)	637,340	16%	3,449,168	84%	4,086,508	100%
2008 (2)	770,915	23%	2,567,905	77%	3,338,821	100%
2009 (3)	917,719	21%	3,446,006	79%	$ 4,363,725	100%
2010 (4)	951,884	22%	3,350,053	78%	4,301,936	100%
2011 (5)	2,868,940	28%	7,229,071	72%	10,098,012	100%
2012 (6)	1,471,969	15%	8,074,467	85%	9,546,436	100%
Commercial & Industrial (total)	**97,471,605**	**96%**	**3,763,121**	**4%**	**101,234,725**	**100%**
2007 (1)	9,163,385	98%	163,539	2%	9,326,924	100%
2008 (2)	7,156,575	97%	250,662	3%	7,407,237	100%
2009 (3)	17,847,286	99%	145,462	1%	$ 17,992,748	100%
2010 (4)	11,734,299	81%	2,737,478	19%	14,471,777	100%
2011 (5)	33,190,983	98%	573,369	2%	33,764,352	100%
2012 (6)	18,379,076	101%	(107,389)	-1%	18,271,687	100%
GRAND TOTAL	**186,623,377**	**55%**	**151,184,314**	**45%**	**337,807,692**	**100%**
2007 (1)	**18,331,348**	**69%**	**8,417,913**	**31%**	**26,749,261**	**100%**
2008 (2)	**13,449,708**	**62%**	**8,107,787**	**38%**	**21,557,495**	**100%**
2009 (3)	**28,923,759**	**71%**	**11,895,110**	**29%**	**$ 40,818,869**	**100%**
2010 (4)	**23,046,072**	**60%**	**15,110,138**	**40%**	**38,156,209**	**100%**
2011 (5)	**64,316,775**	**63%**	**37,146,350**	**37%**	**101,463,125**	**100%**
2012 (6)	**38,555,716**	**35%**	**70,507,017**	**65%**	**109,062,733**	**100%**

Electric Benefits (1)						
Year by Sector	Capacity		Energy		TOTAL Electric Benefits	
	$	%	$	%	$	%
Residential (total)	**25,868,531**	**32%**	**55,664,473**	**68%**	**81,533,005**	**100%**
2007 (1)	2,101,834	25%	6,428,788	75%	8,530,622	100%
2008 (2)	1,969,867	36%	3,552,350	64%	5,522,217	100%
2009 (3)	5,218,523	51%	4,940,231	49%	10,158,754	100%
2010 (4)	2,126,433	21%	8,233,456	79%	10,359,888	100%
2011 (5)	9,068,491	32%	19,188,360	68%	28,256,852	100%
2012 (6)	5,383,383	29%	13,321,288	71%	18,704,671	100%
Low Income (total)	**1,412,473**	**19%**	**6,206,295**	**81%**	**7,618,768**	**100%**
2007 (1)	74,186	12%	563,154	88%	637,340	100%
2008 (2)	98,581	13%	672,335	87%	770,915	100%
2009 (3)	502,555	55%	415,164	45%	917,719	100%
2010 (4)	114,839	12%	837,045	88%	951,884	100%
2011 (5)	388,972	14%	2,479,968	86%	2,868,940	100%
2012 (6)	233,340	16%	1,238,629	84%	1,471,969	100%
Commercial & Industrial (total)	**32,320,269**	**33%**	**65,151,336**	**67%**	**97,471,605**	**100%**
2007 (1)	3,637,556	40%	5,525,830	60%	9,163,385	100%
2008 (2)	3,239,793	45%	3,916,783	55%	7,156,575	100%
2009 (3)	7,135,180	40%	10,712,106	60%	17,847,286	100%
2010 (4)	2,698,009	23%	9,036,290	77%	11,734,299	100%
2011 (5)	8,066,142	24%	25,124,841	76%	33,190,983	100%
2012 (6)	7,543,589	41%	10,835,487	59%	18,379,076	100%
GRAND TOTAL	**59,601,273**	**32%**	**127,022,104**	**68%**	**186,623,377**	**100%**
2007 (1)	**5,813,575**	**32%**	**12,517,772**	**68%**	**18,331,348**	**100%**
2008 (2)	**5,308,241**	**39%**	**8,141,468**	**61%**	**13,449,708**	**100%**
2009 (3)	**12,856,259**	**44%**	**16,067,500**	**56%**	**28,923,759**	**100%**
2010 (4)	**4,939,281**	**21%**	**18,106,791**	**79%**	**23,046,072**	**100%**
2011 (5)	**17,523,605**	**27%**	**46,793,170**	**73%**	**64,316,775**	**100%**
2012 (6)	**13,160,312**	**34%**	**25,395,404**	**66%**	**38,555,716**	**100%**

IV.D Cost Effectiveness

3.1.iii. Benefits Comparison Table - Three Year Plan vs. Previous Years

Capacity Benefits (1)												
Year by Sector	Generation				Trans.		Distrib.		DRIPE		TOTAL	
	Summer		Winter									
	$	%	$	%	$	%	$	%	$	%	$	%
Residential (total)	**7,725,543**	**30%**	**0**	**0%**	**2,552,268**	**10%**	**12,186,490**	**47%**	**3,404,230**	**13%**	**25,868,531**	**100%**
2007 (1)	844,332	40%	0	0%	191,424	9%	714,881	34%	351,196	17%	2,101,834	100%
2008 (2)	912,138	46%	0	0%	165,166	8%	616,820	31%	275,743	14%	1,969,867	100%
2009 (3)	2,040,230	39%	0	0%	401,993	8%	2,462,250	47%	314,050	6%	5,218,523	100%
2010 (4)	528,570	25%	0	0%	235,076	11%	1,166,061	55%	196,725	9%	2,126,433	100%
2011 (5)	2,275,523	25%	0	0%	951,733	10%	4,720,944	52%	1,120,292	12%	9,068,491	100%
2012 (6)	1,124,750	21%	0	0%	606,875	11%	2,505,534	47%	1,146,224	21%	5,383,383	100%
Low Income (total)	**431,773**	**31%**	**0**	**0%**	**135,768**	**10%**	**677,551**	**48%**	**167,381**	**12%**	**1,412,473**	**100%**
2007 (1)	34,218	46%	0	0%	6,656	9%	24,859	34%	8,453	11%	74,186	100%
2008 (2)	47,138	48%	0	0%	8,515	9%	31,799	32%	11,129	11%	98,581	100%
2009 (3)	195,254	39%	0	0%	38,774	8%	237,494	47%	31,033	6%	502,555	100%
2010 (4)	27,944	24%	0	0%	12,913	11%	64,055	56%	9,926	9%	114,839	100%
2011 (5)	76,785	20%	0	0%	41,893	11%	207,804	53%	62,490	16%	388,972	100%
2012 (6)	50,433	22%	0	0%	27,016	12%	111,540	48%	44,350	19%	233,340	100%
Commercial & Industrial (total)	**9,380,381**	**29%**	**0**	**0%**	**3,187,232**	**10%**	**15,042,244**	**47%**	**4,710,411**	**15%**	**32,320,269**	**100%**
2007 (1)	1,650,747	45%	0	0%	320,198	9%	1,195,794	33%	470,816	13%	3,637,556	100%
2008 (2)	1,543,406	48%	0	0%	270,734	8%	1,011,065	31%	414,587	13%	3,239,793	100%
2009 (3)	2,708,921	38%	0	0%	548,802	8%	3,361,471	47%	515,986	7%	7,135,180	100%
2010 (4)	571,471	21%	0	0%	315,789	12%	1,566,426	58%	244,323	9%	2,698,009	100%
2011 (5)	1,443,500	18%	0	0%	911,274	11%	4,520,251	56%	1,191,116	15%	8,066,142	100%
2012 (6)	1,462,335	19%	0	0%	820,435	11%	3,387,236	45%	1,873,582	25%	7,543,589	100%
GRAND TOTAL	**17,537,698**	**29%**	**0**	**0%**	**5,875,268**	**10%**	**27,906,285**	**47%**	**8,282,022**	**14%**	**59,601,273**	**100%**
2007 (1)	**2,529,298**	**44%**	**0**	**0%**	**518,279**	**9%**	**1,935,533**	**33%**	**830,466**	**14%**	**5,813,575**	**100%**
2008 (2)	**2,502,683**	**47%**	**0**	**0%**	**444,415**	**8%**	**1,659,684**	**31%**	**701,459**	**13%**	**5,308,241**	**100%**
2009 (3)	**4,944,405**	**38%**	**0**	**0%**	**989,569**	**8%**	**6,061,216**	**47%**	**861,069**	**7%**	**12,856,259**	**100%**
2010 (4)	**1,127,986**	**23%**	**0**	**0%**	**563,778**	**11%**	**2,796,543**	**57%**	**450,975**	**9%**	**4,939,281**	**100%**
2011 (5)	**3,795,808**	**22%**	**0**	**0%**	**1,904,900**	**11%**	**9,448,999**	**54%**	**2,373,898**	**14%**	**17,523,605**	**100%**
2012 (6)	**2,637,518**	**20%**	**0**	**0%**	**1,454,327**	**11%**	**6,004,310**	**46%**	**3,064,156**	**23%**	**13,160,312**	**100%**

Notes:

(1) Actual values from the Cape Light Compact's 2007 Annual Report D.P.U. 09-68, in 2007$.
(2) Actual values from the Cape Light Compact's 2008 Annual Report D.P.U. 09-69, in 2008$.
(3) Actual values from the Cape Light Compact's 2009 Annual Report D.P.U. 10-97, in 2009$.
(4) Actual values from the Cape Light Compact's 2010 Annual Report D.P.U. 11-68, in 2010$.
(5) As this filing assumes approval of the 2011 Mid-Term Modifications, this data is as filed in the Cape Light Compact's 2011 Mid-Term Modifications Filing, D.P.U. 10-147, in 2011$.
(6) Proposed 2012 changes presented in this filing, representing additional budget requirements for 2012, taking into account 2011 estimated carryover, in 2012$.

IV.D Cost Effectiveness
3.1.iii. Benefits Comparison Table - Three Year Plan vs. Previous Years

Energy Benefits												
Year by Sector	Winter				Summer				DRIPE		TOTAL	
	Peak		Off Peak		Peak		Off Peak					
	$	%	$	%	$	%	$	%	$	%	$	%
Residential (total)	**$12,967,310**	**23%**	**$14,140,721**	**25%**	**$10,306,221**	**19%**	**$7,941,117**	**14%**	**$10,309,104**	**19%**	**$55,664,473**	**100%**
2007 (1)	$2,079,657	32%	$2,171,410	34%	$1,100,697	17%	$1,077,025	17%	$0	0%	$6,428,788	100%
2008 (2)	$1,157,992	33%	$1,134,507	32%	$679,938	19%	$579,914	16%	$0	0%	$3,552,350	100%
2009 (3)	$1,175,016	24%	$1,236,766	25%	$1,025,166	21%	$719,446	15%	$783,836	16%	$4,940,231	100%
2010 (4)	$1,987,694	24%	$2,078,677	25%	$1,006,659	12%	$1,006,900	12%	$2,153,527	26%	$8,233,456	100%
2011 (5)	$4,190,740	22%	$4,640,180	24%	$3,423,538	18%	$2,621,555	14%	$4,312,348	22%	$19,188,360	100%
2012 (6)	$2,376,212	18%	$2,879,183	22%	$3,070,222	23%	$1,936,278	15%	$3,059,393	23%	$13,321,288	100%
Low Income (total)	**$1,615,493**	**26%**	**$1,850,193**	**30%**	**$827,520**	**13%**	**$894,092**	**14%**	**$1,018,997**	**16%**	**$6,206,295**	**100%**
2007 (1)	$191,127	34%	$190,339	34%	$89,731	16%	$91,957	16%	$0	0%	$563,154	100%
2008 (2)	$218,291	32%	$229,453	34%	$112,080	17%	$112,510	17%	$0	0%	$672,335	100%
2009 (3)	$115,756	28%	$122,214	29%	$59,605	14%	$59,771	14%	$57,818	14%	$415,164	100%
2010 (4)	$204,252	24%	$241,109	29%	$102,230	12%	$115,593	14%	$173,861	21%	$837,045	100%
2011 (5)	$607,363	24%	$718,957	29%	$304,300	12%	$343,376	14%	$505,972	20%	$2,479,968	100%
2012 (6)	$278,704	23%	$348,121	28%	$159,573	13%	$170,885	14%	$281,346	23%	$1,238,629	100%
Commercial & Industrial (total)	**$22,699,540**	**35%**	**$9,138,931**	**14%**	**$16,347,204**	**25%**	**$5,973,830**	**9%**		**0%**	**$65,151,336**	**83%**
2007 (1)	$1,866,793	34%	$1,215,023	22%	$1,550,290	28%	$893,723	16%	$0	0%	$5,525,830	100%
2008 (2)	$1,338,791	34%	$869,908	22%	$1,103,597	28%	$604,487	15%	$0	0%	$3,916,783	100%
2009 (3)	$3,614,968	34%	$1,731,030	16%	$2,809,253	26%	$1,238,316	12%	$1,318,538	12%	$10,712,106	100%
2010 (4)	$2,962,425	33%	$982,886	11%	$2,334,484	26%	$680,753	8%	$2,075,742	23%	$9,036,290	100%
2011 (5)	$9,390,790	37%	$3,245,065	13%	$5,765,246	23%	$1,836,512	7%	$4,887,227	19%	$25,124,841	100%
2012 (6)	$3,525,774	33%	$1,095,018	10%	$2,784,334	26%	$720,038	7%	$2,710,324	25%	$10,835,487	100%
GRAND TOTAL	**$37,282,343**	**29%**	**$25,129,845**	**20%**	**$27,480,945**	**22%**	**$14,809,039**	**12%**	**$11,328,101**	**9%**	**$127,022,104**	**91%**
2007 (1)	**$4,137,577**	**33%**	**$3,576,772**	**29%**	**$2,740,719**	**22%**	**$2,062,704**	**16%**	**$0**	**0%**	**$12,517,772**	**100%**
2008 (2)	**$2,715,074**	**33%**	**$2,233,868**	**27%**	**$1,895,615**	**23%**	**$1,296,911**	**16%**	**$0**	**0%**	**$8,141,468**	**100%**
2009 (3)	**$4,905,740**	**31%**	**$3,090,011**	**19%**	**$3,894,024**	**24%**	**$2,017,533**	**13%**	**$2,160,192**	**13%**	**$16,067,500**	**100%**
2010 (4)	**$5,154,371**	**28%**	**$3,302,672**	**18%**	**$3,443,373**	**19%**	**$1,803,246**	**10%**	**$4,403,130**	**24%**	**$18,106,791**	**100%**
2011 (5)	**$14,188,892**	**30%**	**$8,604,201**	**18%**	**$9,493,085**	**20%**	**$4,801,444**	**10%**	**$9,705,547**	**21%**	**$46,793,170**	**100%**
2012 (6)	**$6,180,690**	**24%**	**$4,322,321**	**17%**	**$6,014,129**	**24%**	**$2,827,201**	**11%**	**$6,051,063**	**24%**	**$25,395,404**	**100%**

Non-Electric Benefits						
Year by Sector	Resource Benefits		Non-Resource Benefits		TOTAL	
	$	%	$	%	$	%
Residential (total)	**$94,536,603**	**79%**	**$24,767,921**	**21%**	**$119,304,523**	**100%**
2007 (1)	$4,383,280	91%	$421,926	9%	$4,805,206	100%
2008 (2)	$4,992,833	94%	$296,387	6%	$5,289,220	100%
2009 (3)	$8,438,630	102%	-$134,988	-2%	$8,303,642	100%
2010 (4)	$8,634,144	96%	$388,464	4%	$9,022,607	100%
2011 (5)	$28,306,653	96%	$1,037,256	4%	$29,343,909	100%
2012 (6)	$39,781,064	64%	$22,758,875	36%	$62,539,939	100%
Low Income (total)	**$9,700,588**	**35%**	**$18,416,082**	**65%**	**$28,116,670**	**100%**
2007 (1)	$1,519,763	44%	$1,929,406	56%	$3,449,168	100%
2008 (2)	$1,199,190	47%	$1,368,716	53%	$2,567,905	100%
2009 (3)	$1,472,854	43%	$1,973,152	57%	$3,446,006	100%
2010 (4)	$1,371,742	41%	$1,978,311	59%	$3,350,053	100%
2011 (5)	$1,323,333	18%	$5,905,739	82%	$7,229,071	100%
2012 (6)	$2,813,708	35%	$5,260,759	65%	$8,074,467	100%
Commercial & Industrial (total)	**$91,156**	**2%**	**$3,671,965**	**98%**	**$3,763,121**	**100%**
2007 (1)	$0	0%	$163,539	100%	$163,539	100%
2008 (2)	$0	0%	$250,662	100%	$250,662	100%
2009 (3)	$0	0%	$145,462	100%	$145,462	100%
2010 (4)	$1,090,279	40%	$1,647,198	60%	$2,737,478	100%
2011 (5)	-$891,734	-156%	$1,465,103	256%	$573,369	100%
2012 (6)	-$107,389	100%	$0	0%	-$107,389	100%
GRAND TOTAL	**$104,328,347**	**69%**	**$46,855,967**	**31%**	**$151,184,314**	**100%**
2007 (1)	**$5,903,042**	**70%**	**$2,514,871**	**30%**	**$8,417,913**	**100%**
2008 (2)	**$6,192,022**	**76%**	**$1,915,765**	**24%**	**$8,107,787**	**100%**
2009 (3)	**$9,911,484**	**83%**	**$1,983,626**	**17%**	**$11,895,110**	**100%**
2010 (4)	**$11,096,165**	**73%**	**$4,013,973**	**27%**	**$15,110,138**	**100%**
2011 (5)	**$28,738,252**	**77%**	**$8,408,098**	**23%**	**$37,146,350**	**100%**
2012 (6)	**$42,487,382**	**60%**	**$28,019,635**	**40%**	**$70,507,017**	**100%**

IV.D Cost Effectiveness

3.1.iii. Benefits Comparison Table - Three Year Plan vs. Previous Years

Year by Sector	Non-Electric Resource Benefits															
	Avoided Natural Gas		No. 2 Distillate		No. 4 Fuel Oil		Propane		Wood		Water		Kerosene		TOTAL	
	$	%	$	%	$	%	$	%	$	%	$	%	$	%	$	%
Residential (total)	**$18,884,370**	**20%**	**$65,461,679**	**69%**	**$0**	**0%**	**$9,355,913**	**10%**	**$0**	**0%**	**$834,641**	**1%**	**$0**	**0**	**$94,536,603**	**100%**
2007 (1)	$1,350,973	31%	$1,954,413	45%	$0	0%	$744,663	17%	$0	0%	$333,231	8%	$0	0	$4,383,280	100%
2008 (2)	$1,308,721	26%	$2,169,739	43%	$0	0%	$1,332,153	27%	$0	0%	$182,220	4%	$0	0	$4,992,833	100%
2009 (3)	$525,099	6%	$7,577,885	90%	$0	0%	$283,328	3%	$0	0%	$52,318	1%	$0	0	$8,438,630	100%
2010 (4)	$2,135,291	25%	$5,371,912	62%	$0	0%	$1,072,350	12%	$0	0%	$54,591	1%	$0	0	$8,634,144	100%
2011 (5)	$7,061,808	25%	$18,859,818	67%	$0	0%	$2,240,404	8%	$0	0%	$144,623	1%	$0	0	$28,306,653	100%
2012 (6)	$6,502,477	16%	$29,527,912	74%	$0	0%	$3,683,015	9%	$0	0%	$67,659	0%	$0	0	$39,781,064	100%
Low Income (total)	**$1,730,218**	**18%**	**$6,810,533**	**70%**	**$0**	**0%**	**$632,769**	**7%**	**$0**	**0%**	**$527,069**	**5%**	**$0**	**0**	**$9,700,588**	**100%**
2007 (1)	$608,833	40%	$827,511	54%	$0	0%	$73,730	5%	$0	0%	$9,688	1%	$0	0	$1,519,763	100%
2008 (2)	$51,472	4%	$963,676	80%	$0	0%	$0	0%	$0	0%	$184,042	15%	$0	0	$1,199,190	100%
2009 (3)	$99,873	7%	$1,325,641	90%	$0	0%	$19,504	1%	$0	0%	$27,836	2%	$0	0	$1,472,854	100%
2010 (4)	$499,271	36%	$788,016	57%	$0	0%	$49,853	4%	$0	0%	$34,602	3%	$0	0	$1,371,742	100%
2011 (5)	-$28,014	-2%	$1,156,219	87%	$0	0%	$5,676	0%	$0	0%	$189,452	14%	$0	0	$1,323,333	100%
2012 (6)	$498,783	18%	$1,749,470	62%	$0	0%	$484,006	17%	$0	0%	$81,448	3%	$0	0	$2,813,708	100%
Commercial & Industrial (total)	**-$920,823**	**-1010%**	**$587,463**	**644%**	**$0**	**0%**	**$396,704**	**435%**	**$0**	**0%**	**$27,812**	**31%**	**$0**	**0**	**$91,156**	**100%**
2007 (1)	$0	n/a	$0	n/a	$0	n/a	$0	n/a	$0	n/a	$0	n/a	$0	n/a	$0	100%
2008 (2)	$0	n/a	$0	n/a	$0	n/a	$0	n/a	$0	n/a	$0	n/a	$0	n/a	$0	100%
2009 (3)	$0	n/a	$0	n/a	$0	n/a	$0	n/a	$0	n/a	$0	n/a	$0	n/a	$0	100%
2010 (4)	$641,051	59%	$292,130	27%	$0	0%	$157,099	14%	$0	0%	$0	0%	$0	0	$1,090,279	100%
2011 (5)	-$1,402,806	157%	$282,291	-32%	$0	0%	$228,780	-26%	$0	0%	$0	0%	$0	0	-$891,734	100%
2012 (6)	-$159,068	148%	$13,042	-12%	$0	0%	$10,825	-10%	$0	0%	$27,812	-26%	$0	0	-$107,389	100%
GRAND TOTAL	**$19,693,765**	**19%**	**$72,859,674**	**70%**	**$0**	**0%**	**$10,385,386**	**10%**	**$0**	**0%**	**$1,389,522**	**1%**	**$0**	**0**	**$104,328,347**	**100%**
2007 (1)	**$1,959,807**	**33%**	**$2,781,924**	**47%**	**$0**	**0%**	**$818,393**	**14%**	**$0**	**0%**	**$342,919**	**6%**	**$0**	**0%**	**$5,903,042**	**100%**
2008 (2)	**$1,360,193**	**22%**	**$3,133,415**	**51%**	**$0**	**0%**	**$1,332,153**	**22%**	**$0**	**0%**	**$366,262**	**6%**	**$0**	**0%**	**$6,192,022**	**100%**
2009 (3)	**$624,972**	**6%**	**$8,903,526**	**90%**	**$0**	**0%**	**$302,832**	**3%**	**$0**	**0%**	**$80,154**	**1%**	**$0**	**0%**	**$9,911,484**	**100%**
2010 (4)	**$3,275,613**	**30%**	**$6,452,057**	**58%**	**$0**	**0%**	**$1,279,301**	**12%**	**$0**	**0%**	**$89,193**	**1%**	**$0**	**0**	**$11,096,165**	**100%**
2011 (5)	**$5,630,989**	**20%**	**$20,298,328**	**71%**	**$0**	**0%**	**$2,474,861**	**9%**	**$0**	**0%**	**$334,075**	**1%**	**$0**	**0**	**$28,738,252**	**100%**
2012 (6)	**$6,842,192**	**16%**	**$31,290,425**	**74%**	**$0**	**0%**	**$4,177,846**	**10%**	**$0**	**0%**	**$176,919**	**0%**	**$0**	**0**	**$42,487,382**	**100%**

Notes:

(1) Actual values from the Cape Light Compact's 2007 Annual Report D.P.U. 09-68, in 2007$.
(2) Actual values from the Cape Light Compact's 2008 Annual Report D.P.U. 09-69, in 2008$.
(3) Actual values from the Cape Light Compact's 2009 Annual Report D.P.U. 10-97, in 2009$.
(4) Actual values from the Cape Light Compact's 2010 Annual Report D.P.U. 11-68, in 2010$.
(5) As this filing assumes approval of the 2011 Mid-Term Modifications, this data is as filed in the Cape Light Compact's 2011 Mid-Term Modifications Filing, D.P.U. 10-147, in 2011$.
(6) Proposed 2012 changes presented in this filing, representing additional budget requirements for 2012, taking into account 2011 estimated carryover, in 2012$.

IV.D. Cost Effectiveness
3.2.i. Savings Summary Table

Program	# of Participants (1)	Electric Savings, 2010 (1)								
		Capacity (kW)			Energy (MWh)					
		Annual		Lifetime	Summer		Winter (Annual)		Total Annual MWh	Lifetime
		Summer	Winter		Peak	Off Peak	Peak	Off Peak		
Residential (total)	41,834	2,489	2,032	39,712	1,699	2,057	2,665	3,758	10,179	96,058
Residential New Construction & Major R	59	51	98	941	46	54	72	98	271	2,479
Residential Cooling & Heating Equipme	803	266	48	4,284	89	38	173	74	374	6,568
Multi-Family Retrofit	400	63	103	686	79	122	164	243	609	4,425
MassSAVE	3,900	1,522	740	28,997	830	866	954	1,413	4,063	43,462
Behavior/Feedback Program	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
ENERGY STAR Lighting	30,429	444	904	3,596	546	840	1,134	1,679	4,199	33,672
ENERGY STAR Appliances	6,243	143	140	1,209	108	137	169	250	663	5,452
Low Income (total)	1,317	164	308	1,856	184	283	382	566	1,416	16,195
Low-Income Residential New Construct	8	1	3	25	1	2	3	4	11	100
Low-Income Retrofit	1,309	163	304	1,831	183	281	379	562	1,405	16,095
Commercial & Industrial (total)	641	3,960	2,307	50,809	3,932	1,733	6,293	2,772	14,730	190,815
C&I New Construction and Major Renov	58	763	527	11251	887	277	1,338	415	2,917	43,218
C&I New Construction and Major Renov	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
C&I Large Retrofit	56	1476	906	18277	1,363	588	1,969	849	4,769	61,108
Large C&I Retrofit - Government	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a		n/a
C&I Small Retrofit	527	1720	873	21281	1,682	868	2,986	1,508	7,044	86,489
C&I Small Retrofit - Government	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
GRAND TOTAL	43,792	6,613	4,646	92,376	5,815	4,073	9,341	7,096	26,325	303,068

Program	# of Participants (1)	Electric Savings, 2011 (2)								
		Capacity (kW)			Energy (MWh)					
		Annual		Lifetime	Summer		Winter (Annual)		Total Annual MWh	Lifetime
		Summer	Winter		Peak	Off Peak	Peak	Off Peak		
Residential (total)	91,028	4,182	3,763	62,921	3,096	3,916	5,062	7,290	19,364	173,570
Residential New Construction & Major R	47	39	75	566	43	58	75	111	287	2,850
Residential Cooling & Heating Equipme	1,056	410	55	6,615	178	77	217	113	585	10,208
Multi-Family Retrofit	550	155	209	2,605	102	157	211	313	783	6,114
MassSAVE	3,120	2,225	787	42,955	1,112	1,124	1,212	1,796	5,244	60,423
Behavior/Feedback Program	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
ENERGY STAR Lighting	75,225	1,163	2,369	8,729	1,459	2,244	3,029	4,488	11,220	84,545
ENERGY STAR Appliances	11,030	191	269	1,451	203	256	317	469	1,245	9,429
Low Income (total)	1,549	242	491	2,640	293	450	607	899	2,249	23,249
Low-Income Residential New Construct	9	3	4	62	2	3	4	5	14	111
Low-Income Retrofit	1,540	239	486	2,578	291	447	604	894	2,236	23,137
Commercial & Industrial (total)	986	4,538	2,568	59,473	4,557	2,058	7,585	3,412	17,612	230,622
C&I New Construction and Major Renov	79	1,034	720	15,700	1,175	362	1,766	538	3,841	59,213
C&I New Construction and Major Renov	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
C&I Large Retrofit	23	610	379	7,622	553	236	797	337	1,923	25,270
Large C&I Retrofit - Government	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
C&I Small Retrofit	884	2,894	1,469	36,152	2,829	1,460	5,023	2,537	11,848	146,138
C&I Small Retrofit - Government	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
GRAND TOTAL	93,563	8,962	6,822	125,034	7,946	6,424	13,254	11,602	39,225	427,440

IV.D. Cost Effectiveness
3.2.i. Savings Summary Table

Program	# of Participants (1)	Electric Savings, 2012 (3)								
		Capacity (kW)			Energy (MWh)					
		Annual		Lifetime	Summer		Winter (Annual)		Total Annual MWh	Lifetime
		Summer	Winter		Peak	Off Peak	Peak	Off Peak		
Residential (total)	54,491	2,267	2,843	24,167	2,348	2,757	3,337	4,873	13,315	133,056
Residential New Construction & Major R	65	82	131	1,133	95	125	157	233	610	6,610
Residential Cooling & Heating Equipme	998	474	605	4,983	73	63	120	108	363	4,687
Multi-Family Retrofit	0	0	0	0	0	0	0	0	0	0
MassSAVE	4,658	874	519	11,961	1,171	1,019	968	1,433	4,591	65,707
Behavior/Feedback Program	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
ENERGY STAR Lighting	41,050	705	1,410	4,989	852	1,310	1,769	2,621	6,551	46,359
ENERGY STAR Appliances	7,720	133	178	1,102	158	240	323	478	1,200	9,694
Low Income (total)	1,500	119	296	1,072	184	283	382	565	1,413	12,918
Low-Income Residential New Construct	0	0	0	0	0	0	0	0	0	0
Low-Income Retrofit	1,500	119	296	1,072	184	283	382	565	1,413	12,918
Commercial & Industrial (total)	215	2,825	1,883	33,678	2,617	971	3,859	1,399	8,846	104,692
C&I New Construction and Major Renov	167	957	606	11,284	1,032	358	1,751	590	3,732	42,362
C&I New Construction and Major Renov	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
C&I Large Retrofit	34	1,842	1,262	22,076	1,548	597	2,052	785	4,982	60,764
Large C&I Retrofit - Government	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
C&I Small Retrofit	14	26	14	318	37	15	55	24	132	1,566
C&I Small Retrofit - Government	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
GRAND TOTAL	56,206	5,211	5,022	58,917	5,149	4,010	7,577	6,838	23,573	250,667

Program	# of Participants (1)	Electric Savings, 2010-2012								
		Capacity (kW)			Energy (MWh)					
		Annual		Lifetime	Summer		Winter (Annual)		Total Annual MWh	Lifetime
		Summer	Winter		Peak	Off Peak	Peak	Off Peak		
Residential (total)	187,353	8,939	8,638	126,800	7,143	8,730	11,064	15,922	42,858	402,684
Residential New Construction & Major R	171	172	304	2,639	184	237	305	442	1,168	11,938
Residential Cooling & Heating Equipme	2,857	1,150	708	15,882	340	178	510	295	1,322	21,463
Multi-Family Retrofit	950	218	312	3,291	181	278	376	557	1,392	10,539
MassSAVE	11,678	4,621	2,045	83,913	3,113	3,009	3,134	4,642	13,898	169,592
Behavior/Feedback Program	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
ENERGY STAR Lighting	146,704	2,311	4,682	17,314	2,856	4,394	5,932	8,788	21,970	164,576
ENERGY STAR Appliances	24,993	466	587	3,761	469	633	808	1,197	3,108	24,575
Low Income (total)	4,366	525	1,095	5,568	661	1,016	1,371	2,031	5,078	52,362
Low-Income Residential New Construct	17	5	8	87	4	5	6	10	24	212
Low-Income Retrofit	4,349	520	1,087	5,481	657	1,011	1,365	2,022	5,054	52,151
Commercial & Industrial (total)	1,842	11,323	6,757	143,960	11,106	4,761	17,737	7,583	41,187	526,129
C&I New Construction and Major Renov	304	2,755	1,854	38,235	3,094	998	4,855	1,542	10,489	144,793
C&I New Construction and Major Renov	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
C&I Large Retrofit	113	3,928	2,547	47,975	3,464	1,421	4,819	1,971	11,675	147,143
Large C&I Retrofit - Government	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
C&I Small Retrofit	1,425	4,640	2,356	57,751	4,547	2,343	8,064	4,069	19,023	234,194
C&I Small Retrofit - Government	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
GRAND TOTAL	193,561	20,787	16,490	276,328	18,910	14,507	30,172	25,535	89,123	981,175

Notes

(1) As filed in the Cape Light Compact's 2010 Mid-Year Revisions Filing, D.P.U. 10-106.
(2) As this filing assumes approval of the 2011 Mid-Term Modifications, this data is as filed in the Cape Light Compact's 2011 Mid-Term Modifications Filing, D.P.U. 10-147.
(3) Proposed 2012 changes presented in this filing, representing additional budget requirements for 2012, taking into account 2011 estimated carryover.

IV.D. Cost Effectiveness
3.2.i. Savings Summary Table

Program	Non Electric Resources, 2010 (1)						
	MMBTU						Gallons
	Avoided Natural Gas	No. 2 Distillate	No. 4 Fuel Oil	Propane	Wood	Kerosene	Water
Residential (total)	17,344	28,820	0	3,743	0	0	2,102,765
Residential New Construction & Major R	1	60	0	884	0	0	11,584
Residential Cooling & Heating Equipme	-638	0	0	0	0	0	0
Multi-Family Retrofit	1,551	1,989	0	990	0	0	1,755,419
MassSAVE	16,431	26,771	0	1,869	0	0	335,763
Behavior/Feedback Program	n/a	n/a	n/a	n/a	n/a	n/a	n/a
ENERGY STAR Lighting	0	0	0	0	0	0	0
ENERGY STAR Appliances	0	0	0	0	0	0	0
Low Income (total)	100	3,476	0	13	0	0	2,715,253
Low-Income Residential New Construct	0	0	0	13	0	0	688
Low-Income Retrofit	99	3,476	0	0	0	0	2,714,565
Commercial & Industrial (total)	-6,220	792	0	396	0	0	0
C&I New Construction and Major Renov	0	0	0	0	0	0	0
C&I New Construction and Major Renov	n/a	n/a	n/a	n/a	n/a	n/a	n/a
C&I Large Retrofit	-310	0	0	0	0	0	0
Large C&I Retrofit - Government	n/a	n/a	n/a	n/a	n/a	n/a	n/a
C&I Small Retrofit	-5,910	792	0	396	0	0	0
C&I Small Retrofit - Government	n/a	n/a	n/a	n/a	n/a	n/a	n/a
GRAND TOTAL	11,224	33,088	0	4,153	0	0	4,818,018

Program	Non Electric Resources, 2011 (2)						
	MMBTU						Gallons
	Avoided Natural Gas	No. 2 Distillate	No. 4 Fuel Oil	Propane	Wood	Kerosene	Water
Residential (total)	26,253	42,169	0	4,565	0	0	2,410,433
Residential New Construction & Major R	562	29	0	488	0	0	20,210
Residential Cooling & Heating Equipme	-794	0	0	0	0	0	0
Multi-Family Retrofit	2,100	2,583	0	1,230	0	0	1,976,976
MassSAVE	24,385	39,557	0	2,847	0	0	413,246
Behavior/Feedback Program	n/a	n/a	n/a	n/a	n/a	n/a	n/a
ENERGY STAR Lighting	0	0	0	0	0	0	0
ENERGY STAR Appliances	0	0	0	0	0	0	0
Low Income (total)	-54	3,034	0	8	0	0	3,166,470
Low-Income Residential New Construct	82	0	0	8	0	0	3,870
Low-Income Retrofit	-136	3,034	0	0	0	0	3,162,600
Commercial & Industrial (total)	-10,067	1,466	0	733	0	0	0
C&I New Construction and Major Renov	0	0	0	0	0	0	0
C&I New Construction and Major Renov	n/a	n/a	n/a	n/a	n/a	n/a	n/a
C&I Large Retrofit	-127	0	0	0	0	0	0
Large C&I Retrofit - Government	n/a	n/a	n/a	n/a	n/a	n/a	n/a
C&I Small Retrofit	-9,940	1,466	0	733	0	0	0
C&I Small Retrofit - Government	n/a	n/a	n/a	n/a	n/a	n/a	n/a
GRAND TOTAL	16,132	46,669	0	5,306	0	0	5,576,903

IV.D. Cost Effectiveness
3.2.i. Savings Summary Table

Program	Non Electric Resources, 2012 (3)						
	MMBTU						Gallons
	Avoided Natural Gas	No. 2 Distillate	No. 4 Fuel Oil	Propane	Wood	Kerosene	Water
Residential (total)	32,717	53,754	0	6,364	0	0	896,069
Residential New Construction & Major R	446	42	0	453	0	0	0
Residential Cooling & Heating Equipme	-189	396	0	2,357	0	0	0
Multi-Family Retrofit	0	0	0	0	0	0	0
MassSAVE	32,459	53,317	0	3,554	0	0	896,069
Behavior/Feedback Program	n/a	n/a	n/a	n/a	n/a	n/a	n/a
ENERGY STAR Lighting	0	0	0	0	0	0	0
ENERGY STAR Appliances	0	0	0	0	0	0	0
Low Income (total)	2,984	3,921	0	730	0	0	1,078,698
Low-Income Residential New Construct	0	0	0	0	0	0	0
Low-Income Retrofit	2,984	3,921	0	730	0	0	1,078,698
Commercial & Industrial (total)	-1,754	63	0	31	0	0	486,180
C&I New Construction and Major Renov	-1,242	0	0	0	0	0	486,180
C&I New Construction and Major Renov	n/a	n/a	n/a	n/a	n/a	n/a	n/a
C&I Large Retrofit	-478	0	0	0	0	0	0
Large C&I Retrofit - Government	n/a	n/a	n/a	n/a	n/a	n/a	n/a
C&I Small Retrofit	-34	63	0	31	0	0	0
C&I Small Retrofit - Government	n/a	n/a	n/a	n/a	n/a	n/a	n/a
GRAND TOTAL	33,946	57,738	0	7,125	0	0	2,460,947

Program	Non Electric Resources, 2010-2012						
	MMBTU						Gallons
	Avoided Natural Gas	No. 2 Distillate	No. 4 Fuel Oil	Propane	Wood	Kerosene	Water
Residential (total)	76,314	124,743	0	14,672	0	0	5,409,267
Residential New Construction & Major R	1,009	131	0	1,826	0	0	31,794
Residential Cooling & Heating Equipme	-1,620	396	0	2,357	0	0	0
Multi-Family Retrofit	3,651	4,572	0	2,221	0	0	3,732,395
MassSAVE	73,275	119,644	0	8,269	0	0	1,645,078
Behavior/Feedback Program	n/a	n/a	n/a	n/a	n/a	n/a	n/a
ENERGY STAR Lighting	0	0	0	0	0	0	0
ENERGY STAR Appliances	0	0	0	0	0	0	0
Low Income (total)	3,029	10,432	0	752	0	0	6,960,421
Low-Income Residential New Construct	83	0	0	22	0	0	4,558
Low-Income Retrofit	2,947	10,432	0	730	0	0	6,955,863
Commercial & Industrial (total)	-18,041	2,320	0	1,160	0	0	486,180
C&I New Construction and Major Renov	-1,242	0	0	0	0	0	486,180
C&I New Construction and Major Renov	n/a	n/a	n/a	n/a	n/a	n/a	n/a
C&I Large Retrofit	-916	0	0	0	0	0	0
Large C&I Retrofit - Government	n/a	n/a	n/a	n/a	n/a	n/a	n/a
C&I Small Retrofit	-15,883	2,320	0	1,160	0	0	0
C&I Small Retrofit - Government	n/a	n/a	n/a	n/a	n/a	n/a	n/a
GRAND TOTAL	61,302	137,495	0	16,584	0	0	12,855,869

IV.D. Cost Effectiveness

3.2.ii. Savings Comparison Table - Three Year Plan vs. Previous Years

Program	# of Participants	Electric Savings								
		Capacity (kW)			Energy (MWh)					
		Annual		Lifetime	Summer (Annual)		Winter (Annual)		Total Annual MWh	Lifetime
		Summer	Winter		Peak	Off Peak	Peak	Off Peak		
Residential (total)	**198,410**	**10,482**	**13,862**	**140,726**	**9,782**	**12,865**	**16,785**	**24,269**	**63,700**	**556,439**
2007 (1)	8,445	1,056	2,868	10,896	1,530	2,283	3,085	4,526	11,425	79,821
2008 (2)	6,338	768	1,157	9,706	796	1,128	1,548	2,207	5,680	44,847
2009 (3)	9,992	1,020	1,273	17,531	881	1,136	1,424	2,103	5,544	49,928
2010 (4)	28,116	1,189	1,958	15,504	1,130	1,644	2,329	3,269	8,372	75,217
2011 (5)	91,028	4,182	3,763	62,921	3,096	3,916	5,062	7,290	19,364	173,570
2012 (6)	54,491	2,267	2,843	24,167	2,348	2,757	3,337	4,873	13,315	133,056
Low Income (total)	**5,918**	**619**	**3,470**	**7,094**	**767**	**1,179**	**1,600**	**2,361**	**5,908**	**65,901**
2007 (1)	651	38	203	383	73	112	160	228	573	7,705
2008 (2)	562	54	213	494	82	127	171	253	633	9,412
2009 (3)	702	104	2,142	1,654	54	82	111	165	412	4,451
2010 (4)	954	63	125	852	82	126	170	251	628	8,164
2011 (5)	1,549	242	491	2,640	293	450	607	899	2,249	23,249
2012 (6)	1,500	119	296	1,072	184	283	382	565	1,413	12,918
Comm & Ind (total)	**2,783**	**12,988**	**8,473**	**170,293**	**13,255**	**6,986**	**19,399**	**10,227**	**44,716**	**648,241**
2007 (1)	334	1,315	1,071	18,231	1,208	1,038	1,519	1,386		71,073
2008 (2)	268	1,133	987	15,351	891	731	1,116	1,018	3,757	50,032
2009 (3)	448	1,664	1,166	22,402	2,025	1,395	2,781	1,923	8,124	109,258
2010 (4)	532	1,512	799	21,159	1,957	794	2,539	1,088	6,378	82,565
2011 (5)	986	4,538	2,568	59,473	4,557	2,058	7,585	3,412	17,612	230,622
2012 (6)	215	2,825	1,883	33,678	2,617	971	3,859	1,399	8,846	104,692
GRAND TOTAL	**207,111**	**24,089**	**25,805**	**318,114**	**23,804**	**21,030**	**37,784**	**36,857**	**114,324**	**1,270,580**
2007 (1)	**9,430**	**2,409**	**4,142**	**29,510**	**2,811**	**3,433**	**4,764**	**6,140**	**11,998**	**158,599**
2008 (2)	**7,168**	**1,954**	**2,357**	**25,551**	**1,770**	**1,986**	**2,836**	**3,479**	**10,070**	**104,291**
2009 (3)	**11,142**	**2,788**	**4,581**	**41,587**	**2,960**	**2,613**	**4,315**	**4,191**	**14,079**	**163,637**
2010 (4)	**29,602**	**2,764**	**2,881**	**37,514**	**3,168**	**2,564**	**5,038**	**4,608**	**15,378**	**165,946**
2011 (5)	**93,563**	**8,962**	**6,822**	**125,034**	**7,946**	**6,424**	**13,254**	**11,602**	**39,225**	**427,440**
2012 (6)	**56,206**	**5,211**	**5,022**	**58,917**	**5,149**	**4,010**	**7,577**	**6,838**	**23,573**	**250,667**

Notes:

(1) Actual values from the Cape Light Compact's 2007 Annual Report D.P.U. 09-68, in 2007$.
(2) Actual values from the Cape Light Compact's 2008 Annual Report D.P.U. 09-69, in 2008$.
(3) Actual values from the Cape Light Compact's 2009 Annual Report D.P.U. 10-97, in 2009$.
(4) Actual values from the Cape Light Compact's 2010 Annual Report D.P.U. 11-68, in 2010$.
(5) As this filing assumes approval of the 2011 Mid-Term Modifications, this data is as filed in the Cape Light Compact's 2011 Mid-Term Modifications Filing, D.P.U. 10-147, in 2011$.
(6) Proposed 2012 changes presented in this filing, representing additional budget requirements for 2012, taking into account 2011 estimated carryover, in 2012$.

IV.D. Cost Effectiveness
3.2.ii. Savings Comparis

Program	Non Electric Resources						
	MMBTU						Gallons
	Avoided Natural Gas	No. 2 Distillate	No. 4 Fuel Oil	Propane	Wood	Kerosene	Water
Residential (total)	**91,065**	**148,231**	**0**	**18,359**	**0**	**0**	**23,545,411**
2007 (1)	8,057	9,667	0	1,730	0	0	14,394,389
2008 (2)	5,983	8,916	0	3,289	0	0	4,026,353
2009 (3)	9,799	20,947	0	873	0	0	893,189
2010 (4)	8,256	12,778	0	1,538	0	0	924,978
2011 (5)	26,253	42,169	0	4,565	0	0	2,410,433
2012 (6)	32,717	53,754	0	6,364	0	0	896,069
Low Income (total)	**12,026**	**21,147**	**0**	**1,380**	**0**	**0**	**8,794,752**
2007 (1)	3,696	4,062	0	529	0	0	182,922
2008 (2)	688	4,364	0	0	0	0	3,294,375
2009 (3)	2,507	3,720	0	39	0	0	483,175
2010 (4)	2,205	2,046	0	73	0	0	589,111
2011 (5)	-54	3,034	0	8	0	0	3,166,470
2012 (6)	2,984	3,921	0	730	0	0	1,078,698
Comm & Ind (total)	**-7,057**	**3,142**	**0**	**1,167**	**0**	**0**	**486,180**
2007 (1)	0	0	0	0	0	0	0
2008 (2)	0	0	0	0	0	0	0
2009 (3)	0	0	0	0	0	0	0
2010 (4)	4,764	1,614	0	403	0	0	0
2011 (5)	-10,067	1,466	0	733	0	0	0
2012 (6)	-1,754	63	0	31	0	0	486,180
GRAND TOTAL	**96,033**	**172,521**	**0**	**20,906**	**0**	**0**	**32,826,343**
2007 (1)	**11,753**	**13,729**	**0**	**2,259**	**0**	**0**	**14,577,312**
2008 (2)	**6,671**	**13,281**	**0**	**3,289**	**0**	**0**	**7,320,728**
2009 (3)	**12,306**	**24,668**	**0**	**912**	**0**	**0**	**1,376,364**
2010 (4)	**15,225**	**16,438**	**0**	**2,014**	**0**	**0**	**1,514,089**
2011 (5)	**16,132**	**46,669**	**0**	**5,306**	**0**	**0**	**5,576,903**
2012 (6)	**33,946**	**57,738**	**0**	**7,125**	**0**	**0**	**2,460,947**

IV.D. Cost Effectiveness
3.3.i.a. Avoided Cost Factors Summary Table for 2010 and 2011

Avoided Cost Factors (2009$)																
Year	Capacity ($/kW-yr) (1)		Energy ($/kWh) (1)				Non-Electric (1)								Distribution ($/kW) (2)	Transmission ($/kW) (2)
			Winter		Summer		$/MMBTU						$/Gallons			
	Summer	Winter	Peak	Off Peak	Peak	Off Peak	Avoided Natural Gas	No. 2 Distillate	No. 4 Fuel Oil	Propane	Wood	Kerosene	Water			
2010	65.84	$0.00	$0.075	$0.058	$0.078	$0.057	15.64	13.37	12.89	24.04	5.63	15.18	$0.0086		$77.76	$15.68
2011	50.58	$0.00	$0.080	$0.062	$0.082	$0.059	16.34	14.37	13.96	24.91	5.88	15.87	$0.0086		$77.76	$15.68
2012	35.74	$0.00	$0.087	$0.067	$0.086	$0.063	17.95	15.95	15.58	26.84	6.46	17.44	$0.0086		$77.76	$15.68
2013	16.85	$0.00	$0.088	$0.072	$0.089	$0.069	19.32	17.38	17.05	29.09	6.96	18.76	$0.0086		$77.76	$15.68
2014	16.85	$0.00	$0.089	$0.073	$0.090	$0.070	20.92	18.95	18.62	31.29	7.53	20.32	$0.0086		$77.76	$15.68
2015	18.14	$0.00	$0.089	$0.074	$0.092	$0.070	22.65	20.55	20.21	33.63	8.15	21.99	$0.0086		$77.76	$15.68
2016	19.44	$0.00	$0.090	$0.076	$0.096	$0.071	24.36	22.11	21.75	36.14	8.77	23.65	$0.0086		$77.76	$15.68
2017	19.44	$0.00	$0.093	$0.079	$0.098	$0.075	25.96	23.57	23.21	38.58	9.35	25.21	$0.0086		$77.76	$15.68
2018	20.74	$0.00	$0.097	$0.081	$0.101	$0.078	26.02	23.67	23.33	38.70	9.37	25.27	$0.0086		$77.76	$15.68
2019	20.74	$0.00	$0.098	$0.084	$0.103	$0.079	26.18	23.82	23.50	38.90	9.42	25.43	$0.0086		$77.76	$15.68
2020	22.03	$0.00	$0.098	$0.084	$0.103	$0.080	26.25	23.80	23.46	38.82	9.45	25.49	$0.0086		$77.76	$15.68
2021	23.33	$0.00	$0.096	$0.083	$0.101	$0.079	26.32	23.93	23.61	39.04	9.48	25.57	$0.0086		$77.76	$15.68
2022	24.62	$0.00	$0.098	$0.084	$0.102	$0.080	26.53	24.18	23.86	39.28	9.55	25.77	$0.0086		$77.76	$15.68
2023	25.92	$0.00	$0.100	$0.086	$0.106	$0.082	26.41	24.03	23.69	39.04	9.51	25.65	$0.0086		$77.76	$15.68
2024	27.22	$0.00	$0.105	$0.088	$0.111	$0.086	26.74	24.32	23.97	39.19	9.63	25.97	$0.0086		$77.76	$15.68
2025	40.18	$0.00	$0.107	$0.090	$0.114	$0.088	27.24	24.77		39.86	9.81	26.45	$0.0086		$77.76	$15.68
2026	53.14	$0.00	$0.109	$0.092	$0.117	$0.091	27.75	25.24	24.89	40.54	9.99	26.95	$0.0086		$77.76	$15.68
2027	66.10	$0.00	$0.112	$0.094	$0.119	$0.093	28.26	25.72	25.37	41.24	10.18	27.45	$0.0086		$77.76	$15.68
2028	79.06	$0.00	$0.114	$0.096	$0.122	$0.095	28.79	26.20	25.85	41.94	10.36	27.96	$0.0086		$77.76	$15.68
2029	92.02	$0.00	$0.116	$0.098	$0.125	$0.098	29.33	26.70	26.35	42.66	10.56	28.48	$0.0086		$77.76	$15.68
2030	103.68	$0.00	$0.119	$0.101	$0.128	$0.101	29.87	27.20	26.85	43.39	10.75	29.01	$0.0086		$77.76	$15.68

Notes:

(1) The Avoided Costs are consistent with the 2009 Avoided Energy Supply Costs in New England Report perpared by Synapse Energy Economics, Inc., in 2009$.
(2) The Avoided Transmission and Distribution capacity values are per NSTAR, also in 2009$.
(3) The assumptions used in the BCR model for 2010 were updated to 2010$ and for 2011 were updated to 2011$.

IV.D. Cost Effectiveness

3.3.i.b. Avoided Cost Factors Summary Table for 2012

Avoided Cost Factors (2011$)																	
	Capacity ($/kW-yr) (1)		Energy ($/kWh) (1)				Non-Electric (1)										
			Winter		Summer		$/MMBTU								$/Gallons		
Year	Summer	Winter	Peak	Off Peak	Peak	Off Peak	Res Avoided Natural Gas (Heating)	C&I Avoided Natural Gas (Heating)	Res No. 2 Distillate	C&I No. 2 Distillate	No. 4 Fuel Oil	Propane	Wood	Kerosene	Water	Distribution ($/kW) (2)	Transmission ($/kW) (2)
2012	37.50	$0.00	$0.060	$0.051	$0.071	$0.051	7.80	7.64	26.22	22.29	21.08	39.36	9.78	25.97	$0.0110	$99.93	$24.20
2013	36.76	$0.00	$0.062	$0.054	$0.074	$0.053	8.01	7.85	25.44	21.83	20.83	37.77	9.49	25.20	$0.0110	$99.93	$24.20
2014	36.76	$0.00	$0.064	$0.056	$0.077	$0.055	8.39	8.23	24.69	21.30	20.45	36.55	9.21	24.46	$0.0110	$99.93	$24.20
2015	36.76	$0.00	$0.071	$0.062	$0.083	$0.060	8.86	8.69	24.18	20.95	20.16	35.61	9.02	23.96	$0.0110	$99.93	$24.20
2016	15.09	$0.00	$0.072	$0.063	$0.090	$0.062	8.88	8.71	24.14	20.96	20.15	34.74	9.01	23.92	$0.0110	$99.93	$24.20
2017	22.21	$0.00	$0.073	$0.065	$0.091	$0.062	8.87	8.70	23.94	20.80	20.02	34.07	8.93	23.72	$0.0110	$99.93	$24.20
2018	31.01	$0.00	$0.078	$0.070	$0.100	$0.068	8.89	8.73	24.64	21.44	20.66	34.68	9.19	24.41	$0.0110	$99.93	$24.20
2019	34.80	$0.00	$0.078	$0.071	$0.097	$0.068	8.95	8.78	25.09	21.91	21.17	34.95	9.36	24.86	$0.0110	$99.93	$24.20
2020	48.69	$0.00	$0.080	$0.070	$0.092	$0.069	9.04	8.88	25.47	22.24	21.49	35.19	9.50	25.23	$0.0110	$99.93	$24.20
2021	49.61	$0.00	$0.081	$0.072	$0.093	$0.070	9.15	8.98	25.62	22.41	21.69	35.44	9.56	25.38	$0.0110	$99.93	$24.20
2022	74.46	$0.00	$0.084	$0.074	$0.096	$0.073	9.32	9.15	25.83	22.68	21.96	35.65	9.64	25.59	$0.0110	$99.93	$24.20
2023	89.72	$0.00	$0.089	$0.078	$0.100	$0.077	9.59	9.42	26.17	22.92	22.20	35.95	9.76	25.92	$0.0110	$99.93	$24.20
2024	98.16	$0.00	$0.092	$0.080	$0.102	$0.078	9.76	9.59	26.36	23.08	22.36	36.23	9.84	26.11	$0.0110	$99.93	$24.20
2025	101.86	$0.00	$0.092	$0.080	$0.103	$0.080	9.84	9.68	26.67	23.35	22.64	36.50	9.95	26.42	$0.0110	$99.93	$24.20
2026	104.09	$0.00	$0.092	$0.080	$0.105	$0.080	9.98	9.81	26.95	23.56	22.83	36.66	10.06	26.70	$0.0110	$99.93	$24.20
2027	104.98	$0.00	$0.095	$0.082	$0.108	$0.082	10.11	9.94		23.89	23.17	36.96	10.19	27.06	$0.0110	$99.93	$24.20
2028	105.49	$0.00	$0.098	$0.084	$0.111	$0.084	10.25	10.08	27.67	24.23	23.51	37.26	10.33	27.41	$0.0110	$99.93	$24.20
2029	105.62	$0.00	$0.101	$0.086	$0.114	$0.086	10.38	10.21	28.04	24.56	23.85	37.57	10.46	27.78	$0.0110	$99.93	$24.20
2030	105.75	$0.00	$0.104	$0.089	$0.117	$0.089	10.52	10.35	28.41	24.91	24.21	37.88	10.60	28.14	$0.0110	$99.93	$24.20
2031	105.88	$0.00	$0.107	$0.091	$0.121	$0.091	10.66	10.49	28.79	25.25	24.56	38.19	10.74	28.52	$0.0110	$99.93	$24.20
2032	105.88	$0.00	$0.110	$0.093	$0.124	$0.094	10.80	10.63	29.17	25.61	24.92	38.50	10.88	28.90	$0.0110	$99.93	$24.20

Notes:

(1) The Avoided Costs are consistent with the 2011 Avoided Energy Supply Costs in New England Report perpared by Synapse Energy Economics, Inc., in 2011$.
(2) The Avoided Transmission and Distribution capacity values are per NSTAR, also in 2011$.
(3) The assumptions used in the BCR model for 2012 were updated to 2012$.

IV.D. Cost Effectiveness

3.3.iii. Distribution & Transmission Avoided Costs Factors Comparison Table - Three Year Plan vs. Previous Years

Avoided Cost Factors		
Year	**Distribution ($/kW)**	**Transmission ($/kW)**
2007 (1)	$67.25	$18.01
2008 (2)	$67.25	$18.01
2009 (3)	$144.43	$23.58
2010 (4)	$79.21	$15.97
2011 (5)	$80.68	$16.26
2012 (6)	$101.97	$24.70

Notes:

(1) Actual values from the Cape Light Compact's 2007 Annual Report D.P.U. 09-68, in 2007$.
(2) Actual values from the Cape Light Compact's 2008 Annual Report D.P.U. 09-69, in 2008$.
(3) Actual values from the Cape Light Compact's 2009 Annual Report D.P.U. 10-97, in 2009$.
(4) Actual values from the Cape Light Compact's 2010 Annual Report D.P.U. 11-68, in 2010$.
(5) As this filing assumes approval of the 2011 Mid-Term Modifications, this data is as filed in the Cape Light Compact's 2011 Mid-Term Modifications Filing, D.P.U. 10-147, in 2011$.
(6) Proposed 2012 changes presented in this filing, representing additional budget requirements for 2012, taking into account 2011 estimated carryover, in 2012$.

IV.G. Monitoring and Evaluation
2. Evaluation Activities

Evaluation Activities, 2010 (1)		
Program	**Study**	**(J)oint/(C)ompany Specific**
Residential		
Program 1		
Program 2		
Low Income		
Program 1		
Program 2		
Commercial & Industrial		
Program 1		
Program 2		

Evaluation Activities, 2011 (2)		
Program	**Study**	**(J)oint/(C)ompany Specific**
Residential		
Program 1		
Program 2		
Low Income		
Program 1		
Program 2		
Commercial & Industrial		
Program 1		
Program 2		

Evaluation Activities, 2012 (3)		
Program	**Study**	**(J)oint/(C)ompany Specific**
Residential		
Program 1		
Program 2		
Low Income		
Program 1		
Program 2		
Commercial & Industrial		
Program 1		
Program 2		

Notes:

(1) Please refer to the Evaluation and Monitoring Section (H) of the Statewide Electric 3-Year Plan for Details describing EM&V activities planned
(2) Please refer to the Evaluation and Monitoring Section of the Cape Light Compact's 2011 MTM filing.
(3) Please refer to the Evaluation and Monitoring Section of the Cape Light Compact's 2012 MTM filing.

IV.H. Performance Incentive: Not Applicable to CLC

1. Summary Table

2010				
Sector	**After-Tax Performance Incentives**	**% of PA Costs**	**Pre-Tax Performance Incentives**	**% of PA Costs**
Residential	n/a	n/a	n/a	n/a
Low Income	n/a	n/a	n/a	n/a
Commercial & Industrial	n/a	n/a	n/a	n/a
TOTAL	**n/a**	**n/a**	**n/a**	**n/a**

2011				
Sector	**After-Tax Performance Incentives**	**% of PA Costs**	**Pre-Tax Performance Incentives**	**% of PA Costs**
Residential	n/a	n/a	n/a	n/a
Low Income	n/a	n/a	n/a	n/a
Commercial & Industrial	n/a	n/a	n/a	n/a
TOTAL	**n/a**	**n/a**	**n/a**	**n/a**

2012				
Sector	**After-Tax Performance Incentives**	**% of PA Costs**	**Pre-Tax Performance Incentives**	**% of PA Costs**
Residential	n/a	n/a	n/a	n/a
Low Income	n/a	n/a	n/a	n/a
Commercial & Industrial	n/a	n/a	n/a	n/a
TOTAL	**n/a**	**n/a**	**n/a**	**n/a**

2010-2012				
Sector	**After-Tax Performance Incentives**	**% of PA Costs**	**Pre-Tax Performance Incentives**	**% of PA Costs**
Residential	n/a	n/a	n/a	n/a
Low Income	n/a	n/a	n/a	n/a
Commercial & Industrial	n/a	n/a	n/a	n/a
TOTAL	**n/a**	**n/a**	**n/a**	**n/a**

Notes:

As the Cape Light Compact does not receive performance incentives, this table is not applicable to the Cape Light Compact.

IV.I. Cost Recovery
1. Lost Base Revenue: Not Applicable to CLC

Calculation of Lost Base Revenue, 2010

Program	2007 Savings (kWh)	Savings in 2010 from Measures Installed in 2009 (kWh)		Savings in 2010 from Measures Installed in 2010 (kWh) (3)		Total Incremental Savings (kWh)	LBR Rate (¢/kWh) (1)	Lost Base Revenue ($)
		Total	Incremental	Total	Incremental			
Residential (total)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Low Income (total)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Commercial & Industrial (total)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
GRAND TOTAL	**n/a**	**n/a**	**n/a**	**n/a**	**n/a**	**n/a**	**n/a**	**n/a**

Calculation of Lost Base Revenue, 2011 (2)

Program	2007 Savings (kWh)	Savings in 2011 from Measures Installed in 2009 (kWh)		Savings in 2011 from Measures Installed in 2010 (kWh) (3)		Savings in 2011 from Measures Installed in 2011 (kWh) (3)		Total Incremental Savings (kWh)	LBR Rate (¢/kWh) (1)	Lost Base Revenue ($)
		Total	Incremental	Total	Incremental	Total	Incremental			
Residential (total)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Low Income (total)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Commercial & Industrial (total)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
GRAND TOTAL	**n/a**	**n/a**	**n/a**	**n/a**	**n/a**	**n/a**	**n/a**	**n/a**	**n/a**	**n/a**

Calculation of Lost Base Revenue, 2012 (2)

Program	2007 Savings (kWh)	Savings in 2012 from Measures Installed in 2009 (kWh)		Savings in 2012 from Measures Installed in 2010 (kWh) (3)		Savings in 2012 from Measures Installed in 2011 (kWh) (3)		Savings in 2012 from Measures Installed in 2012 (kWh) (3)		Total Incremental Savings (kWh)	LBR Rate (¢/kWh) (1)	Lost Base Revenue ($)
		Total	Incremental	Total	Incremental	Total	Incremental	Total	Incremental			
Residential (total)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a		n/a	n/a	n/a
Low Income (total)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Commercial & Industrial (total)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
GRAND TOTAL	**n/a**	**n/a**	**n/a**	**n/a**	**n/a**	**n/a**	**n/a**	**n/a**	**n/a**	**n/a**	**n/a**	**n/a**

Total Lost Base Revenue, 2010-2012 (2)

Program	2010	2011	2012	TOTAL
Residential (total)	n/a	n/a	n/a	n/a
Low Income (total)	n/a	n/a	n/a	n/a
Commercial & Industrial (total)	n/a	n/a	n/a	n/a
GRAND TOTAL	**n/a**	**n/a**	**n/a**	**n/a**

Notes:
(1) Not Applicable to CLC
(2) Not applicable to CLC
(3) See Section V.E.1. Bill Impacts for the impact on customers bills from LBR.

IV.I. Cost Recovery

2. Energy Efficiency Reconciliation Factor

Calculation of the Energy Efficiency Reconciliation Factor, 2010			
Sector	**EERF Revenue Requirement (1)**	**Annual kWh**	**EERF ($/kWh)**
Residential	$6,126,905	1,057,934,150	0.00579
Low Income	$43,830	45,933,192	0.00095
Commercial & Industrial	$3,563,190	886,894,069	0.00402
TOTAL	$9,733,925	1,990,761,411	0.00489

Calculation of the Energy Efficiency Reconciliation Factor, 2011			
Sector	**EERF Revenue Requirement (1)**	**Annual kWh**	**EERF ($/kWh)**
Residential	$8,259,551	1,061,272,398	0.00778
Low Income	$59,347	45,105,200	0.00132
Commercial & Industrial	$6,219,742	884,541,932	0.00703
TOTAL	$14,538,640	1,990,919,529	0.00730

Calculation of the Energy Efficiency Reconciliation Factor, 2012			
Sector	**EERF Revenue Requirement (1)**	**Annual kWh**	**EERF ($/kWh)**
Residential	$6,073,402	1,060,106,607	0.00573
Low Income	$63,436	43,780,128	0.00145
Commercial & Industrial	($211,217)	878,082,566	-0.00024
TOTAL	$5,925,621	1,981,969,302	0.00299

Notes:

(1) See Table IV.B.3.6. EERF Funding

(2) See Table IV.B.3.1. Systems Benefit Charge Funds, kWh Sales

(3) EERF = EERF Revenue Requirement / Annual kWh

V.B. Allocation of Funds

1. Low Income Minimum

Electric Minimum Allocation to Low Income for 2010				
Sector	**SBC Collections**	**% of Total SBC Collections**	**Budget**	**% of Total Budget**
Residential	$2,644,835	53.1%	$9,449,462	50.7%
Low Income (1)	$114,833	2.3%	$2,088,750	11.2%
Commercial & Industrial	$2,217,235	44.6%	$7,098,577	38.1%
TOTAL	**$4,976,904**	**100.0%**	**$18,636,789**	**100.0%**

Electric Minimum Allocation to Low Income for 2011				
Sector	**SBC Collections**	**% of Total SBC Collections**	**Budget**	**% of Total Budget**
Residential	$2,653,181	53.3%	$ 12,386,208	49.7%
Low Income (1)	$112,763	2.3%	$ 2,854,275	11.5%
Commercial & Industrial	$2,211,355	44.4%	$ 9,659,199	38.8%
TOTAL	**$4,977,299**	**100.0%**	**$ 24,899,683**	**100.0%**

Electric Minimum Allocation to Low Income for 2012				
Sector	**SBC Collections**	**% of Total SBC Collections**	**Budget**	**% of Total Budget**
Residential	$2,650,267	53.5%	11,163,540	61.0%
Low Income (1)	$109,450	2.2%	3,145,453	17.2%
Commercial & Industrial	$2,195,206	44.3%	4,004,926	21.9%
TOTAL	**$4,954,923**	**100.0%**	**18,313,920**	**100.0%**

Electric Minimum Allocation to Low Income for Three Years				
Sector	**SBC Collections**	**% of Total SBC Collections**	**Budget**	**% of Total Budget**
Residential	$7,948,283	53.3%	32,999,211	53.4%
Low Income (1)	$337,046	2.3%	8,088,478	13.1%
Commercial & Industrial	$6,623,796	44.4%	20,762,703	33.6%
TOTAL	**$14,909,126**	**100.0%**	**61,850,391**	**100.0%**

Notes:

(1)"% of Total Budget" for the Low Income sector needs to be at least 10%, or the percentage that is collected from Low Income customers through the SBC.

V.D. Outsourced/Competitive Procured Services

1. Summary Table

Program	Program Planning and Administration													
	2010 (1)							2011 (2)						
	In-House Activities		Outsourced Activities: Competitively Procured		Outsourced Activities: Non-Competitively Procured		TOTAL	In-House Activities		Outsourced Activities: Competitively Procured		Outsourced Activities: Non-Competitively Procured		TOTAL
	$	%	$	% of Outsource	$	% of Outsource	$	$	%	$	% of Outsource	$	% of Outsource	$
Residential (total)	**$141,435**	**43%**	**$10,041**	**5%**	**$177,766**	**95%**	**$329,241**	**$162,626**	**44%**	**$14,264**	**7%**	**$195,135**	**93%**	**$372,025**
Residential New Construction and Major Renovation	$4,546	37%	$0	0%	$7,755	100%	$12,301	$1,947	37%	$0	0%	$3,266	100%	$5,213
Residential Cooling & Heating Equipment	$10,474	51%	$5,128	50%	$5,128	50%	$20,731	$13,406	52%	$6,093	50%	$6,093	50%	$25,592
Multi-Family Retrofit	$3,952	31%	$0	0%	$8,769	100%	$12,722	$3,381	27%	$0	0%	$9,175	100%	$12,556
MassSAVE	$87,657	37%	$0	0%	$151,201	100%	$238,857	$92,843	36%	$0	0%	$168,430	100%	$261,273
Behavior/Feedback Program	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
ENERGY STAR Lighting	$27,897	76%	$4,336	50%	$4,336	50%	$36,570	$42,183	74%	$7,444	50%	$7,444	50%	$57,071
ENERGY STAR Appliances	$6,907	86%	$576	50%	$576	50%	$8,059	$8,868	86%	$726	50%	$726	50%	$10,320
Residential Education Program	$0	0%	$0	0%	$0	0%	$0	$0	0%	$0	0%	$0	0%	$0
Workforce Development	$0	0%	$0	0%	$0	0%	$0	$0	0%	$0	0%	$0	0%	$0
Heat Loan Program	$0	0%	$0	0%	$0	0%	$0	$0	0%	$0	0%	$0	0%	$0
R&D and Demonstration	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Deep Energy Retrofit	$0	0%	$0	0%	$0	0%	$0	$0	0%	$0	0%	$0	0%	$0
Residential New Construction & Major Renovation - Majo	$0	0%	$0	0%	$0	0%	$0	$0	0%	$0	0%	$0	0%	$0
Residential New Construction Multi Family (4-8 story) sta	$0	0%	$0	0%	$0	0%	$0	$0	0%	$0	0%	$0	0%	$0
Residential New Construction Lighting Design statewide	$0	0%	$0	0%	$0	0%	$0	$0	0%	$0	0%	$0	0%	$0
Residential New Construction V3 Energy Star Homes sta	$0	0%	$0	0%	$0	0%	$0	$0	0%	$0	0%	$0	0%	$0
Heat Pump Water Heater Pilot	$0	0%	$0	0%	$0	0%	$0	$0	0%	$0	0%	$0	0%	$0
Low Income (total)	**$25,034**	**34%**	**$0**	**0%**	**$47,630**	**100%**	**$72,664**	**$26,601**	**32%**	**$0**	**0%**	**$56,975**	**100%**	**$83,576**
Low-Income Residential New Construction	$607	86%	$0	0%	$98	100%	$705	$669	86%	$0	0%	$109	100%	$777
Low-Income Retrofit	$24,428	34%	$0	0%	$47,531	100%	$71,959	$25,932	31%	$0	0%	$56,866	100%	$82,799
Commercial & Industrial (total)	**$150,901**	**64%**	**$0**	**0%**	**$83,195**	**100%**	**$234,095**	**$162,377**	**60%**	**$0**	**0%**	**$106,022**	**100%**	**$268,399**
C&I New Construction and Major Renovation	$24,017	73%	$0	0%	$8,991	100%	$33,008	$27,039	76%	$0	0%	$8,432	100%	$35,471
C&I Large Retrofit	$15,004	64%	$0	0%	$8,501	100%	$23,505	$17,401	67%	$0	0%	$8,620	100%	$26,022
C&I Small Retrofit	$111,879	63%	$0	0%	$65,702	100%	$177,582	$117,937	57%	$0	0%	$88,970	100%	$206,907
Community Based Pilot	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
TOTAL	**$317,370**	**50%**	**$10,041**	**3%**	**$308,590**	**97%**	**$636,000**	**$351,605**	**49%**	**$14,264**	**4%**	**$358,132**	**96%**	**$724,000**

Program	Marketing and Advertising													
	2010 (1)							2011 (2)						
	In-House Activities		Outsourced Activities: Competitively Procured		Outsourced Activities: Non-Competitively Procured		TOTAL	In-House Activities		Outsourced Activities: Competitively Procured		Outsourced Activities: Non-Competitively Procured		TOTAL
	$	%	$	% of Outsource	$	% of Outsource	$	$	%	$	% of Outsource	$	% of Outsource	$
Residential (total)	**$11,270**	**3%**	**$154,057**	**41%**	**$220,882**	**59%**	**$386,209**	**$1,796**	**0%**	**$161,688**	**39%**	**$248,568**	**61%**	**$412,052**
Residential New Construction and Major Renovation	$281	10%	$2,534	100%	$0	0%	$2,815	$135	10%	$1,172	100%	$0	0%	$1,307
Residential Cooling & Heating Equipment	$0	0%	$4,080	86%	$664	14%	$4,744	$0	0%	$5,711	89%	$706	11%	$6,417
Multi-Family Retrofit	$162	6%	$2,749	100%	$0	0%	$2,911	$148	5%	$3,000	100%	$0	0%	$3,148
MassSAVE	$9,000	21%	$0	0%	$34,218	100%	$43,218	$113	0%	$0	0%	$52,862	100%	$52,975
Behavior/Feedback Program	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
ENERGY STAR Lighting	$1,827	2%	$118,234	100%	$0	0%	$120,061	$1,400	1%	$128,344	100%	$0	0%	$129,744
ENERGY STAR Appliances	$0	0%	$26,459	100%	$0	0%	$26,459	$0	0%	$23,461	100%	$0	0%	$23,461
Residential Education Program	$0	0%	$0	0%	$186,000	100%	$186,000	$0	0%	$0	0%	$195,000	100%	$195,000
Workforce Development	$0	0%	$0	0%	$0	0%	$0	$0	0%	$0	0%	$0	0%	$0
Heat Loan Program	$0	0%	$0	0%	$0	0%	$0	$0	0%	$0	0%	$0	0%	$0
R&D and Demonstration	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Deep Energy Retrofit	$0	0%	$0	0%	$0	0%	$0	$0	0%	$0	0%	$0	0%	$0
Residential New Construction & Major Renovation - Majo	$0	0%	$0	0%	$0	0%	$0	$0	0%	$0	0%	$0	0%	$0
Residential New Construction Multi Family (4-8 story) sta	$0	0%	$0	0%	$0	0%	$0	$0	0%	$0	0%	$0	0%	$0
Residential New Construction Lighting Design statewide	$0	0%	$0	0%	$0	0%	$0	$0	0%	$0	0%	$0	0%	$0
Residential New Construction V3 Energy Star Homes sta	$0	0%	$0	0%	$0	0%	$0	$0	0%	$0	0%	$0	0%	$0
Heat Pump Water Heater Pilot	$0	0%	$0	0%	$0	0%	$0	$0	0%	$0	0%	$0	0%	$0
Low Income (total)	**$335**	**2%**	**$16,164**	**99%**	**$129**	**1%**	**$16,628**	**$770**	**4%**	**$19,763**	**98%**	**$423**	**2%**	**$20,956**
Low-Income Residential New Construction	$161	100%	$0	0%	$0	0%	$161	$195	100%	$0	0%	$0	0%	$195
Low-Income Retrofit	$174	1%	$16,164	99%	$129	1%	$16,467	$575	3%	$19,763	98%	$423	2%	$20,761
Commercial & Industrial (total)	**$2,509**	**5%**	**$0**	**0%**	**$51,061**	**100%**	**$53,570**	**$3,698**	**5%**	**$0**	**0%**	**$63,601**	**100%**	**$67,299**
C&I New Construction and Major Renovation	$453	6%	$0	0%	$7,100	100%	$7,554	$393	4%	$0	0%	$8,501	100%	$8,894
C&I Large Retrofit	$430	8%	$0	0%	$4,949	100%	$5,379	$368	6%	$0	0%	$6,156	100%	$6,525
C&I Small Retrofit	$1,626	4%	$0	0%	$39,012	100%	$40,638	$2,937	6%	$0	0%	$48,944	100%	$51,880
Community Based Pilot	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
TOTAL	**$14,114**	**3%**	**$170,221**	**38%**	**$272,072**	**62%**	**$456,407**	**$6,264**	**1%**	**$181,452**	**37%**	**$312,592**	**63%**	**$500,307**

V.D. Outsourced/Competitive Procured Services
1. Summary Table

Program	Sales, Technical Assistance & Training													
	2010 (1)							2011 (2)						
	In-House Activities		Outsourced Activities				TOTAL	In-House Activities		Outsourced Activities				TOTAL
			Competitively Procured		Non-Competitively Procured					Competitively Procured		Non-Competitively Procured		
	$	%	$	% of Outsource	$	% of Outsource	$	$	%	$	% of Outsource	$	% of Outsource	$
Residential (total)	**$4,543**	**0%**	**$1,250,745**	**91%**	**$130,160**	**9%**	**$1,385,448**	**$0**	**0%**	**$1,357,101**	**89%**	**$163,775**	**11%**	**$1,520,876**
Residential New Construction and Major Renovation	$0	0%	$88,008	100%	$0	$0	$88,008	$0	0%	$79,097	100%	$0	0%	$79,097
Residential Cooling & Heating Equipment	$0	0%	$95,844	99%	$968	$0	$96,812	$0	0%	$94,448	99%	$954	1%	$95,402
Multi-Family Retrofit	$0	0%	$76,453	100%	$0	$0	$76,453	$0	0%	$92,462	100%	$0	0%	$92,462
MassSAVE	$4,543	1%	$757,723	90%	$84,191	$0	$846,458	$0	0%	$860,585	90%	$95,621	10%	$956,206
Behavior/Feedback Program	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
ENERGY STAR Lighting	$0	0%	$167,283	100%	$0	$0	$167,283	$0	0%	$177,114	100%	$0	0%	$177,114
ENERGY STAR Appliances	$0	0%	$36,867	100%	$0	$0	$36,867	$0	0%	$32,027	100%	$0	0%	$32,027
Residential Education Program	$0	0%	$0	0%	$0	$0	$0	$0	0%	$0	0%	$0	0%	$0
Workforce Development	$0	0%	$0	0%	$15,000	$1	$15,000	$0	0%	$0	0%	$15,000	100%	$15,000
Heat Loan Program	$0	0%	$0	0%	$30,000	$1	$30,000	$0	0%	$0	0%	$45,000	100%	$45,000
R&D and Demonstration	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Deep Energy Retrofit	$0	0%	$0	0%	$0	$0	$0	$0	0%	$0	0%	$0	0%	$0
Residential New Construction & Major Renovation - Majo	$0	0%	$11,367	100%	$0	0%	$11,367	$0	0%	$11,367	100%	$0	0%	$11,367
Residential New Construction Multi Family (4-8 story) sta	$0	0%	$0	0%	$0	0%	$0	$0	0%	$0	0%	$0	0%	$0
Residential New Construction Lighting Design statewide	$0	0%	$10,000	100%	$0	0%	$10,000	$0	0%	$10,000	100%	$0	0%	$10,000
Residential New Construction V3 Energy Star Homes sta	$0	0%	$0	0%	$0	0%	$0	$0	0%	$0	0%	$0	0%	$0
Heat Pump Water Heater Pilot	$0	0%	$7,200	100%	$0	0%	$7,200	$0	0%	$0	0%	$7,200	100%	$7,200
Low Income (total)	**$12,150**	**3%**	**$94,368**	**20%**	**$370,837**	**80%**	**$477,354**	**$37,789**	**6%**	**$120,159**	**20%**	**$489,326**	**80%**	**$647,273**
Low-Income Residential New Construction	$0	0%	$14,326	100%	$0	0%	$14,326	$0	0%	$14,927	100%	$0	0%	$14,927
Low-Income Retrofit	$12,150	3%	$80,042	18%	$370,837	82%	$463,029	$37,789	6%	$105,232	18%	$489,326	82%	$632,346
Commercial & Industrial (total)	**$119,643**	**12%**	**$664,897**	**79%**	**$178,409**	**21%**	**$962,949**	**$147,449**	**12%**	**$830,460**	**80%**	**$205,922**	**20%**	**$1,183,830**
C&I New Construction and Major Renovation	$68,530	52%	$0	0%	$62,405	100%	$130,935	$80,595	54%	$0	0%	$70,014	100%	$150,609
C&I Large Retrofit	$51,113	55%	$0	0%	$42,127	100%	$93,240	$66,854	61%	$0	0%	$43,634	100%	$110,488
C&I Small Retrofit	$0	0%	$664,897	90%	$73,877	10%	$738,774	$0	0%	$830,460	90%	$92,273	10%	$922,733
Community Based Pilot	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
TOTAL	**$136,336**	**5%**	**$2,010,010**	**75%**	**$679,405**	**25%**	**$2,825,752**	**$185,237**	**6%**	**$2,307,720**	**73%**	**$859,022**	**27%**	**$3,351,979**

Program	Evaluation and Market Research													
	2010 (1)							2011 (2)						
	In-House Activities		Outsourced Activities				TOTAL	In-House Activities		Outsourced Activities				TOTAL
			Competitively Procured		Non-Competitively Procured					Competitively Procured		Non-Competitively Procured		
	$	%	$	% of Outsource	$	% of Outsource	$	$	%	$	% of Outsource	$	% of Outsource	$
Residential (total)	**$81,228**	**15%**	**$433,335**	**95%**	**$23,918**	**5%**	**$538,481**	**$73,978**	**12%**	**$515,755**	**95%**	**$28,256**	**5%**	**$617,989**
Residential New Construction and Major Renovation	$4,120	43%	$5,282	95%	$278	5%	$9,680	$2,670	38%	$4,175	95%	$220	5%	$7,065
Residential Cooling & Heating Equipment	$40,000	59%	$26,517	95%	$1,396	5%	$67,912	$31,419	52%	$28,049	95%	$1,476	5%	$60,945
Multi-Family Retrofit	$12,633	17%	$59,384	95%	$3,125	5%	$75,142	$10,059	15%	$55,535	95%	$2,923	5%	$68,517
MassSAVE	$14,406	5%	$257,142	95%	$13,534	5%	$285,081	$13,234	4%	$313,483	95%	$16,499	5%	$343,215
Behavior/Feedback Program	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
ENERGY STAR Lighting	$7,202	18%	$32,255	95%	$1,698	5%	$41,155	$12,982	15%	$72,360	95%	$3,808	5%	$89,151
ENERGY STAR Appliances	$2,866	40%	$4,012	95%	$211	5%	$7,089	$3,614	36%	$5,988	95%	$315	5%	$9,917
Residential Education Program	$0	0%	$0	0%	$0	0%	$0	$0	0%	$0	0%	$0	0%	$0
Workforce Development	$0	0%	$0	0%	$0	0%	$0	$0	0%	$0	0%	$0	0%	$0
Heat Loan Program	$0	0%	$0	0%	$0	0%	$0	$0	0%	$0	0%	$0	0%	$0
R&D and Demonstration	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Deep Energy Retrofit	$0	0%	$22,166	95%	$1,167	5%	$23,333	$0	0%	$7,600	95%	$400	5%	$8,000
Residential New Construction & Major Renovation - Majo	$0	0%	$24,467	95%	$1,288	5%	$25,755	$0	0%	$26,453	95%	$1,392	5%	$27,845
Residential New Construction Multi Family (4-8 story) sta	$0	0%	$0	0%	$0	0%	$0	$0	0%	$0	0%	$0	0%	$0
Residential New Construction Lighting Design statewide	$0	0%	$2,111	95%	$111	5%	$2,222	$0	0%	$2,111	95%	$111	5%	$2,222
Residential New Construction V3 Energy Star Homes sta	$0	0%	$0	0%	$0	0%	$0	$0	0%	$0	0%	$0	0%	$0
Heat Pump Water Heater Pilot	$0	0%	$0	0%	$1,111	100%	$1,111	$0	0%	$0	0%	$1,111	100%	$1,111
Low Income (total)	**$9,079**	**11%**	**$71,357**	**95%**	**$3,756**	**5%**	**$84,191**	**$12,781**	**11%**	**$97,153**	**95%**	**$5,113**	**5%**	**$115,048**
Low-Income Residential New Construction	$365	88%	$47	95%	$2	5%	$414	$452	88%	$58	95%	$3	5%	$513
Low-Income Retrofit	$8,714	10%	$71,310	95%	$3,753	5%	$83,777	$12,329	11%	$97,095	95%	$5,110	5%	$114,535
Commercial & Industrial (total)	**$9,523**	**8%**	**$104,720**	**95%**	**$5,512**	**5%**	**$119,754**	**$21,214**	**8%**	**$221,556**	**95%**	**$11,661**	**5%**	**$254,431**
C&I New Construction and Major Renovation	$2,821	7%	$34,665	95%	$1,824	5%	$39,310	$3,897	7%	$47,874	95%	$2,520	5%	$54,290
C&I Large Retrofit	$1,007	5%	$18,343	95%	$965	5%	$20,316	$1,798	5%	$32,763	95%	$1,724	5%	$36,286
C&I Small Retrofit	$5,695	9%	$51,712	95%	$2,722	5%	$60,128	$15,519	9%	$140,919	95%	$7,417	5%	$163,855
Community Based Pilot	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
TOTAL	**$99,830**	**13%**	**$609,411**	**95%**	**$33,185**	**5%**	**$742,427**	**$107,973**	**11%**	**$834,464**	**95%**	**$45,030**	**5%**	**$987,467**

V.D. Outsourced/Competitive Procured Services
1. Summary Table

	TOTAL													
	2010 (1)							2011 (2)						
Program	In-House Activities		Outsourced Activities				TOTAL	In-House Activities		Outsourced Activities				TOTAL
			Competitively Procured		Non-Competitively Procured					Competitively Procured		Non-Competitively Procured		
	$	%	$	% of Outsource	$	% of Outsource	$	$	%	$	% of Outsource	$	% of Outsource	$
Residential (total)	**$238,475**	**9%**	**$1,848,178**	**77%**	**$552,725**	**23%**	**$2,639,379**	**$238,401**	**8%**	**$2,048,808**	**76%**	**$635,734**	**24%**	**$2,922,942**
Residential New Construction and Major Renovation	$8,948	8%	$95,824	92%	$8,033	8%	$112,805	$4,752	5%	$84,445	96%	$3,486	4%	$92,683
Residential Cooling & Heating Equipment	$50,475	27%	$131,569	94%	$8,156	6%	$190,200	$44,825	24%	$134,302	94%	$9,229	6%	$188,356
Multi-Family Retrofit	$16,747	10%	$138,586	92%	$11,895	8%	$167,228	$13,588	8%	$150,997	93%	$12,098	7%	$176,683
MassSAVE	$115,606	8%	$1,014,865	78%	$283,144	22%	$1,413,614	$106,189	7%	$1,174,068	78%	$333,412	22%	$1,613,669
Behavior/Feedback Program	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
ENERGY STAR Lighting	$36,926	10%	$322,108	98%	$6,034	2%	$365,068	$56,564	12%	$385,263	97%	$11,253	3%	$453,080
ENERGY STAR Appliances	$9,773	12%	$67,914	99%	$787	1%	$78,475	$12,482	16%	$62,202	98%	$1,041	2%	$75,726
Residential Education Program	$0	0%	$0	0%	$186,000	100%	$186,000	$0	0%	$0	0%	$195,000	100%	$195,000
Workforce Development	$0	0%	$0	0%	$15,000	100%	$15,000	$0	0%	$0	0%	$15,000	100%	$15,000
Heat Loan Program	$0	0%	$0	0%	$30,000	100%	$30,000	$0	0%	$0	0%	$45,000	100%	$45,000
R&D and Demonstration	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Deep Energy Retrofit	$0	0%	$22,166	95%	$1,167	5%	$23,333	$0	0%	$7,600	95%	$400	5%	$8,000
Residential New Construction & Major Renovation - Majo	$0	0%	$35,834	97%	$1,288	3%	$37,122	$0	0%	$37,820	96%	$1,392	4%	$39,212
Residential New Construction Multi Family (4-8 story) sta	$0	0%	$0	0%	$0	0%	$0	$0	0%	$0	0%	$0	0%	$0
Residential New Construction Lighting Design statewide	$0	0%	$12,111	99%	$111	1%	$12,222	$0	0%	$12,111	99%	$111	1%	$12,222
Residential New Construction V3 Energy Star Homes sta	$0	0%	$0	0%	$0	0%	$0	$0	0%	$0	0%	$0	0%	$0
Heat Pump Water Heater Pilot	$0	0%	$7,200	87%	$1,111	13%	$8,311	$0	0%	$0	0%	$8,311	100%	$8,311
Low Income (total)	**$46,599**	**7%**	**$181,889**	**30%**	**$422,351**	**70%**	**$650,838**	**$77,941**	**9%**	**$237,075**	**30%**	**$551,837**	**70%**	**$866,853**
Low-Income Residential New Construction	$1,133	7%	$14,372	99%	$101	1%	$15,606	$1,316	8%	$14,985	99%	$112	1%	$16,412
Low-Income Retrofit	$45,465	7%	$167,517	28%	$422,250	72%	$635,232	$76,625	9%	$222,091	29%	$551,725	71%	$850,441
Commercial & Industrial (total)	**$282,576**	**21%**	**$769,617**	**71%**	**$318,176**	**29%**	**$1,370,369**	**$334,738**	**19%**	**$1,052,016**	**73%**	**$387,205**	**27%**	**$1,773,959**
C&I New Construction and Major Renovation	$95,822	45%	$34,665	30%	$80,321	70%	$210,807	$111,923	45%	$47,874	35%	$89,466	65%	$249,263
C&I Large Retrofit	$67,554	47%	$18,343	24%	$56,542	76%	$142,440	$86,422	48%	$32,763	35%	$60,135	65%	$179,321
C&I Small Retrofit	$119,200	12%	$716,609	80%	$181,314	20%	$1,017,122	$136,393	10%	$971,378	80%	$237,604	20%	$1,345,375
Community Based Pilot	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
TOTAL	**$567,650**	**12%**	**$2,799,684**	**68%**	**$1,293,252**	**32%**	**$4,660,586**	**$651,079**	**12%**	**$3,337,899**	**68%**	**$1,574,776**	**32%**	**$5,563,754**

Notes:
(1) As filed in the Cape Light Compact's 2010 Mid-Year Revisions Filing, D.P.U 10-106, in 2010$
(2) As this filing assumes approval of the 2011 Mid-Term Modifications, this data is as filed in the Cape Light Compact's 2011 Mid-Term Modifications Filing, D.P.U. 10-147, in 2011$
(3) Proposed 2012 changes presented in this filing, representing additional budget requirements for 2012, taking into account 2011 estimated carryover, in 2012$

V.D. Outsourced/Competitive Procured Services
1. Summary Table

Program	Program Planning and Administration													
	2012 (3)							2010-2012						
	In-House Activities		Outsourced Activities				TOTAL	In-House Activities		Outsourced Activities				TOTAL
			Competitively Procured		Non-Competitively Procured					Competitively Procured		Non-Competitively Procured		
	$	%	$	% of Outsource	$	% of Outsource	$	$	%	$	% of Outsource	$	% of Outsource	$
Residential (total)	**$124,064**	**29%**	**$178,139**	**57%**	**$132,016**	**43%**	**$434,219**	**$428,125**	**38%**	**$202,443**	**29%**	**$504,916**	**71%**	**$1,135,485**
Residential New Construction and Major Renovation	$3,736	27%	$5,456	55%	$4,522	45%	$13,715	$10,230	33%	$5,456	26%	$15,543	74%	$31,229
Residential Cooling & Heating Equipment	$8,270	28%	$11,875	56%	$9,424	44%	$29,569	$32,151	42%	$23,096	53%	$20,646	47%	$75,893
Multi-Family Retrofit	$0	0%	$0	0%	$0	0%	$0	$7,333	29%	$0	0%	$17,944	100%	$25,277
MassSAVE	$94,836	29%	$128,161	55%	$104,688	45%	$327,685	$275,336	33%	$128,161	23%	$424,319	77%	$827,815
Behavior/Feedback Program	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
ENERGY STAR Lighting	$12,876	27%	$25,985	73%	$9,522	27%	$48,383	$82,956	58%	$37,766	64%	$21,302	36%	$142,024
ENERGY STAR Appliances	$4,345	29%	$6,661	63%	$3,860	37%	$14,866	$20,120	61%	$7,964	61%	$5,162	39%	$33,246
Residential Education Program	$0	0%	$0	0%	$0	0%	$0	$0	0%	$0	0%	$0	0%	$0
Workforce Development	$0	0%	$0	0%	$0	0%	$0	$0	0%	$0	0%	$0	0%	$0
Heat Loan Program	$0	0%	$0	0%	$0	0%	$0	$0	0%	$0	0%	$0	0%	$0
R&D and Demonstration	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Deep Energy Retrofit	$0	0%	$0	0%	$0	0%	$0	$0	0%	$0	0%	$0	0%	$0
Residential New Construction & Major Renovation - Majo	$0	0%	$0	0%	$0	0%	$0	$0	0%	$0	0%	$0	0%	$0
Residential New Construction Multi Family (4-8 story) sta	$0	0%	$0	0%	$0	0%	$0	$0	0%	$0	0%	$0	0%	$0
Residential New Construction Lighting Design statewide	$0	0%	$0	0%	$0	0%	$0	$0	0%	$0	0%	$0	0%	$0
Residential New Construction V3 Energy Star Homes sta	$0	0%	$0	0%	$0	0%	$0	$0	0%	$0	0%	$0	0%	$0
Heat Pump Water Heater Pilot	$0	0%	$0	0%	$0	0%	$0	$0	0%	$0	0%	$0	0%	$0
Low Income (total)	**$29,929**	**27%**	**$44,686**	**56%**	**$35,511**	**44%**	**$110,125**	**$81,565**	**31%**	**$44,686**	**24%**	**$140,115**	**76%**	**$266,365**
Low-Income Residential New Construction	$0	0%	$0	0%	$0	0%	$0	$1,276	86%	$0	0%	$207	100%	$1,483
Low-Income Retrofit	$29,929	27%	$44,686	56%	$35,511	44%	$110,125	$80,289	30%	$44,686	24%	$139,908	76%	$264,883
Commercial & Industrial (total)	**$111,766**	**32%**	**$117,767**	**48%**	**$125,131**	**52%**	**$354,664**	**$425,043**	**50%**	**$117,767**	**27%**	**$314,348**	**73%**	**$857,159**
C&I New Construction and Major Renovation	$56,725	45%	$16,216	23%	$52,946	77%	$125,887	$107,781	55%	$16,216	19%	$70,369	81%	$194,365
C&I Large Retrofit	$52,225	24%	$97,570	59%	$69,166	41%	$218,962	$84,631	32%	$97,570	53%	$86,287	47%	$268,489
C&I Small Retrofit	$2,815	29%	$3,981	57%	$3,020	43%	$9,816	$232,631	59%	$3,981	2%	$157,692	98%	$394,304
Community Based Pilot	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
TOTAL	**$265,759**	**30%**	**$340,592**	**54%**	**$292,658**	**46%**	**$899,009**	**$934,733**	**41%**	**$364,896**	**28%**	**$959,379**	**72%**	**$2,259,009**

Program	Marketing and Advertising													
	2012 (3)							2010-2012						
	In-House Activities		Outsourced Activities				TOTAL	In-House Activities		Outsourced Activities				TOTAL
			Competitively Procured		Non-Competitively Procured					Competitively Procured		Non-Competitively Procured		
	$	%	$	% of Outsource	$	% of Outsource	$	$	%	$	% of Outsource	$	% of Outsource	$
Residential (total)	**$72,337**	**20%**	**$186,387**	**64%**	**$105,000**	**36%**	**$363,724**	**$85,402**	**7%**	**$502,133**	**47%**	**$574,450**	**53%**	**$1,161,985**
Residential New Construction and Major Renovation	$3,449	20%	$13,724	100%	$0	0%	$17,173	$3,865	18%	$17,430	100%	$0	0%	$21,295
Residential Cooling & Heating Equipment	$4,886	26%	$14,000	100%	$0	0%	$18,886	$4,886	16%	$23,792	95%	$1,370	5%	$30,047
Multi-Family Retrofit	$0	0%	$0	100%	$0	0%	$0	$310	5%	$5,749	100%	$0	0%	$6,059
MassSAVE	$47,202	43%	$62,827	100%	$0	0%	$110,029	$56,314	27%	$62,827	42%	$87,080	58%	$206,222
Behavior/Feedback Program	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
ENERGY STAR Lighting	$10,833	15%	$59,804	100%	$0	0%	$70,637	$14,059	4%	$306,382	100%	$0	0%	$320,441
ENERGY STAR Appliances	$5,967	14%	$36,032	100%	$0	0%	$41,999	$5,967	6%	$85,952	100%	$0	0%	$91,920
Residential Education Program	$0	0%	$0	0%	$105,000	100%	$105,000	$0	0%	$0	0%	$486,000	100%	$486,000
Workforce Development	$0	0%	$0	0%	$0	0%	$0	$0	0%	$0	0%	$0	0%	$0
Heat Loan Program	$0	0%	$0	0%	$0	0%	$0	$0	0%	$0	0%	$0	0%	$0
R&D and Demonstration	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Deep Energy Retrofit	$0	0%	$0	0%	$0	0%	$0	$0	0%	$0	0%	$0	0%	$0
Residential New Construction & Major Renovation - Majo	$0	0%	$0	0%	$0	0%	$0	$0	0%	$0	0%	$0	0%	$0
Residential New Construction Multi Family (4-8 story) sta	$0	0%	$0	0%	$0	0%	$0	$0	0%	$0	0%	$0	0%	$0
Residential New Construction Lighting Design statewide	$0	0%	$0	0%	$0	0%	$0	$0	0%	$0	0%	$0	0%	$0
Residential New Construction V3 Energy Star Homes sta	$0	0%	$0	0%	$0	0%	$0	$0	0%	$0	0%	$0	0%	$0
Heat Pump Water Heater Pilot	$0	0%	$0	0%	$0	0%	$0	$0	0%	$0	0%	$0	0%	$0
Low Income (total)	**$2,071**	**56%**	**$1,649**	**100%**	**$0**	**0%**	**$3,720**	**$3,176**	**8%**	**$37,577**	**99%**	**$552**	**1%**	**$41,304**
Low-Income Residential New Construction	$0	0%	$0	0%	$0	0%	$0	$356	100%	$0	0%	$0	0%	$356
Low-Income Retrofit	$2,071	56%	$1,649	100%	$0	0%	$3,720	$2,820	7%	$37,577	99%	$552	1%	$40,948
Commercial & Industrial (total)	**$8,501**	**71%**	**$3,479**	**100%**	**$0**	**0%**	**$11,980**	**$14,709**	**11%**	**$3,479**	**3%**	**$114,662**	**97%**	**$132,850**
C&I New Construction and Major Renovation	$3,620	85%	$633	100%	$0	0%	$4,252	$4,466	22%	$633	4%	$15,601	96%	$20,700
C&I Large Retrofit	$4,766	64%	$2,630	100%	$0	0%	$7,396	$5,565	29%	$2,630	19%	$11,105	81%	$19,300
C&I Small Retrofit	$115	35%	$216	100%	$0	0%	$332	$4,677	5%	$216	0%	$87,956	100%	$92,850
Community Based Pilot	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
TOTAL	**$82,909**	**22%**	**$191,516**	**65%**	**$105,000**	**35%**	**$379,424**	**$103,287**	**8%**	**$543,188**	**44%**	**$689,664**	**56%**	**$1,336,139**

V.D. Outsourced/Competitive Procured Services
1. Summary Table

Program	Sales, Technical Assistance & Training													
	2012 (3)							2010-2012						
	In-House Activities		Outsourced Activities				TOTAL	In-House Activities		Outsourced Activities				TOTAL
			Competitively Procured		Non-Competitively Procured					Competitively Procured		Non-Competitively Procured		
	$	%	$	% of Outsource	$	% of Outsource	$	$	%	$	% of Outsource	$	% of Outsource	$
Residential (total)	**$300,625**	**37%**	**$506,443**	**100%**	**$0**	**0%**	**$807,067**	**$305,168**	**8%**	**$3,114,289**	**91%**	**$293,934**	**9%**	**$3,713,391**
Residential New Construction and Major Renovation	$7,510	8%	$82,185	100%	$0	0%	$89,695	$7,510	3%	$249,290	100%	$0	0%	$256,801
Residential Cooling & Heating Equipment	$19,062	22%	$67,136	100%	$0	0%	$86,198	$19,062	7%	$257,428	99%	$1,922	1%	$278,412
Multi-Family Retrofit	$0	0%	$0	100%	$0	0%	$0	$0	0%	$168,916	100%	$0	0%	$168,916
MassSAVE	$218,710	69%	$96,066	100%	$0	0%	$314,776	$223,254	11%	$1,714,374	91%	$179,812	9%	$2,117,439
Behavior/Feedback Program	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
ENERGY STAR Lighting	$45,604	32%	$95,525	100%	$0	0%	$141,129	$45,604	9%	$439,922	100%	$0	0%	$485,526
ENERGY STAR Appliances	$9,738	19%	$40,531	100%	$0	0%	$50,269	$9,738	8%	$109,424	100%	$0	0%	$119,163
Residential Education Program	$0	0%	$0	0%	$0	0%	$0	$0	0%	$0	0%	$0	0%	$0
Workforce Development	$0	0%	$15,000	100%	$0	0%	$15,000	$0	0%	$15,000	33%	$30,000	67%	$45,000
Heat Loan Program	$0	0%	$110,000	100%	$0	0%	$110,000	$0	0%	$110,000	59%	$75,000	41%	$185,000
R&D and Demonstration	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Deep Energy Retrofit	$0	0%	$0	0%	$0	0%	$0	$0	0%	$0	0%	$0	0%	$0
Residential New Construction & Major Renovation - Majo	$0	0%	$0	0%	$0	0%	$0	$0	0%	$22,734	100%	$0	0%	$22,734
Residential New Construction Multi Family (4-8 story) sta	$0	0%	$0	0%	$0	0%	$0	$0	0%	$0	0%	$0	0%	$0
Residential New Construction Lighting Design statewide	$0	0%	$0	0%	$0	0%	$0	$0	0%	$20,000	100%	$0	0%	$20,000
Residential New Construction V3 Energy Star Homes sta	$0	0%	$0	0%	$0	0%	$0	$0	0%	$0	0%	$0	0%	$0
Heat Pump Water Heater Pilot	$0	0%	$0	0%	$0	0%	$0	$0	0%	$7,200	50%	$7,200	50%	$14,400
Low Income (total)	**$100,283**	**21%**	**$384,004**	**100%**	**$0**	**0%**	**$484,287**	**$150,221**	**9%**	**$598,531**	**41%**	**$860,163**	**59%**	**$1,608,915**
Low-Income Residential New Construction	$0	0%	$0	0%	$0	0%	$0	$0	0%	$29,253	100%	$0	0%	$29,253
Low-Income Retrofit	$100,283	21%	$384,004	100%	$0	0%	$484,287	$150,221	10%	$569,279	40%	$860,163	60%	$1,579,662
Commercial & Industrial (total)	**$263,653**	**50%**	**$251,499**	**96%**	**$10,345**	**4%**	**$525,496**	**$530,745**	**20%**	**$1,746,855**	**82%**	**$394,675**	**18%**	**$2,672,275**
C&I New Construction and Major Renovation	$168,678	63%	$98,325	100%	$0	0%	$267,003	$317,803	58%	$98,325	43%	$132,419	57%	$548,547
C&I Large Retrofit	$90,955	38%	$150,210	100%	$0	0%	$241,165	$208,922	47%	$150,210	64%	$85,761	36%	$444,893
C&I Small Retrofit	$4,020	23%	$2,964	22%	$10,345	78%	$17,328	$4,020	0%	$1,498,320	89%	$176,495	11%	$1,678,835
Community Based Pilot	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
TOTAL	**$664,560**	**37%**	**$1,141,946**	**99%**	**$10,345**	**1%**	**$1,816,850**	**$986,134**	**12%**	**$5,459,675**	**78%**	**$1,548,772**	**22%**	**$7,994,581**

Program	Evaluation and Market Research													
	2012 (3)							2010-2012						
	In-House Activities		Outsourced Activities				TOTAL	In-House Activities		Outsourced Activities				TOTAL
			Competitively Procured		Non-Competitively Procured					Competitively Procured		Non-Competitively Procured		
	$	%	$	% of Outsource	$	% of Outsource	$	$	%	$	% of Outsource	$	% of Outsource	$
Residential (total)	**$149,795**	**35%**	**$282,526**	**100%**	**$0**	**0%**	**$432,321**	**$305,001**	**19%**	**$1,231,616**	**96%**	**$52,174**	**4%**	**$1,588,791**
Residential New Construction and Major Renovation	$527	6%	$8,445	100%	$0	0%	$8,972	$7,318	28%	$17,903	97%	$498	3%	$25,718
Residential Cooling & Heating Equipment	$6,078	33%	$12,159	100%	$0	0%	$18,237	$77,497	53%	$66,725	96%	$2,872	4%	$147,094
Multi-Family Retrofit	$0	0%	$0	100%	$0	0%	$0	$22,692	16%	$114,919	95%	$6,048	5%	$143,659
MassSAVE	$140,693	38%	$225,469	100%	$0	0%	$366,162	$168,332	17%	$796,094	96%	$30,033	4%	$994,459
Behavior/Feedback Program	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
ENERGY STAR Lighting	$2,123	7%	$30,010	100%	$0	0%	$32,133	$22,308	14%	$134,625	96%	$5,506	4%	$162,439
ENERGY STAR Appliances	$374	5%	$6,442	100%	$0	0%	$6,816	$6,855	29%	$16,442	97%	$526	3%	$23,823
Residential Education Program	$0	0%	$0	0%	$0	0%	$0	$0	0%	$0	0%	$0	0%	$0
Workforce Development	$0	0%	$0	0%	$0	0%	$0	$0	0%	$0	0%	$0	0%	$0
Heat Loan Program	$0	0%	$0	0%	$0	0%	$0	$0	0%	$0	0%	$0	0%	$0
R&D and Demonstration	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Deep Energy Retrofit	$0	0%	$0	0%	$0	0%	$0	$0	0%	$29,766	95%	$1,567	5%	$31,333
Residential New Construction & Major Renovation - Majo	$0	0%	$0	0%	$0	0%	$0	$0	0%	$50,920	95%	$2,680	5%	$53,600
Residential New Construction Multi Family (4-8 story) sta	$0	0%	$0	0%	$0	0%	$0	$0	0%	$0	0%	$0	0%	$0
Residential New Construction Lighting Design statewide	$0	0%	$0	0%	$0	0%	$0	$0	0%	$4,222	95%	$222	5%	$4,444
Residential New Construction V3 Energy Star Homes sta	$0	0%	$0	0%	$0	0%	$0	$0	0%	$0	0%	$0	0%	$0
Heat Pump Water Heater Pilot	$0	0%	$0	0%	$0	0%	$0	$0	0%	$0	0%	$2,222	100%	$2,222
Low Income (total)	**$52,758**	**42%**	**$74,026**	**100%**	**$0**	**0%**	**$126,784**	**$74,618**	**23%**	**$242,536**	**96%**	**$8,869**	**4%**	**$326,023**
Low-Income Residential New Construction	$0	0%	$0	0%	$0	0%	$0	$817	88%	$104	95%	$5	5%	$927
Low-Income Retrofit	$52,758	42%	$74,026	100%	$0	0%	$126,784	$73,801	23%	$242,432	96%	$8,863	4%	$325,096
Commercial & Industrial (total)	**$30,222**	**19%**	**$131,205**	**100%**	**$0**	**0%**	**$161,427**	**$60,959**	**11%**	**$457,481**	**96%**	**$17,172**	**4%**	**$535,612**
C&I New Construction and Major Renovation	$13,516	23%	$46,093	100%	$0	0%	$59,610	$20,234	13%	$128,632	97%	$4,344	3%	$153,210
C&I Large Retrofit	$16,068	16%	$83,497	100%	$0	0%	$99,565	$18,873	12%	$134,603	98%	$2,690	2%	$156,166
C&I Small Retrofit	$638	28%	$1,615	100%	$0	0%	$2,252	$21,852	10%	$194,245	95%	$10,138	5%	$226,235
Community Based Pilot	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
TOTAL	**$232,775**	**32%**	**$487,757**	**100%**	**$0**	**0%**	**$720,532**	**$440,579**	**18%**	**$1,931,632**	**96%**	**$78,216**	**4%**	**$2,450,426**

V.D. Outsourced/Competitive Procured Services

1. Summary Table

	TOTAL													
Program	2012 (3)							2010-2012						
	In-House Activities		Outsourced Activities				TOTAL	In-House Activities		Outsourced Activities				TOTAL
			Competitively Procured		Non-Competitively Procured					Competitively Procured		Non-Competitively Procured		
	$	%	$	% of Outsource	$	% of Outsource	$	$	%	$	% of Outsource	$	% of Outsource	$
Residential (total)	**$646,821**	**32%**	**$1,153,495**	**83%**	**$237,016**	**17%**	**$2,037,331**	**$1,123,697**	**15%**	**$5,050,481**	**78%**	**$1,425,475**	**22%**	**$7,599,652**
Residential New Construction and Major Renovation	$15,223	12%	$109,811	96%	$4,522	4%	$129,555	$28,923	9%	$290,080	95%	$16,041	5%	$335,043
Residential Cooling & Heating Equipment	$38,296	25%	$105,170	92%	$9,424	8%	$152,891	$133,596	25%	$371,041	93%	$26,810	7%	$531,447
Multi-Family Retrofit	$0	0%	$0	0%	$0	0%	$0	$30,335	9%	$289,584	92%	$23,992	8%	$343,911
MassSAVE	$501,441	45%	$512,523	83%	$104,688	17%	$1,118,652	$723,236	17%	$2,701,455	79%	$721,244	21%	$4,145,935
Behavior/Feedback Program	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
ENERGY STAR Lighting	$71,436	24%	$211,325	96%	$9,522	4%	$292,282	$164,926	15%	$918,696	97%	$26,808	3%	$1,110,430
ENERGY STAR Appliances	$20,425	18%	$89,666	96%	$3,860	4%	$113,951	$42,680	16%	$219,782	97%	$5,688	3%	$268,151
Residential Education Program	$0	0%	$0	0%	$105,000	100%	$105,000	$0	0%	$0	0%	$486,000	100%	$486,000
Workforce Development	$0	0%	$15,000	100%	$0	0%	$15,000	$0	0%	$15,000	33%	$30,000	67%	$45,000
Heat Loan Program	$0	0%	$110,000	100%	$0	0%	$110,000	$0	0%	$110,000	59%	$75,000	41%	$185,000
R&D and Demonstration	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Deep Energy Retrofit	$0	0%	$0	0%	$0	0%	$0	$0	0%	$29,766	95%	$1,567	5%	$31,333
Residential New Construction & Major Renovation - Majo	$0	0%	$0	0%	$0	0%	$0	$0	0%	$73,654	96%	$2,680	4%	$76,334
Residential New Construction Multi Family (4-8 story) sta	$0	0%	$0	0%	$0	0%	$0	$0	0%	$0	0%	$0	0%	$0
Residential New Construction Lighting Design statewide	$0	0%	$0	0%	$0	0%	$0	$0	0%	$24,222	99%	$222	1%	$24,444
Residential New Construction V3 Energy Star Homes sta	$0	0%	$0	0%	$0	0%	$0	$0	0%	$0	0%	$0	0%	$0
Heat Pump Water Heater Pilot	$0	0%	$0	0%	$0	0%	$0	$0	0%	$7,200	43%	$9,422	57%	$16,622
Low Income (total)	**$185,040**	**26%**	**$504,365**	**93%**	**$35,511**	**7%**	**$724,917**	**$309,580**	**14%**	**$923,330**	**48%**	**$1,009,698**	**52%**	**$2,242,608**
Low-Income Residential New Construction	$0	0%	$0	0%	$0	0%	$0	$2,449	8%	$29,357	99%	$212	1%	$32,018
Low-Income Retrofit	$185,040	26%	$504,365	93%	$35,511	7%	$724,917	$307,131	14%	$893,973	47%	$1,009,486	53%	$2,210,589
Commercial & Industrial (total)	**$414,142**	**39%**	**$503,950**	**79%**	**$135,476**	**21%**	**$1,053,568**	**$1,031,456**	**25%**	**$2,325,582**	**73%**	**$840,857**	**27%**	**$4,197,895**
C&I New Construction and Major Renovation	$242,539	53%	$161,267	75%	$52,946	25%	$456,752	$450,285	49%	$243,806	52%	$222,732	48%	$916,822
C&I Large Retrofit	$164,015	29%	$333,907	83%	$69,166	17%	$567,088	$317,991	36%	$385,014	67%	$185,843	33%	$888,848
C&I Small Retrofit	$7,588	26%	$8,776	40%	$13,364	60%	$29,728	$263,180	11%	$1,696,763	80%	$432,282	20%	$2,392,224
Community Based Pilot	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
TOTAL	**$1,246,004**	**33%**	**$2,161,810**	**84%**	**$408,002**	**16%**	**$3,815,816**	**$2,464,732**	**18%**	**$8,299,392**	**72%**	**$3,276,030**	**28%**	**$14,040,155**

V.D. Outsourced/Competitively Procured Services
3. Comparison Table - Three Year Plan vs. Previous Years

Outsourced and Competitively Procured Services

Sector	Program Planning and Administration							Marketing and Advertising						
	In-House Activities		Outsourced Activities				TOTAL	In-House Activities		Outsourced Activities				TOTAL
			Competitively Procured		Non-Competitively Procured					Competitively Procured		Non-Competitively Procured		
	$	%	$	%	$	%		$	%	$	%	$	%	
Residential	**$679,236**	**39%**	**$459,700**	**26%**	**$616,213**	**35%**	**$1,755,148**	**$294,864**	**22%**	**$615,197**	**46%**	**$441,674**	**33%**	**$1,351,734**
2007 (1)	$91,960	100%	$0	0%	$0	0%	$91,960	$23,950	100%	$0	0%	$0	0%	$23,950
2008 (2)	$135,910	100%	$0	0%	$0	0%	$135,910	$30,979	100%	$0	0%	$0	0%	$30,979
2009 (3)	$54,918	16%	$103,904	31%	$175,460	52%	$334,283	$65,331	57%	$23,001	20%	$27,294	24%	$115,625
2010 (4)	$109,756	28%	$163,393	42%	$113,602	29%	$386,752	$100,472	25%	$244,120	60%	$60,812	15%	$405,404
2011 (5)	$162,626	44%	$14,264	4%	$195,135	52%	$372,025	$1,796	0.0044	$161,688	39%	$248,568	60%	$412,052
2012 (6)	$124,064	29%	$178,139	41%	$132,016	30%	$434,219	$72,337	20%	$186,387	51%	$105,000	29%	$363,724
Low Income	**$184,782**	**40%**	**$111,091**	**24%**	**$168,651**	**36%**	**$464,523**	**$59,729**	**49%**	**$49,907**	**41%**	**$12,448**	**10%**	**$122,083**
2007 (1)	$35,962	100%	$0	0%	$0	0%	$35,962	$7,745	100%	$0	0%	$0	0%	$7,745
2008 (2)	$51,346	100%	$0	0%	$0	0%	$51,346	$9,020	100%	$0	0%	$0	0%	$9,020
2009 (3)	$13,588	16%	$25,708	31%	$43,413	52%	$82,709	$16,164	48%	$5,691	17%	$12,025	35%	$33,880
2010 (4)	$27,355	27%	$40,697	40%	$32,753	32%	$100,804	$23,959	51%	$22,804	49%	$0	0%	$46,763
2011 (5)	$26,601	32%	$0	0%	$56,975	68%	$83,576	$770	4%	$19,763	94%	$423	2%	$20,956
2012 (6)	$29,929	27%	$44,686	41%	$35,511	32%	$110,125	$2,071	56%	$1,649	44%	$0	0%	$3,720
Commercial & Industrial	**$629,190**	**44%**	**$315,509**	**22%**	**$495,589**	**34%**	**$1,440,287**	**$220,793**	**54%**	**$98,628**	**24%**	**$90,771**	**22%**	**$410,192**
2007 (1)	$103,830	100%	$0	0%	$0	0%	$103,830	$30,306	100%	$0	0%	$0	0%	$30,306
2008 (2)	$112,608	100%	$0	0%	$0	0%	$112,608	$28,608	100%	$0	0%	$0	0%	$28,608
2009 (3)	$54,670	16%	$103,434	31%	$174,665	52%	$332,768	$65,035	57%	$22,897	20%	$27,170	24%	$115,102
2010 (4)	$83,940	31%	$94,308	35%	$89,770	33%	$268,018	$84,645	54%	$72,252	46%	$0	0%	$156,897
2011 (5)	$162,377	60%	$0	0%	$106,022	40%	$268,399	$3,698	5%	$0	0%	$63,601	95%	$67,299
2012 (6)	$111,766	32%	$117,767	33%	$125,131	35%	$354,664	$8,501	71%	$3,479	29%	$0	0%	$11,980
TOTAL	**$1,493,207**	**41%**	**$886,299**	**24%**	**$1,280,453**	**35%**	**$3,659,959**	**$575,386**	**31%**	**$763,731**	**41%**	**$544,892**	**29%**	**$1,884,009**
2007 (1)	**$231,753**	**100%**	**$0**	**0%**	**$0**	**0%**	**$231,753**	**$62,000**	**100%**	**$0**	**0%**	**$0**	**0%**	**$62,000**
2008 (2)	**$299,864**	**100%**	**$0**	**0%**	**$0**	**0%**	**$299,864**	**$68,607**	**100%**	**$0**	**0%**	**$0**	**0%**	**$68,607**
2009 (3)	**$123,176**	**16%**	**$233,046**	**31%**	**$393,538**	**52%**	**$749,760**	**$146,530**	**55%**	**$51,588**	**19%**	**$66,489**	**25%**	**$264,607**
2010 (4)	**$221,051**	**29%**	**$298,398**	**39%**	**$236,125**	**31%**	**$755,574**	**$209,076**	**34%**	**$339,176**	**56%**	**$60,812**	**10%**	**$609,064**
2011 (5)	**$351,605**	**49%**	**$14,264**	**2%**	**$358,132**	**49%**	**$724,000**	**$6,264**	**1%**	**$181,452**	**36%**	**$312,592**	**62%**	**$500,307**
2012 (6)	**$265,759**	**30%**	**$340,592**	**38%**	**$292,658**	**33%**	**$899,009**	**$82,909**	**22%**	**$191,516**	**50%**	**$105,000**	**28%**	**$379,424**

Notes:
(1) Actual values from the Cape Light Compact's 2007 Annual Report D.P.U. 09-68, in 2007$.
(2) Actual values from the Cape Light Compact's 2008 Annual Report D.P.U. 09-69, in 2008$.
(3) Actual values from the Cape Light Compact's 2009 Annual Report D.P.U. 10-97, in 2009$.
(4) Actual values from the Cape Light Compact's 2010 Annual Report D.P.U. 11-68, in 2010$.
(5) As this filing assumes approval of the 2011 Mid-Term Modifications, this data is as filed in the Cape Light Compact's 2011 Mid-Term Modifications Filing, D.P.U. 10-147, in 2011$.
(6) Proposed 2012 changes presented in this filing, representing additional budget requirements for 2012, taking into account 2011 estimated carryover, in 2012$.

V.D. Outsourced/Competitively Procured Services
3. Comparison Table - Three Year Plan vs. Previous Years

Sector	Outsourced and Competitively Procured Services													
	Sales, Technical Assistance & Training							Evaluation and Market Research						
	In-House Activities		Outsourced Activities				TOTAL	n-House Activities		Outsourced Activities				TOTAL
			Competitively Procured		Non-Competitively Procured					Competitively Procured		Non-Competitively Procured		
	$	%	$	%	$	%		$	%	$	%	$	%	
Residential	**$865,617**	**19%**	**$3,461,721**	**77%**	**$165,770**	**4%**	**$4,493,108**	**$273,704**	**20%**	**$1,071,512**	**78%**	**$28,256**	**2%**	**$1,373,471**
2007 (1)	$72,345	100%	$0	0%	$0	0%	$72,345	$11,042	100%	$0	0%	$0	0%	$11,042
2008 (2)	$78,652	100%	$0	0%	$0	0%	$78,652	$5,379	100%	$0	0%	$0	0%	$5,379
2009 (3)	$189,910	15%	$1,112,743	85%	$260	0%	$1,302,913	$0	0%	$77,890	100%	$0	0%	$77,890
2010 (4)	$224,085	32%	$485,434	68%	$1,735	0%	$711,255	$33,509	15%	$195,341	85%	$0	0%	$228,850
2011 (5)	$0	0%	$1,357,101	89%	$163,775	11%	$1,520,876	$73,978	12%	$515,755	83%	$28,256	5%	$617,989
2012 (6)	$300,625	37%	$506,443	63%	$0	0%	$807,067	$149,795	35%	$282,526	65%	$0	0%	$432,321
Low Income	**$269,507**	**16%**	**$867,538**	**53%**	**$498,112**	**30%**	**$1,635,156**	**$75,485**	**27%**	**$200,956**	**71%**	**$5,113**	**2%**	**$281,555**
2007 (1)	$15,743	100%	$0	0%	$0	0%	$15,743	$0		$0		$0		$0
2008 (2)	$16,130	100%	$0	0%	$0	0%	$16,130	$1,566	100%	$0	0%	$0	0%	$1,566
2009 (3)	$46,988	21%	$166,743	75%	$8,786	4%	$222,517	$0	0%	$19,272	100%	$0	0%	$19,272
2010 (4)	$52,575	21%	$196,631	79%	$0	0%	$249,207	$8,380	44%	$10,505	56%	$0	0%	$18,885
2011 (5)	$37,789	6%	$120,159	19%	$489,326	76%	$647,273	$12,781	11%	$97,153	84%	$5,113	4%	$115,048
2012 (6)	$100,283	21%	$384,004	79%	$0	0%	$484,287	$52,758	42%	$74,026	58%	$0	0%	$126,784
Commercial & Industrial	**$843,045**	**30%**	**$1,613,770**	**56%**	**$399,438**	**14%**	**$2,856,253**	**$79,473**	**14%**	**$495,181**	**84%**	**$11,661**	**2%**	**$586,315**
2007 (1)	$29,761	100%	$0	0%	$0	0%	$29,761	$2,885	100%	$0	0%	$0	0%	$2,885
2008 (2)	$34,012	100%	$0	0%	$0	0%	$34,012	$4,968	100%	$0	0%	$0	0%	$4,968
2009 (3)	$189,050	32%	$394,272	68%	$0	0%	$583,322	$0	0%	$77,537	100%	$0	0%	$77,537
2010 (4)	$179,120	36%	$137,540	28%	$183,172	37%	$499,832	$20,184	24%	$64,884	76%	$0	0%	$85,068
2011 (5)	$147,449	12%	$830,460	70%	$205,922	17%	$1,183,830	$21,214	8%	$221,556	87%	$11,661	5%	$254,431
2012 (6)	$263,653	50%	$251,499	48%	$10,345	2%	$525,496	$30,222	19%	$131,205	81%	$0	0%	$161,427
TOTAL	**########**	**22%**	**$5,943,029**	**66%**	**$1,063,320**	**12%**	**$8,984,517**	**$428,662**	**19%**	**$1,767,649**	**79%**	**$45,030**	**2%**	**$2,241,341**
2007 (1)	**$117,849**	**100%**	**$0**	**0%**	**$0**	**0%**	**$117,849**	**$13,927**	**100%**	**$0**	**0%**	**$0**	**0%**	**$13,927**
2008 (2)	**$128,794**	**100%**	**$0**	**0%**	**$0**	**0%**	**$128,794**	**$11,914**	**100%**	**$0**	**0%**	**$0**	**0%**	**$11,914**
2009 (3)	**$425,948**	**20%**	**$1,673,758**	**79%**	**$9,046**	**0%**	**$2,108,752**	**$0**	**0%**	**$174,698**	**100%**	**$0**	**0%**	**$174,698**
2010 (4)	**$455,780**	**31%**	**$819,606**	**56%**	**$184,907**	**13%**	**$1,460,293**	**$62,073**	**19%**	**$270,730**	**81%**	**$0**	**0%**	**$332,803**
2011 (5)	**$185,237**	**6%**	**$2,307,720**	**69%**	**$859,022**	**26%**	**$3,351,979**	**$107,973**	**11%**	**$834,464**	**85%**	**$45,030**	**5%**	**$987,467**
2012 (6)	**$664,560**	**37%**	**$1,141,946**	**63%**	**$10,345**	**1%**	**$1,816,850**	**$232,775**	**32%**	**$487,757**	**68%**	**$0**	**0%**	**$720,532**

V.D. Outsourced/Competitively Procured Services
3. Comparison Table - Three Year Plan vs. Previous Years

	Outsourced and Competitively Procured Services						
	TOTAL						
			Outsourced Activities				
Sector	In-House Activities		Competitively Procured		Non-Competitively Procured		TOTAL
	$	%	$	%	$	%	
Residential	**$2,113,420**	**24%**	**$5,608,130**	**62%**	**$1,251,913**	**14%**	**$8,973,462**
2007 (1)	$199,296	100%	$0	0%	$0	0%	$199,296
2008 (2)	$250,920	100%	$0	0%	$0	0%	$250,920
2009 (3)	$310,159	17%	$1,317,538	72%	$203,014	11%	$1,830,711
2010 (4)	$467,822	27%	$1,088,289	63%	$176,150	10%	$1,732,261
2011 (5)	$238,401	8%	$2,048,808	70%	$635,734	22%	$2,922,942
2012 (6)	$646,821	32%	$1,153,495	57%	$237,016	12%	$2,037,331
Low Income	**$589,503**	**24%**	**$1,229,492**	**49%**	**$684,324**	**27%**	**$2,503,318**
2007 (1)	$59,449	100%	$0	0%	$0	0%	$59,449
2008 (2)	$78,062	100%	$0	0%	$0	0%	$78,062
2009 (3)	$76,740	21%	$217,414	61%	$64,223	18%	$358,377
2010 (4)	$112,270	27%	$270,637	65%	$32,753	8%	$415,659
2011 (5)	$77,941	9%	$237,075	27%	$551,837	64%	$866,853
2012 (6)	$185,040	26%	$504,365	70%	$35,511	5%	$724,917
Commercial & Industrial	**$1,772,501**	**33%**	**$2,523,088**	**48%**	**$997,458**	**19%**	**$5,293,047**
2007 (1)	$166,783	100%	$0	0%	$0	0%	$166,783
2008 (2)	$180,196	100%	$0	0%	$0	0%	$180,196
2009 (3)	$308,754	28%	$598,139	54%	$201,835	18%	$1,108,728
2010 (4)	$367,888	36%	$368,984	37%	$272,942	27%	$1,009,814
2011 (5)	$334,738	19%	$1,052,016	59%	$387,205	22%	$1,773,959
2012 (6)	$414,142	39%	$503,950	48%	$135,476	13%	$1,053,568
TOTAL	**$4,475,423**	**27%**	**$9,360,709**	**56%**	**$2,933,695**	**17%**	**$16,769,827**
2007 (1)	**$425,528**	**100%**	**$0**	**0%**	**$0**	**0%**	**$425,528**
2008 (2)	**$509,179**	**100%**	**$0**	**0%**	**$0**	**0%**	**$509,179**
2009 (3)	**$695,654**	**21%**	**$2,133,090**	**65%**	**$469,072**	**14%**	**$3,297,817**
2010 (4)	**$947,980**	**30%**	**$1,727,910**	**55%**	**$481,844**	**15%**	**$3,157,734**
2011 (5)	**$651,079**	**12%**	**$3,337,899**	**60%**	**$1,574,776**	**28%**	**$5,563,754**
2012 (6)	**$1,246,004**	**33%**	**$2,161,810**	**57%**	**$408,002**	**11%**	**$3,815,816**

VII. Appendix
B.2. Master EE Activities

Electric PA's EE Activities

Year	Sector	Benefits ($)						TRC Costs ($)			TRC B/C Ratio
		Capacity	Energy	DRIPE (Capacity & Energy)	Non-Elec. Resource	Non-Resource	Total Benefits	PA	Customer	TOTAL	
	Residential	$5,355,303	$10,446,304	$2,981,788	$18,558,913	$471,213	$34,831,733	$9,449,462	$1,302,322	$10,751,784	3.24
	Low Income	$256,108	$1,697,233	$413,648	$1,230,474	$2,737,325	$5,921,141	$2,088,750	$0	$2,088,750	2.83
	C&I	$6,581,779	$20,808,349	$5,406,961	-$609,000	$1,074,859	$27,855,987	$7,098,577	$1,276,127	$8,374,704	3.33
2010	**Total**	**$12,193,189**	**$32,951,887**	**$8,802,397**	**$19,180,387**	**$4,283,397**	**$68,608,861**	**$18,636,789**	**$2,578,449**	**$21,215,238**	**3.23**
	Residential	$9,068,491	$19,188,360	$5,432,640	$28,306,653	$1,037,256	$57,600,761	$12,386,208	$2,415,912	$14,802,121	3.89
	Low Income	$388,972	$2,479,968	$568,462	$1,323,333	$5,905,739	$10,098,012	$2,854,275	$0	$2,854,275	3.54
	C&I	$8,066,142	$25,124,841	$6,078,343	-$891,734	$1,465,103	$33,764,352	$9,659,199	$1,519,932	$11,179,131	3.02
2011	**Total**	**$17,523,605**	**$46,793,170**	**$12,079,445**	**$28,738,252**	**$8,408,098**	**$101,463,125**	**$24,899,683**	**$3,935,844**	**$28,835,527**	**3.52**
	Residential	$5,383,383	$13,321,288	$4,205,617	$39,781,064	$22,758,875	$81,244,610	$11,163,540	$3,068,919	$14,232,459	5.71
	Low Income	$233,340	$1,238,629	$325,696	$2,813,708	$5,260,759	$9,546,436	$3,145,453	$0	$3,145,453	3.03
	C&I	$7,543,589	$10,835,487	$4,583,906	-$107,389	$0	$18,271,687	$4,004,926	$799,574	$4,804,500	3.80
2012	**Total**	**$13,160,312**	**$25,395,404**	**$9,115,219**	**$42,487,382**	**$28,019,635**	**$109,062,733**	**$18,313,920**	**$3,868,492**	**$22,182,412**	**4.92**
	Residential	$19,807,177	$42,955,953	$12,620,045	$86,646,629	$24,267,345	$173,677,104	$32,999,211	$6,787,152	$39,786,363	4.37
	Low Income	$878,420	$5,415,831	$1,307,806	$5,367,515	$13,903,823	$25,565,589	$8,088,478	$0	$8,088,478	3.16
	C&I	$22,191,510	$56,768,676	$16,069,210	-$1,608,123	$2,539,962	$79,892,026	$20,762,703	$3,595,633	$24,358,335	3.28
GRAND TOTAL		**$42,877,107**	**$105,140,460**	**$29,997,061**	**$90,406,021**	**$40,711,130**	**$279,134,718**	**$61,850,391**	**$10,382,785**	**$72,233,176**	**3.86**

VII. Appendix
B.2. Master EE Activities

Year	Net Benefits	Electric PA's EE Activities: Savings: Capacity (kW): Annual (Summer)	Capacity (kW): Lifetime	Energy (mWh): Annual	Energy (mWh): Lifetime	Gas (Therms): Annual	Gas (Therms): Lifetime	Other Fuels: Annual	Other Fuels: Lifetime	Avg Measure Life (yrs.)	TR Summer Demand Cost ($/Lifetime	TR Energy Cost ($/Lifetime-mWh saved)	GHG Reductions: Nox	Sox	CO2	Participants
	$24,079,949	2,489	39,712	10,179	96,058	18,380	173,445	3,451	32,563	9.4	$270.75	$111.93	3.4965	7.281	30354	41,834
	$3,832,391	164	1,856	1,416	16,195	87	995	305	3,490	11.4	$1,125.47	$128.97	0.5895	1.228	5117.7	1,317
	$19,481,283	3,960	50,809	14,730	190,815	(4,801)	-62,197	92	1,188	13.0	$164.83	$43.89	6.9457	14.46	60298	641
2010	**$47,393,623**	6,613	92,376	26,325	303,068	**9,749**	112,243	**3,235**	37,241	**11.5**	**$229.66**	**$70.00**	**11.032**	**22.97**	**95769**	**43,792**
	$42,798,641	4,182	62,921	19,364	173,570	29,290	262,533	5,214	46,734	9.0	$235.25	$85.28	6.3179	13.16	54848	91,028
	$7,243,737	242	2,640	2,249	23,249	(52)	-541	294	3,042	10.3	$1,081.13	$122.77	0.8462	1.762	7346.6	1,549
	$22,585,221	4,538	59,473	17,612	230,622	(7,688)	-100,672	168	2,198	13.1	$187.97	$48.47	8.3946	17.48	72876	986
2011	**$72,627,598**	8,962	125,034	39,225	427,440	**14,804**	161,320	**4,770**	51,975	**10.9**	**$230.62**	**$67.46**	**15.559**	**32.4**	**135071**	**93,563**
	$67,012,151	2,267	24,167	13,315	133,056	32,739	327,167	6,016	60,118	10.0	$588.92	$106.97	4.8433	10.09	42046	54,491
	$6,400,983	119	1,072	1,413	12,918	3,263	29,836	509	4,651	9.1	$2,934.06	$243.48	0.4702	0.979	4082.2	1,500
	$13,467,187	2,825	33,678	8,846	104,692	(1,482)	-17,541	8	94	11.8	$142.66	$45.89	3.8108	7.936	33083	215
2012	**$86,880,321**	5,211	58,917	23,573	250,667	**31,924**	339,461	**6,100**	64,863	**10.6**	**$376.50**	**$88.49**	**9.1243**	**19**	**79211**	**56,206**
	$133,890,741	8,939	126,800	42,858	402,684	80,409	763,144	14,681	139,415	9.4	$313.77	$98.80	14.658	30.52	127248	187,353
	$17,477,111	525	5,568	5,078	52,362	3,298	30,290	1,108	11,183	10.3	$1,452.66	$154.47	1.906	3.969	16546	4,366
	$55,533,691	11,323	143,960	41,187	526,129	(13,971)	-180,410	268	3,480	12.8	$169.20	$46.30	19.151	39.88	166257	1,842
GRAND TOTAL	**$206,901,542**	20,787	276,328	89,123	981,175	**69,736**	613,024	**16,056**	154,079	**11.0**	**$261.40**	**$73.62**	**35.715**	**74.37**	**310051**	**193,561**

EXHIBIT H

Technical Reference Manual

Massachusetts Technical Reference Manual

for Estimating Savings from Energy Efficiency Measures

2012 Program Year – Plan Version

October 2011

Table of Contents

Introduction

This *Massachusetts Technical Reference Manual for Estimating Savings from Energy Efficiency Measures* ("TRM") documents for regulatory agencies, customers, and other stakeholders how the energy efficiency Program Administrators ("PAs") consistently, reliably, and transparently calculate savings from the installation of efficient equipment, collectively called "measures." This reference manual provides methods, formulas and default assumptions for estimating energy, peak demand and other resource impacts from efficiency measures.

Within this TRM, efficiency measures are organized by the sector for which the measure is eligible and by the primary energy source associated with the measure. The two sectors are Residential and Commercial & Industrial ("C&I").[1] The primary energy sources addressed in this TRM are electricity and natural gas.

Each measure is presented in its own section as a "measure characterization." The measure characterizations provide mathematical equations for determining savings (algorithms), as well as default assumptions and sources, where applicable. In addition, any descriptions of calculation methods or baselines are provided as appropriate. The parameters for calculating savings are listed in the same order for each measure.

Algorithms are provided for estimating annual energy and peak demand impacts for primary and secondary energy sources if appropriate. In addition, algorithms or calculated results may be provided for other non-energy impacts (such as water savings or operation and maintenance cost savings). Data assumptions are based on Massachusetts PA data where available. Where Massachusetts-specific data is not available, assumptions may be based on , 1) manufacturer and industry data, 2) a combination of the best available data from jurisdictions in the same region, or 3) credible and realistic factors developed using engineering judgment.

The TRM will be reviewed and updated annually to reflect changes in technology, baselines and evaluation results.

[1] In this document, the Residential and Low Income programs are represented in a single "Residential" sector due to the degree of overlap in savings assumptions for similar measures in the standard income programs.

The TRM in the Context of Energy Efficiency Programs

Overview

Due to the ramp-up of energy efficiency spending and savings goals in Massachusetts it is necessary for the acceleration of collaborative efforts focused on:

- Improving processes,
- Reexamining the presentation of planning efforts and reporting results,
- Developing energy efficiency analysis tools,
- Improving source and process documentation, and
- Conducting broader and deeper research initiatives.

In addition, due to the number of initiatives underway, it is important to understand the connections between these efforts. Specifically, how does the effort to create and maintain the TRM influence other efforts, and conversely, how is the TRM impacted by other efforts?

The purpose of this section is to show how the TRM fits into the process of administering energy efficiency programs in Massachusetts. This section explains how the TRM is connected to the following:

- Planning,
- Annual reporting,
- Updates to PA tracking systems,
- Evolution of program and measure cost effectiveness analysis tools,
- Evaluation, Measurement and Verification ("EM&V"),
- Planning and Reporting Information System ("PARIS"), and
- Quality control.

Planning

The PAs are submitting this version of the TRM (the 2012 TRM) to the Department of Public Utilities ("DPU") along with their mid term modification proposals for 2012. This version of the 2012 TRM is called the 2012 Program Year – Plan Version TRM.

While PAs use many of the same assumptions and algorithms for planning and reporting purposes, the TRM – Plan Version is not meant to document the detailed development of the PAs' planning assumptions. The TRM – Plan Version provides regulators and stakeholders with a preview of the assumptions and algorithms that the PAs will use for reporting purposes.

Annual Reporting

Each Massachusetts PA submits an Annual Report to the DPU which summarizes the results of its energy efficiency program activities. The first Annual Reports that were filed with a TRM were the 2010 Annual Reports, submitted to the DPU in the summer of 2011. The version of the TRM that was filed at that time was called the Program Year 2010 – Report Version TRM. The PAs will file a version of the TRM called Program Year 2011 – Report Version TRM at the same time they file the 2011 Annual Reports.

Updates to Program Administrator Tracking Systems

Each Massachusetts PA maintains its own tracking system that contains the energy efficiency data that the PA uses to meet reporting requirements set forth by the DPU. The current design of the PAs' tracking systems influences the types of assumptions and algorithms that appear in this TRM. The current algorithms leverage inputs that the PAs collect.

To the extent that assumptions and algorithms documented in the 2012 TRM – Plan Version were not in use by PAs in 2011[2], PAs are committed to implementing as many of the common assumptions and algorithms contained in the TRM as are feasible in their tracking systems, or by some other means, by January 2012. If PAs cannot implement changes in time for 2012, PAs are committed to implementing these changes as soon as it is feasible. The January 2012 deadline enables the PAs to use the assumptions and algorithms documented in the 2012 TRM when calculating the savings for the 2012 Annual Reports.

Evolution of Program and Measure Cost Effectiveness Analysis Tools

The program and measure cost effectiveness analysis tools are Microsoft® Excel® workbooks used by PAs to ensure that the measures and programs that they implement meet the cost effectiveness requirements defined by the DPU in its order Investigation by the Department of Public Utilities on its own Motion into Updating its Energy Efficiency Guidelines Consistent with An Act Relative to Green Communities, D.P.U. 08-50-A (March 16, 2009).[3] The PAs also use the output from the cost effectiveness analysis tools to develop the input (data, tables, and graphs) for their Energy Efficiency Plans and Annual Reports. The PAs envision aligning the measure names and the categorization of measures in the TRM with the measure names and categorization of measures in the cost effectiveness analysis tools either directly, or through the use of a translation tool.

As stated previously, if the assumptions and algorithms documented in the 2012 TRM are not in use by PAs, the PAs are committed to implementing as many updates as are feasible in their tracking systems, or by some other means, by January 2012. Another means of implementing these updates is by updating the cost effectiveness analysis tool workbooks. For example, some PA tracking systems only calculate gross savings. In this case, any changes to assumptions or calculations that impact net savings need to be made to the cost effectiveness analysis tool workbooks, where the net savings calculations occur.

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[2] In some cases, one or more PAs discovered that updates to assumptions and algorithms could not be implemented in this timeframe, or all agreed that differences are justified. In the event that an assumption or algorithm could not be implemented in this timeframe, the TRM includes a description of the alternate assumption or algorithm that the PA used to calculate savings, along with the appropriate source documentation.

[3] Please see section III. Criteria for Establishing Program Cost-Effectiveness starting on Page 6 for details.

Evaluation, Measurement and Verification

EM&V ensures that "the programs are evaluated, measured, and verified in a way that provides confidence to the public at large that the savings are real and in a way that enables the PAs to report those savings to the Department of Public Utilities with full confidence".[4]

The 2012 Program Year – Report Version TRM will be submitted with the 2012 Annual Reports to communicate any updates to assumptions and algorithms due to key learning from EM&V results produced since the 2012 Energy Efficiency Plans and Plan Version TRM were filed.

A secondary goal of creating a TRM is to identify areas where savings calculations can be improved. The TRM will inform future EM&V planning as a means to make these improvements.

Planning and Reporting Information System

PARIS is a statewide database maintained by the Department of Energy Resources ("DOER") that emulates the PAs' cost effectiveness analysis tools. PAs submit excerpts of the cost effectiveness analysis tool workbooks to DOER which DOER inputs into the PARIS database. As a repository for quantitative data from plans, preliminary reports, and reports, PARIS generates information that includes funding sources, customer profiles, program participation, costs, savings, cost effectiveness and program impact factors from evaluation studies. DOER developed PARIS in 2003 as a collaborative effort with the DPU and the electric PAs. Beginning with the 2010 plans, PARIS holds data from gas PAs as well. As of 2011, PARIS will hold updates made to the PA tracking systems and cost effectiveness analysis tools to align with the assumptions and algorithms shown in the 2012 Plan Version TRM. PAs will submit excerpts of cost effectiveness analysis tool workbooks to DOER. DOER will input these excerpts into the PARIS database.

Quality Control

A secondary function of PARIS is to assist PAs with quality control - to ensure the calculations embodied in the cost effectiveness analysis tool workbooks are accurate. PARIS contains tools and queries which PAs use to ensure that the calculations of net savings are consistent and correct. PAs also conduct their own internal quality control on data.

Regulators and stakeholders can use the TRM to confirm that savings inputs and calculations are reasonable and reliable. However, the TRM cannot be used by regulators and stakeholders to replicate the PAs reported savings. The TRM does not provide regulators and stakeholders with data inputs at a level that is detailed enough to enable replication of the savings reported by PAs. These calculations occur within tracking systems, within separate Excel workbooks, and within cost effectiveness analysis tools. However, in the event that regulators and stakeholders request that PAs provide tracking system details, the reproduction of reported data will be possible using the TRM.

[4] Form the 2010-2012 Massachusetts Joint Statewide Three-Year Electric Energy Efficiency Plan, October 29, 2009, found at: http://www.ma-eeac.org/docs/DPU-filing/ElectricPlanFinalOct09.pdf. Please see page 275.

TRM Update Process

Overview

This section describes the process for updating the TRM. The update process is synchronized with the filing of program plans and Annual Reports by the PAs with the DPU.

Updates to the TRM can include:

- additions of new measures,
- updates to existing TRM measures due to:
  - changes in baseline equipment or practices, affecting measure savings
  - changes in efficient equipment or practices, affecting measure savings
  - changes to deemed savings due the revised assumptions for algorithm parameter values (e.g., due to new market research or evaluation studies)
  - other similar types of changes,
- updates to impact factors (e.g., due to new impact evaluation studies),
- discontinuance of existing TRM measures, and
- updates to the glossary and other background material included in the TRM.

Each TRM is associated with a specific program year, which corresponds to the calendar year. This results in two main versions of the TRM for each program year:

- the "Plan Version" is filed with the PA program plans prior to the program year, and
- the "Report Version" includes updates to the "Plan Version" document as needed and is filed with the PA Annual Reports, with the final savings algorithms and factors used to report actual savings.

The TRM for each program year is updated over time as needed to both plan for future program savings and to report actual savings.

Key Stakeholders and Responsibilities

Key stakeholders and their responsibilities for the TRM updates are detailed in the following table.

Stakeholder	Responsibilities
TRM Coordinating Committee	▪ Administrative coordination of TRM activities, including: ▪ Assure collaboration and consensus by the PAs regarding TRM updates ▪ Assure updates are compiled from the PAs and incorporated into the TRM ▪ Coordinate with related program activities (e.g., evaluation and program reporting processes)
Program Administrators	▪ Provide one or two representatives each to the TRM Coordinating Committee, either by direct representation or through a proxy (e.g., GasNetworks). Both the planning and evaluation functions should be represented on the Committee. ▪ Identify needed updates to the TRM ▪ Coordinate with other PAs on all TRM updates ▪ File TRM updates with the DPU

Stakeholder	Responsibilities
Department of Energy Resources	▪ Provide one representative to the TRM Coordinating Committee ▪ Assure coordination with PA submissions of program plans and reported savings

TRM Update Cycle

The timeline below shows the main milestones of the TRM update cycle over a period of two years. The milestones for the program year ("PY") 2012 TRM Plan and Report versions are described below the timeline.

OCTOBER 2011: The 2012 PY – Plan Version TRM is filed with the PAs' program plans.

The 2012 Program Year – Plan Version TRM is filed with the DPU jointly with the PAs' energy efficiency program plans. With regard to the program plans, the TRM is considered a "planning document" in that it provides the documentation for how the PAs *plan* to count savings for that program year. The TRM is not intended to fully document how the PAs develop their plan estimates for savings.

OCTOBER 2011 - JUNE 2013: The 2012 Program Year TRM will be updated as needed based on evaluation studies and any other updates that will affect reported savings for PY 2012.

After the 2012 Program Year – Plan Version TRM has been filed, there may be updates to the TRM to reflect how savings are actually calculated for PY 2012. The most common updates to the TRM will result from new evaluation studies. Results of evaluation studies will be integrated into the working version of the TRM as the studies are completed. Other updates may include the results of working group discussions to achieve greater consistency among PA assumptions.

JANUARY 2012: PAs begin to track savings based on the 2012 TRM

Beginning in January 2012, the PAs will track savings for PY 2012 based on the 2012 Program Year – Plan Version TRM.

JULY 2013: The 2012 Program Year – Report Version TRM will be filed with the PY 2012 Annual Reports

The 2012 Program Year – Report Version TRM, including any updates relative to the Program Plan version, will be filed with the PAs' Annual Reports. Updates from the Plan Version may include new evaluation results or changes based on working group discussions, and will be clearly identified in the Report Version

AUGUST 2012 - OCTOBER 2012: The PAs prepare the 2013 Program Year – Plan Version TRM for filing with their 2013 program plans

The 2013 Program Year – Plan Version TRM will be based on previous program year versions of the TRM, updated as appropriate for the 2012 program year in preparation for filing with the 2013 program plans. Updates may include results of new evaluations or working group discussions and the addition or removal of energy efficiency measures.

Measure Characterization Structure

This section describes the common entries or inputs that make up each measure characterization. A formatted template follows the descriptions of each section of the measure characterization.

Source citations: The source of each assumption or default parameter value should be properly referenced in a footnote. New source citations should be added to Appendix E: Table of Reference Documents, which serves as a cross-reference to digital versions of the referenced documents.

Measure Name

A single device or behavior may be analyzed as a range of measures depending on a variety of factors which largely translate to where it is and who is using it. Such factors include hours of use, location, and baseline (equipment replaced or behavior modified). For example, the same screw-in compact fluorescent lamp will produce different savings if installed in an emergency room waiting area than if installed in a bedside lamp.

Version Date and Revision History

This section will include information regarding the history of the measure entry including when the data for that measure is effective, and the last date that the measure is offered.

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

This section will include a plain text description of the efficient and baseline technology and the benefit(s) of its installation, as well as subfields of supporting information including:

Description: <Description of the energy efficiency measure>
Primary Energy Impact: <Electric or Natural Gas>
Secondary Energy Impact: <e.g., Natural Gas, Propane, Oil, Electric, None>
Non-Energy Impact: <e.g., Water Resource, O&M, Non-Resource, None>
Sector: <Residential, Low Income or Commercial and Industrial>
Market: <Lost Opportunity, Retrofit and/or Products and Services>
End-Use: <Per PARIS database definition – see list below>
Program: <Per PA definition>

The PARIS database includes the following possible End-Uses:

Lighting	Compressed Air	Demand Response
HVAC	Behavior	Photovoltaic Panels
Motors /Drives	Insulation	Process
Refrigeration	Combined Heat and Power	
Hot Water	Solar Hot Water	

Notes

This is an optional section for additional notes regarding anticipated changes going forward. For example, this section would not if there were upcoming statewide evaluations affecting the measure, or any plans for development of statewide tool for calculating measure savings.

Algorithms for Calculating Primary Energy Impacts

This section will describe the method for calculating the primary energy savings in appropriate units, i.e., kWh for electric energy savings or MMBtu for natural gas energy savings. The savings algorithm will be provided in a form similar to the following:

$$\Delta kWh = \Delta kW \times Hours$$

Similarly, the method for calculating electric demand savings will be provided in a form similar to the following:

$$\Delta kW = \left(Watts_{BASE} - Watts_{EE}\right)/1000$$

Below the savings algorithms, a table contains the definitions (and, in some cases, default values) of each input in the equation(s). The inputs for a particular measure may vary and will be reflected as such in this table (see example below).

ΔkWh	=	gross annual kWh savings from the measure
ΔkW	=	gross connected kW savings from the measure
Hours	=	average hours of use per year
$Watts_{BASE}$	=	baseline connected kW
$Watts_{EE}$	=	energy efficient connected kW

Baseline Efficiency

This section will include a statement of the assumed equipment/operation efficiency in the absence of program intervention. Multiple baselines will be provided as needed, e.g., for different markets. Baselines may refer to reference tables or may be presented as a table for more complex measures.

High Efficiency

This section will describe the high efficiency case from which the energy and demand savings are determined. The high efficiency case may be based on specific details of the measure installation, minimum requirements for inclusion in the program, or an energy efficiency case based on historical participation. It may refer to tables within the measure characterization or in the appendices or efficiency standards set by organizations such as ENERGY STAR® and the Consortium for Energy Efficiency.

Hours

This section will note operating hours for equipment that is either on or off, or equivalent full load hours for technologies that operate at partial loads, or reduced hours for controls. Reference tables will be used as needed to avoid repetitive entries.

Measure Life

Measure Life includes equipment life and the effects of measure persistence. Equipment life is the number of years that a measure is installed and will operate until failure. Measure persistence takes into account business turnover, early retirement of installed equipment, and other reasons measures might be removed or discontinued.

Secondary Energy Impacts

This section described any secondary energy impacts associated with the energy efficiency measure, including all assumptions and the method of calculation.

Non-Energy Impacts

This section describes any non-energy impacts associated with the energy efficiency measure, including all assumptions and the method of calculation.

Impact Factors for Calculating Adjusted Gross Savings

The section includes a table of impact factor values for adjusting gross savings. Impact factors for calculating net savings (free ridership, spillover and/or net-to-gross ratio) are in Appendix C: Net to Gross Impact Factors. Further descriptions of the impacts factors and the sources on which they are based are described below the table.

Measure	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}	CF_{SSP}	CF_{WSP}

Abbreviated program names may be used in the above table. The mapping of full program names to abbreviated names is given below.

	Full Program Name	Abbreviation
Residential-Electric	Residential New Construction & Major Renovation	RNC
	Residential Cooling & Heating Equipment	RHVAC
	Multi-Family Retrofit	MF Retrofit
	MassSAVE	MassSAVE
	Behavior/Feedback Program	Behavior/Feedback
	ENERGY STAR Lighting	ES Lighting
	ENERGY STAR Appliances	ES Appliances
Low Income-Electric	Low-Income Residential New Construction	LI RNC
	Low-Income 1-4 Family Retrofit	LI Retrofit 1-4
	Low-Income Multifamily Retrofit	LI MF Retrofit
C&I – Electric	C&I New Construction and Major Renovation	NC
	C&I Large Retrofit	Large Retrofit
	C&I Small Retrofit	Small Retrofit
Residential – Gas	Residential New Construction & Major Renovation	RNC
	Residential Heating and Water Savings	Residential Heating and Water Savings
	MassSAVE	MassSAVE
	Multifamily Retrofit	MF Retrofit
	Behavior/Feedback Program	Behavior/Feedback
Low Income – Gas	Low-Income Single Family Retrofit	Low-Income Single Family Retrofit
C&I - Gas	C&I New Construction & Major Renovation	C&I NC
	C&I Retrofit	C&I Retrofit
	C&I Direct Install	C&I Direct Install

Impact Factors for Calculating Adjusted Gross and Net Savings

PAs use the algorithms in the Measure Characterization sections to calculate the gross savings for energy efficiency measures. Impact factors are then applied to make various adjustments to the gross savings estimate to account for the performance of individual measures or energy efficiency programs as a whole in achieving energy reductions as assessed through evaluation studies. Impacts factors address both the technical performance of energy efficiency measures and programs, accounting for the measured energy and demand reductions realized compared to the gross estimated reductions, as well as the programs' effect on the market for energy efficient products and services.

This section describes the types of impact factors used to make such adjustments, and how those impacts are applies to gross savings estimates. Definitions of the impact factors and other terms are also provided in Appendix G: Glossary.

Types of Impact Factors

The impact factors used to adjust savings fall into one of two categories:

Impact factors used to adjust gross savings:

- In-Service Rate ("ISR")
- Savings Persistence Factor ("SPF")
- Realization Rate ("RR")
- Summer and Winter Peak Demand Coincidence Factors ("CF").

Impact factors used to calculate net savings:

- Free-Ridership ("FR") and Spillover ("SO") Rates
- Net-to-Gross Ratios ("NTG").

The **in-service rate** is the actual portion of efficient units that are installed. For example, efficient lamps may have an in-service rate less than 1.00 since some lamps are purchased as replacement units and are not immediately installed. The ISR is 1.00 for most measures.

The **savings persistence factor** is the portion of first-year energy or demand savings expected to persist over the life of the energy efficiency measure. The SPF is developed by conducting surveys of installed equipment several years after installation to determine the actual operational capability of the equipment. The SPF is 1.00 for most measures.

In contrast to savings persistence, *measure persistence* takes into account business turnover, early retirement of installed equipment, and other reasons the installed equipment might be removed or discontinued. Measure persistence is generally incorporated as part of the measure life, and therefore is not included as a separate impact factor.

The **realization rate** is used to adjust the gross savings (as calculated by the savings algorithms) based on impact evaluation studies. The realization rate is equal to the ratio of measure savings developed from an impact evaluation to the estimated measure savings derived from the savings algorithms. The realization rate does not include the effects of any other impact factors. Depending on the impact evaluation study, there may be separate realization rates for energy (kWh), peak demand (kW), or fossil fuel energy (MMBtu).

A **coincidence factor** adjusts the connected load kW savings derived from the savings algorithm. A coincidence factor represents the fraction of the connected load reduction expected to occur at the same time as a particular system peak period. The coincidence factor includes both coincidence and diversity factors combined into one number, thus there is no need for a separate diversity factor in this TRM.

Coincidence factors are provided for both the on-peak and seasonal peak periods as defined by the ISO New England for the Forward Capacity Market ("FCM"), and are calculated consistently with the FCM methodology. Electric demand reduction during the ISO New England peak periods is defined as follows:

On-Peak Definition:
- Summer On-Peak: average demand reduction from 1:00-5:00 PM on non-holiday weekdays in June July, and August
- Winter On-Peak: average demand reduction from 5:00-7:00 PM on non-holiday weekdays in December and January

Seasonal Peak Definition:
- Summer Seasonal Peak: demand reduction when the real-time system hourly load is equal to or greater than 90% of the most recent "50/50" system peak forecast for June-August
- Winter Seasonal Peak: demand reduction when the real-time system hourly load is equal to or greater than 90% of the most recent "50/50" system peak load forecast for December-January.

The values described as Coincidence Factors in the TRM are not always consistent with the strict definition of a Coincidence Factor (CF). It would be more accurate to define the Coincidence Factor as "the value that is multiplied by the Gross kW value to calculate the average kW reduction coincident with the peak periods." A coincidence factor of 1.00 may be used because the coincidence is already included in the estimate of Gross kW; this is often the case when the "Max kW Reduction" is not calculated and instead the "Gross kW" is estimated using the annual kWh reduction estimate and a loadshape model.

A **free-rider** is a customer who participates in an energy efficiency program (and gets an incentive) but who would have installed some or all of the same measure(s) on their own, with no change in timing of the installation, if the program had not been available. The **free-ridership rate** is the percentage of savings attributable to participants who would have installed the measures in the absence of program intervention.

The **spillover rate** is the percentage of savings attributable to a measure or program, but additional to the gross (tracked) savings of a program. Spillover includes the effects of 1) participants in the program who install additional energy efficient measures outside of the program as a result of participating in the program, and 2) non-participants who install or influence the installation of energy efficient measures as a result of being aware of the program. These two components are the **participant spillover** (SO_P) and **non-participant spillover** (SO_{NP}).

The **net savings** value is the final value of savings that is attributable to a measure or program. Net savings differs from gross savings because it includes the effects of the free-ridership and/or spillover rates.

The **net-to-gross** ratio is the ratio of net savings to the gross savings adjusted by any impact factors (i.e., the "adjusted" gross savings). Depending on the evaluation study, the NTG ratio may be determined from the free-ridership and spillover rates, if available, or it may be a distinct value with no separate specification of FR and SO values.

Standard Net–to–Gross Formulas

The TRM measure entries provide algorithms for calculating the gross savings for those efficiency measures. The following standard formulas show how the impact factors are applied to calculate the adjusted gross savings, which in turn are used to calculate the net savings. These are the calculations used by the PAs to track and report gross and net savings. The gross savings reported by the PAs are the unadjusted gross savings without the application of any impact factors.

Calculation of Net Annual Electric Energy Savings

$$adj\_gross\_kWh = gross\_kWh \times RR_E \times SPF \times ISR$$
$$net\_kWh = adj\_gross\_kWh \times NTG$$

Calculation of Net Summer Electric Peak Demand Coincident kW Savings

$$adj\_gross\_kW_{SP} = gross\_kW \times RR_{SP} \times SPF \times ISR \times CF_{SP}$$
$$net\_kW_{SP} = adj\_gross\_kW_{SP} \times NTG$$

Calculation of Net Winter Electric Peak Demand Coincident kW Savings

$$adj\_gross\_kW_{WP} = gross\_kW \times RR_{WP} \times SPF \times ISR \times CF_{WP}$$
$$net\_kW_{WP} = adj\_gross\_kW_{WP} \times NTG$$

Calculation of Net Annual Natural Gas Energy Savings

$$adj\_gross\_MMBtu = gross\_MMBtu \times RR_E \times SPF \times ISR$$
$$net\_MMbtu = adj\_gross\_MMBtu \times NTG$$

Depending on the evaluation study methodology:

- NTG is equal to $(1 – FR + SO_P + SO_{NP})$, or
- NTG is a single value with no distinction of FR, SO_P, SO_{NP}, and/or other factors that cannot be reliably isolated.

Where:

Gross_kWh	=	Gross Annual kWh Savings
adj_gross_kWh	=	Adjusted Gross Annual kWh Savings
net_kWh	=	Net Annual kWh Savings
$Gross\_kW_{SP}$	=	Gross Connected kW Savings (summer peak)
$adj\_gross\_kW_{SP}$	=	Adjusted Gross Connected kW Savings (summer peak)
$Gross\_kW_{WP}$	=	Gross Connected kW Savings (winter peak)

$adj\_gross\_kW_{WP}$	=	Adjusted Gross Connected kW Savings (summer peak)
net_kW_{SP}	=	Adjusted Gross Connected kW Savings (winter peak)
net_kW_{WP}	=	Net Coincident kW Savings (winter peak)
Gross_MMBtu	=	Gross Annual MMBtu Savings
adj_gross_MMBtu	=	Adjusted Gross Annual MMBtu Savings
net_MMBtu	=	Net Annual MMBtu Savings
SPF	=	Savings Persistence Factor
ISR	=	In-Service Rate
CF_{SP}	=	Peak Coincidence Factor (summer peak)
CF_{WP}	=	Peak Coincidence Factor (winter peak)
RR_{E}	=	Realization Rate for electric energy (kWh)
RR_{SP}	=	Realization Rate for summer peak kW
RR_{WP}	=	Realization Rate for winter peak kW
NTG	=	Net-to-Gross Ratio
FR	=	Free-Ridership Factor
SO_{P}	=	Participant Spillover Factor
SO_{NP}	=	Non-Participant Spillover Factor

Calculations of Coincident Peak Demand kW Using "Seasonal Peak" Coincidence Factors

The formulas above for peak demand kW savings use the "on-peak" coincidence factors (CF_{SP}, CF_{WP}), which apply the "on-peak" coincidence methodology as allowed for submission to the FCM. The alternative methodology is the "seasonal peak" methodology, which uses the identical formulas, but substituting the "seasonal peak" coincidence factors for the "on-peak" coincidence factors:

CF_{SSP}	=	Peak Coincidence Factor for Summer Seasonal Peak
CF_{WSP}	=	Peak Coincidence Factor for Winter Seasonal Peak

Residential Electric Efficiency Measures

Behavior – Basic Educational Measures

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: Installation of basic educational measures during an audit to help customers become more aware of energy efficiency.
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: Low-Income Annual Discounted Rate Cost Reduction, Low-Income One-Time Arrearage Reduction
Sector: Low Income
Market: Retrofit
End Use: Behavior
Program: Low-Income 1-4 Family Retrofit, Low-Income Multifamily Retrofit

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed based on study results:

$$\Delta kWh = \Delta kWh$$
$$\Delta kW = \max(\Delta kW_{SP}, \Delta kW_{WP})$$

Where:
Unit = Completed audit
ΔkWh = Average annual kWh savings per unit: 138 kWh[5]
ΔkW = Max kW Reduction: 0.038 kW[6]

Baseline Efficiency

The baseline efficiency case assumes no measures installed.

High Efficiency

The high efficiency case includes basic educational measures such as, low flow showerheads, pool and air conditioner timers, and programmable thermostats.

Hours

Not applicable.

[5] The Cadmus Group, Inc. (2009). *Impact Evaluation of the 2007 Appliance Management Program and Low Income Weatherization Program.* Prepared for National Grid.
[6] Estimated using demand allocation methodology described in: Quantec, LLC (2000). *Impact Evaluation: Single-Family EnergyWise Program.* Prepared for National Grid.

Measure Life

The measure life is 5 years.[7]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Baseload	LI 1-4 Retrofit	All	1.00	1.00	1.00	1.00	1.00	0.35	1.00
Baseload	LI MF Retrofit	All (not National Grid)	1.00	1.00	1.00	1.00	1.00	0.35	1.00

In-Service Rates
All installations have 100% in service rate since all PAs programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factors.

Realization Rates
Realization rates are set to 100% since deemed savings are based on evaluation results.

Coincidence Factors
Coincidence factors are estimated using the demand allocation methodology described in the 2000 EnergyWise program impact evaluation.[8]

7 Massachusetts Common Assumption.
8 Quantec, LLC (2000). *Impact Evaluation: Single-Family EnergyWise Program*. Prepared for National Grid.

Behavior – OPOWER Electric

Version Date and Revision History

Effective Date: 1/1/2011 (revised for 1/1/2012)
End Date: TBD

Measure Overview

Description: The Behavior/Feedback programs send energy use reports to participating electric customers in order to change customers' energy-use behavior.
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: None
Sector: Residential
Market: Products and Services
End Use: Behavior
Program: Behavior/Feedback Program

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed based on study results:

$$\Delta kWh = (kWh_{BASE})(\%SAVE)$$
$$\Delta kW = \Delta kWh / 4000$$

Where:

Unit = One participant household.
kWh_{BASE} = Baseline consumption of kWh. See Table 1.
%SAVE = Energy savings percent per program participant. See Table 1.
kW = kWh/4000 hours[9]

Table 1: Savings Factors for OPOWER Electric[10]

PA	Measure Name	kWh_{BASE}	%SAVE	ΔkWh	ΔkW
National Grid	OPOWER Group 2009	11,518	2.05%	236.12	0.059
National Grid	OPOWER Group 2010	12,738	1.60%	203.81	0.051
National Grid	OPOWER Group 2010 Added	15,585	2.16%	336.64	0.084
National Grid	OPOWER Group 2011	9,916	1.75%	173.53	0.043
National Grid	OPOWER Group 2011 Added	12,000	1.91%	229.20	0.057
National Grid, NSTAR	OPOWER Group 2012	11,678	1.44%	168.16	0.042
National Grid, NSTAR	OPOWER Group 2012 Dual	6,100	1.38%	84.18	0.021

Baseline Efficiency

The baseline efficiency case is a customer who does not receive OPOWER reports.

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9 Staff estimate
10 Opinion Dynamics Corporation and Navigant Consulting (2011). Massachusetts Cross-Cutting Behavioral Program Evaluation. Updated with vendor projections for 2012.

High Efficiency

The high efficiency case is a customer who receives an OPOWER report.

Hours

Not applicable.

Measure Life

The measure life is 1 year.

Secondary Energy Impacts

The impacts described in this section are specific to NSTAR's Opower program. See Behavior – OPOWER Gas in the Residential Gas section for information about National Grid's program.

Measure	Energy Type	Savings[11]	ΔMMBtu/Unit
Dual Fuel (Gas)	NG - Res Gas Old Bldg	14.69 Therms	1.47

Non-Energy Impacts

There are no non-energy impacts for this measure.

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
OPOWER Group	Behavior/Feedback	National Grid	1.00	1.00	1.00	1.00	1.00	0.25	1.00

In-Service Rates
In-services rates are 100% since the program tracks all participating customers.

Savings Persistence Factor
Savings persistence is 100% since the measure life for each participant is 1 year.

Realization Rates
Realization rates are 100% because deemed savings are based on assumptions from year-to-date vendor findings

Coincidence Factors
Coincidence Factors are based on staff estimates. [12]

[11] ODC (August 2011) *NSTAR Home Energy Report: Heating Season Program Channeling Findings.*
[12] Staff estimate as evaluation results were not available.

Lighting – CFL Bulbs

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: Compact fluorescent lamps offer comparable luminosity to incandescent lamps at significantly less wattage and significantly longer lamp lifetimes.
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: One Time Non-Resource, Low-Income Annual Discounted Rate Cost Reduction
Sector: Residential, Low-Income
Market: Lost Opportunity
End Use: Lighting
Program: ENERGY STAR Lighting, Residential New Construction & Major Renovation, Home Energy Services, Multi-Family Retrofit, Low-Income Residential New Construction, Low-Income 1-4 Family Retrofit, Low-Income Multifamily Retrofit

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed based on study results:

$$\Delta kWh = \Delta kWh$$
$$\Delta kW = \Delta kW$$

Where:
Unit = Rebated CFL Bulb
ΔkWh = Average annual kWh reduction. See Table 2.
ΔkW = Average kW reduction. See Table 2.

Table 2: Savings for Residential CFL Bulbs

Measure	Program	ΔkW[13]	Hours	ΔkWh
Screw-in Bulbs	ES Lighting	0.046	1,022	47
Screw-in Bulbs (Hard to Reach)	ES Lighting	0.046	1,022	47
Screw-in Bulbs (School Fundraiser)	ES Lighting	0.046	1,022	47
Screw-in Bulbs (Specialty Bulbs)	ES Lighting	0.046	1,022	47
Screw-in Bulbs	RNC, LI RNC	0.046	1,022	47
Screw-in Bulbs	HES	0.046	1,022	47
Screw-in Bulbs (piggyback)	HES	0.046	1,022	47
Screw-in Bulbs	MF Retrofit	0.046	1,022	47
Common Area Fixtures	MF Retrofit, LI MF Retrofit	0.046	1,022	47
CFL Bulb	LI 1-4 Retrofit	0.011[14]	n/a	41[15]
CFL Bulb	LI MF Retrofit	0.011	n/a	41

Baseline Efficiency

The baseline efficiency case is an incandescent bulb.

High Efficiency

The high efficiency case is an ENERGY STAR® rated CFL spiral bulb.

Hours

Average annual operating hours for bulbs are 1,022 hours/year (2.8 hours/day[16] * 365 days/year).

Measure Life

The adjusted measure life is 7 years for screw-in bulbs. [17]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

[13] Nexus Market Research, RLW Analytics and GDS Associates (2009). *Residential Lighting Markdown Impact Evaluation*. Prepared for Markdown and Buydown Program Sponsors in CT, MA, RI, and VT; Page 56.

[14] Estimated using demand allocation methodology described in: Quantec, LLC (2000). *Impact Evaluation: Single-Family EnergyWise Program*. Prepared for National Grid. The value shown here is the winter coincident demand reduction.

[15] The Cadmus Group, Inc. (2009). *Impact Evaluation of the 2007 Appliance Management Program and Low Income Weatherization Program*. Prepared for National Grid; Table 1, Page 5.

[16] Nexus Market Research and RLW Analytics (2008). *Residential Lighting Measure Life Study*. Prepared for New England Residential Lighting Program Sponsors.

[17] The calculated measure life for screw-in bulbs is 8, based on a component life of 8,000 and hours of use of 1,022. The adjusted measure life accounts for changes in the baseline due to EISA standards as shown in the MA Lighting Worksheet.

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Screw-in Bulbs	ES Lighting	All	0.97	1.00	1.00	1.00	1.00	0.11	0.22
Screw-in Bulbs (Hard to Reach)	ES Lighting	All	1.00	1.00	1.00	1.00	1.00	0.11	0.22
Screw-in Bulbs (School Fundraiser)	ES Lighting	All	0.50	1.00	1.00	1.00	1.00	0.11	0.22
Screw-in Bulbs (Specialty Bulbs)	ES Lighting	All	1.00	1.00	1.00	1.00	1.00	0.11	0.22
Screw-in Bulbs	RNC, LI RNC	All	0.99	1.00	1.00	1.00	1.00	0.11	0.22
Screw-in Bulbs	HES	All	0.90	1.00	1.00	1.00	1.00	0.11	0.22
Screw-in Bulbs (piggyback)	HES	All	0.90	1.00	1.00	1.00	1.00	0.11	0.22
Screw-in Bulbs	MF Retrofit	All (not National Grid)	1.00	1.00	1.00	1.00	1.00	0.11	0.22
Common Area Fixtures	MF Retrofit	All (not National Grid)	1.00	1.00	1.00	1.00	1.00	0.11	0.22
CFL Bulb	LI 1-4 Retrofit	All	1.00	1.00	1.00	1.00	1.00	0.35	1. 00
CFL Bulb	LI MF Retrofit	All (not National Grid)	1.00	1.00	1.00	1.00	1.00	0.35	1.00

In-Service Rate

- ES Lighting, MF Retrofit, LI 1-4 Retrofit, LI MF Retrofit: PAs assume a 100% installation rate for direct install programs.
- RNC, LI RNC: 2006 ENERGY STAR® Homes New Homebuyer Survey Report[18]
- HES: Impact evaluation of the MA, RI, VT 2003 Residential Lighting Programs[19]

Savings Persistence Factor

All PAs use 100% savings persistence factors.

Realization Rates

Realization rates are 100% since savings estimates are based on evaluation results.

Coincidence Factors

- ES Lighting, RNC, LI RNC, HES, MF Retrofit: Coincidence factors are based on the 2009 Lighting Markdown Study.[20]

[18] Nexus Market Research & Dorothy Conant (2006). *Massachusetts ENERGY STAR® Homes: 2005 Baseline Study: Part II: Homeowner Survey Analysis Incorporating Inspection Data Final Report.* Prepared for the Massachusetts Joint Management Committee.
[19] Nexus Market Research and RLW Analytics (2004). *Impact Evaluation of the Massachusetts, Rhode Island, and Vermont 2003 Residential Lighting Programs.* Submitted to The Cape Light Compact, State of Vermont Public Service Department for Efficiency Vermont, National Grid, Northeast Utilities, NSTAR and Unitil Energy Systems, Inc.
[20] Nexus Market Research, RLW Analytics and GDS Associates (2009). *Residential Lighting Markdown Impact Evaluation*. Prepared for Markdown and Buydown Program Sponsors in CT, MA, RI, and VT.

- LI MF Retrofit, LI 1-4 Retrofit: Coincidence factors are estimated using the demand allocation methodology described in the 2000 EnergyWise program impact evaluation.[21]

[21] Quantec, LLC (2000). *Impact Evaluation: Single-Family EnergyWise Program*. Prepared for National Grid.

Lighting – Indoor Fixtures

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: The installation of ENERGY STAR® compact fluorescent (CFL) indoor fixtures. Compact fluorescent fixtures offer comparable luminosity to incandescent fixtures at significantly less wattage and significantly longer lifetimes. Hardwired fluorescent fixtures offer comparable luminosity to incandescent fixtures at significantly lower wattage and offer significantly longer lifespan.
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: One-Time O&M Cost Reduction, Low-Income Annual Discounted Rate Cost Reduction
Sector: Residential, Low-Income
Market: Lost Opportunity, Retrofit
End Use: Lighting
Program: Low-Income 1-4 Family Retrofit, Low-Income Multifamily Retrofit, ENERGY STAR Lighting, Residential New Construction & Major Renovation, Low-Income Residential New Construction, Multi-Family Retrofit

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed based on study results:

$$\Delta kWh = \Delta kWh$$
$$\Delta kW = \Delta kW$$

Where:
Unit = Installation of CFL fixture
ΔkWh = Average annual kWh savings per unit. See Table 3.
ΔkW = Max kW reduction. See Table 3.

Table 3: Savings for Residential Indoor Fixtures

Measure	Program	ΔkW[22]	Hours	ΔkWh
Indoor Fixture	ES Lighting	0.049	912.5	44
Indoor Fixture	RNC, LI RNC	0.049	912.5	44
Indoor Fixture	MF Retrofit	0.049	912.5	44
CFL Fixture	LI 1-4 Retrofit	0.035[23]	n/a	128[24]
CFL Fixture	LI MF Retrofit	0.035	n/a	128

Baseline Efficiency

The baseline efficiency case is an incandescent, screw-based fixture with an incandescent lamp.

High Efficiency

The high efficiency case is an ENERGY STAR® qualified compact fluorescent light fixture wired for exclusive use with pin-based CFLs.

Hours

The average annual operating hours are 912.5 hours/year (2.5 hours/day[25] * 365 days/year).

Measure Life

The adjusted measure life is 7 years for indoor fixtures.[26]

Secondary Energy Impact

There are no secondary energy impacts for this measure.

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

[22] Nexus Market Research and RLW Analytics (2004). *Impact Evaluation of the Massachusetts, Rhode Island, and Vermont 2003 Residential Lighting Programs.* Submitted to The Cape Light Compact, State of Vermont Public Service Department for Efficiency Vermont, National Grid, Northeast Utilities, NSTAR and Unitil Energy Systems, Inc.; Table 1-8.
[23] Estimated using demand allocation methodology described in: Quantec, LLC (2000). *Impact Evaluation: Single-Family EnergyWise Program.* Prepared for National Grid.
[24] Environmental Protection Agency (2009). *Life Cycle Cost Estimate for ENERGY STAR Qualified Lighting Fixtures*.
[25] Nexus Market Research and RLW Analytics (2004). *Impact Evaluation of the Massachusetts, Rhode Island, and Vermont 2003 Residential Lighting Programs*. Submitted to The Cape Light Compact, State of Vermont Public Service Department for Efficiency Vermont, National Grid, Northeast Utilities, NSTAR and Unitil Energy Systems, Inc.; Page 104.
[26] The adjusted measure life accounts for changes in the baseline due to EISA standards as shown in the MA Lighting Worksheet

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Indoor Fixture	ES Lighting	All	0.95	1.00	1.00	1.00	1.00	0.11	0.22
Indoor Fixture	RNC, LI RNC	All	0.96	1.00	1.00	1.00	1.00	0.11	0.22
Indoor Fixture	MF Retrofit	All (not National Grid)	0.95	1.00	1.00	1.00	1.00	0.11	0.22
CFL Fixture	LI 1-4 Retrofit	All	1.00	1.00	1.00	1.00	1.00	0.35	1.00
CFL Fixture	LI MF Retrofit	All (not National Grid)	1.00	1.00	1.00	1.00	1.00	0.35	1.00

In-Service Rates

- ES Lighting: 2004 Impact Evaluation of MA, RI, VT Residential Lighting Program[27]
- RNC, LI RNC: 2006 ENERGY STAR® Homes New Homebuyer Survey Report[28]
- MF Retrofit: Impact Evaluation of 2005 EnergyWise Program[29]
- LI 1-4 Retrofit, LI MF Retrofit: PAs assume 100% in-service rates.

Savings Persistence Factor

All PAs use 100% savings persistence factors.

Realization Rates

Realization rates are set to 100% since deemed savings are based on evaluation results.

Coincidence Factors

Coincidence factors for indoor fixtures are based on the 2009 Lighting Markdown Study.[30]
Coincidence factors for CFL fixtures are estimated using the demand allocation methodology described in the 2000 EnergyWise program impact evaluation.[31]

[27] Nexus Market Research and RLW Analytics (2004). *Impact Evaluation of the Massachusetts, Rhode Island, and Vermont 2003 Residential Lighting Programs*. Submitted to The Cape Light Compact, State of Vermont Public Service Department for Efficiency Vermont, National Grid, Northeast Utilities, NSTAR and Unitil Energy Systems, Inc.; Page 11.
[28] Nexus Market Research & Dorothy Conant (2006). *Massachusetts ENERGY STAR® Homes: 2005 Baseline Study: Part II: Homeowner Survey Analysis Incorporating Inspection Data Final Repor*t. Prepared for the Massachusetts Joint Management Committee; Table 8.1
[29] Summit Blue Consulting, LLC (2006). *Impact Evaluation of 2005 EnergyWise Program – Final Report*. Prepared for National Grid.
[30] Nexus Market Research, RLW Analytics and GDS Associates (2009). *Residential Lighting Markdown Impact Evaluation*. Prepared for Markdown and Buydown Program Sponsors in CT, MA, RI, and VT.
[31] Quantec, LLC (2000). *Impact Evaluation: Single-Family EnergyWise Program*. Prepared for National Grid.

Lighting – Outdoor Fixtures

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: The installation of hardwired ENERGY STAR® fluorescent outdoor fixtures with pin-based bulbs. Savings for this measure are attributable to high efficiency outdoor lighting fixtures and are treated similarly to indoor fixtures.
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: One-time Non-Resource
Sector: Residential
Market: Lost Opportunity, Retrofit
End Use: Lighting
Program: ENERGY STAR Lighting, MF Retrofit, Low-Income Multifamily Retrofit

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed based on the following algorithms which use averaged inputs:

$$\Delta kWh = \Delta kW \times Hours$$
$$\Delta kW = \Delta kW$$

Where:

Unit	=	Rebated outdoor fixture
ΔkWh	=	Average annual kWh reduction: 156 kWh (calculated)
ΔkW	=	Average connected kW reduction: 0.095 kW[32]
Hours	=	Average annual operating hours

Baseline Efficiency

The baseline efficiency case is an incandescent, screw-based fixture with an incandescent bulb.

High Efficiency

The high efficiency case is an ENERGY STAR® fixture wired for exclusive use with a pin based CFL.

Hours

The average annual operating hours are 1,642.5 hours/year (4.5 hours per day[33] * 365 days per year).

[32] Nexus Market Research and RLW Analytics (2004). *Impact Evaluation of the Massachusetts, Rhode Island, and Vermont 2003 Residential Lighting Programs*. Submitted to The Cape Light Compact, State of Vermont Public Service Department for Efficiency Vermont, National Grid, Northeast Utilities, NSTAR and Unitil Energy Systems, Inc.; Table 1-8.

Measure Life

The measure life is 6 years for markdown outdoor fixtures.[34]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Outdoor Fixture	ES Lighting	All	0.87	1.00	1.00	1.00	1.00	0.11	0.22
Outdoor Fixture	MF Retrofit	All (not National Grid)	0.87	1.00	1.00	1.00	1.00	0.11	0.22

In-Service Rates

- ES Lighting: 2004 Impact Evaluation of MA, RI, VT Residential Lighting Program[35]
- MF Retrofit: Impact Evaluation of 2005 EnergyWise Program[36]

Savings Persistence Factor

All PAs use 100% savings persistence factors.

Realization Rates

Realization rates are based on Massachusetts Common Assumptions.

Coincidence Factors

Coincidence factors are based on the 2009 Lighting Markdown Study.[37]

[33] Nexus Market Research and RLW Analytics (2004). *Impact Evaluation of the Massachusetts, Rhode Island, and Vermont 2003 Residential Lighting Programs*. Submitted to The Cape Light Compact, State of Vermont Public Service Department for Efficiency Vermont, National Grid, Northeast Utilities, NSTAR and Unitil Energy Systems, Inc.; Page 104

[34] Nexus Market Research and RLW Analytics (2008). *Residential Lighting Measure Life Study*. Prepared for New England Residential Lighting Program Sponsors; Page 1.

[35] Nexus Market Research and RLW Analytics (2004). *Impact Evaluation of the Massachusetts, Rhode Island, and Vermont 2003 Residential Lighting Programs*. Submitted to The Cape Light Compact, State of Vermont Public Service Department for Efficiency Vermont, National Grid, Northeast Utilities, NSTAR and Unitil Energy Systems, Inc.; Page 11.

[36] Summit Blue Consulting, LLC (2006). *Impact Evaluation of 2005 EnergyWise Program – Final Report*. Prepared for National Grid.

[37] Nexus Market Research, RLW Analytics and GDS Associates (2009). *Residential Lighting Markdown Impact Evaluation*. Prepared for Markdown and Buydown Program Sponsors in CT, MA, RI, and VT.

Lighting – Torchieres

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: The installation of high-efficiency ENERGY STAR® torchieres. High efficiency torchieres use fluorescent in place of halogen or incandescent bulbs to provide comparable luminosity at significantly reduced wattage.
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: Low-Income Annual Discounted Rate Cost Reduction
Sector: Residential, Low-Income
Market: Lost Opportunity, Retrofit
End Use: Lighting
Program: ENERGY STAR Lighting, HES, Low-Income 1-4 Family Retrofit, Low-Income Multifamily Retrofit

Algorithms for Calculating Primary Energy Impact

Unit savings are based on the following algorithms which use averaged inputs:

$$\Delta kWh = \Delta kW \times Hours$$
$$\Delta kW = \Delta kW$$

Where:

Unit	=	Rebated ENERGY STAR® Torchiere
ΔkWh	=	Average annual kWh reduction: 106 kWh (calculated)
ΔkW	=	Average connected kW reduction: 0.088 kW[38]
Hours	=	Average annual operating hours

Baseline Efficiency

The baseline efficiency case is a halogen or incandescent torchiere fixture.

High Efficiency

The high efficiency case is a fluorescent torchiere fixture.

[38] Nexus Market Research and RLW Analytics (2004). *Impact Evaluation of the Massachusetts, Rhode Island, and Vermont 2003 Residential Lighting Programs*. Submitted to The Cape Light Compact, State of Vermont Public Service Department for Efficiency Vermont, National Grid, Northeast Utilities, NSTAR and Unitil Energy Systems, Inc.; Table 1-8. Adjusted to account for changes to the baseline technology.

Hours

The average annual operating hours are 1,204.5 hours/year (3.3 hours/day[39] * 365 days/year).

Measure Life

The measure life is 8 years.[40]

Secondary-Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Torchieres	ES Lighting	All	0.83	1.00	1.00	1.00	1.00	0.11	0.22
Torchieres	HES	All	0.83	1.00	1.00	1.00	1.00	0.11	0.22
Torchieres	RNC	All	0.83	1.00	1.00	1.00	1.00	0.11	0.22
Torchieres	LI 1-4 Retrofit	CLC only	1.00	1.00	1.00	1.00	1.00	0.11	0.22
Torchieres	LI MF Retrofit	CLC only	1.00	1.00	1.00	1.00	1.00	0.11	0.22

In-Service Rates
- ES Lighting, HES: 2004 Impact Evaluation of MA, RI, VT Residential Lighting Program[41]
- Low Income: Assumed to be 100% for Low-Income customers.

Savings Persistence Factor
All PAs use 100% savings persistence factors.

Realization Rates
Realization rates are based on Massachusetts Common Assumptions.

Coincidence Factors
Coincidence factors are based on the 2009 Lighting Markdown Study.[42]

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[39] Nexus Market Research and RLW Analytics (2004). *Impact Evaluation of the Massachusetts, Rhode Island, and Vermont 2003 Residential Lighting Programs*. Submitted to The Cape Light Compact, State of Vermont Public Service Department for Efficiency Vermont, National Grid, Northeast Utilities, NSTAR and Unitil Energy Systems, Inc.; Page 104
[40] Ibid.
[41] Nexus Market Research and RLW Analytics (2004). *Impact Evaluation of the Massachusetts, Rhode Island, and Vermont 2003 Residential Lighting Programs*. Submitted to The Cape Light Compact, State of Vermont Public Service Department for Efficiency Vermont, National Grid, Northeast Utilities, NSTAR and Unitil Energy Systems, Inc.; Page 11.
[42] Nexus Market Research, RLW Analytics and GDS Associates (2009). *Residential Lighting Markdown Impact Evaluation*. Prepared for Markdown and Buydown Program Sponsors in CT, MA, RI, and VT.

Lighting – LED Lighting

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: The installation of Light-Emitting Diode (LED) screw-in bulbs. LEDs offer comparable luminosity to incandescent bulbs at significantly less wattage and significantly longer lamp lifetimes.
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: Annual Discounted Rate Cost Reduction (Low Income only)
Sector: Residential
Market: Lost Opportunity
End Use: Lighting
Program: ENERGY STAR Lighting, Residential New Construction & Major Renovation, Low-Income Residential New Construction

Algorithms for Calculating Primary Energy Impact

Unit savings are based on the following algorithms which use averaged inputs:

$$\Delta kWh = (kW_{BASE} - kW_{LED}) \times Hours$$
$$\Delta kW = \Delta kW$$

Where:

Unit	=	Rebated LED lamp or fixture
ΔkWh	=	Average annual energy savings: 48 kWh[43]
kW_{BASE}	=	Average connected kW of baseline bulb: 65 Watts
kW_{LED}	=	Average connected kW of LED bulb: 18 Watts
ΔkW	=	Average connected kW reduction: 0.047 kW
Hours	=	Average annual operating hours

Baseline Efficiency

The baseline efficiency case is a 65-watt incandescent bulb in a screw-based socket or fluorescent under cabinet light.

High Efficiency

The high efficiency case is an 18-watt LED downlight.

[43] Homes: Energy Star. *LED Light Bulbs for Consumers. http://www.energystar.gov/index.cfm?fuseaction=find_a_product.showProductGroup&pgw_code=ILB. Accessed on 10/15/10.*

Hours

The average annual operating hours are 1, 022 hours/year (2.8 hours/day[44] * 365 days/year).

Measure Life

The measure life is 20 years.[45]

Secondary-Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

No operations and maintenance cost adjustments are claimed for this measure. At this time, the incremental cost is unclear given the continual changes in LED technology. In addition, the measure life savings from not replacing incandescent bulbs are also unclear.

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
LED Lamp	ES Lighting	All	1.00	1.00	1.00	1.00	1.00	0.11	0.22
LED Fixture	ES Lighting	All	1.00	1.00	1.00	1.00	1.00	0.11	0.22
LED Fixture	RNC, LI RNC	All	1.00	1.00	1.00	1.00	1.00	0.11	0.22

In-Service Rates
In-service rates are set to 100% based on the assumption that all purchased units are installed.

Savings Persistence Factor
All PAs use 100% savings persistence factors.

Realization Rates
Realization rates are based on Massachusetts Common Assumptions.

Coincidence Factors
Coincidence factors are from the 2009 Lighting Markdown Study.[46]

[44] Nexus Market Research, RLW Analytics and GDS Associates (2009). *Residential Lighting Markdown Impact Evaluation*. Prepared for Markdown and Buydown Program Sponsors in CT, MA, RI, and VT; Page 6.
[45] Expected lifetime from ENERGY STAR ®.
[46] Nexus Market Research, RLW Analytics and GDS Associates (2009). *Residential Lighting Markdown Impact Evaluation*. Prepared for Markdown and Buydown Program Sponsors in CT, MA, RI, and VT.

Lighting – Occupancy Sensors

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: The installation of occupancy sensors for lighting fixtures. Energy savings are achieved by reducing the annual operating hours of the connected lighting fixtures.
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: None
Sector: Residential
Market: Retrofit
End Use: Lighting
Program: Multi-Family Retrofit

Algorithms for Calculating Primary Energy Impact

Unit savings are based on the following algorithms which use averaged inputs[47]:

$$\Delta kWh = kW \times Hours \times \%Unoccupied$$
$$\Delta kW = 0$$

Where:

Unit	=	Rebated occupancy sensor
ΔkWh	=	Annual energy savings: 99 kWh
ΔkW	=	Average kW reduction is 0 during peak periods
kW	=	Average connected kW: 0.094 kW[48]
Hours	=	Average annual operating hours for connected lighting wattage without controls
%Unoccupied	=	Average % of time that controlled space is unoccupied: 35%[49]

Baseline Efficiency

The baseline efficiency case is a lighting fixture that operates without controls.

High Efficiency

The high efficiency case is a lighting fixture that operates with connected occupancy sensors.

[47] Waste Reduction Partners (2004). *Occupancy Sensors - Utility Savings Initiative - Fact Sheet*; Page 2, algorithm based on the Lighting Fixture Basis formula.
[48] Ibid; Page 2, based on the savings for a 3-lamp T8.
[49] Ibid; Page 2, assumption based on the U.S. EPA Prediction for Corridors.

Hours

The average annual operating hours before the measure installation is 3,000 hours per year.[50]

Measure Life

The measure life is 10 years.[51]

Secondary-Energy Impacts

There are no secondary energy impacts counted for this measure.

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Common Area Occupancy Sensors	MF Retrofit	All	1.00	1.00	1.00	1.00	1.00	0.00	0.00

In-Service Rates
In-service rates are set to 100% based on the assumption that all purchased units are installed.

Savings Persistence Factor
All PAs use 100% savings persistence factors.

Realization Rates
Realization rates are based on Massachusetts Common Assumptions.

Coincidence Factors
Coincidence factors are set to zero since demand savings typically occur during off- peak periods.

[50] Ibid; assumption from the Lighting Fixture Basis formula.
[51] GDS Associates, Inc. (2007). *Measure Life Report: Residential and Commercial/Industrial Lighting and HVAC Measures*. Prepared for The New England State Program Working Group.

Hot Water – DHW Measures (Electric)

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: Installation of domestic hot water (DHW) measures including low flow showerheads, faucet aerators, and tank and pipe wraps in homes with electric water heating.
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: Residential Water, Low-Income Annual Discounted Rate Cost Reduction
Sector: Low Income
Market: Retrofit
End Use: Hot Water
Program: Low-Income 1-4 Family Retrofit, Low-Income Multifamily Retrofit

Notes

The savings estimates described in this section are only used for the Low-Income 1-4 Family Retrofit program (all PAs) and the Low-Income Multifamily Retrofit programs (all PAs except National Grid). The savings algorithms for similar measures installed through National Grid's Low-Income Multifamily program are described in the *Multifamily – DHW* sections.

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed based on study results:

$$\Delta kWh = \Delta kWh$$
$$\Delta kW = \Delta kW$$

Where:

Unit	=	Household with hot water efficiency measures installed
ΔkWh	=	Average annual energy savings per unit: 134 kWh[52]
ΔkW	=	Average demand reduction per unit: 0.017 kW[53]

Baseline Efficiency

The baseline efficiency case is the existing hot water equipment.

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52 The Cadmus Group, Inc. (2009). *Impact Evaluation of the 2007 Appliance Management Program and Low Income Weatherization Program.* Prepared for National Grid.
53 Estimated using demand allocation methodology described in: Quantec, LLC (2000). *Impact Evaluation: Single-Family EnergyWise Program.* Prepared for National Grid.

High Efficiency

The high efficiency case includes low flow showerheads and faucet aerators as well as tank and pipe wraps.

Hours

Not applicable.

Measure Life

The measure life is 7 years.[54]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

Benefit Type	Description	Savings
Residential Water	Residential water savings per participant[55]	4,028 Gallons/Participant
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
DHW Measures (Electric)	LI 1-4 Retrofit	All	1.00	1.00	1.00	1.00	1.00	0.75	1.00
DHW Measures (Electric)	LI MF Retrofit	All (not National Grid)	1.00	1.00	1.00	1.00	1.00	0.75	1.00

In-Service Rates
All installations have 100% in service rate since all PAs programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factors.

Realization Rates
Realization rates are set to 100% since deemed savings are based on evaluation results.

Coincidence Factors
Coincidence factors are estimated using the demand allocation methodology described in the 2000 EnergyWise program impact evaluation.[56]

[54] Massachusetts Common Assumption.
[55] NMR Group, Inc., Tetra Tech (2011). *Massachusetts Special and Cross-Sector Studies Area, Residential and Low-Income Non-Energy Impacts (NEI) Evaluation,* Prepared for Massachusetts Program Administrators
[56] Quantec, LLC (2000). *Impact Evaluation: Single-Family EnergyWise Program*. Prepared for National Grid.

Hot Water – DHW Measures (Oil, Gas and Other)

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: Installation of domestic hot water (DHW) measures including low flow showerheads, faucet aerators, and tank and pipe wraps in homes that have oil or gas water heaters.
Primary Energy Impact: Oil or Gas
Secondary Energy Impact: None
Non-Energy Impact: Residential Water, Low-Income Annual Discounted Rate Cost Reduction
Sector: Low Income
Market: Retrofit
End Use: Hot Water
Program: Low-Income 1-4 Family Retrofit, Low-Income Multifamily Retrofit

Notes

The savings estimates described in this section are only used for the Low-Income 1-4 Family Retrofit program (all PAs) and the Low-Income Multifamily Retrofit programs (all PAs except National Grid). The savings algorithms for similar measures installed through National Grid's Low-Income Multifamily program are described in the *Multifamily – DHW* sections.

Algorithms for Calculating Primary Energy Impact

No electric savings are claimed for this measure.

Baseline Efficiency

The baseline efficiency case is the existing hot water equipment.

High Efficiency

The high efficiency case includes low flow showerheads and faucet aerators as well as tank and pipe wraps.

Hours

Not applicable.

Measure Life

The measure life is 7 years.[57]

Secondary Energy Impacts

Measure	Energy Type	Savings[58]	ΔMMBtu/Unit
DHW Measures (Gas/Other)	NG – Residential DHW	9 Therms	0.9
DHW Measures (Oil)	Oil	6.4 Gallons	0.9

Non-Energy Impacts

Benefit Type	Description	Savings
Residential Water	Residential water savings per participant[59]	4,028 Gallons/Participant
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
DHW Measures (Gas/Other)	LI 1-4 Retrofit	All	1.00	1.00	1.00	1.00	1.00	0.00	0.00
DHW Measures (Oil)	LI 1-4 Retrofit	All	1.00	1.00	1.00	1.00	1.00	0.00	0.00

In-Service Rates
All installations have 100% in service rate since all PAs programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factors.

Realization Rates
Realization rates are set to 100% since deemed savings are based on evaluation results.

Coincidence Factors
Coincidence factors are estimated using the demand allocation methodology described in the 2000 EnergyWise program impact evaluation.[60]

[57] Massachusetts Common Assumption.
[58] The Cadmus Group, Inc. (2009). *Impact Evaluation of the 2007 Appliance Management Program and Low Income Weatherization Program.* Prepared for National Grid.
[59] NMR Group, Inc., Tetra Tech (2011). *Massachusetts Special and Cross-Sector Studies Area, Residential and Low-Income Non-Energy Impacts (NEI) Evaluation,* Prepared for Massachusetts Program Administrators
[60] Quantec, LLC (2000). *Impact Evaluation: Single-Family EnergyWise Program*. Prepared for National Grid.

Hot Water – Dishwashers

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: Installation of ENERGY STAR® qualified dishwashers in residential homes during new construction or major renovation. ENERGY STAR® dishwashers are on average, 10% more energy-efficient than non-qualified models.
Primary Energy Impact: Electric
Secondary Energy Impact: Natural Gas, Oil, Propane
Non-Energy Impact: Residential Water, Low-Income Annual Discounted Rate Cost Reduction
Sector: Residential
Market: Lost Opportunity
End Use: Hot Water
Program: Residential New Construction & Major Renovation, Low-Income Residential New Construction

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed based on Energy Star calculations:

$$\Delta kWh = \Delta kWh$$
$$\Delta kW = \Delta kW$$

Where:
Unit = Installation of ENERGY® dishwasher
ΔkWh = Average annual energy reduction per unit: 74 kWh with electric water heating and 33 kWh with non-electric water heating; [61]
ΔkW = Average demand reduction per unit: 0.001 kW[62]

Baseline Efficiency

The baseline efficiency case is a conventional standard sized non-ENERGY STAR® qualified model meeting Federal Standards energy performance metric criteria effective January 1, 2010 for dishwashers with maximum energy consumption of less than or equal to 355 kwh/year and maximum water consumption of 6.5 gallons of water/cycle.[63]

[61] Environmental Protection Agency (2010). *Life Cycle Cost Estimate for ENERGY STAR Residential Dishwasher*.
[62] Estimated using demand allocation methodology described in: Quantec, LLC (2000). *Impact Evaluation: Single-Family EnergyWise Program*. Prepared for National Grid.
[63] Home: ENERGY STAR (2010). *Dishwasher Key Product Criteria*. http://www.energystar.gov/index.cfm?c=dishwash.pr_crit_dishwashers. Accessed on 10/20/10.

High Efficiency

The high efficiency case is an ENERGY STAR® qualified standard sized dishwasher meeting the energy performance metric criteria effective July 1, 2011 for dishwashers with maximum energy consumption of greater than or equal to 307 kwh/year and maximum water consumption of 5.0 gallons/cycle.

Hours

Dishwashers are assumed to run 215 cycles per year.[64]

Measure Life

The measure life is 10 years.[65]

Secondary Energy Impacts

Gas, Oil and Propane savings occur in homes where the water is heated by that fuel.

Measure	Energy Type	ΔMMBtu/Unit[66]
Dishwashers (Gas)	NG – Residential DHW	0.19
Dishwashers (Oil)	Oil	0.19
Dishwashers (Propane)	Propane	0.19

Non-Energy Impacts

Benefit Type	Description	Savings
Residential Water	Reduction in annual water usage compared to conventional unit[67]	430 Gallons/Unit
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Dishwashers	RNC, LI RNC	All	1.00	1.00	1.00	1.00	1.00	0.75	1.00

In-Service Rates
All installations have 100% in service rate since all PAs programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factors.

[64] Environmental Protection Agency (2010). *Life Cycle Cost Estimate for ENERGY STAR Residential Dishwasher*.
[65] Ibid.
[66] Environmental Protection Agency (2010). *Life Cycle Cost Estimate for ENERGY STAR Residential Dishwasher*. Oil and Propane MMBtu savings are assumed to be the same as ENERGY STAR estimated gas savings.
[67] Ibid.

Realization Rates
Realization rates are based on Massachusetts Common Assumptions.

Coincidence Factors
Coincidence factors are based on Massachusetts Common Assumptions.

Hot Water – Waterbed Mattress Replacement

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: Replacement of waterbed mattress with a standard mattress.
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: Low-Income Annual Discounted Rate Cost Reduction
Sector: Low Income
Market: Retrofit
End Use: Hot Water
Program: Low-Income 1-4 Family Retrofit, Low-Income Multifamily Retrofit

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed based on study results:

$$\Delta kWh = \Delta kWh$$
$$\Delta kW = \Delta kW$$

Where:

Unit	=	Mattress replacement
ΔkWh	=	Average annual energy reduction per unit: 872 kWh[68]
ΔkW	=	Average demand reduction per unit: 0.109 kW[69]

Baseline Efficiency

The baseline efficiency case is an existing waterbed mattress.

High Efficiency

The high efficiency case is a new standard mattress.

Hours

Not applicable.

[68] The Cadmus Group, Inc. (2009). *Impact Evaluation of the 2007 Appliance Management Program and Low Income Weatherization Program.* Prepared for National Grid.
[69] Estimated using demand allocation methodology described in: Quantec, LLC (2000). *Impact Evaluation: Single-Family EnergyWise Program.* Prepared for National Grid.

Measure Life

The measure life is 10 years.[70]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Waterbed	LI 1-4 Retrofit	All	1.00	1.00	1.00	1.00	1.00	0.75	1.00
Waterbed	LI MF Retrofit	All (not National Grid)	1.00	1.00	1.00	1.00	1.00	0.75	1.00

In-Service Rates
All installations have 100% in service rate since all PAs programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factors.

Realization Rates
Realization rates are set to 100% since deemed savings are based on evaluation results.

Coincidence Factors
Coincidence factors are estimated using the demand allocation methodology described in the 2000 EnergyWise program impact evaluation.[71]

[70] See the response to the question "How do I know when I need to buy a new mattress?" at the following link for more details: http://www.serta.com/#/best-mattress-FAQs-mattresses-Serta-Number-1-Best-Selling-Mattress.html (8/19/2010).
[71] Quantec, LLC (2000). *Impact Evaluation: Single-Family EnergyWise Program*. Prepared for National Grid.

Hot Water – Heat Pump Water Heater (Electric)

Version Date and Revision History

Effective Date: 1/1/2012
End Date: TBD

Measure Overview

Description: Installation of a heat pump water heater (HPWH) instead of an electric resistance water heater.
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: None
Sector: Residential
Market: Lost Opportunity
End Use: Hot Water
Program: Residential Cooling & Heating Equipment

Notes

The Heat Pump Hot Water Heater is part of an on going pilot study. The savings given in the 2012 Plan TRM version are based on preliminary results and engineering estimates. The pilot study will be completed in December 2012 in order to obtain a full year of metered data.

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed based on preliminary study results:

$$\Delta kWh = \Delta kWh$$
$$\Delta kW = \Delta kW$$

Where:
Unit = Household with heat pump water heater installed
ΔkWh = Average annual energy savings per unit. See table below.
ΔkW = Average demand reduction per unit. See table below.

HPWH Size	ΔkW[72]	ΔkWh[73]
50 gallon	3.32	1,817
80 gallon	3.32	2,712

[72] Demand savings based on engineering estimates. Savings based on 50 gallon tank, which will be conservative for the > 50 gallon scenario.
[73] Energy savings based on metered data from 14 in home installations over a 9 month period (November 2010 – July 2011). Savings are discounted by 5% to account for approximately 10% of units installed in conditioned spaces.

Baseline Efficiency

The baseline efficiency case is a new, standard efficiency electric resistance hot water heater.

High Efficiency

The high efficiency case is a high efficiency heat pump water heater.

Hours

Not applicable.

Measure Life

The measure life is 10 years.[74]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

There are no non-energy impacts for this measure.

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
HPWH (Electric)	RNC	All	1.00	1.00	1.00	1.00	1.00	0.75	1.00

In-Service Rates
All installations have 100% in service rate since all PAs programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factors.

Realization Rates
Realization rates are set to 100% since deemed savings are based on evaluation results.

Coincidence Factors
Coincidence factors are estimated using the demand allocation methodology described in the 2000 EnergyWise program impact evaluation.[75]

[74] Based on warranty of equipment.
[75] Quantec, LLC (2000). *Impact Evaluation: Single-Family EnergyWise Program*. Prepared for National Grid.

Hot Water – Heat Pump Water Heater (Oil and Other FF)

Version Date and Revision History

Effective Date: 1/1/2012
End Date: TBD

Measure Overview

Description: Installation of a heat pump water heater (HPWH) instead of an oil or propane water heater.
Primary Energy Impact: Oil and Other FF
Secondary Energy Impact: Electric
Non-Energy Impact: None
Sector: Residential
Market: Lost Opportunity
End Use: Hot Water
Program: Residential Cooling & Heating Equipment

Notes

The Heat Pump Hot Water Heater is part of an on going pilot study. The savings given in the 2012 Plan TRM version are based on preliminary results and engineering estimates. The pilot study will be completed in December 2012 in order to obtain a full year of metered data.

Algorithms for Calculating Primary Energy Impact

HPWH Size	Energy Type	Savings	ΔMMBtu/Unit
80 Gallon	Oil	190 Gallons[76]	26.4
50 Gallon	Propane		49.1[77]

Baseline Efficiency

The baseline efficiency case is a new, standard efficiency fuel oil or propane hot water heater.

High Efficiency

The high efficiency case is a high efficiency heat pump water heater. The oil water heaters tend to have comparable hot water capacity to larger heat pump water heater units. For example, a 32 gallon oil water heater has the same capacity as a 50 gallon HPWH, and a 50 gallon oil water heater has the same capacity as an 80 gallon HPWH. The comparable tank differences are reflected in the savings.

[76] Oil savings based on metered data from 14 in home installations over a 9 month period (November 2010 – July 2011).
[77] Propane savings based on metered natural gas data from home installations. Natural gas savings of 19.62 MMBtu per unit were multiplied by a conversion factor of 2.5 MMBtus of propane savings for every 1 MMBtu of natural gas savings.

Hours

Not applicable.

Measure Life

The measure life is 10 years.[78]

Secondary Energy Impacts

There is an electric penalty for this measure since the HPWH uses more electricity than the baseline oil water heater, see table below.

HPWH Size	kWh Penalty[79]	kW Penalty[80]
80 Gallon	-1795.11	-1.902
50 Gallon	-1551.87	-1.902

Non-Energy Impacts

There are no non-energy impacts for this measure.

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
HPWH (Oil and Other FF)	RHVAC	All	1.00	1.00	0.00	0.00	0.00	0.75	1.00

In-Service Rates
All installations have 100% in service rate since all PAs programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factors.

Realization Rates
Realization rates are set to 100% since deemed savings are based on evaluation results.

Coincidence Factors
Coincidence factors are estimated using the demand allocation methodology described in the 2000 EnergyWise program impact evaluation.[81]

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[78] Based on warranty of equipment.
[79] Electric penalty based on metered data from 14 in home installations over a 9 month period (November 2010 – July 2011). Penalty represents total annual operating energy use for a HPWH.
[80] Demand penalty based on engineering estimates. Savings based on 50 gallon tank, which will be conservative for the > 50 gallon scenario.
[81] Quantec, LLC (2000). *Impact Evaluation: Single-Family EnergyWise Program*. Prepared for National Grid.

HVAC – Central Air Conditioning

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: The installation of high efficiency Central AC systems.
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: None
Sector: Residential
Market: Lost Opportunity
End Use: HVAC
Program: Residential Cooling & Heating Equipment

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed based on the following algorithms and assumptions:

$$\Delta kWh = Tons \times \frac{12\ kBtu/hr}{Ton} \times \left(\frac{1}{SEER_{BASE}} - \frac{1}{SEER_{EE}} \right) \times Hours$$

$$\Delta kW = Tons \times \frac{12\ kBtu/hr}{Ton} \times \left(\frac{1}{EER_{BASE}} - \frac{1}{EER_{EE}} \right)$$

Where:

Unit	=	Installation of central AC system
Tons	=	Cooling capacity of AC equipment: Current default is 3 tons[82]
$SEER_{BASE}$	=	Seasonal Energy Efficiency Ratio of baseline AC equipment
$SEER_{EE}$	=	Seasonal Energy Efficiency Ratio of new efficient AC equipment
EER_{BASE}	=	Energy Efficiency Ratio of base AC equipment
EER_{EE}	=	Energy Efficiency Ratio of new efficient AC equipment
Hours	=	Equivalent full load hours

Baseline Efficiency

The baseline efficiency case is a central air-conditioning system with SEER = 13 and EER = 11. .

High Efficiency

The high efficiency case is an ENERGY STAR® qualified Central AC system. Average rated efficiency by measure is shown in the table below.[83]

[82] ADM Associates, Inc. (2009). *Residential Central AC Regional Evaluation*. Prepared for NSTAR, National Grid, Connecticut Light & Power and United Illuminating; Page 4-12, Table 4-9.
[83] The PAs are looking into abilities to track and calculate savings based on actual installed efficiencies for each project.

Table 4: Savings for Residential Central Air Conditioners

Measure	EER_{EE}	$SEER_{EE}$	ΔkW	ΔkWh
CoolSmart AC (SEER 14.5 / EER 12.0)	12.0	14.5	0.273	103
CoolSmart AC (SEER 15.0 / EER 12.5)	12.5	15.0	0.393	133
CoolSmart AC (SEER 15.0 / EER 13.0)	13.0	15.0	0.503	133
CoolSmart AC (SEER 16.0 / EER 13.0)	13.0	16.0	0.503	187

Hours

The equivalent full load cooling hours are 360 hours per year.[84]

Measure Life

The measure life is 18 years.[85]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
CoolSmart AC	RHVAC	All	1.00	1.00	1.00	1.00	1.00	0.25	0.00

In-Service Rates
All installations have 100% in service rate since all PAs programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factors.

Realization Rates
Realization rates are set to 100% based on Massachusetts Common Assumptions.

Coincidence Factors
Coincidence factors are based on evaluation study results.[86]

[84] ADM Associates, Inc. (2009). *Residential Central AC Regional Evaluation*. Prepared for NSTAR, National Grid, Connecticut Light & Power and United Illuminating; Page 4-5, Table 4-3.
[85] GDS Associates, Inc. (2007). *Measure Life Report: Residential and Commercial/Industrial Lighting and HVAC Measures*. Prepared for The New England State Program Working Group; Page 1-3, Table 1.
[86] ADM Associates, Inc. (2009). *Residential Central AC Regional Evaluation*. Prepared for NSTAR, National Grid, Connecticut Light & Power and United Illuminating; Page 4-12 Table 4-9.

HVAC – Air Source Heat Pump

Version Date and Revision History

Draft Date: 10/22/2010
Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: The installation of high efficiency Air Source Heat Pumps.
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: None
Sector: Residential
Market: Lost Opportunity
End Use: HVAC
Program: Residential Cooling & Heating Equipment

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed based on the following algorithms and assumptions:

$$\Delta kWh = Tons \times \frac{12\ kBtu/hr}{Ton} \times \left[\left(\frac{1}{SEER_{BASE}} - \frac{1}{SEER_{EE}} \right) \times Hours_C + \left(\frac{1}{HSPF_{BASE}} - \frac{1}{HSPF_{EE}} \right) \times Hours_H \right]$$

$$\Delta kW = \max(\Delta kW_{COOL}, \Delta kW_{HEAT})$$

$$\Delta kW_{COOL} = Tons \times \frac{12\ kBtu/hr}{Ton} \times \left(\frac{1}{EER_{BASE}} - \frac{1}{EER_{EE}} \right)$$

$$\Delta kW_H = Tons \times \frac{12\ kBtu/hr}{Ton} \times \left(\frac{1}{HSPF_{BASE}} - \frac{1}{HSPF_{EE}} \right)$$

Where:

Unit	=	Installation of heat pump system
Tons	=	Capacity of HP equipment: Current default is 3 tons[87]
$SEER_{BASE}$	=	Seasonal efficiency of baseline HP equipment
$SEER_{EE}$	=	Seasonal efficiency of new efficient HP equipment
EER_{BASE}	=	Peak efficiency of base HP equipment
EER_{EE}	=	Peak efficiency of new efficient HP equipment
$HSPF_{BASE}$	=	Heating efficiency of baseline HP equipment
$HSPF_{EE}$	=	Heating efficiency of new efficient HP equipment
$Hours_{C}$	=	EFLH for cooling
$Hours_{H}$	=	EFLH for heating

Baseline Efficiency

The baseline efficiency case is an air-source heat pump with SEER = 13, EER = 11and HSPF = 7. 7.

High Efficiency

The high efficiency case is an ENERGY STAR® qualified Air Source Heat Pump.

Table 5: Savings for Residential Air-Source Heat Pumps

Measure	EER_{EE}	$SEER_{EE}$	$HSPF_{EE}$	ΔkW_{C}	ΔkW_{H}	ΔkWh
CoolSmart HP (SEER 14.5 / EER 12.0 / HSPF 8.2)	12.0	14.5	8.2	0.273	0.347	519
CoolSmart HP (SEER 15.0 / EER 12.5 / HSPF 8.5)	12.5	15.0	8.5	0.393	0.502	735

Hours

Equivalent full load hours are 1200 hours/year for heating[88] and 360 hours/year for cooling.[89]

Measure Life

The measure life is 18 years.[90]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

[87] ADM Associates, Inc. (2009). *Residential Central AC Regional Evaluation*. Prepared for NSTAR, National Grid, Connecticut Light & Power and United Illuminating; Page 4-12, Table 4-9.
[88] Massachusetts Common Assumption.
[89] ADM Associates, Inc. (2009). *Residential Central AC Regional Evaluation*. Prepared for NSTAR, National Grid, Connecticut Light & Power and United Illuminating; Page 4-5, Table 4-3.
[90] GDS Associates, Inc. (2007). *Measure Life Report: Residential and Commercial/Industrial Lighting and HVAC Measures.* Prepared for The New England State Program Working Group; Page 1-3, Table 1.

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
CoolSmart HP	RHVAC	All	1.00	1.00	1.00	1.00	1.00	0.25	0.50

In-Service Rates
All installations have 100% in service rate since all PAs programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factors.

Realization Rates
Realization rates are set to 100% based on Massachusetts Common Assumptions.

Coincidence Factors
Coincidence factors are based on evaluation study results and Massachusetts Common Assumptions.[91]

[91] The coincidence factors included in the BC model do not match the coincidence factors that are in the TRM because the B/C model only allows for a single max kW reduction to be entered for each measure and the TRM provides separate summer and winter kW reductions for some measures. An adjustment was made to the coincidence factors in the BC model in order to get the model to calculate the correct summer and winter kW reductions.

HVAC – Ductless MiniSplit Heat Pump

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: The installation of a more efficient ENERGY STAR® rated Ductless Mini Split HP system. Energy is savings by a more efficient heating and cooling unit and from the elimination of duct losses.
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: None
Sector: Residential
Market: Lost Opportunity
End Use: HVAC
Program: Residential Cooling & Heating Equipment

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed based on the following algorithms and assumptions:

$$\Delta kWh_{HP} = Tons \times \frac{12\ kBtu/hr}{Ton}\left[\left(\frac{1}{SEER_{BASE}} - \frac{1}{SEER_{EE}}\right) \times Hours_C + \left(\frac{1}{HSPF_{BASE}} - \frac{1}{HSPF_{EE}}\right) \times Hours_H\right]$$

$$\Delta kW_{COOL} = Tons \times \frac{12\ kBtu/hr}{Ton} \times \left(\frac{1}{EER_{BASE}} - \frac{1}{EER_{EE}}\right)$$

$$\Delta kW_{HEAT} = Tons \times \frac{12\ kBtu/hr}{Ton} \times \left(\frac{1}{HSPF_{BASE}} - \frac{1}{HSPF_{EE}}\right)$$

Where:

Unit	=	Installation of high efficiency ductless Mini Split System
ΔkWh_{HP}	=	Reduction in annual kWh consumption of HP equipment
ΔkW_{HP}	=	Reduction in electric demand of HP equipment
Tons	=	Capacity of HP equipment: Current default is 1 tons [92]
$SEER_{BASE}$	=	Seasonal efficiency of baseline HP equipment, SEER 13 [93]
$SEER_{EE}$	=	Seasonal efficiency of new efficient HP equipment, see Table 6
EER_{BASE}	=	Peak efficiency of base HP equipment, 10 [94]
EER_{EE}	=	Peak efficiency of new efficient HP equipment, see Table 6
$HSPF_{BASE}$	=	Heating efficiency of baseline HP equipment, 7.7 [95]
$HSPF_{EE}$	=	Heating efficiency of new efficient HP equipment, see Table 6
$Hours_C$	=	EFLH for cooling
$Hours_H$	=	EFLH for heating

Baseline Efficiency

The baseline efficiency case is a non- ENERGY STAR® rated ductless mini split heat pump with SEER 13, EER 10 and HSPF 7.7.

High Efficiency

The high efficiency case is an ENERGY STAR® qualified Ductless Mini Split System.

Table 6: Savings for Residential Ductless MiniSplit Heat Pumps

Measure	$SEER_{EE}$	EER_{EE}	$HSPF_{EE}$	ΔkW_C	ΔkW_H	ΔkWh
Ductless MS HP (SEER 14.5 / EER 12.0 / HSPF 8.2)	14.5	12.0	8.2	0.200	0.095	148
Ductless MS HP (SEER 19, EER 12.83, HSPF 10.0)	19	12.83	10.0	0.265	0.358	535
Ductless MS HP (SEER 23, EER 13, HSPF 10.6)	23	13	10.6	0.277	0.426	656

Hours

The equivalent full load hours are 1200 hours/year for heating[96] and 360 hours/year for cooling.[97]

Measure Life

The measure life is 18 years.[98]

[92] About 75% of the mini-splits installed are 1 ton, regardless of SEER, per CSG.
[93] National Appliance Energy Conservation Act (NAECA) (2006)
[94] AHRI (Air Conditioning, Heating, and Refrigeration Institute) (2011). Average EER of current in-market equipment with a SEER of 13 from website at http://www.ahridirectory.org/ahridirectory/pages/home.aspx. Under Directory of Certified Product Performance>Residential>Variable Speed Mini-Split and Multi-Split Air Conditioners. Specified Model Status = Active, Indoor Type = Mini-Splits, and SEER Min and Max of 13.
[95] National Appliance Energy Conservation Act (NAECA) (2006).
[96] Massachusetts Common Assumption.
[97] ADM Associates, Inc. (2009). *Residential Central AC Regional Evaluation*. Prepared for NSTAR, National Grid, Connecticut Light & Power and United Illuminating; Page 4-5, Table 4-3.

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Ductless Mini Split HP	RHVAC	All	1.00	1.00	1.00	1.00	1.00	0.25	0.50

In-Service Rates
All installations have 100% in service rate since all PAs programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factors.

Realization Rates
Realization rates are set to 100% based on Massachusetts Common Assumptions.

Coincidence Factors
Coincidence factors are based on evaluation study results and Massachusetts Common Assumptions.[99]

[98] GDS Associates, Inc. (2007). *Measure Life Report: Residential and Commercial/Industrial Lighting and HVAC Measures*. Prepared for The New England State Program Working Group; Page 1-3, Table 1.
[99] The coincidence factors included in the BC model do not match the coincidence factors that are in the TRM because the B/C model only allows for a single max kW reduction to be entered for each measure and the TRM provides separate summer and winter kW reductions for some measures. An adjustment was made to the coincidence factors in the BC model in order to get the model to calculate the correct summer and winter kW reductions.

HVAC – Ductless MiniSplit Air Conditioner

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: The installation of an ENERGY STAR® rated Ductless Mini Split AC system.
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: None
Sector: Residential
Market: Lost Opportunity
End Use: HVAC
Program: Residential Cooling & Heating Equipment

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed based on the following algorithms and assumptions:

$$\Delta kWh = Tons \times \frac{12\ kBtu/hr}{Ton} \times \left(\frac{1}{SEER_{BASE}} - \frac{1}{SEER_{EE}} \right) \times Hours + \Delta kWh_{DuctSealing}$$

$$\Delta kW = Tons \times \frac{12\ kBtu/hr}{Ton} \times \left(\frac{1}{EER_{BASE}} - \frac{1}{EER_{EE}} \right) + \Delta kW_{DuctSealing}$$

Where:

Unit	=	Installation of central AC system
Tons	=	Cooling capacity of AC equipment: Current default is 3 tons[100]
$SEER_{BASE}$	=	Seasonal efficiency of baseline AC equipment
$SEER_{EE}$	=	Seasonal efficiency of new efficient AC equipment
EER_{BASE}	=	Peak efficiency of base AC equipment
EER_{EE}	=	Peak efficiency of new efficient AC equipment
Hours	=	Equivalent full load hours
$\Delta kWh_{DuctSealing}$	=	Annual energy savings from duct sealing: See *HVAC – Duct Sealing*
$\Delta kW_{DuctSealing}$	=	Annual demand reduction from duct sealing: See *HVAC – Duct Sealing*

Baseline Efficiency

The baseline efficiency case is a central air-conditioning system with SEER = 13 and EER = 11.

[100] ADM Associates, Inc. (2009). *Residential Central AC Regional Evaluation*. Prepared for NSTAR, National Grid, Connecticut Light & Power and United Illuminating; Page 4-12, Table 4-9.

High Efficiency

The high efficiency case is a Ductless Mini Split system with SEER = 14 and EER = 11.5, and with duct sealing measures implemented.

Measure	EER_{EE}	$SEER_{EE}$	ΔkW	ΔkWh
Ductless Mini Split AC	11.5	14	0.442	283

Hours

Equivalent full load cooling hours are 360 hours per year.[101]

Measure Life

The measure life is 18 years.[102]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Ductless Mini Split AC	RHVAC	All	1.00	1.00	1.00	1.00	1.00	0.25	0.00

In-Service Rates
All installations have 100% in service rate since all PAs programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factors.

Realization Rates
Realization rates are set to 100% based on Massachusetts Common Assumptions.

Coincidence Factors
Coincidence factors are based on evaluation study results[103].

[101] ADM Associates, Inc. (2009). *Residential Central AC Regional Evaluation*. Prepared for NSTAR, National Grid, Connecticut Light & Power and United Illuminating; Page 4-5, Table 4-3.
[102] GDS Associates, Inc. (2007). *Measure Life Report: Residential and Commercial/Industrial Lighting and HVAC Measures*. Prepared for The New England State Program Working Group; Page 1-3, Table 1.
[103] ADM Associates, Inc. (2009). *Residential Central AC Regional Evaluation*. Prepared for NSTAR, National Grid, Connecticut Light & Power and United Illuminating; Page 4-12 Table 4-9.

HVAC – Central AC Quality Installation Verification (QIV)

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: The verification of proper charge and airflow during installation of new Central AC system.
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: None
Sector: Residential
Market: Lost Opportunity
End Use: HVAC
Program: Residential Cooling & Heating Equipment

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed based on the following algorithms and assumptions:

$$\Delta kWh = Tons \times \frac{12\ kBtu/hr}{Ton} \times \frac{1}{SEER} \times Hours \times 5\%$$

$$\Delta kW = Tons \times \frac{12\ kBtu/hr}{Ton} \times \frac{1}{EER} \times 5\%$$

Where:

Units	=	Completed QIV
ΔkW	=	Average demand reduction per unit: 0.164 kW (calculated)
ΔkWh	=	Average annual energy reduction per unit: 50 kWh (calculated)
Tons	=	Cooling capacity of AC equipment: Current default is 3 tons [104]
SEER	=	Seasonal efficiency of AC equipment: Default = 13
EER	=	Peak efficiency of AC equipment: Default = 11
Hours	=	Equivalent full load hours
5%	=	Average percent demand reduction: 5.0%[105]

Baseline Efficiency

The baseline efficiency case is a baseline cooling system (SEER = 13 and EER = 11) whose installation is inconsistent with manufacturer specifications.

[104] ADM Associates, Inc. (2009). *Residential Central AC Regional Evaluation*. Prepared for NSTAR, National Grid, Connecticut Light & Power and United Illuminating; Page 4-12, Table 4-9.
[105] Massachusetts Common Assumption.

High Efficiency

The high efficiency case is the same baseline cooling system whose installation is consistent with manufacturer specifications.

Hours

Equivalent full load cooling hours are 360 hours per year.[106]

Measure Life

The measure life is 18 years.[107]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
CoolSmart AC QIV ES	RHVAC	All	1.00	1.00	1.00	1.00	1.00	0.25	0.00
CoolSmart AC QIV NES	RHVAC	All	1.00	1.00	1.00	1.00	1.00	0.25	0.00

In-Service Rates
All installations have 100% in service rate since all PAs programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factors.

Realization Rates
Realization rates are set to 100% based on Massachusetts Common Assumptions.

Coincidence Factors
Coincidence factors are based on evaluation study results[108].

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106 ADM Associates, Inc. (2009). *Residential Central AC Regional Evaluation*. Prepared for NSTAR, National Grid, Connecticut Light & Power and United Illuminating; Page 4-5, Table 4-3.
107 GDS Associates, Inc. (2007). *Measure Life Report: Residential and Commercial/Industrial Lighting and HVAC Measures*. Prepared for The New England State Program Working Group; Page 1-3, Table 1.
108 ADM Associates, Inc. (2009). *Residential Central AC Regional Evaluation*. Prepared for NSTAR, National Grid, Connecticut Light & Power and United Illuminating; Page 4-12 Table 4-9.

HVAC – Heat Pump Quality Installation Verification (QIV)

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: The verification of proper charge and airflow during installation of new Heat Pump systems.
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: None
Sector: Residential
Market: Lost Opportunity
End Use: HVAC
Program: Residential Cooling & Heating Equipment

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed based on the following algorithms and assumptions:

$$\Delta kWh = Tons \times \frac{12\ kBtu/hr}{Ton} \times \left(\frac{1}{SEER} \times Hours_C + \frac{1}{HSPF} \times Hours_H \right) \times 5\%$$

$$\Delta kW = \max(\Delta kW_{COOL}, \Delta kW_{HEAT})$$

$$\Delta kW_{COOL} = Tons \times \frac{12\ kBtu/hr}{Ton} \times \left(\frac{1}{EER} \right) \times 5\%$$

$$\Delta kW_{HEAT} = Tons \times \frac{12\ kBtu/hr}{Ton} \times \left(\frac{1}{HSPF} \right) \times 5\%$$

Where:

Unit	=	Completed QIV
ΔkW	=	Average demand reduction per unit: 0.237 kW (calculated)
ΔkWh	=	Average annual energy reduction per unit: 334 kWh (calculated)
Tons	=	Cooling capacity of HP equipment: Current default is 3 tons [109]
SEER	=	Seasonal cooling efficiency of HP equipment
EER	=	Peak cooling efficiency of HP equipment
HSPF	=	Heating efficiency of HP equipment
$Hours_C$	=	EFLH for cooling
$Hours_H$	=	EFLH for heating
5%	=	Average demand reduction: 5%[110]

[109] ADM Associates, Inc. (2009). *Residential Central AC Regional Evaluation*. Prepared for NSTAR, National Grid, Connecticut Light & Power and United Illuminating; Page 4-12, Table 4-9.
[110] Massachusetts Common Assumption.

Baseline Efficiency

The baseline efficiency case is a baseline heating and cooling system (SEER = 13, EER = 11 and HSPF = 7.6) whose installation is inconsistent with manufacturer specifications.

High Efficiency

The high efficiency case is the same heating and cooling system whose installation is consistent with manufacturer specifications.

Hours

The equivalent full load heating hours are 1,200 hours per year and the equivalent full load cooling hours are 360 hours per year.[111]

Measure Life

The measure life is 18 years.[112]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
CoolSmart HP QIV ES	RHVAC	All	1.00	1.00	1.00	1.00	1.00	0.25	0.50
CoolSmart HP QIV NES	RHVAC	All	1.00	1.00	1.00	1.00	1.00	0.25	0.50

In-Service Rates
All installations have 100% in service rate since all PAs programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factors.

Realization Rates
Realization rates are set to 100% based on Massachusetts Common Assumptions.

[111] ADM Associates, Inc. (2009). *Residential Central AC Regional Evaluation*. Prepared for NSTAR, National Grid, Connecticut Light & Power and United Illuminating; Page 4-5, Table 4-3.
[112] GDS Associates, Inc. (2007). *Measure Life Report: Residential and Commercial/Industrial Lighting and HVAC Measures*. Prepared for The New England State Program Working Group; Page 1-3, Table 1.

Coincidence Factors

Coincidence factors are based on Massachusetts Common Assumptions.[113]

[113] The coincidence factors included in the BC model do not match the coincidence factors that are in the TRM because the B/C model only allows for a single max kW reduction to be entered for each measure and the TRM provides separate summer and winter kW reductions for some measures. An adjustment was made to the coincidence factors in the BC model in order to get the model to calculate the correct summer and winter kW reductions.

HVAC – Central AC Digital Check-up/Tune–up

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: Tune-up of an existing central AC system.
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: None
Sector: Residential
Market: Lost Opportunity
End Use: HVAC
Program: Residential Cooling & Heating Equipment

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed based on the following algorithms and assumptions:

$$\Delta kWh = Tons \times \frac{12\ kBtu/hr}{Ton} \times \frac{1}{SEER} \times Hours \times 5\%$$

$$\Delta kW = Tons \times \frac{12\ kBtu/hr}{Ton} \times \frac{1}{EER} \times 5\%$$

Where:

Unit	=	Completed tune-up
ΔkWh	=	Average annual energy reduction per unit: 65 kWh (calculated)
ΔkW	=	Average demand reduction per unit: 0.212 kW (calculated)
Tons	=	Cooling capacity of AC equipment: Current default is 3 tons[114]
SEER	=	Seasonal efficiency of AC equipment
EER	=	Peak efficiency of AC equipment
Hours	=	Equivalent full load hours
5%	=	Average demand reduction: 5%[115]

Baseline Efficiency

The baseline efficiency case is a baseline cooling system (SEER = 13 and EER = 11) that does not operate according to manufacturer specifications.

[114] ADM Associates, Inc. (2009). *Residential Central AC Regional Evaluation*. Prepared for NSTAR, National Grid, Connecticut Light & Power and United Illuminating; Page 4-12, Table 4-9.
[115] Massachusetts Common Assumption.

High Efficiency

The high efficiency case is the same cooling system that operates according to manufacturer specifications.

Hours

The equivalent full load cooling hours are 360 hours per year.[116]

Measure Life

The measure life is 5 years.[117]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
CoolSmart AC Digital Check-up/Tune-up	RHVAC	All	1.00	1.00	1.00	1.00	1.00	0.25	0.00

In-Service Rates
All installations have 100% in service rate since all PAs programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factors.

Realization Rates
Realization rates are based on Massachusetts Common Assumptions.

Coincidence Factors
Coincidence factors are based on evaluation study results[118].

[116] ADM Associates, Inc. (2009). *Residential Central AC Regional Evaluation*. Prepared for NSTAR, National Grid, Connecticut Light & Power and United Illuminating; Page 4-5, Table 4-3.
[117] GDS Associates, Inc. (2007). *Measure Life Report: Residential and Commercial/Industrial Lighting and HVAC Measures*. Prepared for The New England State Program Working Group; Page 1-3, Table 1.
[118] ADM Associates, Inc. (2009). *Residential Central AC Regional Evaluation*. Prepared for NSTAR, National Grid, Connecticut Light & Power and United Illuminating; Page 4-12 Table 4-9.

HVAC – Heat Pump Digital Check-up/Tune-up

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: Tune-up of an existing heat pump system.
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: None
Sector: Residential
Market: Lost Opportunity
End Use: HVAC
Program: Residential Cooling & Heating Equipment

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed based on the following algorithms and assumptions:

$$\Delta kWh = Tons \times \frac{12\ kBtu/hr}{Ton} \times \left(\frac{1}{SEER} \times Hours_C + \frac{1}{HSPF} \times Hours_H \right) \times 5\%$$

$$\Delta kW = \max(\Delta kW_{COOL}, \Delta kW_{HEAT})$$

$$\Delta kW_{COOL} = Tons \times \frac{12\ kBtu/hr}{Ton} \times \left(\frac{1}{EER} \right) \times 5\%$$

$$\Delta kW_{HEAT} = Tons \times \frac{12\ kBtu/hr}{Ton} \times \left(\frac{1}{HSPF} \right) \times 5\%$$

Where:

Unit	=	Completed tune-up
ΔkWh	=	Average annual energy reduction per unit: 373 kWh (calculated)
ΔkW	=	Average demand reduction per unit: 0.257 kW (calculated)
Tons	=	Cooling capacity of HP equipment: Current default is 3 tons[119]
SEER	=	Seasonal cooling efficiency of HP equipment
EER	=	Peak cooling efficiency of HP equipment
HSPF	=	Heating efficiency of HP equipment
$Hours_C$	=	EFLH for cooling
$Hours_H$	=	EFLH for heating
5%	=	Average demand reduction: 5%[120]

Baseline Efficiency

[119] ADM Associates, Inc. (2009). *Residential Central AC Regional Evaluation*. Prepared for NSTAR, National Grid, Connecticut Light & Power and United Illuminating; Page 4-12, Table 4-9.
[120] Massachusetts Common Assumption.

The baseline efficiency case is a system baseline heating and cooling system (SEER = 13, EER = 11 and HSPF = 76) that does not operating according to manufacturer specifications.

High Efficiency

The high efficiency case is the same heating and cooling system that does operate according to manufacturer specifications.

Hours

The equivalent full load hours are 1200 hours per year for heating[121] and 360 hours per year for cooling.[122]

Measure Life

The measure life is 5 years[123]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
CoolSmart HP Digital Check-up/Tune-up	RHVAC	All	1.00	1.00	1.00	1.00	1.00	0.25	0.50

In-Service Rates
All installations have 100% in service rate since all PAs programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factors.

Realization Rates
Realization rates are set to 100% based on Massachusetts Common Assumptions.

Coincidence Factors
Coincidence factors are based on evaluation study results and Massachusetts Common Assumptions.[124]

[121] Massachusetts Common Assumption.
[122] ADM Associates, Inc. (2009). *Residential Central AC Regional Evaluation*. Prepared for NSTAR, National Grid, Connecticut Light & Power and United Illuminating; Page 4-5, Table 4-3.
[123] GDS Associates, Inc. (2007). *Measure Life Report: Residential and Commercial/Industrial Lighting and HVAC Measures*. Prepared for The New England State Program Working Group; Page 1-3, Table 1.

HVAC – Duct Sealing

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: A 66% reduction in duct leakage from 15% to 5% of supplied CFM.
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: None
Sector: Residential
Market: Lost Opportunity
End Use: HVAC
Program: Residential Cooling & Heating Equipment

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed based on results of DOE2 modeling:

$$\Delta kWh = \Delta kWh$$

$$\Delta kW = \Delta kW$$

Where:

Unit	=	Completed job
ΔkW	=	Average demand reduction per unit: 0.300 kW[125]
ΔkWh	=	Average annual energy reduction per unit: 212 kWh[126]

Baseline Efficiency

The baseline efficiency case is assumes a 15% leakage.

High Efficiency

The high efficiency case is a system with duct leakage reduced by 66% to 5% leakage.

[124] The coincidence factors included in the BC model do not match the coincidence factors that are in the TRM because the B/C model only allows for a single max kW reduction to be entered for each measure and the TRM provides separate summer and winter kW reductions for some measures. An adjustment was made to the coincidence factors in the BC model in order to get the model to calculate the correct summer and winter kW reductions.
[125] RLW Analytics (2002). *Market Research for the Rhode Island, Massachusetts, and Connecticut Residential HVAC Market*. Prepared for National Grid, Northeast Utilities, NSTAR, Fitchburg Gas and Electric Light Company and United Illuminating; Page 3, Table 2.
[126] Ibid

Hours

Not applicable.

Measure Life

The measure life is 18 years.[127]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Duct Sealing	RHVAC	All	1.00	1.00	1.00	1.00	1.00	0.25	0.00

In-Service Rates
All installations have 100% in service rate since all PAs programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factors.

Realization Rates
Realization rates are set to 100% based on Massachusetts Common Assumptions.

Coincidence Factors
Coincidence factors are based on evaluation study results[128].

[127] GDS Associates, Inc. (2007). *Measure Life Report: Residential and Commercial/Industrial Lighting and HVAC Measures*. Prepared for The New England State Program Working Group; Page 1-3, Table 1.
[128] ADM Associates, Inc. (2009). *Residential Central AC Regional Evaluation*. Prepared for NSTAR, National Grid, Connecticut Light & Power and United Illuminating; Page 4-12 Table 4-9.

HVAC – Down Size ½ Ton

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: Reduction in system size consistent with manual J calculations.
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: One-Time Cost Reduction
Sector: Residential
Market: Lost Opportunity
End Use: HVAC
Program: Residential Cooling & Heating Equipment

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed based on results of DOE2 modeling:

$$\Delta kWh = \Delta kWh / Ton \times \frac{1}{2}\, Ton$$
$$\Delta kW = \Delta kW / Ton \times \frac{1}{2}\, Ton$$

Where:

Units	=	Completed job
ΔkW/Ton	=	Average demand reduction per ton: 0.295 kW[129]
ΔkWh/Ton	=	Average annual energy reduction per ton: 203 kWh[130]

Baseline Efficiency

The baseline efficiency case is a system that is not sized in accordance with manual J calculation.

High Efficiency

The high efficiency case is a system that is sized in accordance with manual J calculation.

Hours

Not applicable.

[129] RLW Analytics (2002). *Market Research for the Rhode Island, Massachusetts, and Connecticut Residential HVAC Market*. Prepared for National Grid, Northeast Utilities, NSTAR, Fitchburg Gas and Electric Light Company and United Illuminating; Page 3, Table 2
[130] ibid.

Measure Life

The measure life is 18 years.[131]

Secondary-Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Down Size ½ Ton	RHVAC	All	1.00	1.00	1.00	1.00	1.00	0.25	0.00

In-Service Rates
All installations have 100% in service rate since all PAs programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factors.

Realization Rates
Realization rates are set to 100% based on Massachusetts Common Assumptions.

Coincidence Factors
Coincidence factors are based on evaluation study results[132].

[131] GDS Associates, Inc. (2007). *Measure Life Report: Residential and Commercial/Industrial Lighting and HVAC Measures*. Prepared for The New England State Program Working Group; Page 1-3, Table 1.
[132] ADM Associates, Inc. (2009). *Residential Central AC Regional Evaluation*. Prepared for NSTAR, National Grid, Connecticut Light & Power and United Illuminating; Page 4-12 Table 4-9.

HVAC – Right Sizing

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: Documentation that system size is in compliance with manual J calculations.
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: O&M
Sector: Residential
Market: Lost Opportunity
End Use: HVAC
Program: Residential Cooling & Heating Equipment

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed based on results of DOE2 modeling:

$$\Delta kWh = \Delta kWh$$

$$\Delta kW = \Delta kW$$

Where:

Units	=	completed job
ΔkWh	=	Average annual energy reduction per unit: 123 kWh[133]
ΔkW	=	Average demand reduction per unit: 0.150 kW[134]

Baseline Efficiency

The baseline efficiency case is a system that is not sized in accordance with manual J calculation.

High Efficiency

The high efficiency case is a system that is sized in accordance with manual J calculation.

Hours

Not applicable.

[133] RLW Analytics (2002). *Market Research for the Rhode Island, Massachusetts, and Connecticut Residential HVAC Market*. Prepared for National Grid, Northeast Utilities, NSTAR, Fitchburg Gas and Electric Light Company and United Illuminating; Page 3, Table 2.
[134] Ibid**.**

Measure Life

The measure life is 18 years.[135]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Right Sizing Tier 1	RHVAC	All	1.00	1.00	1.00	1.00	1.00	0.25	0.00
Right Sizing Tier 2	RHVAC	All	1.00	1.00	1.00	1.00	1.00	0.25	0.00

In-Service Rates
All installations have 100% in service rate since all PAs programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factors.

Realization Rates
Realization rates are set to 100% based on Massachusetts Common Assumptions.

Coincidence Factors
Coincidence factors are based on evaluation study results[136].

[135] GDS Associates, Inc. (2007). *Measure Life Report: Residential and Commercial/Industrial Lighting and HVAC Measures*. Prepared for The New England State Program Working Group; Page 1-3, Table 1.
[136] ADM Associates, Inc. (2009). *Residential Central AC Regional Evaluation*. Prepared for NSTAR, National Grid, Connecticut Light & Power and United Illuminating; Page 4-12 Table 4-9.

HVAC – Early Replacement of Central AC or Heat Pump Unit

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: Early replacement of Central Air Conditioning or Heat Pump Unit. This measure represents the additional savings achieved for the early replacement of existing inefficient AC or heat pump units over the remaining life of the existing equipment.
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: None
Sector: Residential
Market: Retrofit
End Use: HVAC
Program: Residential Cooling & Heating Equipment

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed based on the following algorithms and assumptions:

$$\Delta kWh = Tons \times \frac{12\ kBtu/hr}{Ton} \times \left[\left(\frac{1}{SEER_{BASE}} - \frac{1}{SEER_{EE}} \right) \times Hours_C + \left(\frac{1}{HSPF_{BASE}} - \frac{1}{HSPF_{EE}} \right) \times Hours_H \right]$$

$$\Delta kW = \max(\Delta kW_{COOL}, \Delta kW_{HEAT})$$

$$\Delta kW_{COOL} = Tons \times \frac{12\ kBtu/hr}{Ton} \times \left(\frac{1}{EER_{BASE}} - \frac{1}{EER_{EE}} \right)$$

$$\Delta kW_{HEAT} = Tons \times \frac{12\ kBtu/hr}{Ton} \times \left(\frac{1}{HSPF_{BASE}} - \frac{1}{HSPF_{EE}} \right)$$

Where:

Unit	=	Replacement of existing inefficient system with new efficient system
Tons	=	Capacity of AC/HP equipment: Current default is 3 tons[137]
$SEER_{BASE}$	=	Seasonal efficiency of baseline AC equipment
$SEER_{EE}$	=	Seasonal efficiency of new efficient AC equipment
EER_{BASE}	=	Peak efficiency of base AC equipment
EER_{EE}	=	Peak efficiency of new efficient AC equipment
$HSPF_{BASE}$	=	Heating efficiency of baseline HP equipment
$HSPF_{EE}$	=	Heating efficiency of new efficient HP equipment
$Hours_C$	=	EFLH for cooling
$Hours_H$	=	EFLH for heating

[137] ADM Associates, Inc. (2009). *Residential Central AC Regional Evaluation*. Prepared for NSTAR, National Grid, Connecticut Light & Power and United Illuminating; Page 4-12, Table 4-9.

Baseline Efficiency

The baseline efficiency case is assumed to be a typical 10-12 year-old central air-conditioning or heat pump unit with SEER 10, EER 8.5, HSPF 7.0.

High Efficiency

For the retirement savings over the remaining life of existing AC unit, the efficient case is a SEER 13, EER 11, HSPF 7.6 unit. For the high efficiency savings over lifetime of the new AC unit, the efficient case is a new high efficiency SEER 14.5, EER 12, 8.2 HSPF unit.

Measure	EER_{BASE}	$SEER_{BASE}$	$HSPF_{BASE}$	EER_{EE}	$SEER_{EE}$	$HSPF_{EE}$	ΔkW_C	ΔkW_H	ΔkWh
Early Replacement AC_{RETIRE}	8.5	10	n/a	11	13	n/a	0.963	0.000	299
Early Replacement AC_{EE}	11	13	n/a	12	14.5	n/a	0.273	0.000	103
Early Replacement HP_{RETIRE}	8.5	10	7.0	11	13	7.6	0.963	0.406	786
Early Replacement HP_{EE}	11	13	7.6	12	14.5	8.2	0.273	0.347	519

Hours

The equivalent full load hours are 1,200 hours per year for heating[138] and 360 hours per year for cooling.[139]

Measure Life

The remaining life for the existing unit is 7 years[140], and the measure life of new equipment is 18 years[141]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

[138] Massachusetts Common Assumption.
[139] ADM Associates, Inc. (2009). *Residential Central AC Regional Evaluation*. Prepared for NSTAR, National Grid, Connecticut Light & Power and United Illuminating; Page 4-5, Table 4-3.
[140] Massachusetts Common Assumption: The early replacement measure life of 7 years was determined by subtracting the estimated target age range of existing equipment between 10 and 12 years old from the 18 year measure life for new equipment.
[141] GDS Associates, Inc. (2007). *Measure Life Report: Residential and Commercial/Industrial Lighting and HVAC Measures*. Prepared for The New England State Program Working Group; Page 1-3, Table 1.

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Early Replacement AC	RHVAC	All	1.00	1.00	1.00	1.00	1.00	0.25	0.00
Early Replacement HP	RHVAC	All	1.00	1.00	1.00	1.00	1.00	0.25	0.50

In-Service Rates
All installations have 100% in service rate since all PAs programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factors.

Realization Rates
Realization rates are set to 100% based on Massachusetts Common Assumptions.

Coincidence Factors
Coincidence factors are based on evaluation study results[142] and Massachusetts Common Assumptions. [143]

[142] ADM Associates, Inc. (2009). *Residential Central AC Regional Evaluation*. Prepared for NSTAR, National Grid, Connecticut Light & Power and United Illuminating; Page 4-12 Table 4-9.
[143] The coincidence factors included in the BC model do not match the coincidence factors that are in the TRM because the B/C model only allows for a single max kW reduction to be entered for each measure and the TRM provides separate summer and winter kW reductions for some measures. An adjustment was made to the coincidence factors in the BC model in order to get the model to calculate the correct summer and winter kW reductions.

HVAC – Quality Installation with Duct Modification

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: 50% reduction in duct leakage from 20% to 10%. This measure may also include duct modifications.
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: None
Sector: Residential
Market: Lost Opportunity
End Use: HVAC
Program: Residential Cooling & Heating Equipment

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed based on results of DOE2 modeling:

$$\Delta kWh = \Delta kWh$$

$$\Delta kW = \Delta kW$$

Where:

Unit	=	Completed job
ΔkWh	=	Average annual energy reduction per unit: 513 kWh with duct modifications, 212 kWh without duct modifications[144]
ΔkW	=	Average demand reduction per unit: 0. 850 kW with duct modifications, 0.300 kW without duct modifications[145]

Baseline Efficiency

The baseline efficiency case is a system with an installation that is inconsistent with manufacturer specifications and may include leaky ducts.

High Efficiency

The high efficiency case is a system with an installation that is consistent with manufacturer specifications and may have reduced duct leakage.

[144] RLW Analytics (2002). *Market Research for the Rhode Island, Massachusetts, and Connecticut Residential HVAC Market*. Prepared for National Grid, Northeast Utilities, NSTAR, Fitchburg Gas and Electric Light Company and United Illuminating; Page 3, Table 2.
[145] Ibid.

Hours

Not applicable.

Measure Life

The measure life is 18 years.[146]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Energy Star QI	RHVAC	All	1.00	1.00	1.00	1.00	1.00	0.25	0.00
Energy Star QI w/ Duct Modifications	RHVAC	All	1.00	1.00	1.00	1.00	1.00	0.25	0.00

In-Service Rates
All installations have 100% in service rate since all PAs programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factors.

Realization Rates
Realization rates are set to 100% based on Massachusetts Common Assumptions.

Coincidence Factors
Coincidence factors are based on evaluation study results[147].

[146] GDS Associates, Inc. (2007). *Measure Life Report: Residential and Commercial/Industrial Lighting and HVAC Measures*. Prepared for The New England State Program Working Group; Page 1-3, Table 1.
[147] ADM Associates, Inc. (2009). *Residential Central AC Regional Evaluation*. Prepared for NSTAR, National Grid, Connecticut Light & Power and United Illuminating; Page 4-12 Table 4-9.

HVAC – TXV Valve Replacement of Fixed Orifice

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: The replacement of a fixed orifice with a Thermostatic eXpansion Valve (TXV).
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: None
Sector: Residential
Market: Lost Opportunity
End Use: HVAC
Program: Residential Cooling & Heating Equipment

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed based on the following algorithms and assumptions:

$$\Delta kWh = Tons \times \frac{12\ kBtu/hr}{Ton} \times \frac{1}{SEER} \times Hours \times 10.5\%$$

$$\Delta kW = \Delta kW$$

Where:

Unit	=	Installation of TXV valve
ΔkWh	=	Average annual energy reduction per unit: 105 k Wh (calculated)
ΔkW	=	Average annual kW reduction: 0.156[148]
Tons	=	Cooling capacity of AC equipment: Default is 3 tons[149]
SEER	=	Seasonal efficiency of AC equipment
Hours	=	Annual operating hours
10.5%	=	Average percent demand reduction: 10.5%[150]

Baseline Efficiency

The baseline efficiency case is a system with a fixed orifice expansion and SEER = 13.

High Efficiency

The high efficiency case is a system with a Thermostatic eXpansion Valve (TXV) and SEER = 13.

[148] Estimated using demand allocation methodology described in: Quantec, LLC (2000). *Impact Evaluation: Single-Family EnergyWise Program.* Prepared for National Grid.
[149] ADM Associates, Inc. (2009). *Residential Central AC Regional Evaluation.* Prepared for NSTAR, National Grid, Connecticut Light & Power and United Illuminating; Page 4-12, Table 4-9.
[150] Northeast Energy Efficiency Partnerships (2006). *Strategies to Increase Residential HVAC Efficiency in the Northeast.* Prepared for NASEO; Appendix B.

Hours

Not applicable.

Measure Life

The measure life is 7 years.[151]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
TXV Replacement of Fixed Orifice	RHVAC	All	1.00	1.00	1.00	1.00	1.00	0.25	0.00

In-Service Rates
All installations have 100% in service rate since all PAs programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factors.

Realization Rates
Realization rates are set to 100% based on Massachusetts Common Assumptions.

Coincidence Factors
Coincidence factors are based on evaluation study results[152].

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[151] GDS Associates, Inc. (2007). *Measure Life Report: Residential and Commercial/Industrial Lighting and HVAC Measures*. Prepared for The New England State Program Working Group.
[152] ADM Associates, Inc. (2009). *Residential Central AC Regional Evaluation*. Prepared for NSTAR, National Grid, Connecticut Light & Power and United Illuminating; Page 4-12 Table 4-9.

HVAC – Furnace Fan Motors (ECM)

Version Date and Revision History

Effective Date: 1/1/2011 (revised for 1/1/2012)
End Date: TBD

Measure Overview

Description: Installation of high efficiency motors on residential furnace fans, including electronically commutated variable speed air supply motors.
Primary Energy Impact: Electric
Secondary Energy Impact: Natural Gas (Residential Heat)
Non-Energy Impact: None
Sector: Residential
Market: Lost Opportunity
End Use: HVAC
Program: Residential Cooling & Heating Equipment

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed based on the following algorithms and assumptions:

$$\Delta kWh = \Delta kWh$$
$$\Delta kW = \Delta kW$$

Where:

Unit	=	Installation of high efficiency furnace fan motor
ΔkWh	=	Average annual energy reduction per unit: 168 kWh[153]
ΔkW	=	Average demand reduction per unit: 0.214 kW[154]

Baseline Efficiency

The baseline efficiency case is the installation of a furnace with a standard efficiency steady state motor.

High Efficiency

The high efficiency case is the installation of a furnace with an electronically commutated motor.

Hours

Not applicable.

153 ERS (2011) Pilot Evaluation of BFM DRAFT. Results as of 9/29/2011.
154 Ibid

Measure Life

The measure life is 18 years.[155]

Secondary Energy Impacts

A heating penalty results due to reduced heat loss of the efficient furnace motor.

Measure	Energy Type	ΔMMBtu/Unit[156]
CoolSmart Warm Air Furnace ECM	Natural Gas (Residential Heat)	-0.716

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
CoolSmart Warm Air Furnace ECM	RHVAC	All	1.00	1.00	1.00	1.00	1.00	0. 00	0.16

In-Service Rates
All installations have 100% in service rate since all PAs programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factors.

Realization Rates
Realization rates are set to 100% based on Massachusetts Common Assumptions.

Coincidence Factors
Coincidence factors are based evaluation results[157].

155 Sachs, Harvey (2003). *Energy Savings from Efficient Furnace Air Handlers in Massachusetts.*
156 ERS (2011) Pilot Evaluation of BFM DRAFT. Results as of 9/29/2011.
157 Ibid.

HVAC – Brushless Fan Motors

Version Date and Revision History

Effective Date: 1/1/2011 (revised for 1/1/2012)
End Date: TBD

Measure Overview

Description: Installation of high efficiency motors on residential furnace fans, including steady state brushless furnace fan motors.
Primary Energy Impact: Electric
Secondary Energy Impact: Natural Gas (Residential Heat)
Non-Energy Impact: None
Sector: Residential
Market: Lost Opportunity
End Use: HVAC
Program: Residential Cooling & Heating Equipment

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed based on the following algorithms and assumptions:

$$\Delta kWh = \Delta kWh$$
$$\Delta kW = \Delta kW$$

Where:

Unit	=	Installation of high efficiency furnace fan motor
ΔkWh	=	Average annual energy reduction per unit: 302 kWh[158]
ΔkW	=	Average demand reduction per unit: 0.214 kW[159]

Baseline Efficiency

The baseline efficiency case is the installation of a furnace with a standard efficiency steady state motor.

High Efficiency

The high efficiency case is the installation of a furnace with a brushless fan motor.

Hours

Not applicable.

[158] ERS (2011) Pilot Evaluation of BFM DRAFT. Results as of 9/29/2011.
[159] Ibid.

Measure Life

The measure life is 18 years.[160]

Secondary Energy Impacts

A heating penalty results due to reduced heat loss of the efficient furnace motor.

Measure	Energy Type	ΔMMBtu/Unit[161]
Brushless Furnace Fan Motor	Natural Gas (Residential Heat)	-0.716

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Brushless Furnace Fan Motor	RHVAC	All	1.00	1.00	1.00	1.00	1.00	0.25	0.16

In-Service Rates
All installations have 100% in service rate since all PAs programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factors.

Realization Rates
Realization rates are set to 100% based on Massachusetts Common Assumptions.

Coincidence Factors
Coincidence factors are based on evaluation results[162].

[160] Sachs, Harvey (2003). *Energy Savings from Efficient Furnace Air Handlers in Massachusetts.*
[161] ERS (2011) Pilot Evaluation of BFM DRAFT. Results as of 9/29/2011.
[162] Ibid.

HVAC – Room AC (Lost Opportunity)

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: The installation of ENERGY STAR® qualified room air conditioners. ENERGY STAR® qualified air conditioners are typically 10% more efficient than models meeting federal standards.
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: None
Sector: Residential
Market: Lost Opportunity, Retrofit
End Use: HVAC
Program: ENERGY STAR Appliances, Multifamily Retrofit

Algorithms for Calculating Primary Energy Impact

Unit savings are based on the following algorithms which use averaged inputs:

$$\Delta kWh = \Delta kWh$$
$$\Delta kW = \Delta kWh / Hours$$

Where:

Unit	=	Rebated room AC unit
ΔkWh	=	Average annual energy savings per unit: 49 kWh[163]
ΔkW	=	Average demand reduction per unit: 0.24 kW
Hours	=	Equivalent full load hours

Baseline Efficiency

The baseline efficiency case is a window AC unit that meets the minimum federal efficiency standard for efficiency which currently is EER 9.8.

High Efficiency

The high efficiency level is a room AC unit meeting or exceeding the federal efficiency standard by 10% or more. Average size is 10,000 Btu and average EERs is 10.8.

[163] Environmental Protection Agency (2009). *Life Cycle Cost Estimate for ENERGY STAR Room Air Conditioner*. Interactive Excel Spreadsheet found at www.energystar.gov/ia/business/bulk_purchasing/bpsavings_calc/CalculatorConsumerRoomAC.xls.

Hours

Equivalent full load hours are 200 hours per year.[164]

Measure Life

The measure life is 9 years.[165]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}	CF_{SSP}	CF_{WSP}
Room AC (Upstream)	ES Appliances	All except WMECO	1.00	1.00	1.00	1.00	1.00	0.13	0.00	n/a	n/a
Room AC	MF Retrofit	All except WMECO	1.00	1.00	1.00	1.00	1.00	0.13	0.00	n/a	n/a
Room AC (Upstream)	ES Appliances	WMECO	1.00	1.00	1.00	1.00	1.00	n/a	n/a	0.30	0.00
Room AC	MF Retrofit	WMECO	1.00	1.00	1.00	1.00	1.00	n/a	n/a	0.30	0.00

In-Service Rates
In-service rates are set to 100% based on the assumption that all purchased units are installed.

Savings Persistence Factor
All PAs use 100% savings persistence factors.

Realization Rates
Realization rates are based on Massachusetts Common Assumptions.

Coincidence Factors
All PAs use CFs from a 2008 residential room AC coincidence factor study[166]. CFs are provided for both on-peak and seasonal peak periods.

[164] RLW Analytics (2008). *Coincidence Factor Study: Residential Room Air Conditioners*. Prepared for Northeast Energy Efficiency Partnerships' New England Evaluation and State Program Working Group; Page 32, Table 22 - found by averaging the EFLH values for MA states (Boston and Worcester): (228+172)/2 = 200.
[165] Environmental Protection Agency (2009). *Life Cycle Cost Estimate for ENERGY STAR Room Air Conditioner*.
[166] RLW Analytics (2008). *Coincidence Factor Study: Residential Room Air Conditioners*. Prepared for Northeast Energy Efficiency Partnerships' New England Evaluation and State Program Working Group.

HVAC – Window AC (Retrofit)

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: Replacement of existing inefficient room air conditioners with more efficient models. This is only offered as a measure when an AC timer would not reduce usage during the peak period.
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: Low-Income Annual Discounted Rate Cost Reduction, Low-Income Annual Participant Benefit
Sector: Low Income
Market: Retrofit
End Use: HVAC
Program: Low-Income 1-4 Family Retrofit, Low-Income Multifamily Retrofit

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed based on study results:

$$\Delta kWh = \Delta kWh$$
$$\Delta kW = \Delta kW$$

Where:
Unit = Replacement of an existing window AC unit with a new efficient window AC unit
ΔkWh = Average annual kWh savings per unit: 100 kWh[167]
ΔkW = Max load kW reduction: 0.214 kW[168]

Baseline Efficiency

The baseline efficiency case is the existing air conditioning unit.

High Efficiency

The high efficiency case is the high efficiency room air conditioning unit.

Hours

Not applicable.

[167] Quantec, LLC (2005). *Evaluation of National Grid's 2003 Appliance Management Program: Room Air Conditioning Metering and Non-Energy Benefits Study*. Prepared for National Grid.
[168] Estimated using demand allocation methodology described in: Quantec, LLC (2000). *Impact Evaluation: Single-Family EnergyWise Program.* Prepared for National Grid.

Measure Life

The measure life is 9 years.[169]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Window AC Replacement	LI 1-4 Retrofit	All	1.00	1.00	1.00	1.00	1.00	1.00	0.02
Window AC Replacement	LI MF Retrofit	All (not National Grid)	1.00	1.00	1.00	1.00	1.00	1.00	0.02

In-Service Rates
All installations have 100% in service rate since all PAs programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factors.

Realization Rates
Realization rates are set to 100% since deemed savings are based on evaluation results.

Coincidence Factors
Coincidence factors are estimated using the demand allocation methodology described in the 2000 EnergyWise program impact evaluation[170]

[169] Environmental Protection Agency (2009). *Life Cycle Cost Estimate for ENERGY STAR Room Air Conditioner*. Interactive Excel Spreadsheet found at www.energystar.gov/ia/business/bulk_purchasing/bpsavings_calc/CalculatorConsumerRoomAC.xls.
[170] Quantec, LLC (2000). *Impact Evaluation: Single-Family EnergyWise Program*. Prepared for National Grid.

HVAC – Dehumidifiers

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: Early retirement of existing dehumidifiers and replacement with high efficiency dehumidifiers
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: Low-Income Annual Discounted Rate Cost Reduction
Sector: Residential, Low Income
Market: Lost Opportunity, Retrofit
End Use: HVAC
Program: ENERGY STAR Appliances, Low-Income 1-4 Family Retrofit

Notes

Cape Light Compact is the only PA planning to offer this measure in 2011.

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed based on the following algorithms and assumptions:

$$\Delta kWh_{EE} = Capacity \times \frac{0.473}{24} \times \left(\frac{1}{Eff_{BASE}} - \frac{1}{Eff_{EE}} \right) \times Hours$$

$$\Delta kWh_{RETIRE} = Capacity \times \frac{0.473}{24} \times \left(\frac{1}{Eff_{RETIRE}} - \frac{1}{Eff_{BASE}} \right) \times Hours$$

$$\Delta kW_{EE} = \Delta kWh_{EE} / Hours$$

$$\Delta kW_{RETIRE} = \Delta kWh_{RETIRE} / Hours$$

Where:

Unit	=	Replacement of existing dehumidifier with new ENERGY STAR® dehumidifier
ΔkWh_{EE}	=	Annual energy savings due to ES unit compared to new baseline unit: 66 kWh
ΔkWh_{RETIRE}	=	Annual energy savings of baseline units compared to existing unit: 77 kWh
ΔkW_{EE}	=	ES replacement demand load savings: 0.038 kW
ΔkW_{RETIRE}	=	Retired demand load savings: 0.044 kW
Capacity	=	Average capacity of dehumidifier in Pints/24 Hours: 35 Pints/Day[171]
Eff_{BASE}	=	Average efficiency of conventional model in Liters/kWh
Eff_{EE}	=	Average efficiency of ENERGY STAR® model in Liters/kWh
Eff_{RETIRE}	=	Average efficiency of existing model in Liters/kWh
Hours	=	Dehumidifier annual operating hours

[171] 35 pints per day was the average turn in at the Cape Light Compact's May 2010 event. This event retired 125 units.

0.473 = Conversion factor: 0.473 Liters/Pint
24 = Conversion factor: 24 Hours/Day

Baseline Efficiency

The baseline efficiency case for a retired dehumidifier ($Eff_{RETIRED}$) is 1.20 L/kWh[172], which is the pre-EPACT 2005 efficiency for a 35 pint/day unit. The baseline efficiency for an existing unit (Eff_{BASE}) is 1.30 L/kWh[173], which is the current federal standard for a 35 pint/day unit.

High Efficiency

The high efficiency case is an ENERGY STAR® replacement unit with an efficiency of 1.40 L/kWh[174].

Hours

Average annual operating hours are 1,706 hours, calculated as the sum of average operating hours in the summer, winter and spring/fall seasons, where seasonal hours are calculated at the number of days in that season multiplies by the mean operating hours/day.

Season	Mean Hours/Day[175]	% Days in Season[176]	Seasonal Operating Hours
Summer	7.8	25%	712
Winter	2.3	25%	210
Spring/Fall	4.3	50%	785
All	-	-	1,706*

*Cape Light Compact Annual Hours are adjusted by a factor of 1.02 to account for longer operating hours for Cape Light Compact customers compared to customers in other program territories. The adjustment factor represents the weighted average increase in operating hours compared to PA-average hours over all seasons.

Measure Life

The measure life of a replacement unit is 12 years.[177] The remaining measure life of a retired unit is 5 years.[178]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

[172] Environmental Protection Agency (2002). *Life Cycle Cost Estimate for ENERGY STAR Dehumidifiers*.
[173] Appliance Standards Awareness Project (2007). *Dehumidifiers*. Website accessed on 6/30/10.
[174] Environmental Protection Agency (2002). *Life Cycle Cost Estimate for ENERGY STAR Dehumidifiers*.
[175] Opinion Dynamics Corporation (2009). *Massachusetts Residential Saturation Survey (RASS) - Volume 1: Summary Results and Analysis*. Prepared for Cape Light Compact, National Grid, NSTAR Electric, Unitil and Western Massachusetts Electric Company; Page 94, Table 17.
[176] Simplifying assumption.
[177] Environmental Protection Agency (2002). *Life Cycle Cost Estimate for ENERGY STAR Dehumidifiers*.
[178] On average, turn-in units at the Cape Light Compact's May 2010 event were 7 years old. The full measure life of 12 years minus the average age of the retired equipment of 7 years equals a remaining life of 5 years.

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Dehumidifiers	ES Appliances	CLC	1.00	1.00	1.00	1.00	1.00	0.85	0. 00
Dehumidifiers	LI 1-4 Retrofit	CLC	1.00	1.00	1.00	1.00	1.00	0.85	0.00

In-Service Rates
In-service rates are set to 100% based on the assumption that all purchased units are installed.

Savings Persistence Factor
All PAs use 100% savings persistence factors.

Realization Rates
Realization rates are based on Massachusetts Common Assumptions.

Coincidence Factors
Coincidence factors are based on Massachusetts Common Assumptions.

HVAC – Thermostats

Version Date and Revision History

Effective Date: 1/1/2011 (revised for 1/1/2012)
End Date: TBD

Measure Overview

Description: Replacement of existing thermostats with programmable thermostats in oil heated homes.
Primary Energy Impact: Oil
Secondary Energy Impact: None
Non-Energy Impact: Low-Income Annual Discounted Rate Cost Reduction
Sector: Low Income
Market: Retrofit
End Use: HVAC
Program: Low-Income 1-4 Family Retrofit, Low-Income Multifamily Retrofit

Algorithms for Calculating Primary Energy Impact

No electric savings are claimed for this measure.

Baseline Efficiency

The baseline efficiency case is a non-programmable thermostat.

High Efficiency

The high efficiency case is a programmable thermostat.

Hours

Not applicable.

Measure Life

The measure life is 15 years.[179]

Secondary Energy Impacts

Measure	Energy Type	Savings	ΔMMBtu/Unit
Programmable Thermostat (Oil)	Oil	7.7 MMBtu [180]	7.7

[179] Environmental Protection Agency (2010). *Life Cycle Cost Estimate for ENERGY STAR Programmable Thermostat*..
[180] RLW Analytics (2007). *Validating the Impact of Programmable Thermostats*. Prepared for GasNetworks; Page 2, conversion factor CCF to Therms is 1.024. Oil MMbtu savings are assumed to be the same as Natural Gas MMbtu savings.

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Programmable Thermostat (Oil)	LI 1-4 Retrofit, LI MF Retrofit	All	1.00	1.00	1.00	1.00	1.00	0.00	0.00

In-Service Rates
All installations have 100% in service rate since all PAs programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factors.

Realization Rates
Realization rates are set to 100% since deemed savings are based on evaluation results.

Coincidence Factors
Coincidence factors are set to zero since there are no electric savings for this measure.

HVAC – Boiler Reset Controls

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: Installation of weather responsive controls on oil boilers.
Primary Energy Impact: Oil
Secondary Energy Impact: None
Non-Energy Impact: Low-Income Annual Discounted Rate Cost Reduction
Sector: Residential, Low-Income
Market: Retrofit
End Use: HVAC
Program: HES, Low-Income 1-4 Family Retrofit

Algorithms for Calculating Primary Energy Impact

No electric savings are claimed for this measure.

Baseline Efficiency

The baseline efficiency case has boiler controls installed.

High Efficiency

The high efficiency case includes weather responsive controls installed on the boiler.

Hours

Not applicable.

Measure Life

The measure life is 15 years.[181]

Secondary Energy Impacts

Measure	Energy Type	Savings[182]	ΔMMBtu/Unit
Boiler Reset Controls (Oil)	Oil	7.9 MMBtu/Unit	7.9

[181] ACEEE (2006). *Emerging Technologies Report: Advanced Boiler Controls*. Prepared for ACEEE; Page 2.
[182] Ibid.

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Boiler Reset Controls (Oil)	HES	All	1.00	1.00	1.00	n/a	n/a	n/a	n/a
Boiler Reset Controls (Oil)	LI 1-4 Retrofit	All	1.00	1.00	1.00	n/a	n/a	n/a	n/a

In-Service Rates
All installations have 100% in service rate since all PAs programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factors.

Realization Rates
Realization rates are set to 100% since deemed savings are based on evaluation results.

Coincidence Factors
Coincidence factors are set to zero since there are no electric savings for this measure.

HVAC – Weatherization (Electric)

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: Installation of weatherization measures such as air sealing and insulation in electrically heated homes.
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: Low-Income Annual Discounted Rate Cost Reduction; Low-Income One-Time Arrearage Reduction; Low-Income Annual Fire, Illness and Moving Avoidance Benefits; Low-Income One-Time Property Value Benefit
Sector: Low Income
Market: Retrofit
End Use: HVAC
Program: Low-Income 1-4 Family Retrofit, Low-Income Multifamily Retrofit

Notes

The savings estimates described in this section are only used for the Low-Income 1-4 Family Retrofit program (all PAs) and the Low-Income Multifamily Retrofit programs (all PAs except National Grid). The savings algorithms for similar measures installed through National Grid's Low-Income Multifamily program are described in the *Multifamily – Insulation* and *Multifamily – Air Sealing* sections.

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed based on study results:

$$\Delta kWh = \Delta kWh$$
$$\Delta kW = \Delta kW$$

Where:

Unit = Electrically-heated household with weatherization measures installed
ΔkWh = Average annual energy reduction: 374 kWh[183]
ΔkW = Average demand reduction: 0.047 kW[184]

Baseline Efficiency

The baseline efficiency case is any existing home shell measures.

[183] The Cadmus Group, Inc. (2009). *Impact Evaluation of the 2007 Appliance Management Program and Low Income Weatherization Program.* Prepared for National Grid; Table 1.
[184] Estimated using demand allocation methodology described in: Quantec, LLC (2000). *Impact Evaluation: Single-Family EnergyWise Program.* Prepared for National Grid.

High Efficiency

The high efficiency case includes increased weatherization insulation levels.

Hours

Not applicable.

Measure Life

The measure life is 20 years.[185]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Weatherization (Electric)	LI 1-4 Retrofit	All	1.00	1.00	1.00	1.00	1.00	0.03	1.00
Weatherization (Electric)	LI MF Retrofit	All (not National Grid)	1.00	1.00	1.00	1.00	1.00	0.03	1.00

In-Service Rates
All installations have 100% in service rate since all PAs programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factors.

Realization Rates
Realization rates are set to 100% since deemed savings are based on evaluation results.

Coincidence Factors
Coincidence factors are estimated using the demand allocation methodology described in the 2000 EnergyWise program impact evaluation.[186]

[185] Massachusetts Common Assumption.
[186] Quantec, LLC (2000). *Impact Evaluation: Single-Family EnergyWise Program*. Prepared for National Grid.

HVAC – Weatherization (Oil and Other FF)

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: Installation of weatherization measures such as air sealing and insulation in oil or propane heated homes. Electric savings are achieved from reduced fan run time for heating and cooling systems.
Primary Energy Impact: Oil and Other FF
Secondary Energy Impact: Electric
Non-Energy Impact: Low-Income Annual Discounted Rate Cost Reduction; Low-Income One-Time Arrearage Reduction; Low-Income Annual Fire, Illness and Moving Avoidance Benefits; Low-Income One-Time Property Value Benefit (Electric and Oil)
Sector: Low Income
Market: Retrofit
End Use: HVAC
Program: Low-Income 1-4 Family Retrofit

Notes

The savings estimates described in this section are only used for the Low-Income 1-4 Family Retrofit program (all PAs) and the Low-Income Multifamily Retrofit programs (all PAs except National Grid). The savings algorithms for similar measures installed through National Grid's Low-Income Multifamily program are described in the *Multifamily – Insulation* and *Multifamily – Air Sealing* sections.

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed based on study results:

$$\Delta kWh = \Delta kWh$$
$$\Delta kW = \Delta kW$$

Where:

Unit	=	Oil or propane heated household with weatherization measures installed
ΔkWh	=	Average annual energy reduction per unit: it: 70 kWh[187]
ΔkW	=	Average demand reduction per unit: 0.009 kW[188]

Baseline Efficiency

The baseline efficiency case is any existing home shell measures.

[187] The Cadmus Group, Inc. (2009). *Impact Evaluation of the 2007 Appliance Management Program and Low Income Weatherization Program.* Prepared for National Grid.
[188] Estimated using demand allocation methodology described in: Quantec, LLC (2000). *Impact Evaluation: Single-Family EnergyWise Program.* Prepared for National Grid.

High Efficiency

The high efficiency case includes increased weatherization insulation levels.

Hours

Not applicable.

Measure Life

The measure life is 20 years.[189]

Secondary Energy Impacts

Measure	Energy Type	ΔMMBtu/Unit[190]
Weatherization (Oil)	Oil	13.7
Weatherization (Other FF)	Propane	13.7

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Weatherization (Oil and Other FF)	LI 1-4 Retrofit	All	1.00	1.00	1.00	1.00	1.00	0.03	1.00

In-Service Rates
All installations have 100% in service rate since all PAs programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factors.

Realization Rates
Realization rates are set to 100% since deemed savings are based on evaluation results.

Coincidence Factors
Coincidence factors are estimated using the demand allocation methodology described in the 2000 EnergyWise program impact evaluation.[191]

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[189] GDS Associates, Inc. (2007). *Measure Life Report: Residential and Commercial/Industrial Lighting and HVAC Measures*. Prepared for The New England State Program Working Group; Page A-2.
[190] The Cadmus Group, Inc. (2009). *Impact Evaluation of the 2007 Appliance Management Program and Low Income Weatherization Program*. Prepared for National Grid.
[191] Quantec, LLC (2000). *Impact Evaluation: Single-Family EnergyWise Program*. Prepared for National Grid.

HVAC – Heating System Replacement (Oil)

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: Replacement of existing oil heating system with a new high efficiency system. Electric savings can be attributed to reduced fan run time and reduced usage of electric space heaters.
Primary Energy Impact: Oil
Secondary Energy Impact: Electric
Non-Energy Impact: Annual Discounted Rate Cost Reduction, One-Time Arrearage Reduction, Annual Fire, Illness and Moving Avoidance Benefits, One-Time Property Value Benefit
Sector: Low Income
Market: Retrofit
End Use: HVAC
Program: Low-Income 1-4 Family Retrofit, Low-Income Multifamily Retrofit

Notes

The savings estimates described in this section are only used for the Low-Income 1-4 Family Retrofit program (all PAs) and the Low-Income Multifamily Retrofit programs (all PAs except National Grid).

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed based on study results:

$$\Delta kWh = \Delta kWh$$
$$\Delta kW = \Delta kW$$

Where:

Unit	=	Installation of new high efficiency oil heating system
ΔkWh	=	Average annual energy reduction per unit: 194 kWh[192]
ΔkW	=	Average demand reduction per unit: 0.024 kW[193]

Baseline Efficiency

The baseline efficiency case is the existing inefficient heating equipment.

[192] The Cadmus Group, Inc. (2009). *Impact Evaluation of the 2007 Appliance Management Program and Low Income Weatherization Program.* Prepared for National Grid.
[193] Estimated using demand allocation methodology described in: Quantec, LLC (2000). *Impact Evaluation: Single-Family EnergyWise Program.* Prepared for National Grid.

High Efficiency

The high efficiency case is the new efficient heating equipment.

Hours

Not applicable.

Measure Life

The measure life is 18 years.[194]

Secondary Energy Impacts

Measure	Energy Type	ΔMMBtu/Unit[195]
Heating System Replacement (Oil)	Oil	12.2

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Heating System Replacement (Oil)	LI 1-4 Retrofit	All	1.00	1.00	1.00	1.00	1.00	0.03	1.00
Heating System Replacement (Oil)	LI MF Retrofit	All (not National Grid)	1.00	1.00	1.00	1.00	1.00	0.03	1.00

In-Service Rates
All installations have 100% in service rate since all PAs programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factors.

Realization Rates
Realization rates are set to 100% since deemed savings are based on evaluation results.

Coincidence Factors
Coincidence factors are estimated using the demand allocation methodology described in the 2000 EnergyWise program impact evaluation.[196]

[194] Environmental Protection Agency (2009). *Life Cycle Cost Estimate for ENERGY STAR Furnace*.
[195] The Cadmus Group, Inc. (2009). *Impact Evaluation of the 2007 Appliance Management Program and Low Income Weatherization Program*. Prepared for National Grid.
[196] Quantec, LLC (2000). *Impact Evaluation: Single-Family EnergyWise Program*. Prepared for National Grid.

Process – Computer Monitors

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: Rebates for ENERGY STAR® Computer Monitors
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: None
Sector: Residential
Market: Lost Opportunity
End Use: Process
Program: ENERGY STAR Appliances

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed based on study results:

$$\Delta kWh = \Delta kWh$$
$$\Delta kW = \Delta kW$$

Where:

Unit	=	Rebated ENERGY STAR® computer monitor
ΔkWh	=	Average annual kWh savings per unit: 35 kWh[197]
ΔkW	=	Average annual kW savings per unit: 0.010 kW[198]

Baseline Efficiency

The baseline efficiency case is a conventional computer monitor.

High Efficiency

The high efficiency case is an ENERGY STAR® rated LCD monitor.

Hours

Not applicable.

[197] Deemed savings developed based on assumptions in Consortium for Energy Efficiency (2008). *Consumer Electronics Program Guide: Information on Voluntary Approaches for the Promotion of Energy Efficient Consumer Electronics - Products and Practices*; Page 9, Table 1.
[198] Estimated using demand allocation methodology described in: Quantec, LLC (2000). *Impact Evaluation: Single-Family EnergyWise Program.* Prepared for National Grid.

Measure Life

The measure life is 5 years.[199]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Computer Monitors	ES Appliances	All	1.00	1.00	1.00	1.00	1.00	0.35	1. 00

In-Service Rates
In-service rates are set to 100% based on the assumption that all purchased units are installed.

Savings Persistence Factor
All PAs use 100% savings persistence factors.

Realization Rates
Realization rates are based on Massachusetts Common Assumptions.

Coincidence Factors
Coincidence factors are based on Massachusetts Common Assumptions.

[199] Consortium for Energy Efficiency (2008). *Consumer Electronics Program Guide: Information on Voluntary Approaches for the Promotion of Energy Efficient Consumer Electronics - Products and Practices.*

Process – Computers

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: Rebates for ENERGY STAR® computers.
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: None
Sector: Residential
Market: Lost Opportunity
End Use: Process
Program: ENERGY STAR Appliances

Algorithms for Calculating Primary Energy Impact

Unit savings are based on engineering estimate of delta kW between computers that are idle, in sleep mode, or off:

$$\Delta kWh = \Delta kWh$$
$$\Delta kW = \Delta kW$$

Where:
Unit = Rebated ENERGY STAR® desktop computer
ΔkWh = Average annual kWh reduction per unit: 70 kWh[200]
ΔkW = Average kW savings per unit: 0.009 kW[201]

Baseline Efficiency

The baseline efficiency case is a conventional desktop computer.

High Efficiency

The high efficiency case is an ENERGY STAR® rated desktop computer.

Hours

The operational hours include: 3,322 annual idle hours, 399 annual sleep hours, and 5,039 annual off hours.[202]

[200] Environmental Protection Agency (2010). *Life Cycle Cost Estimate for ENERGY STAR Office Equipment.*
[201] Ibid.
[202] Ibid.

Measure Life

The measure life is 4 years.[203]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Desktop Computers	ES Appliances	All	1.00	1.00	1.00	1.00	1.00	0.35	1. 00

In-Service Rates
In-service rates are set to 100% based on the assumption that all purchased units are installed.

Savings Persistence Factor
All PAs use 100% savings persistence factors.

Realization Rates
Realization rates are based on Massachusetts Common Assumptions.

Coincidence Factors
Coincidence factors are based on Massachusetts Common Assumptions.

203 Ibid.

Process – Pool Pump

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: The installation of a 2-speed or variable speed drive pool pump. Operating a pool pump for a longer period of time at a lower wattage can move the same amount of water using significantly less energy.
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: None
Sector: Residential
Market: Lost Opportunity
End Use: Process
Program: ENERGY STAR Appliances

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed based on the following algorithms which use averaged inputs:

$$\Delta kWh = (kW_{BASE} \times Hours) \times 55\%$$
$$\Delta kW = \Delta kW$$

Where:

Unit	=	Rebated 2-speed or variable speed pool pump
ΔkWh	=	Average annual kWh reduction: 400 kWh[204]
ΔkW	=	Average annual kW reduction: 0.071 kW[205]
Hours	=	Average annual operating hours of pump
kW_{BASE}	=	connected kW of baseline pump
55%	=	average percent energy reduction from switch to 2-speed or variable speed pump[206]

Baseline Efficiency

The baseline efficiency case is a single speed pump.

[204] Estimated using the difference between a Standard Efficiency Single Speed Pump and a Two-Speed with both Speeds Combined * Number of Days in the NE summer season ((13.8 kWh – 9.4 kWh) * 91). Pacific Gas and Electric *The Multi-Speed Pool Pump Fact Sheet.*
[205] Estimated using demand allocation methodology described in: Quantec, LLC (2000). *Impact Evaluation: Single-Family EnergyWise Program.* Prepared for National Grid.
[206] Davis Energy Group (2008). *Proposal Information Template for Residential Pool Pump Measure Revisions*. Prepared for Pacific Gas and Electric Company; Page 2.

High Efficiency

The high efficiency case is a 2-speed or variable speed pump.

Hours

Hours are considered on a case-by-case basis since they are dependent on seasonal factors, pool size, and treatment conditions.

Measure Life

The measure life is 10 years.[207]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Pool Pumps	ES Appliances	All	1.00	1.00	1.00	1.00	1.00	0.30	0.00

In-Service Rates
In-service rates are set to 100% based on the assumption that all purchased units are installed.

Savings Persistence Factor
All PAs use 100% savings persistence factors.

Realization Rates
Realization rates are based on Massachusetts Common Assumptions.

Coincidence Factor
Coincidence factors are based on Massachusetts Common Assumptions.

[207] Davis Energy Group (2008). *Proposal Information Template for Residential Pool Pump Measure Revisions*. Prepared for Pacific Gas and Electric Company.

Process – Room Air Cleaner

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: Rebates provided for the purchase of an ENERGY STAR® qualified room air cleaner. ENERGY STAR® air cleaners are 40% more energy-efficient than standard models.
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: None
Sector: Residential
Market: Lost Opportunity
End Use: Process
Program: ENERGY STAR Appliances

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed and based on the following algorithms which use averaged inputs:

$$\Delta kWh = \Delta kWh$$
$$\Delta kW = \Delta kWh / Hours$$

Where:

Unit	=	Rebated room air cleaner
ΔkWh	=	Average annual kWh savings per unit: 268 kWh[208]
ΔkW	=	Average connected load reduction: 0.031 kw[209]
Hours	=	Annual operating hours

Baseline Efficiency

The baseline efficiency case is a conventional unit with clean air delivery rate (CADR) of 51-100.

High Efficiency

The high efficiency case is an ENERGY STAR® qualified air cleaner with a CADR of 51-100.

Hours

The savings are based on 8,760 operating hours per year.

[208] Environmental Protection Agency (2009). *Life Cycle Cost Estimate for ENERGY STAR Room Air Cleaner.*
[209] Ibid.

Measure Life

The measure life is 9 years.[210]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Room Air Cleaner	ES Appliances	All	1.00	1.00	1.00	1.00	1.00	1.00	1.00

In-Service Rates
All installations have 100% in service rate since all PAs programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factors.

Realization Rates
Realization rates are based on Massachusetts Common Assumptions.

Coincidence Factors
Coincidence factors are based on Massachusetts Common Assumptions.

[210] Ibid.

Process – Set Top Boxes

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: Rebates for ENERGY STAR® Set Top Boxes.
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: None
Sector: Residential
Market: Lost Opportunity
End Use: Process
Program: ENERGY STAR Appliances

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed based on study results:

$$\Delta kWh = \Delta kWh$$
$$\Delta kW = \Delta kW$$

Where:

Unit	=	Rebated set-top box
ΔkWh	=	Average annual kWh savings per unit: 36.3 kWh[211]
ΔkW	=	Average connected load reduction: 0.008 kW[212]

Baseline Efficiency

The baseline efficiency case is a conventional set-top box that is not ENERGY STAR ® rated.

High Efficiency

The high efficiency case is an ENERGY STAR ® rated set-stop box that is 30% more efficient than conventional models.

Hours

The savings are based on 8,760 operational hours per year.

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[211] Home: ENERGY STAR (2010). *Set-top Boxes & Cable Boxes for Consumers*. http://www.energystar.gov/index.cfm?fuseaction=find_a_product.showProductGroup&pgw_code=ST. Accessed on 10/11/11; savings found by taking 30% of the average Total Energy Consumption from the Qualified Set-top Box Product List.
[212] Estimated using demand allocation methodology described in: Quantec, LLC (2000). *Impact Evaluation: Single-Family EnergyWise Program.* Prepared for National Grid.

Measure Life

The measure life is 4 years.[213]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Set Top Box	ES Appliances	All	1.00	1.00	1.00	1.00	1.00	0.35	1.00

In-Service Rates
In-service rates are set to 100% based on the assumption that all purchased units are installed.

Savings Persistence Factor
All PAs use 100% savings persistence factors.

Realization Rates
Realization rates are based on Massachusetts Common Assumptions.

Coincidence Factors
Coincidence factors are based on Massachusetts Common Assumptions.

[213] Massachusetts Common Assumption.

Process – Smart Strips

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: Switches off plug load using current sensors and switching devices which turn off plug load when electrical current drops below threshold low levels. Smart Strips can be used on electrical home appliances or in the workplace.
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: Annual Discounted Rate Cost Reduction (Low Income only)
Sector: Residential, Low Income
Market: Lost Opportunity, Retrofit
End Use: Process
Program: ENERGY STAR Appliances, HES, Low-Income 1-4 Family Retrofit, Multi-Family Retrofit, Low-Income Multifamily Retrofit

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed based on study results:

$$\Delta kWh = \Delta kWh$$
$$\Delta kW = \Delta kW$$

Unit	=	Rebated smart strip
ΔkWh	=	Average annual kWh savings per unit: 79 kWh[214]
ΔkW	=	Max kW savings per unit: 0.060 kW[215]

Baseline Efficiency

The baseline efficiency case is no power strip and leaving peripherals on or using a power surge protector.

High Efficiency

The high efficiency case is a Smart Strip Energy Efficient Power Bar

Hours

Since the power strip is assumed to be plugged in all year, the savings are based on 8,760 operational hours per year.

[214] ECOS 2009 Smart Plug Strips: Draft Report.
[215] Estimated using demand allocation methodology described in: Quantec, LLC (2000). *Impact Evaluation: Single-Family EnergyWise Program*. Prepared for National Grid.

Measure Life

The measure life is 5 years[216]

Secondary-Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Smart Strips	ES Appliances	All	1.00	1.00	1.00	1.00	1.00	0.35	1. 00
Smart Strips	HES	All	1.00	1.00	1.00	1.00	1.00	0.35	1.00
Smart Strips	MF Retrofit	All	1.00	1.00	1.00	1.00	1.00	0.35	1.00
Smart Strips	LI 1-4 Retrofit	All	1.00	1.00	1.00	1.00	1.00	0.35	1.00
Smart Strips	LI MF Retrofit	All	1.00	1.00	1.00	1.00	1.00	0.35	1.00

In-Service Rates
In-service rates are set to 100% based on the assumption that all purchased units are installed.

Savings Persistence Factor
All PAs use 100% savings persistence factors.

Realization Rates
Realization rates are set to 100% based on Massachusetts Common Assumptions.

Coincidence Factors
Coincidence factors are based on Massachusetts Common Assumptions.

[216] Massachusetts Common Assumption.

Process – Televisions

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: Rebates for televisions that meet ENERGY STAR® version 4.1 and 5.1 specifications.
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: None
Sector: Residential
Market: Lost Opportunity
End Use: Process
Program: ENERGY STAR Appliances

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed based on the following algorithms and assumptions:

$$\Delta kWh = \Delta kWh$$
$$\Delta kW = \Delta kW$$

Where:

Unit	=	Rebated television
ΔkWh	=	Average annual kWh reduction per unit. See Table 7.
ΔkW	=	Average electric demand reduction per unit. See Table 7.

Baseline Efficiency

The baseline efficiency case is a CEE Tier 1 television.

High Efficiency

The high efficiency case is an ENERGY STAR® qualified television, which uses about 40% less energy than standard units. Qualifying ENERGY STAR® TV products include standard TVs, HD-ready TVs, and the large flat-screen plasma TVs.[217] The savings, which are weighted between on and standby modes, for various models are given in the following table.

Table 7: Savings for Televisions

Television Size	ΔkW	ΔkWh
LCD/TV	0.021	75
Version 4.1 TV <60”	0.021	180

[217] Homes: Energy Star. *Televisions for Consumers.* http://www.energystar.gov/index.cfm?fuseaction=find_a_product.showProductGroup&pgw_code=TV. Accessed on 10/11/10.

Version 4.1 TV >=60”	0.043	372
Version 5.1 TV <60”	0.027	235
Version 5.1 TV >=60”	0.06	528
Version 5.3 TV <60”	0.028	246
Version 5.3 TV >=60”	0.062	544

Hours

Since the TV is assumed to be plugged in all year, the savings are based on 8,760 operational hours per year. The weighted savings are based on 5 hours on and 19 hours standby each day.

Measure Life

The measure life is 6 years.[218]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
LCD/TV	ES Appliances	All	1.00	1.00	1.00	1.00	1.00	0.50	0.85
Version 4.1 TV < 60"	ES Appliances	All	1.00	1.00	1.00	1.00	1.00	0.50	0.85
Version 4.1 TV >= 60"	ES Appliances	All	1.00	1.00	1.00	1.00	1.00	0.50	0.85
Version 5.1 TV < 60"	ES Appliances	All	1.00	1.00	1.00	1.00	1.00	0.50	0.85
Version 5.1 TV >= 60"	ES Appliances	All	1.00	1.00	1.00	1.00	1.00	0.50	0.85

In-Service Rates
In-service rates are set to 100% based on the assumption that all purchased units are installed.

Savings Persistence Factor
All PAs use 100% savings persistence factors.

Realization Rates
Realization rates are based on Massachusetts Common Assumptions.

Coincidence Factors
Coincidence factors are based on Massachusetts Common Assumptions.

[218] Environmental Protection Agency (2008). Life *Cycle Cost Estimate for ENERGY STAR Television.*

Refrigeration – Refrigerators (Lost Opportunity)

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: Rebates for purchase of ENERGY STAR® qualified refrigerators. ENERGY STAR® qualified refrigerators use at least 20% less energy than new, non-qualified models.
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: Annual Discounted Rate Cost Reduction (Low Income only)
Sector: Residential, Low Income
Market: Lost Opportunity
End Use: Refrigeration
Program: ENERGY STAR Appliances, Residential New Construction & Major Renovation, Low-Income Residential New Construction

Algorithms for Calculating Primary Energy Impact

Unit savings are based on the following algorithms which use averaged inputs:

$$\Delta kWh = \Delta kWh_{BASE} - \Delta kWh_{ES}$$
$$\Delta kW = \Delta kW$$

Where:

Unit	=	Installed ENERGY STAR® refrigerator
ΔkWh	=	Annual savings over non-ES refrigerators averaged by model type: 107 kWh[219]
ΔkW	=	Average kW reduction over non-ES refrigerator: 0.014 kW[220]

Baseline Efficiency

The baseline efficiency case is a residential refrigerator that meets the Federal minimum standard for energy efficiency.

High Efficiency

The high efficiency case is an ENERGY STAR® residential refrigerator that uses 20% less energy than models not labeled with the ENERGY STAR® logo.

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[219] Environmental Protection Agency (2009). *Life Cycle Cost Estimate for ENERGY STAR Residential Refrigerator*. Interactive Excel Spreadsheet found at www.energystar.gov/.../business/bulk_purchasing/bpsavings_calc/Consumer_Residential_Refrig_Sav_Calc.xls; average of savings form all refrigerator models.

[220] Estimated using demand allocation methodology described in: Quantec, LLC (2000). *Impact Evaluation: Single-Family EnergyWise Program*. Prepared for National Grid.

Hours

Not applicable.

Measure Life

The measure life is 12 years.[221]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Refrigerator Rebate	ES Appliances	All	1.00	1.00	1.00	1.00	1.00	1.00	0. 92
Refrigerators	RNC, LI RNC	All	1.00	1.00	1.00	1.00	1.00	1.00	0.92

In-Service Rates
In-service rates are set to 100% based on the assumption that all purchased units are installed.

Savings Persistence Factor
All PAs use 100% savings persistence factors.

Realization Rates
Realization rates are based on Massachusetts Common Assumptions.

Coincidence Factors
Coincidence factors are based on Massachusetts Common Assumptions.

[221] Environmental Protection Agency (2009). *Life Cycle Cost Estimate for ENERGY STAR Residential Refrigerator.*

Refrigeration – Refrigerators (Retrofit)

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: This measure covers the replacement of an existing inefficient refrigerator with a new ENERGY STAR® rated refrigerator. ENERGY STAR® qualified refrigerators use at least 20% less energy than non-qualified models.
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: Low Income only: Annual Discounted Rate Cost Reduction, One-Time Avoided Refrigerator Purchase
Sector: Residential, Low Income
Market: Retrofit
End Use: Refrigeration
Program: Home Energy Services, Multi-Family Retrofit, Low-Income Multifamily Retrofit, Low-Income 1-4 Family Retrofit

Algorithms for Calculating Primary Energy Impact

For HES, Multi-Family Retrofit and Low-Income Multifamily Retrofit:

Unit savings are deemed based on the following algorithms and averaged inputs:

$$\Delta kWh = \Delta kWh_{RETIRE} + \Delta kWh_{EE}$$
$$\Delta kW = \Delta kW_{RETIRE} + \Delta kW_{EE}$$

Where:

Unit	=	Replacement of existing refrigerator with new ENERGY STAR® Refrigerator
ΔkWh_{RETIRE}	=	Annual energy savings over remaining life of existing equipment: 884 kWh[222]
ΔkWh_{EE}	=	Annual energy savings over full life of new ES refrigerator: 107 kWh[223]
ΔkW_{RETIRE}	=	Average demand reduction over remaining life of existing equipment: 0.030 kW[224]
ΔkW_{EE}	=	Average demand reduction over full life of new ES refrigerator: 0.010 kW[225]

For Low-Income 1-4 Family Retrofit:

Unit savings are deemed based on study results:

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[222] Michael Blasnik & Associates (2004). *Measurement & Verification of Residential Refrigerator Energy Use, 2003 - 2004 Metering Study*. Prepared for NSTAR, National Grid and WMECO.
[223] The PAs use the Lost Opportunity savings of 107 kWh as the annual savings over the life of the new ES refrigerator. See *Refrigerator(Lost Opportunity) section.*
[224] Estimated using demand allocation methodology described in: Quantec, LLC (2000). *Impact Evaluation: Single-Family EnergyWise Program*. Prepared for National Grid.
[225] Ibid.

$$\Delta kWh = \Delta kWh$$
$$\Delta kW = \Delta kW$$

Where:

Unit	=	Removal of existing refrigerator and installation of new efficient refrigerator
ΔkWh	=	Average annual kWh savings per unit: 1,122 kWh[226]
ΔkW	=	Max kW Reduction: 0.148 kW[227]

Baseline Efficiency

For HES, Multi-Family Retrofit and Low-Income Multifamily Retrofit:
The baseline efficiency case is an existing refrigerator for savings over the remaining life of existing equipment. The baseline efficiency case is a full-sized refrigerator (7.75 cubic feet) that meets the Federal minimum standard for energy efficiency for savings for the full life.[228]

For Low-Income 1-4 Family Retrofit:
The baseline efficiency case for both the replaced and baseline new refrigerator is an existing refrigerator. It is assumed that low-income customers would otherwise replace their refrigerators with a used inefficient unit.

High Efficiency

The high efficiency case is an ENERGY STAR® rated refrigerator that meets the ENERGY STAR® criteria for full-sized refrigerators (7.75 cubic feet), using at least 20% less energy than models meeting the minimum Federal government standard.

Hours

Savings are based on 8,760 operating hours per year.

Measure Life

For HES, Multi-Family Retrofit and Low-Income Multifamily Retrofit: The remaining life of the existing refrigerator is 1 year, and the measure life for the new refrigerator is 12 years. [229]

For Low-Income 1-4 Family Retrofit: The measure life is 19 years.[230]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

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[226] The Cadmus Group, Inc. (2009). *Impact Evaluation of the 2007 Appliance Management Program and Low Income Weatherization Program.* Prepared for National Grid; Page 5, Table 1.
[227] Estimated using demand allocation methodology described in: Quantec, LLC (2000). *Impact Evaluation: Single-Family EnergyWise Program.* Prepared for National Grid.
[228] Home: ENERGY STAR (2008). *ENERGY STAR Refrigerators & Freezers Key Product Criteria.* http://www.energystar.gov/index.cfm?c=refrig.pr_crit_refrigerators. Accessed 10/11/10.
[229] Environmental Protection Agency (2009). *Life Cycle Cost Estimate for ENERGY STAR Residential Refrigerator.*
[230] Massachusetts Common Assumption.

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Refrigerators	HES	All	1.00	1.00	1.00	1.00	1.00	1.00	0.92
Refrigerators	MF Retrofit, LI MF Retrofit	All (not National Grid)	1.00	1.00	1.00	1.00	1.00	1.00	0.92
Refrigerator Replacement	LI 1-4 Retrofit	All	1.00	1.00	1.00	1.00	1.00	1.00	0.92

In-Service Rates
In-service rates are 100% as it is assumed all refrigerators are in-use.

Savings Persistence Factor
All PAs use 100% savings persistence factors.

Realization Rates
- HES, MF Retrofit, LI MF Retrofit: Realization rates are based on Massachusetts Common Assumptions.
- LI 1-4 Retrofit: Realization rates are set to 100% since deemed savings are based on evaluation results.

Coincidence Factors
Coincidence factors are estimated using the demand allocation methodology described in the 2000 EnergyWise program impact evaluation.[231]

[231] Quantec, LLC (2000). *Impact Evaluation: Single-Family EnergyWise Program*. Prepared for National Grid.

Refrigeration – Freezers (Lost Opportunity)

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: Rebates provided for the purchase of ENERGY STAR® freezers. ENERGY STAR® qualified freezers use at least 10% less energy than new, non-qualified models and return even greater savings compared to old models.
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: None
Sector: Residential
Market: Lost Opportunity
End Use: Refrigeration
Program: ENERGY STAR Appliances

Algorithms for Calculating Primary Energy Impact

Unit savings are based on the following algorithms which use averaged inputs:

$$\Delta kWh = \Delta kWh_{BASE} - \Delta kWh_{ES}$$
$$\Delta kW = \Delta kWh / 8760 hours$$

Where:

Unit	=	Installed ENERGY STAR® freezer
ΔkWh	=	Annual savings over non-ES freezers averaged by model type: 54 kWh[232]
ΔkW	=	Average kW reduction over non-ES freezer: 0.006 kW

Baseline Efficiency

The baseline efficiency case is a residential freezer that meets the Federal minimum standard for energy efficiency.

High Efficiency

The high efficiency case is based on an ENERGY STAR® rated freezer that uses 10% less energy than models not labeled with the ENERGY STAR® logo.

Hours

Not applicable.

[232] Environmental Protection Agency (2011). *Life Cycle Cost Estimate for ENERGY STAR Freezer*. Accessed 9/7/2011.

Measure Life

The measure life is 11 years.[233]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Freezer Rebate	ES Appliances	All	1.00	1.00	1.00	1.00	1.00	1.00	0. 92

In-Service Rates
In-service rates are set to 100% based on the assumption that all purchased units are installed.

Savings Persistence Factor
All PAs use 100% savings persistence factors.

Realization Rates
Realization rates are based on Massachusetts Common Assumptions.

Coincidence Factors
Coincidence factors are based on Massachusetts Common Assumptions.

[233] Environmental Protection Agency (2011). *Life Cycle Cost Estimate for ENERGY STAR Freezer*. Accessed 9/7/2011.

Refrigeration – Freezers (Retrofit)

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: This measure covers the replacement of an existing inefficient freezer with a new energy efficient model.
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: Low Income only: Annual Discounted Rate Cost Reduction, One-Time Avoided Refrigerator Purchase
Sector: Low Income
Market: Retrofit
End Use: Refrigeration
Program: Low-Income 1-4 Family Retrofit, Low-Income Multifamily Retrofit

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed based on study results:

$$\Delta kWh = \Delta kWh$$
$$\Delta kW = \Delta kW$$

Where:

Unit	=	Removal of existing freezer and installation of new efficient freezer
ΔkWh	=	Average annual kWh savings per unit: 637 kWh[234]
ΔkW	=	Max kW Reduction: 0.084 kW [235]

Baseline Efficiency

The baseline efficiency case for both the replaced and baseline new freezer is represented by the existing freezer. It is assumed that low-income customers would replace their freezers with a used inefficient unit.

High Efficiency

The high efficiency case is a new high efficiency freezer.

Hours

Not applicable.

[234] The Cadmus Group, Inc. (2009). *Impact Evaluation of the 2007 Appliance Management Program and Low Income Weatherization Program.* Prepared for National Grid; Page 5, Table 1.
[235] Estimated using demand allocation methodology described in: Quantec, LLC (2000). *Impact Evaluation: Single-Family EnergyWise Program.* Prepared for National Grid.

Measure Life

The measure life is 19 years[236]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Freezer Replacement	LI 1-4 Retrofit	All	1.00	1.00	1.00	1.00	1.00	1.00	0.92
Freezer Replacement	LI MF Retrofit	All (Not National Grid)	1.00	1.00	1.00	1.00	1.00	1.00	0.92

In-Service Rates
All installations have 100% in service rate since all PAs programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factors.

Realization Rates
Realization rates are set to 100% since deemed savings are based on evaluation results.

Coincidence Factors
Coincidence factors are estimated using the demand allocation methodology described in the 2000 EnergyWise program impact evaluation.[237]

[236] Massachusetts Common Assumption: It is assumed that low-income customers would replace with a used inefficient unit so the full savings are counted for the full lifetime.
[237] Quantec, LLC (2000). *Impact Evaluation: Single-Family EnergyWise Program*. Prepared for National Grid.

Refrigeration – Refrigerator/Freezer Recycling

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: The retirement of old, inefficient secondary refrigerators and freezers.
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: None
Sector: Residential
Market: Retrofit
End Use: Refrigeration
Program: ENERGY STAR Appliances

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed and are obtained from the referenced study.

$$\Delta kWh = \Delta kWh$$
$$\Delta kW = \Delta kWh / 8760$$

Where:
Unit = Removed secondary refrigerator or freezer
ΔkWh = Average annual kWh savings per unit. See Table 8.
ΔkW = Average kW reduction per unit. See Table 8.

Table 8: Savings for Refrigerator/Freezer Recycling

Measure	Program	ΔkW	ΔkWh[238]
Refrigerator Recycle Primary	Energy Star Products	0.061	533
Refrigerator Recycle Secondary Replaced	Energy Star Products	0.079	696
Refrigerator Recycle Secondary Not Replaced	Energy Start Products	0.095	835
Freezer Recycle	Energy Start Products	0.076	663
Refrigerator Recycle (combined)	Energy Star Products	0.086	755

Baseline Efficiency

The baseline efficiency case is an old, inefficient secondary working refrigerator or freezer. Estimated average usage is based on combined weight of freezer energy use and refrigerator energy use.

High Efficiency

The high efficiency case assumes no replacement of secondary unit.

[238] NMR Group, Inc. (2011). Massachusetts Appliance Turn-In Program Evaluation Integrated Report Findings – FINAL. Prepared for National Grid, NSTAR Electric, Cape Light Compact, and Western Massachusetts Electric Company.

Hours

Refrigerator and freezer operating hours are 8,760 hours/year.

Measure Life

The measure life is 8 years.[239]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Refrigerator Recycling	ES Appliances	All	1.00	1.00	1.00	1.00	1.00	1.00	0.92
Freezer Recycling	ES Appliances	All	1.00	1.00	1.00	1.00	1.00	1.00	0.92

In-Service Rates
All installations have 100% in service rate since all PAs programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factors.

Realization Rates
Realization rates are based on Massachusetts Common Assumptions.

Coincidence Factors
Coincidence factors are based on Massachusetts Common Assumptions.

239 Ibid.

Refrigeration – Appliance Removal

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: Removal of second working refrigerator or freezer.
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: Annual Discounted Rate Cost Reduction
Sector: Low Income
Market: Retrofit
End Use: Refrigeration
Program: Low-Income 1-4 Family Retrofit

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed based on study results:

$$\Delta kWh = \Delta kWh$$
$$\Delta kW = \Delta kW$$

Where:

Unit	=	Removal of secondary refrigerator or freezer with no replacement
ΔkWh	=	Average annual kWh savings per unit: 1,321 kWh[240]
ΔkW	=	Max kW reduction: 0.174 kW [241]

Baseline Efficiency

The baseline efficiency case is the old, inefficient secondary working refrigerator or freezer.

High Efficiency

The high efficiency case assumes no replacement of secondary unit.

Hours

Not applicable.

[240] The Cadmus Group, Inc. (2009). *Impact Evaluation of the 2007 Appliance Management Program and Low Income Weatherization Program.* Prepared for National Grid; average of refrigerator and freezer removal, Table 15.
[241] Estimated using demand allocation methodology described in: Quantec, LLC (2000). *Impact Evaluation: Single-Family EnergyWise Program.* Prepared for National Grid.

Measure Life

The measure life is 5 years.[242]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Appliance Removal	LI 1-4 Retrofit	All	1.00	1.00	1.00	1.00	1.00	1.00	0.92

In-Service Rates
All installations have 100% in service rate since all PAs programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factors.

Realization Rates
Realization rates are set to 100% since deemed savings are based on evaluation results.

Coincidence Factors
Coincidence factors are estimated using the demand allocation methodology described in the 2000 EnergyWise program impact evaluation.[243]

[242] Massachusetts Common Assumption.
[243] Quantec, LLC (2000). *Impact Evaluation: Single-Family EnergyWise Program*. Prepared for National Grid.

ENERGY STAR® Homes – Heating, Cooling, and DHW Measures

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: To capture lost opportunities, encourage the construction of energy-efficient homes, and drive the market to one in which new homes are moving towards net-zero energy.
Primary Energy Impact: Electric
Secondary Energy Impact: Natural Gas, Oil, Propane
Non-Energy Impact: Annual Discounted Rate Cost Reduction (Low Income only)
Sector: Residential, Low Income
Market: Lost Opportunity
End Use: HVAC, Hot Water
Program: Residential New Construction & Major Renovation, Low-Income Residential New Construction

Algorithms for Calculating Primary Energy Impact

As part of the ENERGY STAR® certification process, projected energy use is calculated for each home completed through the program and a geometrically matching baseline home (User Defined Reference Home) using Beacon, an ICF International proprietary DOE-2 based building energy simulation tool. The difference between the projected energy consumption of these two homes represents the energy savings produced by the certified home. This process is used to calculate electric demand as well as electric and fossil fuel energy savings due to heating, cooling, and water heating for all homes, both single family and multifamily. This process is documented in "Energy/Demand Savings Calculation and Reporting Methodology for the Massachusetts ENERGY STAR® Homes Program."[244]

Baseline Efficiency

The User Defined Reference Home was revised for 2006 as a result of the baseline study completed in 2006.[245] [246]

High Efficiency

The high efficiency case is represented by the specific energy characteristics of each "as-built" home completed through the program.

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[244] ICF International (2008). *Energy/Demand Savings Calculation and Reporting Methodology for the Massachusetts ENERGY STAR ® Homes Program*. Prepared for Joint Management Committee.
[245] Nexus Market Research & Dorothy Conant (2006). *Massachusetts ENERGY STAR® Homes: 2005 Baseline Study: Part I: Inspection Data Analysis Final Report*. Prepared for the Massachusetts Joint Management Committee.
[246] Nexus Market Research & Dorothy Conant (2006). *Massachusetts ENERGY STAR® Homes: 2005 Baseline Study: Part II: Homeowner Survey Analysis Incorporating Inspection Data Final Report*. Prepared for the Massachusetts Joint Management Committee.

Hours

Not applicable.

Measure Life

Measure Type	Measure Life (years)[247]
Cooling	25
Heating	25
Water Heating	15

Secondary Energy Impacts

Gas, Oil and Propane savings for heating and water heating measures are custom calculating using the same methodology described for the electric energy and demand savings.

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
ES Homes – Cooling	RNC, LI RNC	All	1.00	1.00	1.00	1.00	1.00	1.00	0.00
ES Homes – Heating	RNC, LI RNC	All	1.00	1.00	1.00	1.00	1.00	0.00	1.00
ES Homes – Water Heating	RNC, LI RNC	All	1.00	1.00	1.00	1.00	1.00	0.75	1.00

In-Service Rates
All installations have 100% in service rate since all PA programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factors.

Realization Rates
Realization rates are 100% because energy and demand savings are custom calculated based on project specific detail.

Coincidence Factors
Coincidence factors are custom calculated based on project-specific detail.

[247] Massachusetts Common Assumption.

Home Energy Services (MassSAVE) – Vendor Measures

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: Retrofit measures installed through the Home Energy Services (MassSAVE) program including: building envelope insulation and air sealing, duct sealing and insulation, programmable thermostats, heating system replacement, windows and DHW measures.
Primary Energy Impact: Electric
Secondary Energy Impact: Gas, Oil, Propane
Non-Energy Impact: Water
Sector: Residential
Market: Retrofit
End Use: HVAC, Hot Water
Program: Home Energy Services

Notes

The savings calculation methodology for these measures currently varies amongst the PAs. However, the PAs are investigating a common software tool for all implementation contractors. In addition, the 2011 evaluation plan consists of an impact evaluation that will provide updated savings values or consistent algorithms to be used statewide. Between the filing of the 2011 MA TRM – Plan Version and the filing of the 2011 MA TRM – Report Version, the working group will determine the best approach for the PAs. Once these efforts are complete the PAs will include any updates in the 2011 MA TRM – Report Version.

Algorithms for Calculating Primary Energy Impact

The Program Administrators currently use vendor calculated energy savings for these measures in the Residential Home Energy Services electric program. These savings values are calculated using vendor proprietary software where the user inputs a minimum set of technical data about the house and the software calculates building heating and cooling loads and other key parameters. The proprietary building model is based on thermal transfer, building gains, and a variable-based heating/cooling degree day/hour climate model. This provides an initial estimate of energy use that may be compared with actual billing data to adjust as needed for existing conditions. Then, specific recommendations for improvements are added and savings are calculated using measure-specific heat transfer algorithms.

Rather than using a fixed degree day approach, the building model estimates both heating degree days and cooling degree hours based on the actual characteristics and location of the house to determine the heating and cooling balance point temperatures. Savings from shell measures use standard U-value, area, and degree day algorithms. Infiltration savings use site-specific seasonal N-factors to convert measured leakage to seasonal energy impacts. HVAC savings are estimated based on changes in system and/or distribution efficiency improvements, using ASHRAE 152 as their basis. Lighting, appliance, and water heating savings are based on standard algorithms, taking into account operating conditions and pre- and post-retrofit energy consumption. Interactivity between architectural and mechanical measures is always included, to avoid overestimating savings due to incorrectly “adding” individual measure results.

The PAs calculate demand (kW) savings by applying a kW/kWh factor to the vendor-estimated electric energy savings. The kW/kWh factors are provided in Table 9.

Table 9: kW Factors for HES Vendor Measures

Measure	kW/kWh Factor[248]
Air Sealing (Electric)	0.00039
Air Sealing (Gas, Oil, Other FF)	0.00214
DHW ISMs (Electric)	0.00012
DHW ISMs (Gas, Oil, Other FF)	0.00012
Duct Insulation (Electric)	0.00034
Duct Insulation (Gas, Oil, Other FF)	0.00176
Duct Sealing (Electric)	0.00039
Duct Sealing (Gas, Oil, Other FF)	0.00214
Heating System Replacement (Gas, Oil, Other FF)	0
Indirect Water Heater (Oil, Other FF)	0
Insulation (Electric)	0
Insulation (Gas)	0
Insulation (Oil)	0
Insulation (Other FF)	0.00214
On-Demand Tankless Water Heater (Gas)	0.00176
On-Demand Tankless Water Heater (Oil)	0
On-Demand Tankless Water Heater (Other FF)	0.00022
Thermostats (Electric)	0.00013
Thermostats (Gas)	0.00214
Thermostats (Oil, Other FF)	0
Windows (Electric)	0.00013
Windows (Gas, Oil, Other FF)	0

Baseline Efficiency

The baseline efficiency case is the existing conditions of the participating household.

High Efficiency

The high efficiency case includes installed energy efficiency measures that reduce heating, cooling and water heating energy use.

Hours

Hours are project-specific.

248 Based on kW factors from Quantec, LLC (2000). *Impact Evaluation: Single-Family EnergyWise Program*. Prepared for National Grid.

Measure Life

Table 10: Measure Lives for HES Vendor Measures

Measure Name	Measure Life (years)
Air Sealing	15
DHW ISMs	7
Duct Insulation	20
Duct Sealing	20
Heating System Replacement	18
Indirect Water Heater	20
On-Demand Water Heater	20
Insulation	25
Thermostats	15
Windows	25

Secondary Energy Impacts

Gas, Oil and Propane savings are project-specific and estimated by the program vendors as described above.

Non-Energy Impacts

Benefit Type	Description	Savings
Residential Water	Residential water savings for DHW ISMs only[249]	4,028 Gallons /Participant
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

[249] NMR Group, Inc., Tetra Tech (2011). *Massachusetts Special and Cross-Sector Studies Area, Residential and Low-Income Non-Energy Impacts (NEI) Evaluation,* Prepared for Massachusetts Program Administrators

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Air Sealing (Electric)	HES	All	1.00	1.00	1.00	1.00	1.00	0.72	0.28
Air Sealing (Gas, Oil, Other FF)	HES	All	1.00	1.00	1.00	1.00	1.00	1.00	0.00
DHW ISMs (Electric)	HES	All	1.00	1.00	1.00	1.00	1.00	0.75	1.00
DHW ISMs (Gas, Oil, Other FF)	HES	All	1.00	1.00	1.00	1.00	1.00	0.00	0.00
Duct Insulation (Electric)	HES	All	1.00	1.00	1.00	1.00	1.00	0.72	0.28
Duct Insulation (Gas, Oil, Other FF)	HES	All	1.00	1.00	1.00	1.00	1.00	1.00	0.00
Duct Sealing (Electric)	HES	All	1.00	1.00	1.00	1.00	1.00	0.72	0.28
Duct Sealing (Gas, Oil, Other FF)	HES	All	1.00	1.00	1.00	1.00	1.00	1.00	0.00
Heating System Replacement (Gas, Oil, Other FF)	HES	All	1.00	1.00	1.00	1.00	1.00	0.00	0.00
Indirect Water Heater (Oil, Other FF)	HES	All	1.00	1.00	1.00	1.00	1.00	0.00	0.00
On-Demand Tankless Water Heater (Oil, Other FF)	HES	All	1.00	1.00	1.00	1.00	1.00	0.00	0.00
Insulation (Electric)	HES	All	1.00	1.00	1.00	1.00	1.00	0.72	0.28
Insulation (Gas, Oil, Other FF)	HES	All	1.00	1.00	1.00	1.00	1.00	1.00	0.00
Thermostats (Electric)	HES	All	1.00	1.00	1.00	1.00	1.00	0.03	1.00
Thermostats (Gas, Oil, Other FF)	HES	All	1.00	1.00	1.00	1.00	1.00	0.00	0.00
Windows (Electric)	HES	All	1.00	1.00	1.00	1.00	1.00	0.70	0.30
Windows (Gas, Oil, Other FF)	HES	All	1.00	1.00	1.00	1.00	1.00	0.00	0.00

In-Service Rates
In-service rates are set to 100% based on the assumption that all purchased units are installed.

Savings Persistence Factor
All PAs use 100% savings persistence factors.

Realization Rates
Realization rates are based on Massachusetts Common Assumptions.

Coincidence Factor
Coincidence factors are based on Massachusetts Common Assumptions.

Multifamily – Vendor Measures

Version Date and Revision History

Effective Date: 1/1/2011 (revised for 1/1/2012)
End Date: TBD

Measure Overview

Description: Retrofit measures installed through the PAs Multi-Family programs including: building envelope insulation and air sealing, duct sealing and insulation, programmable thermostats, heating system replacement, windows and DHW measures.
Primary Energy Impact: Electric
Secondary Energy Impact: Gas, Oil, Propane
Non-Energy Impact: **Residential Water**
Sector: Residential
Market: Retrofit
End Use: HVAC, Hot Water
Program: Multi-Family Retrofit

Notes

The savings calculation methodology for these measures currently varies amongst the PAs. However, the PAs are investigating opportunities to align their program offerings and savings calculation assumptions and methodologies. In addition, the 2011 evaluation plan consists of an impact evaluation which will provide updated savings values or consistent algorithms to be used statewide. Between the filing of the 2011 MA TRM – Plan Version and the filing of the 2011 MA TRM – Report Version, the working group will determine the best approach for the PAs. Once these efforts are complete the PAs will include any updates in the 2011 MA TRM – Report Version.

This section applies to Cape Light Compact, NSTAR, Unitil, and Western Massachusetts Electric Company multi-family programs. The algorithms and assumptions for similar measures in National Grid's residential and low-income multi-family programs are described in the other Multifamily measure sections.

Algorithms for Calculating Primary Energy Impact

The Program Administrators currently use vendor calculated savings for these measures in the Residential Multifamily Retrofit programs for standard income residential customers. These savings values are calculated using vendor proprietary software where the user inputs a minimum set of technical data about the house and the software calculates building heating and cooling loads and other key parameters. The proprietary building model is based on thermal transfer, building gains, and a variable-based heating/cooling degree day/hour climate model. This provides an initial estimate of energy use that may be compared with actual billing data to adjust as needed for existing conditions. Then, specific recommendations for improvements are added, and savings are calculated using measure-specific heat transfer algorithms.

Rather than using a fixed degree day approach, the building model estimates both heating degree days and cooling degree hours based on the actual characteristics and location of the house to determine the heating and cooling balance point temperatures. Savings from shell measures use standard U-value, area, and degree day algorithms. Infiltration savings use site-specific seasonal N-factors to convert measured leakage to seasonal energy impacts. HVAC savings are estimated based on changes in system and/or distribution efficiency improvements, using ASHRAE 152 as their basis. Lighting, appliance, and water heating savings are based on standard algorithms, taking into account operating conditions and pre- and post-retrofit energy consumption. Interactivity between architectural and mechanical measures is always included, to avoid overestimating savings due to incorrectly “adding” individual measure results.

Baseline Efficiency

The baseline efficiency case is the existing conditions of the participating facility.

High Efficiency

The high efficiency case includes installed energy efficiency measures that reduce heating, cooling and water heating energy use.

Hours

Hours are project-specific.

Measure Life

Measure Name	Measure Life (years)
Air Sealing	15
DHW Measures	7
Insulation	25
Thermostats	15

Secondary Energy Impacts

Gas, Oil and Propane savings are project-specific.

Non-Energy Impacts

Benefit Type	Description	Savings
Residential Water	Residential water savings for DHW measures[250]	4,028 Gallons /Participant
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

[250] NMR Group, Inc., Tetra Tech (2011). *Massachusetts Special and Cross-Sector Studies Area, Residential and Low-Income Non-Energy Impacts (NEI) Evaluation,* Prepared for Massachusetts Program Administrators

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Air Sealing (Electric)	MF Retrofit	All (not National Grid)	1.00	1.00	1.00	1.00	1.00	0.75	1.00
Air Sealing (FF)	MF Retrofit	All (not National Grid)	1.00	1.00	1.00	1.00	1.00	0.47	0.53
DHW Measures (Electric)	MF Retrofit	All (not National Grid)	1.00	1.00	1.00	1.00	1.00	0.75	1.00
DHW Measures (FF)	MF Retrofit	All (not National Grid)	1.00	1.00	1.00	1.00	1.00	0.75	1.00
Insulation (Electric)	MF Retrofit	All (not National Grid)	1.00	1.00	1.00	1.00	1.00	0.47	0.53
Insulation (FF)	MF Retrofit	All (not National Grid)	1.00	1.00	1.00	1.00	1.00	0.47	0.53
Thermostats (Electric)	MF Retrofit	All (not National Grid)	1.00	1.00	1.00	1.00	1.00	0.66	0.50
Thermostats (FF)	MF Retrofit	All (not National Grid)	1.00	1.00	1.00	1.00	1.00	0.00	0.00

In-Service Rates
In-service rates are set to 100% based on the assumption that all purchased units are installed.

Savings Persistence Factor
All PAs use 100% savings persistence factors.

Realization Rates
Realization rates are set to 100% since this program has not been evaluated and similar evaluation support this assumption.[251]

Coincidence Factor
Coincidence factors are based on Massachusetts Common Assumptions.

[251] Massachusetts Common Assumption: Assumed 100% realization rate is supported by the results of multiple impact evaluations of National Grid's EnergyWise program.

Multifamily – Insulation (Walls, Roof, Floor) (National Grid)

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: Insulation upgrades are applied in existing facilities.
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: Low-Income Annual Discounted Rate Cost Reduction; Low-Income Annual Fire, Illness and Moving Avoidance Benefits; Low-Income One-Time Property Value Benefit
Sector: Residential, Low Income
Market: Retrofit
End Use: HVAC
Program: Multi-Family Retrofit, Low-Income Multifamily Retrofit

Notes

The savings algorithms and assumptions described in this section are specific to National Grid's Multi-Family Retrofit and Low-Income Multifamily Retrofit programs. See *Multifamily – Vendor Measures* for information about other PAs' Multi-Family programs.

Algorithms for Calculating Primary Energy Impact

$$\Delta kWh = SQFT \times kWh / SQFT \times \left(\frac{1}{R-VALUE_{BASE}} - \frac{1}{R-VALUE_{EE}} \right)$$

$$\Delta kW = \Delta kWh \times kW / kWh$$

Where:

SQFT = Square feet of insulation installed
$R\text{-}VALUE_{BASE}$ = R-Value of the existing insulation
$R\text{-}VALUE_{EE}$ = R-Value of the new installed insulation
kWh/SQFT = Average annual kWh reduction per SQFT of insulation. See Table below.
kW/kWh = Average annual kW reduction per kWh reduction: 0.000125 kW/kWh[252]

Insulation Type	kWh/Sqft[253]
Basement	10.62
Attic	38.803
WALL (N, S)	11.477
WALL (W, E)	10.025

[252] Estimated using demand allocation methodology described in: Quantec, LLC (2000). *Impact Evaluation: Single-Family EnergyWise Program.* Prepared for National Grid.
[253] National Grid Multifamily Screening Tool. This was developed in the early 1990's. Documentation of the specific variables is unavailable. Evaluation results have consistently shown realization rates close to 100%.

Baseline Efficiency

The baseline efficiency case is the R-value of the existing insulation.

High Efficiency

The high efficiency case is insulation installed with a higher R-Value.

Hours

Not applicable.

Measure Life

The measure life is 25 years.[254]

Secondary Energy Impacts

There are no secondary energy impacts for this measure

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Insulation (Electric)	MF Retrofit, LI MF Retrofit	National Grid	1.00	1.00	0.91	0.91	0.91	0.03	1.00
Insulation (Non-Electric)	MF Retrofit, LI MF Retrofit	National Grid	1.00	1.00	0.99	0.99	0.99	0.03	1.00

In-Service Rates
All installations have 100% in service rate since all PA programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factor.

Realization Rates
Realization rates from the National Grid Energy Wise 2008 Program Evaluation.[255]

Coincidence Factors
Summer and winter coincidence factors are estimated using demand allocation methodology described National Grid 2000 EnergyWise impact evaluation.[256]

[254] GDS Associates, Inc. (2007). *Measure Life Report: Residential and Commercial/Industrial Lighting and HVAC Measures*. Prepared for The New England State Program Working Group.
[255] The Cadmus Group, Inc. (2010). *EnergyWise 2008 Program Evaluation*. Prepared for National Grid.
[256] Quantec, LLC (2000). *Impact Evaluation: Single-Family EnergyWise Program*. Prepared for National Grid.

Multifamily – DHW Measures (Showerheads and Aerators) (National Grid)

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: An existing showerhead or aerator with a high flow rate is replaced with a new low flow showerhead or aerator.
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: Residential Water, Low-Income Annual Discounted Rate Cost Reduction
Sector: Residential, Low Income
Market: Retrofit
End Use: Hot Water
Program: Multi-Family Retrofit, Low-Income Multifamily Retrofit

Notes

The savings algorithms and assumptions described in this section are specific to National Grid's Multi-Family Retrofit and Low-Income Multifamily Retrofit programs. See the section *Multifamily – Vendor Measures* for information about other PAs' Multi-Family programs.

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed based on study results:

$$\Delta kWh = \Delta kWh$$
$$\Delta kW = \Delta kWh \times kW / kWh$$

Unit	=	Showerhead or aerator installation.
ΔkWh	=	Average annual kWh reduction per unit: 80.3 kWh[257]
kW/kWh	=	Average kW reduction per kWh reduction: 0.000125 kW/kWh[258]

Baseline Efficiency

The baseline efficiency case is an existing shower head or faucet aerator with a high flow.

High Efficiency

High efficiency is a low flow showerhead or faucet aerator.

[257] National Grid Multifamily Screening Tool. This was developed in the early 1990's. Documentation of the specific variables is unavailable. Evaluation results have consistently shown realization rates close to 100%.
[258] Estimated using demand allocation methodology described in: Quantec, LLC (2000). *Impact Evaluation: Single-Family EnergyWise Program.* Prepared for National Grid.

Hours

Not applicable.

Measure Life

The measure life is 7 years.[259]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Benefits

Benefit Type	Description	Savings
Residential Water	Gallons water saved per year per unit that received DHW measures[260]	4,028 Gallons/Participant
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Showerhead/Aerator (Electric)	MF Retrofit, LI MF Retrofit	National Grid	1.00	1.00	0.91	0.91	0.91	0.75	1.00
Showerhead/Aerator (Non-Electric)	MF Retrofit, LI MF Retrofit	National Grid	1.00	1.00	0.99	0.99	0.99	0.75	1.00

In-Service Rates
All installations have 100% in service rate since all PA programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factor.

Realization Rates
Realization rates from the National Grid Energy Wise 2008 Program Evaluation[261].

Coincidence Factors
Summer and winter coincidence factors are estimated using demand allocation methodology described National Grid 2000 EnergyWise impact evaluation[262].

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[259] Massachusetts Common Assumption.
[260] NMR Group, Inc., Tetra Tech (2011). *Massachusetts Special and Cross-Sector Studies Area, Residential and Low-Income Non-Energy Impacts (NEI) Evaluation,* Prepared for Massachusetts Program Administrators
[261] The Cadmus Group, Inc. (2010). *EnergyWise 2008 Program Evaluation*. Prepared for National Grid.
[262] Quantec, LLC (2000). *Impact Evaluation: Single-Family EnergyWise Program*. Prepared for National Grid.

Multifamily – DHW Measures (Tank and Pipe Wrap) (National Grid)

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: A wrap is added to the water heater tank or pipes.
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: Low Income Only: Annual Discounted Rate Cost Reduction
Sector: Residential, Low Income
Market: Retrofit
End Use: Hot Water
Program: Multi-Family Retrofit, Low-Income Multifamily Retrofit

Notes

The savings algorithms and assumptions described in this section are specific to National Grid's Multi-Family Retrofit and Low-Income Multifamily Retrofit programs. See the section *Multifamily – Vendor Measures* for information about other PAs' Multi-Family programs.

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed based on study results:

$$\Delta kWh = \Delta kWh$$
$$\Delta kW = \Delta kWh \times kW / kWh$$

Where:

Unit	=	Each installation for tank wraps, per linear foot for pipe wrap.
kWh	=	Average annual kWh reduction per unit: 55 kWh[263]
kW/kWh	=	Average annual kW reduction per kWh reduction: 0.000125 kW/kWh[264]

Baseline Efficiency

The baseline efficiency case is no wrap on the tank or pipes.

High Efficiency

High efficiency is the addition of a wrap.

[263] National Grid Multifamily Screening Tool. This was developed in the early 1990's. Documentation of the specific variables is unavailable. Evaluation results have consistently shown realization rates close to 100%.
[264] Estimated using demand allocation methodology described in: Quantec, LLC (2000). *Impact Evaluation: Single-Family EnergyWise Program.* Prepared for National Grid.

Hours

Not applicable.

Measure Life

The measure life is 7 years.[265]

Secondary-Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Tank/Pipe Wrap (Electric)	MF Retrofit, LI MF Retrofit	National Grid	1.00	1.00	0.91	0.91	0.91	0.75	1.00
Tank/Pipe Wrap (Non-Electric)	MF Retrofit, LI MF Retrofit	National Grid	1.00	1.00	0.99	0.99	0.99	0.75	1.00

<u>In-Service Rates</u>
All installations have 100% in service rate since all PA programs include verification of equipment installations.

<u>Savings Persistence Factor</u>
All PAs use 100% savings persistence factor.

<u>Realization Rates</u>
Realization rates from the National Grid Energy Wise 2008 Program Evaluation.[266]

<u>Coincidence Factors</u>
Summer and winter coincidence factors are estimated using demand allocation methodology described National Grid 2000 EnergyWise impact evaluation.[267]

[265] Massachusetts Common Assumption.
[266] The Cadmus Group, Inc. (2010). *EnergyWise 2008 Program Evaluation*. Prepared for National Grid.
[267] Quantec, LLC (2000). *Impact Evaluation: Single-Family EnergyWise Program*. Prepared for National Grid.

Multifamily – Programmable Thermostats (National Grid)

Version Date and Revision History

Effective Date: 1/1/2011 (revised for 1/1/2012)
End Date: TBD

Measure Overview

Description: Installation of programmable thermostats
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: Low-Income Annual Discounted Rate Cost Reduction
Sector: Residential, Low-Income
Market: Retrofit
End Use: HVAC
Program: Multi-Family Retrofit, Low-Income Multifamily Retrofit

Notes

The savings algorithms and assumptions described in this section are specific to National Grid's Multi-Family Retrofit and Low-Income Multifamily Retrofit programs. See the section *Multifamily – Vendor Measures* for information about other PAs' Multi-Family programs.

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed based on study results:

$$\Delta kWh = \Delta kWh$$
$$\Delta kW = \Delta kWh \times kW / kWh$$

Where:

Unit	=	Installation of programmable thermostat.
ΔkWh	=	Average annual kWh reduction per unit: 288 kWh[268]
kW/kWh	=	Average annual kW reduction per kWh reduction: 0.000125 kW/kWh[269]

Baseline Efficiency

The baseline efficiency case is a system without a set back programmable thermostat.

[268] National Grid Multifamily Screening Tool. This was developed in the early 1990's. Documentation of the specific variables is unavailable. Evaluation results have consistently shown realization rates close to 100%.
[269] Estimated using demand allocation methodology described in: Quantec, LLC (2000). *Impact Evaluation: Single-Family EnergyWise Program.* Prepared for National Grid.

High Efficiency

The high efficiency case is a system with a set-back programmable and fixed set point (common areas) thermostats.

Hours

Not applicable.

Measure Life

The measure life is 15 years.[270]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Programmable Thermostat (Electric)	MF Retrofit, LI MF Retrofit	National Grid	1.00	1.00	0.91	0.91	0.91	0.03	1.00
Programmable Thermostat (Non-Electric)	MF Retrofit, LI MF Retrofit	National Grid	1.00	1.00	0.99	0.99	0.99	0.03	1.00

In-Service Rates
All installations have 100% in service rate since all PA programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factor.

Realization Rates
Realization rates from the National Grid Energy Wise 2008 Program Evaluation[271].

Coincidence Factors
Summer and winter coincidence factors are estimated using demand allocation methodology described National Grid 2000 EnergyWise impact evaluation[272].

[270] Environmental Protection Agency (2010). *Life Cycle Cost Estimate for ENERGY STAR Programmable Thermostat*.
[271] The Cadmus Group, Inc. (2010). *EnergyWise 2008 Program Evaluation*. Prepared for National Grid.
[272] Quantec, LLC (2000). *Impact Evaluation: Single-Family EnergyWise Program*. Prepared for National Grid.

Multifamily – Heat Pump Tune-Up (National Grid)

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: Heat pump tune-up for electrically-heated homes only.
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: Low-Income Annual Discounted Rate Cost Reduction
Sector: Residential, Low-Income
Market: Retrofit
End Use: HVAC
Program: Multi-Family Retrofit, Low-Income Multifamily Retrofit

Notes

The savings algorithms and assumptions described in this section are specific to National Grid's Multi-Family Retrofit and Low-Income Multifamily Retrofit programs. See the section *Multifamily – Vendor Measures* for information about other PAs' Multi-Family programs.

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed based on study results:

$$\Delta kWh = \Delta kWh$$
$$\Delta kW = \Delta kWh \times kW / kWh$$

Where:

Unit	=	Heat pump tune-up performed
ΔkWh	=	Average annual kWh reduction per unit: 1162 kWh[273]
kW/kWh	=	Average kW reduction per kWh reduction: 0.000125 kW/kWh[274]

Baseline Efficiency

The baseline efficiency case is an existing heat pump that is not tuned up.

High Efficiency

The high efficiency case is an existing heat pump that is tuned up.

[273] National Grid Multifamily Screening Tool. This was developed in the early 1990's. Documentation of the specific variables is unavailable. Evaluation results have consistently shown realization rates close to 100%.
[274] Estimated using demand allocation methodology described in: Quantec, LLC (2000). *Impact Evaluation: Single-Family EnergyWise Program.* Prepared for National Grid.

Hours

Not applicable.

Measure Life

The measure life is 5 years.[275]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Heat Pump Tune-up (Electric)	MF Retrofit, LI MF Retrofit	National Grid	1.00	1.00	0.91	0.91	0.91	0.03	1.00

In-Service Rates
All installations have 100% in service rate since all PA programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factor.

Realization Rates
Realization rates from the National Grid Energy Wise 2008 Program Evaluation.[276]

Coincidence Factors
Summer and winter coincidence factors are estimated using demand allocation methodology described National Grid 2000 EnergyWise impact evaluation.[277]

[275] Massachusetts Common Assumption.
[276] The Cadmus Group, Inc. (2010). *EnergyWise 2008 Program Evaluation*. Prepared for National Grid.
[277] Quantec, LLC (2000). *Impact Evaluation: Single-Family EnergyWise Program*. Prepared for National Grid.

Multifamily – Air Sealing (National Grid)

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: Thermal shell air leaks are sealed through strategic use and location of air-tight materials in electrically-heated facilities.
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: Low-Income Annual Discounted Rate Cost Reduction
Sector: Residential, Low Income
Market: Retrofit
End Use: HVAC
Program: Multi-Family Retrofit, Low-Income Multifamily Retrofit

Notes

The savings algorithms and assumptions described in this section are specific to National Grid's Multi-Family Retrofit and Low-Income Multifamily Retrofit programs. See the section *Multifamily – Vendor Measures* for information about other PAs' Multi-Family programs.

Algorithms for Calculating Primary Energy Impact

Unit savings are calculated using the following algorithms and assumptions:

$$\Delta kWh = Stories \times SQFT \times (CFM / SQFT_{PRE} - CFM / SQFT_{POST}) \times \Delta kWh / CFM$$
$$\Delta kW = \Delta kWh \times kW / kWh$$

Where:

Stories	=	Total stories in the multi-family building
SQFT	=	Total SQFT of building
$CFM/SQFT_{PRE}$	=	Estimate of pre-retrofit air leakage in CFM/SQFT based on number of stories in the building and air-tightness ratings of the existing roof and floor.
$CFM/SQFT_{POST}$	=	Estimate of post-retrofit air leakage in CFM/SQFT based on number of stories in the building and air-tightness ratings of the improved roof and floor.
ΔkWh/CFM	=	Average annual kWh reduction per CFM: 2.48633 kWh/CFM[278]
kW/kWh	=	Average kW reduction per kWh reduction: 0.000125 kW/kWh[279]

[278] National Grid Multifamily Screening Tool. This was developed in the early 1990's. Documentation of the specific variables is unavailable. Evaluation results have consistently shown realization rates close to 100%.
[279] Estimated using demand allocation methodology described in: Quantec, LLC (2000). *Impact Evaluation: Single-Family EnergyWise Program.* Prepared for National Grid.

Baseline Efficiency

The baseline efficiency case is a facility that has not received comprehensive air-sealing treatment.

High Efficiency

The high efficiency case is a facility with thermal shell air leaks that are sealed, leading to a reduction in air leakage.

Hours

Not applicable.

Measure Life

The measure life is 15 years.[280]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Air Sealing (Electric)	MF Retrofit, LI MF Retrofit	National Grid	1.00	1.00	0.91	0.91	0.91	0.03	1.00
Air Sealing (Non-Electric)	MF Retrofit, LI MF Retrofit	National Grid	1.00	1.00	0.99	0.99	0.99	0.03	1.00

In-Service Rates
All installations have 100% in service rate since all PA programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factor.

Realization Rates
Realization rates are from the National Grid Energy Wise 2008 Program Evaluation.[281]

[280] GDS Associates, Inc. (2007). *Measure Life Report: Residential and Commercial/Industrial Lighting and HVAC Measures*. Prepared for The New England State Program Working Group.
[281] The Cadmus Group, Inc. (2010). *EnergyWise 2008 Program Evaluation*. Prepared for National Grid.

Coincidence Factors

Summer and winter coincidence factors are estimated using demand allocation methodology described National Grid 2000 EnergyWise impact evaluation.[282]

[282] Quantec, LLC (2000). *Impact Evaluation: Single-Family EnergyWise Program*. Prepared for National Grid.

Multifamily – Refrigerators and Freezers (National Grid)

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: Removal of old inefficient refrigerator or freezer with the installation of new efficient refrigerator or freezer.
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: Low-Income Annual Discounted Rate Cost Reduction, One-Time Avoided Refrigerator Purchase (Low-Income only)
Sector: Residential, Low Income
Market: Retrofit
End Use: Refrigeration
Program: Multi-Family Retrofit, Low-Income Multifamily Retrofit

Notes

The savings algorithms and assumptions described in this section are specific to National Grid's Multi-Family Retrofit and Low-Income Multifamily Retrofit programs. See the section *Multifamily – Vendor Measures* for information about other PAs' Multi-Family programs.

Algorithms for Calculating Primary Energy Impact

Unit savings are calculated using the following algorithms and assumptions:

$$\Delta kWh = kWh_{PRE} - kWh_{POST}$$
$$\Delta kW = \Delta kWh \times kW / kWh$$

Where:

Unit	=	Replacement of existing refrigerator with new ENERGY STAR® refrigerator
kWh_{PRE}	=	Annual kWh consumption of existing equipment. Value entered by the user.
kWh_{POST}	=	Annual kWh consumption of new installed equipment. Value entered by the user.
kW/kWh	=	Average kW reduction per kWh reduction: 0.00013 kW/kWh[283]

Baseline Efficiency

The baseline efficiency case is an existing refrigerator for which the annual kWh may be looked up in a refrigerator database. If the manufacturer and model number are not found, the refrigerator is metered for 1.5 hours in order to determine the annual kWh.

[283] Estimated using demand allocation methodology described in: Quantec, LLC (2000). *Impact Evaluation: Single-Family EnergyWise Program.* Prepared for National Grid.

High Efficiency

The high efficiency case is a new more efficiency refrigerator. The manufacture and model number is looked up in a refrigerator database to determine annual kWh.

Measure Life

The measure life is 12 years for non low income[284] and 19 years for low income.[285]

Hours

Not applicable.

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Refrig/Freezers (Electric)	MF Retrofit, LI MF Retrofit	National Grid	1.00	1.00	0.91	0.91	0.91	1.00	0.92
Refrig/Freezers (Non-Electric)	MF Retrofit, LI MF Retrofit	National Grid	1.00	1.00	0.99	0.99	0.99	1.00	0.92

In-Service Rates
All installations have 100% in service rate since all PA programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factor.

Realization Rates
Realization rates from the National Grid Energy Wise 2008 Program Evaluation.[286]

Coincidence Factors
Summer and winter coincidence factors are estimated using demand allocation methodology described National Grid 2000 EnergyWise impact evaluation.[287]

284 Environmental Protection Agency (2009). *Life Cycle Cost Estimate for ENERGY STAR Residential Refrigerator*.
285 Massachusetts Common Assumption.
286 The Cadmus Group, Inc. (2010). *EnergyWise 2008 Program Evaluation*. Prepared for National Grid.
287 Quantec, LLC (2000). *Impact Evaluation: Single-Family EnergyWise Program*. Prepared for National Grid.

Multifamily – Fixtures and CFLs (National Grid)

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: Removal of existing inefficient fixtures/bulbs with the installation of new efficient fixtures/bulbs
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: O&M, Low-Income Annual Discounted Rate Cost Reduction
Sector: Residential, Low-Income
Market: Retrofit
End Use: Lighting
Program: Multi-Family Retrofit, Low-Income Multifamily Retrofit

Notes

The savings algorithms and assumptions described in this section are specific to National Grid's Multi-Family Retrofit and Low-Income Multifamily Retrofit programs. See the section *Multifamily – Vendor Measures* for information about other PAs' Multi-Family programs.

Algorithms for Calculating Primary Energy Impact

Unit savings are calculated using the following algorithms and assumptions:

$$\Delta kWh = \left[\left(QTY_{PRE} \times Watts_{PRE} \times Hours_{PRE}\right) - \left(QTY_{EE} \times Watts_{EE} \times Hours_{EE}\right)\right] / 1000 \times 52$$
$$\Delta kW = \Delta kWh \times kW / kWh$$

Where:

QTY_{PRE}	=	Quantity of pre-retrofit fixtures/bulbs
QTY_{EE}	=	Quantity of efficient fixtures/bulbs installed
$Watts_{PRE}$	=	Rated watts of pre-retrofit fixtures/bulbs
$Watts_{EE}$	=	Rated watts of efficient fixtures/bulbs installed
$Hours_{PRE}$	=	Weekly hours of operation for pre-retrofit case lighting fixtures/bulbs
$Hours_{EE}$	=	Weekly hours of operation for efficient lighting fixtures/bulbs
52	=	Weeks per year
kW/kWh	=	Average kW reduction per kWh reduction: 0.000273 kW/kWh[288]

Baseline Efficiency

The baseline efficiency case is the existing fixture and bulbs.

[288] Estimated using demand allocation methodology described in: Quantec, LLC (2000). *Impact Evaluation: Single-Family EnergyWise Program.* Prepared for National Grid.

High Efficiency

The high efficiency case is the new fixture and lamps.

Measure Life

The measure life is 7 years for CFLs and 7 years for fixtures.[289]

Hours

Operating hours are estimated by the vendor for each facility. Typical assumptions are 24 hours/day for common area lighting, 12 hours/day for exterior lighting, and 3 hours/day for in-unit lighting, but may be adjusted based on type of housing. Estimates are verified with facility maintenance staff when possible.

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
CFLs (Electric)	MF Retrofit, LI MF Retrofit	National Grid	1.00	1.00	0.91	0.91	0.91	0.35	1. 00
CFLs (Non-Electric)	MF Retrofit, LI MF Retrofit	National Grid	1.00	1.00	0.99	0.99	0.99	0.35	1.00
Fixtures (Electric)	MF Retrofit, LI MF Retrofit	National Grid	1.00	1.00	0.91	0.91	0.91	0.35	1.00
Fixtures (Non-Electric)	MF Retrofit, LI MF Retrofit	National Grid	1.00	1.00	0.99	0.99	0.99	0.35	1.00

<u>**In-Service Rates**</u>
All installations have 100% in service rate since all PA programs include verification of equipment installations.

<u>**Savings Persistence Factor**</u>
All PAs use 100% savings persistence factor.

<u>**Realization Rates**</u>
Realization rates from the National Grid Energy Wise 2008 Program Evaluation.[290]

<u>**Coincidence Factors**</u>
Summer and winter coincidence factors are estimated using demand allocation methodology described National Grid 2000 EnergyWise impact evaluation.[291]

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[289] The adjusted measure life accounts for changes in the baseline due to EISA standards as shown in the MA Lighting Worksheet
[290] The Cadmus Group, Inc. (2010). *EnergyWise 2008 Program Evaluation*. Prepared for National Grid.
[291] Quantec, LLC (2000). *Impact Evaluation: Single-Family EnergyWise Program*. Prepared for National Grid.

Custom Measures

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: Installation of complex custom energy efficiency measures including solar hot water installations and fuel switching projects.
Primary Energy Impact: Electric
Secondary Energy Impact: Project-specific
Non-Energy Impact: Project-specific
Sector: Residential, Low Income
Market: Lost Opportunity, Retrofit
End Use: All
Program: All

Algorithms for Calculating Primary Energy Impact

Gross energy and demand savings estimates for custom projects are calculated using engineering analysis with project-specific details. Custom analyses typically include a weather dependent load bin analysis, whole building energy model simulation, end-use metering or other engineering analysis and include estimates of savings, costs, and an evaluation of the projects' cost-effectiveness.

Baseline Efficiency

The baseline efficiency case for Lost Opportunity projects assumes compliance with the efficiency requirements as mandated by Massachusetts State Building Code or industry accepted standard practice. The baseline efficiency case for retrofit projects is the same as the existing, or pre-retrofit, case for the facility.

High Efficiency

The high efficiency case is specific to the custom project and may include one or more energy efficiency measures. Energy and demand savings calculations are based on projected or measured changes in equipment efficiencies and operating characteristics and are determined on a case-by-case basis. The project must be proven cost-effective in order to qualify for energy efficiency incentives.

Hours

All hours for custom savings analyses should be determined on a case-by-case basis.

Measure Life

For both lost-opportunity and retrofit custom applications, the measure life is determined based on specific project using the common measure life recommendations.

Secondary Energy Impacts

All secondary energy impacts should be determined on a case-by-case basis.

Non-Energy Impacts

All non-energy impacts should be determined on a case-by-case basis.

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Solar DHW	HES	All	1.00	1.00	1.00	1.00	1.00	custom	custom
Solar DHW	LI 1-4 Retrofit	All	1.00	1.00	1.00	1.00	1.00	custom	custom
Fuel Switching	HES	All	1.00	1.00	1.00	1.00	1.00	custom	custom

In-Service Rates
All installations have 100% in service rate since all PAs programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factors.

Realization Rates
Realization rates are set to zero since project savings estimates are based on project-specific detail.

Coincidence Factors
Coincidence factors for summer and winter peak periods are custom-calculated based on project-specific detail.

Commercial and Industrial Electric Efficiency Measures

Lighting – Advanced Lighting Design (Performance Lighting)

Version Date and Revision History

Effective Date: 1/1/2011 (Revised 1/1/2012)
End Date: TBD

Measure Overview

Description: Advanced lighting design refers to the implementation of various lighting design principles aimed at creating a quality and appropriate lighting experience while reducing unnecessary light usage. This is often done by a professional in a new construction situation. Advanced lighting design uses techniques like maximizing task lighting and efficient fixtures to create a system of optimal energy efficiency and functionality.
Primary Energy Impact: Electric
Secondary Energy Impact: Gas, Oil
Non-Energy Impact: O&M
Sector: Commercial and Industrial
Market: Lost Opportunity
End Use: Lighting
Program: ***C&I*** New Construction & Major Renovation

Algorithms for Calculating Primary Energy Impact

$$\Delta kWh = \sum_{i=1}^{n}\left(\frac{LPD_{BASE,i} \times Area_i \times Hours_i}{1000}\right) - \sum_{j=1}^{m}\left(\frac{Count_{EE,j} \times Watts_{EE,j} \times Hours_j}{1000}\right)$$

$$\Delta kW = \sum_{i=1}^{n}\left(\frac{LPD_{BASE,i} \times Area_i}{1000}\right) - \sum_{j=1}^{m}\left(\frac{Count_{EE,j} \times Watts_{EE,j}}{1000}\right)$$

Where:

n	=	Total number of spaces in Space-by-Space Method or 1 for Building Area Method
m		Total number of efficient fixture types installed
$LPD_{BASE,i}$	=	Baseline lighting power density for building or space type i (Watts/ft^2)
$Area_i$	=	Area of building or space *i* (ft^2)
$Hours_i$	=	Annual hours of operation of the lighting equipment for building or space type *i*
$Count_{EE,j}$	=	Quantity of efficient fixture type j
$Watts_{EE,j}$	=	Wattage of fixture type j (Watts)
1000	=	Conversion factor: 1000 watts per 1 kW

Note on HVAC system interaction: Additional Electric savings from cooling system interaction are included in the calculation of adjusted gross savings for Lighting Systems projects. The HVAC interaction adjustment factor is determined from lighting project evaluations and is included in the energy realization rates and demand coincidence factors and realization rates.

Baseline Efficiency

The Baseline Efficiency assumes compliance with lighting power density requirements as mandated by Massachusetts State Building Code. As described in Chapter 13 of the aforementioned document, energy efficiency must be met via compliance with the International Energy Conservation Code (IECC) 2009. IECC offers one compliance path, the Building Area Method. ASHRAE 90.1-2007 offers two compliance paths. For completeness, the lighting power density requirements for both the Building Area Method and the Space-by-Space Method are presented.[292] Table 45 and

[292] IECC 2009 presents requirements consistent with ASHRAE 90.1-2007 for the Building Area Method but does not present requirements for the Space-by-Space Method.

Table 46 in Appendix A: Common Lookup Tables detail the specific power requirements by compliance path.

High Efficiency

The high efficiency scenario assumes lighting systems that achieve lighting power densities below those required by Massachusetts State Building Code. Actual site lighting power densities should be determined on a case-by-case basis. Please refer to the current year application form for minimum percentage better than code efficiency requirements.

Hours

The annual hours of operation for lighting systems are site-specific and should be determined on a case-by-case basis. If site-specific hours are unavailable, refer to the default hours in Table 50 in Appendix A: Common Lookup Tables

Measure Life

The measure life for all new construction lighting installations is 15 years.[293]

Secondary Energy Impacts

Heating energy will be increased due to reduced lighting waste heat. This impact is estimated as an average impact in heating fossil fuel consumption per unit of energy saved.

Measure	Energy Type	Impact (MMBtu/ΔkWh)[294]
Interior Lighting	C&I Gas Heat	-0.0003649
Interior Lighting	Oil	-0.0007129

Non-Energy Impacts

Annual non-energy benefits are claimed due to the reduced operation and maintenance costs associated with the longer measure lived of lamps and ballasts as compared to the base or pre-retrofit case. See Appendix D: Non-Resource Impacts.

Impact Factors for Calculating Adjusted Gross Savings

Measure	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}	CF_{SSP}	CF_{WSP}
All	NC	National Grid	1.00	1.00	1.07	0.80	0.73	custom	custom	n/a	n/a
All	NC	NSTAR	1.00	1.00	1.14	1.11	1.30	0.85	0.59	n/a	n/a
All	NC	CLC	1.00	1.00	1.14	1.11	1.30	0.85	0.59	n/a	n/a
All	NC	Unitil	1.00	1.00	1.00	1.00	1.00	0.85	0.59	n/a	n/a
All	NC	WMECO	1.00	1.00	1.05	1.23	1.05	n/a	n/a	custom	custom

293 Energy & Resource Solutions (2005). *Measure Life Study*. Prepared for The Massachusetts Joint Utilities; Table 1-1.
294 Optimal Energy, Inc. (2008). *MEMO: Non-Electric Benefits Analysis Update*. Prepared for NSTAR. Final savings values calculated in spreadsheet analysis as noted on pg 5 of the memo.

In-Service Rates
All installations have 100% in service rate since programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factor.

Realization Rates
- National Grid: energy and demand RRs derived from impact evaluation of National Grid 2008 custom lighting installations[295]; final realization rates developed in 2008 custom program analysis study[296]
- NSTAR, CLC: energy and demand RRs from impact evaluation of NSTAR 2007 lighting installations[297]
- Unitil: energy and demand RRs are 100% for all C&I New Construction projects based on no evaluations
- WMECO: energy RRs are from 2007/2008 Large C&I Programs impact evaluation[298]

Coincidence Factors
- National Grid, WMECO: CFs are custom calculated based on site-specific information.
- NSTAR, Unitil, CLC: CFs from the 2011 NEEP C&I Lighting Loadshape Study[299]

[295] KEMA, Inc. (2009). *National Grid USA 2008 Custom Lighting Impact Evaluation, Final Report*. Prepared for National Grid.
[296] KEMA, Inc. (2009). *Sample Design and Impact Evaluation Analysis of the the 2008 Custom Program.* Prepared for National Grid; Table 19.
[297] KEMA, Inc. (2009). *2007 Business & Construction Solutions (BS/CS) Programs - Measurement and Verification of 2007 Lighting Measures*. Prepared for NSTAR; Table Ex 3.
[298] KEMA, Inc. (2010). *2007/2008 Large C&I Programs, Phase 1 Report Memo for Lighting and Process Measures.* Prepared for Western Massachusetts Electric Company.
[299] KEMA (2011). C&I Lighting Loadshape Project – Final Report. Prepared for the Regional Evaluation, Measurement and Verification Forum.

Lighting – Lighting Systems

Version Date and Revision History

Effective Date: 1/1/2011 (Revised 1/1/2012)
End Date: TBD

Measure Overview

Description: This measure promotes the installation of efficient lighting including, but not limited to, efficient fluorescent lamps, ballasts, and fixtures, solid state lighting, and efficient high intensity discharge (HID) lamps, ballasts, and fixtures.
Primary Energy Impact: Electric
Secondary Energy Impact: Gas, Oil
Non-Energy Impact: O&M
Sector: Commercial & Industrial
Market: Lost Opportunity, Retrofit
End Use: Lighting
Program: ***C&I*** New Construction & Major Renovation, C&I Large Retrofit, C&I Small Retrofit

Algorithms for Calculating Primary Energy Impact

$$\Delta kWh = \left[\sum_{i=1}^{n} \left(\frac{Count_i * Watts_i}{1000} \right)_{BASE} - \sum_{j=1}^{m} \left(\frac{Count_j * Watts_j}{1000} \right)_{EE} \right] (Hours)$$

$$\Delta kW = \sum_{i=1}^{n} \left(\frac{Count_i * Watts_i}{1000} \right)_{BASE} - \sum_{j=1}^{m} \left(\frac{Count_j * Watts_j}{1000} \right)_{EE}$$

Where:

n	=	Total number of fixture types in baseline or pre-retrofit case
m	=	Total number of installed fixture types
$Count_i$	=	Quantity of existing fixtures of type i (for lost-opportunity, $Count_i = Count_j$).
$Watts_i$	=	Existing fixture or baseline wattage for fixture type i
$Count_j$	=	Quantity of efficient fixtures of type j.
$Watts_j$	=	Efficient fixture wattage for fixture type j.
1000	=	Conversion factor: 1000 watts per kW.
Hours	=	Lighting annual hours of operation.

Note on HVAC system interaction: Additional Electric savings from cooling system interaction are included in the calculation of adjusted gross savings for Lighting Systems projects. The HVAC interaction adjustment factor is determined from lighting project evaluations and is included in the energy realization rates and demand coincidence factors and realization rates (See Impact Factors section).

Baseline Efficiency

For retrofit installations, the baseline efficiency case is project-specific and is determined using actual fixture counts from the existing space. Existing fixture wattages are provided in the MassSAVE Retrofit

Lighting Wattage Tables[300]. For lost opportunity installations, the baseline efficiency case is determined using assumed baseline wattages for each of the installed fixtures[301].

High Efficiency

For both new construction and retrofit installations, the high efficiency case is project-specific and is determined using actual fixture counts for the project and the MassSave Wattage Tables[302] in Appendix A: Common Lookup Tables

Hours

The annual hours of operation for lighting systems are site-specific and should be determined on a case-by-case basis. If site-specific hours of operation are unavailable, refer to the default hours presented in Table 50 in Appendix A: Common Lookup Tables

Measure Life

Lighting system measure lives vary by market sector and equipment type.

Measure Lives for C&I Lighting Systems[303]

Equipment Type	Measure Life (years)	
	Retrofit	Lost Opportunity
Bulb – CFL screw base	5	N/A
Fluorescent Fixture	13	15
Hardwired CFL	13	15
LED Exit Signs	13	15
HID (interior and exterior)	13	15
LED Lighting Fixtures	13	15
LED Integral Replacement Lamps	13	15
LED Low Bay – Garage & Canopy Fixtures	13	15

Secondary Energy Impacts

Heating energy will be increased due to reduced lighting waste heat. This impact is estimated as an average impact in heating fossil fuel consumption per unit of energy saved.

Measure	Energy Type	Impact (MMBtu/ΔkWh)[304]
Interior Lighting	C&I Gas Heat	-0.0003649
Interior Lighting	Oil	-0.0007129

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300 MassSave (2010). *C&I Retrofit Lighting Wattage Tables.*
301 Massachusetts Common Assumption: Baseline wattage per fixture type based on comparable code-compliant installations and standard practice.
302 MassSave (2010). *C&I New Construction Lighting Wattage Tables* AND MassSave (2010). *C&I Retrofit Lighting Wattage Tables.*
303 Energy & Resource Solutions (2005). *Measure Life Study*. Prepared for The Massachusetts Joint Utilities; Table 1-1 AND GDS Associates, Inc. (2007). *Measure Life Report: Residential and Commercial/Industrial Lighting and HVAC Measures*. Prepared for The New England State Program Working Group; Table 2
304 Optimal Energy, Inc. (2008). *MEMO: Non-Electric Benefits Analysis Update*. Prepared for NSTAR. Final savings values calculated in spreadsheet analysis as noted on pg 5 of the memo.

Non-Energy Impacts

Annual non-energy benefits are claimed due to the reduced operation and maintenance costs associated with the longer measure lived of lamps and ballasts as compared to the base or pre-retrofit case. See Appendix D: Non-Resource Impacts.

Impact Factors for Calculating Adjusted Gross Savings

Measure	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}	CF_{SSP}	CF_{WSP}
Large C&I New Construction and Large C&I Retrofit											
All	NC	CLC	1.00	1.00	1.14	1.11	1.30	0.85	0.59	n/a	n/a
All	Retrofit	CLC	1.00	1.00	1.01	1.18	1.26	0.85	0.59	n/a	n/a
All	NC	National Grid	1.00	1.00	0.99	0.97	0.97	0.98	0.73	n/a	n/a
All	Retrofit	National Grid	1.00	1.00	1.04	1.03	1.03	0.89	0.63	n/a	n/a
All	NC	NSTAR	1.00	1.00	1.14	1.11	1.30	0.85	0.59	n/a	n/a
All	Retrofit	NSTAR	1.00	1.00	1.01	1.18	1.26	0.85	0.59	n/a	n/a
All	NC	Unitil	1.00	1.00	1.00	1.00	1.00	0.85	0.59	n/a	n/a
All	Retrofit	Unitil	1.00	1.00	1.00	1.00	1.00	0.85	0.59	n/a	n/a
All	Retrofit	WMECO	1.00	1.00	1.05	1.23	1.05	n/a	n/a	custom	custom
Small C&I Retrofit											
All	Retrofit	CLC	1.00	1.00	1.08	0.99	0.99	0.77	0.39	n/a	n/a
All	Retrofit	National Grid	1.00	1.00	1.08	0.98	0.98	0.79	0.39	n/a	n/a
CFLs, Interior	Retrofit	National Grid	1.00	0.87	1.08	0.98	0.98	0.79	0.39	n/a	n/a
All	Retrofit	NSTAR	1.00	1.00	1.08	0.99	0.99	0.77	0.39	n/a	n/a
All	Retrofit	Unitil	1.00	1.00	1.08	0.99	0.99	0.77	0.39	n/a	n/a
All	Retrofit	WMECO	1.00	1.00	0.83	0.88	0.88	n/a	n/a	0.61	0.29

In-Service Rates
All installations have 100% in service rate since all PAs programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factors with one exception: National Grid uses 0.87 for screw-in CFLs installed through the C&I Small Retrofit program based on 1996 savings persistence study[305].

Realization Rates

New Construction & Major Renovation Commercial

- National Grid energy and demand RRs from impact evaluation of National Grid's 2007 Design 2000plus (New Construction) Lighting installations[306]. Demand RR is the connected demand RR; energy RR includes connected demand RR, hours of use RR and HVAC Interactive adjustment.
- NSTAR, CLC energy and demand RRs from impact evaluation of NSTAR's Business & Construction Solutions Programs Lighting installations[307]. Energy and demand realization rates include interactive adjustments.
- Unitil: energy and demand RRs are 100% for all C&I New Construction projects based on no evaluations

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305 HEC, Inc. (1996). *Persistence of Savings Study*. Prepared for New England Power Service Company.
306 KEMA, Inc. (2009). *Design 2000plus Lighting Hours of Use and Load Shapes Measurement Study*. Prepared for National Grid.
307 RLW Analytics (2008). *Business & Construction Solutions (BS/CS) Programs Measurement & Verification - 2006 Final Report*. Prepared for NSTAR Electric and Gas

- WMECO: energy RRs are from 2007/2008 Large C&I Programs impact evaluation[308]

C&I Large Retrofit

- National Grid energy RR is from impact evaluation of National Grid's 2007 Energy Initiative (Large Retrofit) Lighting program[309]. Energy RR is the ratio measured electric energy savings to gross estimates of electric energy savings, and includes electric HVAC interaction adjustment by default. National Grid demand RRs are from impact evaluation of National Grid's 2003 Energy Initiative Lighting program[310]. Demand RR is the connected demand RR.
- NSTAR, CLC, Unitil, WMECO: Same as *New Construction & Major Renovation Commercial*

C&I Small Retrofit

- Energy RRs are the statewide results from the 2011 Small C&I Non-Controlled Lighting impact evaluation[311]
- National Grid, NSTAR, CLC, Unitil: demand RRs are from the statewide results from the 2011 Small C&I Non-Controlled Lighting impact evaluation[312]

Coincidence Factors

New Construction & Major Renovation Commercial

All CFs are from the 2011 NEEP C&I Lighting Loadshape Project[313] except:
National Grid CFs from National Grid's 2007 Design 2000*plus* Lighting subprogram[314]

C&I Large Retrofit

All CFs are from the 2011 NEEP C&I Lighting Loadshape Project[315] except WMECO which uses custom CFs based on project-specific detail.

C&I Small Retrofit

All CF_{SP} values are from the 2011 NEEP C&I Lighting Loadshape Project[316]
All CF_{WP} values are the statewide results from the 2011 Small C&I Non-Controlled Lighting impact evaluation[317] except WMECO which uses custom CFs based on project-specific detail.

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308 KEMA, Inc. (2010). *2007/2008 Large C&I Programs, Phase 1 Report Memo for Lighting and Process Measures*. Prepared for Western Massachusetts Electric Company.
309 Summit Blue Consulting, LLC (2008). *Large Commercial and Industrial Retrofit Program Impact Evaluation 2007 – Final Report*. Prepared for National Grid.
310 RLW Analytics (2004). *2003 Energy Initiative "EI" Program Lighting Impact Evaluation - Final Report*. Prepared for National Grid.
311 Cadmus Group (2011). *Non-Controls Lighting Evaluation for the Massachusetts Small Commercial Direct Install Program*. Prepared for Massachusetts Utilities.
312 Ibid.
313 KEMA (2011). C&I Lighting Loadshape Project – Final Report. Prepared for the Regional Evaluation, Measurement and Verification Forum.
314 KEMA, Inc. (2009). *Design 2000plus Lighting Hours of Use and Load Shapes Measurement Study*. Prepared for National Grid.
315 KEMA (2011). C&I Lighting Loadshape Project – Final Report. Prepared for the Regional Evaluation, Measurement and Verification Forum.
316 Ibid.
317 Cadmus Group (2011). *Non-Controls Lighting Evaluation for the Massachusetts Small Commercial Direct Install Program*. Prepared for Massachusetts Utilities.

Lighting – Lighting Controls

Version Date and Revision History

Effective Date: 1/1/2011 (Revised 1/1/2012)
End Date: TBD

Measure Overview

Description: This measure promotes the installation of lighting controls in both lost-opportunity and retrofit applications. Promoted technologies include occupancy sensors and daylight dimming controls.
Primary Energy Impact: Electric
Secondary Energy Impact: Heating energy (non-electric)
Non-Energy Impacts: O&M
Sector: Commercial & Industrial
Market: Lost Opportunity, Retrofit
End Use: Lighting
Program: C&I New Construction & Major Renovation, C&I Large Retrofit, C&I Small Retrofit

Algorithms for Calculating Primary Energy Impact

$$\Delta kW = (Controlled\ kW)(Hours_{BASE} - Hours_{EE})$$
$$\Delta kW = (Controlled\ kW)$$

Where:

Controlled kW	=	Controlled fixture wattage
$Hours_{BASE}$	=	Total annual hours that the connected Watts operated in the pre-retrofit case (retrofit installations) or would have operated with code-compliance controls (new construction installations).
$Hours_{EE}$	=	Total annual hours that the connect Watts operate with the lighting controls implemented.

Note on HVAC system interaction: Additional Electric savings from cooling system interaction are included in the calculation of adjusted gross savings for Lighting Systems projects. The HVAC interaction adjustment factor is determined from lighting project evaluations and is included in the energy realization rates and demand coincidence factors and realization rates (See Impact Factors section).

Baseline Efficiency

The baseline efficiency case assumes no controls (retrofit) or code-compliant controls (new construction).

High Efficiency

The high efficiency case involves lighting fixtures connected to controls that reduce the pre-retrofit or baseline hours of operation.

Hours

The annual hours of reduction for lighting controls are site-specific and should be determined on a case-by-case basis. If site-specific hours are unavailable, refer to the default hours in Table 50 in Appendix A: Common Lookup Tables

Measure Life

Lighting system measure lives vary by market sector and equipment type.

Measure Lives for C&I Lighting Controls[318]

Measure	Measure Life (years)	
	Retrofit	Lost Opportunity
Occupancy Sensors	9	10
Daylight Dimming	9	10

Secondary Energy Impacts

Heating energy will be increased due to reduced lighting waste heat. This impact is estimated as an average impact in heating fossil fuel consumption per unit of energy saved.

Measure	Energy Type	Impact (MMBtu/ΔkWh)[319]
Interior Lighting	C&I Gas Heat	-0.0003649 MMBtu/kWh
Interior Lighting	Oil	-0.0007129 MMBtu/kWh

Non-Energy Impacts

Annual non-energy benefits are claimed due to the reduced operation and maintenance costs associated with the longer measure lived of lamps and ballasts as compared to the base or pre-retrofit case. See Appendix D: Non-Resource Impacts.

[318] Energy & Resource Solutions (2005). *Measure Life Study*. Prepared for The Massachusetts Joint Utilities; Table 1-1.
[319] Optimal Energy, Inc. (2008). *MEMO: Non-Electric Benefits Analysis Update*. Prepared for NSTAR. Final savings values calculated in spreadsheet analysis as noted on pg 5 of the memo.

Impact Factors for Calculating Adjusted Gross Savings

Measure	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}	CF_{SSP}	CF_{WSP}
Large C&I New Construction and Large C&I Retrofit											
Occupancy Sensors	All	National Grid	1.00	1.00	0.76	0.96	0.96	0.30	0.19	n/a	n/a
Daylight Dimming	All	National Grid	1.00	1.00	0.38	0.96	0.96	0.15	0	n/a	n/a
All	NC	NSTAR, CLC	1.00	1.00	1.14	1.11	1.30	0.85	0.59	n/a	n/a
All	Retrofit	NSTAR, CLC	1.00	1.00	1.01	1.18	1.26	0.85	0.59	n/a	n/a
All	All	Unitil	1.00	1.00	1.00	1.00	1.00	0.85	0.59	n/a	n/a
All	All	WMECO	1.00	1.00	1.05	1.23	1.05	n/a	n/a	custom	custom
Small C&I Retrofit											
Occupancy Sensors	All	National Grid	1.00	1.00	0.87	0.94	0.94	0.35	0.28	n/a	n/a
All	All	NSTAR, CLC	1.00	1.00	0.89	0.92	0.92	0.80	0.37	n/a	n/a
All	All	Unitil	1.00	1.00	1.08	0.99	0.99	0.77	0.39	n/a	n/a
All	All	WMECO	1.00	1.00	0.94	0.99	0.99	n/a	n/a	custom	custom

In-Service Rates
All installations have 100% in service rate since all PAs programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factors.

Realization Rates
All PAs use the same RRs as for Lighting Systems installations, except National Grid and WMECO Small C&I Retrofit:

- National Grid RRs from National Grid impact evaluation of C&I lighting controls installations.[320]
- WMECO small retrofit RRs are from impact evaluation of 2008 program[321].
- NSTAR, CLC Small C&I Retrofit RRs will be updated with results of lighting controls project in progress

Coincidence Factors
All PAs use the same CFs as for Lighting Systems installations, except National Grid:

- National Grid CFs from National Grid impact evaluation C&I lighting controls installations.[322]
- NSTAR Small, CLC C&I Retrofit RRs will be updated with results of lighting controls project in progress

[320] RLW Analytics (2007). *Lighting Controls Impact Evaluation - Final Report, 2005 Energy Initiative, Design 2000plus and Small Business Services Programs*. Prepared for National Grid.
[321] The Cadmus Group, Inc. (2010). *Western Massachusetts Small Business Energy Advantage Impact Evaluation Report Program Year 2008*. Prepared for Western Massachusetts Electric Company.
[322] RLW Analytics (2007). *Lighting Controls Impact Evaluation - Final Report, 2005 Energy Initiative, Design 2000plus and Small Business Services Programs*. Prepared for National Grid.

Lighting – Freezer/Cooler LEDs

Version Date and Revision History

Effective Date: 1/1/2011 (Revised 1/1/2012)
End Date: TBD

Measure Overview

Description: Installation of LED lighting in freezer and/or cooler cases. The LED lighting consumes less energy, and results in less waste heat which reduces the cooling/freezing load.
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: None
Sector: Commercial & Industrial
Market: Retrofit
End Use: Lighting
Program: C&I Large Retrofit, C&I Small Retrofit

Algorithms for Calculating Primary Energy Impact

$$\Delta kWh = \Delta kWh_{LED} + \Delta kWh_{Heat}$$

$$\Delta kWh_{LED} = \sum_{i=1}^{n}\left(Count_i * kW_i * Hours_i\right)_{BASE} - \sum_{i=1}^{m}\left(Count_j * kW_j * Hours_j\right)_{LED}$$

$$\Delta kWh_{Heat} = \Delta kWh_{LED} * 0.28 * Eff_{RS}$$

$$\Delta kW = \Delta kWh / Hours_j$$

Where:

ΔkWh_{LED}	=	Reduction in lighting energy
ΔkWh_{Heat}	=	Reduction in refrigeration energy due to reduced heat loss from the lighting fixtures
N	=	Total number of lighting fixture types in the pre-retrofit case
M	=	Total number of lighting fixture types in the post-retrofit case
$Count_i$	=	Quantity of type i fixtures in the pre-retrofit case
kW_i	=	Power demand of pre-retrofit lighting fixture type i (kW/fixture)
$Hours_i$	=	Pre-retrofit annual operating hours of fixture type i
$Count_j$	=	Quantity of type j fixtures in the pre-retrofit case
kW_j	=	Power demand of lighting fixture type j (kW/fixture)
$Hours_j$	=	Post-retrofit annual operating hours of fixture type j
0.28	=	Unit conversion between kW and tons calculated as 3,413 Btuh/kW divided by 12,000 Btuh/ton
Eff_{RS}	=	Efficiency of typical refrigeration system: 1.6 kW/ton[323]

[323] Select Energy (2004). *Cooler Control Measure Impact Spreadsheet Users' Manual.* Prepared for NSTAR.

Baseline Efficiency

The baseline efficiency case is the existing lighting fixtures in the cooler or freezer cases.

High Efficiency

The high efficiency case is the installation of LED lighting fixtures on the cooler or freezer cases, replacing the existing lighting fixtures.

Hours

Annual hours of operation are determined on a case-by-case basis and are typically 8760 hours/year. Post-retrofit operating hours are assumed to be the same as pre-retrofit hours unless lighting occupancy sensors were also implemented.

Measure Life

The measure life is 13 years.[324]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

There are no non-energy impacts for this measure.

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}	CF_{SSP}	CF_{WSP}
Freezer/Cooler LEDs	Large Retrofit	National Grid	1.00	1.00	1.00	1.00	1.00	1.00	1.00	n/a	n/a
Freezer/Cooler LEDs	Large Retrofit	NSTAR, CLC, Unitil	1.00	1.00	1.00	1.00	1.00	0.88	0.58	n/a	n/a
Freezer/Cooler LEDs	Large Retrofit	WMECO	1.00	1.00	1.00	1.00	1.00	n/a	n/a	0.10	0.10
Freezer/Cooler LEDs	Small Retrofit	National Grid	1.00	1.00	1.04	1.07	1.15	1.00	1.00	n/a	n/a
Freezer/Cooler LEDs	Small Retrofit	NSTAR, CLC, Unitil	1.00	1.00	1.00	1.00	1.00	0.80	0.37	n/a	n/a
Freezer/Cooler LEDs	Small Retrofit	WMECO	1.00	1.00	0.86	1.00	1.00	n/a	n/a	0.10	0.10

In-Service Rates
All installations have 100% in service rate since PA programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factor.

[324] Energy & Resource Solutions (2005*). Measure Life Study*. Prepared for The Massachusetts Joint Utilities.

Realization Rates

- National Grid: RRs for small retrofit installations based on impact evaluation of 2005 small retrofit custom measures[325]; RRs for large retrofit installations are 100% based on no evaluations
- NSTAR, CLC, Unitil: energy and demand RRs are 100% based on no evaluations
- WMECO small retrofit RRs are from impact evaluation of 2008 program[326].

Coincidence Factors

- National Grid: CFs set to 100% because pre-retrofit unit operate 8760 hours/year.
- NSTAR, CLC, Unitil: CFs from 2007 State Program Working Group study[327]
- WMECO: CFs based on engineering estimates.

[325] RLW Analytics (2007). *Small Business Services Custom Measure Impact Evaluation*. Prepared for National Grid.
[326] The Cadmus Group, Inc. (2010). *Western Massachusetts Small Business Energy Advantage Impact Evaluation Report Program Year 2008*. Prepared for Western Massachusetts Electric Company.
[327] RLW Analytics (2007). *Coincidence Factor Study: Residential and Commercial Industrial Lighting Measures*. Prepared for the New England State Program Working Group (SPWG); Table i-29 & Table i-30 (On-Peak) and Table i-31 & Table i-32 (Seasonal Peak).

HVAC – Single–Package and Split System Unitary Air Conditioners

Version Date and Revision History

Effective Date: 1/1/2011 (Revised 1/1/2012)
End Date: TBD

Measure Overview

Description: This measure promotes the installation of high efficiency unitary air conditioning equipment in lost opportunity applications. Air conditioning (AC) systems are a major consumer of electricity and systems that exceed baseline efficiencies can save considerable amounts of energy. This measure applies to air, water, and evaporatively-cooled unitary AC systems, both single-package and split systems.
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: None
Sector: Commercial & Industrial
Market: Lost Opportunity
End Use: HVAC
Program: C&I New Construction & Major Renovation

Algorithms for Calculating Primary Energy Impact

For units with cooling capacities less than 65 kBtu/h:

$$\Delta kWh = (kBtu/h)\left(\frac{1}{SEER_{BASE}} - \frac{1}{SEER_{EE}}\right)(EFLH_{Cool})$$

$$\Delta kW = (kBtu/h)\left(\frac{1}{EER_{BASE}} - \frac{1}{EER_{EE}}\right)$$

For units with cooling capacities equal to or greater than 65 kBtu/h:

$$\Delta kWh = (kBtu/h)\left(\frac{1}{EER_{BASE}} - \frac{1}{EER_{EE}}\right)(EFLH_{Cool})$$

$$\Delta kW = (kBtu/h)\left(\frac{1}{EER_{BASE}} - \frac{1}{EER_{EE}}\right)$$

Where:

ΔkWh	=	Gross annual kWh savings from the measure.
ΔkW	=	Gross connected kW savings from the measure.
kBtu/h	=	Capacity of the cooling equipment in kBtu per hour (1 ton of cooling capacity equals 12 kBtu/h)
$SEER_{BASE}$	=	Seasonal Energy Efficiency Ratio of the baseline equipment. See Table 11 for values.
$SEER_{EE}$	=	Seasonal Energy Efficiency Ratio of the energy efficient equipment.
$EFLH_{Cool}$	=	Cooling equivalent full load hours. See Appendix A: Common Lookup Tables for default values.
EER_{BASE}	=	Energy Efficiency Ratio of the baseline equipment. See Table 11 for values. Since IECC 2009 does not provide EER requirements for air-cooled air conditioners < 65 kBtu/h, assume the following conversion from SEER to EER: $EER \approx SEER/1.1$.
EER_{EE}	=	Energy Efficiency Ratio of the energy efficient equipment. For air-cooled air conditioners < 65 kBtu/h, if the actual EER_{EE} is unknown, assume the following conversion from SEER to EER: $EER \approx SEER/1.1$.

Baseline Efficiency

The baseline efficiency case for new installations assumes compliance with the efficiency requirements as mandated by Massachusetts State Building Code. As described in Chapter 13 of the aforementioned document, energy efficiency must be met via compliance with the International Energy Conservation Code (IECC) 2009 with Massachusetts specific amendments. Replacement units are not required to meet IECC 2009 code. Instead, replacement installations use the Federal Manufacturing standards (indicated in the table with an asterisk) or the ASHREA 2004 standards as baseline, whichever is most rigorous.

Table 11 details the specific efficiency requirements by equipment type and capacity.

Table 11: Unitary Air Conditioners Baseline Efficiency Levels[328]

Equipment Type	Size Category	Subcategory or Rating Condition	Baseline Efficiency: New Installations	Baseline Efficiency: Replacement Installations
Air conditioners, air cooled	<65,000 Btu/h[b]	Split system	13.0 SEER	13.0 SEER*
		Single package	13.0 SEER	12.0 SEER
	≥65,000 Btu/h and <135,000 Btu/h	Split system and single package	11.2 EER	10.1 EER[a]
	≥135,000 Btu/h and <240,000 Btu/h	Split system and single package	11.0 EER	9.5 EER[a]
	≥240,000 Btu/h and <760,000 Btu/h	Split system and single package	10.0 EER	10.0 EER*[a]
	≥760,000 Btu/h	Split system and single package	9.7 EER	9.0 EER[a]
Air conditioners, Water and evaporatively cooled	<65,000 Btu/h	Split system and single package	12.1 EER	12.1 EER
	≥65,000 Btu/h and <135,000 Btu/h	Split system and single package	11.5 EER	11.3 EER[a]
	≥135,000 Btu/h and <240,000 Btu/h	Split system and single package	11.0 EER	10.8 EER[a]
	≥240,000 Btu/h	Split system and single package	11.5 EER	10.8 EER[a]

a. Deduct 0.2 from the required EERs for units with a heating section other than electric heat.[329]
b. Single-phase air-cooled air conditioners <65,000 Btu/h are regulated by the National Appliance Energy Conservation Act of 1987 (NAECA); SEER values are those set by NAECA.

High Efficiency

The high efficiency case assumes the HVAC equipments meets or exceeds the Consortium for Energy Efficiency's (CEE) specification. This specification results in cost-effective energy savings by specifying higher efficiency HVAC equipment while ensuring that several manufacturers produce compliant equipment. The CEE specification is reviewed and updated annually to reflect changes to the ASHRAE and IECC energy code baseline as well as improvements in the HVAC equipment technology. The minimum efficiency requirements for program participation are outlined on the Cool Choice rebate forms. Equipment efficiency is the rated efficiency of the installed equipment for each project.

Hours

If site-specific hours are unavailable, the equivalent cooling full load hours for unitary AC equipment are determined from the facility type. See Appendix A: Common Lookup Tables for cooling full load hours by building type.

[328] International Code Council (2009). *2009 International Energy Conservation Code*; Page43, Table 503.2.3(1).
[329] The PAs do not differentiate between units by heating section types. To be conservative, the highest Baseline Efficiency is assumed for all heating section types in each equipment category.

Measure Life

The measure life is 15 years.[330]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

There are no non-energy impacts for this measure.

Impact Factors for Calculating Adjusted Gross Savings

Measure	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}	CF_{SSP}	CF_{WSP}
Unitary AC	NC	CLC	1.00	1.00	1.00	0.74	0.00	0.45	0.00	n/a	n/a
Unitary AC	NC	National Grid	1.00	1.00	1.00	1.00	1.00	0.40	0.00	n/a	n/a
Unitary AC	NC	NSTAR	1.00	1.00	1.00	0.74	0.00	0.45	0.00	n/a	n/a
Unitary AC	NC	Unitil	1.00	1.00	1.00	1.00	1.00	0.33	0.00	n/a	n/a
Unitary AC	NC	WMECO	1.00	1.00	1.91	1.20	1.09	n/a	n/a	0.42	0.00

In-Service Rates
All installations have 100% in service rate since all programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factors.

Realization Rates

- CLC, National Grid, NSTAR, Unitil: Energy RRs set to 1.00 based 2011 NEEP C&I Unitary AC Loadshape Project.[331] The PAs use average evaluation Cooling Hours in the kWh savings calculations.
- WMECO: RRs are from 2007/2008 Large C&I Programs impact evaluation[332]

Coincidence Factors
CFs based 2011 NEEP C&I Unitary AC Loadshape Project.[333]

[330] Energy & Resource Solutions (2005). *Measure Life Study*. Prepared for The Massachusetts Joint Utilities; Table 1-1.
[331] KEMA (2011). C&I Unitary AC LoadShape Project – Final Report. Prepared for the Regional Evaluation, Measurement & Verification Forum.
[332] KEMA, Inc. (2010). *2007/2008 Large C&I Programs, Phase 1 Report Memo for Lighting and Process Measures*. Prepared for Western Massachusetts Electric Company.
[333] KEMA (2011). C&I Unitary AC LoadShape Project – Final Report. Prepared for the Regional Evaluation, Measurement & Verification Forum.

HVAC – Single Package or Split System Heat Pump Systems

Version Date and Revision History

Effective Date: 1/1/2011 (Revised 1/1/2012)
End Date: TBD

Measure Overview

Description: This measure applies to the installation of high-efficiency air cooled, water source, ground water source, and ground source heat pump systems.
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: None
Sector: Commercial & Industrial
Market: Lost Opportunity
End Use: HVAC
Program: C&I New Construction & Major Renovation

Algorithms for Calculating Primary Energy Impact

For air cooled units with cooling capacities less than 65 kBtu/h:

$$\Delta kWh = \Delta kWh_{Cool} + \Delta kWh_{Heat}$$

$$\Delta kWh_{Cool} = (kBtu/h)\left(\frac{1}{SEER_{BASE}} - \frac{1}{SEER_{EE}}\right)(EFLH_{COOL})$$

$$\Delta kWh_{Heat} = (kBtu/h)\left(\frac{1}{HSPF_{BASE}} - \frac{1}{HSPF_{EE}}\right)(EFLH_{HEAT})$$

$$\Delta kW = (kBtu/h)_{Cool}\left(\frac{1}{EER_{BASE}} - \frac{1}{EER_{EE}}\right)$$

For all water source, groundwater source, ground source units, and air cooled units with cooling capacities equal to or greater than 65 kBtu/h:

$$\Delta kWh = \Delta kWh_{Cool} + \Delta kWh_{Heat}$$

$$\Delta kWh_{Cool} = (kBtu/h_{COOL})\left(\frac{1}{SEER_{BASE}} - \frac{1}{SEER_{EE}}\right)(EFLH_{COOL})$$

$$\Delta kWh_{Heat} = \frac{(kBtu/h_{HEAT})}{3.412}\left(\frac{1}{COP_{BASE}} - \frac{1}{COP_{EE}}\right)(EFLH_{HEAT})$$

$$\Delta kW = (kBtu/h)_{Cool}\left(\frac{1}{EER_{BASE}} - \frac{1}{EER_{EE}}\right)$$

Where:

ΔkWh_{COOL}	=	Gross annual cooling mode kWh savings from the measure.
ΔkWh_{HEAT}	=	Gross annual heating mode kWh savings from the measure.
ΔkW_{COOL}	=	Gross annual kW savings from the measure. Heating kW savings are negligible.
kBtu/h[334]	=	Capacity of the cooling equipment in kBtu per hour (1 ton of cooling capacity equals 12 kBtu/h).
$SEER_{BASE}$	=	Seasonal Energy Efficiency Ratio of the baseline equipment. See Table 12 for values.
$SEER_{EE}$	=	Seasonal Energy Efficiency Ratio of the energy efficient equipment.
$EFLH_{COOL}$	=	Cooling mode equivalent full load hours.
$HSPF_{BASE}$	=	Heating Seasonal Performance Factor of the baseline equipment. See Table 12 for values.
$HSPF_{EE}$	=	Heating Seasonal Performance Factor of the energy efficient equipment.
$EFLH_{HEAT}$	=	Heating mode equivalent full load hours.
$kBtu/h_{COOL}$	=	Capacity of the cooling equipment in kBtu per hour (1 ton of cooling capacity equals 12 kBtu/h).
EER_{BASE}	=	Energy Efficiency Ratio of the baseline equipment. See Table 12 for values. Since IECC 2009 does not provide EER requirements for air-cooled heat pumps < 65 kBtu/h, assume the following conversion from SEER to EER: EER≈SEER/1.1.
EER_{EE}	=	Energy Efficiency Ratio of the energy efficient equipment. For air-cooled air conditioners < 65 kBtu/h, if the actual EER_{EE} is unknown, assume the following conversion from SEER to EER: EER≈SEER/1.1.
$kBtu/h_{HEAT}$	=	Capacity of the heating equipment in kBtu per hour. If the heating capacity is unknown, it can be calculated from the cooling capacity using the conversion factors defined below.
3.412	=	Conversion factor: 3.412 Btu per Wh.
COP_{BASE}	=	Coefficient of performance of the baseline equipment. See Table 12 for values.
COP_{EE}	=	Coefficient of performance of the energy efficient equipment.

Heating Capacity Conversion Factors:

Air Source HPs
Heating Capacity = Cooling Capacity * 13,900/12,000 (Ratio of heat produced in the heating mode divided by cooling produced in cooling mode)

Water/Ground Source HPs
Heating Capacity = Cooling Capacity * COP/EER (converts the rated cooling output to the rated heating output)

Baseline Efficiency

The baseline efficiency case for new installations assumes compliance with the efficiency requirements as mandated by Massachusetts State Building Code. As described in Chapter 13 of the aforementioned document, energy efficiency must be met via compliance with the International Energy Conservation

[334] For equipment with cooling capacities less than 65 kBtu/h, it is assumed that the heating capacity and cooling capacity are equal.

Code (IECC) 2009 with Massachusetts specific amendments. Table 12 details the specific efficiency requirements by equipment type and capacity. The baseline efficiency case for replacement units are not required to meet the IECC 2009. Instead, replacement installations use the Federal Manufacturing standards (indicated in the table with an asterisk) or the ASHREA 2004 standards as baseline, whichever is most rigorous. details the specific efficiency requirements by equipment type and capacity.

Table 12: Unitary and Applied Heat Pumps Baseline Efficiency Levels[335]

Equipment Type	Size Category (Cooling Capacity)	Subcategory or Rating Condition	Baseline Efficiency (New / Replacement)	
			Cooling Mode	Heating Mode
Air cooled	<65,000 Btu/h[b]	Split system	13.0 SEER / 13.0 SEER*	7.7 HSPF / 6.6 HSPF
		Single package	13.0 SEER / 12.0 SEER	7.7 HSPF / 6.6 HSPF
	≥65,000 Btu/h and <135,000 Btu/h	Split system and single package / 47°F db/43°F wb outdoor air	11.0 EER[a] / 9.9 EER	3.3 COP / 3.2 COP
	≥135,000 Btu/h and <240,000 Btu/h	Split system and single package / 47°F db/43°F wb outdoor air	10.6 EER[a] / 10.6 EER*	3.2 COP / 3.1 COP
	≥240,000 Btu/h	Split system and single package / 47°F db/43°F wb outdoor air	9.5 EER[a] / 9.5 EER	3.2 COP / 3.1 COP
Water source	<17,000 Btu/h	86°F entering water (Cooling Mode) / 68°F entering water (Heating Mode)	11.2 EER / 11.2 EER	4.2 COP / 4.2 COP
	≥17,000 Btu/h and <135,000 Btu/h	86°F entering water / 68°F entering water (Heating Mode)	12.0 EER / 12.0 EER	4.2 COP / 4.2 COP
Groundwater source	<135,000 Btu/h	59°F entering water (Cooling Mode) / 50°F entering water (Heating Mode)	16.2 EER / 16.2 EER	3.6 COP / 3.6 COP
Ground source	<135,000 Btu/h	77°F entering water / 32°F entering water (Heating Mode)	13.4 EER / 13.4 EER	3.1 COP / 3.1 COP

db = dry-bulb temperature, °F; wb = wet-bulb temperature, °F.
a. Deduct 0.2 from the required EERs for units with a heating section other than electric heat[336].
b. Single-phase air-cooled air conditioners <65,000 Btu/h are regulated by the National Appliance Energy Conservation Act of 1987 (NAECA); SEER values are those set by NAECA.

High Efficiency

The high efficiency case assumes the HVAC equipments meets or exceeds the Consortium for Energy Efficiency's (CEE) specification. This specification results in cost-effective energy savings by specifying higher efficiency HVAC equipment while ensuring that several manufacturers produce compliant

[335] International Code Council (2009). *2009 International Energy Conservation Code*; Page 44, Table 503.2.3(2).
[336] The PAs do not differentiate between units by heating section types. To be conservative, the highest baseline efficiency is assumed for all heating section types in each equipment category.

equipment. The CEE specification is reviewed and updated annually to reflect changes to the ASHRAE and IECC energy code baseline as well as improvements in the HVAC equipment technology.

The minimum efficiency requirements for program participation are outlined on the Cool Choice rebate forms. Equipment efficiency is the rated efficiency of the installed equipment for each project.

Hours

The annual equivalent full load hours for single package or split system heat pump systems are site-specific and should be determined on a case-by-case basis. If site-specific hours are unavailable, refer to the default hours presented in Appendix A: Common Lookup Tables.

Measure Life

The measure life is 15 years.[337]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

There are no non-energy impacts for this measure.

Impact Factors for Calculating Adjusted Gross Savings

Measure	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}	CF_{SSP}	CF_{WSP}
Heat Pumps	NC	National Grid	1.00	1.00	1.05	1.00	1.00	0.40	0.00	n/a	n/a
Heat Pumps	NC	NSTAR	1.00	1.00	1.01	1.09	1.57	0.45	0.00	n/a	n/a
Heat Pumps	NC	CLC	1.00	1.00	1.00	1.09	1.57	0.55	0.00	n/a	n/a
Heat Pumps	NC	Unitil	1.00	1.00	1.00	1.00	1.00	0.33	0.00	n/a	n/a
Heat Pumps – Cooling	NC	WMECO	1.00	1.00	0.91	1.20	1.09	n/a	n/a	0.42	0.00
Heat Pumps – Heating	NC	WMECO	1.00	1.00	0.57	0.78	0.81	n/a	n/a	0.00	0.00

<u>In-Service Rates</u>
All installations have 100% in service rate since PA programs include verification of equipment installations.

<u>Savings Persistence Factor</u>
All PAs use 100% savings persistence factors.

<u>Realization Rates</u>
- National Grid and energy and demand RRs based on a 1994 study of hvac and process cooling equipment.[338]
- NSTAR energy and demand RRs from impact evaluation of NSTAR 2006 HVAC installations[339]

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337 Energy & Resource Solutions (2005). *Measure Life Study*. Prepared for The Massachusetts Joint Utilities; Table 1-1.
338 The Fleming Group (1994). *Persistence of Commercial/Industrial Non-Lighting Measures, Volume 2, Energy Efficient HVAC and Process Cooling Equipment*. Prepared for New England Power Service Company.
339 RLW Analytics (2008). *Business & Construction Solutions (BS/CS) Programs Measurement & Verification - 2006 Final Report*. Prepared for NSTAR Electric and Gas; Table 17.

- CLC realization rates same as Unitary AC.
- Unitil realization rates same as *Unitary AC*.
- WMECO: RRs are from 2007/2008 Large C&I Programs impact evaluation[340]

Coincidence Factors

- CFs based 2011 NEEP C&I Unitary AC Loadshape Project.[341]

[340] KEMA, Inc. (2011). *2007/2008 Large C&I Programs,*

[341] KEMA (2011). C&I Unitary AC LoadShape Project – Final Report. Prepared for the Regional Evaluation, Measurement & Verification Forum.

HVAC – Dual Enthalpy Economizer Controls (DEEC)

Version Date and Revision History

Effective Date: 1/1/2011 (Revised 1/1/2012)
End Date: TBD

Measure Overview

Description: The measure is to upgrade the outside-air dry-bulb economizer to a dual enthalpy economizer. The system will continuously monitor the enthalpy of both the outside air and return air. The system will control the system dampers adjust the outside quantity based on the two readings.
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: None
Sector: Commercial & Industrial
Market: Lost Opportunity, Retrofit
End Use: HVAC
Program: C&I New Construction and Major Renovation

Algorithms for Calculating Primary Energy Impacts

$$\Delta kWh = (kBtu/h)\left(\frac{1\,Ton}{12\;kBtu/h}\right)(SAVE_{kWh})$$

$$\Delta kW = (kBtu/h)\left(\frac{1\,Ton}{12\;kBtu/h}\right)(SAVE_{kW})$$

Where:

kBtu/h	=	Capacity of the cooling equipment in kBtu per hour (1 ton of cooling capacity equals 12 kBtu/h).
$SAVE_{kWh}$	=	Average annual kWh reduction per ton of cooling capacity: 289 kWh/ton[342]
$SAVE_{kW}$	=	Average kW reduction per ton of cooling capacity: 0.289 kW/ton[343]

Baseline Efficiency

The baseline efficiency case for this measure assumes the relevant HVAC equipment is operating with a fixed dry-bulb economizer.

High Efficiency

The high efficiency case is the installation of an outside air economizer utilizing two enthalpy sensors, one for outdoor air and one for return air.

[342] Patel, Dinesh (2001). *Energy Analysis: Dual Enthalpy Control*. Prepared for NSTAR.
[343] Ibid.

Hours

Not applicable.

Measure Life

The measure life is 10 years for lost-opportunity applications.[344] The measure life is 7 years for retrofit installations.[345]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

There are no non-energy impacts for this measure.

Impact Factors for Calculating Adjusted Gross Savings

Measure	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}	CF_{SSP}	CF_{WSP}
DEEC	NC	National Grid	1.00	1.00	1.00	1.00	1.00	0.40	0.00	n/a	n/a
DEEC	NC	NSTAR	1.00	1.00	1.01	1.09	1.57	0.45	0.00	n/a	n/a
DEEC	NC	CLC	1.00	1.00	1.00	1.09	1.57	0.55	0.00	n/a	n/a
DEEC	NC	Unitil	1.00	1.00	1.00	1.00	1.00	0.332	0.00	n/a	n/a
DEEC	NC	WMECO	1.00	1.00	0.91	1.20	1.09	n/a	n/a	0.00	0.00

In-Service Rates
All installations have 100% in service rate since PA programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factors.
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Realization Rates
- National Grid RRs are 1.0 since there have been no impact evaluations of the prescriptive savings calculations.
- NSTAR energy and demand RRs from impact evaluation of NSTAR 2006 HVAC installations[346]
- CLC realization rates same as Unitary AC.
- Unitil realization rates same as *Unitary AC*.
- WMECO: RRs are from 2007/2008 Large C&I Programs impact evaluation.[347]

Coincidence Factors
- National Grid, NSTAR, CLC, Unitil: CFs based 2011 NEEP C&I Unitary AC Loadshape Project[348].
- WMECO: CFs set to 0.00 since no DEEC savings are occur during seasonal peak periods.

[344] Energy & Resource Solutions (2005). *Measure Life Study*. Prepared for The Massachusetts Joint Utilities; Table 1-1
[345] GDS Associates, Inc. (2007). *Measure Life Report: Residential and Commercial/Industrial Lighting and HVAC Measures*. Prepared for The New England State Program Working Group; Table 2.
[346] RLW Analytics (2008). *Business & Construction Solutions (BS/CS) Programs Measurement & Verification - 2006 Final Report*. Prepared for NSTAR Electric and Gas; Table 17.
[347] KEMA, Inc. (2011). *2007/2008 Large C&I Programs,*
[348] KEMA (2011). C&I Unitary AC LoadShape Project – Final Report. Prepared for the Regional Evaluation, Measurement & Verification Forum.

HVAC – ECM Fan Motors

Version Date and Revision History

Effective Date: 1/1/2011 (Revised 1/1/2012)
End Date: TBD

Measure Overview

Description: This measure is offered through the Cool Choice program and promotes the installation of electronically commutated motors (ECMs) on fan powered terminal boxes, fan coils, and HVAC supply fans on small unitary equipment.
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: None
Sector: Commercial & Industrial
Market: Lost Opportunity
End Use: HVAC
Program: C&I New Construction & Major Renovation

Algorithms for Calculating Electric Energy Impact

$$\Delta kWh = (Design\,CFM)(Box\,Size\,Factor)(\%Flow_{ANNUAL})(Hours)$$
$$\Delta kW_{SP} = (Design\,CFM)(Box\,Size\,Factor)(\%Flow_{SP})$$
$$\Delta kW_{WP} = (Design\,CFM)(Box\,Size\,Factor)(\%Flow_{WP})$$

Where:

Design CFM	=	Capacity of the VAV box in cubic feet per minute
Box Size Factor	=	Savings factor in Watts/CFM. See Table 13 for values.
$\%Flow_{ANNUAL}$	=	Average % of design flow over all operating hours. See Table 13 for values.
$\%Flow_{SP}$	=	Average % of design flow during summer peak period. See Table 13 for values.
$\%Flow_{WP}$	=	Average % of design flow during summer peak period. See Table 13 for values.
Hours	=	Annual operating hours for VAV box fans

Table 13: ECM Fan Motor Savings Factors [349]

Factor	Box Size	Value	Units
Box Size Factor	< 1000 CFM	0.32	Watts/CFM
Box Size Factor	≥ 1000 CFM	0.21	Watts/CFM
$\%Flow_{ANNUAL}$	All	0.52	-
$\%Flow_{SP}$	All	0.63	-
$\%Flow_{WP}$	All	0.33	-

[349] Factors based on engineering analysis developed at National Grid.

Baseline Efficiency

The baseline efficiency case for this measure assumes the VAV box fans are powered by a single speed fractional horsepower permanent split capacitor (PSC) induction motor.

High Efficiency

The high efficiency case must have a motor installed on new, qualifying HVAC equipment.

Hours

The annual operating hours for ECMs on VAV box fans are site-specific and should be determined on a case-by-case basis.

Measure Life

The measure life is 20 years for lost-opportunity applications.[350]

Algorithms for Calculating Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

There are no non-energy impacts for this measure.

Impact Factors for Calculating Adjusted Gross Savings

Measure	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}	CF_{SSP}	CF_{WSP}
ECM Fan Motors	NC	National Grid	1.00	1.00	1.00	1.00	1.00	1.00	1.00	n/a	n/a
ECM Fan Motors	NC	NSTAR, CLC	1.00	1.00	1.01	1.09	1.57	0.82	0.05	n/a	n/a
ECM Fan Motors	NC	Unitil	1.00	1.00	1.00	1.00	1.00	1.00	0.82	n/a	n/a
ECM Fan Motors	NC	WMECO	1.00	1.00	1.31	0.85	0.60	n/a	n/a	0.72	0.00

In-Service Rates
All installations have 100% in service rate since all PAs programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factors.

Realization Rates
- National Grid: RRs based on engineering estimates
- NSTAR, CLC: energy and demand RRs from impact evaluation of NSTAR 2006 HVAC installations[351]
- Unitil: energy and demand RRs are 100% for all C&I New Construction projects based on no evaluations
- WMECO: RRs are from 2007/2008 Large C&I Programs impact evaluation[352]

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[350] Energy & Resource Solutions (2005). *Measure Life Study*. Prepared for The Massachusetts Joint Utilities; Table 1-1.
[351] RLW Analytics (2008). *Business & Construction Solutions (BS/CS) Programs Measurement & Verification - 2006 Final Report*. Prepared for NSTAR Electric and Gas; Table 17.
[352] KEMA, Inc. (2011). *2007/2008 Large C&I Programs,*

Coincidence Factors

- National Grid: CFs based on engineering estimates.
- NSTAR, CLC, Unitil: CFs based on standard assumptions.
- WMECO: CFs from 2005 coincidence factor study.[353]

[353] RLW Analytics (2007). *Final Report, 2005 Coincidence Factor Study*. Prepared for Connecticut Energy Conservation Management Board, United Illuminating and Connecticut Light & Power.

HVAC – Energy Management System

Version Date and Revision History

Effective Date: 1/1/2011 (Revised 1/1/2012)
End Date: TBD

Measure Overview

Description: The measure is the installation of a new building energy management system (EMS) or the expansion of an existing energy management system for control of non-lighting electric and gas end-uses in an existing building on existing equipment.
Primary Energy Impact: Electric
Secondary Energy Impact: Gas, Oil
Non-Energy Impact: None
Sector: Commercial & Industrial
Market: Retrofit
End Use: HVAC
Program: C&I New Construction & Major Renovation, C&I Large Retrofit, C&I Small Retrofit

Algorithms for Calculating Primary Energy Impacts

Gross energy and demand savings for energy management systems (EMS) are custom calculated using the PA's EMS savings calculation tools. These tools are used to calculate energy and demand savings based on project-specific details including hours of operation, HVAC system equipment and efficiency and points controlled.[354]

Baseline Efficiency

The baseline for this measure assumes the relevant HVAC equipment has no control.

High Efficiency

The high efficiency case is the installation of a new EMS or the expansion of an existing EMS to control additional non-lighting electric or gas equipment. The EMS must be installed in an existing building on existing equipment.

Hours

Not applicable.

Measure Life

For lost-opportunity applications, the measure life is 15 years[355]. For retrofit applications, the measure life is 10 years[356].

[354] Descriptions of the EMS savings calculation tools are included in the TRM Library "C&I Spreadsheet Tools" folder.
[355] Energy & Resource Solutions (2005). *Measure Life Study*. Prepared for The Massachusetts Joint Utilities; Table 1-1.
[356] Ibid.

Secondary Energy Impacts

Heating Impacts: Gas and oil heat impacts are counted for EMS measures for reduction in space heating. If the heating system impacts are not calculated in the EMS savings calculation tool, they can be approximated using the interaction factors described below:

Measure	Energy Type	Impact (MMBtu/ΔkWh)[357]
EMS	C&I Gas Heat	0.001277
EMS	Oil	0.002496

Non-Energy Impacts

There are no non-energy impacts for this measure.

Impact Factors for Calculating Adjusted Gross Savings

Measure	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}	CF_{SSP}	CF_{WSP}
EMS	Large Retrofit	National Grid	1.00	1.00	1.04	1.03	1.03	custom	custom	n/a	n/a
EMS	Large Retrofit	NSTAR, CLC	1.00	1.00	1.01	1.09	1.57	0.82	0.05	n/a	n/a
EMS	Large Retrofit	Unitil	1.00	1.00	1.00	1.00	1.00	1.82	0.05	n/a	n/a
EMS	Large Retrofit	WMECO	1.00	1.00	0.57	0.78	0.81	n/a	n/a	custom	custom
EMS	Small Retrofit	CLC	1.00	1.00	1.01	1.09	1.57	0.82	0.05	n/a	n/a

In-Service Rates
All installations have 100% in service rate since all PAs programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factors.

Realization Rates
- National Grid RRs derived from a 1994 study of hvac and process cooling equipment.[358]
- NSTAR, CLC energy and demand RRs from impact evaluation of NSTAR 2006 HVAC installations[359]
- Unitil: energy and demand RRs are 100% for all C&I New Construction projects based on no evaluations
- WMECO: RRs are based on end use from 2007/2008 Large C&I Programs impact evaluation[360]

Coincidence Factors
- National Grid, WMECO: CFs are custom calculated.
- NSTAR, CLC, Unitil: CFs based on standard assumptions.

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[357] Optimal Energy, Inc. (2008). *MEMO: Non-Electric Benefits Analysis Update*. Prepared for NSTAR. Final savings values calculated in spreadsheet analysis as noted on pg 5 of the memo.
[358] The Fleming Group (1994). *Persistence of Commercial/Industrial Non-Lighting Measures, Volume 3, Energy Management Control Systems*. Prepared for New England Power Service Company.
[359] RLW Analytics (2008). *Business & Construction Solutions (BS/CS) Programs Measurement & Verification - 2006 Final Report*. Prepared for NSTAR Electric and Gas; Table 17.
[360] KEMA, Inc. (2011). *2007/2008 Large C&I Programs,*

HVAC – High Efficiency Chiller

Version Date and Revision History

Effective Date: 1/1/2011 (Revised 1/1/2012)
End Date: TBD

Measure Overview

Description: This measure promotes the installation of efficient water-cooled and air-cooled water chilling packages for comfort cooling applications. Eligible chillers include air-cooled, water cooled rotary screw and scroll, and water cooled centrifugal chillers for single chiller systems or for the lead chiller only in multi-chiller systems.
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: None
Sector: Commercial & Industrial
Market: Lost Opportunity
End Use: HVAC
Program: C&I New Construction & Major Renovation

Algorithms for Calculating Primary Energy Impacts

Gross energy and demand savings for chiller installations may be custom calculated using the PA's Chillers savings calculation tool. These tools are used to calculated energy and demand savings based on site-specific chiller plant details including specific chiller plan equipment, operational staging, operating load profile and load profile.[361]

Alternatively, the energy and demand savings may be calculated using the following algorithms and inputs. Please note that consistent efficiency types (FL or IPLV) must be used between the baseline and high efficiency cases:

Air-Cooled Chillers:

$$\Delta kWh = (Tons)\left(\frac{12}{EER_{BASE}} - \frac{12}{EER_{EE}}\right)(Hours)$$

$$\Delta kW = (Tons)\left(\frac{12}{EER_{BASE}} - \frac{12}{EER_{EE}}\right)(LF)$$

Water-Cooled Chillers:

$$\Delta kWh = (Tons)(kW / ton_{BASE} - kW / ton_{EE})(Hours)$$

[361] Descriptions of the Chiller savings calculation tools are included in the TRM Library "C&I Spreadsheet Tools" folder.

$$\Delta kW = (Tons)(kW/ton_{BASE} - kW/ton_{EE})(LF)$$

Where:

Tons	=	Rated capacity of the cooling equipment
EER_{BASE}	=	Energy Efficiency Ratio of the baseline equipment. See Table 14 for values.
EER_{EE}	=	Energy Efficiency Ratio of the efficient equipment. Site-specific.
kW/ton_{BASE}	=	Energy efficiency rating of the baseline equipment. See Table 14 for values.
kW/ton_{EE}	=	Energy efficiency rating of the efficient equipment. Site-specific.
Hours	=	Equivalent full load hours for chiller operation
LF	=	Load Factor. See table below

Equipment Type	PA	Load Factor[362,363]	
		Full Load	IPLV
Air-cooled chillers	National Grid	0.715	
Water cooled chillers < 300 Tons	National Grid	0.882	0.823
Water cooled chillers > 300 Tons	National Grid	0.762	0.765
All	WMECO	0.80	0.80
All	CLC	Site Specific	Site Specific

Baseline Efficiency

The baseline efficiency case assumes compliance with the efficiency requirements as mandated by Massachusetts State Building Code. As described in Chapter 13 of the aforementioned document, energy efficiency must be met via compliance with the International Energy Conservation Code (IECC) 2009. Table 14 details the specific efficiency requirements by equipment type and capacity.

Table 14: Water Chilling Packages - Minimum Efficiency Requirements[364]

Equipment Type	Size Category (Tons)	Units	Path A		Path B	
			Full Load	IPLV	Full Load	IPLV
Air-cooled chillers	< 150	EER	9.562	12.5	NA	NA
	≥ 150	EER	9.562	12.75	NA	NA
Water cooled, electrically operated, positive displacement (rotary screw and scroll)	< 75	kW/ton	0.780	0.63	0.800	0.600
	≥ 75 and < 150	kW/ton	0.775	0.615	0.790	0.586
	≥ 150 and < 300	kW/ton	0.680	0.580	0.718	0.540
	≥ 300	kW/ton	0.620	0.540	0.639	0.490
Water cooled, electrically operated, centrifugal	< 150	kW/ton	0.634	0.596	0.639	0.450
	≥ 150 and < 300	kW/ton	0.634	0.596	0.639	0.450
	≥ 300 and < 600	kW/ton	0.576	0.549	0.600	0.400
	≥ 600	kW/ton	0.570	0.539	0.590	0.400

Note: Compliance with this standard may be obtained by meeting the minimum requirements of Path A or B, however, both the Full Load and IPLV must be met to fulfill the requirements of Path A or B.

362 National Grid load factors based on 1994 study.
363 WMECO load factors based on staff estimates.
364 DOE (2009). 2009 IECC Based Building Codes; Table 503.2.3(7): Water Chilling Packages, Efficiency Requirements - as of 1/1/2010 minimum efficiency values.

High Efficiency

The high efficiency scenario assumes water chilling packages that exceed the efficiency levels required by Massachusetts State Building Code and meet the minimum efficiency requirements as stated in the New Construction HVAC energy efficiency rebate forms. Energy and demand savings calculations are based on actual equipment efficiencies should be determined on a case-by-case basis.

Hours

The equivalent full load hours of operation for water chilling packages are site-specific and should be determined on a case-by-case basis. If site-specific EFLH is unavailable, refer to the default hours presented in Appendix A: Table 51.

Measure Life

The measure life is 23 years.[365]

Secondary Energy Impacts

There are no secondary energy impacts counted for this measure.

Non-Energy Impacts

There are no non-energy impacts for this measure.

Impact Factors for Calculating Adjusted Gross Savings

Measure	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}	CF_{SSP}	CF_{WSP}
Chillers	NC	National Grid	1.00	1.00	1.04	1.00	1.00	1.00	0.00	n/a	n/a
Chillers	NC	NSTAR, CLC	1.00	1.00	1.01	1.09	1.57	0.82	0.05	n/a	n/a
Chillers	NC	Unitil	1.00	1.00	1.00	1.00	1.00	1.00	0.00	n/a	n/a
Chillers	NC	WMECO	1.00	1.00	0.91	1.20	1.09	n/a	n/a	custom	custom

In-Service Rates
All installations have 100% in service rate since all PAs programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factors.

Realization Rates
- National Grid energy RRs based on a 1994 study of hvac and process cooling equipment.[366]
- NSTAR, CLC energy and demand RRs from impact evaluation of NSTAR 2006 HVAC installations[367]
- Unitil: energy and demand RRs are 100% for all C&I New Construction projects based on no evaluations
- WMECO: RRs are based on end use from 2007/2008 Large C&I Programs impact evaluation[368]

[365] GDS Associates, Inc. (2007). *Measure Life Report: Residential and Commercial/Industrial Lighting and HVAC Measures*. Prepared for The New England State Program Working Group.
[366] The Fleming Group (1994). *Persistence of Commercial/Industrial Non-Lighting Measures, Volume 2, Energy Efficient HVAC and Process Cooling Equipment*. Prepared for New England Power Service Company.
[367] RLW Analytics (2008). *Business & Construction Solutions (BS/CS) Programs Measurement & Verification - 2006 Final Report*. Prepared for NSTAR Electric and Gas; Table 17.

Coincidence Factors

- National Grid: CFs estimated based on 1993-1994 evaluation research and engineering estimates.
- NSTAR, CLC, Unitil: CFs based on standard assumptions.
- Unitil CFs set to 1.0 for summer and 0.0 for winter since no space cooling savings during winter.
- WMECO: CFs are custom calculated

[368] KEMA, Inc. (2011). *2007/2008 Large C&I Programs,*

HVAC – Hotel Occupancy Sensors

Version Date and Revision History

Effective Date: 1/1/2011 (Revised 1/1/2012)
End Date: TBD

Measure Overview

Description: The measure is to the installation of hotel occupancy sensors (HOS) to control packaged terminal AC units (PTACs) with electric heat, heat pump units and/or fan coil units in hotels that operate all 12 months of the year.
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: None
Sector: Commercial & Industrial
Market: Retrofit
End Use: HVAC
Program: C&I Large Retrofit, C&I Small Retrofit

Algorithms for Calculating Primary Energy Impacts

Unit savings are deemed based on evaluation results:

$$\Delta kWh = SAVE_{kWh}$$
$$\Delta kW = SAVE_{kW}$$

Where:

Unit	=	Installed hotel room occupancy sensor
$SAVE_{kWh}$	=	Average annual kWh reduction per unit: 438 kWh[369]
$SAVE_{kW}$	=	Average annual kWh reduction per unit: 0.09 kW[370]

Baseline Efficiency

The baseline efficiency case assumes the equipment has no occupancy based controls.

High Efficiency

The high efficiency case is the installation of controls that include (a) occupancy sensors, (b) window/door switches for rooms that have operable window or patio doors, and (c) set back to 65 F in the heating mode and set forward to 78 F in the cooling mode when occupancy detector is in the unoccupied mode. Sensors controlled by a front desk system are not eligible.

[369] MassSave (2010). *Energy Analysis: Hotel Guest Occupancy Sensors*. Prepared for National Grid and NSTAR.
[370] Ibid.

Hours

Not applicable.

Measure Life

For retrofit applications, the measure life is 10 years.[371]

Secondary Energy Impacts

There are no secondary energy impacts.

Non-Energy Impacts

There are no non-energy impacts for this measure.

Impact Factors for Calculating Adjusted Gross Savings

Measure	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}	CF_{SSP}	CF_{WSP}
HOS	Large Retrofit	National Grid	1.00	1.00	1.00	1.00	1.00	0.30	0.70	n/a	n/a
HOS	Large Retrofit	NSTAR, CLC	1.00	1.00	1.01	1.09	1.57	0.82	0.05	n/a	n/a
HOS	Large Retrofit	Unitil	1.00	1.00	1.00	1.00	1.00	0.82	0.05	n/a	n/a
HOS	Large Retrofit	WMECO	1.00	1.00	0.91	1.20	1.09	n/a	n/a	0.00	0.00
HOS	Small Retrofit	CLC	1.00	1.00	1.01	1.09	1.57	0.82	0.05	n/a	n/a

In-Service Rates
All installations have 100% in service rate since all PAs programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factors.

Realization Rates
- National Grid: RRs based on engineering estimates.
- NSTAR, CLC energy and demand RRs from impact evaluation of NSTAR 2006 HVAC installations[372]
- Unitil: Energy and demand RRs are 100% based on no evaluations.
- WMECO: RRs are based on end use from 2007/2008 Large C&I Programs impact evaluation[373]

Coincidence Factors
- National Grid: CFs based on engineering estimates.
- NSTAR, CLC, Unitil: CFs based on standard assumptions.
- WMECO: CFs set to 0.0 since no DEEC savings are not during seasonal peak periods.

[371] Energy & Resource Solutions (2005). *Measure Life Study*. Prepared for The Massachusetts Joint Utilities; Table 1-1; Measure life is assumed to be the same as for EMS retrofit measure.
[372] RLW Analytics (2008). *Business & Construction Solutions (BS/CS) Programs Measurement & Verification - 2006 Final Report*. Prepared for NSTAR Electric and Gas; Table 17.
[373] KEMA, Inc. (2011). *2007/2008 Large C&I Programs,*

HVAC – Programmable Thermostats

Version Date and Revision History

Effective Date: 1/1/2011 (Revised 1/1/2012)
End Date: TBD

Measure Overview

Description: This measure involves the installation of a programmable thermostat for cooling and/or heating systems in spaces with either no or erratic existing control.
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: None
Sector: Commercial & Industrial
Market: Retrofit
End Use: HVAC
Program: C&I Small Retrofit

Algorithms for Calculating Primary Energy Impacts

$$\Delta kWh = (SQFT)(SAVE_{kWh})$$
$$\Delta kW = (SQFT)(SAVE_{kW})$$

Where:
SQFT = Square feet of controlled space
$SAVE_{kWh}$ = Average kW reduction per SQFT of controlled space. See Table 15.
$SAVE_{kW}$ = Average annual kWh reduction per SQFT of controlled. See Table 15.

Table 15: Savings Factors (Save)[374]

Equipment Type	$SAVE_{kWh}$ (kWh/SQFT)	$SAVE_{kW}$ (kW/SQFT)
Cool Only No Existing Control	0.539	0.00
Cool Only Erratic Existing Control	0.154	0.00
Heat Only No Existing Control	0.418	0.00
Heat Only Erratic Existing Control	0.119	0.00
Cool and Heat No Existing Control	0.957	0.00
Cool and Heat Erratic Existing Control	0.273	0.00
Heat Pump No Existing Control	0.848	0.00
Heat Pump Erratic Existing Control	0.242	0.00

Baseline Efficiency

The baseline efficiency case includes spaces with either no or erratic heating and/or cooling control as indicated in the equipment type selection.

[374] Massachusetts common assumptions.

High Efficiency

The high efficiency case includes control of the space cooling and/or heating system as indicated in the equipment type selection.

Hours

Not applicable.

Measure Life

For retrofit applications, the measure life is 8 years.[375]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

There are no non-energy impacts for this measure.

Impact Factors for Calculating Adjusted Gross Savings

Measure	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}	CF_{SSP}	CF_{WSP}
Thermostats	Small Retrofit	National Grid	1.00	1.00	1.00	1.00	1.00	0.00	0.00	n/a	n/a
Thermostats	Small Retrofit	NSTAR, CLC	1.00	1.00	0.91	0.92	0.92	0.00	0.00	n/a	n/a
Thermostats	Small Retrofit	Unitil	1.00	1.00	1.00	1.00	1.00	0.00	0.00	n/a	n/a
Thermostats	Small Retrofit	WMECO	1.00	1.00	1.00	1.00	1.00	n/a	n/a	0.00	0.00

<u>In-Service Rates</u>
All installations have 100% in service rate since PA programs include verification of equipment installations.

<u>Savings Persistence Factor</u>
All PAs use 100% savings persistence factor.

<u>Realization Rates</u>
- National Grid, Unitil: RRs set to 100% based on no evaluations.
- NSTAR, CLC: RRs based on NSTAR 2002-2004 small retrofit program impact evaluations.
- WMECO: RRs from impact evaluation of 2008 small retrofit program.[376]
-

<u>Coincidence Factors</u>
- National Grid, WMECO, Unitil, NSTAR, CLC: CFs set to zero since no savings are expected during peak periods.

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375 Energy & Resource Solutions (2005). *Measure Life Study*. Prepared for The Massachusetts Joint Utilities; Table 1-1.
376 The Cadmus Group, Inc. (2010). *Western Massachusetts Small Business Energy Advantage Impact Evaluation Report Program Year 2008*. Prepared for Western Massachusetts Electric Company.

Refrigeration – Door Heater Controls

Version Date and Revision History

Effective Date: 1/1/2011 (Revised 1/1/2012)
End Date: TBD

Measure Overview

Description: Installation of controls to reduce the run time of door and frame heaters for freezers and walk-in or reach-in coolers. The reduced heating results in a reduced cooling load.[377]
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: None
Sector: Commercial & Industrial
Market: Retrofit
End Use: Refrigeration
Program: C&I Small Retrofit

Algorithms for Calculating Primary Energy Impact

$$\Delta kWh = kW_{DH} * \%OFF * 8760$$
$$\Delta kW = kW_{DH} * \%OFF$$

Where:

kW_{DH}	=	Total demand of the door heater, calculated as Volts * Amps / 1000
8760	=	Door heater annual run hours before controls
%OFF		Door heater Off time[378]: 46% for freezer door heaters or 74% for cooler door heaters)

Baseline Efficiency

The baseline efficiency case is a cooler or freezer door heater that operates 8,760 hours per year without any controls.

High Efficiency

The high efficiency case is a cooler or freezer door heater connected to a heater control system, which controls the door heaters by measuring the ambient humidity and temperature of the store, calculating the dewpoint, and using pulse width modulation (PWM) to control the anti-sweat heater based on specific algorithms for freezer and cooler doors. Door temperature is typically maintained about 5^{o}F above the store air dewpoint temperature.[379]

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377 The assumptions and algorithms used in this section are specific to NRM products.
378 The value is an estimate by NRM based on hundreds of downloads of hours of use data from Door Heater controllers. These values are also supported by Select Energy Services, Inc. (2004). *Cooler Control Measure Impact Spreadsheet User's Manual*. Prepared for NSTAR.
379 Select Energy Services, Inc. (2004). *Analysis of Cooler Control Energy Conservation Measures*. Prepared for NSTAR.

Hours

Pre-retrofit hours are 8,760 hours per year. After controls are installed, the door heaters in freezers are on for an average 4,730.4 hours/year (46% off time) and the door heaters for coolers are on for an average 2,277.6 hours/year (74% off time).

Measure Life

The measure life for cooler and freezer door heater controls is 10 years.[380]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

There are no non-energy impacts for this measure.

Impact Factors for Calculating Adjusted Gross Savings

Measure	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}	CF_{SSP}	CF_{WSP}
Door Heater Control	Small Retrofit	National Grid	1.00	1.00	1.00	1.00	1.00	0.50	1.00	n/a	n/a
Door Heater Control	Small Retrofit	NSTAR, CLC	1.00	1.00	0.91	0.92	0.92	0.50	1.00	n/a	n/a
Door Heater Control	Small Retrofit	Unitil	1.00	1.00	1.00	1.00	1.00	0.50	1.00	n/a	n/a
Door Heater Control	Small Retrofit	WMECO	1.00	1.00	0.86	0.57	0.57	n/a	n/a	0.10	0.10

In-Service Rates
All installations have 100% in service rate since all PAs' programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factor.

Realization Rates
- National Grid: energy RR based on staff estimates.
- NSTAR, CLC: RRs based on NSTAR 2002-2004 small retrofit program impact evaluations.
- Unitil: RRs set to 100% based on no evaluations.
- WMECO: RRs from impact evaluation of 2008 small retrofit program.[381]

Coincidence Factors
- National Grid, Unitil, NSTAR, CLC: CFs from the 1995 HEC study of walk-in cooler anti-sweat door heater controls.[382]
- WMECO: CFs based on staff estimates.

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380 Energy & Resource Solutions (2005). *Measure Life Study*. Prepared for The Massachusetts Joint Utilities; Table 1-1.
381 The Cadmus Group, Inc. (2010). *Western Massachusetts Small Business Energy Advantage Impact Evaluation Report Program Year 2008*. Prepared for Western Massachusetts Electric Company.
382 HEC, Inc. (1995). *Analysis of Door Master Walk-In Cooler Anti-Sweat Door Heater Controls Installed at Ten Sites in Massachusetts*. Prepared for New England Power Service Company; Table 9. Adjusted to account for updated RR.

Refrigeration – Novelty Cooler Shutoff

Version Date and Revision History

Effective Date: 1/1/2011 (Revised 1/1/2012)
End Date: TBD

Measure Overview

Description: Installation of controls to shut off a facility's novelty coolers for non-perishable goods based on pre-programmed store hours. Energy savings occur as coolers cycle off during facility unoccupied hours.[383]
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: None
Sector: Commercial & Industrial
Market: Retrofit
End Use: Refrigeration
Program: C&I Small Retrofit

Algorithms for Calculating Primary Energy Impact

$$\Delta kWh = (kW_{NC})(DC_{AVG})(HoursOFF)$$
$$\Delta kW = 0$$

Where:

ΔkW	=	0 since savings are assumed to occur during evening hours and are therefore not coincident with either summer or winter peak periods.
kW_{NC}	=	Power demand of novelty cooler calculated from equipment nameplate data and estimated 0.85 power factor[384]
HoursOFF	=	Potential hours off every night per year, estimated as one less than the number of hours the store is closed per day
DC_{AVG}	=	Weighted average annual duty cycle: 48.75%[385]

Baseline Efficiency

The baseline efficiency case is the novelty coolers operating 8,760 hours per year.

High Efficiency

The high efficiency case is the novelty coolers operating fewer than 8,760 hours per year since they are controlled to cycle each night based on pre-programmed facility unoccupied hours.

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383 The assumptions and algorithms used in this section are specific to NRM products.
384 Conservative value based on 15 years of NRM field observations and experience.
385 Ibid; the estimated duty cycles for Novelty Coolers are supported by Select Energy Services, Inc. (2004). *Cooler Control Measure Impact Spreadsheet Users' Manual*. Prepared for NSTAR. The study gives a less conservative value than used by NRM.

Hours

Energy and demand savings are based on the reduced operation hours of the cooler equipment. Hours reduced per day are estimated on a case-by-case basis, and are typically calculated as one less than the number of hours per day that the facility is closed each day.

Measure Life

The measure life is 10 years.[386]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

There are no non-energy impacts for this measure.

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}	CF_{SP}	CF_{WP}
Novelty Cooler Shutoff	Small Retrofit	National Grid	1.00	1.00	1.00	1.00	1.00	0.00	0.00	n/a	n/a
Novelty Cooler Shutoff	Small Retrofit	NSTAR, CLC	1.00	1.00	0.91	0.92	0.92	0.00	0.00	n/a	n/a
Novelty Cooler Shutoff	Small Retrofit	Unitil	1.00	1.00	1.00	1.00	1.00	0.00	0.00	n/a	n/a
Novelty Cooler Shutoff	Small Retrofit	WMECO	1.00	1.00	0.86	0.57	0.57	n/a	n/a	0.00	0.00

In-Service Rates
All installations have 100% in service rate since all PAs' programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factor.

Realization Rates
- National Grid: energy RR based on staff estimates..
- NSTAR, CLC: RRs based on NSTAR 2002-2004 small retrofit program impact evaluations.
- Unitil: RRs set to 100% based on no evaluations.
- WMECO: RRs from impact evaluation of 2008 small retrofit program.[387]

Coincidence Factors
Coincidence factors are set to zero since demand savings typically occur during off-peak hours.

[386] Energy & Resource Solutions (2005). *Measure Life Study*. Prepared for The Massachusetts Joint Utilities; Table 1-1.
[387] The Cadmus Group, Inc. (2010). *Western Massachusetts Small Business Energy Advantage Impact Evaluation Report Program Year 2008*. Prepared for Western Massachusetts Electric Company.

Refrigeration – ECM Evaporator Fan Motors for Walk–in Coolers and Freezers

Version Date and Revision History

Effective Date: 1/1/2011 (Revised 1/1/2012)
End Date: TBD

Measure Overview

Description: Installation of various sizes of electronically commutated motors (ECMs) in walk-in coolers and freezers to replace existing evaporator fan motors.[388]
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: None
Sector: Commercial & Industrial
Market: Retrofit
End Use: Refrigeration
Program: C&I Small Retrofit

Algorithms for Calculating Primary Energy Impact

$$\Delta kWh = \Delta kWh_{Fan} + \Delta kWh_{Heat}$$
$$\Delta kWh_{Fan} = kW_{Fan} * LRF * Hours$$
$$\Delta kWh_{Heat} = \Delta kWh_{Fan} * 0.28 * Eff_{RS}$$
$$\Delta kW = \Delta kWh / 8{,}760$$

Where:

ΔkWh_{Fan}	=	Energy savings due to increased efficiency of evaporator fan motor
ΔkWh_{Heat}	=	Energy savings due to reduced heat from the evaporator fans
kW_{Fan}	=	Power demand of evaporator fan calculated from equipment nameplate data and estimated 0.55 power factor/adjustment[389]: Amps x Voltage x PF x √Phase
LRF	=	Load reduction factor for motor replacement (65%)[390]
Hours	=	Annual fan operating hours.
0.28	=	Conversion factor between kW and tons: 3,413 Btuh/kW divided by 12,000 Btuh/ton
Eff_{RS}	=	Efficiency of typical refrigeration system: 1.6 kW/ton[391]
ΔkW	=	Average demand savings
8,760	=	Hours per year

[388] The assumptions and algorithms used in this section are specific to NRM products.
[389] Conservative value based on 15 years of NRM field observations and experience.
[390] Load factor is an estimate by NRM based on several pre- and post-meter readings of installations; the value is supported by RLW Analytics (2007). *Small Business Services Custom Measure Impact Evaluation.* Prepared for National Grid.
[391] Assumed average refrigeration efficiency for typical installations. Conservative value based on 15 years of NRM field observations and experience. Value supported by Select Energy (2004). *Cooler Control Measure Impact Spreadsheet Users' Manual.* Prepared for NSTAR.

Baseline Efficiency

The baseline efficiency case is an existing evaporator fan motor.

High Efficiency

The high efficiency case is the replacement of existing evaporator fan motors with ECMs.

Hours

The annual operating hours are assumed to be 8,760 * (1-%OFF), where %OFF = 0 if the facility does not have evaporator fan controls or %OFF = 46% if the facility has evaporator fan controls (4,030 hours). See section: Refrigeration – Evaporator Fan Controls for more on %OFF value.

Measure Life

The measure life is 15 years.[392]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

There are no non-energy impacts for this measure.

Impact Factors for Calculating Adjusted Gross Savings[393]

Measure	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}	CF_{SSP}	CF_{WSP}
Evap Fan ECMs	Small Retrofit	National Grid	1.00	1.00	1.00	1.00	1.00	1.00	1.00	n/a	n/a
Evap Fan ECMs	Small Retrofit	NSTAR, CLC	1.00	1.00	0.91	0.92	0.92	1.00	1.00	n/a	n/a
Evap Fan ECMs	Small Retrofit	Unitil	1.00	1.00	1.00	1.00	1.00	1.00	1.00	n/a	n/a
Evap Fan ECMs	Small Retrofit	WMECO	1.00	1.00	0.86	0.57	0.57	n/a	n/a	1.00	1.00

In-Service Rates
All installations have 100% in service rate since PA programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factor.

Realization Rates
- National Grid: RRs set to 100% since changes to calculation methodology made based on 2005 Custom SBS program evaluation.[394]
- NSTAR, CLC: RRs based on NSTAR 2002-2004 small retrofit program impact evaluations.
- Unitil: RRs set to 100% based on no evaluations.

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[392] Energy & Resource Solutions (2005). *Measure Life Study*. Prepared for The Massachusetts Joint Utilities; 15-year measure life for retrofit motor installations.
[393] RLW Analytics (2007). *Small Business Services Custom Measure Impact Evaluation*. Prepared for National Grid.
[394] RLW Analytics (2007). *Impact Evaluation Analysis of the 2005 Custom SBS Program*. Prepared for National Grid.

- WMECO: RRs from impact evaluation of 2008 small retrofit program.[395]

Coincidence Factors
All: CFs set to 1 since demand savings are average

[395] The Cadmus Group, Inc. (2010). *Western Massachusetts Small Business Energy Advantage Impact Evaluation Report Program Year 2008*. Prepared for Western Massachusetts Electric Company.

Refrigeration – Case Motor Replacement

Version Date and Revision History

Effective Date: 1/1/2011 (Revised 1/1/2012)
End Date: TBD

Measure Overview

Description: Installation of electronically commutated motors (ECMs) in multi-deck and freestanding coolers and freezers, typically on the retail floor of convenience stores, liquor stores, and grocery stores.[396]
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: None
Sector: Commercial & Industrial
Market: Retrofit
End Use: Refrigeration
Program: C&I Small Retrofit

Algorithms for Calculating Primary Energy Impacts

$$\Delta kWh = \Delta kWh_{Motor} + \Delta kWh_{Heat}$$
$$\Delta kWh_{motor} = kW_{Motor} * LRF * Hours$$
$$\Delta kWh_{heat} = \Delta kWh_{Motor} * 0.28 * Eff_{RS}$$
$$\Delta kW = \Delta kWh / 8{,}760$$

Where:

ΔkWh_{Motor}	=	Energy savings due to increased efficiency of case motor
ΔkWh_{Heat}	=	Energy savings due to reduced heat from evaporator fans
kW_{motor}	=	Metered load of case motor
LRF	=	Load reduction factor: 53% when shaded pole motors are replaced, 29% when PSC motors are replaced[397]
Hours	=	Average runtime of case motors (8,500 hours)[398]
0.28	=	Conversion of kW to tons: 3,413 Btuh/kW divided by 12,000 Btuh/ton.
Eff_{RS}	=	Efficiency of typical refrigeration system (1.6 kW/ton) [399]
ΔkW	=	Average demand savings
8,760	=	Hours per year

[396] The assumptions and algorithms used in this section are specific to NRM products.
[397] Load factor is an estimate by NRM based on several pre- and post-meter readings of installations
[398] Conservative value based on 15 years of NRM field observations and experience.
[399] Assumed average refrigeration efficiency for typical installations. Conservative value based on 15 years of NRM field observations and experience. Value supported by Select Energy (2004). *Cooler Control Measure Impact Spreadsheet Users' Manual*. Prepared for NSTAR.

Baseline Efficiency

The baseline efficiency case is the existing case motor.

High Efficiency

The high efficiency case is the replacement of the existing case motor with an ECM.

Hours

Hours are the annual operating hours of the case motors.

Measure Life

The measure life is 15 years.[400]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

There are no non-energy impacts for this measure.

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}	CF_{SSP}	CF_{WSP}
Case ECMs	Small Retrofit	National Grid	1.00	1.00	1.00	1.00	1.00	1.00	1.00	n/a	n/a
Case ECMs	Small Retrofit	NSTAR, CLC	1.00	1.00	0.91	0.92	0.92	1.00	1.00	n/a	n/a
Case ECMs	Small Retrofit	Unitil	1.00	1.00	1.00	1.00	1.00	1.00	1.00	n/a	n/a
Case ECMs	Small Retrofit	WMECO	1.00	1.00	0.86	0.57	0.57	n/a	n/a	1.00	1.00

In-Service Rates
All installations have 100% in service rate since all PAs' programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factor.

Realization Rates
- National Grid: RRs set to 100% since changes to calculation methodology made based on 2005 Custom SBS program evaluation.[401]
- Unitil: RRs set to 100% based on no evaluations.
- NSTAR, CLC: RRs based on NSTAR 2002-2004 small retrofit program impact evaluations.
- WMECO: RRs from impact evaluation of 2008 small retrofit program[402].

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[400] Energy & Resource Solutions (2005). *Measure Life Study*. Prepared for The Massachusetts Joint Utilities; 15-year measure life for retrofit motor installations.
[401] RLW Analytics (2007). *Impact Evaluation Analysis of the 2005 Custom SBS Program*. Prepared for National Grid.
[402] The Cadmus Group, Inc. (2010). *Western Massachusetts Small Business Energy Advantage Impact Evaluation Report Program Year 2008*. Prepared for Western Massachusetts Electric Company.

Coincidence Factors
All: CFs set to 1 since demand savings are average

Refrigeration – Cooler Night Covers

Version Date and Revision History

Effective Date: 1/1/2011 (Revised 1/1/2012)
End Date: TBD

Measure Overview

Description: Installation of retractable aluminum woven fabric covers for open-type refrigerated display cases, where the covers are deployed during the facility unoccupied hours in order to reduce refrigeration energy consumption.
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: None
Sector: Commercial & Industrial
Market: Retrofit
End Use: Refrigeration
Program: C&I Small Retrofit

Algorithms for Calculating Primary Energy Impact

$$\Delta kWh = (Width)(Save)(Hours)$$
$$\Delta kW = (Width)(Save)$$

Where:
Width = Width of the opening that the night covers protect (ft)
Save = Savings factor based on the temperature of the case (kW/ft). See Table 16.
Hours = Annual hours that the night covers are in use

Table 16: Savings Factors[403]

Cooler Case Temperature	Savings Factor
Low Temperature (-35 F to -5 F)	0.03 kW/ft
Medium Temperature (0 F to 30 F)	0.02 kW/ft
High Temperature (35 F to 55 F)	0.01 kW/ft

Baseline Efficiency

The baseline efficiency case is the annual operation of open-display cooler cases.

High Efficiency

The high efficiency case is the use of night covers to protect the exposed area of display cooler cases during unoccupied hours.

[403] CL&P Program Savings Documentation for 2011 Program Year (2010). Factors based on Southern California Edison (1997). *Effects of the Low Emissive Shields on Performance and Power Use of a Refrigerated Display Case.*

Hours

Hours represent the number of annual hours that the night covers are in use, and should be determined on a case-by-case basis.

Measure Life

The measure life is 10 years.[404]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

There are no non-energy impacts for this measure.

Impact Factors for Calculating Adjusted Gross Savings

Measure	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}	CF_{SSP}	CF_{WSP}
Cooler Night Cover	Small Retrofit	National Grid	1.00	1.00	1.00	1.00	1.00	0.00	0.00	n/a	n/a
Cooler Night Cover	Small Retrofit	NSTAR, CLC	1.00	1.00	0.91	0.92	0.92	0.00	0.00	n/a	n/a
Cooler Night Cover	Small Retrofit	Unitil	1.00	1.00	1.00	1.00	1.00	0.00	0.00	n/a	n/a
Cooler Night Cover	Small Retrofit	WMECO	1.00	1.00	0.86	0.57	0.57	n/a	n/a	0.00	0.00

In-Service Rates
All installations have 100% in service rate since all PAs' programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factor.

Realization Rates
- National Grid, Unitil: RRs set to 100% based on no evaluations.
- NSTAR, CLC: RRs based on NSTAR 2002-2004 small retrofit program impact evaluations.
- WMECO: RRs from impact evaluation of 2008 small retrofit program.[405]

Coincidence Factors
Coincidence factors are set to zero since demand savings typically occur during off-peak hours.

[404] Energy & Resource Solutions (2005). *Measure Life Study*. Prepared for The Massachusetts Joint Utilities; Page 4-5 to 4-6.
[405] The Cadmus Group, Inc. (2010). *Western Massachusetts Small Business Energy Advantage Impact Evaluation Report Program Year 2008*. Prepared for Western Massachusetts Electric Company.

Refrigeration – Electronic Defrost Control

Version Date and Revision History

Effective Date: 1/1/2011 (Revised 1/1/2012)
End Date: TBD

Measure Overview

Description: A control mechanism to skip defrost cycles when defrost is unnecessary.[406]
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: None
Sector: Commercial & Industrial
Market: Retrofit
End Use: Refrigeration
Program: C&I Small Retrofit

Algorithms for Calculating Primary Energy Impacts

$$\Delta kWh = \Delta kWh_{Defrost} + \Delta kWh_{Heat}$$
$$\Delta kWh_{Defrost} = kW_{Defrost} * Hours * DRF$$
$$\Delta kWh_{Heat} = \Delta kWh_{Defrost} * 0.28 * Eff_{RS}$$
$$\Delta kW = \Delta kWh / 8{,}760$$

Where:

$\Delta kWh_{Defrost}$	=	Energy savings resulting from an increase in operating efficiency due to the addition of electronic defrost controls.
ΔkWh_{Heat}	=	Energy savings due to reduced heat from reduced number of defrosts.
$kW_{Defrost}$	=	Load of electric defrost.
Hours	=	Number of hours defrost occurs over a year without the defrost controls.
DRF	=	Defrost reduction factor- percent reduction in defrosts required per year (35%)[407]
0.28	=	Conversion of kW to tons: 3,413 Btuh/kW divided by 12,000 Btuh/ton.
Eff_{RS}	=	Efficiency of typical refrigeration system (1.6 kW/ton)[408]
ΔkW	=	Average demand savings
8,760	=	Hours per year

[406] The assumptions and algorithms used in this section are specific to NRM products.
[407] Ibid; supported by 3rd party evaluation: Independent Testing was performed by Intertek Testing Service on a Walk-in Freezer that was retrofitted with Smart Electric Defrost capability.
[408] Assumed average refrigeration efficiency for typical installations. Conservative value based on 15 years of NRM field observations and experience. Value supported by Select Energy (2004). *Cooler Control Measure Impact Spreadsheet Users' Manual*. Prepared for NSTAR.

Baseline Efficiency

The baseline efficiency case is an evaporator fan electric defrost system that uses a time clock mechanism to initiate defrost.

High Efficiency

The high efficiency case is an evaporator fan defrost system with electric defrost controls.

Hours

The number of defrost cycles is estimated to decrease by 35% from an average number of defrost cycles of 1460 defrosts/year at 40 minutes each for a total of 973 hours/year.[409] The number of defrost cycles with the defrost controls is 949 cycles/year, or 633 hours/year.

Measure Life

The measure life is 10 years.[410]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

There are no non-energy impacts for this measure.

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}	CF_{SSP}	CF_{WSP}
Defrost Control	Small Retrofit	National Grid	1.00	1.00	1.00	1.00	1.00	1.00	1.00	n/a	n/a
Defrost Control	Small Retrofit	NSTAR, CLC	1.00	1.00	0.91	0.92	0.92	1.00	1.00	n/a	n/a
Defrost Control	Small Retrofit	Unitil	1.00	1.00	1.00	1.00	1.00	1.00	1.00	n/a	n/a
Defrost Control	Small Retrofit	WMECO	1.00	1.00	0.86	0.57	0.57	n/a	n/a	1.00	1.00

In-Service Rates
All installations have 100% in service rate since all PAs' programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factor.

Realization Rates
- National Grid, Unitil: RRs set to 100% based on no evaluations.
- NSTAR, CLC: RRs based on NSTAR 2002-2004 small retrofit program impact evaluations.
- WMECO: RRs from impact evaluation of 2008 small retrofit program.[411]

[409] Conservative value based on 15 years of NRM field observations and experience.
[410] Energy & Resource Solutions (2005). *Measure Life Study*. Prepared for The Massachusetts Joint Utilities.

Coincidence Factors

- All: CFs set to 1 since demand savings are average

[411] The Cadmus Group, Inc. (2010). *Western Massachusetts Small Business Energy Advantage Impact Evaluation Report Program Year 2008.* Prepared for Western Massachusetts Electric Company.

Refrigeration – Evaporator Fan Controls

Version Date and Revision History

Effective Date: 1/1/2011 (Revised 1/1/2012)
End Date: TBD

Measure Overview

Description: Installation of controls to modulate the evaporator fans based on temperature control. Energy savings include: fan energy savings from reduced fan operating hours, refrigeration energy savings from reduced waste heat, and compressor energy savings resulting from the electronic temperature control. Electronic controls allow less fluctuation in temperature, thereby creating savings.[412]
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: None
Sector: Commercial & Industrial
Market: Retrofit
End Use: Refrigeration
Program: C&I Small Retrofit

Algorithms for Calculating Primary Energy Impact

$$\Delta kWh = \Delta kWh_{Fan} + \Delta kWh_{Heat} + \Delta kWh_{Control}$$
$$\Delta kWh_{Fan} = kW_{Fan} * 8760 * \%OFF$$
$$\Delta kWh_{Heat} = \Delta kWh_{Fan} * 0.28 * Eff_{RS}$$
$$\Delta kWh_{Control} = \left[kW_{CP} * Hours_{CP} + kW_{Fan} * 8760 * (1 - \%Off)\right] * 5\%$$
$$\Delta kW = \Delta kWh / 8760$$

[412] The assumptions and algorithms used in this section are specific to NRM products.

Where:

ΔkWh_{Fan}	=	Energy savings due to evaporator being shut off
ΔkWh_{Heat}	=	Energy savings due to reduced heat from the evaporator fans
$\Delta kWh_{Control}$	=	Energy savings due to the electronic controls on compressor and evaporator
kW_{Fan}	=	Power demand of evaporator fan calculated from equipment nameplate data and estimated 0.55 power factor/ adjustment[413]: Amps x Voltage x PF x √Phase
%OFF	=	Percent of annual hours that the evaporator is turned off: 46%[414]
0.28	=	Conversion of kW to tons: 3,413 Btuh/kW divided by 12,000 Btuh/ton.
Eff_{RS}	=	Efficiency of typical refrigeration system: 1.6 kW/ton[415]
kW_{CP}	=	Total power demand of compressor motor and condenser fan calculated from equipment nameplate data and estimated 0.85 power factor[416]: Amps x Voltage x PF x √Phase
$Hours_{CP}$	=	Equivalent annual full load hours of compressor operation: 4,072 hours[417]
5%	=	Reduced run-time of compressor and evaporator due to electronic temperature controls[418]
ΔkW	=	Average demand savings
8,760	=	Hours per year

Baseline Efficiency

The baseline efficiency case assumes evaporator fans that run 8760 annual hours with no temperature control.

High Efficiency

The high efficiency case is the use of an energy management system to control evaporator fan operation based on temperature.

Hours

The operation of the fans is estimated to be reduced by 46% from the 8,760 hours in the base case scenario.

Measure Life

The measure life is 10 years[419].

[413] Conservative value based on 15 years of NRM field observations and experience.
[414] The value is an estimate by NRM based on hundreds of downloads of hours of use data. These values are also supported by Select Energy Services, Inc. (2004). *Cooler Control Measure Impact Spreadsheet User's Manual*. Prepared for NSTAR.
[415] Assumed average refrigeration efficiency for typical installations. Conservative value based on 15 years of NRM field observations and experience. Value supported by Select Energy (2004). *Cooler Control Measure Impact Spreadsheet Users' Manual*. Prepared for NSTAR.
[416] This value is an estimate by NRM based on hundreds of downloads of hours of use data from the electronic controller.
[417] Conservative value based on 15 years of NRM field observations and experience.
[418] Conservative estimate supported by less conservative values given by several utility-sponsored 3rd Party studies including: Select Energy Services, Inc. (2004). *Analysis of Cooler Control Energy Conservation Measures*. Prepared for NSTAR.
[419] Energy & Resource Solutions (2005). *Measure Life Study*. Prepared for The Massachusetts Joint Utilities; Table 1-1.

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

There are no non-energy impacts for this measure.

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}	CF_{SSP}	CF_{WSP}
Evap Fan Control	Small Retrofit	National Grid	1	1	1.00	1.00	1.00	1.00	1.00	n/a	n/a
Evap Fan Control	Small Retrofit	NSTAR, CLC	1	1	0.91	0.92	0.92	1.00	1.00	n/a	n/a
Evap Fan Control	Small Retrofit	Unitil	1	1	1.00	1.00	1.00	1.00	1.00	n/a	n/a
Evap Fan Control	Small Retrofit	WMECO	1	1	0.86	0.57	0.57	n/a	n/a	1.00	1.00

In-Service Rates
All installations have 100% in service rate since all PAs' programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factor.

Realization Rates
- National Grid set to 100% after small retrofit RRs from 1996 savings analysis[420] suggestions for more accurate calculations adopted.
- NSTAR, CLC: RRs based on NSTAR 2002-2004 small retrofit program impact evaluations.
- Unitil: RRs set to 100% based on no evaluations.
- WMECO: RRs from impact evaluation of 2008 small retrofit program[421].

Coincidence Factors
- All: CFs set to 1 since demand savings are average

[420] HEC, Inc. (1996). *Analysis of Savings from Walk-In Cooler Air Economizers and Evaporator Fan Controls*. Prepared for New England Power Service Company.
[421] The Cadmus Group, Inc. (2010). *Western Massachusetts Small Business Energy Advantage Impact Evaluation Report Program Year 2008*. Prepared for Western Massachusetts Electric Company.

Refrigeration – Vending Misers

Version Date and Revision History

Effective Date: 1/1/2011 (Revised 1/1/2012)
End Date: TBD

Measure Overview

Description: Controls can significantly reduce the energy consumption of vending machine lighting and refrigeration systems. Qualifying controls must power down these systems during periods of inactivity but, in the case of refrigerated machines, must always maintain a cool product that meets customer expectations. This measure applies to refrigerated beverage vending machines, non-refrigerated snack vending machines, and glass front refrigerated coolers. This measure should not be applied to ENERGY STAR® qualified vending machines, as they already have built-in controls.
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: None
Sector: Commercial & Industrial
Market: Retrofit
End Use: Refrigeration
Program: C&I Large Retrofit, C&I Small Retrofit

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed based on the following algorithms and assumptions:

$$\Delta kWh = (kW_{RATED})(Hours)(SAVE)$$
$$\Delta kW = \Delta kWh / Hours$$

Where:

kW_{rated}	=	Rated kW of connected equipment. See Table 17 for default rated kW by connected equipment type.
Hours	=	Operating hours of the connected equipment: default of 8,760 hours
SAVE	=	Percent savings factor for the connected equipment. See Table 17 for values.

Table 17: Vending Machine and Cooler Controls Savings Factors [422]

Equipment Type	kW_{RATED}	SAVE (%)	ΔkW	ΔkWh
Refrigerated Beverage Vending Machines	0.40	46	0.184	1612
Non-Refrigerated Snack Vending Machines	0.085	46	0.039	343
Glass Front Refrigerated Coolers	0.46	30	0.138	1208

Baseline Efficiency

The baseline efficiency case is a standard efficiency refrigerated beverage vending machine, non-refrigerated snack vending machine, or glass front refrigerated cooler without a control system capable of powering down lighting and refrigeration systems during periods of inactivity.

High Efficiency

The high efficiency case is a standard efficiency refrigerated beverage vending machine, non-refrigerated snack vending machine, or glass front refrigerated cooler with a control system capable of powering down lighting and refrigeration systems during periods of inactivity.

Hours

It is assumed that the connected equipment operates 24 hours per day, 7 days per week for a total annual operating hours of 8,760.

Measure Life

The measure life is 5 years.[423]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

There are no non-energy impacts for this measure.

[422] USA Technologies Energy Management Product Sheets (2006). http://www.usatech.com/energy_management/energy_productsheets.php. Accessed 9/1/09.
[423] Energy & Resource Solutions (2005). *Measure Life Study*. Prepared for The Massachusetts Joint Utilities; Table 1-1.

Impact Factors for Calculating Adjusted Gross Savings

Measure	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}	CF_{SSP}	CF_{WSP}
Vending Misers	Large Retrofit	National Grid	1	1	1.00	1.00	1.00	0.00	0.00	n/a	n/a
Vending Misers	Small Retrofit	National Grid	1	1	1.00	1.00	1.00	0.00	0.00	n/a	n/a
Vending Misers	Large Retrofit	NSTAR	1	1	0.85	0.41	0.24	0.00	0.00	n/a	n/a
Vending Misers	Small Retrofit	NSTAR	1	1	0.91	0.92	0.92	0.00	0.00	n/a	n/a
Vending Misers	Large Retrofit	CLC	1	1	0.85	0.41	0.24	0.00	0.00	n/a	n/a
Vending Misers	Small Retrofit	CLC	1	1	0.91	0.92	0.92	0.00	0.00	n/a	n/a
Vending Misers	Large Retrofit	Unitil	1	1	1.00	1.00	1.00	0.00	0.00	n/a	n/a
Vending Misers	Small Retrofit	Unitil	1	1	1.00	1.00	1.00	0.00	0.00	n/a	n/a
Vending Misers	Large Retrofit	WMECO	1	1	0.91	2.08	0.87	n/a	n/a	0.00	0.00
Vending Misers	Small Retrofit	WMECO	1	1	0.86	0.57	0.57	n/a	n/a	0.00	0.00

In-Service Rates
All installations have 100% in service rate since all PAs' programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factor.

Realization Rates
- National Grid, Unitil: RRs set to 100% since savings estimated are based on study results.
- NSTAR, CLC: large retrofit RRs from impact evaluation of NSTAR 2006 refrigeration installations[424]; small retrofit RRs from impact evaluation of 2002 program year[425]
- WMECO: RRs from impact evaluation of 2008 small retrofit program[426]; large retrofit RRs are based on end use from 2007/2008 Large C&I Programs impact evaluation[427]

Coincidence Factors
- National Grid, Unitil, NSTAR, CLC, WMECO: CFs based on staff estimates- assumed that savings occur during off peak hours.

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[424] RLW Analytics (2008). *Business & Construction Solutions (BS/CS) Programs Measurement & Verification - 2006 Final Report*. Prepared for NSTAR Electric and Gas; Table 17.
[425] RLW Analytics (2003). *Small Business Solutions Program Year 2002 Impact Evaluation - Final Report*. Prepared for NSTAR.
[426] The Cadmus Group, Inc. (2010). *Western Massachusetts Small Business Energy Advantage Impact Evaluation Report Program Year 2008*. Prepared for Western Massachusetts Electric Company.
[427] KEMA, Inc. (2011). *2007/2008 Large C&I Programs,*

Food Service – Commercial Electric Ovens

Version Date and Revision History

Effective Date: 1/1/2012
End Date: TBD

Measure Overview

Description: Installation of a qualified ENERGY STAR® commercial oven. ENERGY STAR® commercial ovens save energy during preheat, cooking and idle times due to improved cooking efficiency, and preheat and idle energy rates.
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: None
Sector: Commercial
Market: Lost Opportunity
End Use: Food Service
Program: C&I New Construction & Major Renovation

Algorithms for Calculating Primary Energy Impacts

Unit savings are deemed based on study results:

$$\Delta kWh = \Delta kWh$$
$$\Delta kW = \Delta kWh / Hours$$

Where:
ΔkWh = gross annual kWh savings from the measure: 2,262 kWh[428]
ΔkW = gross average kW savings from the measure: 0.52 kW

Baseline Efficiency

The baseline efficiency case is a convection oven with a cooking energy efficiency of 65%, production capacity of 70 pounds per hour, preheat energy of 1.5 kWh and idle energy rate of 2.0 kW.

High Efficiency

The high efficiency case is a convection oven with a cooking energy efficiency of 70%, production capacity of 80 pounds per hour, preheat energy of 1.0 kWh and idle energy rate of 1.5 kW.

Hours

The average commercial oven is assumed to operate 4,380 hours per year[429].

[428] Pacific Gas & Electric Company – Customer Energy Efficiency Department (2007). *Work Paper PGECOFST101, Commercial Convection Oven, Revision #0.*
[429] Ibid.

Measure Life

The measure life for a new commercial electric oven is 12 years[430].

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

There are no non-energy impacts for this measure.

Impact Factors for Calculating Adjusted Gross Savings

Measure	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Electric Convection Oven	D2	All	1.00	1.00	1.00	1.00	1.00	1.00	1.00

<u>In-Service Rates</u>
All installations have 100% in service rate since programs include verification of equipment installations.

<u>Savings Persistence Factor</u>
All PAs use 100% savings persistence factor.

<u>Realization Rates</u>
100% realization rates are assumed because savings are based on researched assumptions by FSTC.

<u>Coincidence Factors</u>
Coincidence factors are 1.0 for both summer and winter seasons because the cooking equipment is assumed to operate throughout the on-peak demand periods.

430 Pacific Gas & Electric Company – Customer Energy Efficiency Department (2007). *Work Paper PGECOFST101, Commercial Convection Oven, Revision #0.*

Food Service – Commercial Electric Steam Cooker

Version Date and Revision History

Effective Date: 1/1/2012
End Date: TBD

Measure Overview

Description: Installation of a qualified ENERGY STAR® commercial steam cooker. ENERGY STAR® steam cookers save energy during cooling and idle times due to improved cooking efficiency and idle energy rates.
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: Water, Wastewater
Sector: Commercial
Market: Lost Opportunity
End Use: Food Service
Program: C&I New Construction & Major Renovation

Algorithms for Calculating Primary Energy Impacts

Unit savings are deemed based on study results:

$$\Delta kWh = (SAVE)(Quantity)(Hours)$$
$$\Delta kW = (SAVE)(Quantity)$$

Where:

ΔkWh	=	gross annual kWh savings from the measure
ΔkW	=	average kW savings from the measure: 2.23 kW
SAVE	=	Savings per pan: 3,258 kWh/pan[431]
Quantity	=	Number of pans. Default of 3 pans.
Hours	=	Average annual equipment operating hours

Baseline Efficiency

The Baseline Efficiency case is a conventional electric steam cooker with a cooking energy efficiency of 30%, pan production capacity of 23.3 pounds per hour, and an idle energy rate of 1.2 kW.

High Efficiency

The High Efficiency case is an ENERGY STAR® electric steam cooker with a cooking energy efficiency of 50%, pan production capacity of 16.7 pounds per hour, and an idle energy rate of 0.4 kW.

[431] ENERGY STAR® Commercial Kitchen Equipment Savings Calculator: Steam Cooker Calcs. < *http://www.energystar.gov/ia/business/bulk_purchasing/bpsavings_calc/commercial_kitchen_equipment_calculator.xls* >

Hours

The average steam cooker is assumed to operate 4,380 hours per year[432].

Measure Life

The measure life for a new steam cooker is 12 years[433].

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

Water and wastewater is saved due to the improved cooking efficiency of the high efficiency equipment.

Benefit Type	Description	Savings[434]
C&I Water	Annual water savings per unit	162,060 gallons/unit
C&I WasteWater	Annual wastewater savings per unit	162,060 gallons/unit

Impact Factors for Calculating Adjusted Gross Savings

Measure	Program	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Electric Steam Cooker	D2	1.00	1.00	1.00	1.00	1.00	1.00	1.00

In-Service Rates
All installations have 100% in service rate since programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factor.

Realization Rates
100% realization rates are assumed because savings are based on researched assumptions by ENERGY STAR®.

Coincidence Factors
Coincidence factors are 1.0 for both summer and winter seasons because the cooking equipment is assumed to operate throughout the on-peak demand periods.

[432] Ibid
[433] Ibid.
[434] Ibid.

Food Service – Commercial Electric Griddle

Version Date and Revision History

Effective Date: 1/1/2012
End Date: TBD

Measure Overview

Description: Installation of a qualified ENERGY STAR® griddle. ENERGY STAR® griddles save energy during preheat, cooking and idle times due to improved cooking efficiency, and preheat and idle energy rates.
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: None
Sector: Commercial
Market: Lost Opportunity
End Use: Food Service
Program: C&I New Construction & Major Renovation

Algorithms for Calculating Primary Energy Impacts

Unit savings are deemed based on study results:

$$\Delta kWh = (SAVE)(Width)(Hours)$$
$$\Delta kW = (SAVE)(Width)$$

Where:

ΔkWh	=	gross annual kWh savings from the measure
ΔkW	=	gross average kW savings from the measure: 0.58 (calculated)
SAVE	=	Savings per foot of griddle width: 845.67 kWh/ft[435]
Width	=	Width of griddle in feet. Default of 3 feet.
Hours	=	Average annual equipment operating hours

Baseline Efficiency

The baseline efficiency case is a conventional 3-foot wide electric griddle with a cooking energy efficiency of 60%, production capacity of 35 pounds per hour, preheat energy of 4 kWh and an idle energy rate of 2.4 kW.

High Efficiency

The high efficiency case is an ENERGY STAR® 3-foot wide electric griddle with a cooking energy efficiency of 70%, production capacity of 40 pounds per hour, preheat energy of 2 kWh and an idle energy rate of 2.13 kW.

[435] Food Service Technology Center, Electric Griddle Life-Cycle Cost Calculator for Griddle Width: http://www.fishnick.com/saveenergy/tools/calculators/egridcalc.php

Hours

The average steam cooker is assumed to operate 4,380 hours per year[436].

Measure Life

The measure life for a new steam cooker is 12 years[437].

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

There are no non-energy impacts for this measure.

Impact Factors for Calculating Adjusted Gross Savings

Measure	Program	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Electric Griddle	D2	1.00	1.00	1.00	1.00	1.00	1.00	1.00

In-Service Rates
All installations have 100% in service rate since programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factor.

Realization Rates
100% realization rates are assumed because savings are based on researched assumptions by FSTC.

Coincidence Factors
Coincidence factors are 1.0 for both summer and winter seasons because the cooking equipment is assumed to operate throughout the on-peak demand periods.

[436] PG&E calculator: http://www.fishnick.com/saveenergy/tools/calculators/egridcalc.php
[437] PG&E calculator: http://www.fishnick.com/saveenergy/tools/calculators/egridcalc.php

Compressed Air – High Efficiency Air Compressors

Version Date and Revision History

Effective Date: 1/1/2011 (Revised 1/1/2012)
End Date: TBD

Measure Overview

Description: Covers the installation of oil flooded, rotary screw compressors with Load/No Load, Variable Speed Drive, or Variable Displacement capacity control with properly sized air receiver. Efficient air compressors use various control schemes to improve compression efficiencies at partial loads. When an air compressor fitted with Load/No Load, Variable Speed Drive, or Variable Displacement capacity controls is used in conjunction with a properly-sized air receiver, considerable amounts of energy can be saved.
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: None
Sector: Commercial & Industrial
Market: Lost Opportunity, Retrofit
End Use: Compressed Air
Program: C&I New Construction, C&I Large Retrofit

Algorithms for Calculating Primary Energy Impacts

$$\Delta kWh = (HP_{COMPRESSOR})(SAVE)(Hours)$$
$$\Delta kW = (HP_{COMPRESSOR})(SAVE)$$

Where:
$HP_{COMPRESSOR}$ = Nominal rated horsepower of high efficiency air compressor.
Save = Air compressor kW reduction per HP. See Table 18 for values.
Hours = Annual operating hours of the air compressor.

Table 18: Air Compressor kW Reduction per Horsepower

Control Type	Nominal Horsepower (HP)	kW Reduction per Horsepower (Save)[438]	
		Lost Opportunity	Retrofit
Load/No Load	≥15 and <25	0.076	0.102
Load/No Load	≥25 and <=75	0.114	0.102
VSD	≥15 and <25	0.159	0.207
VSD	≥25 and <=75	0.228	0.206
Variable Displacement	≥50 and <=75	0.110	0.116

[438] From NSTAR analysis based on metering data. The location of original data and analysis is unknown; however, these values are supported by multiple 3rd party impact evaluations.

Baseline Efficiency

The baseline efficiency case is a typical modulating compressor with blow down valve.

High Efficiency

The high efficient case is an oil-flooded, rotary screw compressor with Load/No Load, Variable Speed Drive, or Variable Displacement capacity control with a properly sized air receiver. Air receivers are designed to provide a supply buffer to meet short-term demand spikes which can exceed the compressor capacity. Installing a larger receiver tank to meet occasional peak demands can allow for the use of a smaller compressor.

Hours

The annual hours of operation for air compressors are site-specific and should be determined on a case-by-case basis.

Measure Life

For lost-opportunity installations, the lifetime for this measure is 15 years. For retrofit projects, the lifetime is 13 years.[439]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

There are no non-energy impacts for this measure.

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}	CF_{SSP}	CF_{WSP}
Air Compressor	NC, Large Retrofit	National Grid	1.00	1.00	1.00	1.00	1.00	0.80	0.54	0.77	0.54
Air Compressor	NC, Large Retrofit	NSTAR, CLC	1.00	1.00	1.25	0.95	0.80	0.88	0.69	n/a	n/a
Air Compressor	NC, Large Retrofit	Unitil	1.00	1.00	1.00	1.00	1.00	0.80	0.54	0.77	0.54
Air Compressor	NC, Large Retrofit	WMECO	1.00	1.00	0.90	1.71	1.22	n/a	n/a	0.77	0.54

<u>In-Service Rates</u>
All installations have 100% in service rate since PA programs include verification of equipment installations.

<u>Savings Persistence Factor</u>
All PAs use 100% savings persistence factor.

[439] Energy & Resource Solutions (2005). *Measure Life Study*. Prepared for The Massachusetts Joint Utilities; Table 1-1.

Realization Rates

- National Grid, Unitil: RRs based on impact evaluation of PY 2004 compressed air installations.[440]
- NSTAR, CLC: energy and demand RRs from impact evaluation of NSTAR 2006 compressed air installations[441]
- WMECO: energy RRs are from 2007/2008 Large C&I Programs impact evaluation[442]

Coincidence Factors

- National Grid, Unitil, WMECO: CFs based on impact evaluation of PY 2004 compressed air installations.[443]
- NSTAR, CLC: CFs based on standard assumptions.

[440] Ibid.
[441] RLW Analytics (2008). *Business & Construction Solutions (BS/CS) Programs Measurement & Verification - 2006 Final Report*. Prepared for NSTAR Electric and Gas; Table 17.
[442] KEMA, Inc. (2010). *2007/2008 Large C&I Programs, Phase 1 Report Memo for Lighting and Process Measures*. Prepared for Western Massachusetts Electric Company.
[443] DMI (2006). *Impact Evaluation of 2004 Compressed Air Prescriptive Rebates*. Prepared for National Grid; results analyzed in RLW Analytics (2006). *Sample Design and Impact Evaluation Analysis for Prescriptive Compressed Air Measures in the Energy Intiative and Design 2000 Programs*. Prepared for National Grid.

Compressed Air – Refrigerated Air Dryers

Version Date and Revision History

Effective Date: 1/1/2011 (Revised 1/1/2012)
End Date: TBD

Measure Overview

Description: The installation of cycling or variable frequency drive (VFD)-equipped refrigerated compressed air dryers. Refrigerated air dryers remove the moisture from a compressed air system to enhance overall system performance. An efficient refrigerated dryer cycles on and off or uses a variable speed drive as required by the demand for compressed air instead of running continuously. Only properly sized refrigerated air dryers used in a single-compressor system are eligible.
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: None
Sector: Commercial & Industrial
Market: Lost Opportunity
End Use: Compressed Air
Program: C&I New Construction and Major Renovation

Algorithms for Calculating Primary Energy Impact

$$\Delta kWh = (CFM_{DRYER})(SAVE)(Hours)$$
$$\Delta kW = (CFM_{DRYER})(SAVE)$$

Where:

CFM_{DRYER}	=	Full flow rated capacity of the refrigerated air dryer in cubic feet per minute (CFM). Obtain from equipment's Compressed Air Gas Institute Datasheet.
Save	=	Refrigerated air dryer kW reduction per dryer full flow rated CFM. See Table 19.
Hours	=	Annual operating hours of the refrigerated air dryer.

Table 19: Default kW Reduction per CFM by Dryer Capacity (*SAVE*)

Dryer Capacity (CFM_{DRYER})	kW Reduction per CFM (Save)[444]
<100	0.00474
≥100 and <200	0.00359
≥200 and <300	0.00316
≥300 and <400	0.00290
≥400	0.00272

[444] From NSTAR analysis based on metering data. The location of original data and analysis is unknown; however, these values are supported by multiple 3rd party impact evaluations. Single set of savings numbers used since VFD and cycling savings similar down to 40-50% load and prescriptive compressor loading is in the 50-60% range.

Baseline Efficiency

The baseline efficiency case is a non-cycling refrigerated air dryer.

High Efficiency

The high efficiency case is a cycling refrigerated dryer or a refrigerated dryer equipped with a VFD.

Hours

The annual hours of operation for compressed air dryers are site-specific.

Measure Life

The measure life is 15 years.[445]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

There are no non-energy impacts for this measure.

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}	CF_{SSP}	CF_{WSP}
Refrigerated Air Dryers	NC	National Grid	1.00	1.00	1.00	1.00	1.00	0.80	0.54	0.77	0.54
Refrigerated Air Dryers	NC	NSTAR, CLC	1.00	1.00	1.25	0.95	0.80	0.88	0.69	n/a	n/a
Refrigerated Air Dryers	NC	Unitil	1.00	1.00	1.00	1.00	1.00	0.80	0.54	0.77	0.54
Refrigerated Air Dryers	NC	WMECO	1.00	1.00	0.90	1.71	1.22	n/a	n/a	0.77	0.54

In-Service Rates
All installations have 100% in service rate since PA programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factor.

Realization Rates
- National Grid, Unitil: RRs based on impact evaluation of PY 2004 compressed air installations.[446]
- NSTAR, CLC: energy and demand RRs from impact evaluation of NSTAR 2006 compressed air installations[447]
- WMECO: energy RRs are from 2007/2008 Large C&I Programs impact evaluation[448]

[445] Energy & Resource Solutions (2005). *Measure Life Study*. Prepared for The Massachusetts Joint Utilities; Table 1-1.
[446] DMI (2006). *Impact Evaluation of 2004 Compressed Air Prescriptive Rebates*. Prepared for National Grid; results analyzed in RLW Analytics (2006). *Sample Design and Impact Evaluation Analysis for Prescriptive Compressed Air Measures in the Energy Intiative and Design 2000 Programs*. Prepared for National Grid.
[447] RLW Analytics (2008). *Business & Construction Solutions (BS/CS) Programs Measurement & Verification - 2006 Final Report*. Prepared for NSTAR Electric and Gas; Table 17.
[448] KEMA, Inc. (2010). *2007/2008 Large C&I Programs, Phase 1 Report Memo for Lighting and Process Measures*. Prepared for Western Massachusetts Electric Company.

Coincidence Factors

- National Grid, Unitil, WMECO: CFs based on impact evaluation of PY 2004 compressed air installations.[449]
- NSTAR, CLC: CFs based on standard assumptions.

[449] DMI (2006). *Impact Evaluation of 2004 Compressed Air Prescriptive Rebates*. Prepared for National Grid; results analyzed in RLW Analytics (2006). *Sample Design and Impact Evaluation Analysis for Prescriptive Compressed Air Measures in the Energy Intiative and Design 2000 Programs*. Prepared for National Grid.

Compressed Air – Low Pressure Drop Filters

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: Filters remove solids and aerosols from compressed air systems. Low pressure drop filters have longer lives and lower pressure drops than traditional coalescing filters resulting in higher efficiencies.
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: None
Sector: Commercial & Industrial
Market: Lost Opportunity & Retrofit
End Use: Compressed Air
Program: C&I New Construction, C&I Large Retrofit

Algorithms for Calculating Primary Energy Impacts

$$\Delta kWh = (Quantity)(HP_{COMP})(0.7457)(\%Savings)(Hours)$$
$$\Delta kW = (Quantity)(HP_{COMP})(0.7457)(\%Savings)$$

Where:

ΔkWh	=	Energy savings
ΔkW	=	Demand savings
Quantity	=	Number of filters installed
HP_{COMP}	=	Average compressor load
0.7457	=	Conversion from HP to kW
% Savings	=	Percent change in pressure drop. Site specific.
Hours	=	Annual operating hours of the lower pressure drop filter.

Baseline Efficiency

The baseline efficiency case is a standard coalescing filter with initial drop of between 1 and 2 pounds per sq inch (psi) with an end of life drop of 10 psi.

High Efficiency

The high efficiency case is a low pressure drop filter with initial drop not exceeding 1 psi over life and 3 psi at element change. Filters must be deep-bed, “mist eliminator” style and installed on a single operating compressor rated 15 – 75 HP.

Hours

The annual hours of operation are site specific and will be determined on a case by case basis.

Measure Life

For lost-opportunity installations, the lifetime for this measure is 5 years. For retrofit projects, the lifetime is 3 years.[450]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

There are no non-energy impacts for this measure.

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}	CF_{SSP}	CF_{WSP}
LP Drop Filter	NC, Large Retrofit	National Grid	1.00	1.00	1.00	1.00	1.00	0.80	0.54	0.77	0.54
LP Drop Filter	NC, Large Retrofit	NSTAR, CLC	1.00	1.00	1.25	0.95	0.80	0.88	0.69	n/a	n/a
LP Drop Filter	NC, Large Retrofit	Unitil	1.00	1.00	1.00	1.00	1.00	0.80	0.54	0.77	0.54
LP Drop Filter	NC, Large Retrofit	WMECO	1.00	1.00	0.90	1.71	1.22	n/a	n/a	custom	custom

In-Service Rates
All installations have 100% in service rate since PA programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factor.

Realization Rates
- National Grid, Unitil: RRs based on impact evaluation of PY 2004 compressed air installations.[451]
- NSTAR, CLC: energy and demand RRs from impact evaluation of NSTAR 2006 compressed air installations[452]
- WMECO: RRs from 2011 WMECO C&I impact evaluation.[453]

Coincidence Factors
- National Grid, Unitil: CFs based on impact evaluation of PY 2004 compressed air installations.454
- NSTAR, CLC: CFs based on standard assumptions.
- WMEC: CFs are custom calculated.

[450] Based on typical replacement schedules for low pressure filters (NSTAR staff estimates).
[451] DMI (2006). *Impact Evaluation of 2004 Compressed Air Prescriptive Rebates*. Prepared for National Grid; results analyzed in RLW Analytics (2006). *Sample Design and Impact Evaluation Analysis for Prescriptive Compressed Air Measures in the Energy Intiative and Design 2000 Programs*. Prepared for National Grid.
[452] RLW Analytics (2008). *Business & Construction Solutions (BS/CS) Programs Measurement & Verification - 2006 Final Report*. Prepared for NSTAR Electric and Gas; Table 17.
[453] KEMA (2011). 2007/2008 Large C&I Programs. Prepared for Western Massachusetts Electric Company.
[454] DMI (2006). *Impact Evaluation of 2004 Compressed Air Prescriptive Rebates*. Prepared for National Grid; results analyzed in RLW Analytics (2006). *Sample Design and Impact Evaluation Analysis for Prescriptive Compressed Air Measures in the Energy Intiative and Design 2000 Programs*. Prepared for National Grid.

Compressed Air – Zero Loss Condensate Drains

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: Drains remove water from a compressed air system. Zero loss condensate drains remove water from a compressed air system without venting any air, resulting in less air demand and consequently greater efficiency.
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: None
Sector: Commercial & Industrial
Market: Lost Opportunity & Retrofit
End Use: Compressed Air
Program: C&I New Construction, C&I Large Retrofit

Algorithms for Calculating Primary Energy Impacts

$$\Delta kWh = (CFM_{pipe})(CFM_{saved})(SAVE)(Hours)$$

$$\Delta kW = (CFM_{pipe})(CFM_{save})(SAVE)$$

Where:

ΔkWh	=	Energy Savings
ΔkW	=	Demand savings
CFM_{pipe}	=	CFM capacity of piping. Site specific.
CFM_{saved}	=	Average CFM saved per CFM of piping capacity: 0.049
Save	=	Average savings per CFM: 0.24386 kW/CFM[455]
Hours	=	Annual operating hours of the zero loss condensate drain.

Baseline Efficiency

The baseline efficiency case is installation of a standard condensate drain on a compressor system.

High Efficiency

The high efficiency case is installation of a zero loss condensate drain on a single operating compressor rated ≤ 75 HP.

Hours

The annual hours of operation are site specific and will be determined on a case by case basis.

[455] Based on NSTAR analysis assuming a typical timed drain settings discharge scenario.

Measure Life

For lost-opportunity installations, the lifetime for this measure is 15 years. For retrofit projects, the lifetime is 13 years.[456]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

There are no non-energy impacts for this measure.

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}	CF_{SSP}	CF_{WSP}
Zero Loss Drain	NC, Large Retrofit	National Grid	1.00	1.00	1.00	1.00	1.00	0.80	0.54	0.77	0.54
Zero Loss Drain	NC, Large Retrofit	NSTAR, CLC	1.00	1.00	1.25	0.95	0.80	0.88	0.69	n/a	n/a
Zero Loss Drain	NC, Large Retrofit	Unitil	1.00	1.00	1.00	1.00	1.00	0.80	0.54	0.77	0.54
Zero Loss Drain	NC, Large Retrofit	WMECO	1.00	1.00	0.90	1.71	1.22	n/a	n/a	custom	custom

In-Service Rates
All installations have 100% in service rate since PA programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factor.

Realization Rates
- National Grid, Unitil: RRs based on impact evaluation of PY 2004 compressed air installations.[457]
- NSTAR, CLC: energy and demand RRs from impact evaluation of NSTAR 2006 compressed air installations[458]
- WMECO: RRs from 2011 WMECO C&I impact evaluation.[459]

Coincidence Factors
- National Grid, Unitil: CFs based on impact evaluation of PY 2004 compressed air installations.[460]
- NSTAR, CLC: CFs based on standard assumptions.
- WMECO: CFs are custom calculated.

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[456] Energy & Resource Solutions (2005). *Measure Life Study*. Prepared for The Massachusetts Joint Utilities; Table 1-1. Drains not expected to change during life of compressor.
[457] DMI (2006). *Impact Evaluation of 2004 Compressed Air Prescriptive Rebates*. Prepared for National Grid; results analyzed in RLW Analytics (2006). *Sample Design and Impact Evaluation Analysis for Prescriptive Compressed Air Measures in the Energy Intiative and Design 2000 Programs*. Prepared for National Grid.
[458] RLW Analytics (2008). *Business & Construction Solutions (BS/CS) Programs Measurement & Verification - 2006 Final Report*. Prepared for NSTAR Electric and Gas; Table 17.
[459] KEMA (2011). 2007/2008 Large C&I Programs. Prepared for Western Massachusetts Electric Company.
[460] DMI (2006). *Impact Evaluation of 2004 Compressed Air Prescriptive Rebates*. Prepared for National Grid; results analyzed in RLW Analytics (2006). *Sample Design and Impact Evaluation Analysis for Prescriptive Compressed Air Measures in the Energy Intiative and Design 2000 Programs*. Prepared for National Grid.

Motors/Drives – Variable Frequency Drives

Version Date and Revision History

Effective Date: 1/1/2011 (Revised 1/1/2012)
End Date: TBD

Measure Overview

Description: This measure covers the installation of variable speed drives according to the terms and conditions stated on the statewide worksheet. The measure covers multiple end use types and building types. The installation of this measure saves energy since the power required to rotate a pump or fan at lower speeds requires less power than when rotated at full speed.
Primary Energy Impact: Electric
Secondary Energy Impact: None
Non-Energy Impact: None
Sector: Commercial & Industrial
Market: Lost Opportunity, Retrofit
End Use: Motors/Drives
Program: C&I New Construction & Major Renovation, C&I Large Retrofit, C&I Small Retrofit

Notes

The Large Commercial & Industrial Evaluation Research Area will be commencing an impact evaluation of this measure starting the Fall of 2010. The results of this study will result in either modifications to the savings factors or the realization rates and will be used for reporting on the 2011 program year.

Algorithms for Calculating Primary Energy Impacts

$$\Delta kWh = (HP)\left(\frac{1}{\eta_{motor}}\right)(kWh/HP)$$

$$\Delta kW = (HP)\left(\frac{1}{\eta_{motor}}\right)(kW/HP)_{SP}$$

Where:

HP	=	Rated horsepower for the impacted motor.
η_{motor}	=	Motor efficiency
kWh/HP	=	Annual electric energy reduction based on building and equipment type. See Table 20.
kW/HP_{SP}	=	Summer demand reduction based on building and equipment type. See Table 20.
kW/HP_{WP}	=	Winter demand reduction based on building and equipment type. See Table 20.

Table 20: Savings Factors for C&I VFDs (kWh/HP and kW/HP)[461]

	Building Exhaust Fan	Cooling Tower Fan	Chilled Water Pump	Boiler Feed Water Pump	Hot Water Circulating. Pump	MAF - Make-up Air Fan	Return Fan	Supply Fan	WS Heat Pump Circulating Loop
Annual Energy Savings Factors (kWh/HP)									
University/College	3,641	449	745	2,316	2,344	3,220	1,067	1,023	3,061
Elm/H School	3,563	365	628	1,933	1,957	3,402	879	840	2,561
Multi-Family	3,202	889	1,374	2,340	2,400	3,082	1,374	1,319	3,713
Hotel/Motel	3,151	809	1,239	2,195	2,239	3,368	1,334	1,290	3,433
Health	3,375	1,705	2,427	2,349	2,406	3,002	1,577	1,487	3,670
Warehouse	3,310	455	816	2,002	2,087	3,229	1,253	1,205	2,818
Restaurant	3,440	993	1,566	1,977	2,047	2,628	1,425	1,363	3,542
Retail	3,092	633	1,049	1,949	2,000	2,392	1,206	1,146	2,998
Grocery	3,126	918	1,632	1,653	1,681	2,230	1,408	1,297	3,285
Offices	3,332	950	1,370	1,866	1,896	3,346	1,135	1,076	3,235
Summer Demand Savings Factors (kW/HP_{SP})									
University/College	0.109	-0.023	0.056	0.457	0.457	0.109	0.102	0.064	0.056
Elm/H School	0.377	-0.023	0.056	0.457	0.457	0.109	0.102	0.064	0.275
Multi-Family	0.109	-0.023	0.056	0.457	0.457	0.109	0.102	0.064	0.056
Hotel/Motel	0.109	-0.023	0.056	0.457	0.457	0.109	0.102	0.064	0.056
Health	0.109	-0.023	0.056	0.457	0.457	0.109	0.102	0.064	0.056
Warehouse	0.109	-0.023	0.056	0.457	0.457	0.261	0.102	0.064	0.056
Restaurant	0.261	-0.023	0.056	0.457	0.457	0.109	0.102	0.064	0.178
Retail	0.109	-0.023	0.056	0.457	0.457	0.109	0.102	0.064	0.056
Grocery	0.261	-0.023	0.056	0.457	0.457	0.109	0.102	0.064	0.178
Offices	0.109	-0.023	0.056	0.457	0.457	0.109	0.102	0.064	0.056
Winter Demand Savings Factors (kW/HP_{WP})									
University/College	0.377	-0.006	0.457	0.457	0.457	0.109	0.113	0.113	0.457
Elementary/High School	0.457	-0.006	0.457	0.457	0.457	0.109	0.113	0.113	0.457
Multi-Family	0.109	-0.006	0.457	0.355	0.384	0.109	0.113	0.113	0.355
Hotel/Motel	0.109	-0.006	0.457	0.418	0.444	0.109	0.113	0.113	0.418
Health	0.377	-0.006	0.457	0.275	0.298	0.109	0.113	0.113	0.275
Warehouse	0.377	-0.006	0.457	0.178	0.193	0.261	0.113	0.113	0.178
Restaurant	0.109	-0.006	0.457	0.355	0.384	0.109	0.113	0.113	0.355
Retail	0.109	-0.006	0.457	0.275	0.298	0.109	0.113	0.113	0.275
Grocery	0.457	-0.006	0.457	0.418	0.444	0.109	0.113	0.113	0.418
Offices	0.457	-0.006	0.457	0.418	0.444	0.109	0.113	0.113	0.418

Baseline Efficiency

The baseline efficiency case for this measure varies with the equipment type. All baselines assume either a constant speed motor or 2-speed motor. In the baselines, air or water volume/temperature is controlled using valves, dampers, and/or reheats.

[461] Chan, Tumin (2010). *Formulation of a Prescriptive Incentive for the VFD and Motors & VFD impact tables at NSTAR.* Prepared for NSTAR.

High Efficiency

In the high efficiency case, pump flow or fan air volume is directly controlled using downstream information. The pump or fan will automatically adjust its speed based on inputted set points and the downstream feedback it receives.

Hours

Hours vary by end use and building type.

Measure Life

For lost-opportunity installations, the lifetime for this measure is 15 years. For retrofit projects, the lifetime is 13 years.[462]

Secondary Energy Impacts

There are no secondary energy impacts.

Non-Energy Impacts

There are no non-energy impacts for this measure.

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}	CF_{SSP}	CF_{WSP}
VFD	NC	All	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
VFD	Large Retrofit	All	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

In-Service Rates
All installations have 100% in service rate since all PAs programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factors.

Realization Rates
RRs for all PAs set to 1.0 pending impact evaluation.

Coincidence Factors
CFs for all PAs set to 1.0 based summer and winter factors in gross calculation and pending impact evaluation.

[462] Energy & Resource Solutions (2005). *Measure Life Study*. Prepared for The Massachusetts Joint Utilities; Table 1-1.

Custom Measures (Large C&I)

Version Date and Revision History

Effective Date: 1/1/2011 (Revised 1/1/2012)
End Date: TBD

Measure Overview

Description: The Custom project track is offered for energy efficiency projects involving complex site-specific applications that require detailed engineering analysis and/or projects which do not qualify for incentives under any of the prescriptive rebate offering. Projects offered through the custom approach must pass a cost-effectiveness test based on project-specific costs and savings.
Primary Energy Impact: Electric
Secondary Energy Impact: Project Specific
Non-Energy Impact: Project Specific
Sector: Commercial & Industrial
Market: Lost Opportunity, Retrofit
End Use: All
Program: C&I New Construction & Major Renovation, C&I Large Retrofit

Notes

In 2011 the PAs agreed on the following set of categories for Large C&I custom projects. All Large C&I Custom projects will be assigned to one of the following categories for future statewide impact evaluation.

Custom Category	Description
Comprehensive Design	New construction projects which address multiple end-uses, reach 20%+ total energy savings, and use whole-building simulations for ex-ante savings estimates and Retrofit projects which address multiple end-uses, reach 15%+ electric energy savings, and do not require whole-building simulations.
Compressed Air	New construction and/or retrofit projects for compressed air systems.
CHP	Combined Heat and Power projects.
HVAC	New construction and/or retrofit projects for HVAC system equipment and controls.
Lighting	New construction and/or retrofit projects for lighting system equipment and controls.
Motor	New construction and/or retrofit projects for motor installations or controls.
Other	New construction and/or retrofit projects that do not fit in with other categories.
Process	New construction and/or retrofit projects for process system equipment and controls.
Refrigeration	New construction and/or retrofit projects for refrigeration system equipment and controls.
Verified Savings	Retrofit “Pay-for-Performance” projects for which savings are estimated based on post-installation measurement and verification.

Algorithms for Calculating Primary Energy Impact

Gross energy and demand savings estimates for custom projects are calculated using engineering analysis with project-specific details. Custom analyses typically include a weather dependent load bin analysis, whole building energy model simulation, end-use metering or other engineering analysis and include estimates of savings, costs, and an evaluation of the projects' cost-effectiveness.

Baseline Efficiency

For Lost Opportunity projects, the baseline efficiency case assumes compliance with the efficiency requirements as mandated by Massachusetts State Building Code or industry accepted standard practice. For retrofit projects, the baseline efficiency case is the same as the existing, or pre-retrofit, case for the facility.

High Efficiency

The high efficiency scenario is specific to the custom project and may include one or more energy efficiency measures. Energy and demand savings calculations are based on projected or measured changes in equipment efficiencies and operating characteristics and are determined on a case-by-case basis. The project must be proven cost-effective in order to qualify for energy efficiency incentives.

Hours

All hours for custom savings analyses should be determined on a case-by-case basis.

Measure Life

For both lost-opportunity and retrofit custom applications, the measure life is determined based on specific project using the common custom measure life recommendations.[463]

Secondary Energy Impacts

All secondary energy impacts should be determined on a case-by-case basis.

Non-Energy Impacts

All non-energy impacts should be determined on a case-by-case basis.

[463] Energy & Resource Solutions (2005). *Measure Life Study*. Prepared for The Massachusetts Joint Utilities; Table 1-2.

Impact Factors for Calculating Adjusted Gross Savings

Measure	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}	CF_{SSP}	CF_{WSP}
Comprehensive Design	NSTAR, CLC, Unitil, WMECO	1.00	1.00	0.91	0.64	0.60	custom	custom	custom	custom
	National Grid	1.00	1.00	0.97	0.64	0.55	custom	custom	n/a	n/a
Compressed Air	National Grid	1.00	1.00	0.82	0.80	0.83	custom	custom	n/a	n/a
	NSTAR, CLC	1.00	1.00	1.25	0.95	0.80	custom	custom	n/a	n/a
	Unitil	1.00	1.00	1.00	1.00	1.00	custom	custom	n/a	n/a
	WMECO	1.00	1.00	0.90	1.71	1.22	n/a	n/a	custom	custom
CHP	All except National Grid	1.00	1.00	1.00	1.00	1.00	custom	custom	custom	custom
CHP	National Grid	1.00	1.00	0.90	1.00	1.00	custom	custom	custom	custom
HVAC	CLC, Unitil, WMECO	1.00	1.00	1.10	0.88	0.86	custom	custom	custom	custom
	National Grid	1.00	1.00	1.01	0.84	0.82	custom	custom	n/a	n/a
	NSTAR	1.00	1.00	1.24	0.94	0.75	custom	custom	n/a	n/a
Lighting	National Grid	1.00	1.00	1.07	0.80	0.73	custom	custom	n/a	n/a
	NSTAR, CLC	1.00	1.00	1.03	1.16	1.26	custom	custom	n/a	n/a
	Unitil	1.00	1.00	1.00	1.00	1.00	custom	custom	n/a	n/a
	WMECO	1.00	1.00	1.06	1.058	1.06	n/a	n/a	custom	custom
Motor	National Grid	1.00	1.00	0.82	0.80	0.83	custom	custom	n/a	n/a
	NSTAR, CLC	1.00	1.00	0.67	0.85	0.78	custom	custom	n/a	n/a
	Unitil	1.00	1.00	1.00	1.00	1.00	custom	custom	n/a	n/a
	WMECO	1.00	1.00	1.31	0.85	0.60	n/a	n/a	custom	custom
Process	National Grid	1.00	1.00	0.82	0.80	0.83	custom	custom	n/a	n/a
	NSTAR, CLC	1.00	1.00	1.03	1.48	0.72	custom	custom	n/a	n/a
	Unitil	1.00	1.00	1.00	1.00	1.00	custom	custom	n/a	n/a
	WMECO	1.00	1.00	0.90	1.71	1.22	n/a	n/a	custom	custom
Refrigeration	National Grid	1.00	1.00	0.82	0.80	0.83	custom	custom	n/a	n/a
	NSTAR, CLC	1.00	1.00	0.85	0.41	0.24	custom	custom	n/a	n/a
	Unitil	1.00	1.00	1.00	1.00	1.00	custom	custom	n/a	n/a
	WMECO	1.00	1.00	0.90	2.08	0.87	n/a	n/a	custom	custom
Verified Savings[464]	Statewide	1.00	1.00	1.00	1.00	1.00	custom	custom	custom	custom

Note: Unless otherwise stated, PA's use Statewide results.

In-Service Rates
All installations have 100% in service rate since all PA programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factor.

[464] The PAs assume 100% realization rates for verified savings projects because gross savings assumptions are based on post-installation verification and analysis. This custom category is new in 2011 and has not been evaluated.

Realization Rates

- Comprehensive: Realization rates from statewide impact evaluation completed in 2011. National Grid uses PA specific values, all other PA's use statewide values due to small sample size.[465]
- HVAC: Realization rates from statewide impact evaluation completed in 2011. National Grid and NSTAR use PA specific values, all other PA's use statewide values due to small sample size.[466]
- CHP: Realization Rates set to 90% pending finalized
- Compressed Air, Lighting, Motor, Other, Process, and Refrigeration realization rates based on previous PA-specific impact evaluations. No statewide evaluations have been performed for these categories:
  - National Grid rates from impact evaluation analysis of the National Grid 2009 custom program[467]. Compressed Air, Motor, Other and Refrigeration projects are included in the Process populatiors.
  - NSTAR, CLC rates for Lighting from NSTAR impact evaluation of large C&I PY 2007 lighting measures[468]; rates for non-lighting from NSTAR impact evaluation of large C&I 2006 programs.[469]
  - Unitil RRs have not been evaluated for this program so 100% is used.
  - WMECO energy RRs are from 2007/2008 Large C&I Programs impact evaluation[470]

Coincidence Factors

For all PAs, gross summer and winter peak coincidence factors are custom-calculated for each custom project based on project-specific information. The actual or measured coincidence factors are included in the summer and winter demand realization rates.

[465] KEMA, Inc. and SBW (2011). Impact Evaluation of 2008 and 2009 Custom CDA Installations. Prepared for Massachusetts Energy Efficiency Program Administrators and Massachusetts Energy Efficiency Advisory Council.
[466] KEMA, Inc. and DMI (2011). Impact Evaluation of 2009 Custom HVAC Installations. Prepared for Massachusetts Energy Efficiency Program Administrators and Massachusetts Energy Efficiency Advisory Council.
[467] KEMA, Inc. (2010). *Sample Design and Impact Evaluation Analysis of the 2009 Custom Program*. Prepared for National Grid; Table 17.
[468] KEMA, Inc. (2009). *2007 Business & Construction Solutions (BS/CS) Programs - Measurement and Verification of 2007 Lighting Measures*. Prepared for NSTAR; Table Ex 1.
[469] RLW Analytics (2008). *Business & Construction Solutions (BS/CS) Programs Measurement & Verification - 2006 Final Report*. Prepared for NSTAR Electric and Gas; Tables 14-18.
[470] KEMA, Inc. (2010). *2007/2008 Large C&I Programs, Phase 1 Report Memo for Lighting and Process Measures*. Prepared for Western Massachusetts Electric Company.

Custom Measures (Small C&I)

Version Date and Revision History

Effective Date: 1/1/2011 (Revised 1/1/2012)
End Date: TBD

Measure Overview

Description: The Custom project track is offered for energy efficiency projects involving complex site-specific applications that require detailed engineering analysis and/or projects which do not qualify for incentives under any of the prescriptive rebate offering. Projects offered through the custom approach must pass a cost-effectiveness test based on project-specific costs and savings.
Primary Energy Impact: Electric
Secondary Energy Impact: Project Specific
Non-Energy Impact: Project Specific
Sector: Commercial & Industrial
Market: Retrofit
End Use: All
Program: C&I Small Retrofit

Algorithms for Calculating Primary Energy Impact

Gross energy and demand savings estimates for custom projects are calculated using engineering analysis with project-specific details. Custom analyses typically include a weather dependent load bin analysis, whole building energy model simulation, end-use metering or other engineering analysis and include estimates of savings, costs, and an evaluation of the projects' cost-effectiveness.

Baseline Efficiency

For Lost Opportunity projects, the baseline efficiency case assumes compliance with the efficiency requirements as mandated by Massachusetts State Building Code or industry accepted standard practice. For retrofit projects, the baseline efficiency case is the same as the existing, or pre-retrofit, case for the facility.

High Efficiency

The high efficiency scenario is specific to the custom project and may include one or more energy efficiency measures. Energy and demand savings calculations are based on projected or measured changes in equipment efficiencies and operating characteristics and are determined on a case-by-case basis. The project must be proven cost-effective in order to qualify for energy efficiency incentives.

Hours

All hours for custom savings analyses should be determined on a case-by-case basis.

Measure Life

For both lost-opportunity and retrofit custom applications, the measure life is determined based on specific project using the common custom measure life recommendations.[471]

Secondary Energy Impacts

All secondary energy impacts should be determined on a case-by-case basis.

Non-Energy Impacts

All non-energy impacts should be determined on a case-by-case basis.

Impact Factors for Calculating Adjusted Gross Savings

Measure	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}	CF_{SSP}	CF_{WSP}
Lighting	National Grid	1.00	1.00	1.04	1.02	1.13	custom	custom	n/a	n/a
Refrigeration	National Grid	1.00	1.00	1.60	1.49	0.69	custom	custom	n/a	n/a
Other	National Grid	1.00	1.00	0.81	0.77	0.53	custom	custom	n/a	n/a
Lighting	NSTAR, CLC	1.00	1.00	1.08	0.99	0.99	custom	custom	n/a	n/a
Non-Lighting	NSTAR, CLC	1.00	1.00	0.91	0.92	0.92	custom	custom	n/a	n/a
Lighting	Unitil	1.00	1.00	1.08	0.99	0.99	custom	custom	n/a	n/a
Non-Lighting	Unitil	1.00	1.00	1.08	1.00	1.00	custom	custom	n/a	n/a
Lighting	WMECO	1.00	1.00	0.83	0.54	0.25	n/a	n/a	custom	custom
Refrigeration	WMECO	1.00	1.00	0.86	0.57	0.57	n/a	n/a	custom	custom
Other	WMECO	1.00	1.00	1.00	1.00	1.00	n/a	n/a	custom	custom

In-Service Rates
All installations have 100% in service rate since all PA programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factor.

Realization Rates

- National Grid RRs derived from impact evaluation of 2005 SBS program[472]
- NSTAR and CLC RRs from the 2011 Small C&I Non-Controlled Lighting impact evaluation [473]; non-lighting energy and all demand RRs based on NSTAR 2002–2004 small retrofit impact evaluations
- Unitil RRs from Small Business program impact evaluation.[474]
- WMECO: RRs from impact evaluation of 2008 small retrofit program.[475]

[471] Energy & Resource Solutions (2005). *Measure Life Study*. Prepared for The Massachusetts Joint Utilities; Table 1-2.
[472] RLW Analytics (2007). *Small Business Services Custom Measure Impact Evaluation*. Prepared for National Grid; Table 4.
[473] Cadmus Group (2011). *Non-Controls Lighting Evaluation for the Massachusetts Small Commercial Direct Install Program*. Prepared for Massachussetts Utilities.
[474] Summit Blue Consulting, LLC (2008). *Multiple Small Business Services Programs Impact Evaluation 2007 – Final Report Update*. Prepared for Cape Light Compact, National Grid, NSTAR, Unitil and Western Massachusetts Electric Company.
[475] The Cadmus Group, Inc. (2010). *Western Massachusetts Small Business Energy Advantage Impact Evaluation Report Program Year 2008*. Prepared for Western Massachusetts Electric Company.

Coincidence Factors

For all PAs, gross summer and winter peak coincidence factors are custom-calculated for each custom project based on project-specific information. The actual or measured coincidence factors are included in the summer and winter demand realization rates.

Residential Natural Gas Efficiency Measures

Behavior – OPOWER Gas

Version Date and Revision History

Effective Date: 1/1/2012
End Date: TBD

Measure Overview

Description: The Behavior/Feedback programs send monthly energy use reports to participating gas customers in order to change customers' energy-use behavior.
Primary Energy Impact: Natural Gas (Residential Heat)
Secondary Energy Impact: None
Non-Energy Impact: None
Sector: Residential
Market: Products and Services
End Use: Behavior
Program: Behavior/Feedback Program

Algorithms for Calculating Primary Energy Impact

Unit saving are deemed based on study results:

$$\Delta MMBtu = (MMBtu_{BASE})(\%SAVE)$$

Where:
Unit = One participant household
ΔMMBtu = Average annual gas heating MMBtu savings per unit. See Table 21.
$MMBtu_{BASE}$ = Average baseline consumption MMBtu per unit. See Table 21.
%SAVE = Annual percent of MMBtu savings per unit. See Table 21.

Table 21: Savings Factors for Behavior/Feedback Program[476]

Measure	PA	$MMBtu_{BASE}$	%SAVE	ΔMMBtu
OPOWER Group 2009	National Grid	137.2	1.46	2.00
OPOWER Group 2010	National Grid	141.4	1.10	1.56
OPOWER Group 2011	National Grid	102.7	1.10	1.13
OPOWER Group 2011 Add	National Grid	135.8	0.97	1.32
OPOWER Group 2012	National Grid	135.8	0.97	1.32
OPOWER Group 2012 Dual	National Grid	162.1	0.97	1.57

Baseline Efficiency

The baseline efficiency case is a customer who does not receive Behavior/Feedback program reports.

[476] ODC/Navigant (2011) *Massachusetts Cross-cutting Behavioral Program Evaluation,* updated with vendor projections for 2012.

High Efficiency

The high efficiency case is a customer who does receive Behavior/Feedback program reports.

Hours

Not applicable.

Measure Life

The measure life is 1 year[477].

Secondary Energy Impacts

There are no secondary energy impacts for this measure

Non-Energy Impacts

There are no-non-energy impacts for this measure.

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
OPOWER Group	Behavior/Feedback	National Grid	1.00	1.00	1.00	n/a	n/a	n/a	n/a
OPOWER Group	Behavior/Feedback	NSTAR	1.00	1.00	1.00	n/a	n/a	n/a	n/a

In-Service Rates
All installations have 100% in service rate since programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factor.

Realization Rates
RRs are 100% because deemed savings are based on assumptions from year-to-date vendor findings. The summer and winter peak realization rates are not applicable for this measure since there are no electric savings claimed.

Coincidence Factors
Not applicable for this measure since no electric savings are claimed.

[477] Vendor estimate.

Hot Water – Water Heaters

Version Date and Revision History

Effective Date: 1/1/2011 (Revised for 1/1/2012)
End Date: TBD

Measure Overview

Description: Installation of high efficiency gas water heaters: *Indirect water heaters* use a storage tank that is heated by the main boiler. The energy stored by the water tank allows the boiler to turn off and on less often, saving considerable energy. *Condensing water heaters* recover energy by using either a larger heat exchanger or a second heat exchanger to reduce the flue-gas temperature to the point that water vapor condenses, thus releasing even more energy. *Stand-alone storage water heaters* are high efficiency water heaters that are not combined with space heating devices. *Tankless water heaters* circulate water through a heat exchanger to be heated for immediate use, eliminating the standby heat loss associated with a storage tank.
Primary Energy Impact: Natural Gas (Residential DHW)
Secondary Energy Impact: None
Non-Energy Impact: Annual Non-Resource, One-Time Non-Resource
Sector: Residential
Market: Lost Opportunity
End Use: Hot Water
Program: Residential Heating and Water Heating

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed based on study results:

$$\Delta MMBtu = \Delta MMBtu$$

Where:
Units = Number of stand alone storage water heaters installed.
ΔMMBtu = Annual MMBtu savings per unit. See Table 22.

Table 22: Savings for Residential Water Heaters

Equipment Type	Efficiency Requirement	ΔMMBtu
Condensing Water Heater	EF >=0.80	7.4 [478]
	TE >=95	25.0[479]
Indirect Water Heater	ENERGY STAR® Boiler	8.0 [480]
Stand-Alone Storage Water Heater	EF >= 0.67	3.7 [481]
On-Demand Tankless Water Heater	EF >= 0.82	9.7 [482]
	EF >= 0.95	10.3 [483]

[478] DOE (2008). *ENERGY STAR® Residential Water Heaters: Final Criteria Analysis*. Prepared for the DOE; Page 10.
[479] GDS Associates, Inc. (2009). *Natural Gas Energy Efficiency Potential in Massachusetts*. Prepared for GasNetworks.
[480] Nexus Market Research and The Cadmus Group (2010). *HEHE Process and Impact Evaluation*. Prepared for GasNetworks.
[481] DOE (2008). *ENERGY STAR® Residential Water Heaters: Final Criteria Analysis*. Prepared for the DOE; Page 10.
[482] Nexus Market Research and The Cadmus Group (2010). *HEHE Process and Impact Evaluation*. Prepared for GasNetworks.

Baseline Efficiency

The baseline efficiency case is a stand alone tank water heater with an energy factor of 0.575.

High Efficiency

The high efficiency case is a stand-alone storage water heater with an energy factor >= 0.62, a condensing water heater with an energy factor >= 0.8, a tankless water heater with an energy factor >= 0.82, or an indirect water heater attached to an ENERGY STAR® rated forced hot water gas boiler.

Hours

Not applicable.

Measure Life

The measure lives vary by water heater type and are described in the table below.

Table 23: Measure Lives for Residential Water Heaters

Measure	Measure Life (years)
Condensing Water Heater	15 [484]
Indirect Water Heater	20 [485]
Stand-Alone Storage Water Heater	13 [486]
On-Demand Tankless Water Heater	20 [487]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

[483] DOE (2008). *ENERGY STAR® Residential Water Heaters: Final Criteria Analysis*. Prepared for the DOE; Page 10, energy consumption estimated using the DOE test procedure. Based on the following formula: (41,045 BTU/EF x 365)/1,000,000.
[484] DOE (2008). *ENERGY STAR® Residential Water Heaters: Final Criteria Analysis*. Prepared for the DOE; Page 10.
[485] GDS Associates, Inc. (2009). *Natural Gas Energy Efficiency Potential in Massachusetts*. Prepared for GasNetworks.
[486] DOE (2008). *ENERGY STAR® Residential Water Heaters: Final Criteria Analysis*. Prepared for the DOE; Page 10.
[487] Ibid.

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Condensing Water Heater	Residential HEHE	All	1.00	1.00	1.00	n/a	n/a	n/a	n/a
Indirect Water Heater	Residential HEHE	All	1.00	1.00	1.00	n/a	n/a	n/a	n/a
Stand Alone Storage Water Heater	Residential HEHE	All	1.00	1.00	1.00	n/a	n/a	n/a	n/a
On-Demand Tankless Water Heater	Residential HEHE	All	1.00	1.00	1.00	n/a	n/a	n/a	n/a

In-Service Rates
All installations have 100% in service rate since programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factor.

Realization Rates
All PAs use 100% energy realization rate. Summer and winter peak realization rates are not applicable for this measure since there are no electric savings claimed.

Coincidence Factors
Not applicable for this measure since no electric savings are claimed.

HVAC – Boilers

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: Installation of a new high efficiency gas-fired boiler for space heating.
Primary Energy Impact: Natural Gas (Residential Heat)
Secondary Energy Impact: None
Non-Energy Impact: Annual Non-Resource, One-Time Non-Resource
Sector: Residential
Market: Lost Opportunity
End Use: HVAC
Program: Residential Heating and Water Heating

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed based on study results:

$$\Delta MMBtu = \Delta MMBtu$$

Where:
Unit = Installation of high efficiency boiler
ΔMMBtu = Annual MMBtu savings per unit. See Table 24 for values.

Table 24: Savings for Residential Boilers

Measure	ΔMMBtu
Boiler (AFUE >= 90%)	13.7 [488]
Boiler (AFUE >= 96%)	21.3 [489]

Baseline Efficiency

The baseline efficiency case is an 80% AFUE boiler.

High Efficiency

The high efficiency case is a boiler with an AFUE of 90% or greater.

Hours

Not applicable.

[488] Nexus Market Research and The Cadmus Group (2010). *HEHE Process and Impact Evaluation*. Prepared for GasNetworks..
[489] GDS Associates, Inc. (2009). *Natural Gas Energy Efficiency Potential in Massachusetts*. Prepared for GasNetworks.

Measure Life

The measure life is 20 years.[490]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Boiler (AFUE >=85%)	Residential HEHE	All	1.00	1.00	1.00	n/a	n/a	n/a	n/a
Boiler (AFUE >=90%)	Residential HEHE	All	1.00	1.00	1.00	n/a	n/a	n/a	n/a
Boiler (AFUE >=95%)	Residential HEHE	All	1.00	1.00	1.00	n/a	n/a	n/a	n/a

In-Service Rates
All installations have 100% in service rate since programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factor.

Realization Rates
All PAs use 100% energy realization rate. The summer and winter peak realization rates are not applicable for this measure since there are no electric savings claimed.

Coincidence Factors
Not applicable for this measure since no electric savings are claimed.

[490] Environmental Protection Agency (2009). *Life Cycle Cost Estimate for ENERGY STAR Qualified Boilers*.

HVAC – Boiler Reset Controls

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: Boiler Reset Controls are devices that automatically control boiler water temperature based on outdoor temperature using a software program.
Primary Energy Impact: Natural Gas (Residential Heat)
Secondary Energy Impact: None
Non-Energy Impact: None
Sector: Residential
Market: Retrofit
End Use: HVAC
Program: Residential Heating and Water Heating

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed based on study results:

$$\Delta MMBtu = \Delta MMBtu$$

Where:
Unit = Installed boiler reset control
ΔMMBtu = Annual MMBtu savings per unit: 7.9 MMBtu[491]

Baseline Efficiency

The baseline efficiency case is a boiler without reset controls.

High Efficiency

The high efficiency case is a boiler with reset controls.

Hours

Not applicable.

Measure Life

The measure life is 15 years.[492]

[491] ACEEE (2006). *Emerging Technologies Report: Advanced Boiler Controls*. Prepared for ACEEE; Page 2.
[492] Ibid.

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

There are no non-energy impacts for this measure.

Impact Factors for Calculating Adjusted Gross Savings

Measure	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Boiler Reset Controls	Residential HEHE	All	1.00	1.00	1.00	n/a	n/a	n/a	n/a

In-Service Rates
All installations have 100% in service rate since programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factor.

Realization Rates
All PAs use 100% energy realization rate. The summer and winter peak realization rates are not applicable for this measure since there are no electric savings claimed.

Coincidence Factors
Not applicable for this measure since no electric savings are claimed.

HVAC – Combo Water Heater/Boiler

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: This measure promotes the installation of a combined high-efficiency boiler and water heating unit. Combined boiler and water heating systems are more efficient than separate systems because they eliminate the standby heat losses of an additional tank.
Primary Energy Impact: Natural Gas (Residential Heat)
Secondary Energy Impact: None
Non-Energy Impact: Annual Non-Resource, One-Time Non-Resource
Sector: Residential
Market: Lost Opportunity
End Use: Residential Heat
Program: Residential Heating and Water Heating

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed based on study results:

$$\Delta MMBtu = \Delta MMBtu$$

Where:
Units = Installation of integrated water heater/boiler unit
ΔMMBtu = Annual MMBtu savings per unit: See Table 25.

Table 25: Savings for Residential Combo Water Heater/Boilers

Measure	ΔMMBtu
Combo Water Heater/Condensing Boiler	21.1[493]

Baseline Efficiency

The baseline efficiency case is an 80% AFUE boiler with a 0.594 EF water heater.

High Efficiency

The high efficiency case is an integrated water heater/boiler unit with a 90% AFUE condensing boiler and a 0.9 EF water heater.

Hours

Not applicable.

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[493] GDS Associates, Inc. (2009). *Natural Gas Energy Efficiency Potential in Massachusetts.* Prepared for GasNetworks.

Measure Life

The measure life is 20 years.[494]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Combo Water Heater/Condensing Boiler	Residential HEHE	All	1.00	1.00	1.00	n/a	n/a	n/a	n/a
Combo Water Heater/Non-Condensing Boiler	Residential HEHE	All	1.00	1.00	1.00	n/a	n/a	n/a	n/a

In-Service Rates
All installations have 100% in service rate since programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factor.

Realization Rates
All PAs use 100% energy realization rate. The summer and winter peak realization rates are not applicable for this measure since there are no electric savings claimed.

Coincidence Factors
Not applicable for this measure since no electric savings are claimed.

[494] Environmental Protection Agency (2009). *Life Cycle Cost Estimate for ENERGY STAR Qualified Boilers*; measure life assumed to be the same as a boiler.

HVAC – Early Replacement Boiler

Version Date and Revision History

Effective Date: 1/1/2011 (revised for 1/1/2012)
End Date: TBD

Measure Overview

Description: Early retirement of inefficient gas-fired boiler and installation of new high efficiency gas-fired boiler.
Primary Energy Impact: Natural Gas (Residential Heat)
Secondary Energy Impact: None
Non-Energy Impact: Annual Non-Resource, One-Time Non-Resource
Sector: Residential
Market: Retrofit
End Use: HVAC
Program: Residential Heating and Water Heating

Algorithms for Calculating Primary Energy Impact

Unit savings for the early replacement of an existing boiler with a high efficiency boiler are counted in two parts: (1) early retirement savings for a code-compliant boiler compared to the existing boiler over the remaining lifetime of the existing boiler, and (2) efficiency savings for the high efficiency boiler compared to a code-compliant boiler for the full life of the new high efficiency boiler:

$$\Delta MMBtu = \Delta MMBtu_{RETIRE} + \Delta MMBtu_{EE}$$

Where:

Unit	=	Removal of existing inefficient boiler and installation of new high efficiency boiler
$\Delta MMBtu_{RETIRE}$	=	Annual MMBtu savings of code-compliant boiler compared to existing boiler: 9.0 MMBtu[495]
$\Delta MMBtu_{EE}$	=	Annual MMBtu savings of high efficiency boiler compared to code-compliant boiler: 13.7 MMBtu[496]

Baseline Efficiency

For the retirement savings over the remaining life of existing boiler, the baseline is the existing inefficient boiler. For the high efficiency unit savings over lifetime of the new boiler, the baseline is a code-compliant boiler (AFUE = 80%).

[495] GDS Associates, Inc. (2009). *Natural Gas Energy Efficiency Potential in Massachusetts*. Prepared for GasNetworks.
[496] Nexus Market Research and The Cadmus Group (2010). *HEHE Process and Impact Evaluation*. Prepared for GasNetworks.

High Efficiency

For the retirement savings over the remaining life of existing boiler, the efficient case is a code-compliant boiler (AFUE = 80%). For the high efficiency savings over lifetime of the new boiler, the efficient case is a new high efficiency (AFUE >= 90%).

Hours

Not applicable.

Measure Life

The remaining life for the existing unit is 14 years[497], and the measure life of new equipment is 20 years.[498]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Early Replacement Boiler (Retire)	Residential HEHE	All	1.00	1.00	1.00	n/a	n/a	n/a	n/a
Early Replacement Boiler (EE)	Residential HEHE	All	1.00	1.00	1.00	n/a	n/a	n/a	n/a

In-Service Rates
All installations have 100% in service rate since programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factor.

Realization Rates
All PAs use 100% energy realization rate. The summer and winter peak realization rates are not applicable for this measure since there are no electric savings claimed.

Coincidence Factors
Not applicable for this measure since no electric savings are claimed.

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[497] Massachusetts Common Assumption: The remaining life of 14 years was determined by subtracting the average age of existing equipment (estimated by program vendor at 26 years) from the full lifetime of standard efficiency boilers (estimated by program vendor at 40 years).
[498] Environmental Protection Agency (2009). *Life Cycle Cost Estimate for ENERGY STAR Qualified Boilers*.

HVAC – Furnaces

Version Date and Revision History

Effective Date: 1/1/2011 (revised for 1/1/2012)
End Date: TBD

Measure Overview

Description: Installation of a new high efficiency space heating gas-fired furnace with an electronically commutated motor (ECM) for the fan.
Primary Energy Impact: Natural Gas (Residential Heat)
Secondary Energy Impact: Electric
Non-Energy Impact: Annual Non-Resource, One-Time Non-Resource
Sector: Residential
Market: Lost Opportunity
End Use: HVAC
Program: Residential Heating and Water Heating

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed based on study results:

$$\Delta MMBtu = \Delta MMBtu$$

Where:
Units = Installation of furnace with ECM
ΔMMBtu = Annual MMBtu savings per unit. See Table 26.

Table 26: Savings for Residential Furnaces

Equipment Type	Efficiency	ΔMMBtu
Furnace (Forced Hot Air) w/ECM	AFUE = 95%	18.0 [499]
	AFUE = 96%	20.7 [500]

Baseline Efficiency

The baseline efficiency case is a 78% AFUE furnace.

High Efficiency

The high efficiency case is a new furnace with AFUE >= 95% with an electronically commutated motor installed.

[499] GDS Associates, Inc. (2009). *Natural Gas Energy Efficiency Potential in Massachusetts*. Prepared for GasNetworks; value adjusted based on results of: Nexus Market Research and The Cadmus Group (2010). *HEHE Process and Impact Evaluation*. Prepared for GasNetworks..
[500] Ibid.

Hours

Not applicable.

Measure Life

The measure life is 18 years.[501]

Secondary Energy Impacts

High efficiency furnaces equipped with ECM fan motors also save electricity from reduced fan energy requirements. See HVAC - Furnace Fan Motors in the Residential Electric section.

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Furnace w/ECM	Residential HEHE	All	1.00	1.00	1.00	1.00	1.00	0.67	0.50

In-Service Rates
All installations have 100% in service rate since programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factor.

Realization Rates
All PAs use 100% energy realization rate. The summer and winter peak realization rates are not applicable for this measure since there are no electric savings claimed.

Coincidence Factors
Not applicable for this measure since no electric savings are claimed.

[501] Environmental Protection Agency (2009). *Life Cycle Cost Estimate for ENERGY STAR Furnace*.

HVAC – Heat Recovery Ventilator

Version Date and Revision History

Effective Date: 1/1/2011 (revised for 2012)
End Date: TBD

Measure Overview

Description: Heat Recovery Ventilators (HRV) can help make mechanical ventilation more cost effective by reclaiming energy from exhaust airflows.
Primary Energy Impact: Natural Gas (Residential Heat)
Secondary Energy Impact: Electric
Non-Energy Impact: None
Sector: Residential
Market: Lost Opportunity
End Use: HVAC
Program: Residential Heating and Water Heating

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed based on study results:

$$\Delta MMbtu = \Delta MMbtu$$

Where:
Units = Number of heat recovery ventilation systems installed

ΔMMBtu = Annual MMBtu savings per unit: 7.7 MMBtu [502]

Baseline Efficiency

The baseline efficiency case is an ASHRAE 62.2-compliant exhaust fan system with no heat recovery.

High Efficiency

The high efficiency case is an exhaust fan system with heat recovery.

Hours

Not applicable.

Measure Life

The measure life is 20 years.[503]

[502] GDS Associates, Inc. (2009). *Natural Gas Energy Efficiency Potential in Massachusetts*. Prepared for GasNetworks.

Secondary Energy Impacts

An electric penalty results due to the electricity consumed by the system fans.

Measure	Energy Type	ΔkWh/Unit[504]	ΔkW/Unit[505]
Heat Recovery Ventilator	Electric	-133	0.017

.

Non-Energy Impacts

There are no non-energy impacts for this measure.

Impact Factors for Calculating Adjusted Gross Savings

Measure	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Heat Recovery Ventilator	Residential HEHE	All	1.00	1.00	1.00	1.00	1.00	0.03	1.00

In-Service Rates
All installations have 100% in service rate since programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factor.

Realization Rates
All PAs use 100% energy realization rate.

Coincidence Factors
Coincidence factors are estimated using the demand allocation methodology described in the 2000 EnergyWise program impact evaluation.[506]

[503] Ibid.
[504] Ibid
[505] Estimated using the demand methodology described in: Quantec, LLC (2000). *Impact Evaluation: Single-Family EnergyWise Program*. Prepared for National Grid.
[506] Ibid.

HVAC – Heating System Replacement

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: Replacement of an existing gas heating system with a new high efficiency system. Electric savings are achieved from reduced fan run time.
Primary Energy Impact: Natural Gas (Residential Heat)
Secondary Energy Impact: Electric
Non-Energy Impact: Annual Non-Resource, One-Time Non-Resource
Sector: Low-Income
Market: Retrofit
End Use: HVAC
Program: Low-Income Single Family Retrofit

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed based on study results:

$$\Delta MMBtu = \Delta MMBtu$$

Where:
Unit = Installation of new high efficiency gas heating system.
ΔMMBtu = Annual MMBtu savings per unit: See Table 27.

Table 27: Savings for Heating System Replacement (Gas)

PA	Savings	ΔMMBtu
CMA, Berkshire, NE Gas	358.05 therms per home [507]	35.8
National Grid, CLC	122 therms per home [508]	12.2
NSTAR	300 therms per home [509]	30.0
Unitil	380 therms per home [510]	38.0

Baseline Efficiency

The baseline efficiency case is the existing inefficient heating equipment.

High Efficiency

The high efficiency case is the new efficient heating equipment.

[507] Oppenheim, Jerrold (2005). *MEMO: Heating System Replacements*. Prepared for Bay State Gas Company.
[508] The Cadmus Group (2009). *Impact Evaluation of the 2007 Appliance Management Program and Low Income Weatherization Program*. Prepared for National Grid; Page 5, Table 1.
[509] NSTAR Analysis of Heating System Replacements (2005). Prepared by Art Wilcox, LEAN.
[510] Savings estimated using SMOC-ERS Software.

Hours

Not applicable.

Measure Life

The measure life is 18 years[511] for new furnaces and 20 years[512] for new boilers.

Secondary Energy Impacts

Unit electric savings are deemed based on study results.

Table 28: Electric Savings for Heating System Replacement (Gas)

PA	ΔkWh	ΔkW
All	0	0
National Grid, CLC	194 [513]	0.024 [514]

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Heating System Replacement (Gas)	LI SF Retrofit	All	1.00	1.00	1.00	1.00	1.00	0.03	1.00

In-Service Rates
All installations have 100% in service rate since programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factor.

Realization Rates
Realization rates are set to 100% because savings estimates are based on evaluation and analysis results.

Coincidence Factors
Coincidence factors are only relevant where electric demand savings are claimed. For National Grid, the CFs are developed based on Quantec demand allocation methodology [515]

[511] Environmental Protection Agency (2009). *Life Cycle Cost Estimate for ENERGY STAR Furnace*.
[512] Environmental Protection Agency (2009). *Life Cycle Cost Estimate for ENERGY STAR Qualified Boilers*.
[513] The Cadmus Group (2009). *Impact Evaluation of the 2007 Appliance Management Program and Low Income Weatherization Program*. Prepared for National Grid; Page 5, Table 1.
[514] Estimated using demand allocation methodology described in: Quantec, LLC (2000). *Impact Evaluation: Single-Family EnergyWise Program*. Prepared for National Grid.
[515] Ibid.

HVAC – Thermostats

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: Installation of a 7-day programmable thermostat, which gives the ability to adjust heating or air-conditioning operating times according to a pre-set schedule.
Primary Energy Impact: Natural Gas (Residential Heat)
Secondary Energy Impact: None
Non-Energy Impact: Annual Non-Resource, One-Time Non-Resource
Sector: Residential
Market: Retrofit
End Use: HVAC
Program: Residential Heating and Water Heating, Home Energy Services, Multifamily Retrofit, Low-Income Multifamily Retrofit

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed based on study results:

$$\Delta MMBtu = \Delta MMBtu$$

Where:

Units	=	Number of Programmable T-stats installed
ΔMMBtu	=	Annual MMBtu savings per unit: 7.7 MMBtu[516]

Baseline Efficiency

The baseline efficiency case is an HVAC system using natural gas to provide space heating without a programmable thermostat.

High Efficiency

The high efficiency case is an HVAC system that has a 7-day programmable thermostat installed.

Hours

Not applicable.

[516] RLW Analytics (2007). *Validating the Impact of Programmable Thermostats*. Prepared for GasNetworks; Page 2, conversion factor CCF to Therms is 1.024.

Measure Life

The measure life is 15 years.[517]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Programmable Thermostats	Residential HEHE	All	1.00	1.00	1.00	n/a	n/a	n/a	n/a
Programmable Thermostats	HES	All	1.00	1.00	1.00	n/a	n/a	n/a	n/a
Programmable Thermostats	MF Retrofit	All	1.00	1.00	1.00	n/a	n/a	n/a	n/a
Programmable Thermostats	LI MF Retrofit	All	1.00	1.00	1.00	n/a	n/a	n/a	n/a

In-Service Rates
All installations have 100% in service rate since programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factor.

Realization Rates
All PAs use 100% energy realization rate. The summer and winter peak realization rates are not applicable for this measure since there are no electric savings claimed.

Coincidence Factors
Not applicable for this measure since no electric savings are claimed.

[517] Environmental Protection Agency (2010). *Life Cycle Cost Estimate for ENERGY STAR Programmable Thermostat*.

HVAC – Wi-Fi Thermostats

Version Date and Revision History

Draft Date: 9/14/2011
Effective Date: 1/1/2012
End Date: TBD

Measure Overview

Description: A communicating thermostat which allows remote set point adjustment and control via remote application. System requires an outdoor air temperature algorithm in the control logic to operate heating and cooling systems
Primary Energy Impact: Natural Gas (Residential Heat)
Secondary Energy Impact: Electric
Non-Energy Impact: Annual Non-Resource, One-Time Non-Resource
Sector: Residential
Market: Retrofit
End Use: HVAC
Program: Residential Heating and Water Heating

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed based on study results:

$$\Delta MMBtu = \Delta MMBtu$$

Where:
Units = Number of Wi-Fi T-stats installed
ΔMMBtu = Annual MMBtu savings per unit: 6.6 MMBtu[518]

Baseline Efficiency

The baseline efficiency case is an HVAC system using natural gas to provide space heating without a programmable thermostat.

High Efficiency

The high efficiency case is an HVAC system that has an Wi-Fi thermostat installed.

Hours

Not applicable.

[518] Cadmus Group (2011). Memo: Wi-fi Programmable Thermostat Billing Analysis. Prepared for Keith Miller and Whitney Domigan, National Grid

Measure Life

The measure life is 15 years.[519]

Secondary Energy Impacts

When the thermostat also controls the cooling system the electric savings are 62.6 kWh[520] and 0.174 kW[521].

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Wi-Fi Thermostats (heating only)	Residential HEHE	All	1.00	1.00	1.00	n/a	n/a	n/a	n/a
Wi-Fi Thermostats (heating and cooling)	Residential HEHE	All	1.00	1.00	1.00	1.00	1.00	1.00	0.00

<u>In-Service Rates</u>
All installations have 100% in service rate since programs include verification of equipment installations.

<u>Savings Persistence Factor</u>
All PAs use 100% savings persistence factor.

<u>Realization Rates</u>
Realization rates are set to 100% since deemed savings are based on evaluation results.

<u>Coincidence Factors</u>
Coincidence factors are based on Massachusetts Common Assumptions.

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[519] Assumed to have the same lifetime as a regular programmable thermostat. Environmental Protection Agency (2010). *Life Cycle Cost Estimate for ENERGY STAR Programmable Thermostat*.
[520] Electric savings based on staff analysis with savings assumptions from Cadmus.
[521] Staff estimate. 62.6 kWh/360 hours = 0.174 kW

HVAC – Weatherization

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: Installation of weatherization measures such as air sealing and insulation in gas heated homes. Electric savings are achieved from reduced fan run time.
Primary Energy Impact: Natural Gas (Residential Heat)
Secondary Energy Impact: Electric
Non-Energy Impact: Annual Non-Resource, One-Time Non-Resource
Sector: Low Income
Market: Retrofit
End Use: HVAC
Program: Low-Income Single Family Retrofit

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed based on study results:

$$\Delta MMBtu = \Delta MMBtu$$

Where:
Unit = Household with weatherization measures installed
ΔMMBtu = Average annual MMBtu savings per unit. See Table 29.

Table 29: Savings for Residential Weatherization (Gas)

PA	Savings	ΔMMBtu
National Grid, CLC	137 therms per home[522]	13.7
CMA, Berkshire, NE Gas, NSTAR, Unitil	Custom	Custom

Baseline Efficiency

The baseline efficiency case is the existing home shell.

High Efficiency

The high efficiency case can be a combination of increased insulation, air sealing, duct sealing, and other improvements to the home shell.

[522] The Cadmus Group (2009). *Impact Evaluation of the 2007 Appliance Management Program and Low Income Weatherization Program.* Prepared for National Grid; Page 5, Table 1.

Hours

Not applicable.

Measure Life

The measure lives for weatherization projects may differ depending on the measures implemented. The final measure life of each application is weighted based on the mix of weatherization measures installed. The measure life for each type of weatherization measure is based on statewide measure lives for residential energy efficiency measures[523]. If installation details are not tracked, the measure life is assumed to be 20 years[524].

Secondary Energy Impact

Unit savings are deemed based on study results.

Table 30: Electric Savings for Weatherization (Gas)

PA	ΔkWh	ΔkW
All	0	0
National Grid, CLC	70 [525]	0.01 [526]

Non-Energy Benefits

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Weatherization (Gas)	LI SF Retrofit	All	1.00	1.00	1.00	1.00	1.00	0.03	1.00

In-Service Rates
All installations have 100% in service rate since programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factor.

Realization Rates
Realization rates are set to 100% because savings estimates are based on evaluation and analysis results.

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[523] GDS Associates, Inc. (2007). *Measure Life Report: Residential and Commercial/Industrial Lighting and HVAC Measures*. Prepared for The New England State Program Working Group.
[524] Ibid.
[525] The Cadmus Group (2009). *Impact Evaluation of the 2007 Appliance Management Program and Low Income Weatherization Program*. Prepared for National Grid; Page 5, Table 1.
[526] Estimated using demand allocation methodology described in: Quantec, LLC (2000). *Impact Evaluation: Single-Family EnergyWise Program*. Prepared for National Grid.

Coincidence Factors
Coincidence factors are only relevant where electric demand savings are claimed. For National Grid, the CFs are developed based on Quantec demand allocation methodology [527]

[527] Ibid.

Multifamily – Vendor Measures

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: Retrofit measures installed in multi-family facilities including: building envelope insulation, air sealing, and DHW measures.
Primary Energy Impact: Natural Gas (Residential Heat), Natural Gas (Residential DHW)
Secondary Energy Impact: None
Non-Energy Impact: Annual Non-Resource, One-Time Non-Resource
Sector: Residential
Market: Retrofit
End Use: HVAC
Program: Multifamily Retrofit, Low-Income Multifamily Retrofit

Notes

The PAs, except National Grid, currently use vendor-calculated savings for their Multifamily gas programs. The vendor methodology and other measure characterization for these programs are described in this section. The savings methodology used for National Grid's program is described in the Multifamily measure characterizations following this section.

Algorithms for Calculating Primary Energy Impact

The Program Administrators use vendor calculated savings for measures in the Multifamily gas programs. The vendors who perform the measure implementations calculate estimated savings for each project based on project-specific detail.

Baseline Efficiency

The baseline efficiency case is the existing conditions of the participating facility.

High Efficiency

The high efficiency case includes installed energy efficiency measures that reduce heating energy use.

Hours

Hours are project-specific.

Measure Life

Measure	Measure Life (years)
Air Sealing	15
Insulation	25

Secondary Energy Impacts

There are no secondary energy impacts counted for these measures.

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Air Sealing	MF Retrofit	All	1.00	1.00	1.00	n/a	n/a	n/a	n/a
Insulation	MF Retrofit	All	1.00	1.00	1.00	n/a	n/a	n/a	n/a
Air Sealing	LI MF Retrofit	All	1.00	1.00	1.00	n/a	n/a	n/a	n/a
Insulation	LI MF Retrofit	All	1.00	1.00	1.00	n/a	n/a	n/a	n/a

In-Service Rates
In-service rates are set to 100% based on the assumption that all purchased units are installed.

Savings Persistence Factor
All PAs use 100% savings persistence factors.

Realization Rates
Realization rates are based on Massachusetts Common Assumptions.

Coincidence Factor
Coincidence factors are based on Massachusetts Common Assumptions.

Multifamily – Air Sealing

Version Date and Revision History

Draft Date: 06/30/2011
Effective Date: 1/1/2012
End Date: TBD

Measure Overview

Description: Thermal shell air leaks are sealed through strategic use and location of air-tight materials.
Primary Energy Impact: Natural Gas (Residential Heat)
Secondary Energy Impact: None
Non-Energy Impact: Annual Non-Resource, One-Time Non-Resource
Sector: Residential, Low-Income
Market: Retrofit
End Use: HVAC
Program: *National Grid only:* Multifamily Retrofit, Low-Income Multifamily Retrofit

Algorithms for Calculating Primary Energy Impact

$$\Delta MMBtu = BldgVolume \times (ACH_{PRE} - ACH_{POST}) \times HDD \times 24 \times 0.018 \times \frac{CorrectionFactor}{SeasonalEff} \times \frac{1}{1{,}000{,}000}$$

Where:

$CFM50_{PRE}$	=	CFM50 measurement before air sealing (ft^3/min)
$CFM50_{POST}$	=	CFM50 measurement after air sealing (ft^3/min)
LBL	=	LBL Factor[528]
BldgVolume	=	Total volume of the project building (ft^3)
ACH_{PRE}	=	Air changes per hour measured before air sealing (1/hr)
ACH_{POST}	=	Air changes per hour measured after air sealing (1/hr)
0.018	=	Heat capacity of 1 cubic foot of air at 70 °F (Btu/ft^3-°F)
HDD	=	Heating degree days (°F-day)
24	=	Hours per day (hr/day)
60	=	Minutes per hour (min/hr)
CorrectionFactor	=	Correction factor determined by auditor (e.g. for seasonal homes): Default = 1.
SeasonalEff	=	Heating system efficiency factor determined by auditor: Default = 0.7 for homes heated with natural gas.
1/1,000,000	=	Conversion from Btu to MMBtu

528 The LBL Factor is determined as the product of the N-factor and a Height Correction Factor according to BPI Protocol. The N-factor is assumed to be 18.5 for all installations in New England; the Height Correction Factor is determined based on the number of stories in the facility.

Baseline Efficiency

The baseline efficiency case is the existing building before the air sealing measure is implemented. The baseline building is characterized by the existing CFM50 measurement ($CFM50_{PRE}$) for single family homes, or the existing air changes per hour (ACH_{PRE}) for multi-family facilities, which is measured prior to the implementation of the air sealing measure.

High Efficiency

The baseline efficiency case is the existing building after the air sealing measure is implemented. The high efficiency building is characterized by the new CFM50 measurement for single family homes ($CFM50_{POST}$), or the new air changes per hour (ACH_{POST}) for multi-family facilities, which is measured after the air sealing measure is implemented.

Hours

Heating hours are characterized by the heating degree days for the facility. The heating degree days are looked up based on the nearest weather station to the customer, as selected by the program vendor.

Measure Life

The measure life is 15 years.[529]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
MF SPACE Air Sealing	MF Retrofit	National Grid	1.00	1.00	1.00	n/a	n/a	n/a	n/a
MF SPACE Air Sealing	LI MF Retrofit	National Grid	1.00	1.00	1.00	n/a	n/a	n/a	n/a

In-Service Rates
All installations have 100% in service rate since all PA programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factor.

529 GDS Associates, Inc. (2007). *Measure Life Report: Residential and Commercial/Industrial Lighting and HVAC Measures*. Prepared for The New England State Program Working Group.

Realization Rates
The energy realization rates are 100% based on no evaluations.

Coincidence Factors
There are no electric savings for this measure.

Multifamily – DHW System

Version Date and Revision History

Draft Date: 06/30/2011
Effective Date: 1/1/2012
End Date: TBD

Measure Overview

Description: Installation of high efficiency water heating equipment to replace the existing inefficient water heater.
Primary Energy Impact: Natural Gas (Residential DHW)
Secondary Energy Impact: None
Non-Energy Impact: Annual Non-Resource, One-Time Non-Resource
Sector: Low Income
Market: Retrofit
End Use: DHW
Program: National Grid only: Low-Income Multifamily Retrofit

Algorithms for Calculating Primary Energy Impact

$$\Delta MMBtu = Units \times \frac{18\ MMBtu}{Unit} \times \left(\frac{1}{EF_{BASE}} - \frac{1}{EF_{EE}} \right)$$

Where:

Unit	=	Total number of apartment units utilizing the water heater
18 MMBtu/Unit	=	Average annual water heating energy demand per apartment unit[530]
EF_{BASE}	=	Energy Factor for the baseline water heater
EF_{EE}	=	Energy Factor for the new efficient water heater

Baseline Efficiency

The baseline water heating equipment is assumed to have an Energy Factor = 0.575.

High Efficiency

The high efficiency case includes the new efficient water heater with an Energy Factor > 0.575.

Hours

Not applicable.

[530] GDS Associates, Inc. (2009). *Natural Gas Energy Efficiency Potential in Massachusetts*. Prepared for GasNetworks.

Measure Life

Measure	Measure Life (years)
Indirect Water Heater	20 [531]
Stand-Alone Storage Water Heater	13 [532]
On-Demand Tankless Water Heater	20 [533]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
MF DHW System	LI MF Retrofit	National Grid	1.00	1.00	1.00	n/a	n/a	n/a	n/a

In-Service Rates
All installations have 100% in service rate since all PA programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factor.

Realization Rates
The energy realization rate is 100% based on no evaluations.

Coincidence Factors
There are no electric savings for this measure.

[531] GDS Associates, Inc. (2009). *Natural Gas Energy Efficiency Potential in Massachusetts*. Prepared for GasNetworks.
[532] DOE (2008). *ENERGY STAR® Residential Water Heaters: Final Criteria Analysis*. Prepared for the DOE; Page 10.
[533] Ibid.

Multifamily – DHW Measures

Version Date and Revision History

Draft Date: 06/30/2011
Effective Date: 1/1/2012
End Date: TBD

Measure Overview

Description: DHW measures include equipment installed to reduce consumption of hot water, insulation installed to reduce losses, or other retrofits which save on hot water heating energy.
Primary Energy Impact: Natural Gas (Residential DHW)
Secondary Energy Impact: None
Non-Energy Impact: Residential Water, Annual Non-Resource, One-Time Non-Resource
Sector: Residential, Low Income
Market: Retrofit
End Use: Hot Water
Program: National Grid only: Multifamily Retrofit, Low-Income Multifamily Retrofit

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed based on program vendor assumptions:

$\Delta MMBtu = \Delta MMBtu$

Where:
Units = Total quantity of installed units. Units are defined in Table 31.
ΔMMBtu/Unit = Annual MMBtu savings per unit. See Table 31.

Table 31: Savings for MF DHW Measures

Measure	Unit	ΔMMBtu[534]
Faucet Aerator	Each	0.944
Low-Flow Showerhead	Each	2.020
DHW pipe sleeve or pipewrap	Linear Feet	0.016
Water Heater Tank Wrap (Small < 50 gallons)	Each	2.187
Water Heater Tank Wrap (Large >= 50 gallons)	Each	2.137
DHW TurnDown to 125°F	Each	0.398

Baseline Efficiency

The baseline is the existing multi-family facility without the efficiency measure(s) installed.

High Efficiency

The high efficiency case is the existing multi-family facility with new efficiency measure(s) installed.

[534] Savings assumptions from National Grid program vendor.

Hours

Not applicable.

Measure Life

The measure life for all DHW measures is 7 years.[535]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Resource	Residential water savings for low-flow showerheads [536]	3,696 gallons/unit
Annual Resource	Residential water savings for faucet aerators [537]	332 gallons/unit
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
MF DHW Measures	MF Retrofit	National Grid	1.00	1.00	1.00	n/a	n/a	n/a	n/a
MF DHW Measures	LI MF Retrofit	National Grid	1.00	1.00	1.00	n/a	n/a	n/a	n/a

In-Service Rates
All installations have 100% in service rate since all PA programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factor.

Realization Rates
The energy realization rates are 100% based on no evaluations.

Coincidence Factors
There are no electric savings for this measure.

[535] Massachusetts Common Assumption.
[536] NMR Group and Tetra Tech (2011). *Residential and Low-Income Non-Energy Impacts (NEI) Evaluation* Prepared for MA Program Administrators
[537] Ibid

Multifamily – Duct Systems

Version Date and Revision History

Draft Date: 06/30/2011
Effective Date: 1/1/2012
End Date: TBD

Measure Overview

Description: Ducts are sealed by reconnecting disconnected duct joints and sealing gaps or seams with mastic and fiber-mesh tape as appropriate
Primary Energy Impact: Natural Gas (Residential Heat)
Secondary Energy Impact: None
Non-Energy Impact: Annual Non-Resource
Sector: Residential, Low Income
Market: Retrofit
End Use: HVAC
Program: National Grid only: Multifamily Retrofit, Low-Income Multifamily Retrofit

Algorithms for Calculating Primary Energy Impact

$$\Delta MMBtu = AnnualHeatingConsumption \times \%SAVE \times \frac{1}{1{,}000{,}000}$$

Where:

AnnualHeatingConsumption	=	The total annual heating consumption for the facility (Btu)
%SAVE	=	Average reduction in energy consumption. See Table 32.
1/1,000,000	=	Conversion from Btu to MMBtu

Table 32: Savings Factors for MF Duct Systems

Measure Type	%SAVE[538]
Surface Area < 50 SQFT	7%
Surface Area > 50 SQFT and < 200 SQFT	3%
Surface Area > 200 SQFT	1%

Baseline Efficiency

The baseline efficiency case is the existing facility or equipment prior to the implementation of duct sealing.

High Efficiency

The baseline efficiency case is the existing facility or equipment after the implementation of duct sealing.

[538] Savings assumptions from National Grid program vendor.

Hours

Not applicable.

Measure Life

The measure life is 20 years.[539]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
MF SPACE Duct Sealing	MF Retrofit	1.00	1.00	1.00	n/a	n/a	n/a	n/a
MF SPACE Duct Sealing	LI MF Retrofit	1.00	1.00	1.00	n/a	n/a	n/a	n/a

In-Service Rates
All installations have 100% in service rate since all PA programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factor.

Realization Rates
The energy realization rate is 100% based on no evaluations.

Coincidence Factors
There are no electric savings for this measure.

[539] GDS Associates, Inc. (2007). *Measure Life Report: Residential and Commercial/Industrial Lighting and HVAC Measures*. Prepared for The New England State Program Working Group.

Multifamily – Heating System

Version Date and Revision History

Draft Date: 06/30/2011
Effective Date: 1/1/2012
End Date: TBD

Measure Overview

Description: Installation of high efficiency heating equipment to replace the existing inefficient gas-fired furnace, hydronic boiler, steam boiler or condensing boiler.
Primary Energy Impact: Natural Gas (Residential Heat)
Secondary Energy Impact: None
Non-Energy Impact: Annual Non-Resource, One-Time Non-Resource
Sector: Low Income
Market: Retrofit
End Use: HVAC
Program: National Grid only: Multifamily Retrofit, Low-Income Multifamily Retrofit

Algorithms for Calculating Primary Energy Impact

$$\Delta MMBtu = \frac{Btu}{hr} \times \left(\frac{1}{AFUE_{BASE}} - \frac{1}{AFUE_{EE}} \right) \times EFLH_{Heat} \times \frac{1}{1{,}000{,}000}$$

Where:

Btu/hr	=	Nominal heating capacity of the installed equipment (Btu/hr)
$AFUE_{BASE}$	=	Average fuel utilization efficiency of the existing equipment (%)
$AFUE_{EE}$	=	Average fuel utilization efficiency of the efficient equipment (%)
$EFLH_{Heat}$	=	Equivalent full load heating hours for the facility (Hr)
1/1,000,000	=	Conversion from Btu to MMBtu

Baseline Efficiency

The baseline efficiency is determined based on the type of heating equipment installed and the table of baseline efficiencies ($AFUE_{BASE}$) below.

Table 33: Baseline Efficiencies for MF Heat System Equipment

Equipment Type	$AFUE_{BASE}$ [540]
Boiler	75%
Furnace	78%

High Efficiency

The high efficiency case is characterized by the rated efficiency ($AFUE_{EE}$) of the new high efficiency furnace or boiler.

[540] Federal Register / Vol. 73, No. 145 / Monday, July 28, 2008 / Rules and Regulations Pg. 43613

Hours

The equivalent full load hours are assumed to be 1,418 for all multi-family residential facilities in Massachusetts (see Appendix A Table 21 in 2011 Plan TRM).

Measure Life

Equipment Type	Lifetime (years)
Boiler	20 [541]
Furnace	18 [542]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
MF Heat System	LI MF Retrofit	National Grid	1.00	1.00	1.00	n/a	n/a	n/a	n/a

In-Service Rates
All installations have 100% in service rate since all PA programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factor.

Realization Rates
The energy realization rate is 100% based on no evaluations.

Coincidence Factors
There are no electric savings for this measure.

[541] Environmental Protection Agency (2009). *Life Cycle Cost Estimate for ENERGY STAR Qualified Boilers*.
[542] Environmental Protection Agency (2009). *Life Cycle Cost Estimate for ENERGY STAR Furnace*.

Multifamily – Other Insulation

Version Date and Revision History

Draft Date: 06/30/2011
Effective Date: 1/1/2012
End Date: TBD

Measure Overview

Description: Insulation upgrades applied in existing facilities.
Primary Energy Impact: Natural Gas (Residential Heat)
Secondary Energy Impact: None
Non-Energy Impact: Annual Non-Resource
Sector: Residential, Low-Income
Market: Retrofit
End Use: HVAC
Program: National Grid only: Multifamily Retrofit, Low-Income Multifamily Retrofit

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed based on program vendor assumptions:

$$\Delta MMBtu = \Delta MMBtu$$

Where:
Units = Total quantity of installed units.
ΔMMBtu/Unit = Deemed savings per unit installed.

Table 34: Savings for MF Other Insulation

Measure	Unit	ΔMMBtu[543]
Existing hatches: weatherstrip, insulate, dam perimeter	Each	1.382
Attic staircase cover (Therma-dome)	Each	2.763

Baseline Efficiency

The baseline efficiency case is the existing facility or equipment prior to the implementation of additional insulation.

High Efficiency

The baseline efficiency case is the existing facility or equipment after the implementation of additional insulation.

[543] Savings assumptions from National Grid program vendor.

Hours

Not applicable.

Measure Life

The measure life is 15 years.[544]

Secondary Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Non-Energy Impacts

There are no non-energy impacts for this measure

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
MF SPACE Other Insulation	MF Retrofit	National Grid	1.00	1.00	1.00	n/a	n/a	n/a	n/a
MF SPACE Other Insulation	LI MF Retrofit	National Grid	1.00	1.00	1.00	n/a	n/a	n/a	n/a

In-Service Rates
All installations have 100% in service rate since all PA programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factor.

Realization Rates
The energy realization rates are 100% based on no evaluations.

Coincidence Factors
There are no electric savings for this measure.

[544] GDS Associates, Inc. (2007). *Measure Life Report: Residential and Commercial/Industrial Lighting and HVAC Measures*. Prepared for The New England State Program Working Group.

Multifamily – Pipe Insulation

Version Date and Revision History

Draft Date: 06/30/2011
Effective Date: 1/1/2012
End Date: TBD

Measure Overview

Description: Insulation upgrades to existing heating system pipes.
Primary Energy Impact: Natural Gas (Residential Heat)
Secondary Energy Impact: None
Non-Energy Impact: Annual Non-Resource, One-Time Non-Resource
Sector: Residential, Low Income
Market: Retrofit
End Use: HVAC
Program: National Grid only: Multifamily Retrofit, Low-Income Multifamily Retrofit

Algorithms for Calculating Primary Energy Impact

$$\Delta MMBtu = LF \times MMBtu / LF$$

Where:
LF = Linear feet of installed pipe insulation
MMBtu/LF = Deemed MMBtu savings per linear foot of installed insulation

Table 35: Savings for MF Pipe Insulation

Measure	Unit	MMBtu/LF[545]
Heating System Pipe Insulation	Linear Feet	0.160

Baseline Efficiency

The baseline efficiency case is the existing facility or equipment prior to the implementation of additional insulation.

High Efficiency

The baseline efficiency case is the existing facility or equipment after the implementation of additional insulation.

Hours

Not applicable.

545 Savings assumptions from National Grid program vendor.

Measure Life

The measure life is 15 years.[546]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
MF Pipe Insulation	MF Retrofit	National Grid	1.00	1.00	1.00	n/a	n/a	n/a	n/a
MF Pipe Insulation	LI MF Retrofit	National Grid	1.00	1.00	1.00	n/a	n/a	n/a	n/a

In-Service Rates
All installations have 100% in service rate since all PA programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factor.

Realization Rates
The energy realization rate is 100% based on no evaluations.

Coincidence Factors
There are no electric savings for this measure.

[546] GDS Associates, Inc. (2007). *Measure Life Report: Residential and Commercial/Industrial Lighting and HVAC Measures*. Prepared for The New England State Program Working Group.

Multifamily – Shell Insulation

Version Date and Revision History

Draft Date: 06/30/2011
Effective Date: 1/1/2012
End Date: TBD

Measure Overview

Description: Shell insulation upgrades are applied in existing facilities including improved insulation in attics, basements and sidewalls.
Primary Energy Impact: Natural Gas (Residential Heat)
Secondary Energy Impact: None
Non-Energy Impact: Annual Non-Resource, One-Time Non-Resource
Sector: Residential, Low-Income
Market: Retrofit
End Use: HVAC
Program: National Grid only: Multifamily Retrofit, Low-Income Multifamily Retrofit

Algorithms for Calculating Primary Energy Impact

$$\Delta MMBtu = SQFT \times \left(\frac{1}{R_{BASE}} - \frac{1}{R_{BASE} + R_{ADD}} \right) \times HDD \times 24 \times \frac{CorrectionFactor}{SeasonalEff} \times \frac{1}{1{,}000{,}000}$$

Where:

SQFT	=	Square feet of insulation installed (ft^2)
R_{BASE}	=	Total R-value of the existing attic, basement or sidewall (ft^2-hr-°F/Btu)
R_{ADD}	=	R-value of the added insulation (ft^2-hr-°F/Btu)
HDD	=	Heating degree days (°F-day)
24	=	Hours per day (hr/day)
CorrectionFactor	=	Correction factor determined by auditor (e.g. for seasonal homes): Default = 1.
SeasonalEff	=	Heating system seasonal efficiency factor determined by auditor: Default = 0.7
1/1,000,000	=	Conversion from Btu to MMBtu

Baseline Efficiency

The baseline efficiency case is characterized by the total R-value of the existing attic, basement or sidewall (R_{BASE}). This is calculated as the R-value of the existing insulation, estimated by the program contractor, plus the R-value of the ceiling, floor, or wall (for all projects: $R_{CEILING} = 3.36$; $R_{FLOOR} = 6.16$; $R_{WALL} = 6.65$)[547].

[547] Savings assumptions from National Grid program vendor.

High Efficiency

The high efficiency case is characterized by the total R-value of the attic after the installation of additional attic, basement or sidewall insulation. This is calculated as the sum of the existing R-value (R_{BASE}) plus the R-value of the added insulation (R_{ADD}).

Hours

Heating hours are characterized by the heating degree days for the facility. The heating degree days are looked up based on the nearest weather station to the customer, as selected by the program vendor.

Measure Life

The measure life is 25 years.[548]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
MF SPACE Shell Insulation	MF Retrofit	National Grid	1.00	1.00	1.00	n/a	n/a	n/a	n/a
MF SPACE Shell Insulation	LI MF Retrofit	National Grid	1.00	1.00	1.00	n/a	n/a	n/a	n/a

In-Service Rates
All installations have 100% in service rate since all PA programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factor.

Realization Rates
The energy realization rates are 100% based on no evaluations.

Coincidence Factors
There are no electric savings for this measure.

548 GDS Associates, Inc. (2007). *Measure Life Report: Residential and Commercial/Industrial Lighting and HVAC Measures*. Prepared for The New England State Program Working Group.

Multifamily – Thermostats

Version Date and Revision History

Draft Date: 06/30/2011
Effective Date: 1/1/2012
End Date: TBD

Measure Overview

Description: Installation of programmable thermostats in multi-family facilities.
Primary Energy Impact: Natural Gas (Residential Heat)
Secondary Energy Impact: None
Non-Energy Impact: Annual Non-Resource, One-Time Non-Resource
Sector: Residential, Low-Income
Market: Retrofit
End Use: HVAC
Program: National Grid only: Multifamily Retrofit, Low-Income Multifamily Retrofit

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed based on program vendor assumptions:

$$\Delta MMBtu = AnnualHeatingConsumption \times \%SAVE \times \frac{1}{1{,}000{,}000}$$

Where:

AnnualHeatingConsumption	=	The total annual heating consumption for the facility (Btu)
%SAVE	=	Average reduction in energy consumption. See Table 36.
1/1,000,000	=	Conversion from Btu to MMBtu

Table 36: Savings for MF Thermostats

Equipment Type	%SAVE[549]
Thermostats	3%
Thermostat – Outdoor Reset Control	11%

Baseline Efficiency

The baseline efficiency case is the existing facility without a set back programmable thermostat. The existing facility is characterized by its average annual heating consumption as determined from the customers' billing data.

High Efficiency

The high efficiency case is the existing facility with a programmable thermostat installed.

[549] Savings assumptions from National Grid program vendor.

Hours

Not applicable.

Measure Life

The measure life is 15 years.[550]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
MF SPACE Thermostat	MF Retrofit	National Grid	1.00	1.00	1.00	n/a	n/a	n/a	n/a
MF SPACE Thermostat	LI MF Retrofit	National Grid	1.00	1.00	1.00	n/a	n/a	n/a	n/a

In-Service Rates
All installations have 100% in service rate since all PA programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factor.

Realization Rates
The energy realization rates are 100% based on no evaluations.

Coincidence Factors
Coincidence factors are not used since there are no electric savings counted for this measure.

[550] Environmental Protection Agency (2010). *Life-Cycle Assessment for Thermostats*.

Home Energy Services (Gas Weatherization) – Vendor Measures

Version Date and Revision History

Draft Date: 08/26/2011
Effective Date: 1/1/2012
End Date: TBD

Measure Overview

Description: Retrofit measures installed through the Home Energy Services program including: building envelope insulation, air sealing, and exterior doors.
Primary Energy Impact: Natural Gas (Residential Heat)
Secondary Energy Impact: None
Non-Energy Impact: Annual Non-Resource, One-Time Non-Resource
Sector: Residential
Market: Retrofit
End Use: HVAC
Program: Home Energy Services (Gas Weatherization)

Algorithms for Calculating Primary Energy Impact

The Program Administrators use vendor calculated savings for measures in the Residential Home Energy Services gas program. These savings values are calculated using vendor proprietary software where the user inputs a minimum set of technical data about the house and the software calculates building heating and cooling loads and other key parameters. The proprietary building model is based on thermal transfer, building gains, and a variable-based heating/cooling degree day/hour climate model. This provides an initial estimate of energy use that may be compared with actual billing data to adjust as needed for existing conditions. Then, specific recommendations for improvements are added and savings are calculated using measure-specific heat transfer algorithms.

Rather than using a fixed degree day approach, the building model estimates both heating degree days and cooling degree hours based on the actual characteristics and location of the house to determine the heating and cooling balance point temperatures. Savings from shell measures use standard U-value, area, and degree day algorithms. Infiltration savings use site-specific seasonal N-factors to convert measured leakage to seasonal energy impacts. HVAC savings are estimated based on changes in system and/or distribution efficiency improvements, using ASHRAE 152 as their basis. Interactivity between architectural and mechanical measures is always included, to avoid overestimating savings due to incorrectly "adding" individual measure results.

Baseline Efficiency

The baseline efficiency case is the existing conditions of the participating household.

High Efficiency

The high efficiency case includes installed energy efficiency measures that reduce heating energy use.

Hours

Hours are project-specific.

Measure Life

Measure	Measure Life (years)
Air Sealing	15[551]
Exterior Doors	25[552]
Shell Insulation	25[553]
Thermostats	15 [554]
Duct and Pipe Insulation	15 [555]
Showerheads	7[556]
Aerator	7[557]

Secondary Energy Impacts

There are no secondary energy impacts counted for these measures.

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Air Sealing	HES	All	1.00	1.00	1.00	n/a	n/a	n/a	n/a
Exterior Doors	HES	All	1.00	1.00	1.00	n/a	n/a	n/a	n/a
Insulation	HES	All	1.00	1.00	1.00	n/a	n/a	n/a	n/a

In-Service Rates
In-service rates are set to 100% based on the assumption that all purchased units are installed.

Savings Persistence Factor
All PAs use 100% savings persistence factors.

551 GDS Associates, Inc. (2007). *Measure Life Report: Residential and Commercial/Industrial Lighting and HVAC Measures*. Prepared for The New England State Program Working Group.
552 GDS Associates, Inc. (2009). *Natural Gas Energy Efficiency Potential in Massachusetts*. Prepared for GasNetworks.
553 GDS Associates, Inc. (2007). *Measure Life Report: Residential and Commercial/Industrial Lighting and HVAC Measures*. Prepared for The New England State Program Working Group.
554 Environmental Protection Agency (2010). *Life-Cycle Assessment for Thermostats*.
555 GDS Associates, Inc. (2007). *Measure Life Report: Residential and Commercial/Industrial Lighting and HVAC Measures*. Prepared for The New England State Program Working Group.
556 Massachusetts Common Assumption
557 Ibid.

Realization Rates

Realization rates are based on Massachusetts Common Assumptions.

Coincidence Factor

Coincidence factors are based on Massachusetts Common Assumptions.

ENERGY STAR® Homes – Heating, Cooling, and DHW Measures

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: To capture lost opportunities, encourage the construction of energy-efficient homes, and drive the market to one in which new homes are moving towards net-zero energy.
Primary Energy Impact: Natural Gas (Residential Heat)
Secondary Energy Impact: Electric, Oil, Propane
Non-Energy Impact: None
Sector: Residential, Low-Income
Market: Lost Opportunity
End Use: HVAC, Hot Water
Program: Residential New Construction & Major Renovation

Algorithms for Calculating Primary Energy Impact

As part of the ENERGY STAR® certification process, projected energy use is calculated for each home completed through the program and a geometrically matching baseline home (User Defined Reference Home) using Beacon, an ICF International proprietary DOE-2 based building energy simulation tool. The difference between the projected energy consumption of these two homes represents the energy savings produced by the certified home. This process is used to calculate electric demand as well as electric and fossil fuel energy savings due to heating, cooling, and water heating for all homes, both single family and multifamily. This process is documented in "Energy/Demand Savings Calculation and Reporting Methodology for the Massachusetts ENERGY STAR® Homes Program."[558]

Baseline Efficiency

The User Defined Reference Home was revised for 2006 as a result of the baseline study completed in 2006.[559] [560]

High Efficiency

The high efficiency case is represented by the specific energy characteristics of each "as-built" home completed through the program.

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[558] ICF International (2008). *Energy/Demand Savings Calculation and Reporting Methodology for the Massachusetts ENERGY STAR ® Homes Program*. Prepared for Joint Management Committee.
[559] Nexus Market Research & Dorothy Conant (2006). *Massachusetts ENERGY STAR® Homes: 2005 Baseline Study: Part I: Inspection Data Analysis Final Report*. Prepared for the Massachusetts Joint Management Committee.
[560] Nexus Market Research & Dorothy Conant (2006). *Massachusetts ENERGY STAR® Homes: 2005 Baseline Study: Part II: Homeowner Survey Analysis Incorporating Inspection Data Final Report*. Prepared for the Massachusetts Joint Management Committee.

Hours

Not applicable.

Measure Life

Measure Type	Measure Life (years)[561]
Cooling	25
Heating	25
Water Heating	15

Secondary Energy Impacts

Electric, Oil and Propane savings for heating and water heating measures are custom calculating using the same methodology described for the electric energy and demand savings.

Non-Energy Impacts

Benefit Type	Description	Savings
Annual Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts
One-Time Non-Resource	See Appendix D: Non-Resource Impacts	See Appendix D: Non-Resource Impacts

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
ES Homes – Cooling	RNC, LI RNC	All	1.00	1.00	1.00	1.00	1.00	1.00	0.00
ES Homes – Heating	RNC, LI RNC	All	1.00	1.00	1.00	1.00	1.00	0.00	1.00
ES Homes – Water Heating	RNC, LI RNC	All	1.00	1.00	1.00	1.00	1.00	0.75	1.00

In-Service Rates
All installations have 100% in service rate since all PA programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factors.

Realization Rates
Realization rates are 100% because energy and demand savings are custom calculated based on project specific detail.

Coincidence Factors
Coincidence factors are custom calculated based on project-specific detail.

[561] Massachusetts Common Assumption.

Commercial and Industrial Gas Efficiency Measures

HVAC – Boilers

Version Date and Revision History

Effective Date: 1/1/2011 (revised for 1/1/2012)
End Date: TBD

Measure Overview

Description: The installation of a high efficiency natural gas fired condensing hot water boiler. High-efficiency condensing boilers can take advantage of improved design, sealed combustion and condensing flue gases in a second heat exchanger to achieve improved efficiency.
Primary Energy Impact: Natural Gas
Secondary Energy Impact: None
Non-Energy Impact: None
Sector: Commercial & Industrial
Market: Lost Opportunity
End Use: HVAC
Program: C&I New Construction & Major Renovation

Notes

The PAs decided to screen steam and hydronic boilers as custom measures beginning in PY 2012 so they were removed from the TRM.

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed based on study results:

$$\Delta MMBtu = \Delta MMBtu$$

Where:
Unit = Installed high efficiency boiler
ΔMMBtu = Average annual MMBtu savings per unit. See Table 37 for values.

Table 37: Savings for C&I Boilers

Equipment Type	Size	Efficiency Requirement	ΔMMBtu [562,563]
Condensing Boilers	<= 300 MBH	>= 90% AFUE	22.1
	301-499 MBH	>= 90% Thermal Efficiency	42.3
	500-999 MBH	>= 90% Thermal Efficiency	77.1
	1000-1700 MBH	>= 90% Thermal Efficiency	142.6
	1701+ MBH	>= 90% Thermal Efficiency	249.0
	<= 300 MBH	>= 96% AFUE	25.2

Baseline Efficiency

The baseline efficiency assumes compliance with the efficiency requirements as mandated by Massachusetts State Building Code. The deemed savings methodology for this measure does not require specific baseline data, but the baseline information is provided here for use in the future when this is converted to a deemed calculated measure.

As described in Chapter 13 of the Massachusetts State Building Code, energy efficiency must be met via compliance with the International Energy Conservation Code (IECC) 2009. Table 38 details the specific efficiency requirements by equipment type and capacity.

Table 38: Baseline Efficiency Requirements for C&I Gas-Fired Boilers[564]

Equipment Type	Size Category (Input)	Subcategory or Rating Condition	Minimum Efficiency[a]
Boiler, Gas-Fired	<300,000 Btu/h	Hot Water	80% AFUE
	>=300,000 Btu/h and <=2,500,000 Btu/h	Minimum Capacity[a]	75% E_t and 80% E_c
	>2,500,000 Btu/h	Hot Water	80% E_c

a. Minimum ratings as provided for and allowed by the unit's controls

High Efficiency

The high efficiency scenario assumes a gas-fired boiler that exceeds the efficiency levels required by Massachusetts State Building Code. Actual site efficiencies should be determined on a case-by-case basis.

Hours

Not applicable.

Measure Life

The measure life is 25 years.[565]

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562 Condensing Boilers: KEMA, Inc. (2011). *Prescriptive Condensing Boiler Impact Evaluation, Project 5 Prescriptive Gas*. Prepared for Massachusetts Energy Efficiency Program Administrators.

563 96% AFUE, <=300 MBH Boiler: Based on the formula found in Opinion Dynamics Corporation (2007). *Evaluation Study of KeySpan's Commercial and Industrial High Efficiency Heating Equipment Program*. Prepared for KeySpan Energy Delivery; Page 40, Gas savings = ((AFUEq-AFUEb)/AFUEq) x CAPY in therms/hour x EFLH. Assumed capacity of 165 MBH, 1500 EFLH, baseline of 80% going to 96% AFUE = 41.3 MMBTUs. Applied the average realization rate (0.61) from the 2011 KEMA study.

564 Adapted from 2009 International Energy Conservation Code; Table 503.2.3(5).

565 ASHRAE Applications Handbook (2003); Page 36.3.

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

There are no non-energy impacts for this measure.

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Condensing Boilers	C&I NC	All	1.00	1.00	1.00	n/a	n/a	n/a	n/a

In-Service Rates
All installations have 100% in service rate since programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factor.

Realization Rates
All PAs use 100% energy realization rate. The summer and winter peak realization rates are not applicable for this measure since there are no electric savings claimed.

Coincidence Factors
Not applicable for this measure since no electric savings are claimed.

HVAC – Boiler Reset Controls

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: Boiler Reset Controls are devices that automatically control boiler water temperature based on outdoor or return water temperature using a software program.
Primary Energy Impact: Natural Gas
Secondary Energy Impact: None
Non-Energy Impact: None
Sector: Commercial & Industrial
Market: Retrofit
End Use: HVAC
Program: C&I Retrofit

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed based on study results:

$$\Delta MMBtu = \Delta MMBtu$$

Where:

Unit	=	Installed boiler reset control
ΔMMBtu	=	Average annual MMBtu savings per unit: 35.5 MMBtu[566]

Baseline Efficiency

The baseline efficiency case is a boiler without reset controls.

High Efficiency

The high efficiency case is a boiler with reset controls.

Hours

Not applicable.

Measure Life

The measure life is 15 years.[567]

[566] GDS Associates, Inc. (2009). *Natural Gas Energy Efficiency Potential in Massachusetts*. Prepared for GasNetworks; the GDS Study assumes 710.46 MMBTU base use with 5% savings factor.
[567] ACEEE (2006). *Emerging Technologies Report: Advanced Boiler Controls*. Prepared for ACEEE; Page 2

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

There are no non-energy impacts for this measure.

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Boiler Reset Controls	C&I Retrofit	All	1.00	1.00	1.00	n/a	n/a	n/a	n/a

In-Service Rates
All installations have 100% in service rate since programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factor.

Realization Rates
All PAs use 100% energy realization rate. The summer and winter peak realization rates are not applicable for this measure since there are no electric savings claimed.

Coincidence Factors
Not applicable for this measure since no electric savings are claimed.

HVAC – Combo Water Heater/Boiler

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: This measure promotes the installation of a combined high-efficiency boiler and water heating unit. Combined boiler and water heating systems are more efficient than separate systems because they eliminate the standby heat losses of an additional tank.
Primary Energy Impact: Natural Gas
Secondary Energy Impact: None
Non-Energy Impact: None
Sector: Commercial & Industrial
Market: Lost Opportunity
End Use: HVAC, Hot Water
Program: New Construction & Major Renovation Commercial

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed based on study results:

$$\Delta MMBtu = \Delta MMBtu$$

Where:
Unit = Installed high efficiency boiler/water heater combo units
ΔMMBtu = Average annual MMBtu savings per unit. See Table 39 for values.

Table 39: Savings for C&I Gas-Fired Combo Water Heater/Boilers

Measure	ΔMMBtu[568]
Combo Water Heater/Condensing Boiler (AFUE 90% and EF 0.90)	24.6

Baseline Efficiency

The baseline efficiency case is a standard efficiency gas-fired storage tank hot water heater with a separate standard efficiency boiler for space heating purposes.

High Efficiency

The high efficiency case is a condensing, integrated water heater/boiler with an AFUE of >=90%.

Hours

Not applicable.

[568] GDS Associates, Inc. (2009). *Natural Gas Energy Efficiency Potential in Massachusetts.* Prepared for GasNetworks.

Measure Life

The measure life is 20 years.[569]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

There are no non-energy impacts for this measure.

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Combo Water Heater/Condensing Boiler (AFUE 90% and EF 0.90)	C&I NC	All	1.00	1.00	1.00	n/a	n/a	n/a	n/a

In-Service Rates
All installations have 100% in service rate since programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factor.

Realization Rates
All PAs use 100% energy realization rate. The summer and winter peak realization rates are not applicable for this measure since there are no electric savings claimed.

Coincidence Factors
Not applicable for this measure since no electric savings are claimed.

[569] GDS Associates, Inc. (2009). *Natural Gas Energy Efficiency Potential in Massachusetts.* Prepared for GasNetworks.

HVAC – Condensing Unit Heaters

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: Installation of a condensing gas-fired unit heater for space heating with capacity up to 300 MBH and minimum combustion efficiency of 90%.
Primary Energy Impact: Natural Gas
Secondary Energy Impact: None
Non-Energy Impact: None
Sector: Commercial & Industrial
Market: Lost Opportunity
End Use: HVAC
Program: C&I New Construction & Major Renovation

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed based on study results:

$$\Delta MMBtu = \Delta MMBtu$$

Where:

Unit	=	Installed condensing unit heater
ΔMMBtu	=	Average annual MMBtu savings per unit: 40.9 MMBtu[570]

Baseline Efficiency

The baseline efficiency case is a standard efficiency gas fired unit heater with minimum combustion efficiency of 80%, interrupted or intermittent ignition device (IID), and either power venting or an automatic flue damper.[571]

High Efficiency

The high efficiency case is a condensing gas unit heater with 90% AFUE or greater.

Hours

Not applicable.

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570 NYSERDA Deemed Savings Database (Rev 11); Measure Name: A.UNIT-HEATER-COND.<300000.CI._._.N. The database provides savings of 204.6 MMBtu per million BTU/hr of heater input capacity. Assume average unit size of 200,000 BTU capacity.
571 2009 International Energy Conservation Code

Measure Life

The measure life is 18 years.[572]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

There are no non-energy impacts for this measure.

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Condensing Unit Heaters	C&I NC	All	1.00	1.00	1.00	n/a	n/a	n/a	n/a

In-Service Rates
All installations have 100% in service rate since programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factor.

Realization Rates
All PAs use 100% energy realization rate. The summer and winter peak realization rates are not applicable for this measure since there are no electric savings claimed.

Coincidence Factors
Not applicable for this measure since no electric savings are claimed.

[572] Ecotrope, Inc. (2003). *Natural Gas Efficiency and Conservation Measure Resource Assessment for the Residential and Commercial Sectors*. Prepared for the Energy Trust of Oregon.

HVAC – Furnaces

Version Date and Revision History

Effective Date: 1/1/2011 (revised for 1/1/2012)
End Date: TBD

Measure Overview

Description: The installation of a high efficiency natural gas warm air furnace with an electronically commutated motor (ECM) for the fan. High efficiency furnaces are better at converting fuel into direct heat and better insulated to reduce heat loss. ECM fan motors significantly reduce fan motor electric consumption as compared to both shaped-pole and permanent split capacitor motors.
Primary Energy Impact: Natural Gas
Secondary Energy Impact: Electric
Non-Energy Impact: None
Sector: Commercial & Industrial
Market: Lost Opportunity
End Use: HVAC
Program: C&I New Construction & Major Renovation

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed based on study results:

$$\Delta MMBtu = \Delta MMBtu$$

Where:
Unit = Installed high efficiency furnace.
ΔMMBtu = Average annual MMBtu savings per unit. See Table 40 for values.

Table 40: Savings for C&I Gas-Fired Furnaces

Equipment Type	Efficiency	ΔMMBtu
Furnace (Forced Hot Air) w/ECM	AFUE = 95%	18.0 [573]
	AFUE = 96%	20.7 [574]

Baseline Efficiency

The baseline efficiency assumes compliance with the efficiency requirements as mandated by Massachusetts State Building Code. The deemed savings methodology for this measure does not require specific baseline data, but the baseline information is provided here for use in the future if this is converted to a deemed calculated measure.

[573] GDS Associates, Inc. (2009). *Natural Gas Energy Efficiency Potential in Massachusetts*. Prepared for GasNetworks; value adjusted based on results of: Nexus Market Research and The Cadmus Group (2010). *HEHE Process and Impact Evaluation*. Prepared for GasNetworks...
[574] Ibid.

As described in Chapter 13 of the Massachusetts State Building Code, energy efficiency must be met via compliance with the International Energy Conservation Code (IECC) 2009. Table 41 details the specific efficiency requirements by equipment type and capacity.

Table 41: Baseline Efficiency Requirements for C&I Gas-Fired Furnaces[575]

Equipment Type	Size Category (Input)	Subcategory or Rating Condition	Minimum Efficiency
Warm air furnaces, gas fired	< 225,000 Btu/h	-	78% AFUE or 80% Et[b]
	>= 225,000 Btu/h	Maximum capacity[a]	80% E_t[c]
Warm air duct furnaces, gas fired	All capacities	Maximum capacity[a]	80% E_c

a. Minimum and maximum ratings as provided for and allowed by the unit's controls.
b. Combination units not covered by the National Appliance Energy Conservation Act of 1987 (NAECA) (3-phase power or cooling capacity greater than or equal to 65,000 Btu/h [19 kW]) shall comply with either rating.
c. Units must also include an Intermittent Ignition Device (IID), have jackets not exceeding 0.75 percent of the input rating, and have either power venting or a flue damper. A vent damper is an acceptable alternative to a flue damper for those furnaces where combustion air is drawn from the conditioned space.

High Efficiency

The high efficiency scenario assumes a gas-fired furnace that exceeds the efficiency levels required by Massachusetts State Building Code. Actual site efficiencies should be determined on a case-by-case basis.

Hours

Not applicable.

Measure Life

The measure life is 18 years.[576]

Secondary Energy Impacts

High efficiency furnaces equipped with ECM fan motors also save electricity from reduced fan energy requirements. The reduction of electric use is 168 kWh and 0.124 kW[577].

Non-Energy Impacts

There are no non-energy impacts for this measure.

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Furnace (<150 MBH) AFUE 95% w/ECM	C&I NC	All	1.00	1.00	1.00	1.00	1.00	0.00	0.16
Furnace (<150 MBH) AFUE 96% w/ECM	C&I NC	All	1.00	1.00	1.00	1.00	1.00	0.00	0.16

575 Adapted from 2009 International Energy Conservation Code; Table 503.2.3(4).
576 ASHRAE Applications Handbook (2003); Page 36.3.
577 ERS (2011) Pilot Evaluation of BFM DRAFT. Results as of 9/29/2011

In-Service Rates
All installations have 100% in service rate since programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factor.

Realization Rates
All PAs use 100% energy realization rate.

Coincidence Factors
Not applicable for this measure since no electric savings are claimed.

HVAC – Infrared Heaters

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: The installation of a gas-fired low intensity infrared heating system in place of unit heater, furnace, or other standard efficiency equipment. Infrared heating uses radiant heat as opposed to warm air to heat buildings. In commercial environments with high air exchange rates, heat loss is minimal because the space's heat comes from surfaces rather than air.
Primary Energy Impact: Natural Gas
Secondary Energy Impact: None
Non-Energy Impact: None
Sector: Commercial & Industrial
Market: Lost Opportunity
End Use: HVAC
Program: C&I New Construction & Major Renovation

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed based on study results:

$$\Delta MMBtu = \Delta MMBtu$$

Where:
Unit = Installed infrared heating unit
ΔMMBtu = Average annual MMBtu savings per unit: 74.4 MMBtu[578]

Baseline Efficiency

The baseline efficiency case is a standard efficiency gas-fired unit heater with combustion efficiency of 80%.

High Efficiency

The high efficiency case is a gas-fired low-intensity infrared heating unit.

Hours

Not applicable.

[578] The savings are based on modeled data from 62 low-intensity infrared heaters installed through the Columbia Gas of MA custom commercial and industrial energy efficiency program. See "Infrared Samples - Bay State Gas.xls" for additional project data.

Measure Life

The measure life is 17 years.[579]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

There are no non-energy impacts for this measure.

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Low-Intensity Infrared Heater	C&I NC	All	1.00	1.00	1.00	n/a	n/a	n/a	n/a

In-Service Rates
All installations have 100% in service rate since programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factor.

Realization Rates
All PAs use 100% energy realization rate. The summer and winter peak realization rates are not applicable for this measure since there are no electric savings claimed.

Coincidence Factors
Not applicable for this measure since no electric savings are claimed.

[579] Nexant (2006). *DSM Market Characterization Report*. Prepared for Questar Gas.

HVAC – Thermostats

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: Installation of a 7-day programmable thermostat with the ability to adjust heating or air-conditioning operating times according to a pre-set schedule to meet occupancy needs and minimize redundant HVAC operation.
Primary Energy Impact: Natural Gas
Secondary Energy Impact: None
Non-Energy Impact: None
Sector: Commercial & Industrial
Market: Retrofit
End Use: HVAC
Program: C&I Retrofit, C&I Direct Install

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed based on study results:

$$\Delta MMBtu = \Delta MMBtu$$

Where:

Unit	=	Installed programmable thermostat
ΔMMBtu	=	Average annual MMBtu reduction per unit: 7.7 MMBtu[580]

Baseline Efficiency

The baseline efficiency case is an HVAC system using natural gas to provide space heating without a programmable thermostat.

High Efficiency

The high efficiency case is an HVAC system using natural gas to provide space heating with a 7-day programmable thermostat installed.

Hours

Not applicable.

[580] RLW Analytics (2007). *Validating the Impact of Programmable Thermostats*. Prepared for GasNetworks; Page 2, conversion factor CCF to Therms is 1.024.

Measure Life

The measure life is 15 years.[581]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

There are no non-energy impacts for this measure.

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Thermostats	C&I Retrofit	All	1.00	1.00	1.00	n/a	n/a	n/a	n/a
Thermostats	C&I Direct Install	All	1.00	1.00	1.00	n/a	n/a	n/a	n/a

In-Service Rates
All installations have 100% in service rate since programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factor.

Realization Rates
All PAs use 100% energy realization rate. The summer and winter peak realization rates are not applicable for this measure since there are no electric savings claimed.

Coincidence Factors
Not applicable for this measure since no electric savings are claimed.

[581] Environmental Protection Agency (2010). *Life Cycle Cost Estimate for ENERGY STAR Programmable Thermostat.*

Hot Water – Water Heaters

Version Date and Revision History

Effective Date: 1/1/2011 (revised for 1/1/2012)
End Date: TBD

Measure Overview

Description: Installation of a high-efficiency gas-fired water heater. *Indirect water heaters* use a storage tank that is heated by the main boiler. The energy stored by the water tank allows the boiler to turn off and on less often, saving considerable energy. *Tankless water heaters* circulate water through a heat exchanger to be heated for immediate use, eliminating the standby heat loss associated with a storage tank.
Primary Energy Impact: Natural Gas
Secondary Energy Impact: None
Non-Energy Impact: None
Sector: Commercial & Industrial
Market: Lost Opportunity
End Use: Hot water
Program: C&I New Construction & Major Renovation

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed based on study results:

$$\Delta MMBtu = \Delta MMBtu$$

Where:

Unit	=	Installed condensing stand-alone water heater
ΔMMBtu	=	Average annual MMBtu savings per unit. See Table 42.

Table 42: Savings for C&I Water Heaters

Measure	ΔMMBtu
Condensing Stand-Alone Water Heater (75-300 MBH)	25.0 [582]
Free-Standing Water Heater (EF 0.67)	3.0 [583]
Indirect Water Heater (EF 0.82 and CAE 85%)	30.4 [584]
On-Demand Tankless Water Heater (EF 0.82)	7.1[585]
On-Demand Tankless Water Heater (EF 0.95)	9.59 [586]

Baseline Efficiency

The baseline efficiency case assumes compliance with the efficiency requirements as mandated by Massachusetts State Building Code. As described in Chapter 13 of the State Building Code, energy efficiency must be met via compliance with the International Energy Conservation Code (IECC) 2009. The two documents present nearly identical requirements for gas-fired storage water heaters. The assumed efficiency slightly exceeds the minimum required by code to reflect the typical baseline unit available in the marketplace.

For indirect, on-demand tankless and free-standing water heaters the baseline is a code-compliant gas-fired storage water heater with EF = 0.59. For condensing stand-alone water heaters, the assumed baseline is a stand-alone tank water heater with a thermal efficiency of 80%.[587]

High Efficiency

Condensing Stand-Alone: The high efficiency case is a condensing stand alone commercial water heater with a thermal efficiency of 95% or greater and a capacity between 75,000 Btu and 300,000 Btu.
Free-Standing: The high efficiency case is an ENERGY STAR® gas-fired freestanding hot water heater with an Energy Factor of at least 0.67 and a nominal input of 75,000 BTU/hour.
Indirect: The high efficiency scenario is an indirect water heater with a Combined Appliance Efficiency (CAE) of 85% or greater.
On-Demand Tankless: The high efficiency equipment is a gas-fired instantaneous hot water heater with an Energy Factor of at least 0.82.

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582 GDS Associates, Inc. (2009). *Natural Gas Energy Efficiency Potential in Massachusetts.* Prepared for GasNetworks; Page 2 of Appendix B-2, measure GDS C-WH-3. The GDS study references "ESource (2007). *Gas Fired Water Heater Screening Tool*. http://www.esource.com/BEA/demo/PDF/P_PA_41.pdf. Accessed on 10/22/10; used 0.96 Thermal Efficiency and 250 gallons per day."
583 GDS Associates, Inc. (2009). *Natural Gas Energy Efficiency Potential in Massachusetts.* Prepared for GasNetworks; Appendix B-2.
584 GDS Associates, Inc. (2009). *Natural Gas Energy Efficiency Potential in Massachusetts.* Prepared for GasNetworks; Page 2 of Appendix B-2, measure GDS C-WH-11. The GDS study references "ESource (2007). *Gas Fired Water Heater Screening Tool*. http://www.esource.com/BEA/demo/PDF/P_PA_41.pdf. Accessed on 10/22/10; used 0.96 Thermal Efficiency and 250 gallons per day."
585 GDS Associates, Inc. (2009). *Natural Gas Energy Efficiency Potential in Massachusetts.* Prepared for GasNetworks; Page 2 of Appendix B-2, measure GDS C-WH-5. The GDS study references "FEMP Calculator for Electric & Gas Water Heaters (assumes 64 gal/day) Base use =27.1 MMBTU."
586 GDS Associates, Inc. (2009). *Natural Gas Energy Efficiency Potential in Massachusetts.* Prepared for GasNetworks; Page 2 of Appendix B-2, measure GDS C-WH-7. The GDS study references "FEMP Calculator for Electric & Gas Water Heaters (assumes 64 gal/day) Base use =25.3 MMBTU."
587 Adapted from 2009 International Energy Conservation Code; Table 504.2.

Hours

Not applicable.

Measure Life

The measure lives for water heater vary by type as listed in the table below.

Table 43: Measure Lives for C&I Water Heaters

Equipment Type	Measure Life (years)
Condensing Stand-Alone Water Heater (75-300 MBH)	15 [588]
Free-Standing Water Heater	13 [589]
Indirect Water Heater	15 [590]
On-Demand Tankless Water Heater	20 [591]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

There are no non-energy impacts for this measure.

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Condensing Stand-Alone Water Heater (75-300 MBH)	C&I NC	All	1.00	1.00	1.00	n/a	n/a	n/a	n/a
Free-Standing Water Heater (EF 0.67)	C&I NC	All	1.00	1.00	1.00	n/a	n/a	n/a	n/a
Indirect Water Heater (EF 0.82 and CAE 85%)	C&I NC	All	1.00	1.00	1.00	n/a	n/a	n/a	n/a
On-Demand Tankless Water Heater (EF 0.82)	C&I NC	All	1.00	1.00	1.00	n/a	n/a	n/a	n/a
On-Demand Tankless Water Heater (EF 0.95)	C&I NC	All	1.00	1.00	1.00	n/a	n/a	n/a	n/a

<u>**In-Service Rates**</u>
All installations have 100% in service rate since programs include verification of equipment installations.

<u>**Savings Persistence Factor**</u>
All PAs use 100% savings persistence factor.

<u>**Realization Rates**</u>

[588] GDS Associates, Inc. (2009). *Natural Gas Energy Efficiency Potential in Massachusetts*. Prepared for GasNetworks; Page 2 of Appendix B-2, measure GDS C-WH-4. The GDS study references "ACEEE (2004). *Emerging technologies and practices*; W1 - pg 46."
[589] GDS Associates, Inc. (2009). *Natural Gas Energy Efficiency Potential in Massachusetts*. Prepared for GasNetworks; Appendix A-2.
[590] Ibid.
[591] Hewitt, D. Pratt, J. & Smith, G. (2005). *Tankless Gas Water Heaters: Oregon Market Status*. Prepared for the Energy Trust of Oregon.

All PAs use 100% energy realization rate. The summer and winter peak realization rates are not applicable for this measure since there are no electric savings claimed.

Coincidence Factors
Not applicable for this measure since no electric savings are claimed.

Hot Water – Pre-Rinse Spray Valve

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: Retrofitting existing standard spray nozzles in locations where service water is supplied by natural gas fired hot water heater with new low flow pre-rinse spray nozzles with an average flow rate of 1.6 GPM.
Primary Energy Impact: Natural Gas
Secondary Energy Impact: None
Non-Energy Impact: C&I Water, C&I Sewer
Sector: Commercial, Industrial
Market: Retrofit
End Use: Hot Water
Program: C&I Retrofit, C&I Direct Install

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed based on study results:

$$\Delta MMBtu = \Delta MMBtu$$

Where:
Unit = Installed pre-rinse spray valve
ΔMMBtu = Average annual MMBtu savings per unit: 33.6 MMBtu[592]

Baseline Efficiency

The baseline efficiency case is a standard efficiency spray valve.

High Efficiency

The high efficiency case is a low flow pre-rinse spray valve with an average flow rate of 1.6 GPM.

Hours

Not applicable.

[592] SBW Consulting, Inc. (2004). *Evaluation, Measurement & Verification Report for the CUWCC Pre-Rinse Spray Head Distribution Program.* Prepared for the California Urban Water Conservation Council; Page 20, savings of 0.92 therms per day * 365 days per year = 335.8 therms.

Measure Life

The measure life is 5 years.[593]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

Benefit Type	Description	Savings[594]
C&I Water	C&I water savings	62,305 gallons/unit
C&I Sewer	C&I sewer water savings	62,305 gallons/unit

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Pre-Rinse Spray Valve	C&I Retrofit	All	1.00	1.00	1.00	n/a	n/a	n/a	n/a
Pre-Rinse Spray Valve	C&I Direct Install	All	1.00	1.00	1.00	n/a	n/a	n/a	n/a

In-Service Rates
All installations have 100% in service rate since programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factor.

Realization Rates
All PAs use 100% energy realization rate. The summer and winter peak realization rates are not applicable for this measure since there are no electric savings claimed.

Coincidence Factors
Not applicable for this measure since no electric savings are claimed.

[593] Veritec Consulting (2005). *Region of Waterloo Pre-Rinse Spray Valve Pilot Study, Final Report*; Page 8.
[594] SBW Consulting, Inc. (2004). *Evaluation, Measurement & Verification Report for the CUWCC Pre-Rinse Spray Head Distribution Program.* Prepared for the California Urban Water Conservation Council; Page 18, savings based on assumptions of 2.24 gallons per minute flow rate, 1.27 hours per day, 365 days per year.

Hot Water – Steam Traps

Version Date and Revision History

Effective Date: 1/1/2011 (revised for 1/1/2012)
End Date: TBD

Measure Overview

Description: Repair or replace malfunctioning steam traps.
Primary Energy Impact: Natural Gas
Secondary Energy Impact: None
Non-Energy Impact: None
Sector: Commercial & Industrial
Market: Retrofit
End Use: HVAC
Program: C&I Retrofit

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed based on study results:

$$\Delta MMBtu = \Delta MMBtu$$

Where:

Unit	=	Repaired/replaced steam trap
ΔMMBtu	=	Average annual MMBtu savings per unit: 25.7 MMBtu[595]

Baseline Efficiency

The baseline efficiency case is a failed steam trap.

High Efficiency

The high efficiency case is a repaired or replaced steam trap.

Hours

Not applicable.

[595] National Grid 2008 based on historical steam trap surveys. Steam losses in lbs/hr are found using "Boiler Efficiency Institute (1987). *Steam Efficiency Improvement*.; Page 34, Table 4.1 under Steam Leak Rate Through Holes. Average loss rate for all trap sizes 1/32" to 1/4" for low steam pressures (5 psig and 10 psig) and high pressures (50 psig and 100 psig). Assume trap failure effective for 540 EFLH per year. Determine to equivalent therms per year and factor for frequency encountered = [80% * (78.50 + 111.46)/2] + [20% * (1,108.04 + 1,982.18)/2] = 385.01 BTU/trap-year. Assume that 50% of traps fail in the open position and savings is grossed up by the efficiency of the boiler supplying the steam of (inverse of 75%). Net savings is 257 therms per trap.

Measure Life

The measure life is 3 year.[596]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

There are no non-energy impacts for this measure.

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Steam Traps	All	C&I Retrofit	1.00	1.00	1.00	n/a	n/a	n/a	n/a

In-Service Rates
All installations have 100% in service rate since programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factor.

Realization Rates
All PAs use 100% energy realization rate. The summer and winter peak realization rates are not applicable for this measure since there are no electric savings claimed.

Coincidence Factors
Not applicable for this measure since no electric savings are claimed.

[596] Massachusetts Common Assumption. Most sources suggest a measure life or equipment life of five years. Massachusetts PAs have traditionally taken equipment life and applied a factor to account for measure persistence when determining measure life.

Hot Water – Low-Flow Shower Heads

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: Installation of a low flow showerhead with a flow rate of 1.5 GPM or less in a commercial setting with service water heated by natural gas.
Primary Energy Impact: Natural Gas
Secondary Energy Impact: None
Non-Energy Impact: C&I Water, C&I Sewer
Sector: Commercial
Market: Retrofit
End Use: Hot water
Program: C&I Direct Install, C&I Retrofit

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed based on study results:

$$\Delta MMBtu = \Delta MMBtu$$

Where:

Unit	=	Installed low-flow shower head.
ΔMMBtu	=	Average annual MMBtu savings per unit: 5.2 MMBtu[597]

Baseline Efficiency

The baseline efficiency case is a 2.5 GPM showerhead.

High Efficiency

The high efficiency case is a 1.5 GPM showerhead.

Hours

The savings estimates for this measure are determined empirically in terms of units installed and so the equivalent heating full load hours are not directly used, however, the calculator used to determine the deemed savings uses a default operation of 20 minutes a day, 365 days a year.

[597] GDS Associates, Inc. (2009). *Natural Gas Energy Efficiency Potential in Massachusetts.* Prepared for GasNetworks; Table B-2a, measure C-WH-15.

Measure Life

The measure life is 10 years.[598]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

Benefit Type	Description	Savings[599]
C&I Water	C&I water savings	7,300 gallons/unit
C&I Sewer	C&I sewer water savings	7,300 gallons/unit

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Low-Flow Shower Heads	C&I Direct Install	All	1.00	1.00	1.00	n/a	n/a	n/a	n/a

In-Service Rates
All installations have 100% in service rate since programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factor.

Realization Rates
All PAs use 100% energy realization rate. The summer and winter peak realization rates are not applicable for this measure since there are no electric savings claimed.

Coincidence Factors
Not applicable for this measure since no electric savings are claimed.

[598] GDS Associates, Inc. (2009). *Natural Gas Energy Efficiency Potential in Massachusetts.* Prepared for GasNetworks; Table B-2a, measure C-WH-15.
[599] US DOE-Federal Energy Management Program (FEMP): Energy Cost Calculator for Faucets and Showerheads. Accessed 9/13/2011.

Hot Water – Faucet Aerator

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: Installation of a faucet aerator with a flow rate of 1.5 GPM or less on an existing faucet with high flow in a commercial setting with service water heated by natural gas.
Primary Energy Impact: Natural Gas
Secondary Energy Impact: None
Non-Energy Impact: C&I Water, C&I Sewer
Sector: Commercial
Market: Retrofit
End Use: Hot water
Program: C&I Direct Install, C&I Retrofit

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed based on study results:

$$\Delta MMBtu = \Delta MMBtu$$

Where:

Unit	=	Installed faucet aerator
ΔMMBtu	=	Average annual MMBtu savings per unit: 1.7 MMBtu[600]

Baseline Efficiency

The baseline efficiency case is a 2.2 GPM faucet.

High Efficiency

The high efficiency case is a faucet with 1.5 GPM or less aerator installed.

Hours

The savings estimates for this measure are determined empirically in terms of units installed and so the equivalent heating full load hours are not directly used, however, the calculator used to determine the deemed savings uses a default operation of 30 minutes a day, 260 days a year.

[600] GDS Associates, Inc. (2009). *Natural Gas Energy Efficiency Potential in Massachusetts.* Prepared for GasNetworks; Table B-2a, measure C-WH-16.

Measure Life

The measure life is 10 years.[601]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

Benefit Type	Description	Savings[602]
C&I Water	C&I water savings	5,460 gallons/unit
C&I Sewer	C&I sewer water savings	5,460 gallons/unit

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Faucet Aerator	C&I Direct Install	All	1.00	1.00	1.00	1.00	1.00	n/a	n/a

In-Service Rates
All installations have 100% in service rate since programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factor.

Realization Rates
All PAs use 100% energy realization rate. The summer and winter peak realization rates are not applicable for this measure since there are no electric savings claimed.

Coincidence Factors
Not applicable for this measure since no electric savings are claimed.

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[601] GDS Associates, Inc. (2009). *Natural Gas Energy Efficiency Potential in Massachusetts.* Prepared for GasNetworks; Table B-2a, measure C-WH-16.
[602] US DOE-Federal Energy Management Program (FEMP): Energy Cost Calculator for Faucets and Showerheads. Accessed 9/13/2011.

Food Service – Commercial Ovens

Version Date and Revision History

Effective Date: 1/1/2011 (revised for 1/1/2012)
End Date: TBD

Measure Overview

Description: Installation of High Efficiency Gas Ovens
Primary Energy Impact: Natural Gas
Secondary Energy Impact: None
Non-Energy Impact: Water
Sector: Commercial & Industrial
Market: Lost Opportunity
End Use: Process
Program: C&I New Construction & Major Renovation

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed based on study results:

$$\Delta MMBtu = \Delta MMBtu$$

Where:
Unit = Installed high efficiency gas oven
ΔMMBtu = Average annual MMBtu savings per unit. See Table 44 for values.

Table 44: Baseline and High Efficiency Ratings and Savings for C&I Ovens

Equipment Type	Baseline Efficiency	Efficiency Requirement	ΔMMBtu
Gas-Fired Convection Oven	30%	>= 44%	24.8[603]
Gas-Fired Combination Oven	35%	>= 44%	110.3 [604]
Gas-Fired Conveyer Oven	20% Heavy Load	>= 44%	84.5[605]
Gas-Fired Rack Oven	30%	>= 50%	211.3[606]

Baseline Efficiency

The baseline efficiency case is a standard efficiency oven. See Table 44 for values by oven type.

[603] Consortium for Energy Efficiency (2008). *Technology Opportunity Assessment: Convection Ovens*; Page 5.
[604] Food Service Technology Center (2010). *Gas Combination Oven Life-Cycle Cost Calculator*. http://www.fishnick.com/saveenergy/tools/calculators/gcombicalc.php. Accessed 9/6/11.
[605] Food Service Technology Center (2010). *Gas Conveyor Oven Life-Cycle Cost Calculator*. http://www.fishnick.com/saveenergy/tools/calculators/gconvovencalc.php. Accessed 6/10/10.
[606] Food Service Technology Center (2010). *Gas Conveyor Oven Life-Cycle Cost Calculator*. http://www.fishnick.com/saveenergy/tools/calculators/grackovencalc.php. Accessed 6/10/10.

High Efficiency

High efficiency case is an oven that meets or exceeds the high efficiency ratings per oven type shown in Table 44.

Hours

Not applicable.

Measure Life

The measure life is 12 years for all commercial ovens.[607]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

43,800 Gallons of water[608] for the combination oven

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Gas-Fired Convection Oven (>=40%)	C&I NC	All	1.00	1.00	1.00	n/a	n/a	n/a	n/a
Gas-Fired Combination Oven (>=40%)	C&I NC	All	1.00	1.00	1.00	n/a	n/a	n/a	n/a
Gas-Fired Conveyer Oven (>=40%)	C&I NC	All	1.00	1.00	1.00	n/a	n/a	n/a	n/a
Gas-Fired Rack Oven (>=50%)	C&I NC	All	1.00	1.00	1.00	n/a	n/a	n/a	n/a

In-Service Rates
All installations have 100% in service rate since programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factor.

Realization Rates
All PAs use 100% energy realization rate. The summer and winter peak realization rates are not applicable for this measure since there are no electric savings claimed.

Coincidence Factors
Not applicable for this measure since no electric savings are claimed.

[607] Food Service Technology Center (2010). *Gas Combination Oven Life-Cycle Cost Calculator*. http://www.fishnick.com/saveenergy/tools/calculators/gcombicalc.php. Accessed 6/10/10. AND Food Service Technology Center (2009). *Gas Rack Oven Life-Cycle Cost Calculator*. http://www.fishnick.com/saveenergy/tools/calculators/grackovencalc.php. Accessed on 6/10/10.
[608] Food Service Technology Center (2010). *Gas Combination Oven Life-Cycle Cost Calculator*. http://www.fishnick.com/saveenergy/tools/calculators/gcombicalc.php. Accessed 9/6/11.

Food Service – Commercial Griddle

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: Installation of a gas griddle with an efficiency of 38%.
Primary Energy Impact: Natural Gas
Secondary Energy Impact: None
Non-Energy Impact: None
Sector: Commercial & Industrial
Market: Lost Opportunity
End Use: Process
Program: C&I New Construction & Major Renovation

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed based on study results:

$$\Delta MMBtu = \Delta MMBtu$$

Where:

Unit = Installed high efficiency gas griddle.
ΔMMBtu = Average annual MMBtu savings per unit: 18.5 MMBtu[609]

Baseline Efficiency

The baseline efficiency case is a standard efficiency (30% efficient) gas griddle.

High Efficiency

The high efficiency case is a gas griddle with an efficiency of 38%.

Hours

Not applicable.

Measure Life

The measure life is 12 years.[610]

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[609] Food Service Technology Center (2010). *Gas Griddle Life-Cycle Cost Calculator.* http://www.fishnick.com/saveenergy/tools/calculators/ggridcalc.php. Accessed on 10/22/10.
[610] Ibid.

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

There are no non-energy impacts for this measure.

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Gas-Fired Griddle	C&I NC	All	1.00	1.00	1.00	n/a	n/a	n/a	n/a

In-Service Rates
All installations have 100% in service rate since programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factor.

Realization Rates
All PAs use 100% energy realization rate. The summer and winter peak realization rates are not applicable for this measure since there are no electric savings claimed.

Coincidence Factors
Not applicable for this measure since no electric savings are claimed.

Food Service – Commercial Fryer

Version Date and Revision History

Effective Date: 1/1/2011
End Date: TBD

Measure Overview

Description: The installation of a natural-gas fired fryer that is either ENERGY STAR® rated or has a heavy-load cooking efficiency of at least 50%. Qualified fryers use advanced burner and heat exchanger designs to use fuel more efficiently, as well as increased insulation to reduce standby heat loss.
Primary Energy Impact: Natural Gas
Secondary Energy Impact: None
Non-Energy Impact: None
Sector: Commercial & Industrial
Market: Lost Opportunity
End Use: Process
Program: C&I New Construction & Major Renovation

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed based on the following algorithm and assumptions:

$$\Delta MMBtu = \left[\left(\frac{A_{BASE}}{\eta_{BASE}} + (B_{BASE} \times IDLE_{BASE}) + C_{BASE}\right) - \left(\frac{A_{EE}}{\eta_{EE}} + B_{EE}(IDLE_{EE}) + C_{EE}\right)\right]\left(\frac{365}{1{,}000{,}000}\right)$$

Where:

Unit	=	Installed high efficiency gas commercial fryer
ΔMMBtu	=	gross annual average MMBtu savings per unit: 58.6[611]
A_{BASE}	=	Baseline equipment daily cooking energy (Btu/day). Default = 85,500 Btu.
η_{BASE}	=	Baseline equipment heavy-load cooking efficiency. Default = 35%.
B_{BASE}	=	Baseline equipment daily fryer idle time (hours). Default = 13.25 hrs.
$IDLE_{BASE}$	=	Baseline equipment idle energy rate (Btu/h). Default = 14,000 Btu/h.
C_{BASE}	=	Baseline equipment total daily preheat energy (Btu). Default = 16,000 Btu.
A_{EE}	=	Efficient equipment daily cooking energy (Btu/day). Default = 85,500 Btu.
η_{EE}	=	Efficient equipment heavy-load cooking efficiency. Default = 55%
B_{EE}	=	Efficiency equipment daily fryer idle time (hours). Default 13.44 hrs.
$IDLE_{EE}$	=	Efficient equipment idle energy rate (Btu/h). Default = 8,500 Btu/hr.
C_{EE}	=	Efficient equipment daily total preheat energy (Btu). Default = 15,500 Btu.
365	=	Days per year.
1,000,000	=	Btu per MMBtu.

[611] Environmental Protection Agency (2009). *Life Cycle Cost Estimate for ENERGY STAR Gas Fryer*.

Baseline Efficiency

The baseline efficiency case is a typical low-efficiency gas-fired fryer with 35% cooking efficiency, 16,000 Btu preheat energy, 14,000 Btu/h Idle Energy Rate, 60 lbs/h production capacity[612].

High Efficiency

The high efficiency case cooking efficiency and Idle Energy Rate are site specific and can be determined on a case-by-case basis. To simplify the savings algorithm, typical values for food load (150 lbs/day) and preheat energy (15,500 Btu) are assumed.

Hours

Not applicable.

Measure Life

The measure life is 12 years.[613]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

There are no non-energy impacts for this measure.

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Gas-Fired Commercial Fryer	C&I NC	All	1.00	1.00	1.00	n/a	n/a	n/a	n/a

In-Service Rates
All installations have 100% in service rate since programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factor.

Realization Rates
All PAs use 100% energy realization rate. The summer and winter peak realization rates are not applicable for this measure since there are no electric savings claimed.

Coincidence Factors
Not applicable for this measure since no electric savings are claimed.

[612] Food Service Technology Center (2010). *Gas Fryer Life-Cycle Cost Calculator*. http://www.fishnick.com/saveenergy/tools/calculators/gfryercalc.php. Accessed on 10/19/2010.
[613] Ibid.

Food Service – Commercial Steamer

Version Date and Revision History

Effective Date: 1/1/2011 (Revised for 1/1/2012)
End Date: TBD

Measure Overview

Description: The installation of an ENERGY STAR® rated natural-gas fired steamer, either connectionless or steam-generator design, with heavy-load cooking efficiency of at least 38%. Qualified steamers reduce heat loss due to better insulation, improved heat exchange, and more efficient steam delivery systems.
Primary Energy Impact: Natural Gas
Secondary Energy Impact: None
Non-Energy Impact: Water, Wastewater
Sector: Commercial & Industrial
Market: Lost Opportunity
End Use: Process
Program: C&I New Construction & Major Renovation

Algorithms for Calculating Primary Energy Impact

Unit savings are deemed based on the following algorithm and assumptions:

$$\Delta MMBtu = \Delta MMBtu$$

Where:

Unit	=	Installed high efficiency gas-fired steamer
ΔMMBtu	=	Average annual MMbtu savings per unit: 106.6 MMBtu

Baseline Efficiency

The baseline efficiency case is a typical boiler-based steamer with the following operating parameters: Preheat Energy rate = 72,000 Btu/hour, Idle Energy Rate = 18,000 Btu/hour, Heavy Load Efficiency = 18.0%, Production Capacity = 23.3 lbs/h/pan, Average Water Consumption Rate = 40 gal/h, and Percentage of Time in Constant Steam Mode = 40%.[614]

High Efficiency

The high efficiency case is an ENERGY STAR® qualified gas-fired steamer with the following operating parameters for a 6 pan steamer: Preheat Energy rate= 36,000 Btu/hour, Idle Energy Rate = 12,500 Btu/hour, Heavy Load Efficiency = 38.0%, Production Capacity = 20.0 lbs/h/pan, Average Water Consumption Rate = 3.0 gal/h, and Percentage of Time in Constant Steam Mode = 40%.[615]

[614] Environmental Protection Agency (2011). *Life Cycle Cost Estimate for ENERGY STAR Gas Steamer*. Interactive Excel Spreadsheet found at http://www.energystar.gov/index.cfm?fuseaction=find_a_product.showProductGroup&pgw_code=COF Accessed on 09/21/2011.
[615] Ibid.

Hours

The deemed savings assumes 4,380 annual operating hours (12 hours a day * 365 days/year).[616]

Measure Life

The measure life is 12 years.[617]

Secondary Energy Impacts

There are no secondary energy impacts for this measure.

Non-Energy Impacts

Benefit Type	Description	Savings[618]
C&I Water	C&I Water Savings	162,060 gallons/unit
C&I Wastewater	C&I Wastewater Savings	162,060 gallons/unit

Impact Factors for Calculating Adjusted Gross Savings

Measure Name	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Gas-Fired Steamer	C&I NC	All	1.00	1.00	1.00	1.00	1.00	n/a	n/a

In-Service Rates
All installations have 100% in service rate since programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factor.

Realization Rates
All PAs use 100% energy realization rate. The summer and winter peak realization rates are not applicable for this measure since there are no electric savings claimed.

Coincidence Factors
Not applicable for this measure since no electric savings are claimed.

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616 Ibid
617 Ibid.
618 Ibid.

Custom Measures

Version Date and Revision History

Effective Date: 1/1/2011 (revised for 1/1/2012)
End Date: TBD

Measure Overview

Description: The Custom project track is offered for energy efficiency projects involving complex site-specific applications that require detailed engineering analysis and/or projects which do not qualify for incentives under any of the prescriptive rebate offering. Projects offered through the custom approach must pass a cost-effectiveness test based on project-specific costs and savings.
Primary Energy Impact: Natural Gas (Heating, Water Heating, or All)
Secondary Energy Impact: Project Specific
Non-Energy Impact: Project Specific
Sector: Commercial & Industrial
Market: Lost Opportunity, Retrofit
End Use: All
Program: All

Algorithms for Calculating Primary Energy Impact

Gross energy and demand savings estimates for custom projects are calculated using engineering analysis and project-specific details. Custom analyses typically include a weather dependent load bin analysis, whole building energy model simulation, or other engineering analysis and include estimates of savings, costs, and an evaluation of the project's cost-effectiveness.

Baseline Efficiency

For Lost Opportunity projects, the baseline efficiency case assumes compliance with the efficiency requirements as mandated by Massachusetts State Building Code or industry accepted standard practice.

For retrofit projects, the baseline efficiency case is the same as the existing, or pre-retrofit, case for the facility.

High Efficiency

The high efficiency scenario is specific to the custom project and may include one or more energy efficiency measures. Energy and demand savings calculations are based on projected changes in equipment efficiencies and operating characteristics and are determined on a case-by-case basis. The project must be proven cost-effective in order to qualify for energy efficiency incentives.

Hours

All hours for custom savings analyses should be determined on a case-by-case basis.

Measure Life

For both lost-opportunity and retrofit custom applications, the measure life is determined on a case-by-case basis.

Secondary Energy Impacts

All secondary energy impacts should be determined on a case-by-case basis.

Non-Energy Impacts

All non-energy impacts should be determined on a case-by-case basis.

Impact Factors for Calculating Adjusted Gross Savings

Measure	Program	PA	ISR	SPF	RR_E	RR_{SP}	RR_{WP}	CF_{SP}	CF_{WP}
Custom NC	NC	Statewide	1.00	1.00	0.88	n/a	n/a	n/a	n/a
Custom NC	NC	National Grid	1.00	1.00	0.75	n/a	n/a	n/a	n/a
Custom NC	NC	Columbia Gas	1.00	1.00	1.09	n/a	n/a	n/a	n/a
Custom Retrofit	Retrofit	Statewide	1.00	1.00	0.88	n/a	n/a	n/a	n/a
Custom Retrofit	Retrofit	National Grid	1.00	1.00	0.75	n/a	n/a	n/a	n/a
Custom Retrofit	Retrofit	Columbia Gas	1.00	1.00	1.09	n/a	n/a	n/a	n/a

In-Service Rates
All installations have 100% in service rate since programs include verification of equipment installations.

Savings Persistence Factor
All PAs use 100% savings persistence factor.

Realization Rates
Realization rates are from 2011 impact evaluation of Custom Gas installations[619]. National Grid and Columbia Gas use PA-specific results; all other PAs use the statewide result.

Coincidence Factors
Not applicable for this measure since no electric savings are claimed.

[619] KEMA, Itron and ERS (2011). *Impact Evaluation of 2009 Custom Gas Installations*. Prepared for Massachusetts Energy Efficiency Program Administrators and Massachusetts Energy Efficiency Advisory Council; See Table 4-4 and Table 4-5.

Appendices

Appendix A: Common Lookup Tables

Table 45: Lighting Power Densities Using the Building Area Method ($WATTS_{b,i}$)[620]

Building Area Type	Lighting Power Density (W/ft^2)
Automotive Facility	0.9
Convention Center	1.2
Court House	1.2
Dining: Bar Lounge/Leisure	1.3
Dining: Cafeteria/Fast Food	1.4
Dining: Family	1.6
Dormitory	1.0
Exercise Center	1.0
Gymnasium	1.1
Healthcare-Clinic	1.0
Hospital	1.2
Hotel	1.0
Library	1.3
Manufacturing Facility	1.3
Motel	1.0
Motion Picture Theatre	1.2
Multi-Family	0.7
Museum	1.1
Office	1.0
Parking Garage	0.3
Penitentiary	1.0
Performing Arts Theatre	1.6
Police/Fire Station	1.0
Post Office	1.1
Religious Building	1.3
Retail	1.5
School/University	1.2
Sports Arena	1.1
Town Hall	1.1
Transportation	1.0
Warehouse	0.8
Workshop	1.4

[620] IECC 2009 Lighting Provisions, Section 505 Electrical Power and Lighting Systems, Table 505.5.2 Interior Lighting Power Allowances, Lighting provisions pgs.5-6.

Table 46: Lighting Power Densities Using the Space-by-Space Method ($WATTS_{b,i}$)[621]

Common Space Types	Lighting Power Density (W/ft^2)
Office – Enclosed	1.1
Office - Open Plan	1.1
Conference/Meeting/Multipurpose	1.3
Classroom/Lecture/Training	1.4
For Penitentiary	1.3
Lobby	1.3
For Hotel	1.1
For Performing Arts Theater	3.3
For Motion Picture Theater	1.1
Audience/Seating Area	0.9
For Gymnasium	0.4
For Exercise Center	0.3
For Convention Center	0.7
For Penitentiary	0.7
For Religious Buildings	1.7
For Sports Arena	0.4
For Performing Arts Theater	2.6
For Motion Picture Theater	1.2
For Transportation	0.5
Atrium - First Three Floors	0.6
Atrium - Each Additional Floor	0.2
Lounge/Recreation	1.2
For Hospital	0.8
Dining Area	0.9
For Penitentiary	1.3
For Hotel	1.3
For Motel	1.2
For Bar Lounge/Leisure Dining	1.4
For Family Dining	2.1
Food Preparation	1.2
Laboratory	1.4
Restrooms	0.9
Dressing/Locker/Fitting Room	0.6
Corridor/Transition	0.5
For Hospitals	1.0
For Manufacturing Facilities	0.5
Stairs – Active	0.6
Active Storage	0.8
For Hospital	0.9
Inactive Storage	0.3
For Museum	0.8
Electrical/Mechanical	1.5

[621] ASHRAE 90.1-2007 Energy Standard for Building Except Low-Rise Residential Buildings, Table 9.6.1, pp.63-64.

Common Space Types	**Lighting Power Density (W/ft^2)**
Gymnasium/Exercise Center	
Exercise Area	0.9
Playing Area	1.4
Court House/Police Station/Penitentiary	
Courtroom	1.9
Confinement Cells	0.9
Judges Chambers	1.3
Fire Stations	
Engine Room	0.8
Sleeping Quarters	0.3
Post Office – Sorting Area	1.2
Convention Center - Exhibit Space	1.3
Library	
Card File and Cataloging	1.1
Stacks	1.7
Reading Area	1.2
Hospital	
Emergency	2.7
Recovery	0.8
Nurses' Station	1.0
Exam/Treatment	1.5
Pharmacy	1.2
Patient Room	0.7
Operating Room	2.2
Nursery	0.6
Medical Supply	1.4
Physical Therapy	0.9
Radiology	0.4
Laundry-Washing	0.6
Automobile - Service/Repair	0.7
Manufacturing	
Low Bay (< 25 ft. Floor to Ceiling Height)	1.2
High Bay (≥ 25 ft. Floor to Ceiling Height)	1.7
Detailed Manufacturing	2.1
Equipment Room	1.2
Control Room	0.5
Hotel/Motel Guest Rooms	1.1
Dormitory - Living Quarters	1.1
Museum	
General Exhibition	1.0
Restoration	1.7
Bank/Office - Banking Activity Areas	1.5
Workshop	1.9
Sales Area [for accent lighting, see Section 9.6.2(b)]	1.7
Religious Buildings	
Worship Pulpit, Choir	2.4

Common Space Types	Lighting Power Density (W/ft^2)
Fellowship Hall	0.9
Retail	
Sales Area [for accent lighting, see Section 9.6.3(c)]	1.7
Mall Concourse	1.7
Sports Arena	
Ring Sports Arena	2.7
Court Sports Arena	2.3
Indoor Playing Field Area	1.4
Warehouse	
Fine Material Storage	1.4
Medium/Bulky Material Storage	0.9
Parking Garage - Garage Area	0.2
Transportation	
Airport – Concourse	0.6
Airport/Train/Bus - Baggage Area	1.0
Terminal - Ticket Counter	1.5

Table 47: MassSAVE New Construction Proposed Lighting Wattage Tables

2012 MassSAVE C&I Lighting Rated Wattage Tables developed by Lighting Worksheet Team

Device Code	Device Description	Rated Watts
LED Exit Signs		
1E0002	2.0 WATT LED	2
1E0003	3.0 WATT LED	3
1E0005	5.0 WLED	5
1E0005C	0.5 WATT LEC	0.5
1E0008	8.0 WLED	8
1E0015	1.5 WATT LED	1.5
1E0105	10.5 WATT LED	10.5
Compact Fluorescents (CFL's)		
2C0007S	2/7W COMPACT HW	18
1C0005S	5W COMPACT HW	7
1C0007S	7W COMPACT HW	9
1C0009S	9W COMPACT HW	11
1C0011S	11W COMPACT HW	13
1C0013S	13W COMPACT HW	15
1C0018E	18W COMPACT HW ELIG	20
1C0018S	18W COMPACT HW	20
1C0022S	22W COMPACT HW	24
1C0023E	1/23W COMPACT HW ELIG	25
1C0026E	26W COMPACT HW ELIG	28
1C0026S	26W COMPACT HW	28
1C0028S	28W COMPACT HW	30
1C0032E	32W COMPACT HW ELIG	34
1C0032S	32W CIRCLINE HW	34
1C0042E	1/42W COMPACT HW ELIG	48
1C0044S	44W CIRCLINE HW	46
1C0057E	1/57W COMPACT HW ELIG	65
1C2232S	22/32W CIRCLINE HW	58
1C2D10E	10W 2D COMPACT HW ELIG	12
1C2D16E	16W 2D COMPACT HW ELIG	18
1C2D21E	21W 2D COMPACT HW ELIG	22
1C2D28E	28W 2D COMPACT HW ELIG	28
1C2D38E	38W 2D COMP.HW ELIG	36
1C3240S	32/40W CIRCLINE HW	80
2C0005S	2/5W COMPACT HW	14
2C0009S	2/9W COMPACT HW	22
2C0011S	2/11W COMPACT HW	26
2C0013E	2/13W COMPACT HW ELIG	28
2C0013S	2/13W COMPACT HW	30
2C0018E	2/18W COMP. HW ELIG	40
2C0026E	2/26W COMP. HW ELIG	54
2C0032E	2/32W COMPACT HW ELIG	68
Device	**Device Description**	**Rated**

Code		Watts
Compact Fluorescents (CFL's) (cont)		
2C0042E	2/42W COMPACT HW ELIG	100
3C0009S	3/9W COMPACT HW	33
3C0013S	3/13W COMPACT HW	45
3C0018E	3/18W COMPACT HW ELIG	60
3C0026E	3/26W COMPACT HW ELIG	82
3C0032E	3/32W COMPACT HW ELIG	114
3C0042E	3/42W COMPACT HW ELIG	141
4C0018E	4/18W COMPACT HW ELIG	80
4C0026E	4/26W COMPACT HW ELIG	108
4C0032E	4/32W COMPACT HW ELIG	152
4C0042E	4/42W COMPACT HW ELIG	188
6C0026E	6/26W COMPACT HW ELIG	162
6C0032E	6/32W COMPACT HW ELIG	228
6C0042E	6/42W COMPACT HW ELIG	282
8C0026E	8/26W COMPACT HW ELIG	216
8C0032E	8/32W COMPACT HW ELIG	304
8C0042E	8/42W COMPACT HW ELIG	376
T5 Systems		
1F14SSE	1L2' 14W T5/ELIG	16
2F14SSE	2L2' 14W T5/ELIG	32
3F14SSE	3L2' 14W T5/ELIG	50
4F14SSE	4L2' 14W T5/ELIG	68
1F24HSE	1L2' 24W T5HO/ELIG	29
2F24HSE	2L2' 24W T5HO/ELIG	52
3F24HSE	3L2' 24W T5HO/ELIG	80
1F21SSE	1L3' 21W T5/ELIG	24
2F21SSE	2L3' 21W T5/ELIG	47
1F39HSE	1L3' 39W T5HO/ELIG	42
2F39HSE	2L3' 39W T5HO/ELIG	85
1F28SSE	1L4' 28W T5/ELIG	32
2F28SSE	2L4' 28W T5/ELIG	63
3F28SSE	3L4' 28W T5/ELIG	95
4F28SSE	4L4' 28W T5/ELIG	126
6F28SSE	6L4' 28W T5/ELIG	189
1F47HSE	1L4' 47W T5HO/ELIG	53
2F47HSE	2L4' 47W T5HO/ELIG	103
3F47HSE	3L4' 47W T5HO/ELIG	157
4F47HSE	4L4' 47W T5HO/ELIG	200
5F47HSE	5L4' 47W T5HO/ELIG	260
6F47HSE	6L4' 47W T5HO/ELIG	303
1F50HSE	1L4' 50W T5HO/ELIG	58
2F50HSE	2L4' 50W T5HO/ELIG	110

Device Code	Device Description	Rated Watts
	T5 Systems (cont.)	
3F50HSE	3L4' 50W T5HO/ELIG	168
4F50HSE	4L4' 50W T5HO/ELIG	215
5F50HSE	5L4' 50W T5HO/ELIG	278
6F50HSE	6L4' 50W T5HO/ELIG	325
1F54HSE	1L4' 54W T5HO/ELIG	59
2F54HSE	2L4' 54W T5HO/ELIG	117
3F54HSE	3L4' 54W T5HO/ELIG	177
4F54HSE	4L4' 54W T5HO/ELIG	234
5F54HSE	5L4' 54W T5HO/ELIG	294
6F54HSE	6L4' 54W T5HO/ELIG	351
8F54HSE	8L4' 54W T5HO/ELIG	468
10F54HSE	10L4' 54W T5HO/ELIG	585
Two Foot High Efficient T8 Systems		
1F17ESL	1L2' 17W T8EE/ELEE LOW PWR	14
1F17ESN	1L2' 17W T8EE/ELEE	17
1F17ESH	1L2' 17W T8EE/ELEE HIGH PWR	20
1F28BXE	1L2' F28BX/ELIG	32
2F17ESL	2L2' 17W T8EE/ELEE LOW PWR	27
2F17ESN	2L2' 17W T8EE/ELEE	32
2F17ESH	2L2' 17W T8EE/ELEE HIGH PWR	40
2F28BXE	2L2' F28BX/ELIG	63
3F17ESL	3L2' 17W T8EE/ELEE LOW PWR	39
3F17ESN	3L2' 17W T8EE/ELEE	46
3F17ESH	3L2' 17W T8EE/ELEE HIGH PWR	61
3F28BXE	3L2' F28BX/ELIG	94
Three Foot High Efficient T8 Systems		
1F25ESL	1L3' 25W T8EE/ELEE LOW PWR	21
1F25ESN	1L3' 25W T8EE/ELEE	24
1F25ESH	1L3' 25W T8EE/ELEE HIGH PWR	30
2F25ESL	2L3' 25W T8EE/ELEE LOW PWR	40
2F25ESN	2L3' 25W T8EE/ELEE	45
2F25ESH	2L3' 25W T8EE/ELEE HIGH PWR	60
3F25ESL	3L3' 25W T8EE/ELEE LOW PWR	58
3F25ESN	3L3' 25W T8EE/ELEE	67
3F25ESH	3L3' 25W T8EE/ELEE HIGH PWR	90

Device Code	Device Description	Rated Watts
Four Foot T8 High Efficient / Reduce Wattage Systems		
1F25EEH	1L4' 25W T8EE/ELEE HIGH PWR	30
1F25EEE	1L4' 25W T8EE/ELEE	22
1F25EEL	1L4' 25W T8EE/ELEE LOW PWR	19
2F25EEH	2L4' 25W T8EE/ELEE HIGH PWR	57
2F25EEE	2L4' 25W T8EE/ELEE	43
2F25EEL	2L4' 25W T8EE/ELEE LOW PWR	37
3F25EEH	3L4' 25W T8EE/ELEE HIGH PWR	86
3F25EEE	3L4' 25W T8EE/ELEE	64
3F25EEL	3L4' 25W T8EE/ELEE LOW PWR	57
4F25EEH	4L4' 25W T8EE/ELEE HIGH PWR	111
4F25EEE	4L4' 25W T8EE/ELEE	86
4F25EEL	4L4' 25W T8EE/ELEE LOW PWR	75
1F28EEH	1L4' 28W T8EE/ELEE HIGH PWR	33
1F28EEE	1L4' 28W T8EE/ELEE	24
1F28EEL	1L4' 28W T8EE/ELEE LOW PWR	22
2F28EEH	2L4' 28WT8EE/ELEE HIGH PWR	64
2F28EEE	2L4' 28W T8EE/ELEE	48
2F28EEL	2L4' 28W T8EE/ELEE LOW PWR	42
3F28EEH	3L4' 28W T8EE/ELEE HIGH PWR	96
3F28EEE	3L4' 28W T8EE/ELEE	72
3F28EEL	3L4' 28W T8EE/ELEE LOW PWR	63
4F28EEH	4L4' 28W T8EE/ELEE HIGH PWR	126
4F28EEE	4L4' 28W T8EE/ELEE	94
4F28EEL	4L4' 28W T8EE/ELEE LOW PWR	83
1F30EEH	1L4' 30W T8EE/ELEE HIGH PWR	36
1F30EEE	1L4' 30W T8EE/ELEE	26
1F30EEL	1L4' 30W T8EE/ELEE LOW PWR	24
2F30EEH	2L4' 30WT8EE/ELEE HIGH PWR	69
2F30EEE	2L4' 30W T8EE/ELEE	52
2F30EEL	2L4' 30W T8EE/ELEE LOW PWR	45
3F30EEH	3L4' 30W T8EE/ELEE HIGH PWR	103
3F30EEE	3L4' 30W T8EE/ELEE	77
3F30EEL	3L4' 30W T8EE/ELEE LOW PWR	68

Device Code	Device Description	Rated Watts
Four Foot T8 High Efficient / Reduce Wattage Systems (cont.)		
4F30EEH	4L4' 30W T8EE/ELEE HIGH PWR	133
4F30EEE	4L4' 30W T8EE/ELEE	101
4F30EEL	4L4' 30W T8EE/ELEE LOW PWR	89
1F32EEH	1L4' 32W T8EE/ELEE HIGH PWR	38
1F32EEE	1L4' 32W T8EE/ELEE	28
1F32EEL	1L4' 32W T8EE/ELEE LOW PWR	25
2F32EEH	2L4' 32W T8EE/ELEE HIGH PWR	73
2F32EEE	2L4' 32W T8EE/ELEE	53
2F32EEL	2L4' 32W T8EE/ELEE LOW PWR	47
3F32EEH	3L4' 32W T8EE/ELEE HIGH PWR	109
3F32EEE	3L4' 32W T8EE/ELEE	82
3F32EEL	3L4' 32W T8EE/ELEE LOW PWR	72
4F32EEH	4L4' 32W T8EE/ELEE HIGH PWR	141
4F32EEE	4L4' 32W T8EE/ELEE	107
4F32EEL	4L4' 32W T8EE/ELEE LOW PWR	95
6F32EEH	6L4' 32W T8EE/ELEE HIGH PWR	218
6F32EEE	6L4' 32W T8EE/ELEE	168
6F32EEL	6L4' 32W T8EE/ELEE LOW PWR	146
Eight Foot T8 Systems		
1F59SSE	1L8' T8/ELIG	60
1F80SSE	1L8' T8 HO/ELIG	85
2F59SSE	2L8' T8/ELIG	109
2F59SSL	2L8' T8/ELIG LOW PWR	100
2F80SSE	2L8' T8 HO/ELIG	160
LED Lighting Fixtures		
1L002	2 WATT LED	2
1L003	3 WATT LED	3
1L004	4 WATT LED	04
1L005	5 WATT LED	05
1L006	6 WATT LED	06
1L007	7 WATT LED	07
1L008	8 WATT LED	08
1L009	9 WATT LED	09
1L010	10 WATT LED	10
1L011	11 WATT LED	11
1L012	12 WATT LED	12

Device Code	Device Description	Rated Watts
LED Lighting Fixtures (cont.)		
1L013	13 WATT LED	13
1L014	14 WATT LED	14
1L015	15 WATT LED	15
1L016	16 WATT LED	16
1L017	17 WATT LED	17
1L018	18 WATT LED	18
1L019	19 WATT LED	19
1L020	20 WATT LED	20
1L021	21 WATT LED	21
1L022	22 WATT LED	22
1L023	23 WATT LED	23
1L024	24 WATT LED	24
1L025	25 WATT LED	25
1L026	26 WATT LED	26
1L027	27 WATT LED	27
1L028	28 WATT LED	28
1L029	29 WATT LED	29
1L030	30 WATT LED	30
1L031	31 WATT LED	31
1L032	32 WATT LED	32
1L033	33 WATT LED	33
1L034	34 WATT LED	34
1L035	35 WATT LED	35
1L036	36 WATT LED	36
1L037	37 WATT LED	37
1L038	38 WATT LED	38
1L039	39 WATT LED	39
1L040	40 WATT LED	40
1L041	41 WATT LED	41
1L042	42 WATT LED	42
1L043	43 WATT LED	43
1L044	44 WATT LED	44
1L045	45 WATT LED	45
1L046	46 WATT LED	46
1L047	47 WATT LED	47
1L048	48 WATT LED	48
1L049	49 WATT LED	49
1L050	50 WATT LED	50
1L055	55 WATT LED	55
1L060	60 WATT LED	60
1L070	70 WATT LED	70
1L073	73 WATT LED	73
1L075	75 WATT LED	75
1L080	90 WATT LED	90
1L085	85 WATT LED	85
1L090	90 WATT LED	90

Device Code	Device Description	Device Code
LED Lighting Fixtures (cont.)		
1L095	95 WATT LED	95
1L100	100 WATT LED	100
1L106	106 WATT LED	106
1L107	107 WATT LED	107
1L116	116 WATT LED	116
1L120	120 WATT LED	120
1L125	125 WATT LED	125
1L130	130 WATT LED	130
1L135	135 WATT LED	135
1L140	140 WATT LED	140
1L145	145 WATT LED	145
1L150	150 WATT LED	150
1L155	155 WATT LED	155
1L160	160 WATT LED	160
1L165	165 WATT LED	165
1L170	170 WATT LED	170
1L175	175 WATT LED	175
1L180	180 WATT LED	180
1L185	185 WATT LED	185
1L190	190 WATT LED	190
1L200	200 WATT LED	200

Device Code	Device Description	Device Code
LED Lighting Fixtures (cont.)		
1L210	210 WATT LED	210
1L220	220 WATT LED	220
1L240	240 WATT LED	240
Electronic Metal Halide Lamps		
1M0150E	150W METAL HALIDE EB	160
1M0200E	200W METAL HALIDE EB	215
1M0250E	250W METAL HALIDE EB	270
1M0320E	320W METAL HALIDE EB	345
1M0350E	350W METAL HALIDE EB	375
1M0400E	400W METAL HALIDE EB	430
1M0450E	400W METAL HALIDE EB	480
MH Track Lighting		
1M0020E	20W MH SPOT	25
1M0025E	25W MH SPOT	25
1M0035E	35W MH SPOT	44
1M0039E	39W MH SPOT	47
1M0050E	50W MH SPOT	60
1M0070E	70W MH SPOT	80
1M0100E	100W MH SPOT	111
1M0150E	150W MH SPOT	162

Table 48: MassSAVE Retrofit Existing Lighting Wattage Tables

2012 MassSAVE C&I Lighting Rated Wattage Tables developed by Lighting Worksheet Team

Device Code	Device Description	Rated Watts
Incandescent Lamps		
1I0015	15W INC	15
1I0020	20W INC	20
1I0025	25W INC	25
1I0034	34W INC	34
1I0036	36W INC	36
1I0040	40W INC	40
1I0042	42W INC	42
1I0045	45W INC	45
1I0050	50W INC	50
1I0052	52W INC	52
1I0054	54W INC	54
1I0055	55W INC	55
1I0060	60W INC	60
1I0065	65W INC	65
1I0067	67W INC	67
1I0069	69W INC	69
1I0072	72W INC	72
1I0075	75W INC	75
1I0080	80W INC	80
1I0085	85W INC	85
1I0090	90W INC	90
1I0093	93W INC	93
1I0100	100W INC	100
1I0120	120W INC	120
1I0125	125W INC	125
1I0135	135W INC	135
1I0150	150W INC	150
1I0200	200W INC	200
1I0300	300W INC	300
1I0448	448W INC	448
1I0500	500W INC	500
1I0750	750W INC	750
1I1000	1000W INC	1000
1I1500	1500W INC	1500
Low Voltage Halogen Fixture (includes Transformer)		
1R0020	20W LV HALOGEN FIXT	30
1R0025	25W LV HALOGEN FIXT	35
1R0035	35W LV HALOGEN FIXT	45
1R0042	42W LV HALOGEN FIXT	52
1R0050	50W LV HALOGEN FIXT	60
1R0065	65W LV HALOGEN FIXT	75

Device Code	Device Description	Rated Watts
Low Voltage Halogen Fixture (includes Transformer) (cont.)		
1R0075	75W LV HALOGEN FIXT	85
Halogen/Quartz Lamps		
1T0035	35W HALOGEN LAMP	35
1T0040	40W HALOGEN LAMP	40
1T0042	42W HALOGEN LAMP	42
1T0045	45W HALOGEN LAMP	45
1T0047	47W HALOGEN LAMP	47
1T0050	50W HALOGEN LAMP	50
1T0052	52W HALOGEN LAMP	52
1T0055	55W HALOGEN LAMP	55
1T0060	60W HALOGEN LAMP	60
1T0072	72W HALOGEN LAMP	72
1T0075	75W HALOGEN LAMP	75
1T0090	90W HALOGEN LAMP	90
1T0100	100W HALOGEN LAMP	100
1T0150	150W HALOGEN LAMP	150
1T0200	200W HALOGEN LAMP	200
1T0250	250W HALOGEN LAMP	250
1T0300	300W HALOGEN LAMP	300
1T0350	350W HALOGEN LAMP	350
1T0400	400W HALOGEN LAMP	400
1T0425	425W HALOGEN LAMP	425
1T0500	500W HALOGEN LAMP	500
1T0750	750W HALOGEN LAMP	750
1T0900	900W HALOGEN LAMP	900
1T1000	1000W HALOGEN LAMP	1000
1T1200	1200W HALOGEN LAMP	1200
1T1500	1500W HALOGEN LAMP	1500
Mercury Vapor (MV)		
1V0040S	40W MERCURY	50
1V0050S	50W MERCURY	75
1V0075S	75W MERCURY	95
1V0100S	100W MERCURY	120
1V0175S	175W MERCURY	205
1V0250S	250W MERCURY	290
1V0400S	400W MERCURY	455
1V0700S	700W MERCURY	775
1V1000S	1000W MERCURY	1075
2V0400S	2/400W MERCURY	880

Device Code	Device Description	Rated Watts
Low Pressure Sodium (LPS)		
1L0035S	35W LPS	60
1L0055S	55W LPS	85
1L0090S	90W LPS	130
1L0135S	135W LPS	180
1L0180S	180W LPS	230
High Pressure Sodium (HPS)		
1H0035S	35W HPS	45
1H0050S	50W HPS	65
1H0070S	70W HPS	90
1H0100S	100W HPS	130
1H0150S	150W HPS	190
1H0200S	200W HPS	240
1H0225S	225W HPS	275
1H0250S	250W HPS	295
1H0310S	310W HPS	350
1H0360S	360W HPS	435
1H0400S	400W HPS	460
1H0600S	600W HPS	675
1H0750S	750W HPS	835
1H1000S	1000W HPS	1085
Metal Halide (MH)		
1M0032S	32W METAL HALIDE	40
1M0050S	50W METAL HALIDE	65
1M0070S	70W METAL HALIDE	95
1M0100S	100W METAL HALIDE	120
1M0150S	150W METAL HALIDE	190
1M0175S	175W METAL HALIDE	205
1M0250S	250W METAL HALIDE	295
1M0360S	360W METAL HALIDE	430
1M0400S	400W METAL HALIDE	455
1M0750S	750W METAL HALIDE	825
1M1000S	1000W METAL HALIDE	1075
1M1500S	1500W METAL HALIDE	1615
1M1800S	1800W METAL HALIDE	1875
Pulse Start Metal Halide Lamp/Ballast		
1M0100P	100W MH CWA	128
1M0100R	100W MH LINEAR	118
1M0150P	150W MH CWA	190
1M0150R	150W MH LINEAR	172
1M0175P	175W MH CWA	208
1M0175R	175W MH LINEAR	190
1M0200P	200W MH CWA	232

Device Code	Device Description	Rated Watts
Pulse Start Metal Halide Lamp/Ballast (cont.)		
1M0200R	200W MH LINEAR	218
1M0250P	250W MH CWA	288
1M0250R	250W MH LINEAR	265
1M0300P	300W MH CWA	342
1M0300R	300W MH LINEAR	324
1M0320P	320W MH CWA	365
1M0320R	320W MH LINEAR	345
1M0350P	350W MH CWA	400
1M0350R	350W MH LINEAR	375
1M0400P	400W MH CWA	455
1M0400R	400W MH LINEAR	430
1M0450P	450W MH CWA	508
1M0450R	450W MH LINEAR	480
1M0750P	750W MH CWA	815
1M0750R	750W MH LINEAR	805
1M0875P	875W MH CWA	950
1M0875R	875W MH LINEAR	927
1M1000P	1000W MH CWA	1080
Two Foot T8 / T12 Systems		
1F20SSS	F20T12/HPF(1)	32
1F80BXE	1L2' F80BXE/ELIG	90
1F55BXE	1L2' F55BX/ELIG	56
2F17SSE	2L2' 17W T8/ELIG	37
2F17SSL	2L2' 17W T8/ELIG LOW POWER	27
2F17SSM	2L2' 17W T8/EEMAG	45
2F20SSS	F20T12/HPF(2)	56
2F24HSS	2L2' 24 T12HO/STD/STD	85
2F40BXE	2L2' F40BX/ELIG	72
2F50BXE	2L2' F50BX/ELIG	108
2F55BXE	2L2'55BXE/ELIG	112
3F17SSE	3L2' 17W T8/ELIG	53
3F17SSL	3L2' 17W T8/ELIG LOW POWER	39
3F20SSS	F20T12/HPF(3)	78
3F40BXE	3L2' F40BX/ELIG	102
3F50BXE	3L2' F50BX/ELIG	162
3F55BXE	3L2' F55BX/ELIG	168
4F17SSE	4L2' 17W T8/ELIG	62
4F36BXE	4L2' F36BX/ELIG	148
4F40BXE	4L2' F40BX/ELIG	144
4F40BXH	4L 40W T5 (Std.) HIGH LMN	170
4F50BXE	4L2' F50BX/ELIG	216
4F55BXE	4L2' F55BX/ELIG	224
5F40BXE	5L2' F40BX/ELIG	190

Device Code	Device Description	Rated Watts
Two Foot T8 / T12 Systems (cont.)		
5F50BXE	5L2' F50BX/ELIG	270
5F55BXE	5L2' F55BX/ELIG	280
6F36BXE	6L2' F36BX/ELIG	212
6F40BXE	6L2' F40BX/ELIG	204
6F50BXE	6L2' F50BX/ELIG	324
6F55BXE	6L2' F55BX/ELIG	336
8F36BXE	8L2' F36BX/ELIG	296
8F40BXE	8L2' F40BX/ELIG	288
8F50BXE	8L2' F50BX/ELIG	432
8F55BXE	8L2' F55BX/ELIG	448
9F36BXE	9L2' F36BX/ELIG	318
9F40BXE	9L2' F40BX/ELIG	306
9F50BXE	9L2' F50BX/ELIG	486
9F55BXE	9L2' F55BX/ELIG	504
12F40BE	12L2' F40BX/ELIG	408
12F50BE	12L2' F50BX/ELIG	648
12F55BE	12L2' F55BX/ELIG	672
Three Foot T8 / T12 Systems		
1F30SEM	1L3' 30W T12 EE/EEMAG	38
1F30SES	1L3' 30W T12 EE/STD	42
1F30SSS	1L3' 30W T12 STD/STD	46
1F25SSE	1L3' 25W T8/ELIG	24
1F25SSH	1L3' 25W T8/ELIG HIGH LMN	28
2F30SEE	2L3' 30W T12 EE/ELIG	49
2F30SEM	2L3' 30W T12 EE/EEMAG	66
2F30SES	2L3' 30W T12 EE/STD	73
2F30SSS	2L3' 30W T12 STD/STD	80
2F25SSE	2L3' 25W T8/ELIG	47
2F25SSM	2L3' 25W T8/EEMAG	65
3F30SSS	3L3' 30W T12 STD/STD	140
3F30SES	3L3' 30W T12 EE/STD	127
3F25SSE	3L3’ 25W T8/ELIG	68
4F25SSE	4L3' 25W T8/ELIG	88
Four Foot F48 T8 Systems		
1F48SES	1L4' F48T12EE/STD	50
1F48SSS	1L4' F48T12/STD	60
2F48SES	2L4' F48T12EE/STD	82
2F48SSS	2L4' F48T12/STD	102
3F48SES	3L4' F48T12EE/STD	132
3F48SSS	3L4' F48T12/STD	162
4F48SES	4L4' F48T12EE/STD	164
4F48SSS	4L4' F48T12/STD	204

Device Code	Device Description	Rated Watts
Four Foot F48HO T8 Systems		
1F48HES	1L4' F48HO/EE/STD	80
1F48HSS	1L4' F48H0/STD/STD	85
2F48HES	2L4' F48HO/EE/STD	135
2F48HSS	2L4' F48H0/STD/STD	145
3F48HES	3L4' F48HO/EE/STD	215
3F48HSS	3L4' F48H0/STD/STD	230
4F48HES	4L4' F48HO/EE/STD	270
4F48HSS	4L4' F48H0/STD/STD	290
Four Foot F48VHO T12 Systems		
1F48VES	1L4' F48VHO/EE/STD	123
1F48VSS	1L4' F48VHO/STD/STD	138
2F48VES	2L4' F48VHO/EE/STD	210
2F48VSS	2L4' F48VHO/STD/STD	240
3F48VES	3L4' F48VHO/EE/STD	333
3F48VSS	3L4' F48VHO/STD/STD	378
4F48VES	4L4' F48VHO/EE/STD	420
4F48VSS	4L4' F48VHO/STD/STD	480
Four Foot T12 Systems		
1F40SEE	1L4' EE/ELIG	38
1F40SEM	1L4' EE/EEMAG	40
1F40SES	1L4' EE/STD	50
1F40SSE	1L4' STD/ELIG	46
1F40SSM	1L4' STD/EEMAG	50
1F40SSS	1L4' STD/STD	57
1F40HSE	1L4' HO/STD/ELIG	59
2F40SEE	2L4' EE/ELIG	60
2F40SEM	2L4' EE/EEMAG	70
2F40SES	2L4' EE/STD	80
2F40SSE	2L4' STD/ELIG	72
2F40SSM	2L4' STD/EEMAG	86
2F40SSS	2L4' STD/STD	94
3F40SEE	3L4' EE/ELIG	90
3F40SEM	3L4' EE/EEMAG	110
3F40SES	3L4' EE/STD	130
3F40SSE	3L4' STD/ELIG	110
3F40SSM	3L4' STD/EEMAG	136
3F40SSS	3L4' STD/STD	151
4F40SEE	4L4' EE/ELIG	120
4F40SEM	4L4' EE/EEMAG	140
4F40SES	4L4' EE/STD	160
4F40SSE	4L4' STD/ELIG	144
4F40SSM	4L4' STD/EEMAG	172
4F40SSS	4L4' STD/STD	188

Device Code	Device Description	Rated Watts
Four Foot T12 Systems (cont.)		
6F40SSS	6L4' STD/STD	282
Four Foot T8 Systems		
1F32SSE	1L4' T8/ELIG	30
1F32SSL	1L4’ T8/ELIG LOW POWER	26
1F32SSM	1L4' T8/EEMAG	37
1F32SSH	1L4’ T8/ELIG HIGH LMN	36
2F32SSE	2L4' T8/ELIG	60
2F32SSH	2L4' T8/ELIG HIGH LMN	78
2F32SSL	2L4’ T8/ELIG LOW PWR	52
2F32SSM	2L4' T8/EEMAG	70
3F32SSE	3L4' T8/ELIG	88
3F32SSH	3L4' T8/ELIG HIGH LMN	112
3F32SSL	3L4’ T8/ELIG LOW POWER	76
3F32SSM	3L4' T8/EEMAG	107
4F32SSE	4L4' T8/ELIG	112
4F32SSH	4L4' T8/ELIG HIGH LMN	156
4F32SSL	4L4’ T8/ELIG LOW PWR	98
4F32SSM	4L4' T8/EEMAG	140
5F32SSE	5L4' T8/ELIG	148
5F32SSH	5L4' T8/ELIG HIGH LMN	190
6F32SSE	6L4' T8/ELIG	174
8F32SSH	8L4' T8/ELIG HIGH LMN	312
Five Foot T8 / T12 Systems		
1F60HSM	1L5' HO/STD/EEMAG	90
1F60HSE	1L5' HO/STD/ELIG	70
1F60SSM	1L5’/STD/EEMAG	73
1F60TSM	1L5’ T10HO/STD/EEMAG	135
2F40HSE	2L5' HO/STD/ELIG	123
2F40TSE	2L5'T8/ELIG	68
2F60HSM	2L5' HO/STD/EEMAG	178
2F60SSM	2L5’/STD/EEMAG	122
3F40TSE	3L5'T8/ELIG	106
Six Foot T12 & T12HO Systems		
1F72HSE	1L6’ T8HO/ELIG	80
1F72HSS	1L6' F72HO/STD/STD	113
1F72SSM	1L6' STD/EEMAG	80
1F72SSS	1L6' STD/STD	95
2F72HSE	2L6'T8 HO/ELIG	160
2F72HSM	2L6' F72HO/STD/EEMAG	193
2F72HSS	2L6' F72HO/STD	195
2F72SSM	2L6' STD/EEMAG	135
2F72SSS	2L6' STD/STD	173

Device Code	Device Description	Rated Watts
Eight Foot T12HO Systems		
1F96HES	1L8' HO/EE/STD	125
1F96HSS	1L8' HO/STD/STD	135
2F96HEE	2L8' HO/EE/ELIG	170
2F96HEM	2L8' HO/EE/EEMAG	207
2F96HES	2L8' HO/EE/STD	227
2F96HSE	2L8' HO/STD/ELIG	195
2F96HSM	2L8' HO/STD/EEMAG	237
2F96HSS	2L8' HO/STD/STD	257
3F96HES	3L8' HO/EE/STD	352
3F96HSS	3L8' HO/STD/STD	392
4F96HEE	4L8' HO/EE/ELIG	340
4F96HEM	4L8' HO/EE/EEMAG	414
4F96HES	4L8' HO/EE/STD	454
4F96HSE	4L8' HO/STD/ELIG	390
4F96HSM	4L8' HO/STD/EEMAG	474
4F96HSS	4L8' HO/STD/STD	514
Eight Foot T12VHO Systems		
1F96VES	1L8' VHO/EE/STD	200
1F96VSS	1L8' VHO/STD/STD	230
2F96VES	2L8' VHO/EE/STD	390
2F96VSS	2L8' VHO/STD/STD	450
3F96VES	3L8' VHO/EE/STD	590
3F96VSS	3L8' VHO/STD/STD	680
4F96VES	4L8' VHO/EE/STD	780
4F96VSS	4L8' VHO/STD/STD	900
Eight Foot T8 Systems		
1F59SSE	1L8' T8/ELIG	60
1F80SSE	1L8' T8 HO/ELIG	85
2F59SSE	2L8' T8/ELIG	109
2F59SSL	2L8' T8/ELIG LOW PWR	100
2F80SSE	2L8' T8 HO/ELIG	160
Eight Foot T12 Systems		
1F96SEE	1L8' EE/ELIG	60
1F96SES	1L8' EE/STD	83
1F96SSE	1L8' STD/ELIG	70
1F96SSS	1L8' STD/STD	100
2F96SEE	2L8' EE/ELIG	109
2F96SEM	2L8' EE/EEMAG	123
2F96SES	2L8' EE/STD	138
2F96SSE	2L8' STD/ELIG	134
2F96SSM	2L8' STD/EEMAG	158
2F96SSS	2L8' STD/STD	173
3F96SES	3L8' EE/STD	221

Device Code	Device Description	Rated Watts
Eight Foot T12 Systems (cont.)		
3F96SSS	3L8' STD/STD	273
4F96SEE	4L8' EE/ELIG	218
4F96SEM	4L8' EE/EEMAG	246

Device Code	Device Description	Rated Watts
Eight Foot T12 Systems (cont.)		
4F96SES	4L8' EE/STD	276
4F96SSE	4L8' STD/ELIG	268
4F96SSM	4L8' STD/EEMAG	316
4F96SSS	4L8' STD/STD	346

Table 49: MassSAVE Retrofit Proposed Lighting Wattage Tables

2012 MassSAVE C&I Lighting Rated Wattage Tables developed by Lighting Worksheet Team

Device Code	Device Description	Rated Watts
LED Exit Signs		
1E0002	2.0 WATT LED	2
1E0003	3.0 WATT LED	3
1E0005	5.0 WLED	5
1E0005C	0.5 WATT LEC	0.5
1E0008	8.0 WLED	8
1E0015	1.5 WATT LED	1.5
1E0105	10.5 WATT LED	10.5
Compact Fluorescents (CFL's)		
2C0007S	2/7W COMPACT HW	18
1C0005S	5W COMPACT HW	7
1C0007S	7W COMPACT HW	9
1C0009S	9W COMPACT HW	11
1C0011S	11W COMPACT HW	13
1C0013S	13W COMPACT HW	15
1C0018E	18W COMPACT HW ELIG	20
1C0018S	18W COMPACT HW	20
1C0022S	22W COMPACT HW	24
1C0023E	1/23W COMPACT HW ELIG	25
1C0026E	26W COMPACT HW ELIG	28
1C0026S	26W COMPACT HW	28
1C0028S	28W COMPACT HW	30
1C0032E	32W COMPACT HW ELIG	34
1C0032S	32W CIRCLINE HW	34
1C0042E	1/42W COMPACT HW ELIG	48
1C0044S	44W CIRCLINE HW	46
1C0057E	1/57W COMPACT HW ELIG	65
1C2232S	22/32W CIRCLINE HW	58
1C2D10E	10W 2D COMPACT HW ELIG	12
1C2D16E	16W 2D COMPACT HW ELIG	18
1C2D21E	21W 2D COMPACT HW ELIG	22
1C2D28E	28W 2D COMPACT HW ELIG	28
1C2D38E	38W 2D COMP.HW ELIG	36
1C3240S	32/40W CIRCLINE HW	80
2C0005S	2/5W COMPACT HW	14
2C0009S	2/9W COMPACT HW	22
2C0011S	2/11W COMPACT HW	26
2C0013E	2/13W COMPACT HW ELIG	28
2C0013S	2/13W COMPACT HW	30
2C0018E	2/18W COMP. HW ELIG	40
2C0026E	2/26W COMP. HW ELIG	54
2C0032E	2/32W COMPACT HW ELIG	68

Device Code	Device Description	Rated Watts
Compact Fluorescents (CFL's) (cont.)		
2C0042E	2/42W COMPACT HW ELIG	100
3C0009S	3/9W COMPACT HW	33
3C0013S	3/13W COMPACT HW	45
3C0018E	3/18W COMPACT HW ELIG	60
3C0026E	3/26W COMPACT HW ELIG	82
3C0032E	3/32W COMPACT HW ELIG	114
3C0042E	3/42W COMPACT HW ELIG	141
4C0018E	4/18W COMPACT HW ELIG	80
4C0026E	4/26W COMPACT HW ELIG	108
4C0032E	4/32W COMPACT HW ELIG	152
4C0042E	4/42W COMPACT HW ELIG	188
6C0026E	6/26W COMPACT HW ELIG	162
6C0032E	6/32W COMPACT HW ELIG	228
6C0042E	6/42W COMPACT HW ELIG	282
8C0026E	8/26W COMPACT HW ELIG	216
8C0032E	8/32W COMPACT HW ELIG	304
8C0042E	8/42W COMPACT HW ELIG	376
T5 Systems		
1F14SSE	1L2' 14W T5/ELIG	16
2F14SSE	2L2' 14W T5/ELIG	32
3F14SSE	3L2' 14W T5/ELIG	50
4F14SSE	4L2' 14W T5/ELIG	68
1F24HSE	1L2' 24W T5HO/ELIG	29
2F24HSE	2L2' 24W T5HO/ELIG	52
3F24HSE	3L2' 24W T5HO/ELIG	80
1F21SSE	1L3' 21W T5/ELIG	24
2F21SSE	2L3' 21W T5/ELIG	47
1F39HSE	1L3' 39W T5HO/ELIG	42
2F39HSE	2L3' 39W T5HO/ELIG	85
1F28SSE	1L4' 28W T5/ELIG	32
2F28SSE	2L4' 28W T5/ELIG	63
3F28SSE	3L4' 28W T5/ELIG	95
4F28SSE	4L4' 28W T5/ELIG	126
6F28SSE	6L4' 28W T5/ELIG	189
1F47HSE	1L4' 47W T5HO/ELIG	53
2F47HSE	2L4' 47W T5HO/ELIG	103
3F47HSE	3L4' 47W T5HO/ELIG	157
4F47HSE	4L4' 47W T5HO/ELIG	200
5F47HSE	5L4' 47W T5HO/ELIG	260
6F47HSE	6L4' 47W T5HO/ELIG	303
1F50HSE	1L4' 50W T5HO/ELIG	58

Device Code	Device Description	Rated Watts
T5 Systems (cont.)		
2F50HSE	2L4' 50W T5HO/ELIG	110
3F50HSE	3L4' 50W T5HO/ELIG	168
4F50HSE	4L4' 50W T5HO/ELIG	215
5F50HSE	5L4' 50W T5HO/ELIG	278
6F50HSE	6L4' 50W T5HO/ELIG	325
1F54HSE	1L4' 54W T5HO/ELIG	59
2F54HSE	2L4' 54W T5HO/ELIG	117
3F54HSE	3L4' 54W T5HO/ELIG	177
4F54HSE	4L4’ 54W T5HO/ELIG	234
5F54HSE	5L4' 54W T5HO/ELIG	294
6F54HSE	6L4’ 54W T5HO/ELIG	351
8F54HSE	8L4' 54W T5HO/ELIG	468
10F54HSE	10L4’ 54W T5HO/ELIG	585
Two Foot High Efficient T8 Systems		
1F17ESL	1L2' 17W T8EE/ELEE LOW PWR	14
1F17ESN	1L2' 17W T8EE/ELEE	17
1F17ESH	1L2' 17W T8EE/ELEE HIGH PWR	20
1F28BXE	1L2' F28BX/ELIG	32
2F17ESL	2L2' 17W T8EE/ELEE LOW PWR	27
2F17ESN	2L2' 17W T8EE/ELEE	32
2F17ESH	2L2' 17W T8EE/ELEE HIGH PWR	40
2F28BXE	2L2' F28BX/ELIG	63
3F17ESL	3L2' 17W T8EE/ELEE LOW PWR	39
3F17ESN	3L2' 17W T8EE/ELEE	46
3F17ESH	3L2' 17W T8EE/ELEE HIGH PWR	61
3F28BXE	3L2' F28BX/ELIG	94
Three Foot High Efficient T8 Systems		
1F25ESL	1L3' 25W T8EE/ELEE LOW PWR	21
1F25ESN	1L3' 25W T8EE/ELEE	24
1F25ESH	1L3' 25W T8EE/ELEE HIGH PWR	30
2F25ESL	2L3' 25W T8EE/ELEE LOW PWR	40
2F25ESN	2L3' 25W T8EE/ELEE	45
2F25ESH	2L3' 25W T8EE/ELEE HIGH PWR	60
3F25ESL	3L3' 25W T8EE/ELEE LOW PWR	58
3F25ESN	3L3' 25W T8EE/ELEE	67
3F25ESH	3L3' 25W T8EE/ELEE HIGH PWR	90

Device Code	Device Description	Rated Watts
Four Foot T8 High Efficient / Reduce Wattage Systems		
1F25EEH	1L4' 25W T8EE/ELEE HIGH PWR	30
1F25EEE	1L4' 25W T8EE/ELEE	22
1F25EEL	1L4' 25W T8EE/ELEE LOW PWR	19
2F25EEH	2L4' 25W T8EE/ELEE HIGH PWR	57
2F25EEE	2L4' 25W T8EE/ELEE	43
2F25EEL	2L4' 25W T8EE/ELEE LOW PWR	37
3F25EEH	3L4' 25W T8EE/ELEE HIGH PWR	86
3F25EEE	3L4' 25W T8EE/ELEE	64
3F25EEL	3L4' 25W T8EE/ELEE LOW PWR	57
4F25EEH	4L4' 25W T8EE/ELEE HIGH PWR	111
4F25EEE	4L4' 25W T8EE/ELEE	86
4F25EEL	4L4' 25W T8EE/ELEE LOW PWR	75
1F28EEH	1L4' 28W T8EE/ELEE HIGH PWR	33
1F28EEE	1L4' 28W T8EE/ELEE	24
1F28EEL	1L4' 28W T8EE/ELEE LOW PWR	22
2F28EEH	2L4' 28WT8EE/ELEE HIGH PWR	64
2F28EEE	2L4' 28W T8EE/ELEE	48
2F28EEL	2L4' 28W T8EE/ELEE LOW PWR	42
3F28EEH	3L4' 28W T8EE/ELEE HIGH PWR	96
3F28EEE	3L4' 28W T8EE/ELEE	72
3F28EEL	3L4' 28W T8EE/ELEE LOW PWR	63
4F28EEH	4L4' 28W T8EE/ELEE HIGH PWR	126
4F28EEE	4L4' 28W T8EE/ELEE	94
4F28EEL	4L4' 28W T8EE/ELEE LOW PWR	83
1F30EEH	1L4' 30W T8EE/ELEE HIGH PWR	36
1F30EEE	1L4' 30W T8EE/ELEE	26
1F30EEL	1L4' 30W T8EE/ELEE LOW PWR	24
2F30EEH	2L4' 30WT8EE/ELEE HIGH PWR	69
2F30EEE	2L4' 30W T8EE/ELEE	52
2F30EEL	2L4' 30W T8EE/ELEE LOW PWR	45
3F30EEH	3L4' 30W T8EE/ELEE HIGH PWR	103
3F30EEE	3L4' 30W T8EE/ELEE	77

Device Code	**Device Description**	**Rated Watts**
Four Foot T8 High Efficient / Reduce Wattage Systems (cont.)		
3F30EEL	3L4' 30W T8EE/ELEE LOW PWR	68
4F30EEH	4L4' 30W T8EE/ELEE HIGH PWR	133
4F30EEE	4L4' 30W T8EE/ELEE	101
4F30EEL	4L4' 30W T8EE/ELEE LOW PWR	89
1F32EEH	1L4' 32W T8EE/ELEE HIGH PWR	38
1F32EEE	1L4' 32W T8EE/ELEE	28
1F32EEL	1L4' 32W T8EE/ELEE LOW PWR	25
2F32EEH	2L4' 32W T8EE/ELEE HIGH PWR	73
2F32EEE	2L4' 32W T8EE/ELEE	53
2F32EEL	2L4' 32W T8EE/ELEE LOW PWR	47
3F32EEH	3L4' 32W T8EE/ELEE HIGH PWR	109
3F32EEE	3L4' 32W T8EE/ELEE	82
3F32EEL	3L4' 32W T8EE/ELEE LOW PWR	72
4F32EEH	4L4' 32W T8EE/ELEE HIGH PWR	141
4F32EEE	4L4' 32W T8EE/ELEE	107
4F32EEL	4L4' 32W T8EE/ELEE LOW PWR	95
6F32EEH	6L4' 32W T8EE/ELEE HIGH PWR	218
6F32EEE	6L4' 32W T8EE/ELEE	168
6F32EEL	6L4' 32W T8EE/ELEE LOW PWR	146
Eight Foot T8 Systems		
1F59SSE	1L8' T8/ELIG	60
1F80SSE	1L8' T8 HO/ELIG	85
2F59SSE	2L8' T8/ELIG	109
2F59SSL	2L8' T8/ELIG LOW PWR	100
2F80SSE	2L8' T8 HO/ELIG	160
LED Lighting Fixtures		
1L002	2 WATT LED	2
1L003	3 WATT LED	3
1L004	4 WATT LED	04
1L005	5 WATT LED	05
1L006	6 WATT LED	06
1L007	7 WATT LED	07
1L008	8 WATT LED	08

1L009	9 WATT LED	09
Device Code	**Device Description**	**Rated Watts**
LED Lighting Fixtures (cont.)		
1L010	10 WATT LED	10
1L011	11 WATT LED	11
1L012	12 WATT LED	12
1L013	13 WATT LED	13
1L014	14 WATT LED	14
1L015	15 WATT LED	15
1L016	16 WATT LED	16
1L017	17 WATT LED	17
1L018	18 WATT LED	18
1L019	19 WATT LED	19
1L020	20 WATT LED	20
1L021	21 WATT LED	21
1L022	22 WATT LED	22
1L023	23 WATT LED	23
1L024	24 WATT LED	24
1L025	25 WATT LED	25
1L026	26 WATT LED	26
1L027	27 WATT LED	27
1L028	28 WATT LED	28
1L029	29 WATT LED	29
1L030	30 WATT LED	30
1L031	31 WATT LED	31
1L032	32 WATT LED	32
1L033	33 WATT LED	33
1L034	34 WATT LED	34
1L035	35 WATT LED	35
1L036	36 WATT LED	36
1L037	37 WATT LED	37
1L038	38 WATT LED	38
1L039	39 WATT LED	39
1L040	40 WATT LED	40
1L041	41 WATT LED	41
1L042	42 WATT LED	42
1L043	43 WATT LED	43
1L044	44 WATT LED	44
1L045	45 WATT LED	45
1L046	46 WATT LED	46
1L047	47 WATT LED	47
1L048	48 WATT LED	48
1L049	49 WATT LED	49
1L050	50 WATT LED	50
1L055	55 WATT LED	55
1L060	60 WATT LED	60
1L070	70 WATT LED	70

1L073	73 WATT LED	73
Device Code	**Device Description**	**Rated Watts**
LED Lighting Fixtures (cont.)		
1L075	75 WATT LED	75
1L080	90 WATT LED	90
1L085	85 WATT LED	85
1L090	90 WATT LED	90
1L095	95 WATT LED	95
1L100	100 WATT LED	100
1L106	106 WATT LED	106
1L107	107 WATT LED	107
1L116	116 WATT LED	116
1L120	120 WATT LED	120
1L125	125 WATT LED	125
1L130	130 WATT LED	130
1L135	135 WATT LED	135
1L140	140 WATT LED	140
1L145	145 WATT LED	145
1L150	150 WATT LED	150
1L155	155 WATT LED	155
1L160	160 WATT LED	160
1L165	165 WATT LED	165
1L170	170 WATT LED	170
1L175	175 WATT LED	175
1L180	180 WATT LED	180
1L185	185 WATT LED	185
1L190	190 WATT LED	190
1L200	200 WATT LED	200
Device Code	**Device Description**	**Rated Watts**
LED Lighting Fixtures (cont.)		
1L210	210 WATT LED	210
1L220	220 WATT LED	220
1L240	240 WATT LED	240
Electronic Metal Halide Lamps		
1M0150E	150W METAL HALIDE EB	160
1M0200E	200W METAL HALIDE EB	215
1M0250E	250W METAL HALIDE EB	270
1M0320E	320W METAL HALIDE EB	345
1M0350E	350W METAL HALIDE EB	375
1M0400E	400W METAL HALIDE EB	430
1M0450E	400W METAL HALIDE EB	480
MH Track Lighting		
1M0020E	20W MH SPOT	25
1M0025E	25W MH SPOT	25
1M0035E	35W MH SPOT	44
1M0039E	39W MH SPOT	47
1M0050E	50W MH SPOT	60
1M0070E	70W MH SPOT	80
1M0100E	100W MH SPOT	111
1M0150E	150W MH SPOT	162

Table 50: Default Effective Lighting Hours by Building Type[622]

Building Type	Annual Operating Hours
Assembly	2857 (one shift)
Automobile	4056 (retail)
Big Box	4057 (retail)
Community College	3255
Dormitory	3,056
Fast Food	5110
Full Service Restaurant	5110
Grocery	6074
Heavy Industrial	4,057
Hospital	8036
Hotel	8583
Large Refrigerated Space	2602 (warehouse)
Large Office	3610
Light Industrial	4,730 (two shift)
Motel	8583
Multi Story Retail	4089
Multifamily high-rise	7665 (Common Area)
Multifamily low-rise	7665 (Common Area)
Other	3951
Religious	1955
K-12 Schools	2596
Small Office	3610
Small Retail	4089
University	3255
Warehouse	3759

Table 51: Cooling and Heating Equivalent Full Load Hours

Building (or Space) Type	Cooling Full Load Hours ($EFLH_{cool}$)	Heating Full Load Hours ($EFLH_{heat}$)
Average – CLC	1,172	530
Average – NSTAR	1,172	N/A
Average – National Grid	989	881
Average – Unitil	719	1,398
Average – WMECO	755	1,329
Site Specific - NSTAR	800, 1000-6000 at 1000 hour increments	N/A

- Average Cooling EFLHs from the 2010 NEEP HVAC Loadshape study.[623]
- Average Heating EFLHs derived from 2010 NEEP HVAC Loadshape study[624] and the Connecticut Program Savings Document for 2011 Program Year. [625]

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[622] Lighting hours developed from Massachusetts Common Assumptions and New York Standard Approach for Estimating Energy Savings from Energy Efficiency Programs (2010). Values are provided for use when site-specific hours are not available.
[623] KEMA (2011). C&I Unitary AC LoadShape Project – Final Report. Prepared for the Regional Evaluation, Measurement & Verification Forum.
[624] Ibid.
[625] United Illuminating Company, Connecticut Light & Power Company (2010). *UI and CL&P Program Savings Documentation for 2011 Program Year.*

Table 52: EPACT 1992 Baseline Motor Efficiencies[626]

Motor Horsepower	Open Drip Proof			Totally Enclosed Fan Cooled		
	1200 rpm	1800 rpm	3600 rpm	1200 rpm	1800 rpm	3600 rpm
1	80.0	82.5	N/A	80.0	82.5	75.5
1.5	84.0	84.0	82.5	85.5	84.0	82.5
2	85.5	84.0	84.0	86.5	84.0	84.0
3	86.5	86.5	84.0	87.5	87.5	85.5
5	87.5	87.5	85.5	87.5	87.5	87.5
7.5	88.5	88.5	87.5	89.5	89.5	88.5
10	90.2	89.5	88.5	89.5	89.5	89.5
15	90.2	91.0	89.5	90.2	91.0	90.2
20	91.0	91.0	90.2	90.2	91.0	90.2
25	91.7	91.7	91.0	91.7	92.4	91.0
30	92.4	92.4	91.0	91.7	92.4	91.0
40	93.0	93.0	91.7	93.0	93.0	91.7
50	93.0	93.0	92.4	93.0	93.0	92.4
60	93.6	93.6	93.0	93.6	93.6	93.0
75	93.6	94.1	93.0	93.6	94.1	93.0
100	94.1	94.1	93.0	94.1	94.5	93.6
125	94.1	94.5	93.6	94.1	94.5	94.5
150	94.5	95.0	93.6	95.0	95.0	94.5
200	94.5	95.0	94.5	95.0	95.0	95.0

[626] Energy Policy Act of 1992

Table 53: Minimum Premium Efficiency Motors Compliance Efficiencies[627]

Motor Horsepower	Open Drip Proof			Totally Enclosed Fan Cooled		
	1200 rpm	1800 rpm	3600 rpm	1200 rpm	1800 rpm	3600 rpm
1	82.5	85.5	N/A	82.5	85.5	77.0
1.5	86.5	86.5	84	87.5	86.5	84
2	87.5	86.5	85.5	88.5	86.5	85.5
3	88.5	89.5	85.5	89.5	89.5	86.5
5	89.5	89.5	86.5	89.5	89.5	88.5
7.5	90.2	91	88.5	91	91.7	89.5
10	91.7	91.7	89.5	91	91.7	90.2
15	97.7	93	90.2	91.7	92.4	91
20	92.4	93	91	91.7	93	91
25	93	93.6	91.7	93	93.6	91.7
30	93.6	94.1	91.7	93	93.6	91.7
40	94.1	94.1	92.4	94.1	94.1	92.4
50	94.1	94.5	93	94.1	94.5	93
60	94.5	95	93.6	94.5	95	93.6
75	94.5	95	93.6	94.5	95.4	93.6
100	95	95.4	93.6	95	95.4	94.1
125	95	95.4	94.1	95	95.4	95
150	95.4	95.8	94.1	95.8	95.8	95
200	95.4	95.8	95	95.8	96.2	95.4

[627] NEMA Premium MG1-2006 Table 12-12

Appendix B: Common Program Names

The common Program Naming (CPN) of the efficiency programs offered by the program administrators is a work in progress. Among other things, the goals of the CPN are to:

- avoid the use of product names (e.g., OPower),
- provide a commonality for gas and electric programs (e.g., MassSAVE for electric, and weatherization for gas), and
- characterize programs such that a consistent primary name (e.g., Retrofit) is used for all sectors.

CPN was introduced to PAs in the late summer of 2009. Given the tight schedule for filing 2010-2012 program plans, the PAs agreed to work to incorporate these names at a later date.

The PAs will work with the DOER to integrate these into future plan updates.

Appendix C: Net to Gross Impact Factors

Residential Electric Measures					
Measure	**PA**	**FR**	**SO_P**	**SO_{NP}**	**NTG**
Residential New Construction & Major Renovation					
Dishwashers	All	0%	0%	0%	100%
ES Homes - Cooling	All	0%	0%	0%	100%
ES Homes - Heating	All	0%	0%	0%	100%
ES Homes - Water Heating	All	0%	0%	0%	100%
Indoor Fixture	All	0%	0%	0%	100%
LED Fixture	All	0%	0%	0%	100%
Refrigerators	All	0%	0%	0%	100%
Screw-in Bulbs	All	0%	0%	0%	100%
Residential Cooling & Heating Equipment					
Brushless Furnace Fan Motor	All	15%	0%	0%	85%
CoolSmart AC (SEER >= 15 / EER >= 12.5)	All	15%	0%	0%	85%
CoolSmart AC (SEER >= 15 / EER >= 13)	All	15%	0%	0%	85%
CoolSmart AC (SEER 14.5 / EER 12)	All	15%	0%	0%	85%
CoolSmart AC Digital Check-up/Tune-up	All	15%	0%	0%	85%
CoolSmart AC MS (SEER 16 / EER 13)	All	15%	0%	0%	85%
CoolSmart AC QIV ES	All	15%	0%	0%	85%
CoolSmart AC QIV NES	All	15%	0%	0%	85%
CoolSmart HP (SEER >= 15)	All	15%	0%	0%	85%
CoolSmart HP (SEER 14.5 / EER 12)	All	15%	0%	0%	85%
CoolSmart HP Digital Check-up/Tune-up	All	15%	0%	0%	85%
CoolSmart HP MS (SEER 19 / EER 12.8 / HSPF 10.1)	All	15%	0%	0%	85%
CoolSmart HP MS (SEER 23 / EER 13 / HSPF 10.6)	All	15%	0%	0%	85%
CoolSmart HP QIV ES	All	15%	0%	0%	85%
CoolSmart HP QIV NES	All	15%	0%	0%	85%
CoolSmart Warm Air Furnace ECM	All	15%	0%	0%	85%
Down Size 1/2 Ton	All	15%	0%	0%	85%
Duct Sealing	All	15%	0%	0%	85%
Ductless Mini Split AC	All	15%	0%	0%	85%
Ductless Mini Split HP	All	15%	0%	0%	85%
Ductless Mini Split HP/AC Retrofit	All	15%	0%	0%	85%
Early Replacement of AC/HP Equipment	All	15%	0%	0%	85%
Energy Star QI	All	15%	0%	0%	85%
Energy Star QI w/ Duct modifications	All	15%	0%	0%	85%
Right Sizing	All	15%	0%	0%	85%
HPWH, Electric, 80 gal	All	0%	0%	0%	100%
HPWH, Electric, 50 gal	All	0%	0%	0%	100%
HPWH, Propane, 50 gal	CLC	0%	0%	0%	100%
HPWH, Oil, 80 gal	All	0%	0%	0%	100%
HPWH, Oil, 50 gal	All	0%	0%	0%	100%

TXV Replacement of Fixed Orifice	All	15%	0%	0%	85%
Residential Retrofit 1-4					
Air Sealing, Electric	All	7%	0%	0%	93%
Air Sealing, Gas	All	7%	0%	0%	93%
Air Sealing, Oil	All	7%	0%	0%	93%
Air Sealing, Other FF	All	7%	0%	0%	93%
Boiler Reset Controls	All	0%	0%	0%	100%
DHW ISMs, Electric	All	2%	0%	0%	98%
DHW ISMs, Gas	All	2%	0%	0%	98%
DHW ISMs, Oil	All	2%	0%	0%	98%
DHW ISMs, Other FF	All	2%	0%	0%	98%
Duct Insulation, Electric	All	20%	8%	50%	138%
Duct Insulation, Gas	All	20%	8%	50%	138%
Duct Insulation, Oil	All	20%	8%	50%	138%
Duct Insulation, Other FF	All	20%	8%	50%	138%
Duct Seal, Electric	All	7%	0%	0%	93%
Duct Seal, Gas	All	7%	0%	0%	93%
Duct Seal, Oil	All	7%	0%	0%	93%
Duct Seal, Other FF	All	7%	0%	0%	93%
ES Window, Electric	All	0%	0%	0%	100%
ES Window, Gas	All	0%	0%	0%	100%
ES Window, Oil	All	0%	0%	0%	100%
ES Window, Other FF	All	0%	0%	0%	100%
Heating System Replacement, Gas	All	28%	0%	0%	72%
Heating System Replacement, Oil	All	28%	0%	0%	72%
Heating System Replacement, Other FF	All	28%	0%	0%	72%
Indirect Water Heater, Oil	All	25%	0%	0%	75%
Indirect Water Heater, Other FF	All	25%	0%	0%	75%
Insulation, Electric	All	20%	8%	50%	138%
Insulation, Gas	All	20%	8%	50%	138%
Insulation, Oil	All	20%	8%	50%	138%
Insulation, Other FF	All	20%	8%	50%	138%
Refrigerator (ES Value)	All	5%	0%	0%	95%
Refrigerator (Retriement Value)	All	5%	0%	0%	95%
Screw-in Bulbs	All	22%	19%	0%	97%
Screw-in Bulbs (piggyback)	All	22%	19%	0%	97%
Smart Strips	All	0%	0%	0%	100%
Thermostats, Electric	All	11%	0%	0%	89%
Thermostats, Gas	All	11%	0%	0%	89%
Thermostats, Oil	All	11%	0%	0%	89%
Thermostats, Other FF	All	11%	0%	0%	89%
Torchiere	All	6%	3%	0%	97%
Residential Retrofit Multifamily					
Air Sealing (Electric)	All	3%	0%	0%	97%

Air Sealing (FF)	All	3%	0%	0%	97%
CFL (Electric)	All	3%	0%	0%	97%
CFL (Non-Electric)	All	3%	0%	0%	97%
Common Area Interior Fixtures	All	3%	0%	0%	97%
Common Area Occupancy Sensors	All	3%	0%	0%	97%
DHW Measures (FF)	All	3%	0%	0%	97%
DHW Measures (Electric)	All	3%	0%	0%	97%
Fixtures (Electric)	National Grid	3%	0%	0%	97%
Fixtures (Non-Electric)	National Grid	3%	0%	0%	97%
Heat Pump Tune-Up (Electric)	All	3%	0%	0%	97%
Indoor Fixture	All	8%	4%	0%	96%
Insulation (Electric)	All	3%	0%	0%	97%
Insulation (FF)	All	3%	0%	0%	97%
Outdoor Fixture	All	12%	7%	0%	95%
Programmable Thermostats (Electric)	All	3%	0%	0%	97%
Programmable Thermostats (FF)	All	3%	0%	0%	97%
Refrigerator (ES Value)	All	3%	0%	0%	97%
Refrigerator (Retirement Value)	All	3%	0%	0%	97%
Refrigerators/Freezers (Electric Heat)	National Grid	3%	0%	0%	97%
Refrigerators/Freezers (Non-Electric Heat)	National Grid	3%	0%	0%	97%
Room AC	All	35%	0%	0%	65%
Screw-in Bulbs	All	3%	0%	0%	97%
Smart Strips	All	0%	0%	0%	100%
SPACE Air Sealing (Electric)	National Grid	3%	0%	0%	97%
SPACE Air Sealing (Non-Electric)	National Grid	3%	0%	0%	97%
SPACE Insulation (Electric)	National Grid	3%	0%	0%	97%
SPACE Insulation (Non-Electric)	National Grid	3%	0%	0%	97%
SPACE Thermostats (Electric)	National Grid	3%	0%	0%	97%
SPACE Thermostats (Non-Electric)	National Grid	3%	0%	0%	97%
Behavior/Feedback Program					
Group 2009 Pilot	National Grid	0%	0%	0%	100%
Group 2010 Added	National Grid	0%	0%	0%	100%
Group 2010 February	National Grid	0%	0%	0%	100%
Group 2011 February	National Grid	0%	0%	0%	100%
Group 2012 February	National Grid	0%	0%	0%	100%
2012 Dual Fuel	NSTAR	0%	0%	0%	100%
Residential Lighting					
Indoor Fixture	All	8%	4%	0%	96%
LED Fixture	All	0%	0%	0%	100%
LED Lamp	All	0%	0%	0%	100%
Outdoor Fixture	All	12%	7%	0%	95%
Screw-in Bulbs	All	57%	0%	0%	43%
Screw-in Bulbs (Hard to Reach)	All	40%	0%	0%	60%
Screw-in Bulbs (School Fundraiser)	All	0%	0%	0%	100%

Screw-in Bulbs (Specialty bulbs)	All	40%	0%	0%	60%
Torchiere	All	6%	3%	0%	97%
Residential Appliances					
Computer Monitors	All	25%	0%	0%	75%
Dehumidifiers (ES Value)	All	25%	0%	0%	75%
Dehumidifiers (Retirement Value)	All	25%	0%	0%	75%
Freezer Rebate	All	25%	0%	0%	75%
LCD/TV	All	25%	0%	0%	75%
PC Computers	All	25%	0%	0%	75%
Pool Pumps	All	0%	0%	0%	100%
Refrigerator Recycle – Secondary Replaced	All	27%	0%	0%	73%
Refrigerator Recycle – Primary	All	45%	0%	0%	55%
Refrigerator Recycle – Secondary, Not Replaced	All	29%	0%	0%	71%
Refrigerator Recycling – Combined	NSTAR	31%	0%	0%	69%
Freezer Recycling	All	41%	0%	0%	59%
Refrigerator Rebate	All	25%	0%	0%	75%
Room AC (Upstream)	All	35%	0%	0%	65%
Room Air Cleaner	All	25%	0%	0%	75%
Set Top Box	All	25%	0%	0%	75%
Smart Strips	All	0%	0%	0%	100%
Version 4.1 TV <60”	All	25%	0%	0%	75%
Version 4.1 TV >=60”	All	25%	0%	0%	75%
Version 5.3 TV <60”	All	25%	0%	0%	75%
Version 5.3 TV >=60”	All	25%	0%	0%	75%
Low Income Residential New Construction & Major Renovation					
Dishwashers	All	0%	0%	0%	100%
ES Homes - Cooling	All	0%	0%	0%	100%
ES Homes - Heating	All	0%	0%	0%	100%
ES Homes - Water Heating	All	0%	0%	0%	100%
Indoor Fixture	All	0%	0%	0%	100%
LED Fixture	All	0%	0%	0%	100%
Refrigerators	All	0%	0%	0%	100%
Screw-in Bulbs	All	0%	0%	0%	100%
Low Income 1-4 Family Retrofit					
Appliance (refrigerator or freezer) Removal	All	0%	0%	0%	100%
Baseload/Education	All	0%	0%	0%	100%
Boiler Reset Controls	All	0%	0%	0%	100%
CFLs	All	0%	0%	0%	100%
CFL Fixture	All	0%	0%	0%	100%
Dehumidifiers (ES Value)	All	0%	0%	0%	100%
Dehumidifiers (Retirement Value)	All	0%	0%	0%	100%
DHW Measures (Electric)	All	0%	0%	0%	100%
DHW Measures (Gas/Other)	All	0%	0%	0%	100%
DHW Measures (Oil)	All	0%	0%	0%	100%

Electric Weatherization	All	0%	0%	0%	100%
Freezer Replacement	All	0%	0%	0%	100%
Heating System Replacement (Oil)	All	0%	0%	0%	100%
Oil Weatherization	All	0%	0%	0%	100%
Gas Weatherization	CLC	0%	0%	0%	100%
Other FF Weatherization	CLC	0%	0%	0%	100%
Programmable Thermostats (Oil)	All	0%	0%	0%	100%
Refrigerator Replacement	All	0%	0%	0%	100%
Smart Strips	All	0%	0%	0%	100%
Torchieres	All	0%	0%	0%	100%
Waterbed	All	0%	0%	0%	100%
Window AC Replacement	All	0%	0%	0%	100%
Low Income Multi-Family Retrofit					
Baseload	All	0%	0%	0%	100%
CFL Fixtures	All	0%	0%	0%	100%
CFLs	All	0%	0%	0%	100%
DHW Measures	All	0%	0%	0%	100%
Electric Weatherization	All	0%	0%	0%	100%
Oil Weatherization	CLC, Unitil	0%	0%	0%	100%
Freezer Replacement	All	0%	0%	0%	100%
Heating System Replacement (Oil)	All	0%	0%	0%	100%
Programmable Thermostats (Oil)	CLC, Unitil	0%	0%	0%	100%
Refrigerator (ES Value)	All	0%	0%	0%	100%
Refrigerator (Retirement Value)	All	0%	0%	0%	100%
Second Refrigerator Removal	CLC	0%	0%	0%	100%
Smart Strips	All	0%	0%	0%	100%
Torchieres	All	0%	0%	0%	100%
Waterbed	All	0%	0%	0%	100%
Window AC Replacement	All	0%	0%	0%	100%

Evaluations

Unless otherwise stated below, all PA's use Massachusetts common assumptions for all residential electric measure free-ridership and spillover values.

All PAs base the NTG factors for the ENERGY STAR Lighting Screw-In Bulbs and Screw-In Bulbs (Specialty bulbs) measures on the Massachusetts ENERGY STAR® Lighting Program: 2010 Annual Report.[628]

All PAs base the NTG factors for the MassSAVE Screw-In Bulbs, Screw-In Bulbs (piggyback), Refrigerator, Air Sealing, Insulation, Duct Seal, Duct Insulation, Thermostats, Heating System Replacement and Indirect Water Heater measures on the 2010 Net-to-Gross Findings: Home Energy Assessment study.[629]

[628] NMR Group, Inc (2011). *Massachusetts ENERGY STAR® Lighting Program: 2010 Annual Report.* Prepared for the Electric Program Administrators of Massachusetts; June 13, 2011.
[629] The Cadmus Group (2011). *2010 Net-to-Gross Findings: Home Energy Assessment.* Prepared for the Electric and Gas Program Administrators of Massachusetts; July 5, 2011.

Commercial Electric Measures					
Measure	**PA**	**FR**	**SO_P**	**SO_{NP}**	**NTG**
C&I New Construction and Major Renovation					
Advanced Lighting Design (Performance Lighting)	National Grid	33%	29%	0%	96%
Advanced Lighting Design (Performance Lighting)	NSTAR	12%	4%	0%	92%
Advanced Lighting Design (Performance Lighting)	Unitil	19.9%	8.8%	0%	88.9%
Advanced Lighting Design (Performance Lighting)	WMECo	20%	7%	0%	89%
Advanced Lighting Design (Performance Lighting)	CLC	20%	0%	0%	80%
Lighting Controls	National Grid	33%	29%	0%	96%
Lighting Controls	NSTAR	12%	4%	0%	92%
Lighting Controls	Unitil	19.9%	8.8%	0%	88.9%
Lighting Controls	WMECo	20%	7%	0%	89%
Lighting Controls	CLC	20%	0%	0%	80%
Lighting Systems	National Grid	33%	29%	0%	96%
Lighting Systems	NSTAR	12%	4%	0%	92%
Lighting Systems	Unitil	19.9%	8.8%	0%	88.9%
Lighting Systems	WMECo	20%	7%	0%	89%
Lighting Systems	CLC	20%	0%	0%	80%
Demand Control Ventilation (DCV)	National Grid	26%	2%	0%	75%
Demand Control Ventilation (DCV)	NSTAR	21%	14%	0%	94%
Demand Control Ventilation (DCV)	Unitil	30.6%	0%	3.6%	73%
Demand Control Ventilation (DCV)	WMECo	30%	1%	0%	71%
Demand Control Ventilation (DCV)	CLC	22%	12%	0%	90%
Dual Enthalpy Economizer Controls (DEEC)	National Grid	26%	2%	0%	75%
Dual Enthalpy Economizer Controls (DEEC)	NSTAR	21%	14%	0%	94%
Dual Enthalpy Economizer Controls (DEEC)	Unitil	30.6%	0%	3.6%	73%
Dual Enthalpy Economizer Controls (DEEC)	WMECo	30%	1%	0%	71%
Dual Enthalpy Economizer Controls (DEEC)	CLC	22%	12%	0%	90%
ECM Fan Motors	National Grid	26%	2%	0%	75%
ECM Fan Motors	NSTAR	21%	14%	0%	94%
ECM Fan Motors	Unitil	30.6%	0%	3.6%	73%
ECM Fan Motors	WMECo	30%	1%	0%	71%
ECM Fan Motors	CLC	22%	12%	0%	90%
Energy Management System (EMS)	CLC	22%	12%	0%	90%
HE Chiller	National Grid	26%	2%	0%	75%
HE Chiller	NSTAR	21%	14%	0%	94%
HE Chiller	Unitil	30.6%	0%	3.6%	73%
HE Chiller	WMECo	30%	1%	0%	71%
HE Chiller	CLC	22%	12%	0%	90%
Single-Package and SS Heat Pump Systems	National Grid	29%	2%	0%	73%
Single-Package and SS Heat Pump Systems	NSTAR	21%	14%	0%	94%
Single-Package and SS Heat Pump Systems	Unitil	30.6%	0%	3.6%	73%
Single-Package and SS Heat Pump Systems	WMECo	30%	1%	0%	71%
Single-Package and SS Heat Pump Systems	CLC	22%	12%	0%	90%
Single-Package and SS Unitary air conditioners	National Grid	29%	2%	0%	73%
Single-Package and SS Unitary air conditioners	NSTAR	21%	14%	0%	94%
Single-Package and SS Unitary air conditioners	Unitil	30.6%	0%	3.6%	73%

Single-Package and SS Unitary air conditioners	WMECo	30%	1%	0%	71%
Single-Package and SS Unitary air conditioners	CLC	22%	12%	0%	90%
HE Air Compressor	National Grid	32%	0%	2%	70%
HE Air Compressor	NSTAR	37%	10%	1%	74%
HE Air Compressor	Unitil	30.6%	0%	3.6%	73%
HE Air Compressor	WMECo	34%	4%	2%	94%
HE Air Compressor	CLC	34%	4%	2%	72%
Refrigerated Air Dryers	National Grid	32%	0%	2%	70%
Refrigerated Air Dryers	NSTAR	37%	10%	1%	74%
Refrigerated Air Dryers	Unitil	30.6%	0%	3.6%	73%
Refrigerated Air Dryers	WMECo	34%	4%	2%	94%
Refrigerated Air Dryers	CLC	34%	4%	2%	72%
Variable Frequency Drives	National Grid	25%	0%	8%	82%
Variable Frequency Drives	NSTAR	23%	2%	8%	86%
Variable Frequency Drives	Unitil	30.6%	0%	3.6%	73%
Variable Frequency Drives	WMECo	23%	1%	8%	88%
Variable Frequency Drives	CLC	23%	1%	8%	86%
Commercial Electric Ovens	All	0%	0%	0%	100%
Commercial Electric Steam Cooker	All	0%	0%	0%	100%
Commercial Electric Griddle	All	0%	0%	0%	100%
Custom	National Grid	16%	29%	0%	113%
Custom	Unitil	20.%	11.5%	0%	92.3%
Custom - Compressed Air	NSTAR	37%	10%	1%	74%
Custom - Cooling	WMECo	30%	1%	0%	71%
Custom - HVAC	NSTAR	21%	14%	0%	94%
Custom - HVAC	CLC	22%	12%	0%	90%
Custom - Lighting	NSTAR	12%	4%	0%	92%
Custom - Lighting	WMECo	20%	7%	0%	88%
Custom - Lighting	CLC	20%	0%	0%	80%
Custom - Motors	NSTAR	23%	2%	8%	86%
Custom - Process	WMECo	7%	0%	0%	93%
Custom - Process Equipment	NSTAR	10%	1%	0%	91%
Custom - Refrigeration	NSTAR	13%	35%	0%	122%
Custom - Refrigeration	CLC	13%	35%	0%	122%
C&I Large Retrofit					
Lighting Controls	National Grid	17%	13%	0%	96%
Lighting Controls	NSTAR	18%	18%	0%	101%
Lighting Controls	Unitil	16.9%	8.4%	0%	91.5%
Lighting Controls	WMECo	20%	3%	0%	85%
Lighting Controls	CLC	17%	5%	0%	88%
Lighting Systems	National Grid	17%	13%	0%	96%
Lighting Systems	NSTAR	18%	18%	0%	101%
Lighting Systems	Unitil	16.9%	8.4%	0%	91.5%
Lighting Systems	WMECo	20%	3%	0%	85%
Lighting Systems	CLC	17%	5%	0%	88%
Vending Machine and Cooler Controls (Lighting)	NSTAR	18%	18%	0%	101%
Energy Management System (EMS)	National Grid	11%	4%	0%	93%
Energy Management System (EMS)	NSTAR	13%	6%	0%	93%

Energy Management System (EMS)	Unitil	13.4%	6.4%	0%	93%
Energy Management System (EMS)	WMECo	13%	6%	0%	88%
Energy Management System (EMS)	CLC	13%	6%	0%	93%
Hotel Occupancy Sensors	National Grid	11%	4%	0%	93%
Hotel Occupancy Sensors	NSTAR	13%	6%	0%	93%
Hotel Occupancy Sensors	Unitil	13.4%	6.4%	0%	93%
Hotel Occupancy Sensors	WMECo	13%	6%	0%	88%
Hotel Occupancy Sensors	CLC	17%	5%	0%	88%
LEDs in Freezers/Coolers	CLC	17%	5%	0%	88%
Vending Machine and Cooler Controls	National Grid	11%	4%	0%	93%
Vending Machine and Cooler Controls	Unitil	13.4%	6.4%	0%	93%
Vending Machine and Cooler Controls	WMECo	13%	6%	0%	88%
Vending Machine and Cooler Controls (Refrigeration)	NSTAR	14%	56%	0%	142%
Vending Misers	CLC	9%	36%	0%	127%
HE Air Compressor	National Grid	23%	0%	2%	78%
HE Air Compressor	NSTAR	7%	0%	2%	95%
HE Air Compressor	Unitil	7%	0%	1.5%	94.5%
HE Air Compressor	WMECo	7%	0%	1%	87%
HE Air Compressor	CLC	7%	0%	2%	95%
Variable Frequency Drives	National Grid	10%	7%	8%	104%
Variable Frequency Drives	NSTAR	14%	7%	8%	101%
Variable Frequency Drives	Unitil	9.6%	6%	7.7%	104.1%
Variable Frequency Drives	WMECo	10%	6%	8%	94%
Variable Frequency Drives	CLC	10%	6%	8%	104%
CHP	NSTAR	7%	16%	0%	108%
Custom	National Grid	14%	8%	1%	95%
Custom	Unitil	15.7%	9.1%	0.7%	94.1%
Custom - Compressed Air	NSTAR	7%	0%	2%	95%
Custom - HVAC	NSTAR	13%	6%	0%	93%
Custom - HVAC	CLC	13%	6%	0%	93%
Custom - Lighting	NSTAR	18%	18%	0%	101%
Custom - Lighting	WMECo	20%	3%	0%	85%
Custom - Lighting	CLC	17%	5%	0%	88%
Custom – Motors	NSTAR	14%	7%	8%	101%
Custom - Process Equipment	NSTAR	26%	11%	0%	85%
Custom – Refrigeration	NSTAR	14%	56%	0%	142%
Custom – Refrigeration	CLC	9%	36%	0%	127%
C&I Small Retrofit					
Lighting Controls	National Grid	5%	1%	0%	96%
Lighting Controls	NSTAR	9%	4%	0%	95%
Lighting Controls	Unitil	4.8%	8.7%	0%	103.9%
Lighting Controls	WMECo	11%	11%	0%	91%
Lighting Controls	CLC	9%	7%	0%	98%
Lighting Systems	National Grid	5%	1%	0%	96%
Lighting Systems	NSTAR	9%	4%	0%	95%
Lighting Systems	Unitil	4.8%	8.7%	0%	103.9%
Lighting Systems	WMECo	11%	11%	0%	91%
Lighting Systems	CLC	9%	7%	0%	98%

Energy Management Systems (EMS)	CLC	7%	14%	0%	107%
Hotel Occupancy Sensors	CLC	7%	14%	0%	107%
Programmable Thermostats	National Grid	2%	2%	0%	100%
Programmable Thermostats	NSTAR	10%	27%	0%	117%
Programmable Thermostats	Unitil	6.8%	14%	0%	107.2%
Programmable Thermostats	CLC	7%	14%	0%	107%
Case Motor Replacement	National Grid	2%	2%	0%	100%
Case Motor Replacement	NSTAR	2%	13%	0%	111%
Case Motor Replacement	Unitil	2.2%	9.2%	0%	107%
Case Motor Replacement	WMECo	3%	2%	0%	99%
Case Motor Replacement	CLC	4%	0%	0%	96%
Cooler Night Covers	National Grid	2%	2%	0%	100%
Cooler Night Covers	NSTAR	2%	13%	0%	111%
Cooler Night Covers	Unitil	2.2%	9.2%	0%	107%
Cooler Night Covers	WMECo	3%	2%	0%	99%
Cooler Night Covers	CLC	4%	0%	0%	96%
Cooler/Freezer Door Heater Control	National Grid	2%	2%	0%	100%
Cooler/Freezer Door Heater Control	NSTAR	2%	13%	0%	111%
Cooler/Freezer Door Heater Control	Unitil	2.2%	9.2%	0%	107%
Cooler/Freezer Door Heater Control	WMECo	3%	2%	0%	99%
Cooler/Freezer Door Heater Control	CLC	4%	0%	0%	96%
Cooler/Freezer Evaporator Fan Controls	National Grid	2%	2%	0%	100%
Cooler/Freezer Evaporator Fan Controls	NSTAR	2%	13%	0%	111%
Cooler/Freezer Evaporator Fan Controls	Unitil	2.2%	9.2%	0%	107%
Cooler/Freezer Evaporator Fan Controls	WMECo	3%	2%	0%	99%
Cooler/Freezer Evaporator Fan Controls	CLC	4%	0%	0%	96%
ECM for Evaporator Fans in Walk-in Coolers and Freezers	National Grid	2%	2%	0%	100%
ECM for Evaporator Fans in Walk-in Coolers and Freezers	NSTAR	2%	13%	0%	111%
ECM for Evaporator Fans in Walk-in Coolers and Freezers	Unitil	2.2%	9.2%	0%	107%
ECM for Evaporator Fans in Walk-in Coolers and Freezers	WMECo	3%	2%	0%	99%
ECM for Evaporator Fans in Walk-in Coolers and Freezers	CLC	4%	0%	0%	96%
Electronic Defrost Control	National Grid	2%	2%	0%	100%
Electronic Defrost Control	NSTAR	2%	13%	0%	111%
Electronic Defrost Control	Unitil	2.2%	9.2%	0%	107%
Electronic Defrost Control	WMECo	3%	2%	0%	99%
Electronic Defrost Control	CLC	4%	0%	0%	96%
LEDs in Freezers/Coolers	National Grid	5%	1%	0%	96%
LEDs in Freezers/Coolers	NSTAR	9%	4%	0%	95%
LEDs in Freezers/Coolers	Unitil	4.8%	8.7%	0%	103.9%
LEDs in Freezers/Coolers	WMECo	11%	1%	0%	91%
LEDs in Freezers/Coolers	CLC	9%	7%	0%	98%
Novelty Cooler Shutoff	National Grid	2%	2%	0%	100%
Novelty Cooler Shutoff	NSTAR	2%	13%	0%	111%
Novelty Cooler Shutoff	Unitil	2%	9%	0%	107%
Novelty Cooler Shutoff	WMECo	3%	2%	0%	99%
Novelty Cooler Shutoff	CLC	4%	0%	0%	96%
Vending Misers	CLC	4%	0%	0%	96%
Variable Frequency Drives	CLC	14%	0%	0%	86%

Hot Water	NSTAR	0%	98%	0%	198%
Process	NSTAR	17%	0%	0%	83%

Evaluations

All factors, except for participant spillover rates for measures in the lighting end use, are from the National Grid, NSTAR, Western Massachusetts Electric Company, Unitil, and Cape Light Compact 2010 Commercial and Industrial Electric Programs Free-ridership and Spillover Study.[630] Participant spillover rates for measures in the lighting end use are PA-specific and calculated using the High Bay Lighting (HBL) Market Effects Study.[631]

[630] TetraTech (2011). National Grid, NSTAR, Western Massachusetts Electric Company, Unitil, and Cape Light Compact 2010 Commercial and Industrial Electric Programs Free-ridership and Spillover Study. June 23, 2011
[631] KEMA (2011). Final Report HBL Market Effects Study Project 1A New Construction Market Characterization. June 7, 2011

Residential Natural Gas Measures						
Measure Name	**Program**	**PA**	**FR**	**SO_P**	**SO_{NP}**	**NTG**
Residential New Construction and Major Renovation						
Refrigerators		All	0%	0%	0%	100%
ES Homes - Cooling		All	0%	0%	0%	100%
ES Homes - Heating		All	0%	0%	0%	100%
ES Homes - Water Heating		All	0%	0%	0%	100%
Indoor Fixture		All	0%	0%	0%	100%
LED Fixture		All	0%	0%	0%	100%
Screw-in Bulbs		All	0%	0%	0%	100%
Dishwashers		All	0%	0%	0%	100%
Residential Heating and Water Heating						
Boiler (AFUE >= 90%)		All	60%	14%	0%	54%
Boiler (AFUE >= 96%)		All	25%	14%	0%	89%
HTR Boiler (AFUE >= 90%)		All	20%	0%	0%	80%
HTR Boiler (AFUE >= 96%)		All	8%	0%	0%	92%
Boiler Reset Controls		All	0%	0%	0%	100%
HTR Boiler Reset Controls		All	0%	0%	0%	100%
Condensing Water Heater		All	37%	0%	0%	63%
HTR Condensing Water Heater		All	12%	0%	0%	88%
Early Replacement Boiler		All	0%	0%	0%	100%
ES Programmable Thermostats		All	58%	0%	0%	42%
HTR ES Programmable Thermostats		All	19%	0%	0%	81%
Wi-Fi Thermostat		NGRID	0%	0%	0%	100%
Furnace w/ ECM (AFUE = 95%)		All	40%	19%	0%	79%
Furnace w/ ECM (AFUE = 96%)		All	25%	19%	0%	94%
HTR Furnace w/ ECM (AFUE = 95%)		All	13%	0%	0%	87%
HTR Furnace w/ ECM (AFUE = 96%)		All	8%	0%	0%	92%
Heat Recovery Ventilator		All	0%	0%	0%	100%
HTR Heat Recovery Ventilator		All	0%	0%	0%	100%
Indirect Water Heater		All	66%	0%	0%	34%
HTR Indirect Water Heater		All	22%	0%	0%	78%
Integrated water heater/condensing boiler		All	60%	14%	0%	54%
HTR Integrated water heater/condensing boiler		All	20%	0%	0%	80%
Stand Alone Storage Water Heater (EF >= 0.67)		All	37%	0%	0%	63%
HTR Stand Alone Storage Water Heater (EF >= 0.67)		All	12%	0%	0%	88%
Tankless Water Heaters (EF >= 0.82)		All	63%	0%	0%	37%
Tankless Water Heaters (EF >= 0.95)		All	37%	0%	0%	63%
HTR Tankless Water Heaters (EF >= 0.82)		All	21%	0%	0%	79%
HTR Tankless Water Heaters (EF >= 0.95)		All	12%	0%	0%	88%
Gas Heating System Replacement (Low Income)		All	0%	0%	0%	100%
Gas Weatherization (Low Income)		All	0%	0%	0%	100%
Home Energy Services (Gas Weatherization)						
Faucet Aerators		All	0%	0%	0%	100%

Low-Flow Shower Heads	All	0%	0%	0%	100%
Air Sealing	All	7%	0%	0%	93%
Exterior Doors	All	0%	0%	0%	100%
Insulation	All	20%	8%	50%	138%
Thermostats	All	11%	0%	0%	89%
Multifamily					
Faucet Aerators	All	23%	0%	0%	77%
Low-Flow Shower Heads	All	23%	0%	0%	77%
Air Sealing	All	0%	0%	0%	100%
Insulation	All	20%	0%	0%	80%
Thermostats	All	12%	0%	0%	88%
Low Income (Single Family and Multifamily)					
Gas Heating System Replacement	All	0%	0%	0%	100%
Gas Weatherization	All	0%	0%	0%	100%
Faucet Aerators	All	0%	0%	0%	100%
Low-Flow Shower Heads	All	0%	0%	0%	100%
Air Sealing	All	0%	0%	0%	100%
Insulation	All	0%	0%	0%	100%
Thermostats	All	0%	0%	0%	100%
Behavior/Feedback Program					
Group 2009 Pilot	National Grid	0%	0%	0%	100%
Group 2010 October	National Grid	0%	0%	0%	100%
Group 2011 October	National Grid	0%	0%	0%	100%
Group 2012 October	National Grid	0%	0%	0%	100%
Group 2010 August	NSTAR	0%	0%	0%	100%
Group 2011 January	NSTAR	0%	0%	0%	100%

Evaluations

All NTG factors are set to 100% based on no completed evaluations, unless noted otherwise below.

In the Residential Heating and Water Heating program, free-ridership rates are based on the results of the 2010 impact evaluation[632] , the 2011 NTG study[633] or NTGR agreed upon with the PAs and Consultants. The hard-to-reach (HTR) version of each of these measures has assumed free-ridership rates set to 1/3 the value of the non-HTR measure[634].

In the Multifamily program, NTG rates are based on the 2010 NTG Study[635] while Home Energy Services (Gas Weatherization) is based on the results of the Home Energy Assessment NTG study[636].

[632] Nexus Market Research (2010). HEHE Process and Impact Evaluation. Prepared for GasNetworks
[633] Nexus Market Research (2011). *Estimated Net-To-Gross (NTG) Factors for the Massachusetts Program Administrators (PAs) 2010 Residential New Construction Programs, Residential HEHE and Multi-Family Gas Programs, and Commercial and Industrial Gas Programs.* Prepared for Massachusetts Program Administrators and the Energy Efficiency Advisory Council. Study 11 in the 2010 Massachusetts Electric Energy Efficiency Annual Report
[634] Massachusetts common assumption.
[635] Nexus Market Research (2011). *Estimated Net-To-Gross (NTG) Factors for the Massachusetts Program Administrators (PAs) 2010 Residential New Construction Programs, Residential HEHE and Multi-Family Gas Programs, and Commercial and Industrial Gas Programs.* Prepared for Massachusetts Program Administrators and the Energy Efficiency Advisory Council. Study 11 in the 2010 Massachusetts Electric Energy Efficiency Annual Report

Commercial Natural Gas Measures						
TRM Measure Group	**Program**	**PA**	**FR**	**SO_P**	**SO_{NP}**	**NTG**
C&I New Construction & Major Renovation						
Gas Condensing Hot Water Boilers		NGRID	19.9%	2.4%	0%	82.5%
Gas Condensing Hot Water Boilers		NSTAR	28.8%	0.3%	0%	71.5%
Gas Condensing Hot Water Boilers		Columbia	45.6%	14.3%	0%	68.7%
Gas Condensing Hot Water Boilers		Berkshire	39.3%	43.9%	0%	104.6%
Gas Condensing Hot Water Boilers		NEG	27.2%	8.0%	0%	80.8%
Gas Condensing Hot Water Boilers		Unitil	32.1%	0%	0%	67.9%
Integrated Water Heater/Condensing Boiler (0.90 EF, 0.90 AFUE)		NGRID	19.9%	2.4%	0%	82.5%
Integrated Water Heater/Condensing Boiler (0.90 EF, 0.90 AFUE)		NSTAR	28.8%	0.3%	0%	71.5%
Integrated Water Heater/Condensing Boiler (0.90 EF, 0.90 AFUE)		Columbia	45.6%	14.3%	0%	68.7%
Integrated Water Heater/Condensing Boiler (0.90 EF, 0.90 AFUE)		Berkshire	39.3%	43.9%	0%	104.6%
Integrated Water Heater/Condensing Boiler (0.90 EF, 0.90 AFUE)		NEG	27.2%	8.0%	0%	80.8%
Integrated Water Heater/Condensing Boiler (0.90 EF, 0.90 AFUE)		Unitil	32.1%	0%	0%	67.9%
Condensing Stand-Alone Water Heater		NGRID	19.9%	2.4%	0%	82.5%
Condensing Stand-Alone Water Heater		NSTAR	28.8%	0.3%	0%	71.5%
Condensing Stand-Alone Water Heater		Columbia	45.6%	14.3%	0%	68.7%
Condensing Stand-Alone Water Heater		Berkshire	39.3%	43.9%	0%	104.6%
Condensing Stand-Alone Water Heater		NEG	27.2%	8.0%	0%	80.8%
Condensing Stand-Alone Water Heater		Unitil	32.1%	0%	0%	67.9%
Furnaces		NGRID	19.9%	2.4%	0%	82.5%
Furnaces		NSTAR	28.8%	0.3%	0%	71.5%
Furnaces		Columbia	45.6%	14.3%	0%	68.7%
Furnaces		Berkshire	39.3%	43.9%	0%	104.6%
Furnaces		NEG	27.2%	8.0%	0%	80.8%
Furnaces		Unitil	32.1%	0%	0%	67.9%
Infrared Heaters		NGRID	19.9%	2.4%	0%	82.5%
Infrared Heaters		NSTAR	28.8%	0.3%	0%	71.5%
Infrared Heaters		Columbia	45.6%	14.3%	0%	68.7%
Infrared Heaters		Berkshire	39.3%	43.9%	0%	104.6%
Infrared Heaters		NEG	27.2%	8.0%	0%	80.8%
Infrared Heaters		Unitil	32.1%	0%	0%	67.9%
Water Heaters		NGRID	19.9%	2.4%	0%	82.5%
Water Heaters		NSTAR	28.8%	0.3%	0%	71.5%
Water Heaters		Columbia	45.6%	14.3%	0%	68.7%
Water Heaters		Berkshire	39.3%	43.9%	0%	104.6%

[636] Cadmus (2011). *2010 Net-to-Gross Findings: Home Energy Assessment.* The Electric and Gas Program Administrators of Massachusetts. Study 6 in the 2010 Massachusetts Electric Energy Efficiency Annual Report

Water Heaters	NEG	27.2%	8.0%	0%	80.8%
Water Heaters	Unitil	32.1%	0%	0%	67.9%
Commercial Ovens	NGRID	19.9%	2.4%	0%	82.5%
Commercial Ovens	NSTAR	28.8%	0.3%	0%	71.5%
Commercial Ovens	Columbia	45.6%	14.3%	0%	68.7%
Commercial Ovens	Berkshire	39.3%	43.9%	0%	104.6%
Commercial Ovens	NEG	27.2%	8.0%	0%	80.8%
Commercial Ovens	Unitil	32.1%	0%	0%	67.9%
Commercial Griddle	NGRID	19.9%	2.4%	0%	82.5%
Commercial Griddle	NSTAR	28.8%	0.3%	0%	71.5%
Commercial Griddle	Columbia	45.6%	14.3%	0%	68.7%
Commercial Griddle	Berkshire	39.3%	43.9%	0%	104.6%
Commercial Griddle	NEG	27.2%	8.0%	0%	80.8%
Commercial Griddle	Unitil	32.1%	0%	0%	67.9%
Commercial Fryers	NGRID	19.9%	2.4%	0%	82.5%
Commercial Fryers	NSTAR	28.8%	0.3%	0%	71.5%
Commercial Fryers	Columbia	45.6%	14.3%	0%	68.7%
Commercial Fryers	Berkshire	39.3%	43.9%	0%	104.6%
Commercial Fryers	NEG	27.2%	8.0%	0%	80.8%
Commercial Fryers	Unitil	32.1%	0%	0%	67.9%
Commercial Steamer	NGRID	19.9%	2.4%	0%	82.5%
Commercial Steamer	NSTAR	28.8%	0.3%	0%	71.5%
Commercial Steamer	Columbia	45.6%	14.3%	0%	68.7%
Commercial Steamer	Berkshire	39.3%	43.9%	0%	104.6%
Commercial Steamer	NEG	27.2%	8.0%	0%	80.8%
Commercial Steamer	Unitil	32.1%	0%	0%	67.9%
Custom Measures	NGRID	31.2%	0.3%	0%	69.1%
Custom Measures	NSTAR	24.0%	4.6%	0%	80.6%
Custom Measures	Columbia	32.6%	44.2%	0%	111.6%
Custom Measures	Berkshire	29.3%	21.5%	0%	92.2%
Custom Measures	NEG	29.3%	21.5%	0%	92.2%
Custom Measures	Unitil	29.3%	21.5%	0%	92.2%
C&I Retrofit					
Boiler Reset Controls	NGRID	19.9%	2.4%	0%	82.5%
Boiler Reset Controls	NSTAR	28.8%	0.3%	0%	71.5%
Boiler Reset Controls	Columbia	45.6%	14.3%	0%	68.7%
Boiler Reset Controls	Berkshire	39.3%	43.9%	0%	104.6%
Boiler Reset Controls	NEG	27.2%	8.0%	0%	80.8%
Boiler Reset Controls	Unitil	32.1%	0%	0%	67.9%
ES Programmable Thermostats	NGRID	19.9%	2.4%	0%	82.5%
ES Programmable Thermostats	NSTAR	28.8%	0.3%	0%	71.5%
ES Programmable Thermostats	Columbia	45.6%	14.3%	0%	68.7%
ES Programmable Thermostats	Berkshire	39.3%	43.9%	0%	104.6%
ES Programmable Thermostats	NEG	27.2%	8.0%	0%	80.8%

ES Programmable Thermostats	Unitil	32.1%	0%	0%	67.9%
Pre-Rinse Spray Valve	NGRID	19.9%	2.4%	0%	82.5%
Pre-Rinse Spray Valve	NSTAR	28.8%	0.3%	0%	71.5%
Pre-Rinse Spray Valve	Columbia	45.6%	14.3%	0%	68.7%
Pre-Rinse Spray Valve	Berkshire	39.3%	43.9%	0%	104.6%
Pre-Rinse Spray Valve	NEG	27.2%	8.0%	0%	80.8%
Pre-Rinse Spray Valve	Unitil	32.1%	0%	0%	67.9%
Steam Traps	NGRID	19.9%	2.4%	0%	82.5%
Steam Traps	NSTAR	28.8%	0.3%	0%	71.5%
Steam Traps	Columbia	45.6%	14.3%	0%	68.7%
Steam Traps	Berkshire	39.3%	43.9%	0%	104.6%
Steam Traps	NEG	27.2%	8.0%	0%	80.8%
Steam Traps	Unitil	32.1%	0%	0%	67.9%
Custom Measures	NGRID	31.2%	0.3%	0%	69.1%
Custom Measures	NSTAR	24.0%	4.6%	0%	80.6%
Custom Measures	Columbia	32.6%	44.2%	0%	111.6%
Custom Measures	Berkshire	29.3%	21.5%	0%	92.2%
Custom Measures	NEG	29.3%	21.5%	0%	92.2%
Custom Measures	Unitil	29.3%	21.5%	0%	92.2%
C&I Direct Install					
ES Programmable Thermostats	NGRID	19.9%	2.4%	0%	82.5%
ES Programmable Thermostats	NSTAR	28.8%	0.3%	0%	71.5%
ES Programmable Thermostats	Columbia	45.6%	14.3%	0%	68.7%
ES Programmable Thermostats	Berkshire	39.3%	43.9%	0%	104.6%
ES Programmable Thermostats	NEG	27.2%	8.0%	0%	80.8%
ES Programmable Thermostats	Unitil	32.1%	0%	0%	67.9%
Pre-Rinse Spray Valve	NGRID	19.9%	2.4%	0%	82.5%
Pre-Rinse Spray Valve	NSTAR	28.8%	0.3%	0%	71.5%
Pre-Rinse Spray Valve	Columbia	45.6%	14.3%	0%	68.7%
Pre-Rinse Spray Valve	Berkshire	39.3%	43.9%	0%	104.6%
Pre-Rinse Spray Valve	NEG	27.2%	8.0%	0%	80.8%
Pre-Rinse Spray Valve	Unitil	32.1%	0%	0%	67.9%
Faucet Aerators	NGRID	19.9%	2.4%	0%	82.5%
Faucet Aerators	NSTAR	28.8%	0.3%	0%	71.5%
Faucet Aerators	Columbia	45.6%	14.3%	0%	68.7%
Faucet Aerators	Berkshire	39.3%	43.9%	0%	104.6%
Faucet Aerators	NEG	27.2%	8.0%	0%	80.8%
Faucet Aerators	Unitil	32.1%	0%	0%	67.9%
Low Flow Shower Heads	NGRID	19.9%	2.4%	0%	82.5%
Low Flow Shower Heads	NSTAR	28.8%	0.3%	0%	71.5%
Low Flow Shower Heads	Columbia	45.6%	14.3%	0%	68.7%
Low Flow Shower Heads	Berkshire	39.3%	43.9%	0%	104.6%
Low Flow Shower Heads	NEG	27.2%	8.0%	0%	80.8%
Low Flow Shower Heads	Unitil	32.1%	0%	0%	67.9%

Evaluations

All NTG factors are based on the results of the 2010 Commercial and Industrial Natural Gas Programs Free-ridership and Spillover Study conducted by TetraTech for the MA Gas PAs.[637] This study developed free-ridership and participant spillover rates for each PA for prescriptive and custom measures. PAs that had fewer than 10 customers surveyed for a program type used the statewide rates.

[637] TetraTech (2011). *National Grid, NSTAR, Unitil, Berkshire Gas, Columbia Gas, and New England Gas 2010 Commercial and Industrial Natural Gas Programs Free-ridership and Spillover Study*. Draft Report September 12, 2011

Appendix D: Non-Resource Impacts

Residential Program Non-Energy Impacts

End Use	TRM Measures	NEI	Description	Value or Algorithm	Basis	Duration	Notes on Programs
Lighting	Indoor Fixture Outdoor Fixture LED Fixture	Lighting Quality and Lifetime	O&M savings due to more efficient fixtures	$3.50	per measure	One Time	
	CFL Bulb LED Bulb	Lighting Quality and Lifetime	O&M savings due to more efficient bulbs	$3.00	per measure	One Time	
Products	Refrigerator/ Freezer Recycling	Refrigerator/ Freezer Turn-in	Non-energy benefits of turning in a refrigerator and/or freezer as part of the MA turn-in program. The total benefit is comprised of 3 parts: $1.06 for avoided landfill space, $1.25 for recycling of plastics and glass, and $170.22 for incineration of insulating foam	$172.53	per measure	One Time	Appliance Turn-in programs only
HVAC	Heating System (Retrofit and Rebate)	Improved Safety	Reduced incidence of fire and carbon monoxide exposure as a result of installing a new heating system	$45.05	per measure	Annual	Low Income programs only
	Window AC (Retrofit)	Window Air Conditioner Replacement	Non-energy benefits associated with installing a new room air conditioner replacement	$45.00	per measure	Annual	Low Income programs only
Various	All Measures with oil savings	National Security	Reducing the need for foreign energy imports thereby increasing national security	MMBTU Oil Savings * $1.83	per measure	Annual	Retrofit programs only
	All electric measures with kWh savings and all gas measures with MMBTU	Rate Discounts	Financial savings to utility as a result of a smaller portion of energy being sold at the low income rate	Elec: (kwh savings per measure)*(R1-R2) Gas: (therms savings per measure)*(R3-R4)	per measure	Annual	Low Income programs only

	savings						

(1) The NEIs in this table represent impacts that accrue specifically measures in the 2012 MA portfolio of programs. Additional NEIs that accrue to participants are used in the benefit - cost analysis of the programs but are not detailed in this manual.
(2) The DHW measures NEI is applied to the DHW ISMs measures that are bundled together and are modeled in units of households, assuming one showerhead and one faucet aerator per household.
(3) Source of NEIs is "Massachusetts Program Administrators: Massachusetts Special and Cross-Sector Studies Area, Residential and Low-Income Non-Energy Impacts (NEI) Evaluation," NMR Group, Inc., Tetra Tech. August 15, 2011.

Commercial & Industrial Program Non-Energy Impacts

End Use	TRM Measures	NEI	Description	Value	Basis	Type
Lighting	New Construction CFL O&M	O&M Savings	Operation & Maintenance savings from fewer replacements over the life of the more efficient measure	$17.93	Unit	Annual
	Retrofit CFL O&M	O&M Savings	Operation & Maintenance savings from fewer replacements over the life of the more efficient measure	$18.67	Unit	Annual
	New Construction LED Traffic Light O&M	O&M Savings	Operation & Maintenance savings from fewer replacements over the life of the more efficient measure	$30.02	Unit	Annual
	Retrofit LED Traffic Light O&M	O&M Savings	Operation & Maintenance savings from fewer replacements over the life of the more efficient measure	$29.37	Unit	Annual
	New Construction and Retrofit Control/Sensor O&M	O&M Savings	Operation & Maintenance savings from fewer replacements over the life of the more efficient measure	$6.69	kW Saved	Annual
	Retrofit Fluorescent Lamp-Ballast O&M	O&M Savings	Operation & Maintenance savings from fewer replacements over the life of the more efficient measure	$0.41	Unit	Annual
	SBS Retrofit Fluorescent Lamp-Ballast w/ Reflector O&M	O&M Savings	Operation & Maintenance savings from fewer replacements over the life of the more efficient measure	$0.91	Unit	Annual
	Retrofit Exit Sign O&M	O&M Savings	Operation & Maintenance savings from fewer replacements over the life of the more efficient measure	$33.65	Unit	Annual

(1) Source is Optimal Energy, Inc. MEMO "Non-Electric Benefits Analysis Update" November 7, 2008.

In addition to the NEIs in these tables, the 2011 study of Residential and Low Income NEIs identified a number of participant-based NEIs which are claimed in the 2012 plan. These NEIs and their application are summarized in the tables below.

Per Participant Non-Energy Impacts for Electric Programs

Program	NEI	Description	Measure Category	Value	Duration	Notes on Model Application
Residential New Construction	Thermal Comfort	Greater participant-perceived comfort in home	N/A	$77.00	Annual	Values are applied to the "Heating" measure quantity in this program as an approximation of program participants.
	Noise Reduction	Less participant-perceived noise in the home		$40.00	Annual	
	Property Value Increase	Increased value of property and expected ease of selling home		$72.00	Annual	
Residential Cooling and Heating Equipment	Thermal Comfort	Greater participant-perceived comfort in home	Heating System	$48.63	Annual	Values are applied per participant. Since program participants = rebates, measure category values are counted for every unit. The "heating and cooling system" values are applied to heat pumps.
			Cooling System	$3.92		
			Heating and Cooling System	$5.05		
	Noise Reduction	Less participant-perceived noise in the home	Cooling System	$2.83	Annual	
			Heating and Cooling System	$1.42		
	Home Durability	Increased home durability in terms of maintenance requirements because of better quality heating, cooling and structural materials	Heating System	$17.42	Annual	
			Cooling System	$1.54		
			Heating and Cooling System	$1.98		
	Equipment Maintenance	Reduced maintenance costs of owning newer and/or more efficient appliance equipment	Heating System	$102.40	Annual	
			Cooling System	$7.54		
			Heating and Cooling System	$9.42		
	Health Benefits	Fewer colds and viruses, improved indoor air	Heating System	$1.56	Annual	
			Cooling System	$0.13		

Program	NEI	Description	Measure Category	Value	Duration	Notes on Model Application
		quality and ease of maintaining healthy relative humidity as a result of weatherization in home	Heating and Cooling System	$0.16		
	Property Value Increase	Increased value of property and expected ease of selling home	Heating System	$678.52	One Time	
			Cooling System	$62.65		
			Heating and Cooling System	$80.69		
MassSave	Thermal Comfort	Greater participant-perceived comfort in home	N/A	$125.00	Annual	As an approximation of program weatherization participants, values are reduced to 30% of original value and applied to the planned audits for the 2012 National Grid MassSave program. 30% represents the approximate conversion rate of audits to weatherization participants.
	Noise Reduction	Less participant-perceived noise in the home		$31.00	Annual	
	Home Durability	Increased home durability in terms of maintenance requirements because of better quality heating, cooling and structural materials		$149.00	Annual	
	Equipment Maintenance	Reduced maintenance costs of owning newer and/or more efficient appliance equipment		$124.00	Annual	
	Health Benefits	Fewer colds and viruses, improved indoor air quality and ease of maintaining healthy relative humidity as a result of weatherization in home		$4.00	Annual	

Program	NEI	Description	Measure Category	Value	Duration	Notes on Model Application
	Property Value Increase	Increased value of property and expected ease of selling home		$1,998.00	One Time	
Multifamily Retrofit	Thermal Comfort	Greater participant-perceived comfort in home	N/A	$125.00	Annual	Values are applied to the 2012 quantity of the SPACE measure as an approximation of weatherization program participants.
	Noise Reduction	Less participant-perceived noise in the home		$31.00	Annual	
	Home Durability	Increased home durability in terms of maintenance requirements because of better quality heating, cooling and structural materials		$149.00	Annual	
	Equipment Maintenance	Reduced maintenance costs of owning newer and/or more efficient appliance equipment		$124.00	Annual	
	Health Benefits	Fewer colds and viruses, improved indoor air quality and ease of maintaining healthy relative humidity as a result of weatherization in home		$4.00	Annual	
	Property Value Increase	Increased value of property and expected ease of selling home		$1,998.00	One Time	
Low Income Residential New Construction	Arrearages	Reduced arrearage carrying costs as a result of customers being more able to pay their lower bills	N/A	$2.61	Annual	Values are applied to the "Heating" measure quantity in this program as an approximation of program participants.

Program	NEI	Description	Measure Category	Value	Duration	Notes on Model Application
	Bad Debt Write-offs	Reduced costs to utility of uncollectable, unpaid balances as a result of customers being more able to pay their lower bills		$3.74	Annual	
	Terminations and Reconnections	Reduced costs associated with terminations and reconnections to utility due to nonpayment as a result of customers being more able to pay their lower bills		$0.43	Annual	
	Customer Calls and Collections	Utility savings in staff time and materials for fewer customer calls as a result of more timely bill payments		$0.58	Annual	
	Notices	Financial savings to utility as a result of fewer notices sent to customers for late payments and terminations		$0.34	Annual	
	Thermal Comfort	Greater participant-perceived comfort in home		$101.00	Annual	
	Noise Reduction	Less participant-perceived noise in the home		$30.00	Annual	

Program	NEI	Description	Measure Category	Value	Duration	Notes on Model Application
	Home Durability	Increased home durability in terms of maintenance requirements because of better quality heating, cooling and structural materials		$35.00	Annual	
	Equipment Maintenance	Reduced maintenance costs of owning newer and/or more efficient appliance equipment		$54.00	Annual	
	Health Benefits	Fewer colds and viruses, improved indoor air quality and ease of maintaining healthy relative humidity as a result of weatherization in home		$19.00	Annual	
	Property Value Increase	Increased value of property and expected ease of selling home		$949.00	One Time	
Low Income 1 to 4 Family Retrofit	Arrearages	Reduced arrearage carrying costs as a result of customers being more able to pay their lower bills	N/A	$2.61	Annual	As an approximation of program weatherization participants, values are reduced to 33% of original value and applied to the planned audits for the 2012 National Grid MassSave program. 33% represents the approximate conversion rate of audits to weatherization participants.
	Bad Debt Write-offs	Reduced costs to utility of uncollectable, unpaid balances as a result of customers being more able to pay their lower bills		$3.74	Annual	

Program	NEI	Description	Measure Category	Value	Duration	Notes on Model Application
	Terminations and Reconnections	Reduced costs associated with terminations and reconnections to utility due to nonpayment as a result of customers being more able to pay their lower bills		$0.43	Annual	
	Customer Calls and Collections	Utility savings in staff time and materials for fewer customer calls as a result of more timely bill payments		$0.58	Annual	
	Notices	Financial savings to utility as a result of fewer notices sent to customers for late payments and terminations		$0.34	Annual	
	Thermal Comfort	Greater participant-perceived comfort in home		$101.00	Annual	
	Noise Reduction	Less participant-perceived noise in the home		$30.00	Annual	
	Home Durability	Increased home durability in terms of maintenance requirements because of better quality heating, cooling and structural materials		$35.00	Annual	

Program	NEI	Description	Measure Category	Value	Duration	Notes on Model Application
	Equipment Maintenance	Reduced maintenance costs of owning newer and/or more efficient appliance equipment		$54.00	Annual	
	Health Benefits	Fewer colds and viruses, improved indoor air quality and ease of maintaining healthy relative humidity as a result of weatherization in home		$19.00	Annual	
	Property Value Increase	Increased value of property and expected ease of selling home		$949.00	One Time	
	Safety-Related Emergency Calls	Financial savings to the utility as a result of fewer safety related emergency calls being made	Heating System	$8.43	Annual	As an approximation of program participants with heating equipment, this value is applied to the 2012 planned quantity for the Heating System Replacement measure.
Low Income Multifamily Retrofit	Arrearages	Reduced arrearage carrying costs as a result of customers being more able to pay their lower bills	N/A	$2.61	Annual	Values are applied to the SPACE measure quantity as an approximation of weatherization program participants.
	Bad Debt Write-offs	Reduced costs to utility of uncollectable, unpaid balances as a result of customers being more able to pay their lower bills		$3.74	Annual	

Program	NEI	Description	Measure Category	Value	Duration	Notes on Model Application
	Terminations and Reconnections	Reduced costs associated with terminations and reconnections to utility due to nonpayment as a result of customers being more able to pay their lower bills		$0.43	Annual	
	Customer Calls and Collections	Utility savings in staff time and materials for fewer customer calls as a result of more timely bill payments		$0.58	Annual	
	Notices	Financial savings to utility as a result of fewer notices sent to customers for late payments and terminations		$0.34	Annual	
	Thermal Comfort	Greater participant-perceived comfort in home		$101.00	Annual	
	Noise Reduction	Less participant-perceived noise in the home		$30.00	Annual	
	Home Durability	Increased home durability in terms of maintenance requirements because of better quality heating, cooling and structural materials		$35.00	Annual	

Program	NEI	Description	Measure Category	Value	Duration	Notes on Model Application
	Equipment Maintenance	Reduced maintenance costs of owning newer and/or more efficient appliance equipment		$54.00	Annual	
	Health Benefits	Fewer colds and viruses, improved indoor air quality and ease of maintaining healthy relative humidity as a result of weatherization in home		$19.00	Annual	
	Property Value Increase	Increased value of property and expected ease of selling home		$949.00	One Time	
	Safety-Related Emergency Calls	Financial savings to the utility as a result of fewer safety related emergency calls being made	Heating System	$8.43	Annual	
	Rental Units Marketability	Financial savings to owners of LI rental housing as a result of increased marketability of the more efficient housing.	N/A	$0.96	Annual	
	Property Durability	Financial savings to owners of LI rental housing as a result of more durable and efficient materials being installed.		$36.85	Annual	

Program	NEI	Description	Measure Category	Value	Duration	Notes on Model Application
	Reduced Tenant Complaints	Savings to owners of LI rental housing in terms of staff time and materials as a result of fewer tenant complaints with the more efficient measures.		$19.61	Annual	
	Rental Unit Increased Property Value	Owner-perceived increased property value due to more energy efficient measures		$17.03	One Time	

(1) Source of NEIs is "Massachusetts Program Administrators: Massachusetts Special and Cross-Sector Studies Area, Residential and Low-Income Non-Energy Impacts (NEI) Evaluation," NMR Group, Inc., Tetra Tech. August, 15 2011.

Per Participant Non-Energy Impacts for Gas Programs

Program	NEI	Description	Measure Category	Value	Duration	Notes on Model Application
Residential Heating and Hot Water	Thermal Comfort	Greater participant-perceived comfort in home	Heating System	$48.63	Annual	Values are applied per participant. Since program participants = rebates, measure category values are counted for every unit except for Thermostats which are counted for every 1.15 units. The average number of thermostats installed per participant is 1.15. The "heating and hot water system" values are applied to integrated water heater/condensing boilers.
			Heating and Hot Water System	$1.83		
			Thermostats	$3.99		
	Home Durability	Increased home durability in terms of maintenance requirements because of better quality heating, cooling and structural materials	Heating System	$17.42	Annual	
			Hot Water System	$2.13		
			Heating and Hot Water System	$0.72		
			Thermostats	$1.33		
	Equipment Maintenance	Reduced maintenance costs of owning newer and/or more efficient appliance equipment	Heating System	$102.40	Annual	
			Heating and Hot Water System	$3.41		
	Health Benefits	Fewer colds and viruses, improved indoor air quality and ease of maintaining healthy relative humidity as a result of weatherization in home	Heating System	$1.56	Annual	
			Heating and Hot Water System	$0.06		
			Thermostats	$0.13		
	Property Value Increase	Increased value of property and expected ease of selling home	Heating System	$678.52	One Time	
			Hot Water System	$82.56		
			Heating and Hot Water System	$29.17		
			Thermostats	$51.49		
Weatherization	Thermal Comfort	Greater participant-perceived comfort in home	N/A	$25.00	Annual	As an approximation of program weatherization participants, values

Program	NEI	Description	Measure Category	Value	Duration	Notes on Model Application
	Noise Reduction	Less participant-perceived noise in the home		$11.22	Annual	are applied to the 2012 insulation measure quantity.
	Home Durability	Increased home durability in terms of maintenance requirements because of better quality heating, cooling and structural materials		$9.57	Annual	
	Health Benefits	Fewer colds and viruses, improved indoor air quality and ease of maintaining healthy relative humidity as a result of weatherization in home		$0.79	Annual	
	Property Value Increase	Increased value of property and expected ease of selling home		$381.28	One Time	
Multifamily Retrofit	Thermal Comfort	Greater participant-perceived comfort in home	Insulation	$25.15	Annual	As an approximation of program weatherization participants, values are reduced to 75% and applied to the 2012 air sealing & insulation measure. 75% represents the number of planned
			Air Sealing	$10.13		
	Noise Reduction	Less participant-perceived noise in the home	Insulation	$11.54	Annual	
			Air Sealing	$4.88		
	Home	Increased	Insulation	$9.82	Annual	

Program	NEI	Description	Measure Category	Value	Duration	Notes on Model Application
	Durability	home durability in terms of maintenance requirements because of better quality heating, cooling and structural materials	Air Sealing	$3.95		units that result in weatherization participants.
	Health Benefits	Fewer colds and viruses, improved indoor air quality and ease of maintaining healthy relative humidity as a result of weatherization in home	Insulation	$0.80	Annual	
			Air Sealing	$0.32		
	Property Value Increase	Increased value of property and expected ease of selling home	Insulation	$378.05	One Time	
			Air Sealing	$135.83		
Residential New Construction	Thermal Comfort	Greater participant-perceived comfort in home	N/A	$77.00	Annual	Values are applied to the "Heating" measure quantity in this program as an approximation of program participants.
	Noise Reduction	Less participant-perceived noise in the home		$40.00	Annual	
	Property Value Increase	Increased value of property and expected ease of selling home		$72.00	Annual	
Low Income Single Family Low Income Multifamily	Arrearages	Reduced arrearage carrying costs as a result of customers being more able to pay their lower bills	N/A	$2.61	Annual	Values are applied to program participants.

Program	NEI	Description	Measure Category	Value	Duration	Notes on Model Application
	Bad Debt Write-offs	Reduced costs to utility of uncollectable, unpaid balances as a result of customers being more able to pay their lower bills		$3.74	Annual	
	Terminations and Reconnections	Reduced costs associated with terminations and reconnections to utility due to nonpayment as a result of customers being more able to pay their lower bills		$0.43	Annual	
	Customer Calls and Collections	Utility savings in staff time and materials for fewer customer calls as a result of more timely bill payments		$0.58	Annual	
	Notices	Financial savings to utility as a result of fewer notices sent to customers for late payments and terminations		$0.34	Annual	
	Safety-Related Emergency Calls	Financial savings to the utility as a result of fewer safety related emergency calls being made	Heating System	$8.43	Annual	As an approximation of program participants with heating equipment, this value is applied to the 2012 planned quantity for the Heating System Replacement measure.
	Thermal	Greater	Insulation	$25.38	Annual	As an

Program	NEI	Description	Measure Category	Value	Duration	Notes on Model Application
	Comfort	participant-perceived comfort in home	Air Sealing	$30.23		approximation of program participants receiving each of these measure category values, insulation and air sealing values were applied to the Weatherization measure (LI SF) or the Air Sealing & Insulation Measure (LI MF) and heating system values were applied to the Heating System Replacement measure.
			Heating System	$28.01		
	Noise Reduction	Less participant-perceived noise in the home	Insulation	$13.56	Annual	
			Air Sealing	$16.39		
	Home Durability	Increased home durability in terms of maintenance requirements because of better quality heating, cooling and structural materials	Insulation	$8.76	Annual	
			Air Sealing	$10.61		
			Heating System	$9.72		
	Equipment Maintenance	Reduced maintenance costs of owning newer and/or more efficient appliance equipment	Heating System	$27.43	Annual	
	Health Benefits	Fewer colds and viruses, improved indoor air quality and ease of maintaining healthy relative humidity as a result of weatherization in home	Insulation	$4.77	Annual	
			Air Sealing	$5.69		
			Heating System	$5.27		
	Property Value Increase	Increased value of property and expected ease of selling home	Insulation	$223.63	One Time	
			Air Sealing	$144.93		
			Heating System	$249.20		

Program	NEI	Description	Measure Category	Value	Duration	Notes on Model Application
Additional NEIs for Low Income Multifamily	Rental Units Marketability	Financial savings to owners of LI rental housing as a result of increased marketability of the more efficient housing.	Air Sealing	$0.07	Annual	Values are applied to the 2012 planned quantity for Air Sealing with the assumption that one air sealing job is done per household.
	Property Durability	Financial savings to owners of LI rental housing as a result of more durable and efficient materials being installed.		$2.58	Annual	
	Reduced Tenant Complaints	Savings to owners of LI rental housing in terms of staff time and materials as a result of fewer tenant complaints with the more efficient measures.		$1.37	Annual	
	Rental Unit Increased Property Value	Owner-perceived increased property value due to more energy efficient measures		$1.19	One Time	

(1) Source of NEIs is "Massachusetts Program Administrators: Massachusetts Special and Cross-Sector Studies Area, Residential and Low-Income Non-Energy Impacts (NEI) Evaluation," NMR Group, Inc., Tetra Tech. August, 15 2011.

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Appendix F: Acronyms

ACRONYM	DESCRIPTION
AC	Air Conditioning
AFUE	Annual Fuel Utilization Efficiency (see the Glossary)
AHU	Air Handling Unit
Btu	British Thermal Unit (see the Glossary)
CF	Coincidence Factor (see the Glossary)
CFL	Compact Fluorescent Lamp
CHP	Combined Heat and Power
COP	Coefficient of Performance (see the Glossary)
DCV	Demand Controlled Ventillation
DHW	Domestic Hot Water
DOER	Department of Energy Resources
DSM	Demand Side Management (see the Glossary)
ECM	Electrically Commutated Motor
EER	Energy Efficiency Ratio (see the Glossary)
EF	Efficiency Factor
EFLH	Equivalent Full Load Hours (see the Glossary)
ES	ENERGY STAR® (see the Glossary)
FCM	Forward Capacity Market
FR	Free-Ridership (see the Glossary)
HE	High-Efficiency
HID	High-Intensity Discharge (a lighting technology)
HP	Horse Power (see the Glossary)
HSPF	Heating Seasonal Performance Factor (see the Glossary)
HVAC	Heating, Ventilating, and Air Conditioning
ISO	Independent System Operator
ISR	In-Service Rate (see the Glossary)
kW	Kilo-Watt, a unit of electric demand equal to 1,000 watts
kWh	Kilowatt-Hour, a unit of energy (1 kilowatt of power supplied for one hour)
LED	Light-Emitting Diode (one type of solid-state lighting)
LCD	Liquid Crystal Display (a technology used for computer monitors and similar displays)
MMBtu	One million British Thermal Units (see “Btu” in the Glossary)
MW	Megawatt – a measure of electric demand equal to 1,000 kilowatts
MWh	Megawatt-hour – a measure of energy equal to 1,000 kilowatt-hours
NEB	Non-Electric Benefit (see the Glossary)
NEI	Non-Energy Impact
NE-ISO	New England Independent System Operator
NTG	Net-to-Gross (see the Glossary)
O&M	Operations and Maintenance
PA	Program Administrator (see the Glossary)
PARIS	Planning And Reporting Information System (a DOER database - see the Glossary)
PC	Personal Computer
RR	Realization Rate (see the Glossary)
SEER	Seasonal Energy Efficiency Ratio (see the Glossary)
SO	Spillover (see the Glossary)
SPF	Savings Persistence Factor (see the Glossary)
SSL	Solid-State Lighting (e.g., LED lighting)
VSD	Variable-Speed Drive

Appendix G: Glossary

This glossary provides definitions as they are applied in this TRM for Massachusetts' energy efficiency programs. Alternate definitions may be used for some terms in other contexts.

TERM	DESCRIPTION
Adjusted Gross Savings	Gross savings (as calculated by the measure savings algorithms) that have been subsequently adjusted by the application of all impact factors except the net-to-gross factors (free-ridership and spillover). For more detail, see the section on Impact Factors for Calculating Adjusted Gross and Net Savings.
AFUE	Annual Fuel Utilization Efficiency. The measure of seasonal or annual efficiency of a furnace or boiler. AFUE takes into account the cyclic on/off operation and associated energy losses of the heating unit as it responds to changes in the load, which in turn is affected by changes in weather and occupant controls.
Baseline Efficiency	The level of efficiency of the equipment that would have been installed without any influence from the program or, for retrofit cases where site-specific information is available, the actual efficiency of the existing equipment.
Btu	British thermal unit. A Btu is approximately the amount of energy needed to heat one pound of water by one degree Fahrenheit.
Coefficient of Performance (COP)	Coefficient of Performance is a measure of the efficiency of a heat pump, air conditioner, or refrigeration system. A COP value is given as the Btu output of a device divided by the Btu input of the device. The input and output are determined at AHRI testing standards conditions designed to reflect peak load operation.
Coincidence Factor (CF)	Coincidence Factors represent the fraction of connected load expected to occur concurrent to a particular system peak period; separate CF are found for summer and winter peaks. The CF given in the TRM includes both coincidence and diversity factors multiplied into one number. Coincidence factors are provided for peak periods defined by the NE-ISO for FCM purposes and calculated consistent with the FCM methodology.
Connected Load kW Savings	The connected load kW savings is the power saved by the equipment while in use. In some cases the savings reflect the maximum power draw of equipment at full load. In other cases the connected load may be variable, which must be accounted for in the savings algorithm.
Deemed Savings	Savings values (electric, fossil fuel and/or non-energy benefits) determined from savings algorithms with assumed values for all algorithm parameters. Alternatively, deemed savings values may be determined from evaluation studies. A measure with deemed savings will have the same savings per unit since all measure assumptions are the same. Deemed savings are used by program administrators to report savings for measures with well-defined performance characteristics relative to baseline efficiency cases. Deemed savings can simplify program planning and design, but may lead to over- or under-estimation of savings depending on product performance.
Deemed Calculated Savings	Savings values (electric, fossil fuel and/or non-energy benefits) that depend on a standard savings algorithm and for which at least one of the algorithm parameters (e.g., hours of operation) is project specific.
Demand Savings	The reduction in demand due to installation of an energy efficiency measure, usually expressed as kW and measured at the customer's meter (see Connected Load kW Savings).
Demand Side Management (DSM)	Strategies used to manage energy demand including energy efficiency, load management, fuel substitution, and load building.
Diversity	A characteristic of a variety of electric loads whereby individual maximum demands occur at different times. For example, 50 efficient light fixtures may be installed, but they are not necessarily all on at the same time. See Coincidence Factor.

TERM	DESCRIPTION
Diversity Factor	This TRM uses coincidence factors that incorporate diversity (See Coincidence Factor), thus this TRM has no separate diversity factors. A diversity factor is typically calculated as: 1) the percent of maximum demand savings from energy efficiency measures available at the time of the company's peak demand, or 2) the ratio of the sum of the demands of a group of users to their coincident maximum demand.
End Use	Refers to the category of end use or service provided by a measure or technology (e.g., lighting, cooling, etc.). For the purpose of this manual, end uses with their PARIS codes include: ALght Lighting HEUBe Behavior HVAC HVAC Ienvl Insulation & Air Sealing CMoDr Motors & Drives JGchp Combined Heat & Power DRefr Refrigeration KSdhw Solar Hot Water EHoWa Hot Water LDmdR Demand Response FComA Compressed Air MPvEl Photovoltaic Panels GProc Process* *For residential measures, "process" is used for products that have low savings, such as consumer electronics, or do not conform to existing end use categories. For commercial and industrial measures, "process" is used for systematic improvements to manufacturing or pump systems, or efficient models of specialty equipment not covered in other end uses.
Energy Efficiency Ratio (EER)	The Energy Efficiency Ratio is a measure of the efficiency of a cooling system at a specified peak, design temperature, or outdoor temperature. In technical terms, EER is the steady-state rate of heat energy removal (i.e. cooling capacity) of a product measured in Btuh output divided by watts input.
ENERGY STAR® (ES)	Brand name for the voluntary energy efficiency labeling initiative sponsored by the U.S. Environmental Protection Agency.
Energy Costing Period	A period of relatively high or low system energy cost, by season. The energy periods defined by ISO-NE are: • **Summer Peak**: 6am–10pm, Monday–Friday (except ISO holidays), June–September • **Summer Off-Peak:** Summer hours not included in the summer peak hours: 10pm–6am, Monday–Friday, all day on Saturday and Sunday, and ISO holidays, June–September • **Winter Peak:** 6am–10pm, Monday–Friday (except ISO holidays), January–May and October–December • **Winter Off-Peak:** Winter hours not included in the sinter peak hours: 10pm–6am, Monday–Friday, all day on Saturday and Sunday, and ISO holidays, January–May and October–December.
Equivalent Full Load Hours (EFLH)	The equivalent hours that equipment would need to operate at its peak capacity in order to consume its estimated annual kWh consumption (annual kWh/connected kW).
Free Rider	A customer who participates in an energy efficiency program, but would have installed some or all of the same measure(s) on their own, with no change in timing of the installation, if the program had not been available.
Free-Ridership Rate	The percentage of savings attributable to participants who would have installed the measures in the absence of program intervention.
Gross kW	Expected demand reduction based on a comparison of standard or replaced equipment and equipment installed through an energy efficiency program.
Gross kWh	Expected kWh reduction based on a comparison of standard or replaced equipment and equipment installed through an energy efficiency program.

TERM	DESCRIPTION
Gross Savings	A saving estimate calculated from objective technical factors. In this TRM, "gross savings" are calculated with the measure algorithms and do not include any application of impact factors. Once impact factors are applied, the savings are called "Adjusted Gross Savings". For more detail, see the section on Impact Factors for Calculating Adjusted Gross and Net Savings.
High Efficiency (HE)	Refers to the efficiency measures that are installed and promoted by the energy efficiency programs.
Horsepower (HP)	A unit for measuring the rate of doing work. One horsepower equals about three-fourths of a kilowatt (745.7 watts).
Heating Seasonal Performance Factor (HSPF)	A measure of the seasonal heating mode efficiencies of heat pumps expressed as the ratio of the total heating output to the total seasonal input energy.
Impact Factor	Generic term for a value used to adjust the gross savings estimated by the savings algorithms in order to reflect the actual savings attributable to the efficiency program. In this TRM, impact factors include realization rates, in-service rates, savings persistence, peak demand coincidence factors, free-ridership, spillover and net-to-gross factors. See the section on Impact Factors for more detail.
In-Service Rate	The percentage of units that are actually installed. For example, efficient lamps may have an in-service rate less than 100% since some lamps are purchased as replacement units and are not immediately installed. The in-service rate for most measures is 100%.
Measure Life	The number of years that an efficiency measure is expected to garner savings. These are generally based on engineering lives, but sometimes adjusted based on observations of market conditions.
Lost Opportunity	Refers to a measure being installed at the time of planned investment in new equipment or systems. Often this reflects either new construction, renovation, remodeling, planned expansion or replacement, or replacement of failure.
Measure	A product (a piece of equipment), combination of products, or process designed to provide energy and/or demand savings. Measure can also refer to a service or a practice that provides savings. Measure can also refer to a specific combination of technology and market/customer/practice/strategy (e.g., direct install low income CFL).
Net Savings	The final value of savings that is attributable to a program or measure. Net savings differs from gross savings (or adjusted gross savings) because it includes adjustments due to free-ridership and/or spillover. Net savings is sometimes referred to as "verified" or "final" savings. For more detail see the section on Impact Factors for Calculating Adjusted Gross and Net Savings.
Net-to-Gross Ratio	The ratio of net savings to the adjusted gross savings (for a measure or program). The adjusted gross savings include any adjustment by the impact factors other than free-ridership or spillover. Net-to-gross is usually expressed as a percent.
Non-Electric Benefits (NEBs)	Quantifiable benefits (beyond electric savings) that are the result of the installation of a measure. Fossil fuel, water, and maintenance are examples of non-electric benefits. Non-electric benefits can be negative (i.e. increased maintenance or increased fossil fuel usage which results from a measure) and therefore are sometimes referred to as "non-electric impacts".
Non-Participant	A customer who is eligible to participate in a program, but does not. A non-participant may install a measure because of a program, but the installation of the measure is not through regular program channels; as a result, their actions are normally only detected through evaluations.
On-Peak kW	See Summer/Winter On-peak kW
Operating Hours	Hours that a piece of equipment is expected to be in operation, not necessarily at full load (typically expressed per year).

TERM	DESCRIPTION
PARIS	Planning And Reporting Information System, a statewide database maintained by the Department of Energy Resources (DOER) that emulates the program administrators' screening model. As a repository for quantitative data from plans, preliminary reports, and reports, PARIS generates information that includes funding sources, customer profiles, program participation, costs, savings, cost-effectiveness and program impact factors from evaluation studies. DOER developed PARIS in 2003 as a collaborative effort with the Department of Public Utilities and the electric program administrators. Beginning with the 2010 plans, PARIS holds data from gas program administrators.
Participant	A customer who installs a measure through regular program channels and receives any benefit (i.e. incentive) that is available through the program because of their participation. Free-riders are a subset of this group.
Prescriptive Measure	A prescriptive measure is generally offered by use of a prescriptive form with a prescribed incentive based on the parameters of the efficient equipment or practice.
Program Administrator (PA)	Those entities that oversee public benefit funds in the implementation of energy efficiency programs. This generally includes regulated utilities, other organizations chosen to implement such programs, and state energy offices. The Massachusetts electric PAs include Cape Light Compact, National Grid, NSTAR, Western Massachusetts Electric Company (WMECo), and Unitil. The Massachusetts natural gas PAs include Bay State Gas, Berkshire Gas, and New England Gas.
Realization Rate (RR)	The ratio of measure savings developed from impact evaluations to the estimated measure savings derived from the TRM savings algorithms. This factor is used to adjust the estimated savings when significant justification for such adjustment exists. The components of the realization rate are described in detail in the section on Impact Factors.
Retrofit	The replacement of a piece of equipment or device before the end of its useful or planned life for the purpose of achieving energy savings. "Retrofit" measures are sometimes referred to as "early retirement" when the removal of the old equipment is aggressively pursued.
Savings Persistence Factor (SPF)	Percentage of first-year energy or demand savings expected to persist over the life of the installed energy efficiency equipment. The SPF is developed by conducting surveys of installed equipment several years after installation to determine the operational capability of the equipment. In contrast, *measure persistence* takes into account business turnover, early retirement of installed equipment, and other reasons the installed equipment might be removed or discontinued. Measure persistence is generally incorporated as part of the measure life, and therefore is not included as a separate impact factor.
Seasonal Energy Efficiency Ratio (SEER)	A measurement of the efficiency of a central air conditioner over an entire season. In technical terms, SEER is a measure of equipment the total cooling of a central air conditioner or heat pump (in Btu) during the normal cooling season as compared to the total electric energy input (in watt-hours) consumed during the same period.
Seasonal Peak kW	See Summer/Winter Seasonal Peak kW, and Summer/Winter On-Peak Peak kW.
Sector	A system for grouping customers with similar characteristics. For the purpose of this manual, the sectors are Commercial and Industrial (C&I), Small Business, Residential, and Low Income.
Spillover Rate	The percentage of savings attributable to the program, but additional to the gross (tracked) savings of a program. Spillover includes the effects of (a) participants in the program who install additional energy efficient measures outside of the program as a result of hearing about the program and (b) non-participants who install or influence the installation of energy efficient measures as a result of being aware of the program.
Summer/Winter On-Peak kW	The average demand reduction during the summer/winter on-peak period. The summer on-peak period is 1pm-5pm on non-holiday weekdays in June, July and August; the winter on-peak period is 5pm-7pm on non-holiday weekdays in December and January.

TERM	DESCRIPTION
Summer/Winter Seasonal Peak kW	The demand reduction occurring when the actual, real-time hourly load for Monday through Friday on non-holidays, during the months of June, July, August, December, and January, as determined by the ISO, is equal to or greater than 90% of the most recent 50/50 system peak load forecast, as determined by the ISO, for the applicable summer or winter season.
Ton	Unit of measure for determining cooling capacity. One ton equals 12,000 Btu.
Watt	A unit of electrical power. Equal to 1/1000 of a kilowatt.

<u>Appendix 1</u>

COMPACT SPECIFIC NOTIFICATIONS OF ANNUAL VARIANCE

The information set forth in this Appendix is for informational purposes only, and the Compact is not seeking approval for these adjustments, which do not constitute mid-term modifications pursuant to the Orders or the Guidelines. For numerical information, please see Exhibit B, Attachment 1.

I. KEY ASSUMPTIONS

1) Current benefit/cost analysis incorporates updated avoided costs from the recently completed study "Utilizing Avoided Energy Supply Costs in New England: 2011 Report (July 21, 2011, Amended August 11, 2011)", available at http://www.synapse-energy.com/Downloads/SynapseReport.2011-07.AESC.AESC-Study-2011.11-014.pdf ("2011 Avoided Cost Study"). The screening models reflect the following tables from the 2011 Avoided Cost Study: the Massachusetts tables set forth in Appendix B for electric PAs, and the Northern and Central New England tables set forth in Appendix D for gas PAs.

2) Proposed 2012 savings reflect recent program experience, anticipated program enhancements, and recent EM&V results as set forth in the updated Massachusetts Technical Reference Manual- 2012 Planned Version ("TRM") (including, but not limited to, the Residential and Low-Income Non-Energy Impacts study). The TRM is available on the consultants' SharePoint site.

3) Discount and inflation rates have been updated in compliance with the D.P.U. 08-50 Order and the Energy Efficiency Guidelines.

4) 2012 budgets take into account preliminary 2011 projected carryover.

5) Performance incentives do not apply to the Cape Light Compact.

II. NOTIFICATIONS

FOR INFORMATIONAL PURPOSES ONLY

A. BUDGET CHANGE OF +/-20% OR MORE ANNUALLY AT PROGRAM LEVEL
1. Residential New Construction & Major Renovation, 55% increase: Due to the conclusion of the Green Affordable Homes Program and the inclusion of a large project that will begin in 2011, it is anticipated that more budget will be needed to fulfill the program needs.
2. Residential Cooling & Heating Equipment, 40% decrease: Due to anticipated carryover funds from 2011, the 2012 budgets have been adjusted.
3. Multi-Family Retrofit, 100% decrease: Due to anticipated carryover funds from 2011, the 2012 budgets have been adjusted.
4. ENERGY STAR Lighting, 47% decrease: Due to anticipated carryover funds from 2011, the 2012 budgets have been adjusted.
5. ENERGY STAR Appliances, 30% decrease: Due to anticipated carryover funds from 2011, the 2012 budgets have been adjusted.
6. Residential New Construction – Major Renovation Statewide Pilot, 100% decrease: Due to anticipated carryover funds from 2011, the 2012 budgets have been adjusted.
7. Residential New Construction – Lighting Design Statewide Pilot, 100% decrease: Due to anticipated carryover funds from 2011, the 2012 budgets have been adjusted.
8. Home Automation Pilot, 100% decrease: Consistent with the information provided in the Mid-Term Modification section of this document, this reflects termination of the pilot
9. Heat Pump Water Heater Pilot, 100% decrease: Consistent with the information provided in the Mid-Term Modification section of this document, this reflects termination of this pilot as it will move to become a measure within programs.
10. Low-Income Residential New Construction, 100% decrease: Due to the Green Affordable Homes Program, the majority of the expenditures were spent in 2010. There are currently no units in the pipeline for this program.
11. C&I Large Retrofit, 73% increase: It is anticipated that an increase in budget will be needed to fulfill the program needs due to many projects in the pipeline.
12. C&I Small Retrofit, 99% decrease: Due to anticipated carryover funds from 2011, the 2012 budgets have been adjusted.

B. SAVINGS GOAL ADJUSTMENT OF 20% OR MORE ANNUALLY AT PROGRAM LEVEL
1. Residential New Construction & Major Renovation, 116% increase: Due to the conclusion of the Green Affordable Homes Program and the inclusion of a large project that will begin in 2011, it is anticipated that more savings can be achieved.
2. Residential Cooling & Heating Equipment, 48% decrease: Due to 2012 budget adjustments, the 2012 savings have been adjusted.
3. Multi-Family Retrofit, 100% decrease: Due to 2012 budget adjustments, the 2012 savings have been adjusted.
4. MassSAVE, 29% decrease: Due to 2012 budget adjustments, the 2012 savings have been adjusted.
5. ENERGY STAR Lighting, 52% decrease: Due to 2012 budget adjustments, the 2012 savings have been adjusted.
6. ENERGY STAR Appliances, 38% decrease: Due to 2012 budget adjustments, the 2012 savings have been adjusted.
7. Low-Income Residential New Construction, 100% decrease: Due to the Green Affordable Homes Program, the majority of the savings were realized in 2010. There are currently no units in the pipeline for this program.
8. Low-Income Retrofit, 47% decrease: Due to 2012 budget adjustments, the 2012 savings have been adjusted.
9. C&I New Construction, 25% decrease: Due to the uncertainty of projects in the pipeline as of 2011, the 2012 savings have been adjusted.
10. C&I Large Retrofit, 92% increase: It is anticipated that an increase in savings will be realized as a result of the many projects in the pipeline.
11. C&I Small Retrofit, 99% decrease: Due to 2012 budget adjustments, the 2012 savings have been adjusted.

C. PERFORMANCE INCENTIVE CHANGE OF 20% OR MORE ANNUALLY BASED ON PROGRAM MODIFICATION
Not Applicable

D. ANNUAL BUDGET INCREASE AT THE SECTOR LEVEL OF +15% OR MORE FOR C&I OR +20% OR MORE FOR RESIDENTIAL OR LOW-INCOME
1. Residential – Not Applicable
2. Low-Income – Not Applicable
3. C&I – Not Applicable

E. MATERIAL PROGRAM DESIGN CHANGES
The ***Codes and Standards (C&S) Initiative*** being proposed by the Program Administrators (PAs) will encompass long term code compliance enhancement and C&S advocacy related initiatives designed to increase the efficiency of buildings constructed and appliances used in Massachusetts. This fills gap in the current energy efficiency portfolio by capturing sectors of the market that would not normally participate in traditional, voluntary, incentive based programs. This serves the purpose of meeting the PA energy savings targets across a larger population, in addition to enabling the state of Massachusetts and the local communities to meet their own energy savings and emissions reductions targets. PAs will not be claiming savings for this initiative in 2012; potential to claim savings and refine initiatives in the next three-year plan. Massachusetts PAs are launching an ***Upstream C&I Lighting Initiative*** to transform the current linear fluorescent lamp market to energy-efficient lamps. PAs have partnered with electrical distributors and lighting manufacturers to offer customers reduced wattage lamps at a comparable cost to conventional standard wattage lamps. This initiative enables PAs to leverage the sales and marketing resources of the channel partners and target a larger population. This track under the New Construction Program fills a gap in the current delivery by capturing savings from market sectors that would not normally participate. The PA's statewide residential program enhancements planned for 2012 do not require an MTM filing.

Appendix 2

BENEFITS SUMMARY TABLE

CAPE LIGHT COMPACT, 2012 MID-TERM MODIFICATIONS, OCTOBER 28, 2011

$ BENEFITS - For Informational Purposes

Program	2010 Actuals [1]	2011 MTM [3]	2012 Proposed Goal [4]	Proposed Goal 2010-2012 [6]	2010 MYR [2]	2011 MTM [3]	2012 Filed Goal [5]	Filed Goal 2010-2012 [7]	Annual % Difference [8]	3 Year % Difference [9]
Residential	**$ 19,382,496**	**$ 57,600,761**	**$ 81,244,610**	**$ 158,227,867**	**$ 34,831,733**	**$ 57,600,761**	**$ 73,189,249**	**$ 165,621,743**	**11.0%**	**-4.5%**
Residential New Construction & Major Renovation	$ 902,816	$ 928,618	$ 1,686,167	$ 3,517,601	$ 1,079,130	$ 928,618	$ 1,195,345	$ 3,203,093	41.1%	9.8%
Residential Cooling & Heating Equipment	$ 1,400,725	$ 1,852,339	$ 3,427,250	$ 6,680,315	$ 1,131,262	$ 1,852,339	$ 2,274,302	$ 5,257,903	50.7%	27.1%
Multi-Family Retrofit	$ 64,853	$ 2,845,701	$ -	$ 2,910,553	$ 1,920,590	$ 2,845,701	$ 3,471,196	$ 8,237,487	-100.0%	-64.7%
MassSAVE	$ 12,846,893	$ 38,952,913	$ 68,811,551	$ 120,611,357	$ 25,346,901	$ 38,952,913	$ 50,685,302	$ 114,985,117	35.8%	4.9%
Behavior/Feedback Program	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
ENERGY STAR Lighting	$ 3,121,448	$ 11,717,686	$ 6,038,677	$ 20,877,811	$ 4,566,401	$ 11,717,686	$ 13,664,946	$ 29,949,034	-55.8%	-30.3%
ENERGY STAR Appliances	$ 1,045,762	$ 1,303,504	$ 1,280,964	$ 3,630,230	$ 787,448	$ 1,303,504	$ 1,898,157	$ 3,989,109	-32.5%	-9.0%
Low Income	**$ 4,301,936**	**$ 10,098,012**	**$ 9,546,436**	**$ 23,946,384**	**$ 5,922,383**	**$ 10,098,012**	**$ 9,980,260**	**$ 26,000,655**	**-4.3%**	**-7.9%**
Low-Income Residential New Construction	$ 134,686	$ 44,988	$ -	$ 179,674	$ 28,702	$ 44,988	$ 40,460	$ 114,151	-100.0%	57.4%
Low-Income Retrofit [10]	$ 4,167,251	$ 10,053,023	$ 9,546,436	$ 23,766,710	$ 5,893,681	$ 10,053,023	$ 9,939,800	$ 25,886,504	-4.0%	-8.2%
C&I	**$ 14,471,777**	**$ 33,764,352**	**$ 18,271,687**	**$ 66,507,816**	**$ 27,855,987**	**$ 33,764,352**	**$ 40,438,792**	**$ 102,059,132**	**-54.8%**	**-34.8%**
C&I New Construction and Major Renovation	$ 2,033,334	$ 9,138,214	$ 6,747,151	$ 17,918,699	$ 6,608,366	$ 9,138,214	$ 10,982,545	$ 26,729,125	-38.6%	-33.0%
C&I Large Retrofit	$ 3,584,193	$ 3,791,075	$ 11,269,587	$ 18,644,855	$ 9,035,693	$ 3,791,075	$ 4,816,231	$ 17,642,999	134.0%	5.7%
C&I Small Retrofit	$ 8,854,250	$ 20,835,063	$ 254,949	$ 29,944,262	$ 12,211,928	$ 20,835,063	$ 24,640,017	$ 57,687,007	-99.0%	-48.1%
Total Portfolio	**$ 38,156,209**	**$ 101,463,125**	**$109,062,733**	**$ 248,682,067**	**$ 68,610,103**	**$ 101,463,125**	**$ 123,608,302**	**$ 293,681,530**	**-11.8%**	**-15.3%**

Notes:
1. As filed in the Cape Light Compact's 2010 Energy Efficiency Annual Report, D.P.U. 11-68, in 2010$
2. As filed in the Cape Light Compact's 2010 Mid-Year Revisions Filing, D.P.U 10-106, in 2010$
3. As this filing assumes approval of the 2011 Mid-Term Modifications, this data is as filed in the Cape Light Compact's 2011 Mid-Term Modifications Filing, D.P.U. 10-147, in 2011$
4. Proposed 2012 changes presented in this filing, representing additional budget requirements for 2012, taking into account 2011 estimated carryover, in 2012$
5. As filed in the Cape Light Compact's 2010-2012 Three-Year Plan Filing, D.P.U. 09-119, and amended in the 2011 Mid-Term Modifications Filing, D.P.U. 10-147 in Exhibit F, page 2 of 4, as this filing assumes approval of the 2011 Mid-Term Modifications filing. In 2010$.
6. 2010 Actuals, 2011 MTM and 2012 Proposed Goal
7. 2010 Appvd Mid-Year Revisions (D.P.U. 10-106), 2011 MTM (D.P.U. 10-147) and 2012 Goal
8. Annual % Difference = (2012 Proposed Goal - 2012 Goal)/2012 Goal
9. 3 Year % Difference = (Proposed Goal 2010-2012 - Filed Goal 2010-2012)/Filed Goal 2010-2012
10. Combined Low-Income 1 to 4 Family Retrofit and Low-Income MultiFamily Retrofit

<u>Appendix 3</u>

MATERIALS PROVIDED TO ENERGY EFFICIENCY ADVISORY COUNCIL

Cape Light Compact
2012 Mid-Term Modifications
Summary Presentation to EEAC for October 11, 2011 Meeting

Table of Contents

I. KEY ASSUMPTIONS

1) Current benefit/cost analysis incorporates updated avoided costs from the recently completed study "Utilizing Avoided Energy Supply Costs in New England: 2011 Report (July 21, 2011, Amended August 11, 2011)", available at http://www.synapse-energy.com/Downloads/SynapseReport.2011-07.AESC.AESC-Study-2011.11-014.pdf ("2011 Avoided Cost Study"). The screening models reflect the following tables from the 2011 Avoided Cost Study: the Massachusetts tables set forth in Appendix B for electric PAs, and the Northern and Central New England tables set forth in Appendix D for gas PAs.

2) Proposed 2012 savings reflect recent program experience, anticipated program enhancements, and recent EM&V results as set forth in the updated Massachusetts Technical Reference Manual- 2012 Planned Version ("TRM") (including, but not limited to, the Residential and Low-Income Non-Energy Impacts study). The TRM is available on the consultants' SharePoint site.

3) Discount and inflation rates have been updated in compliance with the D.P.U. 08-50 Order and the Energy Efficiency Guidelines.

4) 2012 budgets take into account preliminary 2011 projected carryover.

5) Performance incentives do not apply to the Cape Light Compact.

II. MID TERM MODIFICATIONS[1]

A. ADDED/TERMINATED OR ENHANCED PROGRAMS/PILOTS
1. Home Automation Pilot (Terminated): As stated in its 2010 Annual Report, the Cape Light Compact did not sign a contract with an implementation partner in 2010, as the available partners did not have technologies that met the pilot requirements. While additional attempts were made to find and work with a partner in 2011, there continued to be an issue finding a partner that had a technology that would work within the pilot's parameters. At this time, as a partner has not been identified, the Cape Light Compact does not anticipate the need for any budget for this pilot in 2012.
2. Heat Pump Water Heater Pilot (Terminated): Based on favorable evaluation results to date, no funding in 2012 for this pilot is planned, as this pilot will move to become a measure within programs.
3. As further described below (please see Item #5 of the Notification section) the Cape Light Compact with other PAs have continued to make enhancements to their programs, including: the launch of the Upstream C&I Lighting Initiative and the Codes and Standards (C&S) Initiative. In addition, the PA's statewide residential program enhancements planned for 2012 do not require an MTM filing.
4. The Cape Light Compact, in coordination with all electric and gas PAs on a statewide basis, is proposing to consolidate its low-income single family retrofit and low-income multifamily retrofit programs into one low-income retrofit program. This consolidation has a number of benefits including: 1) providing greater flexibility to address market circumstances and demands for program services in the field by low-income customers; 2) helping ensure robust overall program cost-effectiveness; 3) providing in-the-field experience with operating a consolidated program in the low-income sector (similar to the C&I model where separate initiatives are grouped under a single program) which is an approach that will be explored for the next three year plan; and 4) potentially providing opportunities for administrative efficiencies over time. The Compact notes that it would continue to track expenses and participation for both its single family and multi-family low income initiatives in order to maintain transparent reporting and would not change contractual arrangements with service providers for these initiatives as a result of this consolidation. The PAs have had initial discussions with LEAN with respect to this consolidation and LEAN has indicated that such an approach could yield benefits.

B. BUDGET CHANGE OF +/-20% OR MORE OVER THREE YEAR PERIOD AT PROGRAM/PILOT LEVEL
1. Residential New Construction & Major Renovation, 31% increase: Based on projects that have applied for participation and actuals thus far, the Cape Light Compact will have a change of budget by more than +20%. This is the result of one large unexpected project with 39 units that began in 2011, as well as past participation in the Green Affordable Homes Program that was

[1] Twenty percent variations are calculated as the new three-year plan minus the original three-year plan as modified by mid-year-revisions and mid-term modifications divided by original three-year plan as modified by mid-year-revisions and mid-term modifications, as expressed by this formula: ((2010 Actuals + 2011 Plan MTM + 2012 Plan MTM) – (2010 Plan MYR + 2011 Plan MTM + 2012 Plan)) / (2010 Plan MYR + 2011 Plan MTM + 2012 Plan).

referenced in the 2010 Annual Report.
2. Residential Cooling & Heating Equipment, 23% decrease: This program has experienced a significant ramp up in budget since the Cape Light Compact reintroduced it in 2009. However, based on experience in 2010 and YTD actuals for 2011, participation levels cannot support an additional ramp up of program budget as originally planned for 2012.
3. Multi-Family Retrofit, 66% decrease: As stated in its 2010 Annual Report, the Cape Light Compact does not have many traditionally defined Residential Multi-Family customers in its territory (for example, high rises and apartment complexes). Further, the new program design, finalized after plan approval, now precludes the Cape Light Compact from serving gas customers. As a result, the Cape Light Compact does not anticipate enough participation to substantiate significant budget increases beyond spending in 2010.
4. ENERGY STAR Lighting, 29% decrease: As stated in its 2010 Annual Report, this program started off slowly but has progressed at a good pace. However, due to a change in measure mix, available shelf space, 2010 actuals and YTD actuals for 2011, anticipated participation levels cannot support the additional ramp up as originally planned for 2012.
5. Deep Energy Retrofit, 35% decrease: Planned budgets for 2010 were not fully spent, which has resulted in a significant offset of the three-year budget need.
6. Residential New Construction - Major Renovation Statewide Pilot, 62% decrease: As stated in its 2010 Annual Report, the renovation and new construction markets for new, efficient additions are significantly smaller than expected, which is greatly impacting participation. As a result, the Cape Light Compact does not expect enough participants to substantiate additional budget increases beyond the carryover of 2011 funds into 2012.
7. Residential New Construction – Lighting Design Statewide Pilot, 50% decrease: Based on expected carryover of funds from plan year 2011, the necessary budget to continue the pilot in 2012 will be minimal.
8. Low-Income Residential New Construction, 36% increase: The 2010 planned budget was exceeded due to the Green Affordable Homes grant, which resulted in a significant increase in the three-year budget need.
9. C&I New Construction and Major Renovation, 25% decrease: As stated in its 2010 Annual Report, the current economic climate makes it especially difficult to plan for C&I New Construction and Major Renovation projects. While the Cape Cod and Martha's Vineyard new construction industry is holding steady with many new starts in progress, some project scopes were scaled back between planning and implementation phases in 2010, and that pattern, so far, exists in 2011. As a result, the Cape Light Compact cannot support a significant ramp up of program budget beyond the planned budget for 2011.
10. C&I Small Retrofit, 52% decrease: As stated in its 2010 Annual Report, this program did not spend its budget in 2010 because there were fewer participants and a lower cost per participant than anticipated. The Cape Light Compact expects this trend to continue. Therefore, the Cape Light Compact cannot support the ramp up in budget as originally planned for in 2012.

C. SAVINGS GOAL ADJUSTMENT OF 20% OR MORE OVER THREE-YEAR PERIOD AT PROGRAM LEVEL
1. Residential New Construction & Major Renovation, 46% increase: Based on current projects and actuals thus far, the Cape Light Compact will have a change of savings by more than +20%. This is the result of one large unexpected project with 39 units that began in 2011, as well as past

participation in the Green Affordable Homes Program that was referenced in the 2010 Annual Report.
2. Residential Cooling & Heating Equipment, 27% decrease: This program has experienced a significant ramp up in savings since the Cape Light Compact reintroduced it in 2009. However, based on experience in 2010 and YTD actuals for 2011, participation levels cannot support an additional ramp up of program savings as originally planned for in2012.
3. Multi-Family Retrofit, 64% decrease: As stated in its 2010 Annual Report, the Cape Light Compact does not have many traditionally defined Residential Multi-Family customers in its territory (for example, high rises and apartment complexes). Further, the new program design, finalized after plan approval, now precludes the Cape Light Compact from serving gas customers. As a result, the Cape Light Compact does not anticipate enough participation to substantiate significant increases beyond savings in 2010.
4. ENERGY STAR Lighting, 36% decrease: As stated in its 2010 Annual Report, this program started off slowly but has progressed at a good pace. However, due to a change in measure mix, available shelf space, 2010 actuals and YTD actuals for 2011, anticipated participation levels cannot support the additional ramp up as originally planned for in 2012.
5. Low-Income Residential New Construction, 40% increase: The 2010 planned budget was exceeded due to the Green Affordable Homes grant, which resulted in a significant increase in the three-year budget need.
6. Low-Income Retrofit, 33% decrease: Both Low-Income 1 to 4 Family Retrofit and Low-Income MultiFamily Retrofit programs are contributing to the need for revised savings goals. As stated in its 2010 Annual Report, in order to better service the Low Income Multi-Family program, the implementation vendor hired a Multi-Family assessor in 2010 that has recently become fully operational. However, several challenges still exist, including program design changes that now preclude the Cape Light Compact from serving gas customers. Also, as stated in its 2010 Annual Report, there were understated savings for Low Income 1 to 4 Family due to the continued use of a deemed savings value for weatherization. As a result, the Cape Light Compact plans to increase savings beyond levels in 2010, but cannot support the ramp up in savings as originally planned for in 2012.
7. C&I New Construction and Major Renovation, 53% decrease: As stated in its 2010 Annual Report, the current economic climate makes it especially difficult to plan for C&I New Construction and Major Renovation projects. While the Cape Cod and Martha's Vineyard new construction industry is holding steady with many new starts in progress, some project scopes were scaled back between planning and implementation phases in 2010, and that pattern, so far, exists in 2011. As a result, the Cape Light Compact cannot support a significant ramp up of savings beyond the planned savings for 2011.
8. C&I Small Retrofit, 51% decrease: As stated in its 2010 Annual Report, this program did not achieve savings goals in 2010 because there were fewer participants and the cost to achieve the savings was higher than projected. The Cape Light Compact expects this trend to continue. Therefore, the Cape Light Compact cannot support the ramp up in savings as originally planned for in 2012.

D. PERFORMANCE INCENTIVE CHANGE OF 20% OR MORE OVER THREE-YEAR PERIOD BASED ON PROGRAM MODIFICATION
Not Applicable

III. NOTIFICATIONS

FOR INFORMATIONAL PURPOSES ONLY

A. BUDGET CHANGE OF +/-20% OR MORE ANNUALLY AT PROGRAM LEVEL
1. Residential New Construction & Major Renovation, 49% increase: Due to the conclusion of the Green Affordable Homes Program and the inclusion of a large project that will begin in 2011, it is anticipated that more budget will be needed to fulfill the program needs.
2. Residential Cooling & Heating Equipment, 44% decrease: Due to anticipated carryover funds from 2011, the 2012 budgets have been adjusted.
3. Multi-Family Retrofit, 100% decrease: Due to anticipated carryover funds from 2011, the 2012 budgets have been adjusted.
4. ENERGY STAR Lighting, 55% decrease: Due to anticipated carryover funds from 2011, the 2012 budgets have been adjusted.
5. ENERGY STAR Appliances, 30% decrease: Due to anticipated carryover funds from 2011, the 2012 budgets have been adjusted.
6. Residential New Construction – Major Renovation Statewide Pilot, 100% decrease: Due to anticipated carryover funds from 2011, the 2012 budgets have been adjusted.
7. Residential New Construction – Lighting Design Statewide Pilot, 100% decrease: Due to anticipated carryover funds from 2011, the 2012 budgets have been adjusted.
8. Home Automation Pilot, 100% decrease: Consistent with the information provided in the Mid-Term Modification section of this document, this reflects termination of the pilot
9. Heat Pump Water Heater Pilot, 100% decrease: Consistent with the information provided in the Mid-Term Modification section of this document, this reflects termination of this pilot as it will move to become a measure within programs.
10. Low-Income Residential New Construction, 100% decrease: Due to the Green Affordable Homes Program, the majority of the expenditures were spent in 2010. There are currently no units in the pipeline for this program.
11. C&I New Construction, 46% decrease: Due to the uncertainty of projects in the pipeline as of 2011, the 2012 budgets have been adjusted.
12. C&I Large Retrofit, 78% increase: It is anticipated that an increase in budget will be needed to fulfill the program needs due to many projects in the pipeline.
13. C&I Small Retrofit, 99% decrease: Due to anticipated carryover funds from 2011, the 2012 budgets have been adjusted.

B. SAVINGS GOAL ADJUSTMENT OF 20% OR MORE ANNUALLY AT PROGRAM LEVEL
1. Residential New Construction & Major Renovation, 116% increase: Due to the conclusion of the Green Affordable Homes Program and the inclusion of a large project that will begin in 2011, it is anticipated that more savings can be achieved.
2. Residential Cooling & Heating Equipment, 54% decrease: Due to 2012 budget adjustments, the 2012 savings have been adjusted.
3. Multi-Family Retrofit, 100% decrease: Due to 2012 budget adjustments, the 2012 savings have been adjusted.
4. MassSAVE, 29% decrease: Due to 2012 budget adjustments, the 2012 savings have been

adjusted.
5. ENERGY STAR Lighting, 66% decrease: Due to 2012 budget adjustments, the 2012 savings have been adjusted.
6. ENERGY STAR Appliances, 38% decrease: Due to 2012 budget adjustments, the 2012 savings have been adjusted.
7. Low-Income Residential New Construction, 100% decrease: Due to the Green Affordable Homes Program, the majority of the savings were realized in 2010. There are currently no units in the pipeline for this program.
8. Low-Income Retrofit, 47% decrease: Due to 2012 budget adjustments, the 2012 savings have been adjusted.
9. C&I New Construction, 75% decrease: Due to the uncertainty of projects in the pipeline as of 2011, the 2012 savings have been adjusted.
10. C&I Large Retrofit, 92% increase: It is anticipated that an increase in savings will be realized as a result of the many projects in the pipeline.
11. C&I Small Retrofit, 99% decrease: Due to 2012 budget adjustments, the 2012 savings have been adjusted.

C. PERFORMANCE INCENTIVE CHANGE OF 20% OR MORE ANNUALLY BASED ON PROGRAM MODIFICATION
Not Applicable

D. ANNUAL BUDGET INCREASE AT THE SECTOR LEVEL OF +15% OR MORE FOR C&I OR +20% OR MORE FOR RESIDENTIAL OR LOW-INCOME
1. Residential – Not Applicable
2. Low-Income - Not Applicable
3. C&I - Not Applicable

E. MATERIAL PROGRAM DESIGN CHANGES
The ***Codes and Standards (C&S) Initiative*** being proposed by the Program Administrators (PAs) will encompass long term code compliance enhancement and C&S advocacy related initiatives designed to increase the efficiency of buildings constructed and appliances used in Massachusetts. This fills gap in the current energy efficiency portfolio by capturing sectors of the market that would not normally participate in traditional, voluntary, incentive based programs. This serves the purpose of meeting the PA energy savings targets across a larger population, in addition to enabling the state of Massachusetts and the local communities to meet their own energy savings and emissions reductions targets. PAs will not be claiming savings for this initiative in 2012; potential to claim savings and refine initiatives in the next three-year plan. Massachusetts PAs are launching an ***Upstream C&I Lighting Initiative*** to transform the current linear fluorescent lamp market to energy-efficient lamps. PAs have partnered with electrical distributors and lighting manufacturers to offer customers reduced wattage lamps at a comparable cost to conventional standard wattage lamps. This initiative enables PAs to leverage the sales and marketing resources of the channel partners and target a larger population.

This track under the New Construction Program fills a gap in the current delivery by capturing savings from market sectors that would not normally participate.

The PA's statewide residential program enhancements planned for 2012 do not require an MTM filing.

IV. BCR SCREENING MODELS

Please see Sharepoint site for uploaded models.

V. EVALUATION, MONITORING, & VERIFICATION

Introduction

In accordance with the EM&V resolution agreed to on September 8, 2009, statewide evaluation efforts have been divided into multiple research areas. As presented in Table 1, each research area has contracted with an independent evaluation team that is responsible for the completion of all agreed upon evaluation efforts within its research area.

Table 1: Statewide Research Area & Evaluation Contractor

RESEARCH AREA	LEAD EVALUATION CONTRACTOR
Residential Lighting & Appliances	Nexus Market Research
Residential Retrofit & Low Income	Cadmus
Residential New Construction	Nexus Market Research
Non-Residential Small Business	Cadmus
Large Commercial & Industrial	KEMA
Special & Cross-Cutting	Tetra Tech & Opinion Dynamics (2 contracts)

Current and Planned Research

Table 2 details the studies in each of the six research areas that (1) have been completed since the filing of the 2010 Annual Reports on August 15, 2011, (2) are underway but not yet complete, or (3) are expected to commence in 2011 or early 2012. Using this numbering system, the status of each study is noted in the last column. Some of the descriptions have expected completion dates, and some of the studies that recently kicked off currently do not have expected completion dates listed in this draft.

This table includes only those studies that have been already been planned; additional evaluation may be planned throughout 2012. In addition, these studies and schedules are tentative and subject to change based, among other things, on the results of in-progress evaluation studies.

Table 2: Current and Planned EM&V Research

STUDY	DESCRIPTION	EXPECTED START DATE/STATUS
Residential New Construction		
Phase II: Baseline Study/Code Compliance Assessment	Underway, three quarters of the way through the field work, draft report due December 31, 2011	Currently ongoing Status: (2)
Major Renovation Pilot	Waiting for more completions, draft report due January 31, 2012.	Currently ongoing Status: (2)
Homebuyer Survey	Surveys complete, analysis underway, final report due December 31, 2011	Currently ongoing Status: (2)
Assessment of New Technologies	Initial memo completed August 29, 2011. Subsequent research will be performed on a quarterly basis if Program Managers identify additional technologies of interest.	Currently ongoing Status: (2)

STUDY	DESCRIPTION	EXPECTED START DATE/STATUS
Builder Focus Groups	Complete, final report due September 30, 2011.	Final stages Status: (1)

Residential Retrofit & Low Income		
Impact Evaluation of the Home Energy Services program	The goal of this study is to review and quantify savings assumptions used by the PAs and determine the best value or calculation to enable PAs to have consistent assumptions statewide. This program includes Mass Save and the gas weatherization program.	March 2011 Status: (2)
Market Research of the Home Energy Services program (to support the Residential Performance Metric #2 – Threshold)	Scope to be discussed. A market research plan will be developed and conducted to explore the potential of leveraging existing market opportunities within this program.	Late fall 2011 Status: (3)
Potential Study of the Multifamily Program	The goal of the evaluation is to provide a descriptive, cross-sectional assessment of the market size and characteristics of multi-family buildings within the state. Site visits to support the effort were completed in late August 2011.	August 2010 Status: (2)
Process and Impact evaluation of Multifamily Program	The goal of this research is to assess program processes and identify similarities and differences between the perspectives and assumptions of program staff, trade allies, and customers regarding the goals, design, and implementation of the program. Additionally, an impact evaluation will be performed to review and quantify savings assumptions and impact factors used by the PAs and determine the best value or calculation to enable PAs to have consistent assumptions statewide.	March 2011 Status: (2)
Net-to-Gross study on Residential Cooling & Heating Equipment (Cool Smart)	The goal of this study is to perform a free ridership and spillover study to assess the true impacts to this program.	Fall 2011 Status: (3)
Process and Impact evaluation of Low Income program	The goal of this research is to do some follow up analysis from the process work already completed, and to assess program processes and identify similarities and differences between the perspectives and assumptions of program staff, trade allies, and customers regarding the goals, design, and implementation of the program. Additionally, an impact evaluation will be performed to review and quantify savings assumptions used by the PAs and determine the best value or calculation to enable PAs to have consistent assumptions statewide.	March 2011 Status: (2)

Process and Impact Evaluation of Home Energy Services Bundled Measure Pilot	The goal is to assess customers' perceptions of packaged measures and their effect on decision making process and an analysis of the acceptance rate for packaged measures. In addition we want to estimate aggregated savings; compare with non- bundled participants for estimate of interactive effects by PA and statewide. This analysis will assist PAs in determining whether this pilot could potentially be a program offering.	September 2011 Status: (2)
Coincident Factor Study	The goal of this study is update the Quantec model currently used to calculate coincident factors utilized in the cost effectiveness model. This study will provide 8760 load shapes and will include a variety of measures; all PAs will be able to utilize this study for determining accurate coincident factors.	September 2011 Status: (2)
NTG study of the High Efficiency Heating Equipment (HEHE) program.	This goal of this NTG study is to obtain spillover for this program.	August 2011 Status: (2)
Process and Impact Evaluation of the Solar Thermal Domestic Hot Water Pilot	The goal of this evaluation is to obtain customer/contractor perceptions of the pilot in addition to obtaining actual savings associated with this measure and to recommend whether the pilot could potentially be offered as a program measure.	June 2011 Status: (2)
Process and Impact Evaluation of the WI FI Thermostat Pilot	The goal of this evaluation will assist in understanding the energy impacts attributable to the pilot, as well as to determine potential ways to improve the program offering should it expand beyond the pilot phase.	June 2011 Status: (2)
Electronically Commutated Motor (ECM) Circulator Pump pilot program.	The goal of this evaluation is to determine the energy savings potential of replacing split phase motors in residential boiler pumps with high-efficiency ECMs. In addition to assessing energy savings, the study aims to test the reliability of single and multiple pump installations.	June 2011 Status: (2)
Impact Evaluation of the Brushless Fan Motor (BFM)	This study seeks to identify savings associated with the BFM retrofits in residential HVAC applications. Anticipated completion of this study is October 2011.	August 2010 Status: (2)
Impact of Gas Training	Scope has not yet been determined.	TBD Status: (3)

Residential Lighting & Appliances		
Market assessment on lighting measures	Assess the changing and evolving lighting marketplace	Fall/winter 2011 Status: (3)
Shelf stocking survey of MA retailers	Understanding retailers stocking of efficient lighting equipment	Fall 2011 Status: (3)
Lighting on-site saturation study	Understanding lighting and products market	Fall/winter 2011 Status: (3)
Baseline study for lighting based on EISA	Guiding principles and measurement of baseline based on new CFL efficiency standards	October 2011 Status: (3)
Consumer electronic exploratory evaluation	Still under discussion	TBD Status: (3)
Non-Residential Small Business		
Integrated Program Process Evaluations	1. Effectiveness of DI program in serving 200-300kW customers 2. Focused study of incentive and financing options to motivate program participation Scope currently under discussion.	Fall 2011 Status: (3)
Lighting Fixture Summer Metering Impact Evaluation	Additional metering for a subset of Non-Controls Lighting Fixture Impact study sites with uncertain seasonal operating hours	July 2011 Status: (2)
Lighting Controls Impact Evaluation	Pre/Post metering impact evaluation of 2011 program participant sites with lighting control measures	January 2011 Status: (2)
Large Commercial & Industrial		
Process Evaluation of the Large Commercial and Industrial Energy Efficiency Programs	Examination of efficiency of current practices. Suggested topics for study span gas and electric integration to similarities and differences of PA tracking systems.	September 2011 Status: (2)
New Construction Baseline Code Compliance Study	On-site interviewing of EE customers, property owners, etc to gauge program effects on adoption. Also on-site interviewing of non-EE customers to determine actual baseline efficiencies.	September 2011 Status: (2)
Custom Electric Measures Impact Evaluations (Lighting, Process, Compressed Air)	Determination of PA specific and statewide realization rates. Lighting involves a 12 month logger study and lighting is the first stage of a two year custom electric evaluation to be followed by refrigeration and motors.	September 2011 Status: (2)
Prescriptive Gas Measures Impact Evaluation	On-site monitoring of furnaces, conventional boilers, and infrared heaters. Possible inclusion of condensing boilers.	September 2011 Status: (2)
Custom Gas Measures Impact Evaluation	Continuation of 2010 study examining custom measures. Determination of PA specific and statewide realization rates.	September 2011 Status: (2)

Prescriptive Measure Impact Evaluation (VSDs)	Determination of PA specific and statewide realization rates. VSD involves pre and post VSD installation metering.	Ongoing Status: (2)
Prescriptive Measure Impact Evaluation (Lighting)	Determination of PA specific and statewide realization rates. Lighting involves a 12 month logger study.	September 2011 Status: (2)
CHP Impact Evaluation	Determination of PA specific and statewide realization rates. All CHP installations currently being metered and evaluated for therms and kWh.	Ongoing Status: (2)
Special & Cross Cutting		
Phase II: Behavioral Pilots	Tasks include impact analysis of NSTAR's OPower program, impact analysis of the WMECO Efficiency 2.0 program, Effective Useful Life of National Grid's impact findings, and initiating a baseline survey for CLC Tendril pilot.	June 2011 Status: (2)
Phase II: Community Based Pilots	Phase II of 2011 research includes participant interviews, participation analysis and a possible costs/savings assessment. The form and extent of the cost/savings assessment is currently under discussion.	September 2011 Status: (2)
Phase II: Umbrella Marketing	Evaluate the framework, reach and effectiveness of the statewide marketing campaign, and provide actionable recommendations to inform ongoing program design and implementation.	February 2011 Status: (2)
C&I Gas Net-to-Gross Study 2010 Projects	Quantify the Net-to-Gross impact factors for 2010 C&I projects. Study was completed in late August 2011.	April 2011 Status: (1)
C&I Gas Net-to-Gross Study 2011 Projects	Quantify the Net-to-Gross impact factors for 2011 C&I projects.	TBD – Early 2012 Status: (3)
Non-Energy Impacts 2011 – Residential & Low Income	Quantify the Non-Energy Impacts of the Residential & Low-Income programs. Study was completed in late August 2011.	June 2010 Status: (1)
Non-Energy Impacts 2011 - C&I: non-Custom	Quantify the Non-Energy Impacts of prescriptive C&I measures.	Fall 2011 Status: (3)
Non-Energy Impacts 2011 – Deep Energy Retrofit	This study is TBD based on planned pilot redesign	TBD Status: (3)

VI. PERFORMANCE INCENTIVES

The Cape Light Compact does not have performance incentives. Therefore, this section is not applicable to the Cape Light Compact.

CAPE LIGHT COMPACT, 2012 MID-TERM MODIFICATIONS, SUMMARY PRESENTATION TO EEAC FOR OCTOBER 11, 2011 MEETING

SAVINGS (Annual MWhs)

Program	2010 Actuals [1]	2011 MTM [3]	2012 Proposed Goal [4]	Proposed Goal 2010-2012 [6]	2010 MYR [2]	2011 MTM [3]	2012 Filed Goal [5]	Filed Goal 2010-2012 [7]	Annual % Difference [8]	3 Year % Difference [9]	MTM Trigger on Savings [10]
Residential	**8,372**	**19,364**	**11,321**	**39,058**	**10,179**	**19,364**	**23,888**	**53,432**	**-52.6%**	**-26.9%**	
Residential New Construction & Major Renovation	333	287	610	1,229	271	287	283	841	115.5%	46.2%	MTM TRIGGER
Residential Cooling & Heating Equipment	305	585	322	1,212	374	585	701	1,660	-54.0%	-27.0%	MTM TRIGGER
Multi-Family Retrofit	70	783	-	853	609	783	971	2,363	-100.0%	-63.9%	MTM TRIGGER
MassSAVE	3,917	5,244	4,591	13,752	4,063	5,244	6,423	15,731	-28.5%	-12.6%	
Behavior/Feedback Program	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
ENERGY STAR Lighting	2,844	11,220	4,591	18,655	4,199	11,220	13,571	28,990	-66.2%	-35.6%	MTM TRIGGER
ENERGY STAR Appliances	903	1,245	1,208	3,356.61	663	1,245	1,939	3,847	-37.7%	-12.8%	
Low Income	**628**	**2,250**	**1,413**	**4,291**	**1,416**	**2,250**	**2,669**	**6,335**	**-47.1%**	**-32.3%**	
Low-Income Residential New Construction	41	14	-	55	11	14	15	39	-100.0%	39.8%	MTM TRIGGER
Low-Income Retrofit [11]	587	2,236	1,413	4,236	1,405	2,236	2,654	6,295	-46.8%	-32.7%	MTM TRIGGER
C&I	**6,378**	**17,612**	**6,360**	**30,350**	**14,730**	**17,612**	**22,040**	**54,381**	**-71.1%**	**-44.2%**	
C&I New Construction and Major Renovation	407	3,841	1,246	5,495	2,917	3,841	4,960	11,717	-74.9%	-53.1%	MTM TRIGGER
C&I Large Retrofit	1,623	1,923	4,982	8,529	4,769	1,923	2,596	9,289	91.9%	-8.2%	
C&I Small Retrofit	4,347	11,848	132	16,326	7,044	11,848	14,484	33,375	-99.1%	-51.1%	MTM TRIGGER
Total Portfolio	**15,378**	**39,226**	**19,095**	**73,699**	**26,325**	**39,226**	**48,597**	**114,148**	**-60.7%**	**-35.4%**	

Notes:
1. As filed in the Cape Light Compact's 2010 Energy Efficiency Annual Report, D.P.U. 11-68
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9. 3 Year % Difference = (Proposed Goal 2010-2012 - Filed Goal 2010-2012)/Filed Goal 2010-2012
10. Indicates if the 3 Year % Difference is greater than or equal to +/- 20% at the program level
11. Combined Low-Income 1 to 4 Family Retrofit and Low-Income MultiFamily Retrofit (see below):

CAPE LIGHT COMPACT, 2012 MID-TERM MODIFICATIONS, SUMMARY PRESENTATION TO EEAC FOR OCTOBER 11, 2011 MEETING

BUDGET (PA Costs $)

Program	2010 Actuals [1]	2011 MTM [3]	2012 Proposed Goal [4]	Proposed Goal 2010-2012 [6]	2010 MYR [2]	2011 MTM [3]	2012 Filed Goal [5]	Filed Goal 2010-2012 [7]	Annual % Difference [8]	3 Year % Difference [9]	MTM Trigger on Savings [10]
Residential	**$ 6,388,566**	**$ 12,386,208**	**$ 10,944,451**	**$ 29,719,225**	**$ 9,449,462**	**$ 12,386,208**	**$ 15,306,769**	**$ 37,142,439**	**-28.5%**	**-20.0%**	
Residential New Construction & Major Renovation	$ 525,503	$ 235,663	$ 373,810	$ 1,134,976	$ 380,019	$ 235,663	$ 251,010	$ 866,692	48.9%	31.0%	MTM TRIGGER
Residential Cooling & Heating Equipment	$ 522,990	$ 890,256	$ 669,855	$ 2,083,101	$ 640,525	$ 890,256	$ 1,186,949	$ 2,717,730	-43.6%	-23.4%	MTM TRIGGER
Multi-Family Retrofit	$ 37,519	$ 521,038	$ -	$ 558,557	$ 443,571	$ 521,038	$ 681,917	$ 1,646,526	-100.0%	-66.1%	MTM TRIGGER
MassSAVE	$ 3,626,015	$ 7,408,109	$ 7,837,803	$ 18,871,926	$ 5,516,024	$ 7,408,109	$ 9,394,107	$ 22,318,240	-16.6%	-15.4%	
Behavior/Feedback Program	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
ENERGY STAR Lighting	$ 817,217	$ 2,018,330	$ 1,029,962	$ 3,865,509	$ 1,159,453	$ 2,018,330	$ 2,300,966	$ 5,478,749	-55.2%	-29.4%	MTM TRIGGER
ENERGY STAR Appliances	$ 386,404	$ 358,766	$ 397,170	$ 1,142,340	$ 253,545	$ 358,766	$ 564,411	$ 1,176,721	-29.6%	-2.9%	
Residential Education Program	$ 60,812	$ 195,000	$ 105,000	$ 360,812	$ 186,000	$ 195,000	$ 205,000	$ 586,000	-48.8%	-38.4%	
Workforce Development	$ 3,309	$ 15,000	$ 15,000	$ 33,309	$ 15,000	$ 15,000	$ 15,000	$ 45,000	0.0%	-26.0%	
Heat Loan Program	$ 120,133	$ 45,000	$ 110,000	$ 275,133	$ 30,000	$ 45,000	$ 60,000	$ 135,000	83.3%	103.8%	
R&D and Demonstration	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
Deep Energy Retrofit	$ 26,659	$ 80,000	$ -	$ 106,659	$ 83,333	$ 80,000	$ -	$ 163,333	0.0%	-34.7%	MTM TRIGGER
Behavior/Feedback Pilot	$ 74,496	$ 161,667	$ 176,486	$ 412,649	$ 233,333	$ 161,667	$ -	$ 395,000	0.0%	4.5%	
Residential New Construction - Major Renovation Statewide Pilot	$ 43,992	$ 278,452	$ -	$ 322,444	$ 257,547	$ 278,452	$ 308,752	$ 844,751	-100.0%	-61.8%	MTM TRIGGER
Residential New Construction - Multi Family (4-8 story) Statewide Pilot	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
Residential New Construction - Lighting Design Statewide Pilot	$ 11,264	$ 22,222	$ -	$ 33,486	$ 22,222	$ 22,222	$ 22,222	$ 66,667	-100.0%	-49.8%	MTM TRIGGER
Residential New Construction - V3 Energy Star Homes Statewide Pilot	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.0%	0.0%	
Heat Pump Water Heater Pilot	$ 9,022	$ 11,111	$ -	$ 20,133	$ 11,111	$ 11,111	$ 11,111	$ 33,333	-100.0%	-39.6%	MTM TRIGGER
Residential Technical Development	$ 12,611	$ 20,000	$ 20,000	$ 52,611	$ 20,000	$ 20,000	$ 20,000	$ 60,000	0.0%	-12.3%	
Hot Roofs	$ -	$ 9,000	$ 15,000	$ 24,000	$ 3,000	$ 9,000	$ 15,000	$ 27,000	0.0%	-11.1%	
Home Automation Pilot	$ -	$ 25,000	$ -	$ 25,000	$ 10,800	$ 25,000	$ 25,000	$ 60,800	-100.0%	-58.9%	MTM TRIGGER
Community Based Pilot	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
Statewide Marketing & Education	$ 39,970	$ 50,000	$ 90,000	$ 179,970	$ 50,000	$ 50,000	$ 50,000	$ 150,000	80.0%	20.0%	
EEAC Consultants	$ -	$ -	$ -	$ -	$ 93,555	$ -	$ 152,000	$ 245,555	-100.0%	-100.0%	
DOER Assessment	$ 46,639	$ 28,505	$ 89,598	$ 164,742	$ 28,456	$ 28,505	$ 28,557	$ 85,517	213.8%	92.6%	
Sponsorships & Subscriptions	$ 24,010	$ 13,090	$ 14,768	$ 51,868	$ 11,967	$ 13,090	$ 14,768	$ 39,825	0.0%	30.2%	
Low Income	**$ 1,826,691**	**$ 2,854,274**	**$ 3,145,453**	**$ 7,826,419**	**$ 2,088,750**	**$ 2,854,274**	**$ 3,755,545**	**$ 8,698,569**	**-16.2%**	**-10.0%**	
Low-Income Residential New Construction	$ 100,180	$ 33,772	$ -	$ 133,952	$ 28,666	$ 33,772	$ 36,301	$ 98,739	-100.0%	35.7%	MTM TRIGGER
Low-Income Retrofit [11]	$ 1,704,413	$ 2,791,728	$ 3,027,265	$ 7,523,406	$ 2,033,309	$ 2,791,728	$ 3,687,470	$ 8,512,508	-17.9%	-11.6%	
Statewide Marketing & Education	NA	NA	$ 15,000	$ 15,000	NA	NA	NA	NA	NA	NA	
Low-Income Energy Affordability Network Funding	$ 11,790	$ 24,000	$ 80,000	$ 115,790	$ 22,000	$ 24,000	$ 27,000	$ 73,000	196.3%	58.6%	
DOER Assessment	$ 10,309	$ 4,774	$ 23,188	$ 38,271	$ 4,774	$ 4,774	$ 4,774	$ 14,322	385.7%	167.2%	
C&I	**$ 5,315,961**	**$ 9,659,199**	**$ 3,560,354**	**$ 18,535,514**	**$ 7,098,577**	**$ 9,659,199**	**$ 13,181,769**	**$ 29,939,546**	**-73.0%**	**-38.1%**	
C&I New Construction and Major Renovation	$ 729,220	$ 1,287,876	$ 941,484	$ 2,958,580	$ 905,004	$ 1,287,876	$ 1,755,174	$ 3,948,054	-46.4%	-25.1%	MTM TRIGGER
C&I New Construction and Major Renovation - Government	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
C&I Large Retrofit	$ 1,575,123	$ 941,260	$ 2,375,749	$ 4,892,132	$ 1,807,995	$ 941,260	$ 1,331,718	$ 4,080,972	78.4%	19.9%	
Large C&I Retrofit - Government	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
C&I Small Retrofit	$ 2,972,638	$ 7,403,822	$ 110,675	$ 10,487,134	$ 4,289,871	$ 7,403,822	$ 9,936,866	$ 21,630,559	-98.9%	-51.5%	MTM TRIGGER
C&I Small Retrofit - Government	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
Community based Pilot	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
Statewide Marketing & Education	NA	NA	$ 46,000	$ 46,000	NA	NA	NA	NA	NA	NA	
EEAC Consultants	$ -	$ -	$ -	$ -	$ 70,295	$ -	$ 130,500	$ 200,795	-100.0%	-100.0%	
DOER Assessment	$ 35,036	$ 15,331	$ 74,214	$ 124,581	$ 15,380	$ 15,331	$ 15,279	$ 45,991	385.7%	170.9%	
Sponsorships & Subscriptions	$ 3,945	$ 10,910	$ 12,232	$ 27,087	$ 10,033	$ 10,910	$ 12,232	$ 33,175	0.0%	-18.4%	
Total Portfolio	**$ 13,531,218**	**$ 24,899,682**	**$ 17,650,258**	**$ 56,081,158**	**$ 18,636,789**	**$ 24,899,682**	**$ 32,244,083**	**$ 75,780,554**	**-45.3%**	**-26.0%**	

Notes:
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PERFORMANCE INCENTIVES

The Cape Light Compact does not have performance incentives, therefore this is not applicable to the Cape Light Compact.

Appendix 4

TRADITIONAL BILL IMPACTS

Approval of the Compact's proposed 2012 Modification will result in: (1) a decrease in its residential program budget of $4,196,362; (2) a decrease in its low-income residential budget of $610,092; and (3) a decrease in its commercial and industrial program budget of $9,176,843 for 2012 from the approved Compact's Three-Year Energy Efficiency Plan (2010-2012) for Plan Year 2012 ("Compact's Three Year Plan, Plan Year 2012"). Further, the Compact states that:

- A typical residential customer using 500 kilowatt-hours ("kWh") of electricity per month would experience a monthly bill decrease of approximately $2.13 or -43 percent in 2012 when compared to the amounts originally approved in the Compact's Three Year Plan, Plan Year 2012.

- A typical low-income residential customer using 500 kilowatt-hours ("kWh") of electricity per month would experience a monthly bill decrease of approximately $0.15 or -18 percent in 2012 when compared to the amounts originally approved in the Compact's Three Year Plan, Plan Year 2012.

- Bill impacts for commercial and industrial customers will vary. These customers should contact the Cape Light Compact for specific bill impact information.

Residential Sector Traditional Bill Impact Analysis

Line No.	Description	Original Plan	2012 2012 Mid-Term Modifications	$ Change	% Change
1	Residential EERF ($/kWh) (1)	$ 0.01000	$ 0.00573		
2	Avg. Residential Monthly Consumption (kWh) (2)	500	500		
3	Residential Monthly EERF ($) (3)	$ 5.00	$ 2.86	$ (2.13)	-42.68%

Notes:
1) Residential EERF from columns C and D in EERF Calculation table in associated 08-50 tables.
2) A general assumption, based on historical data, has been applied.
3) Monthly EERF = EERF * Avg. Monthly Consumption

Low Income Sector Traditional Bill Impact Analysis

Line No.	Description	Original Plan	2012 2012 Mid-Term Modifications	$ Change	% Change
1	Low Income EERF ($/kWh) (1)	$ 0.00176	$ 0.00145		
2	Avg. Low Income Monthly Consumption (kWh) (2)	500	500		
3	Low Income Monthly EERF ($) (3)	$ 0.88	$ 0.72	$ (0.15)	-17.52%

Notes:
1) Low Income EERF from columns C and D in EERF Calculation table in associated 08-50 tables.
2) A general assumption, based on historical data, has been applied.
3) Monthly EERF = EERF * Avg. Monthly Consumption

Appendix 5

EVALUATION STUDIES

STUDY NUMBER	STUDY NAME
1.	Avoided Energy Supply Costs in New England: 2011 Report

Synapse
Energy Economics, Inc.

Avoided Energy Supply Costs in New England:

2011 Report

July 21, 2011

Amended August 11, 2011

AUTHORS

Rick Hornby, Paul Chernick, Dr. Carl Swanson, Dr. David White, Jason Gifford, Max Chang, Nicole Hughes, Matthew Wittenstein, Rachel Wilson, and Bruce Biewald

PREPARED FOR

Avoided-Energy-Supply-Component (AESC) Study Group

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Table of Exhibits

Chapter 1: Executive Summary

This 2011 Avoided-Energy-Supply-Component Study ("AESC 2011," or "the Study") provides projections of marginal energy supply costs that will be avoided due to reductions in the use of electricity, natural gas, and other fuels resulting from energy efficiency programs offered to customers throughout New England. All reductions in use referred to in the Study are measured at the customer meter, unless noted otherwise.

AESC 2011 provides estimates of avoided costs for program administrators throughout New England to support their internal decision-making and regulatory filings for energy efficiency program cost-effectiveness analyses. The AESC 2011 project team understands that, ultimately, the relevant regulatory agencies in each state: specify the categories of avoided costs that program administrators in their states are expected to use in their regulatory filings, and; approve the values used for each category of avoided cost.

In order to determine the value of those programs, projections of avoided electric capacity and energy prices have been developed for a hypothetical future, the "Reference Case," in which no new energy efficiency is implemented from 2012 onward. It is important to note that the projections in AESC 2011 should not be interpreted as projections of or proxies for the market prices of natural gas, electricity, or other fuels at any future point in time, for the following two reasons. First, the projections of electric capacity and energy prices are for a hypothetical future and thus do not reflect the actual market conditions and prices likely to prevail in an actual future with significant amounts of new efficiency measures. Second, the Study is providing projections of the avoided costs of these fuels in the long-term. The actual market prices of those fuels at any future point in time will vary above and below their long-run avoided costs due to the various factors that affect short-term market prices at any point in time.

AESC 2011 updates the 2009 AESC Study ("AESC 2009") to reflect changes in observed facts and in expectations regarding future market conditions and future costs. Specific changes in expectations that contribute to changes from the AESC 2009 avoided costs are projections of:

- Dramatic increases in the quantity of technically recoverable shale gas resources—coupled with decreases in the expected costs of finding, developing, and producing gas from those resources—leading to lower projections of avoided costs for natural gas and gas-fired electric energy;
- Retirements of a significant quantity of existing generating capacity, leading to higher estimates of avoided costs for electric capacity;
- A delay in the start of federal regulation of carbon emissions from 2013 to 2018, leading to lower projections of avoided costs for electric energy; and

- Lower avoided costs of gas distribution margins, leading to lower projections of avoided costs for natural gas delivered to end users.

The Study provides detailed projections of avoided costs by year for an initial 15 year period, 2012 through 2026, and extrapolated values for another 15 years, from 2027 through 2041. All values are reported in 2011 dollars ("2011$") unless noted otherwise. For ease of reporting and comparison with AESC 2009, many results are expressed as levelized values over 15 years.[1] These levelized results are calculated using the real discount rate of 2.46 percent solely for illustrative purposes.

1.1. Background to Study

AESC 2011 was sponsored by a group of electric utilities, gas utilities, and other efficiency program administrators (collectively, "program administrators" or "PAs"). The sponsors, along with non-utility parties and their consultants, formed an AESC 2011 Study Group to oversee the design and execution of the report. The Study sponsors include: Berkshire Gas Company; Cape Light Compact; National Grid USA; New England Gas Company; NSTAR Electric & Gas Company; New Hampshire Electric Co-Op; Columbia Gas of Massachusetts; Northeast Utilities (Connecticut Light and Power, Western Massachusetts Electric Company, Public Service Company of New Hampshire, and Yankee Gas); Unitil (Fitchburg Gas and Electric Light Company, Unitil Energy Systems, Inc., and Northern Utilities); United Illuminating; Southern Connecticut Gas and Connecticut Natural Gas; Efficiency Maine; and the State of Vermont. The non-utility parties represented in the Study Group include: Connecticut Energy Conservation Management Board; Massachusetts Department of Public Utilities; Massachusetts Department of Energy Resources; Massachusetts Attorney General; Massachusetts Low-Income Energy Affordability Network ("LEAN"); Massachusetts Energy Efficiency Advisory Council; New Hampshire Public Utilities Commission; and Rhode Island Division of Public Utilities and Carriers.

The AESC 2011 Study Group specified the scope of work, selected the Synapse Energy Economics ("Synapse") project team, and monitored progress of the study. The Synapse project team presented its analyses and projections to the 2011 AESC Study Group in eight substantive tasks.

The draft deliverable for each task was reviewed in a conference call. The relationship between the chapters in this report and the task deliverables is as follows:

- Chapter 2 – Methodologies and Assumptions Underlying Projections of Avoided Electric Supply Costs (Task 3);

[1] 15 year levelization periods of 2010-2024 for AESC 2009 and 2012-2026 for AESC 2011.

- Chapter 3 – Wholesale Natural Gas Prices (Task 4);
- Chapter 4 – Avoided Natural Gas Costs (Task 6);
- Chapter 5 – Forecast of New England Regional Oil Prices and Avoided Costs of Other Fuels by Sector (Tasks 5 and 9);
- Chapter 6 – Regional Electric Energy Supply Prices Avoided by Energy Efficiency and Demand Response Programs (Task 7);
- Chapter 7 – Sensitivity Analyses (Task 8);
- Chapter 8 – Usage Instructions (Task 10).

The report was prepared by a project team assembled and led by Synapse. Synapse's Rick Hornby and Max Chang managed the project. Dr. Carl Swanson of the Swanson Energy Group led the analysis of avoided natural gas costs. Paul Chernick of Resource Insight led the analysis of wholesale capacity costs and Demand Reduction Induced Price Effect ("DRIPE"). Dr. David White and Nichole Hughes of Synapse developed the projections of wholesale electric energy prices. Jason Gifford and Bob Grace of Sustainable Energy Advantage ("SEA") provide estimates of renewable energy credit ("REC") demand, supply, and price. Dr. David White and Matt Wittenstein of Synapse developed projections of avoided costs of other fuels. Rachel Wilson, Matt Wittenstein, and Bruce Biewald of Synapse developed externality values for air emissions avoided due to reductions in electricity and fuel use.

1.2. Avoided Costs of Electricity to Retail Customers

An electric energy efficiency program that enables a retail customer to reduce his or her peak and annual electricity use has a number of key monetary and environmental benefits. Major categories of benefits include:

- Generation capacity and energy costs avoided due to reductions in quantities required to meet electric energy demand. *Electric capacity costs* are avoided due to a reduction in the annual quantity of electric capacity that load serving entities ("LSEs") will have to acquire from the Forward Capacity Market ("FCM") to ensure an adequate quantity of generation during hours of peak demand. *Electric energy costs* are avoided due to a reduction in the annual quantity of electric energy that LSEs will have to acquire. These avoided costs include a reduction in the cost of renewable energy incurred to comply with the applicable Renewable Portfolio Standards ("RPS");[2]

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[2]Electric energy is measured in kilowatt hours (kWh) or megawatt hours MWh; electricity capacity is measured in kilowatts (kW) or megawatts (MW).

- Generation capacity and energy costs avoided due to reductions in wholesale market prices required for capacity and energy. Reductions in the quantities of capacity and of energy being acquired from those markets will cause prices in those markets to decline relative to Reference Case levels for a certain period of time, after which responses by market participants will lead to a shift in the supply curve and cause prices to rise back towards the Reference Case levels. AESC 2011 refers to the reduction or mitigation of market prices due to reductions in demand for capacity and energy as capacity DRIPE and energy DRIPE, respectively.
- Environmental externality costs avoided due to a reduction in the required quantity of electric energy that has to be generated. An environmental externality is the value of an environmental impact associated with the use of a product or service, such as electricity, that is not reflected in the price of that product. AESC 2011 uses the long-term abatement cost of carbon dioxide emissions as a proxy for these externalities.
- Local transmission and distribution ("T&D") infrastructure costs avoided due to a reduction in the timing and/or size of new projects that have to be built, resulting from the reduction in electric energy that has to be delivered.

AESC 2011 provides estimates of each category of avoided costs except avoided T&D, which is utility-specific and beyond the scope of the study. The projected avoided costs are provided by geographic area, by year, and by costing period within each year. These components are:

- **Avoided energy.** This is the largest component. It consists of the wholesale electric energy price, the REC cost, and a wholesale risk premium. Levelized annual avoided energy costs are approximately 17 percent lower on average than those in AESC 2009. The levelized annual wholesale electric energy costs are lower primarily due to projections of lower natural gas prices and a delay in Federal regulation of carbon emissions. The decline in that component is offset somewhat in summer peak periods by lower efficiency gas-fired units setting market prices due to an increase in the quantity of existing capacity projected to retire.
- **Avoided capacity.** Avoided capacity costs consist of revenue from demand reductions bid into the FCM and the value of generating capacity avoided by demand reductions that are not bid into the FCM. Levelized annual avoided capacity costs for demand reductions bid into the FCM are approximately 91 percent higher than AESC 2009. This increase is primarily due to the extension of floor prices through Forward Capacity Auction ("FCA") 6, the exclusion of reductions in demand from existing efficiency, and higher projections of new

capacity additions due to the increased quantity of existing capacity projected to retire.

- **Energy DRIPE.** This is the value of the reduction in energy market prices due to kWh reductions. Levelized annual intrastate energy DRIPE values are approximately 43 percent higher on average than AESC 2009, primarily due to changes in wholesale energy prices from AESC 2009 offset by changes in the DRIPE dissipation factor for new generation.
- **Capacity DRIPE.** This is the value of the reduction in capacity market prices due to kW reductions. Levelized annual capacity DRIPE values are approximately 370 percent higher on average than AESC 2009 due to projections of higher capacity prices and a longer dissipation period.
- **Avoided CO_2 environmental externalities.** This is the cost of controlling CO_2 emissions not reflected in wholesale energy market prices. Levelized annual values are approximately 16 percent higher due to the five-year delay in federal regulation of CO_2 emissions and higher modeled emission rates compared to two years ago.

The relative magnitude of each component for the summer peak costing period is illustrated in Exhibit 1.1 for an efficiency measure with a 55 percent load factor implemented in the West Central Massachusetts zone (“WCMA”).

Exhibit 1-1: Illustration of Avoided Electricity Cost Components, AESC 2011 vs. AESC 2009 (WCMA Zone, Summer On-Peak, 15 Year Levelized Results, 2011$)

Component	AESC 2009	AESC 2011	Difference Relative to AESC 2009	
	cents/kWh	cents/kWh	cents/kWh	% Difference
Avoided Energy Costs	9.63	9.06	-0.57	-5.9%
Avoided Capacity Costs[1,2]	0.59	1.08	0.49	83.2%
Energy and Capacity Subtotal	**10.22**	**10.14**	**-0.08**	**-0.8%**
DRIPE				
Intrastate Energy[3]	2.76	3.18	0.43	15.4%
Capacity[2]	0.26	1.23	0.97	371.9%
DRIPE Subtotal	**3.02**	**4.41**	**1.39**	**46.1%**
Subtotal: Avoided Energy and Capacity + Intrastate DRIPE	**13.23**	**14.55**	**1.31**	**9.9%**
CO_2 Externality[4]	2.95	3.41	0.46	15.5%
Total	**16.19**	**17.96**	1.77	10.9%

Notes
-Values may not sum due to rounding
-Avoided energy costs for Summer On-Peak incorporate avoided REC costs (All Classes for AESC 2011, Class I for AESC 2009)
-AESC 2009 values levelized (2010-2024) escalated to 2011$
1) Avoided capacity costs assumes 100% ***selling*** into Forward Capacity Markets
2) Assuming a 55% load factor
3) Values are for Intrastate *energy* DRIPE
4) 2011 CO_2 prices and physical emission rates

For this costing location and period, AESC 2011 is projecting total avoided costs from direct reductions in energy and capacity of 10.2 cents per kWh, approximately 0.6 percent lower than the corresponding AESC 2009 total.

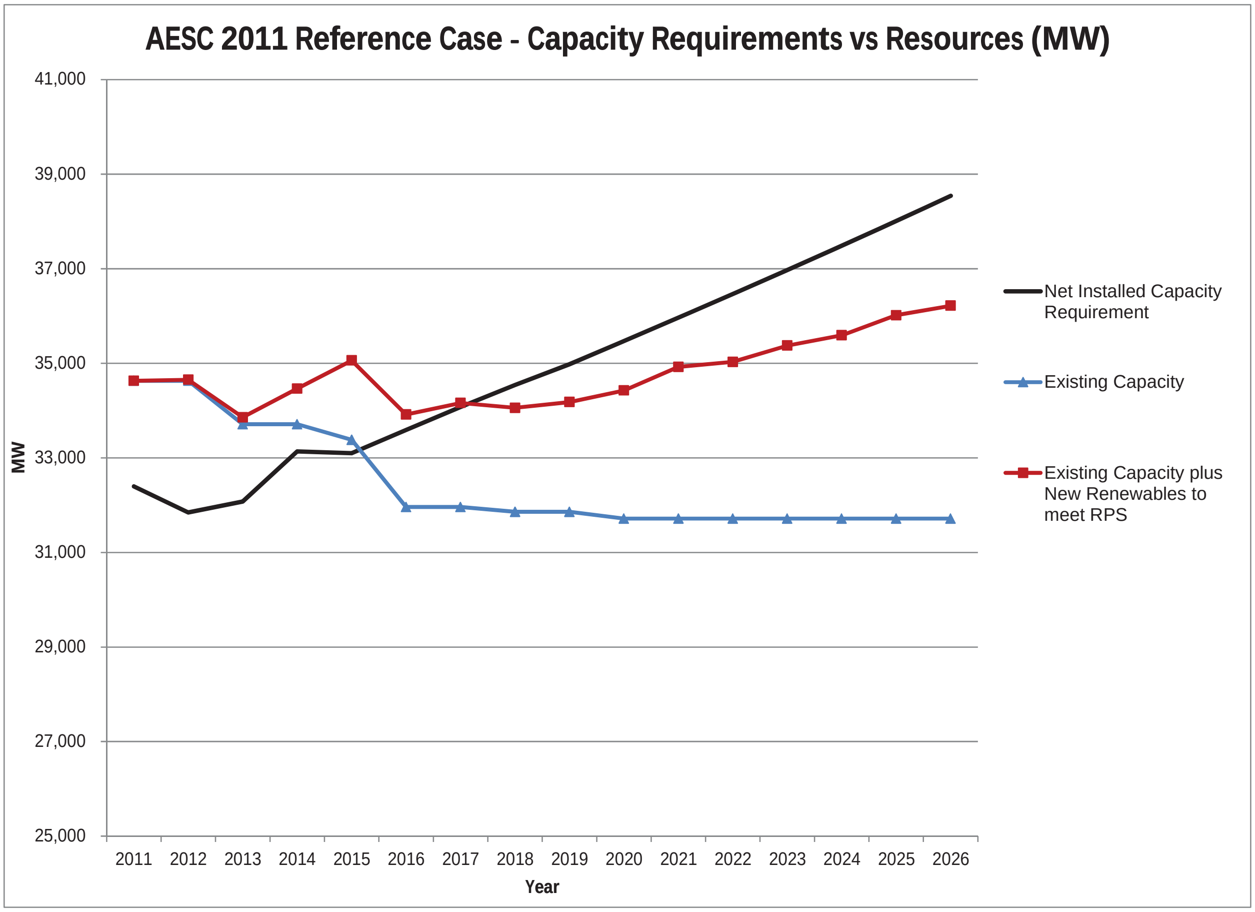
In total, the Study's projection of the avoided cost of energy and capacity reductions (10.16 cents per kWh), plus intrastate DRIPE and CO_2 externality, is 17.98 cents per kWh—about 11.1 percent higher than AESC 2009. The factors driving the differences between the AESC 2011 and AESC 2009 estimates are discussed by component below.

1.2.1. Avoided Capacity Costs

Avoided electric capacity costs are an estimate of the value of a reduction in energy use by retail customers during hours of system peak demand. The major input to this calculation is the avoided wholesale electric capacity cost. To develop an avoided cost at the meter, the avoided wholesale electric capacity cost is first increased by the reserve margin requirements forecasted for the year, then increased by eight percent to reflect ISO-NE losses.

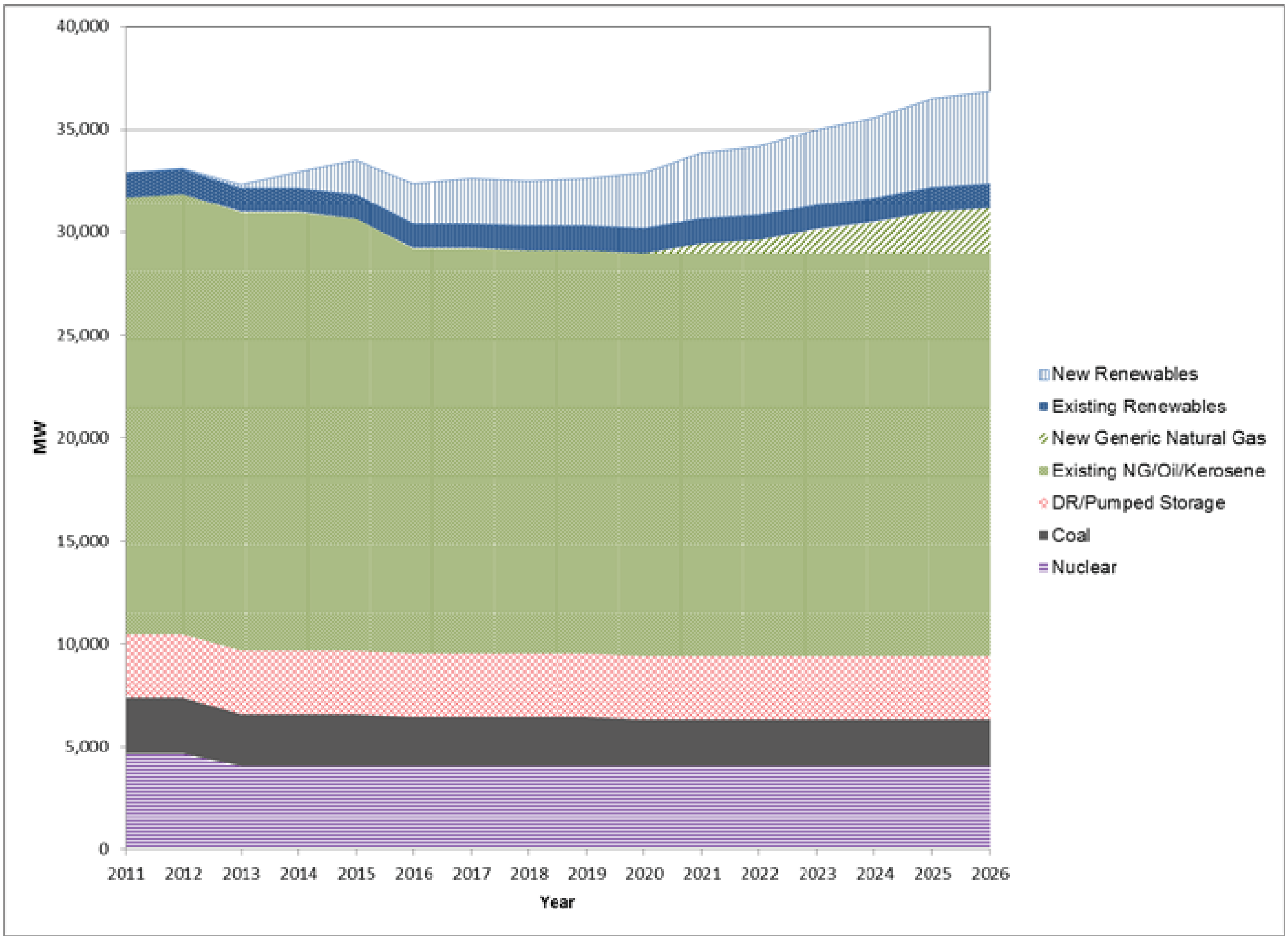
The major drivers of avoided wholesale capacity costs are system peak demand, retirements of existing capacity, new capacity from resources added to comply with RPS requirements, and new non-RPS capacity additions. AESC 2009 projected there would not be a need to add new capacity other than renewable resources until after 2024. In contrast, as indicated in Exhibit 1-2, AESC 2011 is projecting that new capacity, other than RPS-related renewable resources, will have to be added starting in 2020. This is for two main reasons.

Exhibit 1-2: AESC 2011 Capacity Requirements vs. Resources (Reference Case)



First, our Reference Case assumes approximately 2,000 MW more existing capacity will retire during the Study period than the AESC 2009 Reference Case assumed. The anticipated retirements include Vermont Yankee (600 MW) and over 1,000 MW at older coal plants that are facing significant costs to comply with tighter restrictions on air emissions under recent and impending changes in federal regulations. Second, the Reference Case assumes transmission constraints will prevent a portion of the capacity located in Maine from affecting the regional capacity market price until 2014. The AESC 2011 Reference Case capacity mix is presented in Exhibit 1-3.

Exhibit 1-3: AESC 2011 Reference Case, Capacity by Source (MW)



The 15 year levelized projections of capacity costs avoided by reducing purchases from the FCM from AESC 2011 and AESC 2009 are shown in Exhibit 1-4.

Exhibit 1-4: Avoided Electric Capacity Costs, AESC 2011 vs. AESC 2009 (15 year Levelized, 2011$)

	Annual Capacity Market Values (2011$/kW-yr)		
Zone	**AESC 2009**	**AESC 2011**	**Change**
Maine (ME)	25.15	48.09	91%
Vermont (VT)	25.15	48.09	91%
New Hampshire (NH)	25.15	48.09	91%
Connecticut (statewide)	25.15	48.09	91%
Massachusetts (statewide)	25.15	48.09	91%
Rhode Island (RI)	25.15	48.09	91%
SEMA	25.15	48.09	91%
Central & Western Massachusetts (WCMA)	25.15	48.09	91%
NEMA	25.15	48.09	91%
Rest of Massachusetts (non-NEMA)	25.15	48.09	91%
Norwalk / Stamford (NS)	25.15	48.09	91%
Southwest Connecticut (SWCT) including Norwalk/Stamford	25.15	48.09	91%
Southwest Connecticut (SWCT) excluding Norwalk/Stamford	25.15	48.09	91%
Rest of Connecticut (non-SWCT)	25.15	48.09	91%
Note: Bid into FCM, 15-year levelized (AESC 2009 2010-2024, AESC 2011 2012-2026)			

The AESC 2011 estimates of avoided capacity costs are approximately 91 percent higher than those from AESC 2009 on a 15 year levelized basis. The higher values are primarily due to the extension of the floor price through FCA 6 and the projected need for additional, new, non-RPS related capacity starting in 2020. That need, in turn, is driven by the projected retirements of existing capacity and regulatory changes causing certain existing capacity to be treated as out-of-market ("OOM") resources, and therefore prohibited from setting the market price.[3]

The actual amount of wholesale electric capacity costs avoided by kW reductions from energy efficiency measures will vary according to the approach that the PA responsible for those measures takes towards the FCM. PAs achieve the maximum avoided cost by bidding the entire anticipated kW reduction from measures in a given year into the FCA for that power year. However, PAs have to submit those bids when the FCA is held, which is approximately three years in advance of the applicable power year. PAs also avoid capacity costs from kW reductions that are not bid into FCAs, since those kW reductions lower actual demand, and ISO-NE eventually reflects those lower demands when setting the maximum demand to be met in future FCAs. However, the total amount of avoided capacity costs is lower because of the time lag, up to four years, between the

[3] Out-of-Market resources include capacity from energy efficiency programs that are not allowed to set capacity prices, but are allowed to participate in the capacity market.

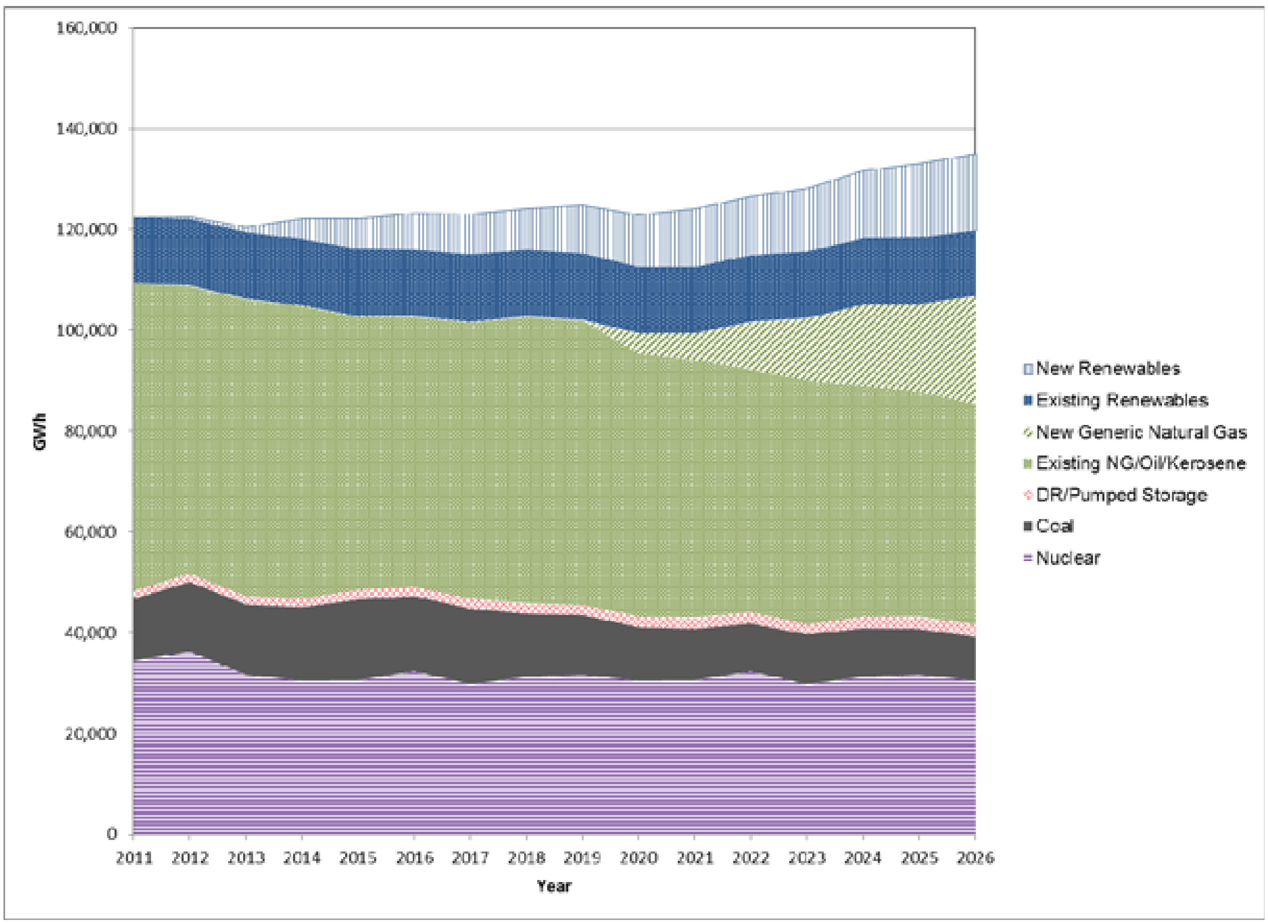
year in which the kW reduction first causes a lower actual peak demand and the year in which ISO-NE translates that kW reduction into a reduction in the total demand for which capacity has to be acquired in a FCA.

1.2.2. Avoided Electric Energy Costs

Avoided electric energy costs are an estimate of the value of a reduction in annual electric energy use by retail customers. The major input to this calculation is the avoided wholesale electric energy cost. To develop an avoided cost at the meter in each state, the avoided wholesale electric energy cost is first increased by the avoided costs of complying with the RPS in that state, and that amount is then increased by the wholesale risk premium mentioned earlier.

Natural gas fired units are the dominant marginal source of generation under the Reference Case, i.e., they set the market price in most hours of most years. The AESC 2011 Reference Case forecast of annual generation by resource type is depicted in Exhibit 1-5.

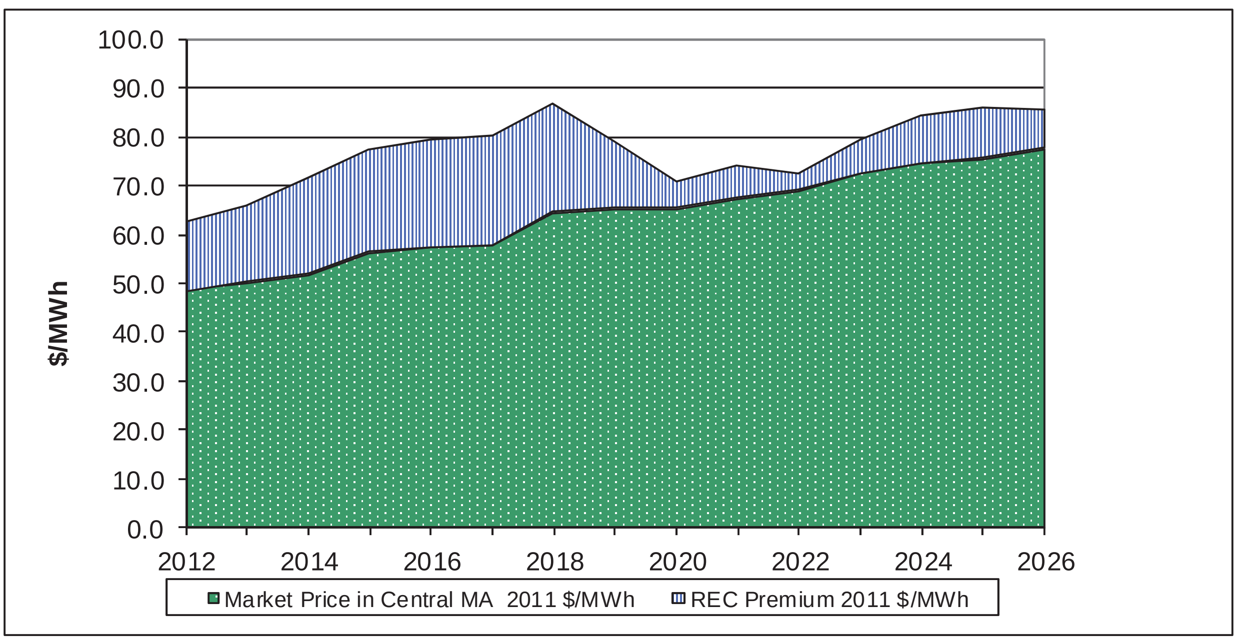
Exhibit 1-5: AESC 2011 Reference Case, Generation by Source (GWh)



The major drivers of avoided electric energy costs are annual load, natural gas prices, and costs to comply with carbon emission regulations. AESC 2011 is projecting levelized annual wholesale electric energy costs to be 15 percent lower than AESC 2009.[4] The majority of the reduction is attributable to the Reference Case projection of wholesale natural gas costs, which is much lower than in AESC 2009. The AESC projection of wholesale natural gas costs is described later in the Executive Summary. The remaining portion of the reduction is due to a change in the assumption of when federal regulation of carbon emissions will start, from 2013 assumed in AESC 2009 to 2018 assumed in AESC 2011.

The avoided costs of RECs are a function of two factors. One factor is the forecast quantity of renewable energy that LSEs will have to acquire in order to comply with the relevant RPS. The second factor is the forecast premium over wholesale electric energy market prices that LSEs will have to pay to acquire that renewable energy. The forecast REC premium is based upon an estimate of REC prices (applicable for each RPS tier), the cost of new entry of Class I renewables from 2019 onward, and the forecast annual wholesale electric energy price. For illustrative purposes for Class 1 RECs, see Exhibit 1-6.

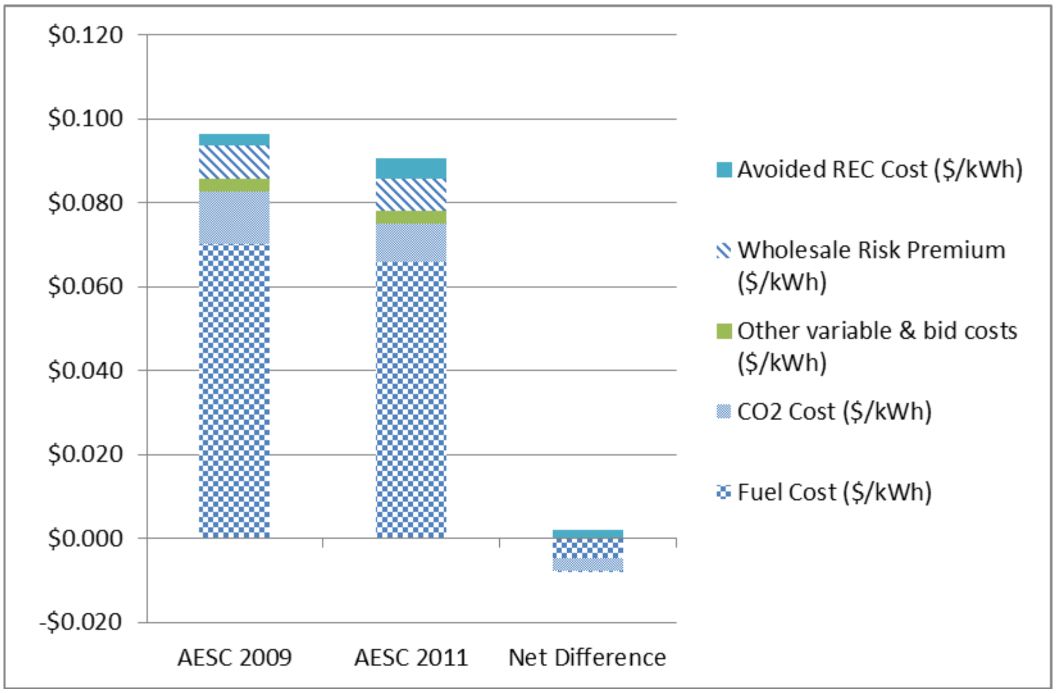
Exhibit 1-6: AESC 2011 Reference Case, Wholesale Electric Energy Prices and REC Premiums



[4] Levelized (2012-2026) for AESC 2011 and AESC 2009 (2010-2024)

The relative magnitude of each component of avoided electric energy cost is illustrated in Exhibit 1-7, which assumes the same efficiency measure implemented in the summer on-peak period in the WCMA zone that is shown in Exhibit 1-1. This illustration indicates that the levelized 0.5 cent per kWh difference between the AESC 2009 avoided energy cost of 9.6 cents per kWh and the AESC 2011 avoided energy cost of 9.1 cents per kWh is primarily attributable to lower natural gas costs, lower carbon costs, and offset by higher REC costs.

Exhibit 1-7: Illustration of Avoided Electric Energy Cost Composition, AESC 2011 vs. AESC 2009 (WCMA Zone, Summer On-Peak, 15 Year Levelized Results, 2011$)



The 15 year levelized projections of avoided electric energy costs for the AESC 2011 and 2009 studies, by zone, are shown in Exhibit 1-8.[5]

[5] AESC 2011 levelized (2012-2026), AESC 2009 levelized (2010-2024)

Revised August 11, 2011

Exhibit 1-8: Avoided Electric Energy Costs, AESC 2011 vs. AESC 2009 (15 Year Levelized 2011$)

		Winter On Peak Energy	Winter Off-Peak Energy	Summer On Peak Energy	Summer Off-Peak Energy	Annual Weighted Average
	AESC 2011	**$/kWh**	**$/kWh**	**$/kWh**	**$/kWh**	**$/kWh**
1	Maine (ME)	0.067	0.059	0.072	0.058	0.063
2	Vermont (VT)	0.074	0.064	0.087	0.063	0.071
3	New Hampshire (NH)	0.072	0.064	0.078	0.062	0.068
4	Connecticut (statewide)	0.075	0.065	0.089	0.064	0.072
5	Massachusetts (statewide)	0.077	0.067	0.090	0.066	0.074
6	Rhode Island (RI)	0.065	0.055	0.076	0.055	0.061
7	SEMA	0.076	0.067	0.089	0.066	0.073
8	Central & Western Massachusetts (WCMA)	0.077	0.068	0.091	0.066	0.074
9	NEMA	0.076	0.067	0.090	0.065	0.073
10	Rest of Massachusetts (non-NEMA)	0.077	0.068	0.091	0.066	0.074
11	Norwalk / Stamford (NS)	0.076	0.066	0.090	0.065	0.072
12	Southwest Connecticut (SWCT) including Norwalk/Stamford	0.076	0.066	0.090	0.065	0.072
13	Southwest Connecticut (SWCT) excluding Norwalk/Stamford	0.075	0.066	0.090	0.064	0.072
14	Rest of Connecticut (non-SWCT)	0.074	0.064	0.088	0.063	0.071
	AESC 2009	**$/kWh**	**$/kWh**	**$/kWh**	**$/kWh**	**$/kWh**
1	Maine (ME)	0.084	0.072	0.088	0.070	0.078
2	Vermont (VT)	0.091	0.076	0.095	0.073	0.083
3	New Hampshire (NH)	0.089	0.074	0.092	0.072	0.081
4	Connecticut (statewide)	0.097	0.080	0.101	0.077	0.088
5	Massachusetts (statewide)	0.093	0.077	0.097	0.074	0.085
6	Rhode Island (RI)	0.084	0.068	0.086	0.065	0.075
7	SEMA	0.093	0.077	0.096	0.073	0.084
8	Central & Western Massachusetts (WCMA)	0.093	0.077	0.096	0.074	0.085
9	NEMA	0.094	0.077	0.097	0.074	0.085
10	Rest of Massachusetts (non-NEMA)	0.093	0.077	0.096	0.074	0.085
11	Norwalk / Stamford (NS)	0.098	0.081	0.102	0.078	0.089
12	Southwest Connecticut (SWCT) including Norwalk/Stamford	0.098	0.081	0.102	0.078	0.089
13	Southwest Connecticut (SWCT) excluding Norwalk/Stamford	0.098	0.081	0.102	0.078	0.089
14	Rest of Connecticut (non-SWCT)	0.096	0.080	0.100	0.076	0.087
	Change from AESC 2009	**$/kWh**	**$/kWh**	**$/kWh**	**$/kWh**	**$/kWh**
1	Maine (ME)	(0.017)	(0.013)	(0.016)	(0.012)	(0.014)
2	Vermont (VT)	(0.017)	(0.012)	(0.008)	(0.010)	(0.013)
3	New Hampshire (NH)	(0.016)	(0.011)	(0.014)	(0.009)	(0.013)
4	Connecticut (statewide)	(0.022)	(0.015)	(0.012)	(0.013)	(0.016)
5	Massachusetts (statewide)	(0.017)	(0.010)	(0.006)	(0.008)	(0.011)
6	Rhode Island (RI)	(0.019)	(0.013)	(0.009)	(0.010)	(0.014)
7	SEMA	(0.017)	(0.010)	(0.007)	(0.007)	(0.011)
8	Central & Western Massachusetts (WCMA)	(0.016)	(0.010)	(0.006)	(0.008)	(0.011)
9	Boston (NEMA)	(0.018)	(0.011)	(0.008)	(0.008)	(0.012)
10	Rest of Massachusetts (non-NEMA)	(0.016)	(0.010)	(0.006)	(0.007)	(0.011)
11	Norwalk / Stamford (NS)	(0.022)	(0.015)	(0.012)	(0.013)	(0.017)
12	Southwest Connecticut (SWCT) including Norwalk/Stamford	(0.022)	(0.015)	(0.012)	(0.013)	(0.017)
13	Southwest Connecticut (SWCT) excluding Norwalk/Stamford	(0.022)	(0.015)	(0.012)	(0.013)	(0.017)
14	Rest of Connecticut (non-SWCT)	(0.022)	(0.015)	(0.012)	(0.013)	(0.016)
	% Change from AESC 2009	**%**	**%**	**%**	**%**	**%**
1	Maine (ME)	-20.1%	-17.5%	-18.3%	-17.5%	-18.5%
2	Vermont (VT)	-19.2%	-15.3%	-8.3%	-14.2%	-15.2%
3	New Hampshire (NH)	-18.6%	-14.3%	-15.0%	-13.2%	-15.7%
4	Connecticut (statewide)	-22.6%	-18.9%	-11.9%	-17.1%	-18.7%
5	Massachusetts (statewide)	-17.7%	-12.8%	-6.5%	-10.3%	-13.0%
6	Rhode Island (RI)	-22.7%	-19.4%	-10.8%	-15.1%	-18.4%
7	SEMA	-18.3%	-12.7%	-6.9%	-9.7%	-13.2%
8	Central & Western Massachusetts (WCMA)	-16.8%	-12.7%	-5.9%	-10.6%	-12.6%
9	Boston (NEMA)	-18.9%	-13.8%	-8.1%	-11.5%	-14.2%
10	Rest of Massachusetts (non-NEMA)	-17.2%	-12.6%	-5.8%	-10.1%	-12.6%
11	Norwalk / Stamford (NS)	-22.6%	-18.9%	-11.9%	-17.1%	-18.6%
12	Southwest Connecticut (SWCT) including Norwalk/Stamford	-22.6%	-18.9%	-11.9%	-17.1%	-18.6%
13	Southwest Connecticut (SWCT) excluding Norwalk/Stamford	-22.6%	-18.9%	-11.9%	-17.1%	-18.6%
14	Rest of Connecticut (non-SWCT)	-22.6%	-18.9%	-11.9%	-17.1%	-18.7%

As mentioned earlier, the 15 year levelized AESC 2011 avoided energy costs are approximately 15 percent less than those from AESC 2009 on an annual average basis. The decline in summer peak period costs between AESC 2009 and AESC 2011 is generally less than the annual average because of the higher levels of existing capacity retirements projected in AESC 2011. Those retirements change the supply curve, leading to less-efficient units being on the margin during high load hours, and setting prices, in summer peak periods than in AESC 2009. In contrast, the decline in avoided energy costs in AESC 2011 versus AESC 2009 is generally greater than the annual average in the three remaining periods, because the impacts of lower natural gas prices and lower carbon prices is not offset by less-efficient marginal units.

1.2.3. Demand Reduction Induced Price Effects ("DRIPE")

DRIPE is the reduction in prices in the wholesale energy and capacity markets, relative to those forecast in the Reference Case, resulting from the reduction in need for energy and/or capacity due to efficiency and/or demand response programs (i.e., the latter are programs under which consumers agree to reduce their energy consumption during peak demand periods in exchange for financial or other benefits). Thus DRIPE is a measure of the value of efficiency in terms of the reductions in **wholesale prices** seen by all retail customers in a given period. In contrast, avoided electric energy costs and capacity costs measure the value of efficiency in terms of the reductions in the **quantity** of energy used by retail customers in a given period.

The first step in the development of DRIPE is to estimate the impact a reduction in load will have upon the market price, assuming no other changes occur ("gross DRIPE"). The second step is to estimate the pace at which suppliers participating in that market will respond to that reduction with actions that offset the reduction and eventually cause the market price to move toward the level it would have been under the Reference Case ("net DRIPE"). In other words, responses taken by market participants will eventually offset, or dissipate, the DRIPE impact.

The three charts below illustrate the concept using the calculation of capacity DRIPE for FCA 7 as an example.

- **Exhibit 1-9** presents the supply and demand curve used to estimate the Reference Case market price for FCA 7.
- **Exhibit 1-10** illustrates the gross DRIPE effect, i.e., the reduction in price as the demand curve shifts left due to a 100-MW reduction in demand.
- **Exhibit 1-11** illustrates the net DRIPE effect, i.e., the increase in price as the supply curve shifts left due to actions taken by suppliers in response to the lower price in Exhibit 1-10.

Exhibit 1-9: FCA 7 Supply and Demand Curve for FCA 7

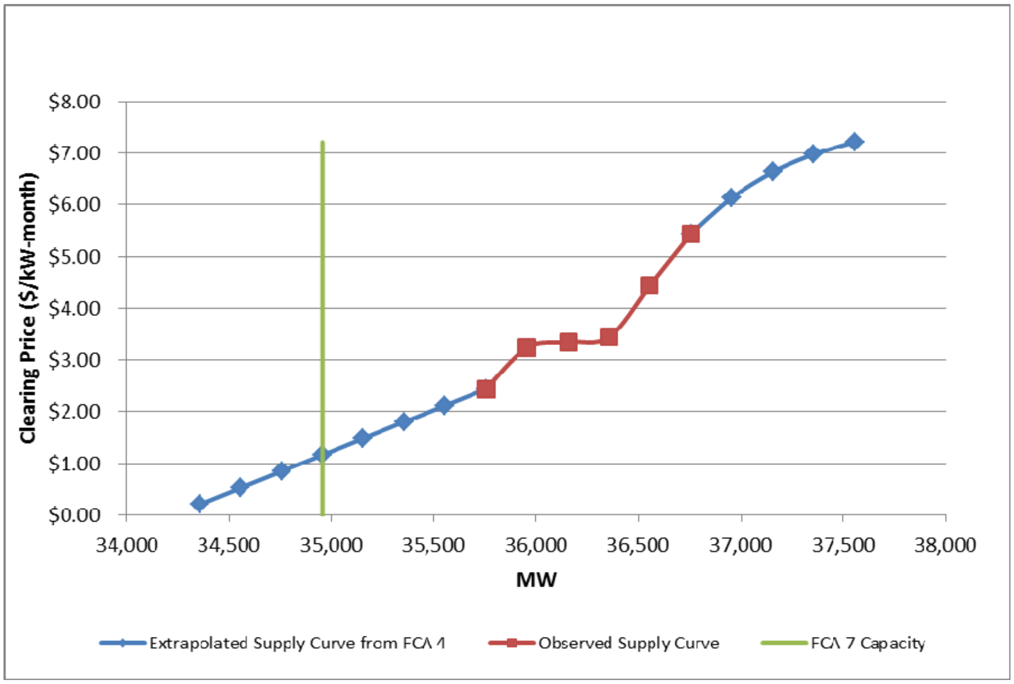


Exhibit 1-10: Gross Capacity DRIPE Response for FCA 7

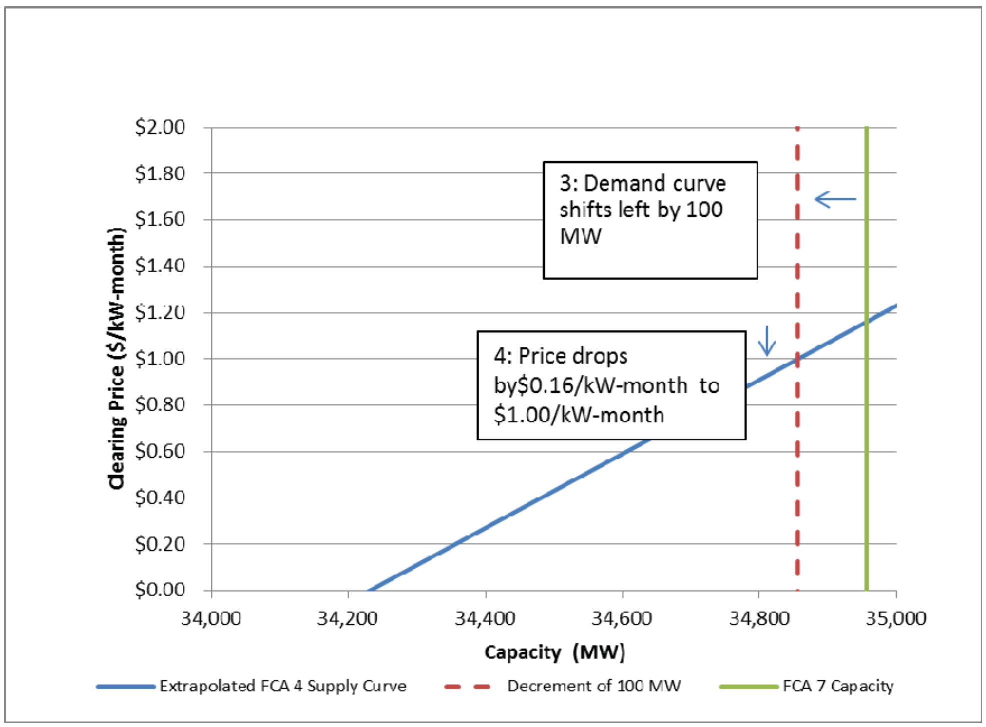
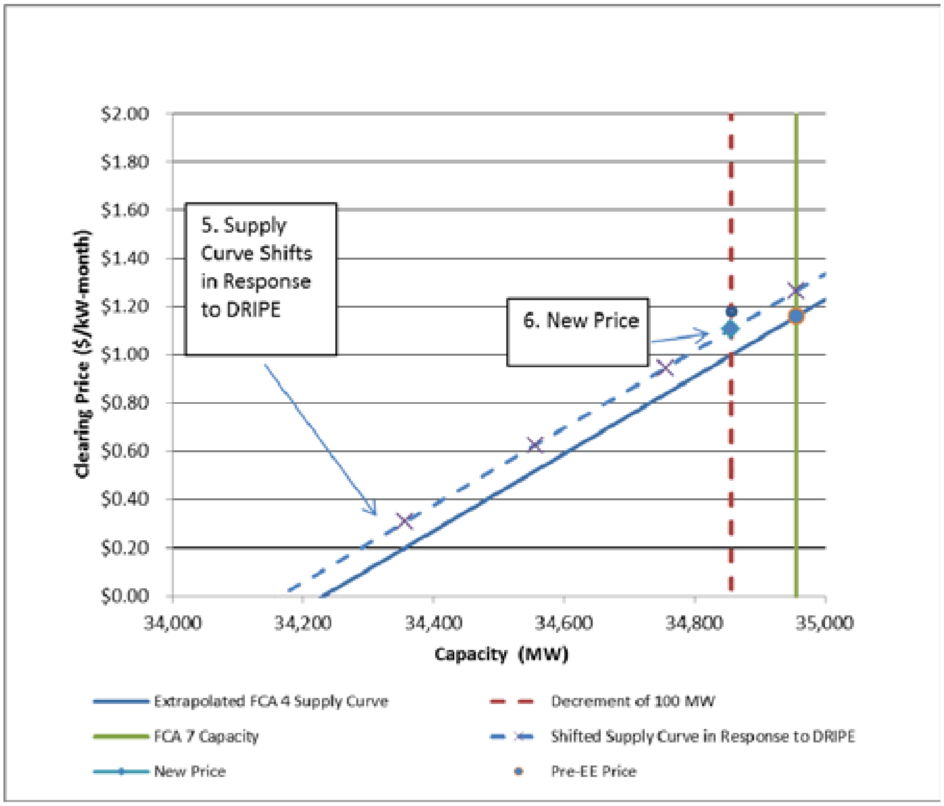


Exhibit 1-11: Net Capacity DRIPE Response for FCA 7



DRIPE impacts are small when expressed as percentage impacts on the market prices of energy and capacity. However, DRIPE impacts are significant when expressed in absolute dollar terms, since very small impacts on market prices, when applied to all energy and capacity being purchased in the market, translate to large absolute dollar amounts. DRIPE will have an impact on market prices within the zone where the reduction occurs, referred to as intrastate impacts, as well as throughout the rest of the New England market, referred to as "rest of pool" ("ROP"). Thus DRIPE impacts can be expressed as intrastate only or total (intrastate plus ROP).

Exhibit 1-12 presents 15 year levelized intrastate energy and capacity DRIPE estimates by zone for AESC 2011 and AESC 2009. We recommend that program administrators include DRIPE values in their analyses of demand side management ("DSM"), unless specifically prohibited from doing so by state or local law or regulation.

Exhibit 1-12: Intrastate Energy DRIPE and State Capacity DRIPE for Installations in 2012, AESC 2011 vs. AESC 2009 (15 year Levelized by Zone, 2011$)

	Intrastate Energy DRIPE				State Capacity DRIPE
AESC 2011	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	
Zone	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr
Maine (ME)	0.005	0.004	0.006	0.005	10.93
Vermont (VT)	0.001	0.001	0.002	0.001	2.23
New Hampshire (NH)	0.004	0.005	0.009	0.005	7.51
Connecticut (statewide)	0.014	0.014	0.028	0.019	30.72
Massachusetts (statewide)	0.018	0.017	0.032	0.018	59.07
Rhode Island (RI)	0.006	0.005	0.007	0.004	9.48
SEMA	0.018	0.017	0.032	0.018	59.07
Central & Western Massachusetts (WCMA)	0.018	0.017	0.032	0.018	59.07
NEMA	0.018	0.017	0.032	0.018	59.07
Rest of Massachusetts (non-NEMA)	0.018	0.017	0.032	0.018	59.07
Norwalk / Stamford (NS)	0.014	0.014	0.028	0.019	30.72
Southwest Connecticut (SWCT) including Norwalk/Stamford	0.014	0.014	0.028	0.019	30.72
Southwest Connecticut (SWCT) excluding Norwalk/Stamford	0.014	0.014	0.028	0.019	30.72
Rest of Conneticut	0.014	0.014	0.028	0.019	30.72

AESC 2009	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr
Maine (ME)	0.005	0.003	0.004	0.003	2.19
Vermont (VT)	0.001	0.000	0.001	0.001	0.71
New Hampshire (NH)	0.002	0.002	0.003	0.001	1.18
Connecticut (statewide)	0.019	0.012	0.020	0.009	6.57
Massachusetts (statewide)	0.025	0.020	0.027	0.014	12.54
Rhode Island (RI)	0.006	0.006	0.003	0.002	1.99
SEMA	0.025	0.020	0.027	0.014	12.54
Central & Western Massachusetts (WCMA)	0.025	0.020	0.027	0.014	12.54
Boston (NEMA)	0.025	0.020	0.027	0.014	12.54
Rest of Massachusetts (non-NEMA)	0.025	0.020	0.027	0.014	12.54
Norwalk / Stamford (NS)	0.019	0.012	0.020	0.009	6.57
Southwest Connecticut (SWCT) including Norwalk/Stamford	0.019	0.012	0.020	0.009	6.57
Southwest Connecticut (SWCT) excluding Norwalk/Stamford	0.019	0.012	0.020	0.009	6.57
Rest of Connecticut (non-SWCT)	0.019	0.012	0.020	0.009	6.57

On a 15 year levelized basis, the 2011 AESC estimates of capacity DRIPE are approximately four times greater than those from AESC 2009.[6] This increase is primarily due to the projection of higher wholesale capacity prices than in AESC 2009, as well as to the projection of a longer phase-out of capacity DRIPE effects than in AESC 2009. The AESC 2011 projections assume the phase-out, or dissipation, of capacity DRIPE will last up to 11 years, versus four years assumed in AESC 2009. The longer projected dissipation of capacity DRIPE is based upon an analysis of the various factors that tend to offset the reduction in capacity prices. Those factors include timing of new capacity additions, timing of retirements of existing capacity, elasticity of customer demand, and the portion of capacity that LSEs acquire from the FCM.

[6] AESC 2009 values for 2010 Installations levelized from 2010-2024.

The AESC 2011 estimates of intrastate energy DRIPE are approximately 22 percent higher on a simple average basis than those from AESC 2009. These higher estimates are primarily due to a longer delay, compared to AESC 2009, before new generation is assumed to begin offsetting gross energy DRIPE.

The projected duration of energy DRIPE and capacity DRIPE in three studies reviewed in detail for AESC 2011 ranges from 7 to 12 years.[7] The AESC 2011 projection of a 13-year phase-out for energy DRIPE and an 11-year phase-out for capacity DRIPE are within the range of dissipation values presented in other studies.[8]

Although uncertainty remains regarding the projections of energy DRIPE and capacity DRIPE, the consensus among the Study Group members and the Project Team is that these projections are comprehensive and reasonable based on the available information.

1.2.4. Carbon-Dioxide Externalities

Externalities are impacts from the production of a good or service that are neither reflected in the price of that good or service nor considered in the decision to provide that good or service. There are many externalities associated with the production of electricity, including the adverse impacts of emissions of SO_2, mercury, particulates, NO_x, and CO_2. However, the magnitude of most of those externalities has been reduced over time, as regulations limiting emission levels have forced suppliers and buyers to consider at least a portion of their adverse impacts in their production and use decisions. In other words, a portion of the costs of the adverse impact of most of these externalities has already been “internalized” in the price of electricity.

AESC 2011 identifies the impacts of carbon dioxide as the dominant externality associated with marginal electricity generation in New England over the study period, for two main reasons. First, policy makers are just starting to develop and implement regulations that will “internalize” the costs associated with the impacts of carbon dioxide from electricity production and other energy uses. Under the Regional Greenhouse Gas Initiative (“RGGI”) a portion of the long-term marginal abatement cost (LTMAC) of carbon is “internalized” in wholesale electric energy prices. AESC 2011 assumes that, by 2018, new federal CO_2 regulations will increase the portion of the LTMAC of carbon that is internalized in those wholesale market prices. However, even with those current and projected regulations, AESC 2011 projects a significant externality value for CO_2. Second, New England avoided electric energy costs over the study period are likely to be

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[7] These studies are summarized in Exhibit 6-43.

[8] DRIPE durations described for 2012 installations. For 2013 installations, the energy DRIPE duration is 12 years and the capacity DRIPE duration is 13 years.

dominated by natural gas-fired generation, which has minimal emissions of SO_2, mercury, particulates and NO_x, but substantial emissions of CO_2.

The AESC 2011 estimate of the LTMAC of carbon, at $80 per ton, is essentially the same as the AESC 2009 estimate. It is based on the same approach as AESC 2009, wherein we estimate the cost of limiting CO_2 emissions to a "sustainability target" level. The AESC 2011 estimate reflects the most recent literature on the cost of achieving this level.

AESC 2011 estimates of 15 year levelized CO_2 externality costs by zone are presented in Exhibit 1-13 below.[9] The AESC 2011 estimates of CO_2 externalities per kWh are approximately 16 percent higher than those from AESC 2009 on a 15 year levelized basis. These unit values are higher because AESC 2011 internalizes a smaller portion of the LTMAC of carbon in market prices.

Exhibit 1-13: Avoided CO_2 Externality Costs by Zone, 15 year Levelized ($/kWh)

	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy
AESC 2011	**$/kWh**	**$/kWh**	**$/kWh**	**$/kWh**
Maine (ME)	0.035	0.036	0.034	0.037
Vermont (VT)	0.035	0.036	0.034	0.037
New Hampshire (NH)	0.035	0.036	0.034	0.037
Connecticut (statewide)	0.035	0.036	0.034	0.037
Massachusetts (statewide)	0.035	0.036	0.034	0.037
Rhode Island (RI)	0.042	0.043	0.041	0.045
SEMA	0.035	0.036	0.034	0.037
Central & Western Massachusetts (WCMA)	0.035	0.036	0.034	0.037
NEMA	0.035	0.036	0.034	0.037
Rest of Massachusetts (non-NEMA)	0.035	0.036	0.034	0.037
Norwalk / Stamford (NS)	0.035	0.036	0.034	0.037
Southwest Connecticut (SWCT) including Norwalk/Stamford	0.035	0.036	0.034	0.037
Southwest Connecticut (SWCT) excluding Norwalk/Stamford	0.035	0.036	0.034	0.037
Rest of Connecticut (non-SWCT)	0.035	0.036	0.034	0.037

Efficiency measures can lead to reductions in the absolute quantity of CO_2 emissions primarily by demonstrating that existing caps can be met at less cost than anticipated, and thus justifying new, tighter caps. As with DRIPE, we recommend that program administrators include CO_2 additional environmental costs in their analyses of DSM, unless specifically prohibited from doing so by state or local law or regulation.

[9] Values for Rhode Island incorporate RGGI only scenario.

1.3. Avoided Costs of Natural Gas

Gas efficiency programs, like electric energy efficiency programs, have a number of key energy cost benefits. The benefits from those reductions include some or all of the following avoided costs:

- Avoided gas supply costs due to a reduction in the annual quantity of gas that has to be produced, transported by pipeline, and stored to meet winter heating requirements;
- Avoided gas costs of local distribution infrastructure due to a reduction in the timing and/or size of new projects that have to be built resulting from the reduction in gas that has to be delivered; and
- Avoided environmental externalities due to a reduction in the quantity of gas that is burned.

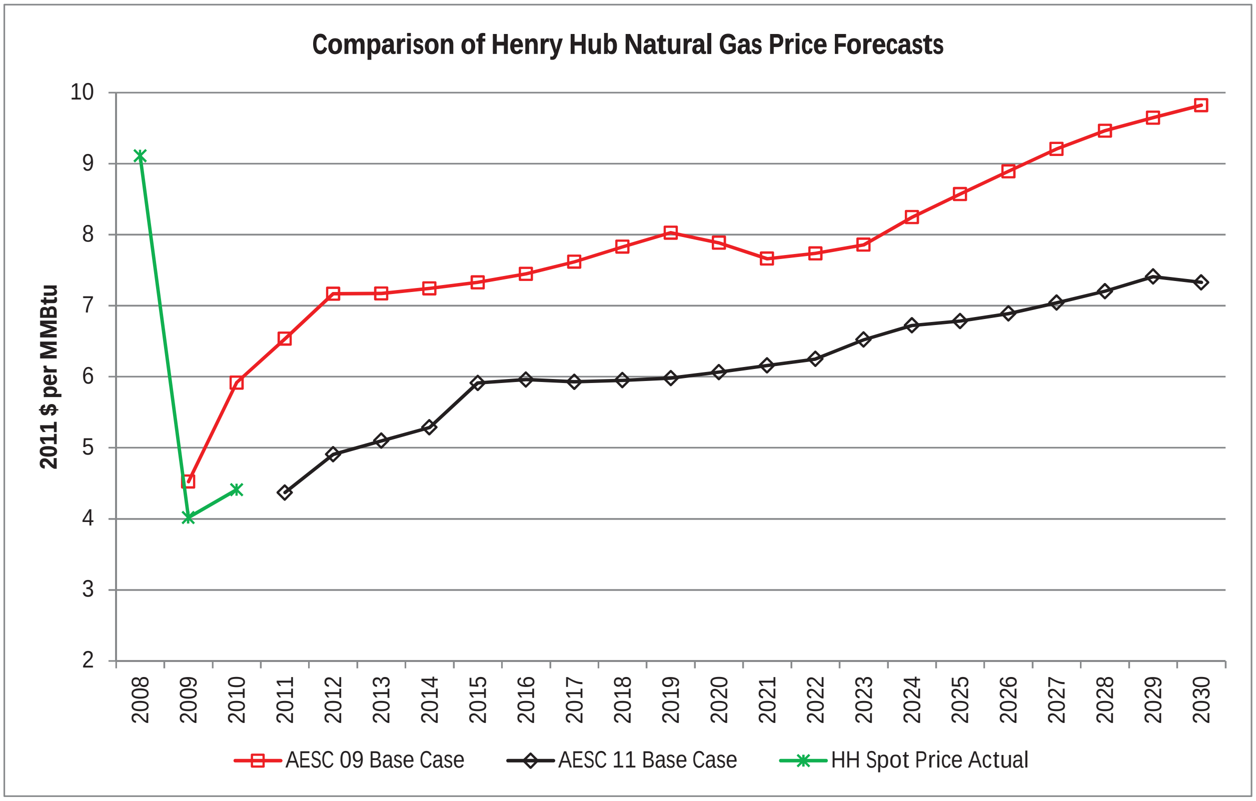
1.3.1. Projected Henry Hub Prices

The largest component of avoided gas supply costs is the cost of buying gas. In developing the Reference Case for AESC 2011, we use the price of gas at the Henry Hub in Louisiana as a proxy for that cost. The forecast is based upon the New York Mercantile Exchange ("NYMEX") gas futures prices for the Henry Hub for the years 2011 to 2014 and the "High Shale Gas" Case forecast from the Energy Information Administration's ("EIA") 2010 Annual Energy Outlook ("AEO 2010") for the years 2015 onward.

We drew upon the AEO 2010 High Shale Gas Case because its forecast prices are consistent with our estimate of the full-cycle, all-in cost of finding, developing, and producing gas from shale resources, and because it assumes unproved shale gas resources comparable in size to the Reference Case presented in the AEO 2011. In contrast, the long-run marginal cost of shale gas implicit in the AEO 2011 Reference Case is significantly less than our estimate of the full-cycle, all-in cost of finding, developing, and producing shale gas.

The AESC 2011 Reference Case forecast is presented in Exhibit 1-14.

Exhibit 1-14: Comparison of Henry Hub Gas Price Forecasts, AESC 2011 vs. AESC 2009 (2011$ $/MMBtu)

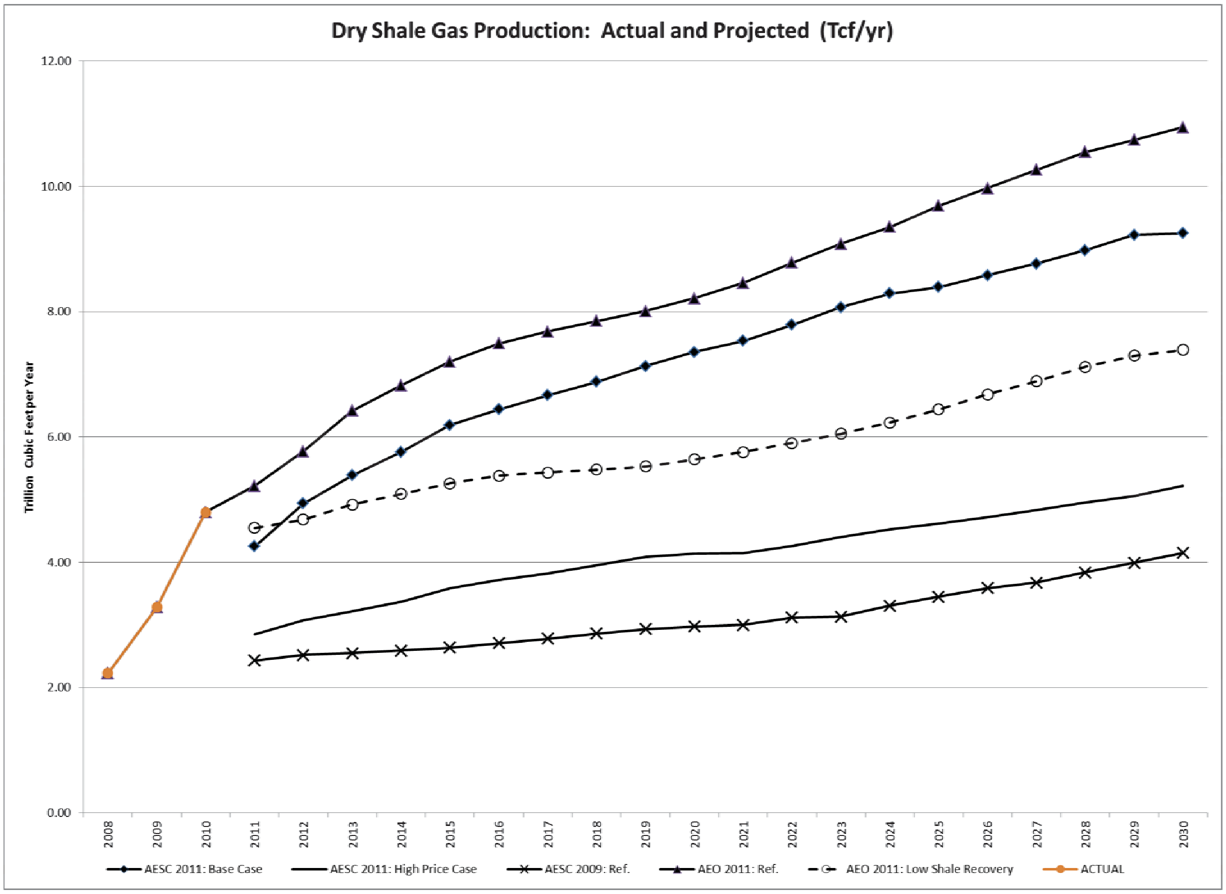


The AESC 2011 price forecast is lower than the AESC 2009 forecast due to the significant changes in expectations regarding the cost of finding, developing, and producing gas from shale gas resources, and the quantity of shale gas production. Our AESC 2011 forecast, based on a more detailed analysis of published data from seven major shale gas producers, indicates a lower full-cycle cost of shale gas, one equating to a Henry Hub price of $5.50 per MMBtu.[10]

As indicated in Exhibit 1-15, the AEO 2011 Reference Case assumes a shale gas production of 9.69 Tcf in 2025. The AESC 2011 Reference Case forecast is consistent with a somewhat lower level of shale gas development and production; for example, it assumes shale gas production of 8.39 Tcf in 2025, about 13 percent lower than the AEO 2011 Reference Case. The AESC 2011 High Gas Price Case assumes an even lower level of production.

[10] The AESC 2009 forecast was based on our estimate that the full-cycle cost of producing shale gas equated to a Henry Hub price ranging between $6.50 per MMBtu and $8.00 per MMBtu

Exhibit 1-15: Shale Gas Production, Actual and Projected (Tcf/year)



There is considerable uncertainty regarding projections of shale gas production quantities and costs. First, AEO 2011 has identified several uncertainties that could result in less production or higher costs. Since AEO 2011 projections are based upon limited experience with many shale gas formations, the projections may overestimate the quantity of shale gas production or underestimate the future cost of shale gas production. Alternatively, technical advances may reduce production costs and currently untested shale gas formations could prove to be highly productive. Second, concerns have been raised regarding the need for additional regulation of hydraulic fracturing in order to minimize its environmental impacts on groundwater, surface water, and air emissions. However, during the preparation of this Study we did not find any public projections of specific changes in existing Federal, state and local regulations, including scope and timing, from which to credibly estimate the impact on the cost of shale gas production.[11]

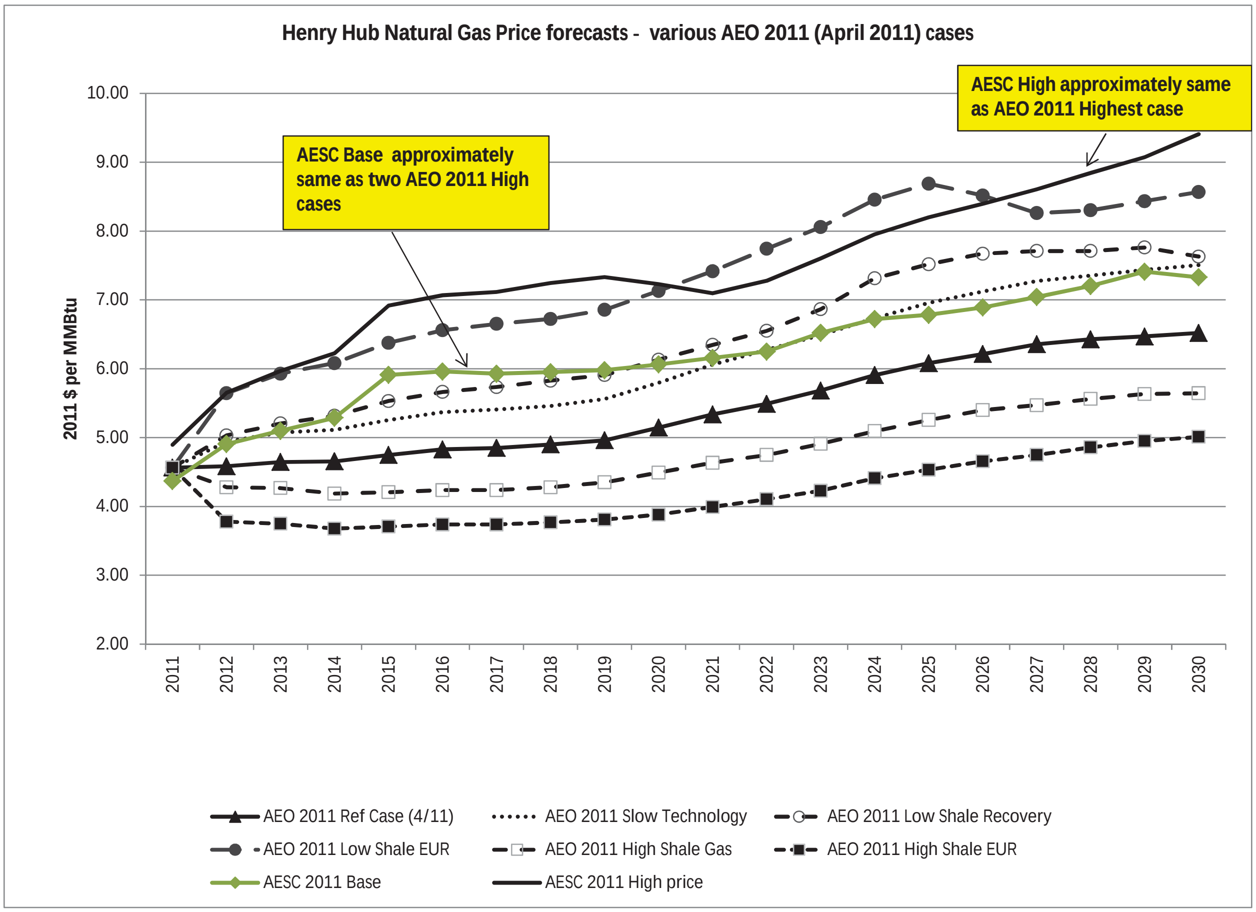
[11] Unlike expectations regarding future Federal regulation of CO_2 emissions, there are not dozens of projections available for parties to analyze and upon which parties can make an informed judgment.

We do expect that companies will be required to disclose the chemicals they use in their fracturing fluids, but that such disclosures will not have a material impact on shale gas production quantities or cost.

The AESC 2011 High Gas Price Case provides a projection that reflects the uncertainty regarding projections of quantities and costs related to shale gas production. The High Gas Price Case projects gas prices for a scenario in which the development of shale gas is restricted to approximately 50 percent of Reference Case levels with correspondingly higher development costs.

As indicated in Exhibit 1-16, the AESC 2011 Reference Case forecast of prices is comparable to two of the high gas price cases from AEO 2011. The AESC 2011 High Case gas prices are comparable to gas prices in the highest AEO 2011 gas price case.

Exhibit 1-16: Comparison of Henry Hub Gas Price Forecasts, AESC 2011 vs. AEO 2011 ($/MMBtu)



Given the uncertainty associated with projections of shale gas resource availability, production quantities, regulations, and costs, there is certainly a possibility that material changes in the long-term outlook for shale gas production and cost may occur after the completion of AESC 2011 and before the initiation of AESC 2013. Those material changes might be driven by public developments such as significant revisions to public geological analyses; a legislative body, policy agency, or regulatory agency identifying specific changes in the regulation of hydraulic fracturing; published estimates of the costs associated with regulatory changes; or changes in natural gas market prices. In the event of such public developments, members of the Study Group may choose to determine if the AESC 2011 Reference Case and High Gas Price Case projections of natural gas prices are still suitable for use in energy efficiency cost-effectiveness analyses. If they determine that neither of those projections is within a range of reasonableness in light of the public developments, the members of the Study Group should consider revising the natural gas price forecast and the avoided costs.

1.3.2. Projected Avoided City-Gate and Retail Gas Costs

AESC 2011 provides estimates of each category of avoided costs for three regions. These are Connecticut and Rhode Island ("southern New England"), Massachusetts, Maine, and New Hampshire ("central and northern New England") and Vermont. For each region the estimates are presented by year and by major end-use. These estimates of avoided gas costs reflect all fixed and variable costs that would be avoided due to a reduction in gas use. Unlike the electric industry, which has an FCM separate from the energy market, there is no separate avoided gas capacity cost beyond, or additional to, the estimated avoided gas supply costs.

The AESC 2011 projections of avoided natural gas costs to retail customers over the next 15 years range from $10.00 to $12.00 per dekatherm ("DT") (2011$) depending on the end-use and location, as shown in Exhibit 1-17.

Exhibit 1-17: Comparison of Avoided Gas Costs by End-Use Assuming Some Avoidable Retail Margin, AESC 2011 vs. AESC 2009 (15 year Levelized, 2011$/DT)

	RESIDENTIAL				COMMERCIAL & INDUSTRIAL			ALL RETAIL
	Non Heating	Hot Water	Heating	All	Non Heating	Heating	All	
Southern New England								
AESC 2009 (2009$/DT)	11.42	11.42	14.52	13.52	9.88	11.83	11.21	12.26
AESC 2009 (a)	11.63	11.63	14.79	13.77	10.07	12.05	11.42	12.49
AESC 2011	7.64	7.64	9.39	9.11	7.58	8.82	8.44	8.75
2009 to 2011 change	-34.33%	-34.33%	-36.54%	-33.82%	-24.71%	-26.84%	-26.08%	-29.92%
Northern & Central New England								
AESC 2009 (2009$/DT)	10.87	10.87	13.54	12.67	10.02	12.05	11.40	12.03
AESC 2009 (a)	11.08	11.08	13.79	12.91	10.21	12.28	11.61	12.25
AESC 2011	7.47	7.47	8.96	8.73	7.59	8.79	8.43	8.58
2009 to 2011 change	-32.57%	-32.57%	-35.03%	-32.38%	-25.64%	-28.37%	-27.41%	-29.99%
Vermont								
AESC 2009 (2009$/DT)	9.72	9.72	12.43	11.56	8.01	9.44	9.00	9.93
AESC 2009 (a)	9.90	9.90	12.66	11.77	8.16	9.62	9.17	10.12
AESC 2011	7.54	7.54	9.88	9.37	7.30	9.08	8.54	8.86
2009 to 2011 change	-23.86%	-23.86%	-21.95%	-20.36%	-10.57%	-5.67%	-6.82%	-12.44%

(a) Factor to convert 2009$ to 2011 $ 1.0186
Note: AESC 2009 levelized costs for 15 years, 2010 - 2024 at a discount rate of 2.22%.
AESC 2011 levelized costs for 15 years 2012 - 2026 at a discount rate of 2.465%.

AESC 2011 is projecting avoided costs for each end-use that are 25 percent to 35 percent lower than AESC 2009. The lower avoided costs are due to the forecast of lower Henry Hub natural gas prices and lower avoided distribution costs. The lower forecast of avoided distribution costs is based upon the results of the most recent estimates of marginal costs prepared by several of the gas utility members of the AESC Study Group.

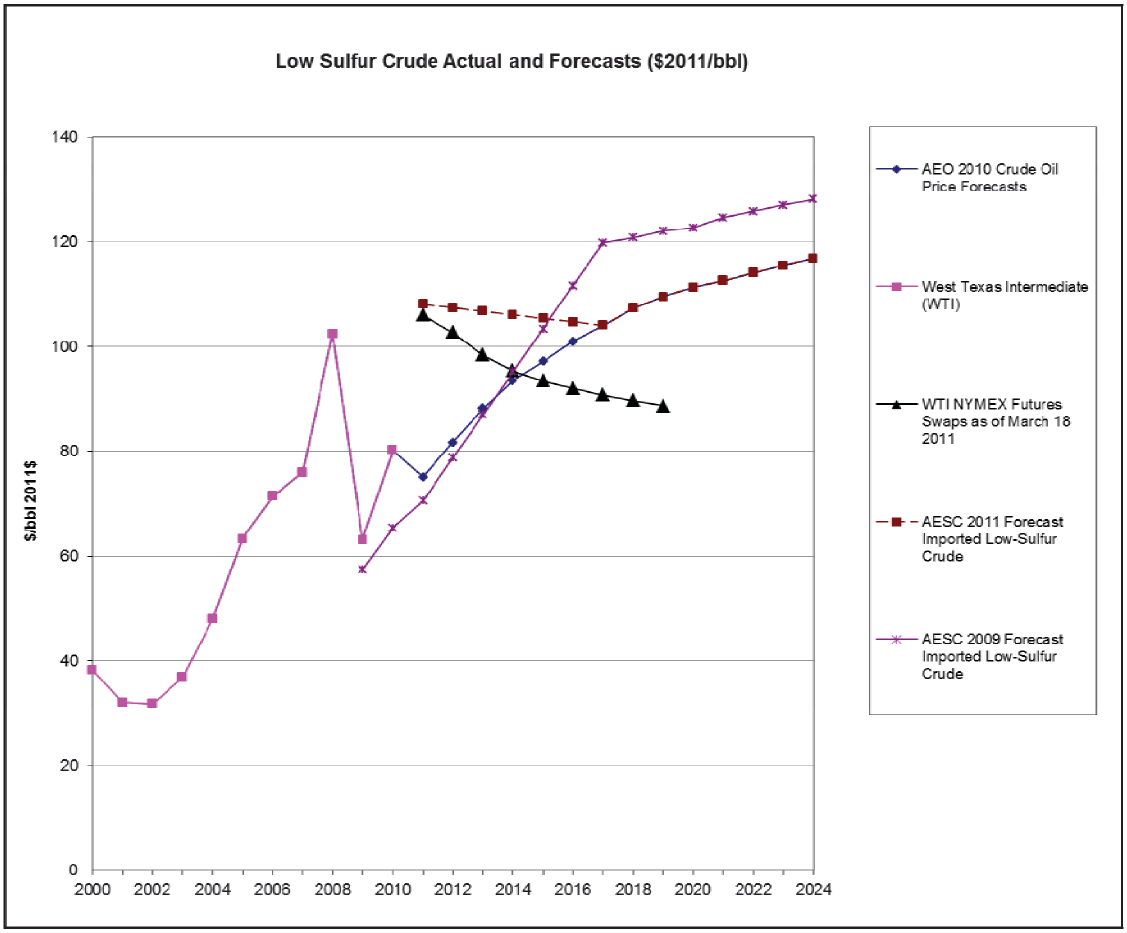
1.4. Avoided Costs of Other Fuels

Some electric and gas efficiency programs enable retail customers to reduce their use of energy sources other than electricity or natural gas. The benefits from reducing the use of other fuels include avoided fuel supply costs and avoided environmental externalities.

The major driver of these avoided fuel costs are forecast crude oil costs. Given the significant uncertainty regarding the future price of crude oil, the AESC 2011 forecast of crude oil prices is based upon the EIA’s Short-Term Energy Outlook (“STEO”) of March 2010 for 2011 and 2012, NYMEX prices for 2013 as of March 18, 2011, and then AEO 2010 Reference Case forecast prices from 2014 onward. This forecast is higher than the AESC 2009 forecast in the years prior to 2015 and lower thereafter.

The AESC 2011 and AESC 2009 forecasts of crude oil are presented in Exhibit 1-18.

Exhibit 1-18: Low-Sulfur Crude Oil Actual and Forecast (2011$ per bbl)



The AESC 2011 forecasts of avoided costs of fuels by sector and region are summarized in Exhibit 1-19.

Exhibit 1-19: Comparison of Avoided Costs of Other Retail Fuels (15 year Levelized, 2011$)

	No. 2 Distillate	**No. 2 Distillate**	**No. 6 Residual (low Sulfur)**	**Propane**	**Kerosene**	**BioFuel**	**BioFuel**	**Wood**
Sector	**Res**	**Com**	**Com**	**Res**	**Res & Com**	**B5 Blend**	**B20 Blend**	**Res**
AESC 2011 Levelized Values (2011$/MMBtu)								
2012-2026	25.37	23.53	17.26	36.00	25.50	25.37	25.37	9.47
AESC 2009 Levelized Values (2011$/MMBtu)								
2010-2024	23.25	22.09	17.85	34.66	22.59	23.25	23.25	8.38
Percent Difference from AESC 2009								
	9.1%	6.5%	-3.3%	3.9%	12.9%	9.1%	9.1%	13.0%

Notes
Res = Residential Sector
Com = Commercial Sector

The AESC 2011 avoided costs for these fuel prices are generally higher than those from AESC 2009 primarily due to a higher forecast of underlying crude oil prices. On a 15 year levelized basis, the AESC 2011 values are higher by six to 13 percent depending on the fuel and sector. The values reported for wood are for cordwood. Values for wood pellets would be approximately twice as high according to the limited available data on wood pellet prices.

Chapter 2: Methodology & Assumptions Underlying Projections of Avoided Electricity Supply Costs

2.1. Background

One goal of the AESC study is to project the electricity supply costs that would be avoided by reductions in retail energy and/or demand through energy efficiency initiatives. The avoided electricity supply costs incorporate: avoided electric energy market prices, avoided capacity market prices, avoidable costs not internalized in those market prices, and demand reduction induced price effects (DRIPE). The developed avoided electricity supply costs are presented in Chapter 6. This Chapter describes the methodology and assumptions used to develop those avoided electricity supply costs.

For AESC 2011, we use Market Analytics, under license from Ventyx, to estimate electric energy market prices by simulating the operation of the wholesale electric-energy market. We use a spreadsheet model to estimate electric capacity market prices by simulating future Forward Capacity Auctions in the forward capacity market. Section 2.2 describes the general common assumptions used in both models. Sections 2.3 and 2.4 describe the methodologies used to develop electric energy market prices and electric capacity market prices respectively, as well as the specific values of the assumptions used as inputs to each model. Section 2.5 describes the methodology and assumptions we use to develop a forecast of the components of avoided electricity supply costs that are not internalized in the wholesale market prices for energy and capacity, as well as estimates of DRIPE.

Chapter 6 details the avoided electricity supply costs for the New England region as a whole as well as for each of 14 component zones in each year of the planning horizon (2011–2041). Each set of avoided electricity supply costs comprises avoided energy costs by year for the four energy costing periods: Summer On-Peak, Summer Off-Peak, Winter On-Peak, and Winter Off-Peak.

For all zones, Summer On-peak is as defined by ISO-New England (ISO-NE), June-September, weekdays 7 am to 11 pm; Off-peak is 11 pm to 7 am weekdays, plus weekends, and holidays. Winter period is the remaining eight months with the same diurnal time divisions, weekends and holidays.

2.2. Wholesale Market Prices for Electric Energy and Capacity: Common Methodologies & Assumptions

2.2.1. Structure of Wholesale Markets

The ISO-NE market is part of the Northeast Power Coordinating Council and includes the six states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and

Vermont.[12] ISO-New England is the regional transmission organization (RTO) for the New England power market. It coordinates several markets for electric-power products including energy, capacity, and operating reserves markets (regulation up and down, spinning reserves, ten-minute non-spinning reserves, and thirty-minute non-spinning reserves).

The modeling and reporting zones are discussed in section 2.3.2.1

2.2.1.1. Wholesale Energy Markets

The wholesale energy markets are managed by ISO-NE. There are two primary markets: (1) the Day-Ahead Market where the majority of the transactions occur and (2) the Real-Time Market where the remaining energy supplies and demands are balanced. These two markets represent the bulk of the electricity transactions and their prices on average are very close to each other, although there is greater volatility in the real-time market.

According to ISO-New England (2010, 28–30):

> Locational marginal pricing is a way for wholesale electric energy prices to efficiently reflect the value of electric energy at different locations based on the patterns of load, generation, and the physical limits of the transmission system. Wholesale electricity prices are identified at 900 pricing points (i.e., *pnodes*) on the bulk power grid. LMPs differ among these locations because transmission and reserve constraints prevent the next-cheapest megawatt (MW) of electric energy from reaching all locations of the grid. Even during periods when the cheapest megawatt can reach all locations, the marginal cost of physical losses will result in different LMPs across the system.
>
> If the system were entirely unconstrained and had no losses, all LMPs would be the same, reflecting only the cost of serving the next increment of load. This incremental megawatt of load would be served by the generator with the lowest-cost energy offer that is available to serve that load, and electric energy from that generator would be able to flow to any node over the transmission system.
>
> New England has five types of pnodes: one type is an external proxy node interface with neighboring *balancing authority areas*, and four types are internal to the New England system.57 The internal pnodes include individual generator-unit nodes, load nodes, *load zones* (i.e., aggregations of load pnodes within a specific area), and the Hub. The *Hub* is a collection of locations with a load-weighted price intended to represent an uncongested price for electric energy; facilitate trading; and enhance transparency and liquidity in the marketplace. New England is divided into the following eight load zones: Maine (ME), New Hampshire (NH), Vermont (VT), Rhode Island (RI), Connecticut (CT), Western/Central Massachusetts (WCMA), Northeast Massachusetts and Boston (NEMA), and Southeast Massachusetts (SEMA).Generators are paid the real-time LMP for electric energy at their respective nodes, and participants serving demand pay the price at their respective load zones. The load-zone price is a load-weighted average price of the load-node prices in that zone.

[12]Parts of northeastern Maine are not included in ISO-New England.

The intersection of the supply and demand curves as offered and bid, along with transmission constraints and other system conditions, determines the Day-Ahead Energy Market price at each node and results in the binding financial schedules and commitment orders (refer to Figure 2-1). Market participants that have *real-time load obligations* (RTLOs) (i.e., they are serving load) may submit demand bids in the Day-Ahead Energy Market. Participants may bid *fixed demand* (i.e., they will buy at any price) and *price-sensitive demand* (i.e., they will buy up to a certain price) at their load zone (or pnode, for some participants that meet certain requirements). Generating units may submit three-part supply offers for their output at the pricing node specific to their location, including start-up, no-load, and incremental energy offers. Start-up offers reflect the costs associated with bringing a unit from an off-line state to the point of synchronizing with the grid. No-load offers reflect the hourly cost of operating that does not depend on the megawatt level of output. Incremental energy offers represent the willingness of participants to operate a resource at higher output levels for higher compensation. The incremental energy offers produce the upward sloping supply curve that is used to calculate the LMP. Market participants have the incentive to submit offers for start-up, no-load, and incremental energy consistent with their true costs to maximize the chance they will be running at profitable levels.

Any participant that satisfies the financial-assurance requirements detailed in the market rules also may bid price-sensitive *virtual demand* at any pricing node on the system in the Day-Ahead Energy Market. Participants also may offer *virtual supply*. Virtual trading enables market participants that are not generator owners or load-serving entities (LSEs) to participate in the Day-Ahead Energy Market by establishing virtual (or financial) positions. It also allows more participation in the day-ahead price-setting process, allows participants to manage risk in a multi-settlement environment, and enables arbitrage that promotes price convergence between the day-ahead and real-time markets.

Demand bids and virtual demand bids both can be used to hedge the difference between day-ahead and real-time prices. Demand bids are well suited to hedge RTLOs, and virtual demand bids can be used to arbitrage expected differences between day-ahead and real-time prices at a node or to hedge a nodal load.

For each megawatt of virtual supply that clears in the Day-Ahead Energy Market, the participant receives the day-ahead LMP and has a financial obligation to pay the real-time LMP at the same location. For each megawatt of cleared virtual demand, the participant pays the day-ahead LMP and receives the real-time LMP at that location. That is, an accepted virtual supply offer in the Day-Ahead Energy Market is offset by a "purchase" in the Real-Time Energy Market, and a cleared virtual demand bid in the Day-Ahead Energy Market is offset by a "sale" in the Real-Time Energy Market. While these transactions affect the day-ahead prices, they do not represent physical supply or withdrawal of energy in real time. The financial outcome for a particular participant is determined by the difference between the day-ahead and real-time LMPs at the location at which the participant's offer or bid clears, plus all applicable transaction costs, including daily reliability costs (refer to Section 2.5).

Real-Time Market Supply and Demand and Generator Commitment

The Real-Time Energy Market is a physical delivery market rather than a financial forward market like the Day-Ahead Energy Market. The Real-Time Energy Market is the environment in which the ISO control room commits and dispatches physical resources to meet actual real-time load, including the minute-to-minute balancing of energy and reserves while accounting for transmission system limits and the need to provide contingency coverage. While the financial schedules produced by the Day-Ahead Energy Market clearing process provide a starting point for the operation of the Real-Time Energy Market, the amount of needed and available supply at each location can increase or decrease for a number of reasons. First, all generators have the flexibility to revise their incremental energy supply offers during the *reoffer period*. In addition, generating-unit and transmission line outages, along with unexpected changes in demand, can cause the ISO to call on additional generating resources to preserve the balance of supply and demand.

2.2.1.2. Wholesale Capacity Market

The capacity markets previously operated by ISO-NE were superseded in June 2010 by the Forward Capacity Market (FCM). The power year for the FCM, also referred to as an FCM year is from June through May. Thus, for a calendar year the unit cost (expressed as dollars per kW-year) of capacity in the FCM, will be the average of January through May from one power year and June through December of the following power year.

Under the FCM, ISO-NE acquires sufficient capacity to satisfy the installed capacity requirement (ICR) it has set for a given power-year through a forward-capacity auction (FCA) for that power-year.[13] The price for capacity in that power year is based upon the results of the FCA for that year. The FCA for each power year is conducted roughly three years in advance of the start of that year. ISO-NE has held four FCAs to date, FCA 1 for the power year starting June 2010 held in 2008 through FCA 4 for the power year starting June 2013 which was held in 2010.

Under current FCM rules, each FCA will have a ceiling price and a floor price through FCA 6. The original FCA rules provided for floor prices only through FCA 3, however the ISO and FERC have extended the floor prices through FCA 6. The status of floor prices for auctions after FCA 6 is at this time uncertain. For the first four FCAs, the floors were $4.50, $3.60, $2.95, and $2.95/kW-month respectively. Each of these auctions concluded when it reached the floor price, although the amount of capacity

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[13]Some of the ICR (1,400 MW in the first FCA, and 911–916 MW in the second through fourth FCA) was met by installed capacity credits from the Phase I/II interconnection, which are allocated to the transmission owners with entitlements in the line. The Hydro Quebec Interconnect Certificate rights are valued at the market-clearing price, and the actual auction acquires the remaining ICR, called the net ICR or NICR.

offered at that price still exceeded the requirement. [14] The floor price for FCA 5 was set at, and cleared at, $3.21/kW-month.[15] The floor price for FCA 6 will rise from the FCA 5 floor price by an escalation factor set by the Handy-Whitman Index of Public Utility Costs.

Suppliers of capacity whose bids are accepted in the FCA are paid an amount equal to the quantity of capacity they bid multiplied by the final auction price (prorated as described in footnote 14). In each month of the capacity year, this amount is reduced by *peak energy rents,* (PER), an estimate by ISO-NE of the annual wholesale energy market revenues that of a hypothetical generator with a heat rate of 22,000 Btu/kWh would earn[16]. Suppliers are also subject to penalties for any failure to perform.

Buyers of capacity, i.e. load-serving entities, pay an amount approximately equal to the quantity of capacity ISO-NE requires them to support in the power year, times the auction-clearing price for that power year.[17] The quantity of capacity that a particular load is required to hold in the power-year is set by ISO-NE and is called the Capacity Load Obligation (ISO-NE Market Rule 1 §III.13.7.3). This obligation is based on the estimated contribution of that load to the ISO annual peak in the preceding power year. Thus, the total cost of capacity to a load-serving entity for a given power year, i.e., required kW of capacity multiplied by FCA price in dollars per kW, is mostly set in advance of that power-year. The price is determined roughly three years in advance, and each load's individual share of the cost is set the summer before.

2.2.1.3. Energy Efficiency Programs and the Capacity Market

An energy efficiency program that produces a reduction in peak demand has the ability to avoid the wholesale capacity cost associated with that reduction. The capacity-cost amount that a particular reduction in peak demand will avoid in a given year will depend

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[14]If, in a given FCA, more capacity clears at the floor price than is required to satisfy the ICR, each cleared resource must accept downward proration of either the quantity of capacity that it bid or the final auction price. For example, if the capacity clearing at the market is roughly 6% above the net ICR (as in FCA 1), each resource must choose between being paid 94% of the floor price (about $4.23 in FCA 1) for all its bid capacity, or the floor price for 94% of its bid capacity. In FCA 4, the excess remaining capacity at the floor price was 4,619 MW (about 14% above the NICR) and most resources will be paid $2.54 for their bid capacity. Emergency generation and resources in Maine are subject to additional constraints and proration.

[15] ISO-NE posted the results of FCA 5 on June 27, 2011.

[16] Our analyses do not adjust for PER as it appears to be minimal, based on a review of estimates for 2007 through 2009.

[17] These costs will be reduced by the PER and credits for supplier performance penalties, as well as by adjustments due to reconfiguration auctions (in which the ISO can buy back unnecessary capacity obligations, or purchase additional obligations). Load-serving entities can also self-supply a portion of their capacity requirements.

upon the approach that the program administrator responsible for that energy efficiency program takes towards bidding all, or some, of that reduction into the applicable FCAs.

A program administrator (PA) can choose an approach that ranges between bidding 100% of the anticipated demand reduction from the program into the relevant FCAs to bidding zero percent of the anticipated reduction into any FCA.

- A PA that wishes to bid 100% of the anticipated demand reduction from the program into the relevant FCA has to do so when that FCA is conducted, which can be up to three years in advance of the program implementation year. For example, a PA responsible for an efficiency program that will be implemented starting January 2012 would have had to have bid 100% of the forecast demand reduction for June 2012 onwards from that program into FCA 3, which was held in 2009. Since a bid is a firm financial commitment, there is an associated financial risk if the PA is unable to actually deliver the full demand reduction for whatever reason. The value of this approach is the compensation paid by ISO-NE, i.e. the quantity of peak reduction each year times the FCA price for the corresponding year.
- If a PA does not bid any of the anticipated demand reduction into any FCA, the program can still avoid some capacity costs if it has a measure life longer than three years.[18] Under this approach, a PA responsible for an efficiency program starting January 2012 simply implements that program. The customers' contribution to the ISO peak load, whenever that occurs in the summer of 2012, would be lower due to the program. This PA's customers would see some benefit from a lower capacity share starting in June 2013 (the following year). The reduced capacity requirement will reduce the capacity acquired in future FCAs, starting as early as the reconfiguration auctions for the power year starting in June 2013 and affecting all the auctions for the power years from June 2016 onward; the entire region will benefit from the reduction of capacity purchases.

[18] In many cases, the PA is a utility; in other cases it is a state agency or other entity. In any case, the reduction in load benefits the customers served by the PA, whether they pay for generation supply through a utility standard-offer supply, an aggregator, or a competitive supplier.

2.2.2. Loads and Resources

2.2.2.1. Load Forecast

In order to forecast electric energy and capacity prices that would occur in the absence of new demand side management (DSM) programs, the project team developed a forecast of peak demand and energy requirements in the absence of new DSM programs.[19]

The forecasts of annual energy and peak load AESC 2011 uses to calculate avoided costs in AESC 2011 are derived from the ISO-NE 2011-2020 Forecast Report of Capacity, Energy, Loads and Transmission ("CELT 2011" or ISO-NE (2011)), as discussed below. Beyond 2020, AESC 2011extrapolates using the last five years of the long-term (2015–2020) Compound Annual Growth Rate (CAGR) reflected in that report.

Load Forecast for 2011 through 2020 (CELT 2011)

ISO-NE developed the CELT 2011 forecast of peak demand and energy requirements through 2020 based upon econometric models.[20]

The ISO forecasts annual energy for New England as a whole and for each individual state. ISO-NE (2011) is based on previous-year usage along with real electricity price, real personal income, gross state product and heating and cooling degree days (ISO-NE 2010b).[21] The ISO developed the model and its coefficients by analyzing the historical relationships between energy requirements and those independent variables since 1984. Therefore, the forecast implicitly assumes some level of reductions from efficiency programs because the programs in effect during the historical period would have influenced the actual level of energy use and be reflected in the derived model coefficients, most likely for the personal income and electricity price variables. However, it is difficult to estimate the size of the effect of prior DSM on the energy forecast. One way to calculate those effects would be to explicitly include the DSM energy savings and recalculate the model coefficients. This would be a fairly significant task to undertake and is beyond the scope of this Study. Such work would probably best conducted by ISO-NE.

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[19]The purpose of the overall the study is to develop avoided costs for program administrators to use in their economic evaluations of measures for inclusion in DSM program budgets for calendar years 2012 and beyond. The program administrators will submit those proposed budgets in regulatory filings from mid-2011 onward. If the program budgets are approved, the measures would be installed after January 1, 2012, causing savings from that point onward.

[20]Further information about the CELT forecasting process can be found at ISO-NE's web page, http://www.iso-ne.com/trans/celt/fsct_detail/2011/index.html as of April 23, 2011 .

[21] The CELT 2011 econometric model variables differ by state as shown in the "rsp11_ene_models.pdf" document on the above website.

For its forecast of peak-load, ISO-NE develops peak-load models for each calendar month, for New England as a whole and each state, using daily historic data. The models are based on the annual energy load, a temperature humidity index and several dummy variables for weekends and holidays. The historic and forecast loads are then explicitly modified by Passive Demand Resources (PDRs) based on DSM programs that qualified in the capacity market. These resources are called passive because they cannot be dispatched, but do have identified effects on loads and qualify as capacity resources.

CELT 2011 includes explicit calculations of PDR effects to develop its estimates of net peak and energy loads. CELT 2011 estimates that PDRs would lower the summer peak (relative to the econometric forecast) by 774 MW in 2011, 960 MW in 2012 and 1,148 MW in 2013.

The forecast of annual energy load AESC 2011 uses to calculate avoided costs is derived from the ISO-NE (2011) annual energy load forecast by excluding the effects of all post 2010 PDRs as reported in CELT 2010, i.e., 572 MW for peak loads and 3,545 GWh for energy.[22] These exclusions are consistent with estimating avoided-costs in the absence of future energy-efficiency effects.

The forecast of peak load AESC 2011 uses to calculate avoided costs is taken directly from ISO-NE (2011) since those resources can participate in the capacity market.

Load Forecast Post 2020

Beyond 2020, we extrapolate using the CAGR from the last five years reflected in the CELT 2011 forecast. AESC 2011 excludes the first five years of CELT 2011 when calculating the CAGR because load growth during that period of economic recovery is not representative of longer-term load growth within New England. For context, ISO-NE's (2011) long-term annual average rate of summer peak growth for the ISO-NE control area is 1.24 percent. The energy load growth is a little less at 0.98 percent.

The following two exhibits show ISO-NE's (2011) projections of net summer peak load and annual net energy consumption for ISO-NE relative to historic levels. Note that the historic values are actuals and represent the embedded effects of DSM programs whereas the forecasts do not.

[22] AESC 2011 used PDRs reported in CELT 2010 because the PDRS reported in CELT 2011 were not available at the time the annual load forecast was developed.

Exhibit 2-1: ISO-NE Peak Summer Load

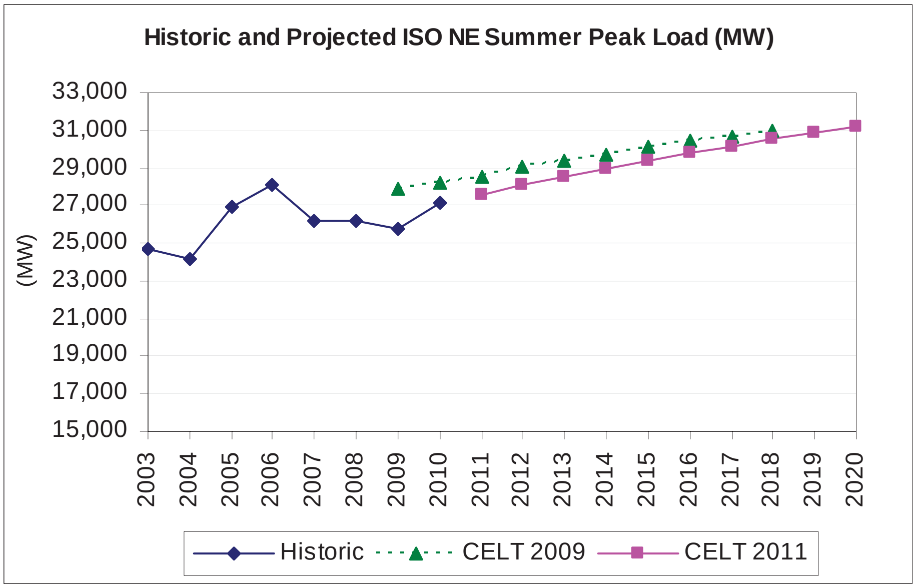
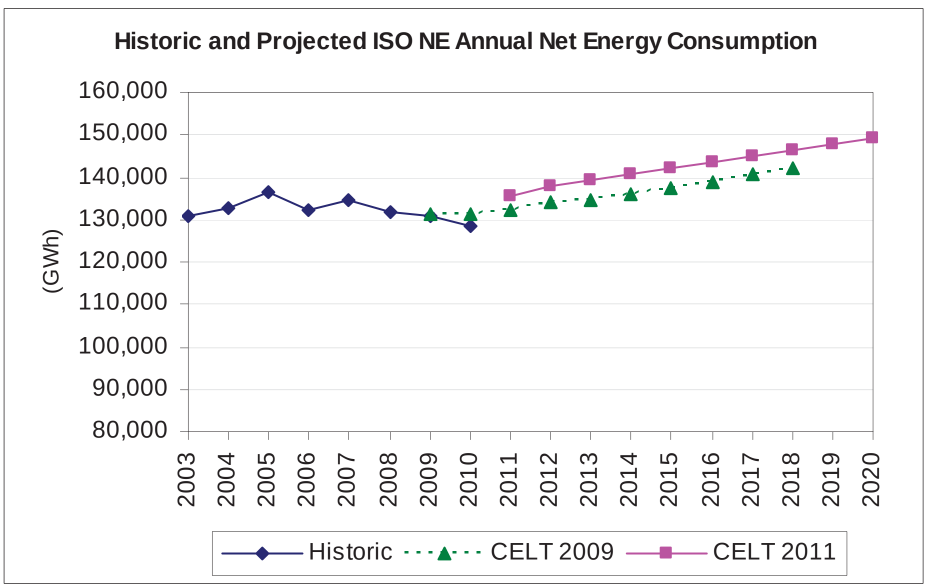


Exhibit 2-2: ISO-NE Net Annual Consumption



2.2.2.2. Transmission

The interface limits used in the simulations reflect the existing system, ongoing transmission upgrades including those discussed in the ISO-NE Regional System Plan, and the reference Market Analytics database. We also consider any congestion identified during our modeling.

The detailed transmission assumptions are closely related to the modeling topology and are presented in Section 2.3.2.3

2.2.2.3. Retirements

In general AESC 2011 assumes that plants that have been operating since the implementation of restructured markets will continue to operate in the absence of any major changes in market and regulatory conditions. AESC 2011 assumes that retirements of existing plants will be driven by the following factors:

- Requirements for environmental retrofits due to regulatory changes. A discussion of changing environmental and economic conditions that will drive retirements is presented in Section 2.2.3.
- Failure of major components in old and marginally cost-effective units. In these situations, restoring the plant to service may not be cost-effective. Component failure is inherently unpredictable. Our assumptions about the retirement of older capacity reflect anticipated effects of equipment failure.
- The expiration of nuclear, hydro or other licenses for plants that cannot economically meet requirements for license extension. We describe the relicensing of New England nuclear units in Section 2.3.2.4 .Relicensing of hydroelectric plants has resulted in reduced capacity or retirement of a few small units; we do not anticipate any significant effects on hydro capacity in the future.
- Construction of new capacity at the site of existing capacity, requiring retirement due to lack of space, transmission capacity or emission compliance restructuring of the New England electric-utility industry, several units have been retired in order to provide space for the construction of new generation. Those retired units include Mystic units 4–6 and the Edgar jets. No pending capacity additions are expected to drive retirements of existing units, even new additions being sited at existing plant sites, such as Middletown, New Haven, and Devon. When new generic units are added, some existing units on those sites may retire; we assume that the additions will offset the retirements with little effect on market prices.

2.2.2.4. Resource Additions

Over the course of the study period, new generation resources will be needed in addition to the existing mix of generating capacity in order to satisfy renewable portfolio standards, meet future load growth, and respond to retirements. Since Market Analytics is not a capacity expansion model, these additions are inputs to the model. Our assumptions regarding new capacity additions are presented below.

Additions to Meet Renewable Portfolio Standards

Each New England state has adopted some form of renewable portfolio standard or renewable energy standard (RPS). Connecticut, Maine, Massachusetts, New Hampshire and Rhode Island all have mandatory RPS requirements and require penalty payments for non-compliance. Vermont currently has a voluntary RPS, with a legislatively-driven option to convert to a mandatory requirement if the voluntary goal is not met.[23] A summary of the region's RPS requirements and eligibility criteria are summarized, by state and RPS sub-category is found in Appendix C.

The quantity of *new* or *incremental* renewables that will be added each year during the study period is driven by these requirements. In particular, new renewable additions are driven by demand from the "Premium RPS tiers" which consist of:

- "Class I" (Connecticut, Massachusetts, New Hampshire, Maine);
- "New" (Rhode Island) RPS tiers;
- The 'Class II' (solar) tier in New Hampshire; and
- The MA Solar Carve-Out[24]The MA Solar Carve-Out is the most recent addition to this set of standards, completing its first compliance year in 2010.

It is also important to note that while past experience has favored the creation of new or accelerated RPS requirements, the delay or reduction of future RPS targets is also proposed and discussed from time to time.

With the exception of Vermont, all states require the use and retirement of NEPOOL Generation Information System (GIS) certificates in order to demonstrate RPS compliance.[25] In the marketplace where this commodity is traded, NEPOOL GIS Certificates are often referred to as Renewable Energy Certificates (RECs). While the definition of a GIS Certificate is narrower than that of a REC, the two terms are used interchangeably and their reciprocal meaning is commonly understood.

The gross demand for new renewable generation resources is derived by multiplying the load of obligated entities (those retail load-serving entities subject to RPS requirements, often excluding public power) by the applicable annual RPS percentage target for the RPS Tier.

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[23] Vermont has also recently initiated a study to identify RPS best practices and quantify the potential costs and benefits of implementing a mandatory RPS. A report is due to the legislature in October 2011.

[24] The Massachusetts Solar Carve-Out is technically a sub-component of the MA Class 1 RPS target.

[25]Currently, Vermont's requirement will allow RECs to be sold off elsewhere (presumably for compliance in other states), therefore not leading to incremental renewable-energy additions beyond what would be predicted in the presence of other states' requirements. (However, it has been argued that the Vermont requirements will support financing and therefore lead to more renewables being built and therefore less reliance on Alternative Compliance Payments). We assume that by 2013, Vermont's standard will be altered to require retirement of RECs, and which increase the total RPS additions we project.

The net demand for incremental renewable generation within New England is derived by subtracting from the gross demand: (a) existing eligible generation already operating (including biomass co-fired at existing fossil-fueled facilities); and (b) the current level of RPS certified imports.

Over time, the net demand to be met by resources within ISO-NE will be further reduced by an estimate of additional RPS-eligible imports over existing tie lines, phased in towards a maximum level of usage (consistent with competing uses of the lines and appropriate capacity factors of imported resources) at a rate consistent with the recent historical rate of increase in RPS-eligible imports over a ten-year period.

Renewable resources eligible to satisfy state RPS requirements have considerable overlap, but vary by state. From approximately 2015 onward AESC 2011 assumes that renewable resources eligible in one or only a few states are insufficient to completely fulfill the demand of the limited states in which they are eligible. In effect, we assume that beyond 2015 every state in New England is competing at the margin to satisfy its requirements for new renewables, other than the solar tiers, from the same group of eligible supply resources.

In the near term (from 2012 to 2016), we assume that the aggregate net RPS demand for new renewable energy will be met by a mix of renewable resource generation consistent with: (1) RPS-eligible resources in the New England administered systems and Maine Public Service interconnection queues, plus (2) other expected RPS-eligible generation in the development pipeline, which has not entered the queue. This includes both large projects which have not yet filed for interconnection studies and distributed wind, solar and fuel cell projects, which- due to their size- are not required to go through the large generator interconnection process. Due to the increasing expense of entering and maintaining a position in the interconnection queue, some proposed projects must delay this stage of the process until early site evaluation and permitting progress has been sufficient to attract substantial development capital.

In some cases, the development and interconnection processes are also delayed by regulatory uncertainty. The critical example in today's market is the Massachusetts Department of Energy Resources' (DOER) revision of the RPS-eligibility of biomass generators and feedstock. A lengthy stakeholder and rule promulgation process has delayed the development of nearly all of the region's proposed biomass projects. The DOER's most recent draft RPS regulation was filed on May 3, 2011 and is now subject to legislative committee review. DOER will incorporate the legislature's comments and then promulgate final regulations. This analysis takes into account the fuel sustainability, efficiency, and other standards found in these near-final regulations. The changes are expected to cause not only project delays but also changes in the scale and configuration of proposed projects. The overall probability of success for all proposed biomass projects has been reduced as a result.

All proposed generators for which information has entered the public domain are included in this analysis. This generation is derated to reflect the likelihood that not all proposed projects will ultimately be built, and may not be built on the timetable reflected in the queue. This information is grouped by load area as an input to the Market Analysis model.

For the longer term (generally after 2015), we estimate the quantity and types of renewables that will be developed using a supply-curve approach based on resource potential studies. In this approach, potentially available resources are sorted from least to greatest REC premium required to attract financing. This approach identifies the incremental resources required to meet net incremental demand in each year through 2026.

The one exception to this methodology is solar PV. We assume that resource is developed in proportion to various state policies intended to promote solar, including solar RPS tiers and other factors.

In this work we assume full compliance with established RPS requirements via one of two possible mechanisms. First, entities subject to RPS requirements are expected to comply primarily through the acquisition and retirement of GIS Certificates/RECs. In the alternative, an obligated entity can comply with RPS requirements by making an Alternative Compliance Payment (ACP).[26] ACP levels have been set at prices above the minimum REC price level expected to be necessary to allow plants to be financed and built. Because of the presence of the ACP as a valid form of compliance, actual non-compliance with RPS requirements will be extremely rare. In other words, if the market is short on supply, there is a valid alternative route to comply. Given these options we expect load-serving entities to comply each year, particularly since regulators have the authority to impose penalties or ultimately withdraw the generator’s right to participate in the RPS market.

Planned Additions and Uprates

The non-renewable generation resources used as inputs to our simulations are drawn from the capacities in ISO-NE (2011). Exhibit 2-9 below (page 2-36) lists the specific

[26]In Massachusetts, Rhode Island, New Hampshire, and Maine, the Class-I or new-renewables tiers utilize an ACP mechanism set at a common level. For these states, the ACP is $62.13/MWh in 2011, and increases with inflation thereafter. In Connecticut, the penalty for non-compliance is set at $55/MWh., with no annual escalation. While it is called a penalty rather than ACP in Connecticut, its effect is similar and it is often referred to as an ACP, which has become the generic term of art in the industry.

generation additions we assume beyond that. These are primarily the new units that are under contract to the Connecticut utilities and those under construction for municipal utilities, and include the generators that cleared in the Forward Capacity Auctions.

Demand-Response Resources

Demand Response (DR) resources participate in the FCA. For simulation purposes we start with the quantities of DR that cleared in FCA 4 and project quantities for future FCAs. DR resources, when dispatched, affect energy prices primarily in peak hours.

Generic Non-Renewable Additions

New generic non-renewable resources will be added to meet any residual installed capacity requirements after adding planned and RPS additions. We developed our assumptions regarding the quantity, type, and timing of these generic additions in coordination with our simulation of the FCM because revenues from FCA prices help support those investments.

Based on the mix of resources in the interconnection queue, and the constraints on construction of new coal or nuclear units in New England in the foreseeable future, we assume generic additions comprising gas-oil-fired 490-MW combined-cycle (CC) units and 180-MW combustion turbines (CT). These additions are dispersed throughout New England based on zonal need and historical zonal capacity surplus-deficit patterns.

2.2.3. Environmental Regulations

Market Analytics has the ability to model, and apply, unit costs of compliance for multiple emissions. For AESC 2011, we modeled the costs of complying with regulations governing the emissions of SO_2, NO_x and CO_2. The model includes the unit costs associated with each of these emissions when calculating bid prices and making commitment and dispatch decisions.[27] In this way AESC 2011 projects market prices which reflect, or “internalize” the unit-compliance costs for each emission, except mercury. The unit compliance costs assumed for each pollutant are presented in Exhibit 2-3.

The assumptions for NO_x and SO_2 allowances are based on the Market Analytics default data and consistent with the current futures prices.[28] Since there is still considerable

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[27] These are the carbon values that are internalized in the cost of electricity. For a discussion of the overall cost of carbon, including its externality/climate plan compliance cost and overall value, see Chapter 6.

[28] NOx allowance prices have fallen considerably since the previous AESC report in 2009. The NOx prices in AESC 2009 started at $1,500 and fell to $284. The SO_2 prices are also much lower than AESC 2009 where they started at $60.8 and fell to $4.83 per ton. Compared to AESC 2009, CO_2 prices are approximately 50% lower for RGGI and start five years later for the Synapse forecast.

uncertainty about the longer term we have kept NO_x and SO_2 prices at level constant 2011 dollar (2011$) values. For mercury, we assume no trading, and hence no allowance price. CO_2 prices are based on RGGI prices through 2017 and thereafter they are based on assumed prices under Federal regulation according to the February 2011 Synapse carbon dioxide price forecast.[29] [30]

The following explanation for the Market Analytics NOx and SO2 emission price forecasts is from the Ventyx Database Release Notes of February 2011. Further discussion of EPA regulations is in the next section.

> As with previous releases, Ventyx Advisors continue to project both the emissions market prices for NO_X and SO_2, and the necessary emissions controls that will be installed on generators to meet federal as well as local air quality limits. Beginning with this data release (NERC 9.1), NOx and SO2 forecasts reflect the Federal Clean Air Transportation Rule (CATR) rather than the previously modeled Federal Clean Air Interstate Rule (CAIR) due to the DC Circuit Court vacating CAIR in 2008 and EPAs response of CATR. Given the differences in the programs being modeled including their reduction requirements and geographic scope, it may not be entirely appropriate to compare these prices graphically – nonetheless they are provided for information and with the caveat that they are different programs. Note that higher emissions requirements in CATR for NOx have resulted in requirements being already met and thus there is no marginal cost of compliance (or emissions penalty).

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[29] Johnston et al, "2011 Carbon Dioxide Price Forecast", February 2011.   http://www.synapse-energy.com/Downloads/SynapsePaper.2011-02.0.2011-Carbon-Paper.A0029.pdf

[30] See footnote 15.

Exhibit 2-3: Emission Allowance Prices per Short Ton (2011$ and Nominal Dollars)

	NOx		**SO_2**		**CO_2 (Synapse)**		**CO_2 (RGGI)**	
Year	2011$	Nominal	2011$	Nominal	2011$	Nominal	2011$	Nominal
2011	$230	$230	$3.75	$3.75	$1.89	$1.89	$1.89	$1.89
2012	145	148	3.21	3.27	1.89	1.93	1.89	1.93
2013	134	139	1.65	1.72	1.89	1.97	1.89	1.97
2014	132	141	1.62	1.72	1.89	2.01	1.89	2.01
2015	*132*	143	*1.62*	1.75	1.89	2.05	1.89	2.05
2016	*132*	146	*1.62*	1.79	1.89	2.09	1.89	2.09
2017	*132*	149	*1.62*	1.83	1.89	2.13	1.89	2.13
2018	*132*	152	*1.62*	1.86	15.30	17.57	1.89	2.17
2019	*132*	155	*1.62*	1.90	18.28	21.41	1.89	2.21
2020	*132*	158	*1.62*	1.94	21.25	25.40	1.89	2.26
2021	*132*	161	*1.62*	1.98	24.23	29.53	1.89	2.30
2022	*132*	165	*1.62*	2.02	27.20	33.82	1.89	2.35
2023	*132*	168	*1.62*	2.06	30.18	38.27	1.89	2.40
2024	*132*	171	*1.62*	2.10	33.15	42.88	1.89	2.44
2025	*132*	175	*1.62*	2.14	36.13	47.67	1.89	2.49
2026	*132*	178	*1.62*	2.18	39.10	52.62	1.89	2.54
2027	*132*	182	*1.62*	2.23	42.08	57.76	1.89	2.59
2028	*132*	185	*1.62*	2.27	45.05	63.08	1.89	2.65
2029	*132*	189	*1.62*	2.31	48.03	68.59	1.89	2.70
2030	*132*	193	*1.62*	2.36	51.00	74.30	1.89	2.75

NOx & SO_2 from CCE March 2011 through 2014, level thereafter. CO2 (RGGI) from 11th auction, CO2 (Synapse) starting in 2018 from Synapse report of February 2011.

2.2.3.1. EPA Regulations

The EPA is in the process of numerous rulemakings, many of them court-ordered, which implement statutory requirements under the Clean Air Act, Clean Water Act and Resource Conservation and Recovery Act (RCRA). Several of these rules will regulate the power sector directly. These include revisions of Clean Air Act new source performance standards for power plants, regulation of interstate pollutant emissions from power plants, regulation of hazardous air pollutant emissions from power plants, haze regulations, new standards governing cooling intake water, and new effluent limitation guidelines for wastewater discharges from power plants. In addition, EPA has proposed to regulate the disposal of coal combustion wastes for the first time. Finally, the EPA is in the process of revising several National Ambient Air Quality Standards (NAAQS) for pollutants including particulate matter (PM), ozone, sulfur dioxide, and nitrogen oxides. Revised NAAQS will result in the designation of additional nonattainment areas, which in turn will obligate states to require emissions reductions from major pollution sources including power plants.

When considered individually, these rules to varying extents will require retrofits and associated outages and may result in retirements and/or the repowering of existing electric generating units across the United States. Taken together, these rules will have a significant effect on the generating fleet.

Following is a short description of the rules anticipated to have the most economically consequential impacts on the power sector. Appendix C provides a summary description of these rules and a timeline of their anticipated implementation

Clean Air Transport Rule (CATR)

The Clean Air Transport Rule, proposed in July 2010, will reduce emissions that contribute to non-attainment of National Ambient Air Quality Standards or that interfere with maintenance of those standards by downwind states.[31] Based on the current proposal, emissions of sulfur dioxide and nitrogen oxide from electric generating units in 31 eastern states and the District of Columbia will be capped to help enable downwind states to comply with the NAAQS, including the annual $PM_{2.5}$ NAAQS (promulgated in 1997) and the 24 hour $PM_{2.5}$ NAAQS (promulgated in 2006).[32] Compliance with the transport rule will require substantial investments in scrubbers and other control devices at many generation stations.

Air Toxics Standards (MACT Rule)

The EPA is under court order to set emission limits for hazardous air pollutant emissions from electric generating units under section 112(d) of the Clean Air Act. More than 180 hazardous air pollutants are listed under the Clean Air Act, and those most relevant to the electric power industry include mercury, dioxins, and acid gases. This "air toxics rule" would require that sources meet emission limits based on EPA's assessment of "Maximum Achievable Control Technology" or "MACT." For existing sources, this means that the level of control achieved must be in line with the average of the top twelve percent of top-performing power plants. Requirements for new sources are at least as stringent as the single best performing source, reflecting the maximum emissions reductions achievable with state-of-the-art pollution controls. Existing units will have three years to comply with the final rule once it is issued, while new sources will have to comply immediately upon issuance of the rule.[33] The EPA issued the new proposed rule

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[31] U.S. EPA, *Federal Implementation Plans To Reduce Interstate Transport of Fine Particulate Matter and Ozone*, Federal Register / Vol. 75, No. 147 / Monday, August 2, 2010 / Proposed Rules, pp. 45210 ff.

[32] US EPA, Office of Air and Radiation. *Proposed Air Pollution Transport Rule*. July 26, 2010. Slide 4. Available at: http://www.epa.gov/airtransport/pdfs/FactsheetTR7-6-10.pdf.

[33] Bryson, Joe. US EPA, Office of Air and Radiation. *Key EPA Power Sector Rulemakings*. Eastern Interconnection States' Planning Council. August 26, 2010. Slide 17. Available at: http://communities.nrri.org/c/document_library/get_file?folderId=107847&name=DLFE-3419.pdf.

in March 2011 and is expected to finalize the rule in November 2011.[34] New standards must be implemented within three years after the rule is finalized, so compliance by 2014 is implied.

The EPA has not yet released an analysis of costs and benefits of the MACT rule. However, as discussed below, several recent analyses assess their impact on the power sector.

Coal Combustion Residuals

Coal combustion residuals are byproducts from the combustion of coal that include fly ash, bottom ash, boiler slag, and flue gas materials. . The EPA's long-term objective is to phase out the wet handling of coal ash and the use of surface impoundments (ash ponds) in favor of dry ash handling and disposal in lined landfills. Approximately one-third of the coal capacity in the United States uses wet ash handling and storage systems.[35]

Clean Water Act § 316(b)

Thermal power plants using water for cooling purposes use one of three types of cooling systems: once-through, recirculating, and dry cooling. Once-through systems withdraw water in large volumes and then discharge it back into the same water body at elevated temperatures. Recirculating systems withdraw water in smaller volumes, and continuously circulate the cooling water through a plant's heat exchangers with the aid of cooling towers. Dry cooling systems are closed-loop systems that do not rely on cooling water, but instead on forced draft air flow.

Section 316(b) of the Clean Water Act requires that new power plants use the best available cooling water intake technologies for minimizing adverse environmental impacts. Adverse environmental impacts include the intake of aquatic organisms with cooling water when using once-through systems.

Regional Haze Rule

The Clean Air Act defines as a national goal the remedying of existing visibility impairment that results from manmade air pollution in all "Class I" areas (e.g., most national parks and wilderness areas). See 42 U.S.C. § 7491(a)(1). EPA's implementing rules require states to create plans to achieve natural visibility conditions by 2064 with enforceable reductions in haze-causing pollution from individual sources and other

[34] US EPA, Office of Air and Radiation. *Reducing Air Pollution from Power Plants*. September 24, 2010. Slide 7. Available at: http://www.naruc.org/Domestic/EPA-Rulemaking/Docs/EPA%20AIR%20Presentation%20Sept%2024%202010%20_%20Sam%20Napolitano.pdf.

[35] Bernstein Research. *U.S. Utilities: Coal-Fired Generation Is Squeezed in the Vice of EPA Regulation; Who Wins and Who Loses?* October 2010. Page 66.

measures to meet “reasonable further progress” milestones. See generally 40 C.F.R. §51.308-309.

New Source Review

Changes in EPA regulations for New Source Review (NSR) may affect the economics of keeping some existing plants in operation which we will consider on a case by case basis.

2.2.3.2. CO_2 Regulation

AESC 2011 assumes RGGI allowances prices as reported in Exhibit 2-3 based upon recent auction results which have been at the reserve price and are likely to remain so in the future. At the 11th quarterly RGGI auction held March 9, 2011, the allowances for the current and future control periods cleared at the reserve price of $1.89.[36]

After 2017, we use prices estimated by Johnston et al. (2011) for our Reference Case, in which a national cap-and-trade program for GHG is enacted.[37] From 2026 onward, we assume allowance prices in the Reference Case will rise at the rate of inflation.

As requested, we have also estimated CO_2 allowance prices for a special case that assumes no new Federal regulatory framework and thus continuation of RGGI indefinitely (RGGI-only). We do not believe this case is likely. Under the RGGI-only scenario we assume that RGGI prices will remain relatively stable due to electricity imports. Thus, we assume allowance prices in that RGGI-only case will rise at the rate of inflation.

2.2.4. Results of Forward Capacity Auctions and Regional Greenhouse Gas Initiative Auctions

Results of Forward Capacity Auctions

As noted in Section 2.2.1.2, revenues from FCAs will influence decisions regarding continued operation of existing generating units and investments in new generating units.

Results of Regional Greenhouse-Gas-Initiative Auctions

As noted in Section 2.2.3.2, the 11th RGGI auction was held in March of 2011. The current and future control period allowances cleared at the reserve price of $1.89. Considering future RGGI requirements, the modest expected load growth in the Northeast and the effect of RPS programs, we expect future RGGI auctions to also clear at the reserve price. New England states use revenues from RGGI auctions to fund state energy efficiency and renewable energy programs. This is discussed more fully as described above.

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[36] Accessed 3/21/11 at http://www.rggi.org/docs/Auction_11_Release_Report.pdf

[37] Johnston (2011)

2.3. Wholesale Electric Energy Market Simulation Model and Inputs

2.3.1. The Energy-Market-Simulation Model

Market Analytics is a zonal locational marginal-price-forecasting model that simulates the operation of the energy and operating reserves markets. The simulation engine used is PROSYM. The modeling system and the default data is provided by the model vendor Ventyx.

The model does not simulate the forward capacity market and, therefore, does not require assumptions regarding the capital costs of new generation capacity, and the interconnection costs associated with such capacity. However, the model does require assumptions about the quantity and type of existing and new capacity over the study horizon.

Market Analytics also requires assumptions of monthly regional prices of fuels used to generate electricity. Those -prices forecasts are described in Chapter 3 and 5. The remaining inputs are discussed in the sections below.

2.3.1.1. Zonal Locational Marginal Price-Forecasting Model

The following section provides a high-level overview of the Market Analytics data-management and production-simulation-model functionality. Market Analytics uses the PROSYM simulation engine to produce optimized unit commitment and dispatch options. The model is a security-constrained chronological dispatch model that produces detailed and accurate results for hourly electricity prices and market operations.

The smallest location in Market Analytics is a Location (typically representing a utility service territory) which for modeling purposes is mapped into a Transmission Area (TA). A TA may represent one or more Locations. Transmission areas represent sub regions of Control Areas such as ISO New England. Transmission areas are defined in practice by actual transmission constraints within a control area. That is, power flows from one area to another in a control area are governed by the operational characteristics of the actual transmission lines involved. PROSYM can also simulate operation in any number of control areas. Groups of contiguous control areas were modeled in order to capture all regional impacts of the dynamics under scrutiny.

PROSYM uses highly detailed information on generating units. Data on specific units in the Market Analytics database are based on data drawn from various sources including the U.S. Energy Information Administration, U.S. Environmental Protection Agency, North American Electric Reliability Corporation, Federal Energy Regulatory Commission (FERC), and ISO-New England databases as well as various trade press announcements and Ventyx's own professional assessment. Total existing capacity in the Market Analytics database was compared with that of ISO-NE CELT 2011 and found to be reasonably consistent, although we made a few adjustments to reflect retirements as detailed below.

For larger units, emission rates and operating characteristics are based on unit-specific data reported to EPA and EIA rather than on data based on unit type. Operating costs for each unit are based on plant-level operating costs reported to FERC and assessment of unit type and age. For smaller units (e.g., combustion turbines), most input data are based on unit type. All generating units in PROSYM operate at different heat rates (efficiencies) at different loading levels. This distinction is especially important in the case of combined-cycle units, which often operate in a simple-cycle mode at low loadings. PROSYM determines the fuel a unit burns by placing each generating unit into a “fuel group.” PROSYM does not limit the number of fuel groups used, and creating new fuel groups to simulate a few unusual units is a simple matter. In New England, for example, it is especially important to model the operation of dual-fueled units as accurately as possible.

Based upon hourly loads, PROSYM determines generating unit commitment and operation by transmission zone based upon economic bid-based dispatch, subject to system operating procedures and constraints. PROSYM operates using hourly load data and simulates unit dispatch in chronological order. In other words, 8,760 distinct hourly load levels are used for each transmission area for each study year. The model begins on January 1st and dispatches generating units to meet load in each hour of the year. Using this chronological approach, PROSYM takes into account time-sensitive dynamics such as transmission constraints and operating characteristics of specific generating units. For example, one power plant might not be available at a given time due to its minimum down time (i.e., the period it must remain off line once it is taken off). Another unit might not be available to a given transmission area because of transmission constraints created by current operating conditions. These are dynamics that system operators wrestle with daily, and they often cause generating units to be dispatched out of merit order. Few other electric system models simulate dispatch in this kind of detail.

The model’s fundamental assumption of behavior in competitive energy markets is that generators will bid their marginal cost of producing electric energy into the energy market. The model calculates this marginal cost from the unit’s opportunity cost of fuel or the spot price of gas at the location closest to the plant, variable operating and maintenance costs, and opportunity cost of tradable permits for air emissions.

PROSYM does not make capacity-expansion decisions internally. Instead, the user specifies capacity additions, a practice that increases transparency and allows the system-expansion plans to be specified to reflect non-market considerations. As discussed in more detail, PROSYM also models randomly occurring forced outages of generating units probabilistically rather than as deterministic capacity de-rating, thereby producing more accurate estimates of avoided costs, particular for peak-load periods. PROSYM models generating units with a much higher level of detail including inputs for unit specific ramp rates, minimum up/down times, and multiple capacity blocks, all of which are critical for accurately modeling hourly prices. This modeling capability enabled production of locational prices by costing period in a consistent manner at the desired level of detail.

PROSYM simulates the effects of forced (i.e., random) outages probabilistically, using one of several Monte Carlo simulation modes. These simulation modes initiate forced outage events (full or partial) based on unit-specific outage probabilities and a Monte Carlo–type random number draw. Many other models simulate the effect of forced outages by “de-rating” the capacity of all generators within the system. That is, the capacities of all units are reduced at all times to simulate the outage of several units at any given time. While such de-rating usually results in a reasonable estimate of the amount of annual generation from baseload plants, the result for intermediate and peaking units can be inaccurate, especially over short periods.

PROSYM calculates emissions of NO_x, SO_2, CO_2 and mercury based on unit-specific emission rates. Emissions of other pollutants (e.g., particulates and air toxics) are calculated from emissions factors applied to fuel groups.

2.3.2. Input Assumptions to Electric-Energy-Price Model

The input assumptions to the Market Analytics locational-price-forecasting model include market rules and topology, hourly load profiles, forecasted annual peak demand and total energy, thermal-unit characteristics, conventional hydro and pumped storage unit characteristics, fuel prices, renewable unit characteristics, transmission system paths and upgrades, generation retirements, additions and uprates, outages, environmental regulations, and demand-response resources.

2.3.2.1. Market Rules and Topology

The major assumptions are described below as inputs to the model.

Marginal-Cost Bidding

In deregulated markets generation units are assumed to bid marginal cost (opportunity cost of fuel plus variable operating and maintenance costs (VOM) plus opportunity cost of tradable permits). It is reasonable to assume that the real markets are not perfectly competitive and thus the model prices based on marginal costs tend to underestimate the prices in the real markets. To represent that effect we investigated bid adders to represent more realistic market behavior. The resulting energy-price outputs are benchmarked against historic and futures prices.

Installed Capacity

Installed-capacity requirements for the resource-addition model include reserve requirements established by ISO-NE on an annual basis. Current estimates of the reserve-margin and installed-capacity requirement (with and without the Hydro Quebec (HQ) installed capacity credits) as described in Chapter 6. Installed capacity for the energy model in each model year will be consistent with the values assumed in the FCA analysis, although the values will not be the same, due to imports and exports.

Ancillary Services

Market Analytics allows users to define generating units based on their ability to participate in various ancillary services markets including Regulation, Spinning Reserves, and Non-Spinning Reserves. The database includes specifications for these abilities based on unit type. Market Analytics generates prices for these markets in conjunction with the energy market. The spinning reserves market affects energy prices since units that spin cannot produce electricity under normal conditions. The energy prices are higher when reserves markets are modeled. Reserves requirements for New England are applied to the model.

Electric Model Topology

Market Analytics represents load and generation areas at various levels of aggregation. Assets within the model, including physical or contractual resources such as generators, transmission links, loads, and transactions, are mapped to physical locations which are then mapped to transmission areas. Multiple transmission areas are linked by transmission paths to create the control area.

The load and generation areas to be modeled are presented in Exhibit 2-4 below.

CELT 2011 reports load for thirteen subareas. Those load areas correspond to the locations used in the Market Analytics data. Our modeling maps those thirteen load subareas into ten transmission areas, which is the level of detail required to report results for the fourteen zones specified for AESC 2011.[38]

Neighboring regions that are modeled in this study are New York, Quebec Ontario, and the Maritime Provinces.[39] Areas outside of New England are represented with a high level of zonal aggregation to minimize model run time.

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[38] We produce results for four of the AESC zones by aggregating the results for certain of the areas we model. For example, the results for Massachusetts is the aggregate results for SEMA, WCMA, and NEMA. The results for the aggregate zones are based on the weighted averages of their constituent subzones.

[39]The Maritimes zone includes Maine Public Service (MPS) and Eastern Maine Electric Cooperative (EMEC) which are not part of ISO-New England and, therefore, are not included in any of the New England pricing zones

Exhibit 2-4: Load Areas Used to Model New England

	AESC Zones	Load Area CELT SubArea (13)	Market Analytics Modeling Areas (10)	AESC Zone Mapping
1	Maine	ME + BHE + SME	BHE + ME Central + ME Southwest	Direct
2	Vermont	VT	Vermont	Direct
3	New Hampshire	NH	New Hampshire	Direct
4	Connecticut (Statewide)	CT		*Aggregated*
5	Massachusetts (Statewide)	BOST + CMA/NEMA + SEMA + WMA		*Aggregated*
6	Rhode Island	RI	Rhode Island	Direct
7	SEMA (Southeast Massachusetts)	SEMA	MA Southeast	Direct
8	WCMA (West-Central Massachusetts)	WMA	MA Western	Direct
9	NEMA (Northeast Massachusetts)	(CMA/NEMA)	MA Central-Northeast	Direct
10	Rest of Massachusetts (Massachusetts excluding NEMA)	BOST + (CMA/NEMA) + SEMA + WMA		*Aggregated*
11	Norwalk/Stamford	NOR	CT Norwalk	Direct
12	Southwest Connecticut, including Norwalk/Stamford	SWCT		*Aggregated*
13	Southwest Connecticut, excluding Norwalk/Stamford	SWCT - NOR	CT Southwest	Direct
14	Rest of Connecticut (Connecticut excluding all of Southwest Connecticut)	CT - SWCT	CT Central-Northeast	Direct

This study explicitly models neighboring control areas that have direct connections to the New England grid, including New York ISO, the Maritimes region (New Brunswick, Nova Scotia, and Prince Edward Island), and Quebec. These external markets are modeled in the same manner and simultaneously with New England. The Market Analytics database is used as the primary data source for external regions. New capacity is added to meet RPS requirements and generic gas capacity is added based on the same methodology that is used in New England.

The forecasts of electricity prices for each load area from the model are mapped and load-weighted into the AESC zones.

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used in this study. MPS and EMEC are not modeled as part of the Maine pricing zone and were modeled as part of the New Brunswick transmission area.

2.3.2.2. Load Forecast

Forecasts of peak demand and annual energy by year for each of the ten areas modeled in Market Analytics were derived from ISO-NE (2011) as described in Section 2.2.2. Historical profiles for each utility were developed by Ventyx for Market Analytics based on a set of annual historical load shapes. Hourly load profiles based on historical profiles were calculated for each load serving entity. Loads were then mapped to transmission areas based on location ratios. Hourly load data for future years were scaled based on forecasted annual peak demand and total energy.

The area ISO-NE load forecasts are used to produce the transmission area loads required for the Market Analytics modeling.

Exhibit 2-5: Summer Peak Forecast by Model Load Area

Load Area	2011 (MW)	2020 (MW)	2015- 2020 CAGR	2026 (MW)
BHE	306	356	1.47%	389
ME	962	1,087	1.14%	1,164
SME	698	818	1.67%	903
NH	2,004	2,369	1.69%	2,619
VT	1,201	1,366	1.21%	1,469
BOST	5,616	6,301	1.12%	6,735
CMA/NEMA	1,710	1,965	1.38%	2,133
WMA	2,147	2,442	1.23%	2,628
SEMA	2,845	3,180	1.07%	3,390
RI	2,490	2,915	1.58%	3,203
CT	3,438	3,853	1.10%	4,114
SWCT	2,285	2,560	1.09%	2,732
NOR	1,271	1,436	1.15%	1,538
ISO-NE	**26,973**	**30,648**	**1.24%**	**33,016**
2026 values were developed by growing 2020 values by 2015-2020 Compound Annual Growth Rate.				
Loads include the effects of 2010 Passive Demand Resources.				

Exhibit 2-6: Energy Forecast by Model Load Area

Load Area	2011 (GWh)	2020 (GWh)	2015- 2020 CAGR	2026 (GWh)
BHE	1,830	1,980	0.78%	2,161
ME	5,806	6,216	0.69%	6,654
SME	3,959	4,334	0.92%	4,787
NH	10,291	11,746	1.35%	12,986
VT	6,981	7,651	0.80%	8,226
BOST	26,832	29,412	0.95%	31,436
CMA/NEMA	8,070	8,965	1.09%	9,732
WMA	10,624	11,684	0.98%	12,575
SEMA	13,774	15,199	1.02%	16,203
RI	11,478	13,033	1.28%	14,320
CT	15,825	17,320	0.82%	18,494
SWCT	10,579	11,589	0.83%	12,367
NOR	5,862	6,477	0.94%	6,938
ISO-NE	**131,911**	**145,606**	**0.98%**	**156,879**
2026 values were developed by growing 2020 values by 2015-2020 Compound Annual Growth Rate.				
Loads include the effects of 2010 Passive Demand Resources.				

2.3.2.3. Transmission Upgrades

Transmission-path assumptions were based on those developed by Market Analytics based on the transmission paths represented in ISO-NE (2010b). We have modified those based on ISO data and proposed projects to represent future additions. These transmission assumptions, like our other resource assumptions, are not intended to represent specific forecasts or projections, but a reasonable allowance for likely, but unknown additions.

The transmission system within Market Analytics is represented by links between transmission areas. These links represent aggregated actual physical transmission paths between locations. Each link is specified by the following variables: (a) “From” location, (b) “To” location, (c) Transmission capability in each direction, (d) Line losses in each direction and (e) Wheeling charges.

- “From” location
- “To” location
- Transmission capability in each direction
- Line losses in each direction
- Wheeling charges

Exhibit 2-7 shows the transmission capabilities of each path between New England zones and between New England and external areas as indicated in the Market Analytics database, reconciled to the interface limits reported in recent ISO reports. The exhibit below shows the transmission capability assumptions of each path.

Exhibit 2-7: Existing Transmission Paths and Future Upgrades

Path Type	Path Name	"From" TransArea	"To" TransArea	Capacity "From-To" (MW)	Notes	Capacity Back (MW)	Notes
Transmission Paths within New England	BHE-ME	BHE	ME	1,200		1,050	
	CMA-BOSTON	CMA-NEMA	BOST	3,200		3,000	
	CMA-NH	CMA-NEMA	NH	912		925	
	CMA-WMA	CMA-NEMA	WMA	1,360		2,000	
	CT-RI	CT-CNE	RI	720		797	(a) part of CT import
				1,170	1/1/2016	1,247	(b) 1/1/2016
	CTSW-CT	CT-SW	CT-CNE	2,000		3,500	
	CTSW-NOR	CT-SW	CT-NOR	1,650		1,650	
	MPS-BHE	MPS	BHE	10		10	
	NH-BOSTON	NH	BOST	900		912	
	NH-SME	NH	SME	1,400		1,475	
				2,400	1/1/2014	2,475	(c) 1/1/2014
	NH-VERMONT	NH	VT	720		715	
	RI-BOSTON	RI	BOST	400		400	
	RI-CMA	RI	CMA-NEMA	1,480		720	
	RI-SEMA	RI	SEMA	1,000		3,000	
	SEMA-BOSTON	SEMA	BOST	400		400	
	SME-ME	SME	ME	1,250		1,150	
	VERMONT-WMA	VT	WMA	875		875	
	WMA-CT	WMA	CT-CNE	980		1,085	(a) part of CT import
				1,480	1/1/2014	1,585	(d) As of 1/1/2014
Transmission Paths between New England and External Control Areas	BHE-NBPC	BHE	NBPC	425		1,000	
	CMA-HYQB (Phase II)	CMA-NEMA	HYQB	1,457		1,400	
						2,400	(e) As of 1/1/2020
	EMEC-NBPC	EMEC	NBPC	20		20	
	HYQB-VT (Highgate)	HYQB	VT	200		170	
	MPS-NBPC	MPS	NBPC	100		100	
	NOR-NYZK	CT-NOR	NYZK	100		80	
	NYZD-VERMONT	NYZD	VT	86		150	(f) part of NY-NENG
	NYZF-WMA	NYZF	WMA	330		650	(f) part of NY-NENG
	NYZG-CT	NYZG	CT-CNE	558		618	(f) part of NY-NENG
	NYZK-CT (CSC)	NYZK	CT-CNE	346		330	

Notes

(a) Connecticut import total of 2,500 MW distributed among several paths.
(b) Interstate Reliability Project (IRP) or equivalent increase CT-RI ties by 450 MW by 2016.
(c) Increased Maine interconnection associated with the Maine Power Reliability Project (MPRP) of 1000 MW in 2014.
(d) GSRP increases CT-WMA ties by 500 MW by 2016. Total CT ties increased by 950 MW of 1,100 MW proposed for NEEWS.
(e) Increased import capacity of 1000 MW from Quebec based on a number of proposals.
(f) Based on NY - New England import limit,

The New England East-West Solutions (“NEEWS) transmission program consists of four major components:

1) The Rhode Island Reliability Project (RIRP),

2) The Greater Springfield Reliability Project (GSRP),

3) The Interstate Reliability Project (IRP),

4) The Central Connecticut Project (CCP).

ISO-NE transmission-planning documents have assumed that Connecticut import capability will increase by 1,100 MW from NEEWS. AESC 2011 assumes increases of 950 MW of the 1,100 MW proposed under the IRP and GSRP components of NEEWS, both of which have been approved by the relevant state siting agencies and are under construction.

- 500 MW is effective in 2014 from the Western Massachusetts–Connecticut transfer capacity, reflecting the effect of the GSRP;
- 450 MW is effective in 2016 from the IRP. This timing is based on the experience of the GSRP. Allowing time for project design, review of alternatives, and preparation of siting filings, the siting filings for the final design of the IRP would be expected in 2012. The GSRP required approval in two states; the IRP will apparently require siting review in three states (Massachusetts, Rhode Island and Connecticut). Hence, 2016 appears to be a realistic in-service date for the next phase of NEEWS for our modeling purposes.

Most of the additional transfer capability into Connecticut (and on the East-West and SE Massachusetts–Rhode Island export interfaces as well) results from the IRP and CCP. These two projects were justified primarily by the objective of meeting Connecticut’s load with combined generation and transmission outages at times of extraordinary (once in ten year) high-load conditions, even if more than 1,200 MW of Connecticut generation is retired. Since the original analyses, Connecticut has contracted for over 1,500 MW of additional capacity, load forecasts have fallen, and the GSRP is expected to increase import capacity, greatly reducing the prospect of shortfalls in the Connecticut transmission-security analysis. As a result, both the IRP and CCP have been subject to reconsideration by the ISO.

In consideration of a number of proposals to increase imports from Hydro Quebec to Central New England (e.g. Northern Pass), we assume 1,000 MW of HQ-CMA in 2020.

AESC 2011 also assumes a 1,000 MW increase the transmission capacity between Maine and the rest of New England, effective 2014. This assumption is based in part on estimates of the transfer effects in the Maine Power Reliability Plan (MPRP). Additional transmission is also necessary to allow new renewable resources access to load. Modeling results indicate if new capacity is not added, then energy prices in Maine fall substantially below the rest of New England which provides a strong economic argument for increased interties.

2.3.2.4. Generating Unit Retirements

Various policies, economic and environmental regulations will lead to the retirement of various New England generating units. The specific units we assume that will be retired are presented in . AESC 2011 treats retirements as occurring on January 1 of the relevant year. AESC 2011 l retires about 10 MW of old gas turbines annually after 2012.

Exhibit 2-8: Unit Retirements for Energy Modeling

Retirement Date	Unit Type	Station Name	Unit ID	Summer CELT Capacity (MW)
10/1/2010	ST	Somerset	6	108.5
10/1/2010	GT	Somerset	Jet 2	21.8
10/1/2010	GT	St Albans	1 & 2	2.2
1/1/2013	ST	Salem Harbor	1	83.9
1/1/2013	ST	Salem Harbor	2	80.5
1/1/2013	ST	Bridgeport	2	130.5
1/1/2013	ST	Holyoke Cabot	6 & 8	19.3
1/1/2013	NUC	Vermont Yankee		604.3
1/1/2015	ST	Norwalk Harbor	1	162.0
1/1/2015	ST	Norwalk Harbor	2	168.0
1/1/2016	ST	Salem Harbor	3	149.9
1/1/2016	ST	Salem Harbor	4	436.5
1/1/2016	ST	Cleary	8	26.0
1/1/2016	ST	Montville	6	407.4
1/1/2016	ST	Middletown	4	400.0
1/1/2016	ST	Cleary	8	26.0
1/1/2018	ST	Wyman	1	52.0
1/1/2018	ST	Wyman	2	51.0
1/1/2020	ST	Mount Tom		143.4

Notes
ST Steam Turbine
GT Gas Turbine
NUC Nuclear

The basis for these assumptions is presented below.

Vermont Yankee

The AESC 2011 Reference Case assumes Vermont Yankee retires in 2013.

The NRC has granted Vermont Yankee a 20-year license extension, but the plant also requires state permission to operate past March 2012. The Vermont Senate voted 26–4 in February 2010 to deny that extension, in part due to tritium leaks, a cooling-tower collapse, and errors found in the owner's testimony before the Legislature. Since then, the plant has experienced additional tritium leaks. Vermont Yankee is of the same vintage (early 1970s) and design (Mark I boiling-water reactor) as the Fukushima Daiishi reactors that suffered fuel melting, explosions, radiation releases, and draining of the spent-fuel pools in March 2011. The Vermont Legislature appears unlikely to reverse its decision under these circumstances.

Environmentally-Driven Retirements of Coal Plants

Eight coal plants (consisting of 15 units) are operating in New England. The AESC 2011 Reference Case assumes five of those units will retire over the Study period.

- **Somerset 6** (Massachusetts) has shut down and we treat it as retired. Somerset has not cleared in any of the FCAs held to date.
- **Salem Harbor 1–3** (Massachusetts) has submitted high bids for the third and fourth FCA. Units 1 and 2 were allowed to delist, but Unit 3 has been required to stay on line for reliability, at a price of $5.22/kW-month. Salem filed permanent delist bids for all four units in FCA 5, which was rejected, and then filed a non-price bid. Salem has no baghouse, SCR or scrubber, and is subject to 136(b) requirements. All indications are that the owner intends to retire the plant. We treat Units 1 and 2 as being retired in June 2012, and Units 3 being retired in June 2015, assuming that transmission upgrades will eliminate the reliability need for the plant.[40]
- **Mt. Tom** (Massachusetts) has installed SCR and a baghouse, but is very small. We assume this unit retires in 2020.

Our understanding of the environmental regulatory status of the remaining plants is as follows:

- **Thames A and B** (CT) is a fluidized-bed plant built in the late 1980s, with relatively low emissions. We expect this plant to operate throughout the modeling period. However, the plant is currently in bankruptcy, allegedly due to sales contracts for steam (with Smurfit Container) and electricity (with CL&P) that are now below costs. The plant's owner asserts that its "variable costs" have risen from $37.09/MWh in 2000 to $53.81/MWh in

[40] Dominion, the owner of Salem Harbor, has announced that it will retire Units 3 and 4 in June 2014.

2009, largely due to: increased (a) cost of coal, (b) transportation costs and (c) environmental compliance costs affecting ash disposal and the need to purchase $C0_2$ allowances in compliance with the RGGI." (Declaration of Brian Chatlosh in Support of First Day Motions, February 1, 2011, p. 7) It is not clear whether "variable costs" are limited to costs that vary with energy output. We expect that, as a result of the bankruptcy, Thames will no longer be dispatched as a must-run plant and instead will operate as an intermediate plant We expect this plant to operate throughout the modeling period. (Thames did not clear in FCA 5.)

- **Bridgeport 3** (CT) has relatively low NO_x emission rates (0.14 lb/MMBtu in 2010) for a coal plant and a baghouse to control particulate and mercury emissions, but does not have a scrubber or post-combustion NO_x controls. The plant burns very-low-sulfur coal. Bridgeport 3 has been bidding into the ISO energy markets at prices in the range of $40–$50/MWh, and bidding 130 MW (its minimum load level) as must-take energy in the summer, presumably to minimize NO_x emissions. The unit operated at capacity factors up to the 80% range a few years ago but in only the 30–40% range in 2009 and 2010, presumably due to lower gas prices (and hence lower electricity energy prices) and higher coal prices. It is also subject to 136(b) cooling-water restrictions. While Bridgeport 3 is highly vulnerable and its future is uncertain, we assume that it continues operating in the Reference Case.
- **Brayton 1–3** (Massachusetts) appears committed to making the improvements necessary to meet all pending emission and water-use requirements and stay in operation. The plant has installed, or is installing, SCR, scrubbers, and cooling towers. We assume that Brayton will continue operating. The same is true for the Brayton 4 oil unit.
- **Merrimack 1 and 2** (New Hampshire) have a scrubber and SCR, and are owned by a vertically-integrated utility, with a lower cost of capital than merchant generators . We expect that the plant will continue to operate.
- **Schiller 4 and 6** (New Hampshire) are small (48 MW) and old (1952 and 1957 in-service date), with no major pollution controls other than SNCR and precipitators. In 2010, the units' NOx emissions were nearly 0.3 lb/MMBtu. New Hampshire will likely be excluded from the Clean Air Transport Rule. We have not identified any particular factor that would lead to the shutdown of these units, but given their age and the potential for additional environmental controls (such as to minimize haze in Acadia National Park), they should be considered to be vulnerable.

Environmentally Driven Retirements of Oil- and Oil-and-Gas-Fired Steam Plants

We have less complete information on the old steam plants fired by oil and/or gas. None of these plants are likely to be able to support the cost of major emissions controls. We do not have the type of evidence of owner commitment to continuing operation of these units as we do for Brayton, Bridgeport 3, Mt. Tom, and Merrimack.

The AESC 2011 Reference Case assumes the following units will retire over the Study period:

- **Bridgeport Harbor 2** has delisted for FCA 4 and FCA 5. It has high NOx emissions, no special emissions controls, particularly low capacity factors, and 136(b) exposure. We assume it is retired in June 2013.
- **Salem 4** burns only oil, and its owner has been attempting to delist it from the FCAs, along with the coal units. We assume this unit retires in June 2015, along with Unit 3.
- **Norwalk Harbor** (Connecticut) has reported very high O&M costs (both under regulation and in its RMR cost claim). While it has SNCR installed, and hence relatively low emissions, it is also subject to 136(b) restrictions. These units have cleared through FCA 4 (except for a play for higher RMR payments in FCA 1). We assume that units 1 and 2 will retire in 2015.
- **Middletown 4** and **Montville 6** (Connecticut) are relatively large (400 MW) and modern (early 1970s), and have moderate NOx emission rates, but burn only oil, operate at low capacity factors, and have particularly high heat rates. We assume that they will be retired in 2016.
- **Cleary 8** (Massachusetts) burns oil, is only 26 MW, and has the highest NOx emission rates in New England. We assume that the unit will retire in 2016.

The information we have regarding the remaining major units in this category is summarized below:

- **New Haven Harbor** (Connecticut) is dual-fueled (although not as flexible as some other dual-fuel units), with moderate NOx emissions and capacity factors.
- **Middletown 2 and 3** (Connecticut) have relatively low NOx emissions, dual-fuel capability, and high capacity factors for oil/gas units.
- **Montville 5** (Connecticut) has very low NOx emissions, dual-fuel capability, and relatively high capacity factors. The owner has proposed converting the unit to co-fire biomass.

- **Canal 1** (Massachusetts) has installed selective catalytic reduction (SCR) and operates with very low NOx emissions, while **Canal 2** has installed selective non-catalytic reduction (SNCR) and has moderate emissions. Unit 2 is dual-fueled. The units' capacity factors have been variable, from low to moderate. They are subject to continuing proceeding with EPA regarding compliance with 136(b) requirements.
- **Wyman 1–4** (Maine) run on higher-sulfur (0.72 percent sulfur by weight) and hence less expensive fuel than other oil plants in New England (generally 0.5 percent in Massachusetts and 0.3 percent in Connecticut), and hence operate more often, even though they are in Maine, the zone with the lowest market energy and capacity prices.[41] Other than a requirement to switch to 0.5 percent sulfur oil in 2018, Wyman does not appear to face any environmental challenges. Maine, like New Hampshire, has not been subject to as stringent NOx controls as the southern New England. The Wyman units are subject to 136(b). ISO-NE determined in May 2009 that both Units 1 & 2 are needed for reliability until completion of transmission upgrades in southern Maine. These units have not filed above-market delist bids, suggesting that their forward-going costs are less than the FCM prices through FCA 4, when the price paid to generation in Maine fell to $2.336/kW-month, or $28/kW-year.[42] The completion of the Maine Power Reliability Project will apparently eliminate the reliability need for Wyman 1 & 2, and we assume the retirement of those units in June 2014.
- **West Springfield 3** (Massachusetts) burns both oil and gas, has moderately low NOx emissions and relatively high capacity factors and does not appear to face any specific environmental challenges. (This unit did not clear in FCA 5.)
- **Brayton 4** is dual-fueled and has low NOx emissions, and will share a cooling tower with the coal plants, but has operated at low capacity factors.

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[41] This plant is also sometimes referred to as Yarmouth 1–4.

[42] The Wyman owner has asserted that "Units No. 1 and 2 are not expected to realize any energy revenues in the foreseeable future. Additionally, a bleak capacity revenue outlook makes it unlikely that the subject units will recover their full operations and maintenance costs, and capital expenditures. Since it is not economically feasible to maintain the units, FPL Energy is seriously contemplating retiring Units No. 1 and 2 in the near future." (Request for Determination of Need for System Reliability and Consideration of RMR Cost-of-Service Agreement for Wyman Units No. 1 and 2; December 11, 2008) Despite these warnings, Wyman 1 & 2 have continued clearing with only market capacity prices.

- **Newington** (New Hampshire) burns both oil and gas, has relatively high capacity factors, has been allowed to burn higher-sulfur oil than most New England plants, and does not appear to face any special environmental challenges.
- **Mystic 7** (Massachusetts) burns both oil and gas, has very low NO_x emissions and moderate capacity factors, and does not appear to face any environmental challenges.

Economic Shutdown and Retirements

The economic viability of old (pre-1980) New England combustion turbines as well as old oil- and gas-fired steam plants is strongly influenced by capacity-market prices, which is their primary source of revenue. Starting in June 2016, the extended floor on the FCM price is scheduled to end, and (barring a further extension of the floor) the capacity price in New England could fall dramatically for several years if no existing resources delist (that is, withdraw from the auction either in advance or as the price falls).).

In FCA 4, the floor price of $2.95/kWh ($2.84/kW-month in 2011$) was reached with 4,563 MW of excess capacity

AESC 2011 assumes that approximately 1% of pre-1980 combustion turbines (roughly 10 MW, or a unit every year or two) will retire annually through the modeling period. We assume that the Somerset Jet has been permanently retired; it has not cleared in any of the capacity auctions. listed the specific retirements AESC 2011e assumes, including the retirement of two small Holyoke municipal units that have delisted in FCA4.

2.3.2.5. Generating Unit Additions

Appendix C provides specific information about the resource types that qualify for each state program and the future RPS requirements levels for each state.

As discussed in Section 2.2.2.4, specific renewable energy resources will be based in the near-term on generation in the interconnection queues and other sources in the near-term, and based on a supply curve analysis in the longer term.

The operating characteristics of renewable generation units will be reasonably consistent between the Market Analytics modeling inputs and the SEA analysis. Inputs into the model will be verified by SEA to ensure consistency.

Planned Additions & Uprates

The AESC 2011 forecast of non-renewable generator additions is based on capacity that has cleared in FCA 4 and filings with the Connecticut DPUC for projects under contract with the Connecticut utilities. New entry assumptions are shown in the exhibit below. These planned additions are highly likely to reach commercial operation. Further additions will be treated as generic units.

Exhibit 2-9: Planned Non-Renewable Additions (in Addition to ISO-NE 2011)

	Unit Type	Fuel Type	Summer Net MW	State	Projected Commercial Operation Date
New Haven	GT	NG, DFO	133	Conn.	6/1/2012
Ansonia Generating	GT	NG	60	Conn.	6/1/2010

This tabulation does not include the fuel cell projects under contract in the Connecticut DPUC Project 150 process, since these are treated as renewable generation for Connecticut purposes.

Generic Additions

In order to reliably serve the forecasted load in the mid- to long-term portion of the forecast period, new generic additions will be added as needed to the model. These, generic additions will be comprised of a 50/50 mix of capacity from gas/oil fired 490 MW combined-cycle and 180 MW combustion turbines. No coal or nuclear units will be added.

Generic additions will be added to meet the New England Installed Capacity Requirement in conjunction with our analysis of the forward capacity market. New resources will be dispersed geographically based on a combination of zonal need and historical zonal capacity surplus/deficit patterns. Maine's surplus of capacity, low energy prices and export constraints will tend to suppress development of new generic capacity in that zone. The locational markets for energy and forward reserves will tend to provide incentives to build new generation in import-constrained zones, principally Connecticut.

2.3.2.6. Generic Generating Unit Operating Characteristics

Thermal Units

Market Analytics represents generation units in detail, in order to accurately simulate their operational characteristics and therefore project realistic hourly dispatch and prices. These characteristics include:

- Unit type (steam-cycle, combined-cycle, simple-cycle, cogeneration, etc.)
- Heat rate values and curve
- Seasonal capacity ratings (maximum and minimum)

- Variable operation and maintenance costs
- Forced and planned outage rates
- Minimum up and down times
- Quick start and spinning reserves capabilities
- Startup costs
- Ramp rates
- Emission rates (SO_2, NO_x, CO_2, and mercury)

The Market Analytics data is based on a variety of reliable public sources such as EIA reports and FERC filings, although some sources are proprietary.[43]

Exhibit 2-10: Characteristics of Market Analytics Generic Unit Additions

Characteristics	**NG CC**	**NG CT**
Typical Size (MW)	490	180
Heat Rate (Btu/kWh)	6,800	10,500
Variable O&M costs (2010 dollars per MWh)	$2.15	$3.75
Availability	90.4%	92.3%
NO_x (lb/MMBtu)	0.01	0.03
SO_2 (lb/MMBtu)	0	0
CO_2 (lb/MMBtu)	120	120

Notes
NG CC Natural Gas Combined Cycle
NG CT Natural Gas Combustion Turbine

Fuel Prices

Prices for electric generation fuels are detailed in Chapter 3 and Chapter 5.

Nuclear Units

There are four nuclear plants and five nuclear units in New England (Millstone 2 and 3, Pilgrim, Seabrook, and Vermont Yankee) with a combined summer capacity of 4,541 MW, representing approximately 15 percent of the total New England capacity.

[43] Specific details about the Market Analytics Model inputs can be requested and provided under appropriate confidentiality agreements.

Exhibit 2-11: New England Nuclear Unit Capacity and License Expirations

Unit	AESC Zone	Capacity (MW)[a]	License-Expiration Year[b]
Millstone 2	CT	876 [a]	2035 [b]
Millstone 3	CT	1,225 [a]	2045 [b]
Pilgrim	SEMA	677 [a]	2012 [b]
Seabrook	NH	1,247 [a]	2017 [b]
Vermont Yankee	VT	604 [a]	2012 [b]

[a]CELT 2011 Summer capability [b]U.S. Nuclear Regulatory Commission

Of the five operating nuclear units in New England, the Nuclear Regulatory Commission (NRC) has relicensed Millstone 2 and 3, along with 60 other reactors outside New England, without denying a single extension). Based on this track record and the lack of evidence that suggests that the NRC would deny the license renewals for any of these plants, we assume that all of the nuclear plants in New England will receive NRC licenses to operate for another 20 years, through the entire modeling period.

Seabrook filed a license-extension application in June 2010, which is nearly certain to be granted.

As discussed, the NRC recently granted Vermont Yankee a 20-year license extension, but the plant also requires state permission to operate past March 2012.

Pilgrim’s operating license expires in June 2012. Its design and vintage is very similar to that of Vermont Yankee and Fukushima Daiishi, and it is also located on the coast. Serious earthquakes along the Massachusetts coast are very rare, but not unknown. Pilgrim is thus among the US nuclear units most likely to be affected by increased safety requirements following the Fukushima disaster, either as part of an extended relicensing review or subsequently. Many such measures (hardening of spent-fuel pools and back-up power supply, transferring spent fuel to dry casks, building higher seawalls) would have little effect on Pilgrim’s power output. Nor are those measures likely to result in economic retirement of the plant. On the other hand, if the NRC were to require fundamental design changes in the Mark I reactors, Pilgrim would be likely to retire. The NRC has rarely required such major modifications to licensed reactors. We thus assume that Pilgrim will continue operating.

The licensed capacity of all five New England nuclear units has been increased, most recently by an, 80 MW increase in Millstone 3 capacity in 2010.

Conventional Hydro and Pumped Storage Unit Characteristics

The Market Analytics database will be used as the primary source all hydro unit information. Conventional reservoir and run-of-river hydro resources are considered a “fixed energy” station or contract in the model. Like thermal stations, these stations have a maximum and minimum generating capacity, but they also have a fixed amount of energy available within a specified time (i.e., a week or a month). Hydro stations operate generally on peak in a manner that levels the load shape served by other stations. Hydro stations are scheduled one at a time over the horizon of a week, subject to hourly constraints for minimum and maximum generation, and weekly constraints for ramp rates and total energy. Although the load shape they intend to level is the overall system load, a hydro station can be scheduled against the load of a specified transmission area or control area.

Pumped-storage type resources (with exchange contracts) have slightly different modeling requirements, typically involving a series of reservoirs used to release water for energy generation during peak load periods and pump water back uphill during off-peak times when energy demand and price is lower. The water (fuel) of pumped hydro generation is valued at the cost of pumping, allowing for net plant efficiency. Hourly reservoir levels are computed and a look-ahead is employed to prevent drawing the reservoir below the level where pumping space allows refilling to the desired level before the beginning of the next peak period.

2.3.2.7. Demand Resources

Demand resources will be included in the model consistent with the ISO-NE 2008 RSP and the FCA results (through FCA-4). These resources will be modeled as generating units that act as load reduction resources that are committed only if all other available generating resources are operating at full capacity and load is about to be lost. These resources do not set the marginal clearing price.

2.3.2.8. Emission allowance costs

The proposed inputs for emission allowances costs are summarized in Exhibit 2-3, above.

2.3.3. Model Calibration

Since a key objective of this study is the calculation of avoided electric energy costs, we took steps to ensure that the model is forecasting energy market prices accurately. The calibration approach we use is to compare the prices forecast by the model to electric energy historic and futures prices at the ISO-NE hub. The ability to make this comparison is complicated by the SOW requirement for the model to forecast prices assuming no continuation of energy-efficiency activities, i.e. no “new” reductions. The complication is that the electric-energy future prices will reflect the expectations of buyers and sellers in the actual market, who are likely assuming continuation if not escalation of existing efficiency programs.

Consequently, we model the current market situation with the energy efficiency resources that cleared in the 2010 forward capacity auctions. We then make appropriate model adjustments (e.g. bidding strategies, etc.) to reasonably match the electric-energy historic and futures prices at the ISO-NE hub over the three years (2010–2012).

2.4. Wholesale Electric Capacity Market Simulation Model and Inputs

2.4.1. Description of Forward Capacity Market Simulation Model

AESC 2011 uses a spreadsheet model to develop FCM auction prices for power-years from June 2014 onward. The major input assumptions regarding the forecasts of peak load and available capacity in each power-year are coordinated with, and consistent with, the input assumptions used in the Market Analytics energy market simulation model.

The major assumptions used to simulate the future operation of the FCM are listed below*:*

- The FCM remains as currently structured.
- Installed capacity requirements (including the Hydro Quebec capacity credits), estimated from the peak loads in the 2011 CELT and the required reserve margins (ICR ÷ peak load–1) in the 2010 RSP. Both are extrapolated through the analysis period. Growth in Maine requirements is met by some of the 427 MW of Maine capacity in excess of Maine’s requirements and export capability. Since the required reserve margin rises steadily over time in the 2010 RSP, we will extend that trend.
- Resources generally continue to bid FCM capacity in a manner similar to their bidding in FCA 4. Most existing resources continue to bid in as a “price-taker,” at or below the minimum FCM price. Units built by municipal utilities or under contract to the Connecticut utilities bid as price-takers.
- Generators facing large costs for maintenance, equipment replacement or environmental compliance will submit bids high enough to cover their costs. If the FCM price falls below that level, the generators will not clear in the FCA and will be free to shut down.
- In the event of a major drop in the New England capacity price, a large amount of capacity now imported to New England from Quebec and New York (including imports from Quebec through New York) could withdraw

from the New England market, and instead sell capacity into the markets in New York or PJM. Some domestic New England capacity could probably also delist to sell capacity out of the region, while continuing to be available to serve energy loads in New England. It is not clear how much more appealing other capacity markets will be. Capacity prices in upstate New York have been even lower than in New England. In 2010 and 2011, the capacity price averaged about $1.15/kW-month. These low prices may be the result of capacity additions to meet requirements in New York City (which increase total statewide capacity and reduce upstate prices), plus additions of renewables. The clearing price for capacity imports to PJM is even lower, at about $0.84/kW-month. Lower capacity prices would probably cause the providers of some of the existing demand-response resources that the capacity revenues are not worth the cost and inconvenience of reducing load, resulting in their delisting.

- FCA 4 cleared at the floor price with over 4,000 MW of excess capacity. However, ISO NE has classified 1,527 MW of the cleared capacity in FCA4 as being “out of market” (OOM), meaning that it could not be supported by market revenues alone. OOM resources are not allowed to set the market-clearing capacity price.
- Once the existing surplus no longer exists, due to retirements and load growth, FCM prices will be determined by the price of new peaking units under long-term contracts, net of a conservative estimate of energy profits and operating-reserve revenues. We assume that one or more states or utilities will intervene to ensure that new generation is built without waiting for the price becoming high enough to motivate merchant generators. Capacity will be added preferentially in the areas with the lowest reserves and the highest market prices, gradually equalizing reserves across the region. Connecticut is most likely to have energy and possibly FCM prices higher than average, and Maine is the zone most likely to energy and possibly effective FCM prices below average.
- Assumptions regarding FCM prices will be based upon the slope of the supply curve. We have detailed supply curves above $2.95/kW-month from the published results of FCA 4. Below $2.95/kW-month, we assume the average slope from the bottom of FCA 4 supply curve.

AESC 2011 uses these assumptions to estimate FCM prices for power years from June 2014 onward. We start with the capacity that cleared in FCA 4, adding the capacity and subtracting the retirements described in Section 2.2.2.3 above. The resulting capacity available to bid in each power is compared to the future ICR. In both retirements and load growth, we net Maine changes against the Maine-specific surplus.

2.4.2. Values for Input Assumptions to FCM Model

The underlying driver to the Forward Capacity Auctions is the Installed Capacity Requirement (ICR). The ICR is calculated by applying a percentage reserve requirement to the CELT peak load forecast. The owners of capacity entitlements on the Hydro Quebec Phase I/II interconnection (the New England utilities that pay for the HVDC transmission link) are price-takers, and the auction is actually for the remaining capacity need, the Net Installed Capacity Requirement (NICR). Holders of Hydro Quebec Interconnect Certificates (HQICC) receive the resulting auction price although they do not participate in the auction itself.

Our analysis is based on the ISO's projections of NICR through 2019/20 published in the 2010 Regional System Plan. We will project the ICR based on the trend in the ISO's forecasts of load and reserve requirements.

Based on the historical relationship between the price in each round of the auctions and the amount of capacity offered at that price, we estimate that, once the capacity price is no longer bound by the floor price in FCA7, the capacity price will rise by about $0.003/kW-month for each addition MW required above the resources that cleared in FCA 4.

2.5. External Costs Avoided

The calculation of avoided electricity costs incorporate some costs that that are not internalized, or reflected, in our projections of wholesale market prices for energy and capacity. We address the following components:

- Reliability contracts;
- Renewable Energy Credit (REC) purchases;
- Demand-reduction-induced price effects (DRIPE) in the wholesale energy and capacity markets; and
- Environmental externalities.

These avoided electricity-supply costs do not include several components of wholesale power costs that we consider to be largely or entirely unavoidable through Demand Side Management (DSM). These components include the locational forward reserve market, real-time operating reserves, automatic generation control (also called regulation), uplift, and the reliability contracts with particular generators.

2.5.1. Reliability Contracts

In the past, ISO-NE granted special reliability-must-run (RMR) contracts to a set of power plants. The ISO determined that these plants needed to continue to operate in order to ensure reliability, typically because of their unique location, but that they would not be economically viable based solely upon the revenues from then-current market prices. The prices in the RMR contracts covered the plants' variable production costs (e.g., operations and maintenance) as well as their fixed costs (mostly capital).

All of the RMR contracts have expired, the last of them on June 1 2010. A few units have received special reliability contracts in connection with transmission constraints in the FCAs:

- Norwalk Harbor 1 is covered by a contract at $1.75/kW-month above the market-clearing price of $4.50/kw-month in 2010/11. Lower loads and increased generation in Connecticut allowed the ISO to delist Norwalk Harbor 2, which had originally been offered a reliability contract, as well.
- Salem 3 and 4 will likely be paid $5.33/kW month in 2012/13 and $5.005/kW-month in 2013/14. In FCA4, the ISO found that 460 MW of Salem capacity was required for reliability; since Unit 4 is 437 MW, a load reduction of 23 MW (or a smaller amount, combined with other changes) could eliminate the need for Unit 3. The ISO also reported that the need for Salem had been reduced, between FCA 3 and FCA4, by an 82 MW reduction in load forecast for portions of the Boston area. (FCA results filing, August 30, 2010)
- Vermont Yankee will receive a reliability contract for 2013/14; the price may be as high as $3.933, but the price has not been reviewed by the ISO or FERC. Since Vermont Yankee is unlikely to be licensed to operate past March 2012, that contract is unlikely to have any effect.

It thus appears that some of the costs of reliability contracts have been avoidable. Accelerated energy efficiency in the NEMA area, along with distributed generation and transmission improvements, may avoid the cost of one of the Salem units in 2012–2014 and beyond. Additional reliability contracts may have been avoided by load reductions that have already occurred, or are reflected in the demand resources bid into the FCAs. Continuing reductions may avoid reliability contracts for other generators that may seek to delist in future years.

2.5.2. Other Wholesale-Load-Cost Components

In addition to the locational marginal energy prices and capacity prices, the ISO-NE monthly "Wholesale Load Cost Report" includes the following cost components:

- First-Contingency Net Commitment Period Compensation (NCPC),
- Second-Contingency NCPC,
- Regulation (automatic generator control),
- Forward Reserves,
- Real-Time Reserves,
- Inadvertent Energy,
- Marginal Loss Revenue Fund,
- Auction Revenue Rights revenues,
- ISO Tariff Schedule 2 Expenses,
- ISO Tariff Schedule 3 Expenses,
- NEPOOL Expenses.

These cost components are described in more detail in the Wholesale Load Cost Reports, available from the ISO's web site, www.isone.com.

None of these components vary clearly enough with the level of load to warrant inclusion in the avoided-cost computation. More specifically:

- The NCPC costs are compensation to generators that are comply with ISO instructions to warm up their boilers, ramp up to operating levels, remain available for dispatch, possibly generate some energy, and then shut down without earning enough energy- or reserve-market revenue to cover their bid costs. Older boiler plants may take many hours to reach full load and have minimum run-times and shut-down periods, requiring plants to continue running at minimum levels overnight. Smaller loads would tend to reduce the need for bringing these plants into warm reserve, thus reducing NCPC costs. On the other hand, lower energy prices would tend to increase the net compensation due to these units when they were required, since they would earn less when they actually operated. Hence, while energy efficiency may affect NCPC costs, the direction and magnitude of the effects are not clear.
- Regulation costs are associated with units that follow variations in load and supply in the range of seconds to a few minutes. Reduced load due to efficiency is likely to result in reduced variation in load (in megawatts per minute), reducing regulation costs. On the other hand, some controls may increase regulation costs, if end-use equipment responds more quickly to changing ambient conditions. Overall, energy efficiency programs will

probably reduce regulation costs, but we cannot estimate the magnitude of the effect.

- Forward and real-time reserve requirements should decrease slightly with energy efficiency, for two reasons. First, lower load will tend to leave more available capacity on transmission lines, which will tend to reduce the need for local reserves. (This factor could be important in the Connecticut Locational Forward Reserve Market, as well as in other areas in the real-time market.) Second, a portion of real-time reserves are priced to recover forgone energy for units that remain in reserve; lower energy prices will tend to depress reserve prices. We expect that these effects would be small and difficult to measure.
- Inadvertent Energy exchanges with other system operators (NY ISO, Hydro Quebec, and New Brunswick) are small and probably not affected by energy efficiency.
- The Marginal Loss Revenue Fund returns to load the difference between marginal losses included in locational energy prices and the average losses actually experienced over the pool transmission facilities. That fund is—by definition—generated by infra-marginal usage, and will not be affected by reduction of loads at the margin.
- Auction Revenue Right revenues are generated by the sale of Financial Transmission Rights (FTR), to return to load the value of transfers on the ISO transmission facilities. To the extent that efficiency programs reduce energy congestion, the value of these rights will tend to decrease.
- Expenses (ISO Tariff Schedules 2 and 3 and NEPOOL) are largely fixed for the pool as a whole, although a portion of the ISO tariffs are recovered on a per-MWh basis. Some of the ISO costs may decrease slightly as energy loads decline, if that leads to a reduction in the number of energy transactions, dispatch decisions, and other ISO actions required. Any such effect is likely to be small and slow of occur, and energy-efficiency programs add their own costs in load forecasting, resource-adequacy planning, and operation of the forward capacity market.

2.5.3. Cost of Compliance with Renewable Portfolio Standards

Five out of the six New England states have adopted renewable portfolio standards. See Chapter 6 and Appendix C for a detailed summary and description. In all RPS markets, LSEs demonstrate compliance through the acquisition and retirement of NEPOOL Generation Information System certificates, which are also more casually referred to as RECs. Some states have also implemented additional requirements that specific percentages of energy be provided by unconventional non-renewable or efficiency resources. Two examples of such alternative requirements are the Massachusetts Alternative Portfolio Standard (which includes combined heat and power, flywheel storage, coal gasification, and efficient steam technologies) and the Connecticut Class III RPS requirement (which includes CHP, conservation and load management, and waste heat or pressure recovery).

AESC 2011 assumes LSEs will comply fully with established RPS requirements each year – either by securing RECs or by making Alternative Compliance Payments. For ease of presentation, this discussion generally refers to all of these requirements as RPS requirements, which must be met with RECs, even though some of the resources are not renewable.

Our estimate of avoided costs includes an estimate of the REC costs that reduction in load will enable an LSE to avoid. Reduction in load due to DSM will reduce the RPS requirement of the LSE and therefore reduce the cost they incur to comply with that requirements. That RPS compliance cost is equal to the price of renewable energy in excess of market prices, i.e., the REC price, multiplied by the portion of retail load that a supplier must meet from renewable energy under the RPS. In other words,

Avoided RPS cost = REC price × RPS percentage

For example, in a year in which REC prices are at $30/MWh (or 3¢/kWh) and the RPS percentage was 10%, the avoided RPS cost to a retail customer would be $0.30 cents/kWh. We will calculate the RPS compliance costs that retail customers in each state avoid through reductions in their energy usage in each year for each major applicable RPS tier as follows:

$$(\text{REC Price}_n \times \text{RPS }\%_n)/(1-L)$$

Where:

n = the RPS tier

L = the load-weighted average loss rate from ISO wholesale load accounts to retail meters

We forecast annual REC prices for three major RPS tiers. These are new renewables (primarily Class I), all New Hampshire Class II solar, and all other renewables.

The major drivers of new renewable energy are the new-renewables RPS tiers. These include Class I in Massachusetts, Maine, Connecticut, and New Hampshire; the "New" RPS requirement in Rhode Island, and the expected Vermont RPS as assumed to be in place by 2013. For 2011 and 2012 we rely upon recent broker quotes to estimate the market prices at which RECs are transacted. REC markets in New England continue to suffer from a lack of depth, liquidity, and price visibility. Broker quotes for RECs represent the best visibility into the market's view of current spot prices. However, since RPS compliance must be substantiated annually, and actual REC transactions occur sporadically throughout the year, the actual weighted average annual price at which RECs are transacted will not necessarily correspond to the straight average of broker quotes over time. Broker quotes for RECs may span several months with few changes and no actual transactions (being represented by offers to buy or sell), and at other times may represent a significant volume of actual transactions. As a result, care should be taken to filter such data for reasonableness.

Exhibit 2-12 below provides the type of REC prices we will use to characterize the near-term REC market prices.[44]

Exhibit 2-12: Annual Average REC and APS Prices 2010, and January–March 2011 (Dollars per MWh)

		2010	2011
Conn.	Class I	$13.50	$13.50
	Class II	$0.50	$0.90
	Class III	$11.25	$10.00
Mass.	Class I	$15.00	$14.95
	Class II renewable	$23.75	$23.00
	Class II waste-energy	$4.00	$5.25
	Class APS	*$19.00*	*$19.00*
R.I.	New	$16.00	$15.25
	Existing	$0.75	$0.75
Maine	Class I	$7.75	$9.00
	Class II	$0.18	$0.18
N.H.	Class I	$13.50	$15.50
	Class II solar	*$25.00*	*$25.00*
	Class III	$21.50	$18.75
	Class IV	*Not Available*	$24.50
Data from confidential REC brokers quotations compiled by Sustainable Energy Advantage, LLC			

[44]This table was developed from a representative sampling of REC brokers quotes, which is comprised of both consummated transactions and bid-ask spreads in periods where transactions were not reported.

The AESC 2011 estimates of Class 1 REC prices in the longer-term (after 2012) are based on analysis of the near-term supply and demand balance, banking limits and observed practices, and the cost of entry of new renewable energy resources in each applicable year. That analysis relies on SEA's renewable energy supply curve model to determine the marginal (or market-clearing) resource in each year, through 2026. The supply curve takes various resource potential studies as inputs, calculated the cost of energy for each block and then stacks the supply resources from lowest to highest cost of energy – taking into account recent estimates of equipment, operating and financing costs. The intersection between supply and demand determines the marginal resource. REC prices are estimated based on the difference between the levelized cost for the marginal renewable resource and the resource's commodity market value based on our reference-case forecast of wholesale electric-energy-market prices. A more detailed explanation of the supply curve analysis is provided in Chapter 6.

We will forecast REC prices for the remaining two tiers as follows:

- For New Hampshire Class II (solar) REC prices are estimated at the lesser of (1) the alternative compliance payment rate and (2) the difference between a levelized cost of energy estimate for solar and our production-weighted reference-case forecast of wholesale electric-energy-market prices.
- For all other RPS tiers we will escalate recent broker-derived prices at inflation. The exception to this methodology will be for RPS classes focused on existing supply but for which such existing supply has not been certified by the applicable RPS authority in a quantity sufficient to meet demand. Near-term REC prices for such classes will be estimated based on current broker quotes and the applicable ACP. REC prices will be assumed to trend toward values which reflect a market in equilibrium or modest surplus over time, as existing generators become certified and participate in the program.

2.5.4. Demand Reduction Induced Price Effects – Methodology and Assumptions

AESC 2011 provides estimates of the effect of reductions in demand and energy from DSM programs on wholesale market prices for capacity and energy in Chapter 6. Our general approach is described below.

2.5.4.1. Wholesale Capacity Market Effects

AESC 2011 estimates capacity DRIPE using our estimates of capacity price in each FCA as a function of the ISO's net installed capacity requirements and available resources. From June 2016 onward, we assume that the FCM price will be set by the market, rather than ISO-NE setting floor prices. From that point onward, FCM prices will be determined by the prices at which generators choose to delist. (By delisting, generators in New England are able to sell into another market such as New York, or to shut down.) We use the model described above in Section 2.4.

Our analysis includes the phase-out of capacity DRIPE over time, in response to factors similar to those affecting energy DRIPE.

2.5.4.2. Wholesale Energy Market Effects

AESC 2011 estimates the magnitude of wholesale energy market DRIPE by year by conducting a set of regressions of historical zonal hourly market prices against zonal and regional load similar to the process conducted in AESC 2007 and AESC 2009.

We estimate the duration of energy DRIPE after estimating the magnitude. We estimate the phase-out of energy DRIPE based upon the assumption that the effect of reductions from efficiency programs on energy market prices will not last indefinitely. Instead, over time, customers will respond to lower energy prices by using somewhat more energy, the market will respond to sustained lower loads, for example by retiring existing generating capacity or delaying new supply and demand-response resources, and lower loads will tend to result in lower acquisition mandates under renewable and other alternative-energy standards.[45] While the shutdown of peaking units (gas turbines and older steam units) has little effect on market energy prices, the shutdown of coal plants or the delay in construction of new renewable or combined-cycle plants may have larger effects. We develop a phase-out of DRIPE effects consistent with the load-related retirements above in Section 2.2.2.

Our analysis of the phase-out of DRIPE effects is informed by a review of the literature on the effect of load reductions (or alternatively, load increases or addition of other resources) on market prices in competitive electricity markets is presented in Chapter 6.

Finally, in order to develop the energy DRIPE to be used in avoided costs we have phased in its impact based upon the portion of retail electricity power that reflects wholesale market prices at any point in time. This adjustment is required because the actual percentage of electricity supply being acquired at prices reflecting current wholesale market prices varies among the states, among the utilities within

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[45] Simple delisting of generators in the forward-capacity markets, such as to permit exports, does not directly change their operation in the energy markets.

some states, between municipal utilities and independently owned utilities (IOUs), and between customers on standard utility offer (standard service, default service, last-resort service, etc.) and those served by competitive suppliers.

2.5.4.3. Carbon Mitigation Value

Our approach to quantifying the reduction in physical emissions d**ue** to energy efficiency is as follows:

- Identify the marginal unit in each hour in each transmission area from our energy model;
- Draw the heat rates, fuel sources, and emission rates for NO_x andCO_2, of those marginal units from the database of input assumptions used in our Market Analytics simulation;
- Calculate the physical environmental benefits from energy efficiency and demand reductions by calculating the emissions of each of those marginal units in terms of lbs/MWh and lbs/kW. We multiply the quantity of fuel each marginal unit burned by the corresponding emission rate for each pollutant for that type of unit and fuel.

Our recommended dollar values to use for relevant avoided pollutant emissions are summarized in Exhibit 2-3.

Externalities are values that are not reflected in market prices. AESC 2011 identifies CO_2 as the key significant non-internalized environmental cost for evaluation of energy-efficiency programs. Other air pollutants from generators (NO_x, SO_2, particulates, mercury) have been and are being significantly reduced through direct regulation, and NO_x and SO_2 are subject to cap-and-trade regulations that charge generators for their remaining emissions. Other environmental effects, such as water discharges, are not clearly related to energy usage. AESC 2011 calculates these externalities based upon a "sustainability-target" approach as described in Chapter Six.

2.6. Wholesale Risk Premium

The retail price of electricity supply from a full-requirements fixed-price contract over a given period of time is generally greater than the sum of the wholesale market prices for energy, capacity, and ancillary-service in effect during that supply period.

This premium over wholesale prices, or *wholesale risk premium,* is attributable to various costs that retail electricity suppliers incur in addition to the cost of acquiring wholesale energy, capacity, and ancillary-service at wholesale market prices. These additional costs include costs incurred to mitigate cost risks associated with uncertainty in charges that will be borne by the supplier but whose unit prices cannot be definitely determined or hedged in advance. These cost risks include costs of hourly energy balancing, transitional capacity, ancillary services, and uplift.

The larger component of the risk is the difference between projected and actual energy requirements under the contract, driven by unpredictable variations in weather, economic activity, and/or customer migration. For example, during hot summers and cold winters load-serving entities (LSEs) may need to procure additional energy at shortage prices while in mild weather they may have excess supply under contract that they need to "dump" into the wholesale market at a loss. The same pattern holds in economic boom and bust cycles. In addition, the suppliers of power for utility standard-service offers run risks related to migration of customer load from utility service to competitive supply (presumably at times of low market prices, leaving the supplier to sell surplus into a weak market at a loss) and from competitive supply to the utility service (at times of high market prices, forcing the supplier to purchase additional power in a high-cost market).

AESC 2011 applies the same wholesale risk premium to avoided wholesale energy prices and to avoided wholesale capacity prices.[46]Estimates of the appropriate premium range from less than 8 percent to around 10 percent, based on analyses of confidential supplier bids, primarily in Massachusetts, Connecticut, and Maryland, to which the project team or sponsors have been privy. Short-term procurements (for six months or a year into the future) may have smaller risk adders than longer-term procurements (upwards to about three years, which appears to be the limit of suppliers' willingness to offer fixed prices). Utilities that require suppliers to maintain higher credit levels will tend to see the resulting costs incorporated into the adders in supplier bids.

In the absence of robust information on the retail premium implicit in the prices being bid for retail supply in New England we assume 9 premium as a default risk premium. The risk premium will be a separate input to the avoided-cost

[46]Capacity costs present a different risk profile than energy costs. With the advent of the Forward Capacity Market, suppliers have a good estimate of the capacity price three years in advance and of the capacity requirement for any given set of customers about one year in advance. (Reconfiguration auctions may affect on the capacity charges, but the change in average costs is likely to be small.) On the other hand, since suppliers generally charge a dollars-per-MWh rate, and energy sales are subject to variation, the supplier retains some risk of under-recovery of capacity costs. There is no way to determine the extent to which an observed risk premium in bundled prices reflects adders on energy, capacity, ancillary services, RPSs, and other factors. Given the uncertainty and variability in the overall risk premium, we do not believe that differentiating between energy and capacity premiums is warranted under this scope of work. We thus apply the retail premium uniformly to both energy and capacity values.

spreadsheet. Therefore, program administrators will be able to input whatever level of risk premium they feel best reflects their specific experience, circumstances, economic and financial conditions, or regulatory direction.

The details of the risks and costs of serving load are somewhat different for Vermont, Public Service of New Hampshire (PSNH), and various municipal utilities, where vertically-integrated utilities procure power from owned resources and a variety of long- and short-term contracts. For Vermont, we will include the 11.1 premium risk premium mandated by the Vermont Public Service Board. For PSNH and the municipal utilities, program administrators should use a risk premium less than the 9 premium default.

2.7. Reserve Margin Requirements

The New England ISO acquires sufficient capacity to ensure reliability in each power-year. In the FCM, the absolute cost of that capacity equals the required capacity, i.e. the installed capacity requirements (ICR), times the FCA auction price. The percentage by which the ICR exceeds the projected system peak is the reserve margin.

The assumptions regarding ISO-NE specified reserve margins for AESC 2011 are presented in Chapter 6.

2.8. Adjustment of Capacity Costs for Losses on ISO-Administered Pool Transmission Facilities

There is a loss of electricity between the generating unit and the ISO's delivery points, where power is delivered from the ISO-administered pool transmission facilities (PTF) to the distribution utility local transmission and distribution systems. Therefore, a one kilowatt load reduction at the ISO's delivery points, as a result of DSM on a given distribution network, reduces the quantity of electricity that a generator has to produce by one kilowatt plus the additional quantity it would have had to generate to compensate for losses.[47] The energy prices forecast by the Market Analytics model reflect these losses. However, the forecast of capacity costs from the FCM do not. Therefore, the forecast capacity costs should be adjusted for these losses.

[47] Computations of avoided costs sometimes assume that only average, and not marginal, losses are relevant at the peak hour. The reasoning for that approach is that changes in peak load will lead to changes in transmission and distribution investment, keeping average percentage losses approximately equal. The AESC 2007 avoided costs do not include any avoided PTF investments, so marginal losses are relevant in this situation.

The ISO does not appear to publish estimates of the losses on the ISO-administered transmission system at system peak. We estimated the marginal peak losses on the PFT system for each summer 2006–2008 by regressing the system losses against real-time demand for the top 100 summer hours. We computed losses as the difference between ISO-reported values for System Load, which it defines as the sum of generation and net interchange, minus pumping load, and Non-PTF Demand, the term that the ISO uses for the load delivered into the networks of distribution utilities. While PTF losses probably vary among zones, marginal losses by zone could not be identified using the available data.

While there was a large scatter in the data (probably due to plant availability, import availability, and the changing geographical mix of load), there was a clear upward trend in losses with load as shown in Exhibit 2-13 and Exhibit 2-14 below.

Exhibit 2-13: PTF Losses vs. Non-PTF Demand for the Top 100 Summer Hours, 2006

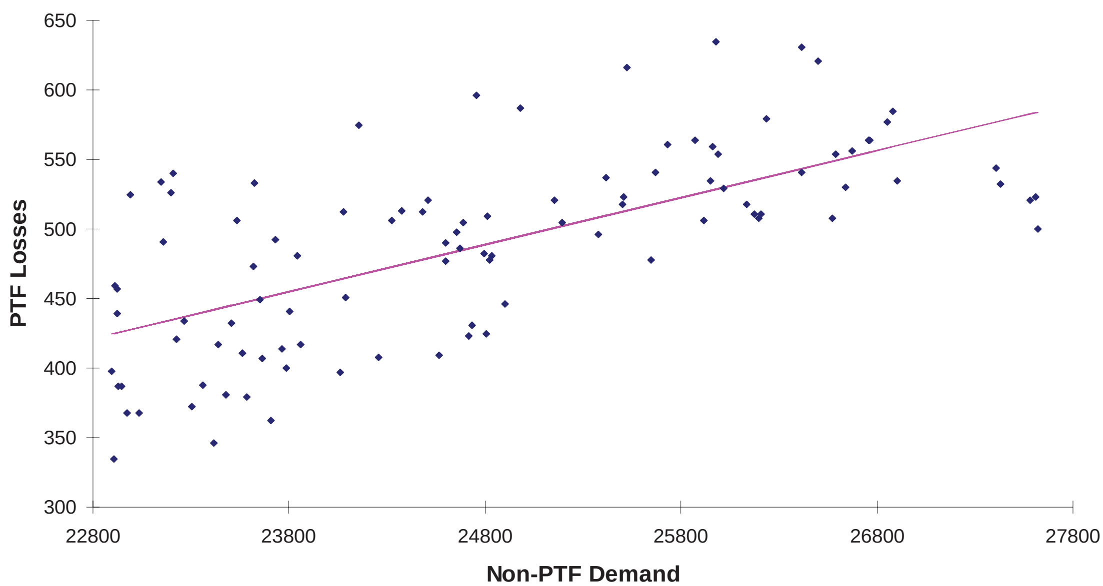
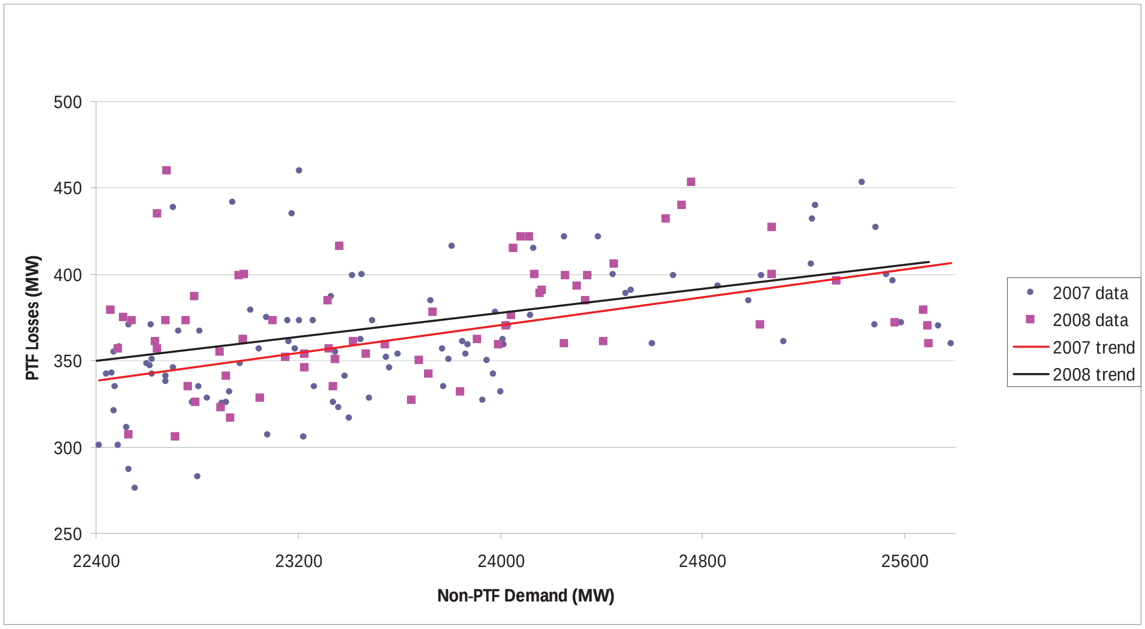


Exhibit 2-14: PTF Losses vs. Non-PTF Demand for the Top 100 Summer Hours, 2007 and 2008



The regression equations (with all variables in MW) were

2006: PTF Losses = 0.0338 × Non-PTF Demand–350.

2007: PTF Losses = 0.0201 × Non-PTF Demand–112

2008: PTF Losses = 0.0177 × Non-PTF Demand–57

The marginal demand loss coefficients were all highly significant, with t-statistics over 5.9.

It is not clear whether the downward shift over time of the data represent permanent changes in the transmission system, load and/or generation dispatch or temporary fluctuations in regional loads and/or dispatch due to weather patterns and the varying ratios of fuel prices.

AESC 2011 estimates the costs of avoiding capacity purchased from each FCA to be the FCA price adjusted by the estimated marginal demand loss factor of 1.9 percent. That factor is an average of the results for 2007 and 2008, which is the same as AESC 2009.

Chapter 3: Wholesale Natural Gas Prices

This Chapter describes the derivation of our projection of wholesale natural gas prices, in constant 2011$, for the New England region and each state over the forecast horizon of 2011 through 2030. It also provides a forecast of natural gas prices for electric generation. The forecast of New England wholesale natural gas prices is an input to the forecast of sector specific natural gas prices presented in Chapters 4 and 6.

The AESC 2011 Base Case price forecast is lower than the AESC 2009 Base Case forecast due to the significant changes in expectations regarding the cost of finding, developing and producing gas from shale gas resources and the quantity of shale gas production.[48] The AESC 2009 forecast was based on our estimate that the full-cycle cost of producing shale gas equated to a Henry Hub price ranging between $6.50 per MMBtu and $8.00 per MMBtu. Our updated estimate of the full-cycle cost of shale gas underlying the AESC 2011 Base Case forecast equates to a Henry Hub price of $5.50 per MMBtu. This updated estimate is based on a more detailed analysis of published data from seven major producers.

The AESC 2011 Base Case forecast is based upon New York Mercantile Exchange (“NYMEX”) gas futures prices for the years 2011 to 2014 and the AEO 2010 “High Shale Gas” case forecast for 2015 onward. The AESC 2011 Base Case forecast draws upon NYMEX futures as a reasonable estimate based on short-term market dynamics and the AEO 2010 High Shale case as a reasonable estimate based on long-term market fundamentals. The AEO 2010 High Shale case assumes shale gas unproved resources comparable in size to the AEO 2011 Reference Case and projects prices consistent with our estimate of the full-cycle, all-in cost of finding, developing and producing gas from shale resources.

The AESC 2011 High Price case and Low Price gas case forecasts reflect the considerable uncertainty regarding projections of shale gas production quantities and costs. As AEO 2011 notes, these projections are based upon limited experience with many shale gas formations. As a result the AEO 2011 Reference Case projections may overestimate the quantity of shale gas production or underestimate the future cost of shale gas production. Alternatively, technical advances may reduce production costs and currently untested shale gas formations could prove to be highly productive. In addition, concerns have been raised regarding the need for additional regulation of hydraulic fracturing in order to

[48] This Chapter refers to our forecast as the AESC Base Case rather than Reference Case to minimize confusion with the various AEO Reference cases to which we refer.

minimize its environmental impacts on groundwater, surface water, and air emissions. These concerns create uncertainty regarding the potential impact of future changes in regulation on shale gas production quantities and costs.

3.1. Overview of New England Gas Market

In order to place our forecast of wholesale natural gas prices for New England in context we begin with an overview of 1) natural gas demand in New England, 2) the physical supply of gas to the region, and 3) the "product" that is being purchased at wholesale commodity prices.

3.1.1. Demand for Wholesale Gas in New England

Natural gas accounts for approximately 24 percent of total New England energy consumption.[49] The market for wholesale gas in New England can be grouped into two distinct categories. First, natural gas purchased for direct use by, or on behalf of, very large end-users in the electric-generation, industrial, commercial, and institutional sectors. Second is gas purchased by local distribution companies (LDCs) for re-sale to retail customers in the residential, commercial, and industrial (RC&I) sector.

The annual quantity of natural gas purchased for direct use by very large end users, primarily for electric generation, has increased dramatically since the 1990s. That demand today accounts for roughly half of the annual gas consumption in New England. In its 2011 Annual Energy Outlook (AEO 2011) Reference Case, the Energy Information Administration (EIA) forecast annual gas use for electric generation in New England to grow by an average of 0.6% between 2011 and 2025, and by an average of 1.3% thereafter.[50]

The annual quantity of gas purchased by LDCs for resale to residential, commercial and industrial customers has remained relatively stable since the 1990s. In the Reference Case, annual gas use in this category is forecast to grow at about 0.9% per year between 2011 and 2025.

Actual and projected levels of annual natural gas use in these two categories are presented in Exhibit 3-1 below. (The projections are drawn from the AEO 2011 Reference Case.)

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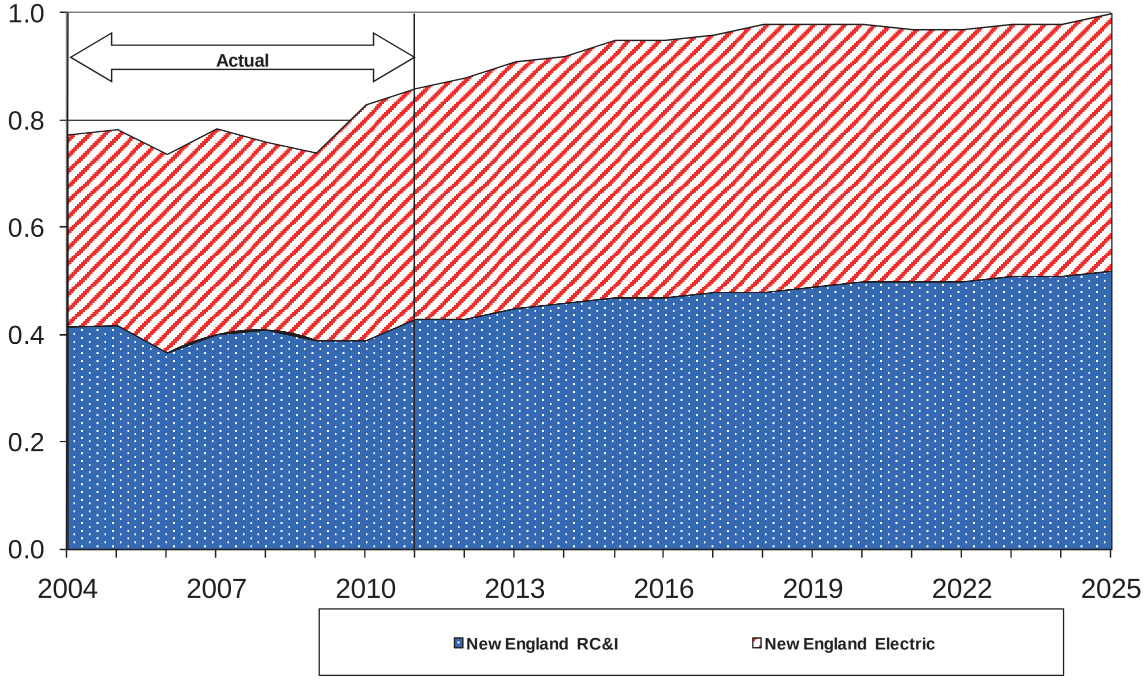
[49] 2008 energy consumption estimates by source in EIA State Energy Data System available at http://www.eia.doe.gov/emeu/states/hf.jsp?incfile=sep_sum/plain_html/sum_btu_eu.html.

[50] AEO 2011, Table 136

Exhibit 3-1: Annual Gas Use (Tcf) in New England Actual and AEO 2011 Reference Case projection

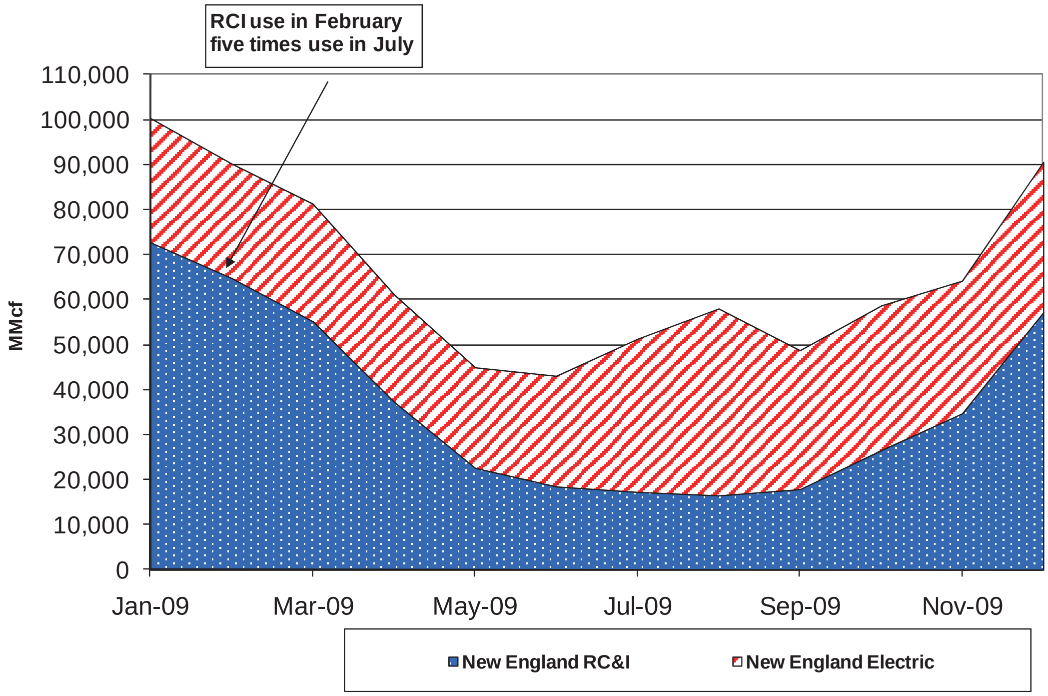


The demand for wholesale gas in New England in these two categories also varies substantially by season, and from month by month within each season.

The quantity of gas for direct use varies by month, with the greatest use occurring in summer months. In contrast, the greatest gas use by retail customers occurs in winter months since the dominant end-use is heating. As a result, LDCs have a much greater seasonal *swing* in gas load during the course of a year. For example, an LDC's gas load in January or February can be five times its load in July or August. Because of these large swings in gas load, LDCs acquire a portion of their winter requirements during the summer, store it in underground facilities outside of New England, and withdraw it during the winter when needed. In addition, LDCs use liquefied natural gas (LNG) and propane stored in New England to meet a portion of their peak requirements on the coldest days of the winter.

The variation in gas use by month in New England in 2009 is illustrated in Exhibit 3-2.

Exhibit 3-2: Monthly Gas Use in New England in 2009



3.1.2. Supply of Wholesale Gas in New England

The natural gas used in New England is acquired from producing regions elsewhere and delivered to the region via pipeline or by ship as LNG. Adequate delivery capacity from producing areas to New England is essential to the firm supply of natural gas to the region.

Most of the gas consumed in New England is delivered by pipeline from producing areas in Appalachia and the Southwest as well as from western Canada, Nova Scotia, and New Brunswick. LNG is delivered by ship from LNG-exporting countries, principally Trinidad and Tobago.

The physical system through which gas is delivered to New England, and within the region, excluding Vermont, currently comprises six interstate and intrastate pipelines and three LNG facilities.

Pipelines deliver gas directly to a number of electric generating units and very large customers, as well as indirectly through deliveries to LDCs who in turn distribute that gas to retail customers. Two pipelines, Tennessee Gas Pipeline and Algonquin Gas Pipeline, deliver the majority of gas to New England. The Tennessee Gas Pipeline delivers primarily into Massachusetts, New Hampshire and Maine while the Algonquin Gas Pipeline delivers primarily into Connecticut and Rhode Island. (Consistent with prior AESC reports this report refers a)

Massachusetts, New Hampshire and Maine as Northern and Central New England and b) Connecticut and Rhode Island as Southern New England.) Also, the Maritimes & Northeast and Portland Natural Gas pipelines deliver into Maine, Massachusetts, and New Hampshire. Those pipelines ultimately deliver into the Tennessee Gas system at the interconnection in Dracut, Massachusetts and into Algonquin via the Hubline project from Beverly to Weymouth, Massachusetts. The Iroquois Gas Pipeline delivers into Connecticut while Granite State Pipeline delivers gas in New Hampshire and Maine. The one LDC serving northern Vermont receives its gas from TransCanada Pipelines at Highgate Springs on the border with Canada.

LNG is delivered to three LNG facilities in New England and one in New Brunswick. The three LNG facilities in New England are Distrigas in Everett, Massachusetts, the Northeast Gateway facility offshore Cape Ann, Massachusetts and the Neptune LNG facility completed in 2010 off the coast of Gloucester. The Distrigas facility delivers gas into the Algonquin Gas Pipeline, the National Grid (formerly KeySpan) system, the Mystic Electric Generating Station, and sends LNG by truck to LDC storage tanks throughout the region. The Northeast Gateway and Neptune facilities deliver gas into the Algonquin Gas Pipeline via the Hubline. The Canaport LNG facility in Saint John, New Brunswick began operating in June 2009 and delivers gas into the Brunswick Pipeline which connects to the Maritimes and Northeast Pipeline.

A more extensive discussion of the New England gas industry and gas supply is published by the Northeast Gas Association (2010).

3.1.3. Prices for Purchases of Wholesale Commodity Supply in New England

The AESC 2011 forecast of commodity prices for wholesale supply in each New England state, and in the region in general, are for a monthly supply of gas expressed in dollars per million Btu ($/MMBtu). These are prices for one of the major "products" that is bought and sold in the wholesale market in New England. For example, one product is a one month supply of gas for delivery at one of the region's market hubs.[51] Another major product is a one day supply of gas for delivery at a market hub. The prices for these monthly and daily products are published in various gas industry publications.

The first and largest component of the forecast price for this product is a forecast of the monthly commodity price at the Henry Hub (HH), which is located in

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[51]The major market hubs in New England are Tennessee Gas Pipeline Zone 6, Algonquin Gas Pipeline City Gate, and Dracut.

Louisiana and is the most liquid trading hub in North America, as described in more detail below. The second component is an estimate of the *basis differential* between the wholesale price of natural gas at the Henry Hub and the wholesale price of natural gas at the relevant market hub in New England.

Thus, the forecast of wholesale natural-gas prices in New England in each month are estimates of the market value of a spot supply of gas at that location in that month. As such the wholesale commodity price in a given month does not necessarily reflect the actual long-term fixed costs that a seller would incur to ensure firm delivery of natural gas to New England every month of the year over a long-term planning horizon. This forecast will be a key input to the forecast of regional electric-energy-supply prices. Natural gas-fired plants base their daily bids into the wholesale electric energy market on the corresponding market value or opportunity cost of a one day supply of natural gas in New England for that day. Our forecast of wholesale gas prices by month is a reasonable proxy for those daily prices over time.

The forecast of monthly wholesale prices in New England is not be an input to the forecast of retail natural-gas prices for residential, commercial and industrial customers, which, as described in chapter 4, LDCs who serve customers in those categories purchase gas from major producing areas at prices tied to the Henry Hub price and assure firm delivery of that gas to their city-gate receipt points through long-term contracts for firm pipeline transportation service and underground storage service. [52] Some LDCs also acquire supply from local LNG facilities.

3.2. Gas Forecast Methodology

3.2.1. Henry Hub as a Starting Point

The forecast of wholesale commodity prices of gas in New England begins with a forecast of the price of gas at the Henry Hub. These prices are the most relevant starting point for forecasting US gas supply costs for several reasons.

First, the Henry Hub is located in the U.S. Gulf Coast area, which is the dominant producing region of the United States. As indicated in Exhibit 3-3, AEO 2011[53] projects production from the “Lower 48” will be the dominant source of physical gas supply to U.S. markets over the AESC 2011 study period. In 2010 that production accounted for about 87% of US supply with the remaining supply coming from imports via pipeline, primarily from Canada, and by ship as LNG.

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[52]A city-gate is a point at which a pipeline delivers gas into the system of an LDC.

[53] EIA Annual Energy Outlook 2011 published April 26, 2011. www.eia.gov/forecasts/aeo

AEO 2011 projects U.S. production to increase to approximately 93% of total national supply by 2020 due primarily to forecast increased production from shale gas. AEO 2011 projects a corresponding decline in pipeline imports from Canada, and little charge of LNG.

Exhibit 3-3: Sources of US Natural-gas Supply 2010 and 2020 (Trillion cubic feet)

Sources of Supply	**2010** (Actual)	**2020** (AEO 2011: Reference Case)
Shale gas production	**4.80**	**8.21**
Other categories of gas production	16.55	15.28
US Production, incl. Alaska & Supplemental	21.35	23.49
Imports via Pipeline	2.33	1.40
Imports via LNG	0.44	0.50
Total	24.12	25.39

Source: AEO 2011 (Tables 13 & 14).

Second, the market for wholesale natural gas is a North American market. The Henry Hub is the most liquid trading hub with the longest history of public trading of NYMEX gas futures contracts. The wholesale market prices of gas in various regions of the United States and Canada reflect Henry Hub prices with an adjustment for their location—generally referred to as a basis differential. A basis differential is the difference between the wholesale natural-gas price at a given market hub and the corresponding Henry Hub natural gas price.

3.2.2. Forecast Methodology

Consistent with the approach used to develop the gas price forecast in AESC 2007 and AESC 2009, the AESC 2011 Henry Hub gas price forecast is based upon data from two sources - futures prices from the New York Mercantile Exchange (NYMEX) for the near-term and a forecast from an appropriate Annual Energy Outlook forecast for the long-term. Using this methodology we developed a Base Case forecast of Henry Hub gas prices that is a “blend” of NYMEX and AEO projections. Specifically, it is NYMEX futures (as of March 18, 2011) through

2014 and prices projected in the AEO 2010 “High Shale Gas Resource” case of AEO 2010 from 2015 onward.[54]

This methodology is used by many forecasters, including various electric utility IRPs, and is consistent with reports by the National Regulatory Research Institute and Lawrence Berkeley Lab. It reflects the fact that futures prices are generally considered to provide the most accurate forecast of near-term Henry Hub natural gas prices while forecasts from a model that simulates market fundamentals of physical demand, physical supply and long-run marginal costs of supply provide a better estimate of long-term prices.

3.2.2.1. NYMEX Prices

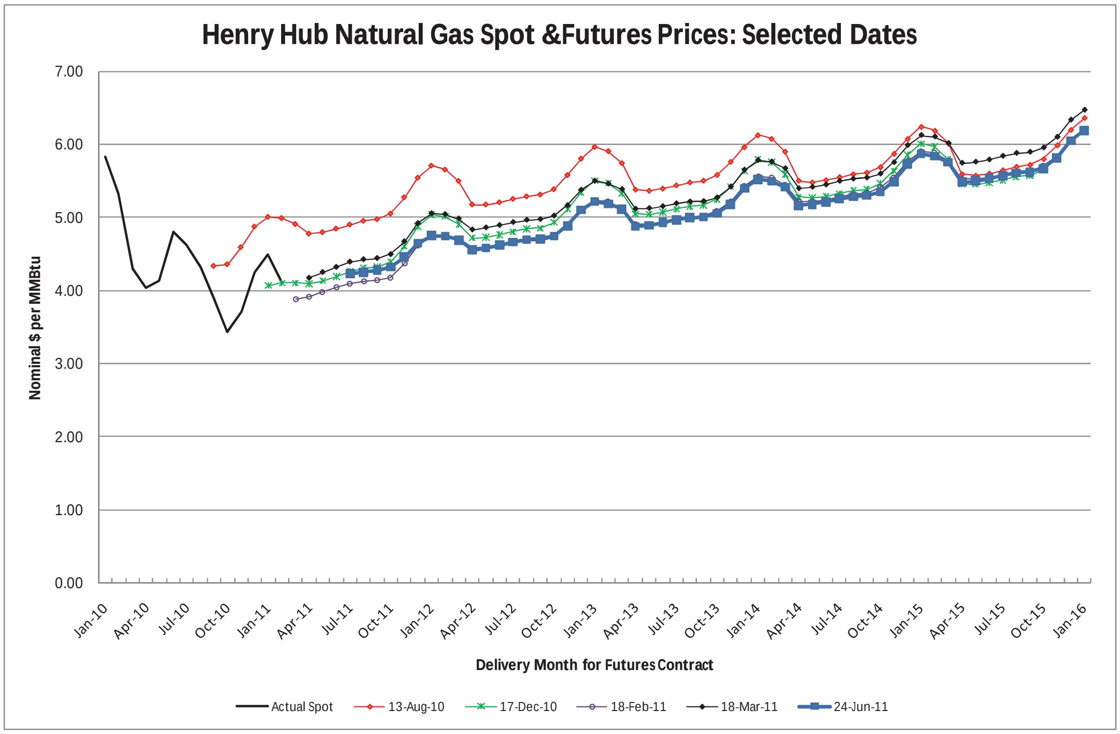
We rely on futures prices in the near term because they reflect the purchases of many buyers and the sales of many sellers. We limit our reliance upon futures prices to the near-term because NYMEX prices for outer years are not established through the transactions of many buyers and sellers.[55]

NYMEX futures have been quite consistent since August 2010 as shown in Exhibit 3-4.

[54] In order to develop consistent inputs for the AESC 2011 model and all analyses, the Project Team needed a single pricing date. The project team checked NYMEX futures as of June 24 to verify that the futures as of March 18 remained valid.

[55] A market is considered to be “liquid” if changes in demand for the product being bought and sold, or changes in the supply of that product, causes small changes in the price of the product. Markets with a high level of liquidity provide accurate prices because they have the characteristics of the textbook economics “perfect” market, i.e., multiple well-informed buyers, multiple well-informed sellers, ease of market exit and ease of market entry. Analyses routinely demonstrate that the liquidity of the Henry Hub Natural Gas Futures is very high for near term months, e.g. out 12 to 24 months, but is very low for months further out in the future.

Exhibit 3-4: Recent Futures Prices



3.2.2.2. AEO Forecasts

For the long-term we rely upon forecasts from an appropriate AEO case because the inputs and model algorithms underlying the AEO projections are public, transparent and incorporate the long-term feedback mechanisms of energy prices upon supply, demand, and competition among fuels. Our selection of which specific AEO forecast to rely upon was informed by our analysis of the full cycle cost of finding, developing and producing shale gas. We focused upon shale gas because, consistent with most analysts, we expect shale gas to be the dominant marginal source of supply, and market price setter, in the long-term.

3.3. Estimated Costs of Finding and Producing Natural Gas from Shale in North America

Shale gas refers to natural gas produced from shale formations. To extract gas from those formations, companies drill wells vertically down for 3,000 to 15,000 feet to the shale layer and then horizontally for 2,000 to 5,000 feet through the shale layer. The well is often cased with pipe cemented in place and the shale rock near the horizontal well bore is fractured. To fracture the shale rock, water is injected under high pressure which opens cracks in the shale and sand mixed with the water moves into the cracks to hold them open when the pressure is removed.

Natural gas from the shale layer then flows through these cracks into and up the well.

In 2009 we identified shale gas as an important and growing source of gas supply in the U.S. which had become the marginal source of natural gas and thus would set the price of natural gas at the Henry Hub. Since 2009 exploration for and production of gas from U.S. and more recently Canadian shale has grown faster than expected in 2009. The result has been a rapid expansion of gas production, which combined with the recession of 2008, has resulted in ample supply and dramatic decreases in the annual average price of natural gas. For example, the annual average Henry Hub price dropped from $8.86 per MMBtu in 2008 to $3.94 in 2009 and then rose slightly to $4.37 in 2010.[56]

The dramatic change in expectations for shale gas production is reflected in the AEO 2011 Reference Case projection of 8.21 Tcf from shale in 2020 compared with a projection of 2.7 Tcf from shale in 2020 according to the AEO 2009 Update.[57] Thus, shale gas has assumed an even more important role in setting the price of natural gas in the U.S. There has been very rapid leasing of shale gas producing areas and a rapid rise in drilling these leases with horizontal drilling since early to mid-2009. This rise in drilling occurred even as gas prices averaged $3.94 per MMBtu in 2009 and seldom rose above $5.00 per MMBtu at the Henry Hub.

AESC 2011 projects that, as the marginal source of natural gas, the costs of finding, developing and producing shale gas should set the long-run price of natural gas. This projection is based upon our assumption that, in the long run, companies will not spend money to find and produce shale gas unless they expect the revenues from the sale of that gas to cover their costs plus provide an acceptable rate of return on invested capital. Thus we compute the full-cycle cost of shale gas, including a rate of return.

Because independent producers have concentrated so much on exploiting shale gas, we can examine their SEC Form 10-K data to estimate their full-cycle costs of shale gas.[58] In order to develop an estimate of the "full-cycle" costs of exploiting

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[56]Henry Hub spot price from EIA website in nominal dollars. Supplied by Thompson Reuters.

[57] AEO 2009 Update and AEO 2011 early release Table 17: Oil and Gas Supply.

[58] The large international, integrated producers such as Exxon-Mobil, Chevron, and BP have until recently been absent from developing the shale gas resource. However in 2008, BP purchased all of the Woodford Shale interests and then 25% of the Fayetteville shale interests of Chesapeake Energy. In 2010, Exxon-Mobil purchased all of XTO Energy. Chevron purchased Atlas Energy with large holdings in the

U.S. shale gas we obtained and analyzed data reported for 2010 in 10-K filings and other sources by seven major companies active in shale gas development - Cabot Oil and Gas (COG), Chesapeake Energy (CHK), Comstock Resources (CRK), Devon Energy (DVN), EOG Resources (EOG), Range Resources (RRC) and Southwestern Energy (SWN). Highlights from our analysis of that data are reported in exhibit 3-5.

Three of the companies, Chesapeake, Devon and EOG; are very large producers (Chesapeake is the second largest gas producer in the U.S. behind Exxon). Two concentrate in specific and apparently low-cost shale areas: Cabot in the Marcellus shale and Southwestern in the Fayetteville shale. Comstock and Range Resources are small but representative producers. A list which ranks shale producers by their costs show these seven to be among the 17 lowest finding-and-operating cost producers among the 54 listed.[59]

Marcellus shale in early 2011. BHP Billiton agreed to buy all of Chesapeake Energy's remaining interests in the Fayetteville shale during 2011.

[59] Comstock Resources, March 2011 Presentation, page 26. Operating costs based on data from the first 3 quarters of 2010 and finding costs based on 2009 data.

Exhibit 3-5: Natural Gas Wellhead Prices Implied by Estimated Full-Cycle Costs of Selected Oil & Gas Companies (2010 Data)

Company Stock Symbol	Units	Cabot O & G COG	Chesapeake CHK	Comstock CRK	Devon DVN	EOG Resources EOG	Range RRC	Southwestern SWN	Average Price excl SWN
I. Company Characterization									
Production in 2010									
Natural Gas	Bcf	125.5	924.9	70.0	930.0	633.4	142.0	403.6	
Crude Oil and NGLs	million bbls	0.8	18.4	0.7	73.0	38.4	6.5	0.2	
Total Revenues	million $	$844.0	$9,366.0	$349.1	$9,940.0	$6,099.9	$1,039.0	$2,610.7	
Net Profit in 2010	million $	$103.4	$1,774.0	($19.6)	$2,333.0	$160.7	($239.3)	$603.8	
II. Reserve and Cost Data					(c)				
Additions to O&G Proved Reserves (a)	Bcfe (b)	650.6	5,098.0	430.6	2,124.0	2,375.9	1,410.4	1,431.1	
Proved Developed (PD)	Bcfe	258.8	1,888.0	174.4	1,254.0	846	261.1	697.9	
Proved Undeveloped (PUD)	Bcfe	391.8	3,210.0	256.2	870.0	1,530.0	1,149.3	733.2	
Estimated Finding and Developing (F & D) Costs									
a For Proved Developed (PD) Reserves	$/Mcfe	1.74	2.43	2.44	2.35	2.25	2.60	1.60	
b To Convert PUDs to PD	$/Mcfe	0.85	1.35	1.34	1.70	1.81	1.00	1.47	
c Weighted Average of a & b	$/Mcfe	$1.29	$1.89	$1.89	$2.03	$2.03	$1.80	$1.54	
Estimated Cash Expenses									
Production	$/Mcfe	0.70	1.00	1.10	1.28	0.83	0.75	0.90	
Production Taxes	$/Mcfe	0.35	0.27	0.20	0.29	0.37	0.17	0.11	
G & A	$/Mcfe	0.60	0.37	0.35	0.43	0.33	0.60	0.34	
Interest	$/Mcfe	0.50	0.80	0.40	0.20	0.15	0.70	0.14	
Sub-total	$/Mcfe	$2.15	$2.44	$2.05	$2.20	$1.68	$2.22	$1.49	
III. Estimate of Required Natural Gas prices									
Required Wellhead Price @ 20% IRR	$/Mcfe	**$5.31**	**$5.16**	**$4.63**	**$5.12**	**$4.61**	**$4.82**	**$3.70**	$4.94
Basis to Henry Hub (d)	$/Mcf	na	$ 1.00	na	10%	na	$ 0.68	$ 0.47	$ 0.76
Estimated Henry Hub price	$/Mcf		$6.16		$5.69		$5.50	$4.17	$5.70
At 1.03 MMBtu/Mcf	$/MMBtu		$5.98		$5.52		$5.34	$4.05	$5.54

Data Source: Analyses of SEC Form 10Ks for 2010 and various company presentations and publications.
(a) Excludes revisions to reserves. 1 barrel of oil equals 6 Mcf of gas.
(b) Bcfe is Billion of cubic feet equivalent in which 1 barrel (bbl) of oil = 6 Mcf.
(c) Net earnings from continuing operations; excludes earnings from discontinued operations.
(d) In AEO 2010 the difference between the wellhed price and the Henry Hub spot price is approximtely $0.74 per MMBtu or $0.76 per Mcf.

3.3.1.1. Reserve and Cost Data

We begin our analysis of the full-cycle cost of shale gas by examining two sets of costs (1) finding and developing (F & D) costs and (2) production costs. The first set is the cost of finding and developing a unit of proved reserves, which is expressed as $ per Mcf[60] of proved reserves that is underground. The second set is the production cost, which represents the cost of bringing the gas from the underground reservoir to the wellhead at the surface. Beyond the wellhead there are additional costs to gather the gas from various wellheads, process the gas to bring it to pipeline quality and transport the gas to a high-pressure transmission pipeline. Our estimates of these two sets of costs for seven companies are presented in section II of Exhibit 3-6.

Estimates of Finding and Developing ("F&D") Costs

Companies incur finding and development costs for the following activities: 1) geological and geophysical surveys, 2) purchase of leases giving the right to the producer to look for and produce oil and gas under specific landholdings, and 3) drilling and completion of wells.

In addition to the direct costs for those three activities, companies incur indirect costs such as general and administrative (G & A) costs associated with F & D activities and interest costs, such as those to finance the purchase of leases, which also are directly attributable to the F & D stage. Analysts divide those direct and indirect costs by the proved reserves found in the F&D stage to obtain the unit F&D cost per Mcf of finding and developing proved reserves.

Our estimates of unit F&D costs, shown in Exhibit 3-5, distinguish between the unit F&D cost of adding new "proved developed" reserves (PD) and the unit F&D costs of converting "proved undeveloped" reserves (PUD) into PD reserves. We make this distinction because of the difference between PD and PUD reserves. Proved developed reserves refer to gas in the underground reservoir that can be produced by existing wells and associated surface equipment. Proved undeveloped reserves refer to gas which the relevant company believes to be in the underground reservoir that can be produced when new wells are drilled and completed and new surface equipment is installed. Not surprisingly, the costs of finding new PD reserves are higher than converting PUDs to PD reserves. Finding new reserves includes geological and geophysical costs, the cost of lease acquisition and the costs of exploration that fails.

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60 An Mcf is one thousand cubic feet of gas at standard conditions, which contains about 1.03 million Btu of heat content.

Our estimates of total unit F & D costs are shown in the Reserve and Cost Data section of Exhibit 3-5 at line c. These totals reflect the fact that companies incur a blend of F & D costs to add PD reserves and to convert PUD reserves to PD. Our total uses a 50-50 weighting based on judgment and the approximate quantities of each category of reserves reported for 2010.

Our estimates of total unit F&D costs tend to be higher than the total F&D costs generally reported in company presentations because those presentations generally do not make this distinction between PD and PUD reserves. Instead, the presentations typically report total unit F & D costs equal to total absolute F&D costs in a year divided by the total of proved reserves, PD and PUDs found in that year. As can be seen in the Reserve and Cost Data section of Exhibit 3-5, with the exception of Devon, each of the companies reported a higher quantity of PUD reserves in 2010 than PD reserves. We believe that estimates of total unit F & D costs that do not distinguish between unit F&D costs of PD reserves and unit F&D costs of PUD reserves understate actual F&D costs. The Companies will need to drill and complete new wells, and install new surface equipment, before PUDs reserves can produce gas.

Drawing distinctions between proved developed and proved undeveloped reserves is especially important when using 10-K data from the 2010 reports. The SEC altered and relaxed its definitions of proved developed and, more importantly, of proved undeveloped reserves, effective January 1, 2010.[61] One important change is to allow PUDs to include reserves more than one offset well away from a producing well. Another change very useful to estimating F & D costs in 2010 is the SEC requirement that producers disclose changes in PUDs from year to year, including both the amount of reserves changed from PUD to PD and the cost of the associated wells. The net result of the rule changes is not clear but it may have increased PUDs.[62]

Estimates of Production Costs

The costs to produce gas are the cash expenses that are incurred. They include what we label production costs, which are also called lease operating expenses (LOE). This category includes costs for the maintenance and operation of lease equipment, recording of measurements, labor costs, workovers, property taxes, insurance, etc. In addition, there are production taxes, also called severance taxes,

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61 Ryder Scott Petroleum Engineers, Reservoir Solutions, A Quarterly Newsletter, Vol. 12, No. 1 (March – May 2009)

62 Ryder Scott, Vol. 13, No. 1 (March-May 2010)

the G & A expenses of the company, and interest costs. The total is the cash expenses of production.

One issue that must be discussed is royalty. When a landowner sells a lease to a producer he keeps a royalty interest (RI) in the production from the property, which is generally 15 – 25 percent in the shale gas areas. The producer has a working interest (WI) in the production which is the remaining interest in the production. The owner of the RI receives cash from the sale of production, which is generally based on the value at the wellhead. The RI bears no cost for finding, development or production, but does generally pay its share of production taxes. The producer pays all the cost of finding, development and production.

The cost of royalty is very high to the producer, but it is not represented in Exhibit 3-5. Oil and gas accounting in the United States, as prescribed by the SEC for its Form 10-K, specifies that both reserve quantities and production quantities be specified on a net interest basis.[63] Thus, the reserves and production for a producing company do not include reserves or production quantities related to the royalty owner’s interest or to the working interest of others. Similarly, revenues received by a producer reflect only its interest in the sale of production; the money received by the royalty owner is excluded from the producer’s reporting of revenue. The costs of finding, developing and producing are applied only to the producer’s working interest volumes. Thus 100% percent of these costs are applied to the 75-85% of reserves and production owned by the producer. The cost of royalty is taken care of by the way the accounting is specified, and is not explicitly represented here in our calculation of the full-cycle costs of gas. Rather, the costs of royalty are implicitly represented by the accounting definitions of reserves, production and the associated costs.

3.3.1.2. Required Well-Head and Henry Hub prices Required to Recover Full-Cycle Costs

Since there is a lag in time between investment in finding and developing shale gas reserves and the revenue that comes from producing and selling the gas from those reserves, the standard approach to estimate the price needed to cover full-cycle costs is to use a present value model representing the cash flow of the business. Cash inflow is the revenue generated by the sale of gas. Cash outflow is the initial investment, the cash expenses of production and annual payment of income taxes. Then a price is found that applied over the period of the model produces a target internal rate of return on the cash flow.

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[63] Charlotte J. Wright & Rebecca A. Gallun, <u>Fundamentals of Oil & Gas Accounting</u>, 5th Edition, PennWell (2008), pages 619, 625 and 627.

Our present value model has the following assumptions:

1. Ten year life with all investment and initial gas production in the first year.
2. The present value calculation is from mid-year.
3. A target internal rate of return of 20 percent per year is used.
4. Investment is the finding and development costs shown in Exhibit 3-5. In the first year 70 percent is expensed and 30 percent is depreciated over eight years, including one-half first year, according to an IRS prescribed MACRS 200 percent double declining balance method.
5. Gas production starts at the middle of the first year and declines at an exponential rate of 60 percent per year for the first four years and from years 5 through 10 is 5 percent of the initial production.
6. The cash expenses as shown in Exhibit 3-5 are based on production each year.
7. Income tax is 39 percent to represent both federal and state income taxes.
8. A wellhead price for the gas is found that produces a zero net present value.

The results are shown in the bottom portion of Exhibit 3-5 in the "Required Wellhead Price" line. Not surprisingly, the required wellhead price to cover full-cycle costs varies from company to company. However, with the exception of Southwestern Energy, there is a relatively small ($0.60 per Mcf) difference between the required wellhead prices of the other six producers. Excluding the Southwestern Energy price, the average wellhead price is $4.94 per Mcf

But the wellhead price is not the price of gas at the Henry Hub. After gas leaves the wellhead any heavy liquids, such as condensate, are removed. The remaining gas is then piped in a gathering pipeline system to a processing plant where lighter natural gas liquids (NGLs) such as propane, butane and sometimes ethane are removed. The NGLs have more value per Btu than does the pipeline quality gas, but the cost for gathering the gas and removing the liquids must be paid. After processing the gas is piped to a high pressure pipeline, which incurs costs of the transportation and perhaps costs of compression. According to the AEO 2010 the average difference in price between the wellhead and the Henry Hub is $ 0.74 per MMBtu or $ 0.76 per Mcf at 1.03 MMBtu per Mcf converted to 2011$. Thus, using the full-cycle costs we estimate the price of gas at the Henry Hub is $5.70 per Mcf or $5.54 per MMBtu.

This full-cycle cost based price is significantly higher than the Henry Hub spot price on March 18, 2011 of $3.94 per MMBtu or even than the Henry Hub futures 12 month strip price on March 18, 2011 of $4.59 per MMBtu.

One check on this full-cycle cost estimate is to compare it to what gas industry leaders are saying. Mr. Aubrey McClendon, CEO of Chesapeake Energy, said, "We estimate the marginal cost of gas supply in the US is around $5.50 per Mcf."[64] He did not say whether this was at the wellhead or at the Henry Hub. Mr. Jeff Ventura, COO Range Resources, and Mr. Larry Nichols, CEO Devon Energy, "…agreed that a wellhead price of $5 - 7/Mcf at the oil field service operating costs of about a year ago should be sufficient for a 20% rate of return in most US basins (of unconventional oil and gas plays) due to the size of the unconventional resource, but they did not speculate on when the gas price might rise to that range."[65] Mr. George Kirkland, head of E & P for Chevron Corp. said gas prices "in the $6s and $7s are needed over the long term to cover unconventional resource investment costs." referring to U.S. shale plays.[66]

But for U.S. natural gas prices to rise from the levels of the last two years the supply-demand balance must shift to greater demand and/or less supply. There is some indication that the supply of natural gas from the U.S. may decline. The independent producers, particularly the large ones such as Chesapeake, Devon and EOG Resources, all plan to shift exploration and drilling to U.S. places where production will be liquids rich either for crude oil and condensate or at least larger volume NGL production associated with natural gas production. They plan to reduce drilling for dry gas. This shift appears to be under way. According to the weekly active drilling rig report from Baker-Hughes, rigs drilling for natural gas in the U.S. peaked in August 2010 at 983 rigs and for the four weeks ending March 18, 2011 the average number of rigs drilling for gas had dropped to 891. For the four weeks ending May 13, 2011 the number of rigs drilling for gas was 881.

3.4. Review of AEO 2011 and AEO 2010 Forecasts

The next step in developing a forecast of annual Henry Hub natural-gas prices is to review the forecasts available from AEO 2011 and AEO 2010 to determine which forecast is most consistent with our estimate of the Henry Hub price needed to cover the full-cost of shale gas.

Exhibit 3-6 below shows, in 2011$, the AEO 2009 Update Reference case forecast, the AEO 2010 Reference Case forecast, the AEO 2010 High Shale case forecast and the AEO 2011 Reference Case forecast. It also plots the NYMEX futures price settlements on March 18, 2011. The AEO 2011 ER Reference case forecast seemed particularly low, not reaching the $5.50 Henry Hub price we estimate as need to recover full cycle shale gas costs until 2022.

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64 Chesapeake Energy, 4th quarter earnings conference call, February 23, 2011.

65 Oil and Gas journal, "Industry Climbs unconventional learning curves", October 11, 2010, page 27.

66 NGI Shale Daily, "Chevron's U.S. Shale Plays to 'Generate Opportunities,' says E&P Chief", March 21, 2011; page 2.

Exhibit 3-6: Comparison of EIA Henry Hub Natural Gas Price Forecasts & NYMEX Futures as of March 18, 2011 (2011$ per MMBtu)

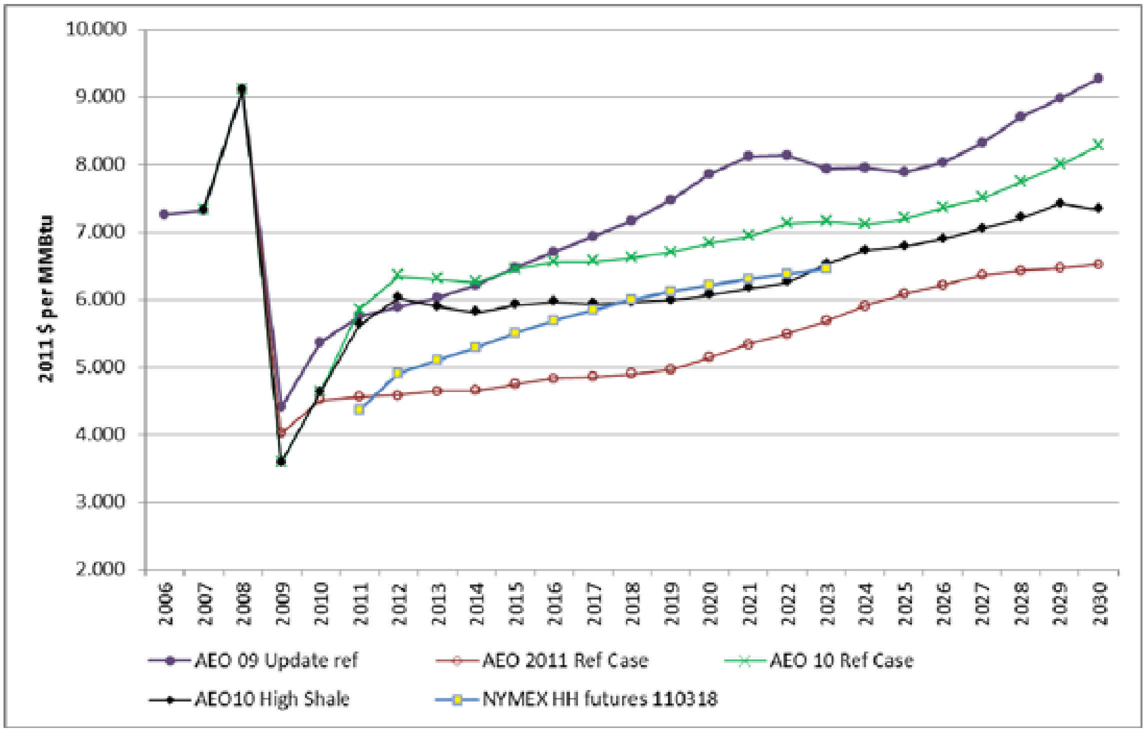


Exhibit 3-7 reviews actual values for 2010 and projections for 2020 for several key parameters including gas production and gas prices. The projections are from the AEO 2009 Reference case (the basis for AESC 2009 Base Case), the AEO 2010 Reference Case, the AEO 2010 High Shale case basis for AESC 2011 Base Case) and the AEO 2011 Release Reference Case. The values for GDP, total electricity production and crude prices are very similar. The major differences are in the Henry Hub price and shale gas production. These differences reflect the very different assumptions about the size of the shale gas resource (Unproved Shale Gas Resource) among the various cases as of the time those case forecasts were prepared:

- 267 Tcf in the AEO 2009 Reference Case;
- 347 Tcf in the AEO 2010 Reference Case and Slow Oil & Gas Technology Case;
- 652 Tcf in the AEO 2010 High Shale Case; and
- 827 Tcf in the AEO 2011 Reference Case.

Exhibit 3-7: Comparison of results of AEO 2011 Reference Case, AEO 2010 High Shale, AEO 2010 Reference Case, and AEO 2009 Reference Case

			Forecast for Year 2020			
	units	Actual 2010	AEO 2011 Reference	AEO 2010 High Shale	AEO 2010 Reference	AEO 2009 Reference (g)
Supply of Natural Gas						
U.S. Dry Gas Production	Tcf/year	21.57	23.49	21.50	19.98	21.42
Shale Gas Production (e)	Tcf/year	4.87	8.21	7.35	4.51	2.97
Net Imports of Natural Gas	Tcf/year	2.56	1.90	2.14	2.51	1.86
LNG	Tcf/year	0.43	0.50	1.41	1.50	1.36
Total	Tcf/year	24.20	25.39	23.70	22.61	23.34
Unproved Lower 48 Gas Resources (j)	Tcf		na	na	1,586	1,367
Unproved Shale Gas Resources (j)	Tcf		827	652	347	267
Completion of Alaskan Gas Pipeline	year		post 2035	2030	2023	2020
Consumption of Natural Gas						
Total	Tcf/year	24.13	25.34	23.72	22.63	23.46
In Electric Power Generation (c)	Tcf/year	7.38	6.84	6.41	5.66	6.54
Total U.S. Energy Consumption (e)	Quads/year	97.7	104.9	105.3	105.0	105.4
Prices of Energy						
Natural Gas at the Henry Hub	$/MMBtu (b)	4.41	5.14	6.06	6.83	7.80
Imported Low S Light Crude Oil	$/bbl (b)	(f) 76.56	110.11	101.44	100.87	121.27
Net Generation of Electricity by Fuel Type (d)		(h)				
Total	billion Kwh	4,120	4,453	4,559	4,525	4,618
Coal	billion Kwh	1,851	1,907	2,046	2,093	2,156
Natural Gas	billion Kwh	982	1,002	876	767	898
Nuclear Power	billion Kwh	807	877	883	883	862
Renewables, Incl hydro	billion Kwh	425	608	683	713	617
Macroeconomic Indicators		**Year 2009**				
Real Gross Domestic Product	billion 2005 $	12,881	17,421			
Real Gross Domestic Product	billion 2000$			15,440	15,416	15,876
Total Energy Intensity (i)	Mbtu/2005 $	7.35	6.02			
Total Energy Intensity	Mbtu/2000$			6.82	6.81	6.79

(a) Sources: EIA Annual Energy Outlook 2009, 2010 and 2011.
(b) Prices in 2011 $, except macroeconomic indicators.
(c) Includes gas consumption in plants that sell to the public but not the end-use that geneates heat and electricity.
(d) Includes generation in utiities, plants producing heat and power for sale and end-use production of heat and power.
(e) Source for shale gas production in 2010: EIA Annual Energy Outlook 2011 early release table 14.
(f) Source for 2010: EIA Petroleum Marketing Monthly, March 2011, Table 1 Refiners cost of imported crude oil.
(g) The AEO 2009 HH price projection was adopted as the AESC 2009 Henry Hub base case price forecast for years after 2011.
(h) Source for 2010: EIA Electric Power Monthly, March 2011
(i) Total energy intensity is thousands of Btu per dollar of real GDP, which is valued at a specified real $.
(j) Estimate as of date of forecast preparation

Based upon our review of those cases we chose the AEO 2010 High Shale case as the source of our long-term forecast of Henry Hub prices.

- The AEO 2010 High Shale case is based upon an estimate of shale gas resources consistent with AEO 2011 Reference Case, as shown in Exhibit 3-7.
- The AEO 2010 High Shale case projection of Henry Hub prices is consistent with our estimates of the full-cycle costs of shale gas as shown in Exhibit 3-6. In contrast, as noted, the AEO 2011 Reference case forecast seemed particularly low relative to the full-cycle cost.
- Documentation for the AEO 2010 High Shale case was available in February and March 2011, when we were preparing our initial projections. However, our review of the full AEO 2011 documentation, which became available in late April 2011, supports our decisions to rely on the AEO 2010 High Shale Case. The estimate of the marginal cost of shale gas implicit in the various AEO 2011 cases are significantly less that our estimate of the full-cycle, all-in cost of finding, developing and producing shale gas.

3.5. Forecast of Annual Natural Gas Prices at the Henry Hub

This section presents our base case as well as our High Price and Low Price cases. The High and Low Price cases represent the possible variation in expected annual average Henry Hub gas prices recognizing the uncertainty associated with all long-term forecasts. These prices are not intended to address the issue of price volatility, which is discussed in the next section.

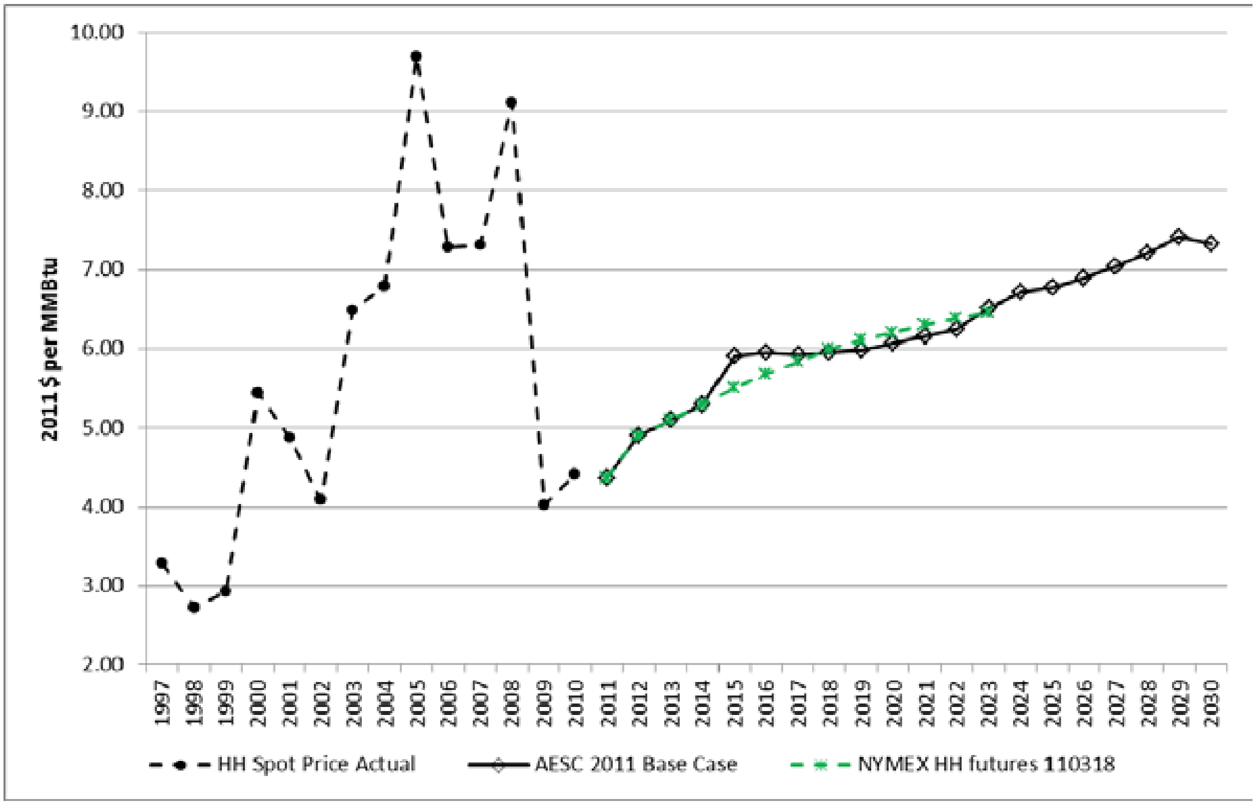
3.5.1. Base Case Forecast of Henry Hub prices

Based on the above presentation of our analyses, the AESC 2011 Base Forecast uses NYMEX futures, as of March 18, 2011, through 2014 and the AEO 2010 High Shale case from 2015 onward.

Comparisons to Historical Prices and other Forecasts

Exhibit 3-8 shows the AESC 2011 Base case annual Henry Hub natural gas price forecast and the annual average actual Henry Hub gas prices since 1997 through 2010. The forecast shows gas prices rising from current low levels to about $6.00 per MMBtu by 2015, holding flat and then rising again. The forecast rise in prices over the next few years is consistent with current prices being below our estimated full-cycle costs of finding and producing natural gas from shale. There will continue to be technological improvements and improvements in drilling and completion practices, which should tend to reduce the costs of finding and producing gas. However, producers, especially when gas prices are low, tend to produce from fields where costs are low and/or reserves are high, i.e. the best areas, before moving to fields where costs are higher and/or reserves are lower.

Exhibit 3-8: Actual, AESC 2011 forecast and NYMEX Futures Henry Hub prices



Thus, we expect prices to rise in the long term as the best areas are depleted and production migrates to areas of higher cost and/or lower productivity.[67]

Exhibit 3-8 also indicates that the AESC 2011 Base case forecast and the NYMEX HH futures prices as of March 18, 2011 are very similar beyond 2014. Nonetheless we continue to believe that in the long-term a price forecast based on fundamentals, especially estimates of the full-cycle, all-in cost of natural gas, is a better price forecast than the out years of the futures prices.

The AESC 2011 Base Case forecast of Henry Hub prices for 2015 is approximately 10 % higher than the average projections of four other

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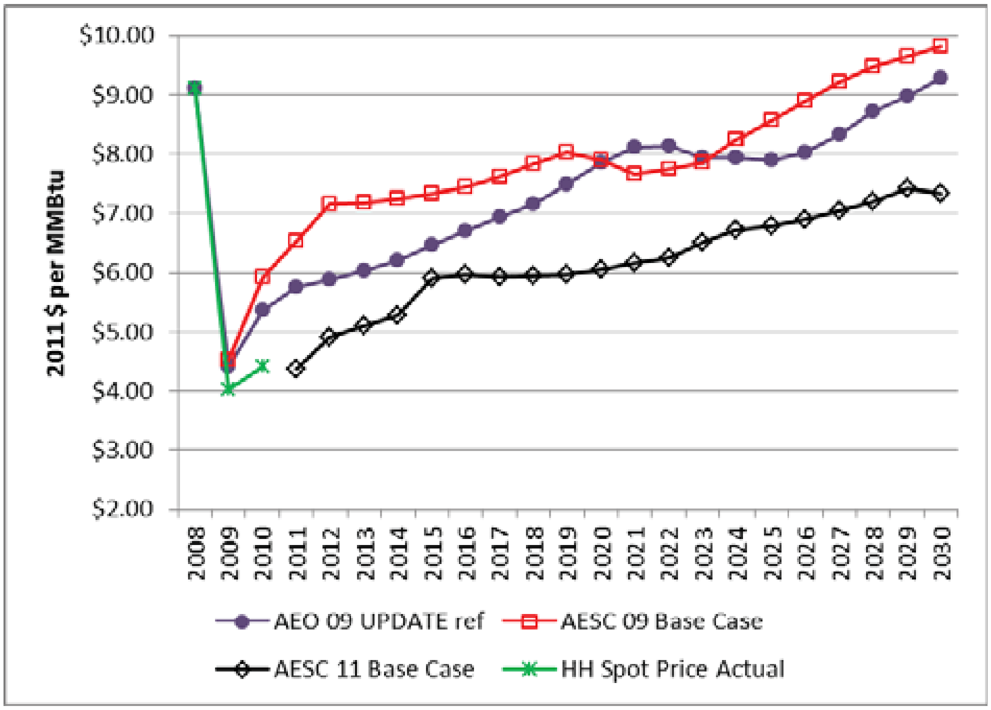
[67] Vello Kuuskraa and Scott Stevens, “Lessons learned help optimize development” Oil & Gas Journal, October 5, 2009, page52.

organizations reported in AEO 2011, and approximately the same as their average forecast for 2025.[68]

3.5.1.1. Comparison to AESC 2009 Base Case

Exhibit 3-9 compares the AESC 2011 Base Case forecast with the AESC 2009 Base Case forecast and the AEO 2009 Update projection of annual Henry Hub gas prices. As can be seen the AESC 2011 forecast is considerably lower than the AESC 2009 forecast.

Exhibit 3-9: Comparison of Henry Hub Natural Gas Price Forecasts



The lower prices forecast in AESC 2011 is attributable to the remarkable progress that gas producers and service contractors have made in producing shale gas; in particular in being able to drill horizontal wells and the hydro fracturing of the shale to allow the gas trapped in the shale to travel to the well. Specifically we estimated in AESC 2009 (see pages 3-13 to 3-15, AESC 2009) that the full-cycle cost of shale gas was in the $6.50 to $8.00 per MMBtu range. For AESC 2011 we estimate the full-cycle cost of shale gas equates to about $5.50 per MMBtu at the Henry Hub.

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[68] Forecasts of IHSGI, EVA, DB and ICF reported in AEO 2011, pages 97 to 99.

3.5.2. High and Low Forecasts of Henry Hub Prices

The AESC 2011 Base Case forecast assumes a significant increase in shale gas reserves and production compared with AESC 2009. That assumption may be incorrect. The reserves may not be as large or economic to develop as assumed in that forecast. Alternatively, the reserves may be larger, or less expensive, to develop than assumed in that forecast. This section describes the AESC 2011 High Price case and Low Price gas case forecasts developed to reflect the range of uncertainty regarding projections of shale gas production quantities and costs. The sources of this uncertainty are discussed in more detail in Section 3.6.1.

The forecasts of the AESC 2011 Base case, High Price case, and Low Price case are shown in Exhibit 3-10.

Exhibit 3-10: Forecasts of AESC 2011 Henry Hub Natural Gas Prices: Base, High and Low

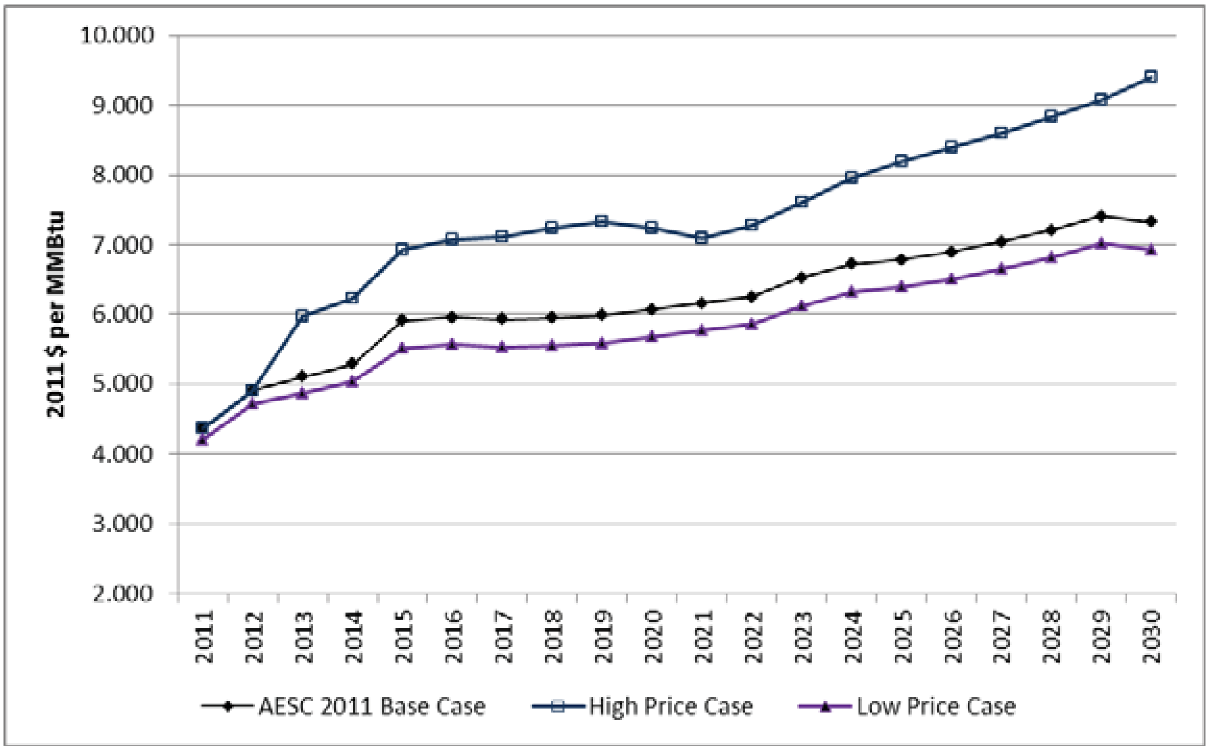

Exhibit 3-11 presents Henry Hub gas price projections based on four different assumptions regarding the future quantity of shale gas resources. (Shale gas resources are a measure of the quantity of estimated unproved, technically recoverable gas reserves.) The four shale gas resource cases are[69]:

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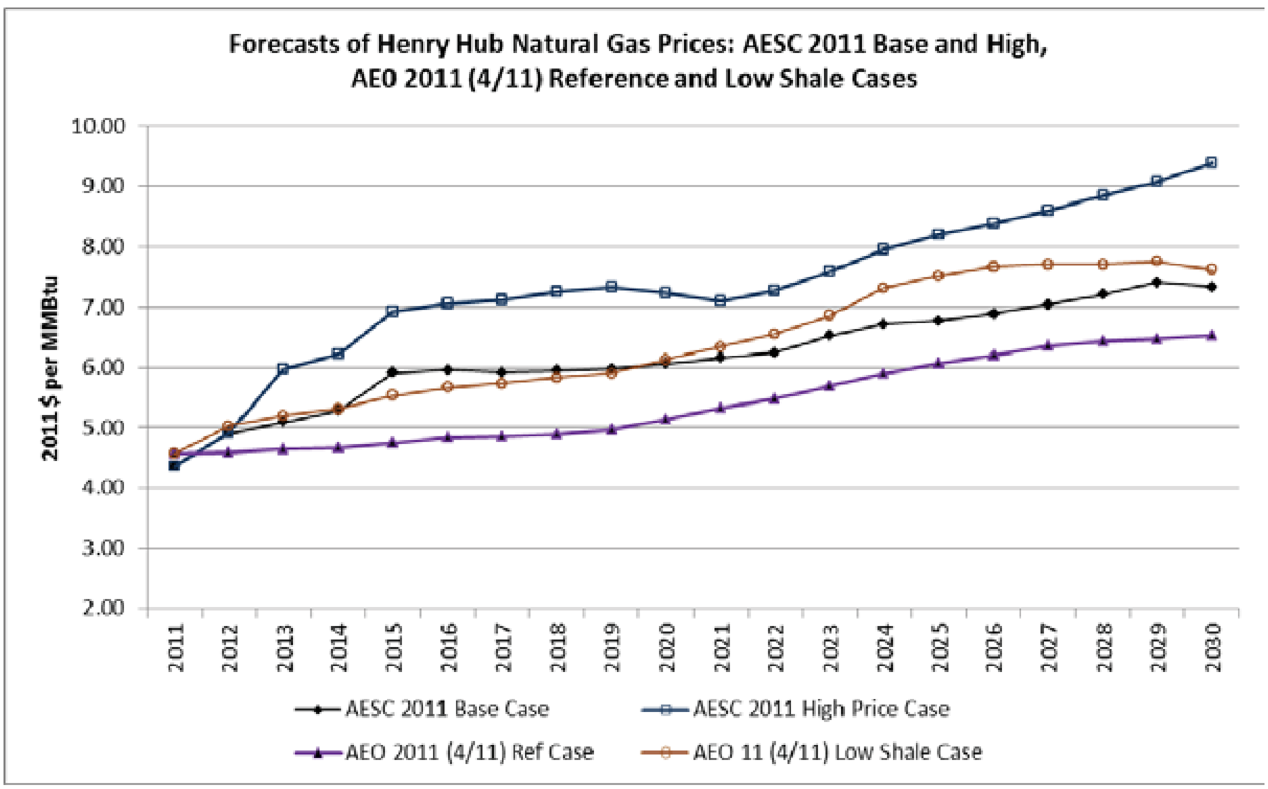
[69] Shale gas resource estimates are found in AEO 2011 report page 38 and AEO 2010 report page 41.

- 347 Tcf, AESC 2011 High Price Case, (AEO 2010 Slow Technology case);
- 423 Tcf, AEO 2011 Low Shale Recovery case
- 652 Tcf, AESC 2011 Base Case (AEO 2010 High Shale Gas Resource case); and
- 827 Tcf, AEO 2011 Reference case.

As noted earlier, the AESC 2011 Base Case is based on more conservative assumptions for shale gas production and cost than the AE0 2011 Reference Case. First, the AESC 2011 Base Case assumes a lower quantity of shale gas resources, at 652 Tcf versus 827 Tcf. Second, the AESC 2011 Base Case projects Henry Hub gas prices that are $0.70 to $1.10 per MMBtu higher than the AEO 2011 Reference Case starting in 2015. These higher prices appear to be due to the lower shale gas resource and higher drilling costs than assumed in that case. In confirmation of this note that the AEO 2011 Low Shale Recovery case, with an estimated shale gas resource 37 percent less than in the AESC 2011 Base case, has prices which are very similar to AESC 2011 Base case for the next 10 years out to 2022.

Exhibit 3-11: Comparison of AESC 2011 and AEO 2011 Henry Hub Gas Prices for Different Estimates of the Shale Gas Resource



3.5.3. AESC 2011 High Price Case

The AESC 2011 High Price case reflects a future in which access to shale gas resources is 47 percent less than the AESC 2011 Base Case and in which the costs of finding, development and production of the available resources are higher than in the AESC Base Case.

The AESC High Price Case is drawn from the AEO 2010 Slow Oil & Gas Technology case. That AEO 2010 case assumes shale gas resources of 347 Tcf rather than the 652 Tcf assumed in the AESC 2011 Base Case forecast. In addition the AEO 2010 slow technology case assumes that technology will be adopted at 50 percent of the rate assumed in the AESC Base case. These two assumptions represent a much lower ability to produce shale gas. For example the AESC 2011 High Price case assumes shale gas production of 4.14 Tcf in 2020 compared with 7.35 Tcf for the AESC 2011 Base case. The AESC 2011 High Price case represents a reasonable upper boundary on the long-run, average price of gas in the future given current views on natural gas supply and demand.

The AESC 2011 High Price represents the impact of cutting the quantity of shale gas resources that can be developed nearly in half relative to the AESC 2011 Base case and of raising the cost of shale gas development in the remaining areas relative to the costs in the AESC Base Case. One possible cause of such an impact would be a future in which the quantity of technically and economically recoverable shale gas reserves proves to be dramatically less than current estimates, the potential for new technological improvements and cost reductions to be achieved proves to be much less than current estimates, that more stringent regulations are imposed upon shale gas development and production, or some combination of those possible factors,

To be consistent with using the NYMEX gas futures prices as the basis of the AESC 2011 Base Case forecast for the years 2011 – 2014, the AESC 2011 High Price Case uses the NYMEX for 2011 and 2012. For 2013 and 2014 we compute the difference in the projected Henry Hub gas price between AEO 2010 Slow Technology case and the AEO 2010 High Shale case and add that difference to the NYMEX futures prices for 2013 and 2014. From 2015 onward our High Price case forecast is the price projected in the AEO 2010 Slow Technology case.

3.5.4. AESC 2011 Low Price Case

The AESC 2011 Low Price case assumes a decrease in finding, development and production costs for natural gas due to developments in oil and gas technology 50% more rapid than in the Base Case. The result is a lower Henry Hub gas price as technology reduces costs and increases the exploitation of gas reservoirs.

To develop the AESC 2011 Low Price Case we begin by estimating the effect of the more rapid technology on Henry Hub prices. We estimate this effect to be a reduction in Henry Hub gas prices equal to the difference between Henry Hub gas prices under the AEO 2010 Reference Case and Henry Hub prices under the AEO 2010 rapid technology case. The difference between the Henry Hub prices in those cases reflects the impact of more rapid technological development because all other parameters of those two cases are the same; in particular these two cases assume the same quantity of shale gas resources.

In the next step we develop the AESC 2011 Low Price case forecast by applying the reductions in price caused by more rapid technology as calculated in step one to the AESC 2011 Base Case forecast. For years 2011 through 2014 the AESC Low Price case each year is the AESC Base case forecast in that year less the rapid technology reduction for that year estimated in step one. For years 2015 through 2030 the AESC Low Price case each year is the AESC Base case forecast in that year less the average price reduction between the AEO 2010 reference case and the AEO 2010 rapid technology case over the period 2015 through 2030. We use the long-term average instead of the corresponding yearly reductions during that period because the difference in prices between the two cases in years 2023 to 29 seems to be caused by the EIA model bringing on the Alaska Natural Gas pipeline in the AEO 2010 reference case but not in the AEO 2010 rapid technology case. As a consequence the price differences represent the impact of more factors than just the difference between rapid technology development and Reference Case technology development.

3.6. Special Issues: Uncertainty Regarding Shale Gas Projections and Volatility of gas prices

3.6.1. Uncertainty Regarding Shale Gas Projections

There is considerable uncertainty regarding projections of shale gas production quantities and costs, as described below. Given the uncertainty associated with projections of shale gas resource availability, production quantities, regulations, and costs, there is certainly a possibility that material changes in the long-term outlook for shale gas production and cost may occur after the completion of AESC 2011 and before the initiation of AESC 2013. Those material changes might be driven by public developments such as significant revisions to public geological analyses; a legislative body, policy agency, or regulatory agency identifying specific changes in the regulation of hydraulic fracturing; published estimates of the costs associated with regulatory changes; or changes in natural gas market prices. In the event of such public developments, members of the Study Group may choose to determine if the AESC 2011 Reference Case and High Gas Price Case projections of natural gas prices are still suitable for use in energy efficiency cost-effectiveness analyses. If they determine that neither of those projections is within a range of reasonableness in light of the public developments, the members of the Study Group should consider revising the natural gas price forecast and the avoided costs.

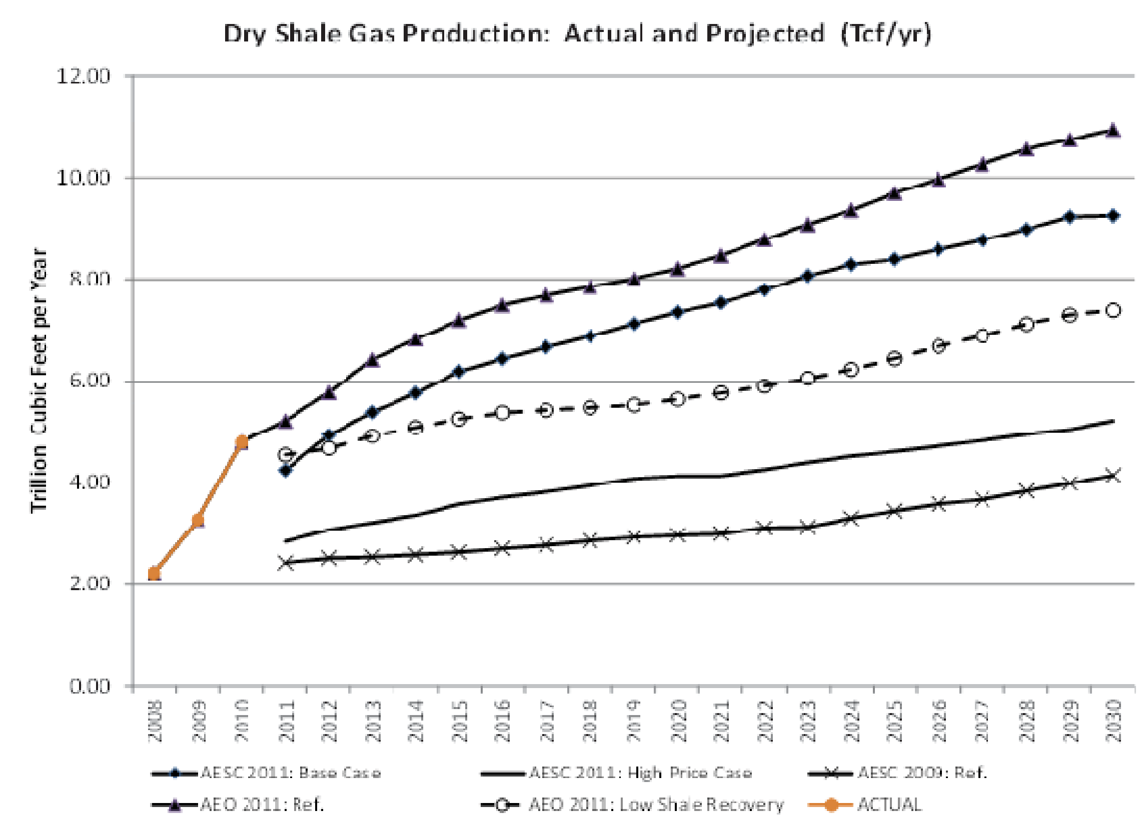
3.6.1.1. Technical Uncertainty

The first area of uncertainty relates to the estimates of technically recoverable quantities of shale gas and the costs of recovering those volumes. AEO 2011 acknowledges this uncertainty and identifies several factors that could tend to result in less production or higher costs under some scenarios, or more production and lower costs under other scenarios.[70] These factors include limited reliable data on long-term production profiles and ultimate gas recovery rates, use of production rates from portions of certain formations to infer the productive potential of the entire formation and the possibility that technical advances could reduce drilling and completion costs.

Exhibit 3-12 presents actual levels of annual shale gas production from 2008 through 2010 as well as the projected production underlying the various cases we examined.

[70] AEO 2011 report pages 37-38.

Exhibit 3-12: Dry Shale Gas Production: Actual and Projected (Tcf/year)



3.6.1.2. Regulatory Uncertainty

A second area of uncertainty is the potential impact of changes in the future regulation of shale gas development; in particular changes in the future regulation of hydraulic fracturing. Concerns have been raised regarding the need for additional regulation of hydraulic fracturing in order to minimize its environmental impacts on groundwater, surface water, and air emissions and the potential impact of such changes in regulation on shale gas production quantities and cost. However, AEO projections do not consider potential impacts of pending or proposed legislation but instead are generally based upon the Federal, State, and local laws and regulations in effect as of the date the AEO is prepared. Therefore, we reviewed the most recent literature regarding potential changes in regulation of hydraulic fracturing in order to determine whether we should include an explicit adjustment for such changes in the development of our Base Case or High Price Case forecasts.

Our review, summarized below, demonstrates that there is certainly considerable debate surrounding future changes to the regulation of hydraulic fracturing of shale gas. A June 2011 report by the International Energy Agency notes these issues and states that they must be, and can be, addressed[71]. However, other than the disclosure of chemicals in fracturing fluid, our review of the literature did not find any public projections of specific changes in existing Federal, state and local regulations, including scope and timing, from which to develop a credible estimate of a material impact on the cost of shale gas production.[72]

History. Hydraulic fracturing of oil and gas wells reportedly started in 1949 in the United States. Since then many thousands of wells have been hydraulically fractured.[73] All aspects of oil and gas well drilling, development and production, including hydraulic fracturing, are regulated;

> “There exists an extensive framework of federal, state, and local requirements designed to manage virtually every aspect of the natural gas development process. These regulatory efforts are primarily led by state agencies and include such things as ensuring conservation of gas resources, prevention of waste, and protection of the rights of both surface and mineral owners while protecting the environment. As part of their environmental protection mission, state agencies are responsible for safeguarding public and private water supplies, preserving air quality, addressing safety, and ensuring that wastes from drilling and production are properly contained and disposed of.”[74]

3.6.1.3. Potential Impact on Water Supply

One of the major concerns about hydraulic fracturing is the possibility that fracturing fluids might flow into and contaminate water supplies. For example:

- The US EPA is studying the impacts of hydraulic fracturing used in shale gas wells with an initial set of findings expected at the end of 2012 and a final report in 2014.
- New York State had moratorium on shale gas drilling while it evaluated the impacts of hydraulic fracturing.

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[71] ___. *Are We Entering A Golden Age of Gas.* International Energy Agency. June 2011.

[72] Unlike expectations regarding future Federal regulation of CO_2 emissions, there are not dozens of projections available for parties to analyze and upon which parties can make an informed judgment.

[73] Halliburton claims over one million wells have been successfully fractured in the U.S. www.halliburton.com at its overview page in its description of fracturing as one type of stimulation service.

[74] DOE, Office of Fossil Energy, Modern Shale Gas Development in the United States: A Primer, April 2009 (DOE primer 2009) The regulatory framework and environmental considerations of shale gas wells are reviewed in this report pages 25 - 76

- Two reports by researchers at Duke University maintain that hydraulic fracturing in the Northeast is contaminating drinking water and should be regulated under the Safe Water Drinking Act.[75]
- The Administrator of the EPA, Lisa P. Jackson, in testimony on May 24, 2011 before the U.S. House Oversight and Government Reform Committee said that she is "…not aware of any proven case where the fracking process itself has affected water."[76]
- An MIT study published in June 2011 found no evidence that fracturing fluids were contaminating freshwater zones.[77]

Another concern has been the quantity of water used in hydraulic fracturing of gas shale. The MIT study estimates that water usage is small compared to other uses of water. (MIT gas 2011, page 44)

3.6.1.4. Air Emissions

Another area of concern is the emissions of methane and nitrogen oxides associated with shale gas production. We found no quantitative estimates of the quantity of NO_x emissions associated with shale gas development and conflicting estimates of methane emissions. For example:

- A study by Cornell University Professor Robert Howarth estimates that methane released into the atmosphere in shale gas development and subsequent transportation can generate over a 20-year horizon a greenhouse gas (GHG) footprint at least 20 percent greater than for coal when expressed per quantity of energy available during combustion.[78]
- A Wood Mackenzie report states that the Howarth study overestimated methane emissions by up to 90 percent by failing to consider that methane emissions can be flared and that reduced emission completions (RECs) are increasingly used in shale gas development including the Barnett shale, Fayetteville shale and Piceance tight gas play.[79]

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[75] Osborn, Stephen et al. *Methane Contamination of Drinking Water Accompanying Gas-well drilling and Hydraulic Fracturing.* and *Research and Policy Recommendations for Hydraulic Fracturing and Shale Gas Extraction.*

[76] Video of the testimony accessed via the committee website and Natural Gas Intelligence, Vol. 30, No. 39, May 30, 2011, page 3

[77] MIT Energy Initiative, The Future of Natural Gas, July 2011, page 7. (MIT gas 2011)

[78] Robert A, Howarth, Renee Santoro and Anthony Ingraffea, "Methane and the greenhouse-gas footprint of natural gas from shale formations", Climatic Change Letters, May 2011, page 9. (Howarth 2011)

[79] Foster Natural Gas Report, "Wood Mackenzie report addresses perceived gaps in Cornell study of methane emissions associated with flowback gas", Report No. 2847, May 13, 2011, page 14. (Wood Mackenzie 2011)

3.6.1.5. Disclosure of Chemicals in Fracturing Fluids

Also being discussed is the need for hydraulic fracturing operations to disclose the chemicals that are in the fracturing fluid. It has been estimated that various chemicals make up 0.5 percent to two percent of the fracturing fluid and the remainder is water and sand. (DOE primer 2009, page 61) On June 17, 2011 the Governor of Texas signed into law a requirement that companies make public the chemicals used on every hydraulic fracturing job: a requirement supported by the industry.[80] We believe that the chemical disclosure requirement will become widespread among the states in the US. It does not appear that the disclosure requirement will have a material effect upon the availability and cost of developing shale gas.

3.6.2. Representation of Volatility in Henry Hub Prices

Volatility is a measure of the randomness of variations in prices over time as affected by short-term factors such as extreme temperatures, hurricanes, supply systems disruptions, etc. It is not a measure of the underlying trend in the price over the long-term. Our forecasts of Henry Hub prices under the Base, high, and low cases provide projections of expected average natural-gas price in any year. Actual gas prices are volatile and in any future month, week or day will vary around the expected annual average prices forecast in each of those three cases. We have not attempted to forecast the actual monthly or weekly prices that would reflect historic price volatility primarily because we are forecasting prices used to evaluate avoided costs in the long term. Our analyses indicate that the levelized price of gas over the long term would not be materially different if one estimated increases from an occasional one-to-three-day price spike during a cold snap or even the type of several month gas price increases following Hurricane Katrina in the fall of 2005. For example, monthly Henry Hub prices were very volatile from 2000 through 2010, ranging from less than $4.00/MMbtu to over $14/MMbtu. See Exhibit 3-13. However, the levelized average annual cost over that period was $5.80/MMBtu. If one substitutes annual average prices for certain months with very high prices, such as the four months affected by Hurricanes Katrina and Rita, and the three month price spike in mid-2008, the levelized price over the entire eleven year period remains very similar at $5.65/MMBtu.

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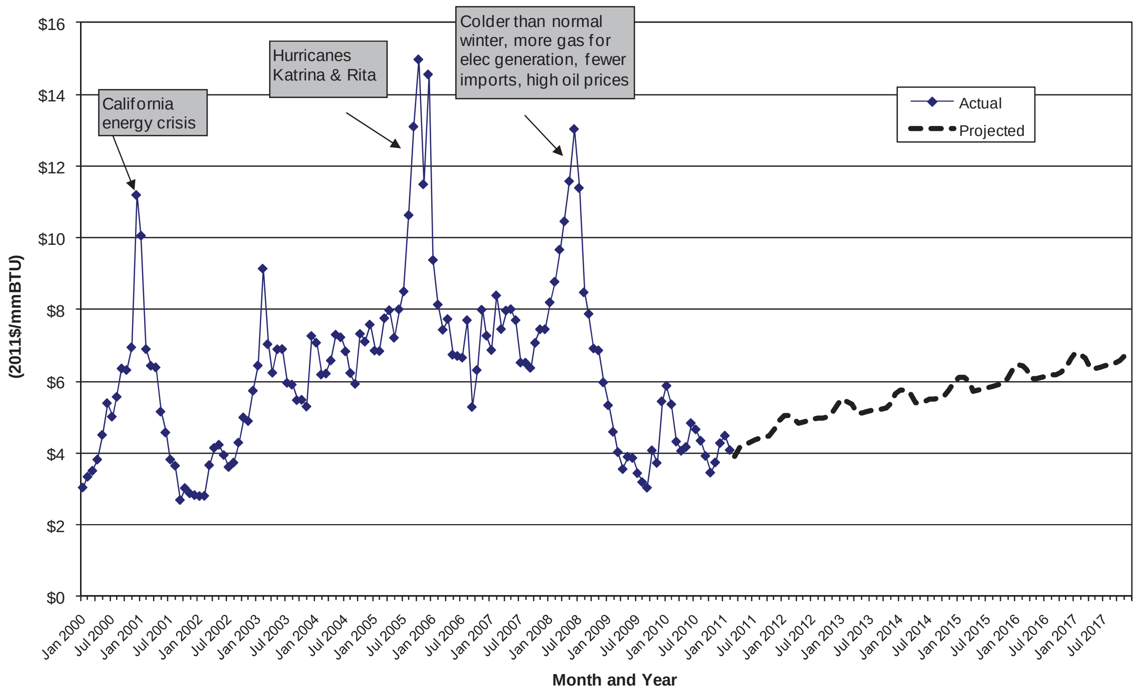
[80] Wall Street Journal, "'Fracking' Disclosure to Rise", June 20, 2011, page B1.

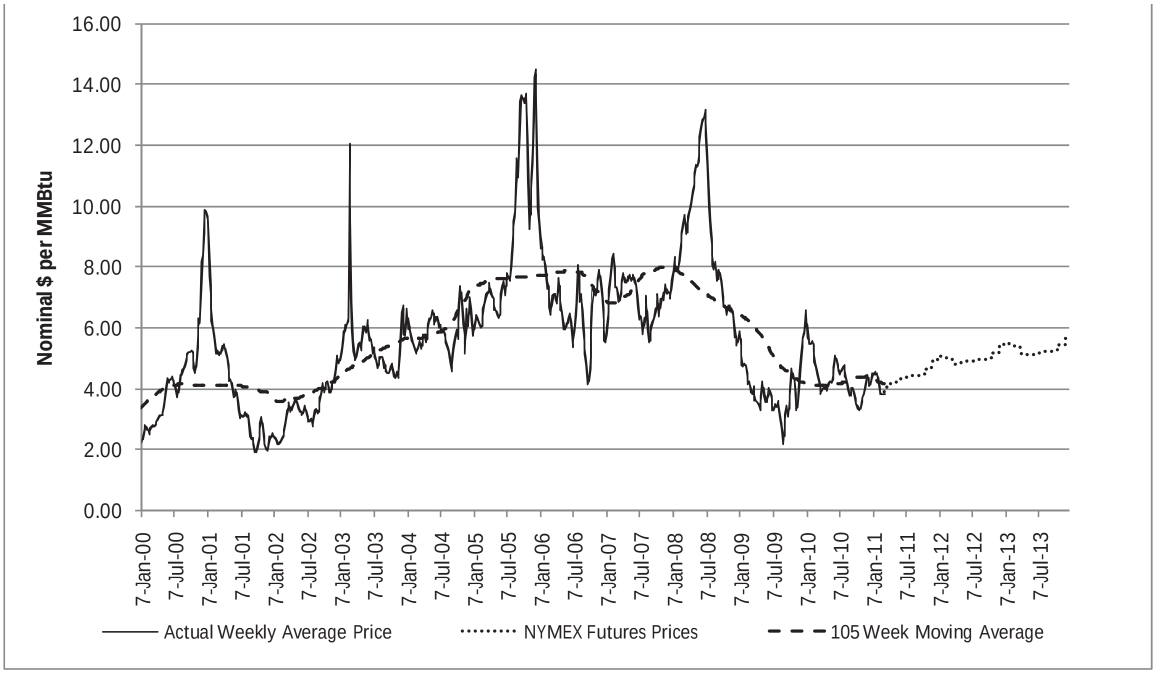
Exhibit 3-13: Monthly Henry Hub Prices, Historical (EIA) and Projected (2011 Dollars per MMBtu)



The range of volatility in weekly Henry Hub gas prices is even higher. See Exhibit 3-14.

Exhibit 3-14 shows the weekly average of the daily spot price of natural gas at the Henry Hub from 2000 through March of 2011 and then monthly NYMEX gas futures prices through December 2013. These prices are in nominal dollars; they have not been adjusted for inflation because this discussion of volatility does not require prices in real terms.

Exhibit 3-14: Henry Hub Average Weekly Natural-Gas Prices, Actual and Futures, Jan 2000 – Dec 2013



Price spikes and dips show price volatility. In New England and in other gas consuming areas there have been daily price spikes during very cold weather. In addition, natural-gas prices have increased for longer periods. The recent example of Hurricane Katrina in 2005 is illustrative, as follows.

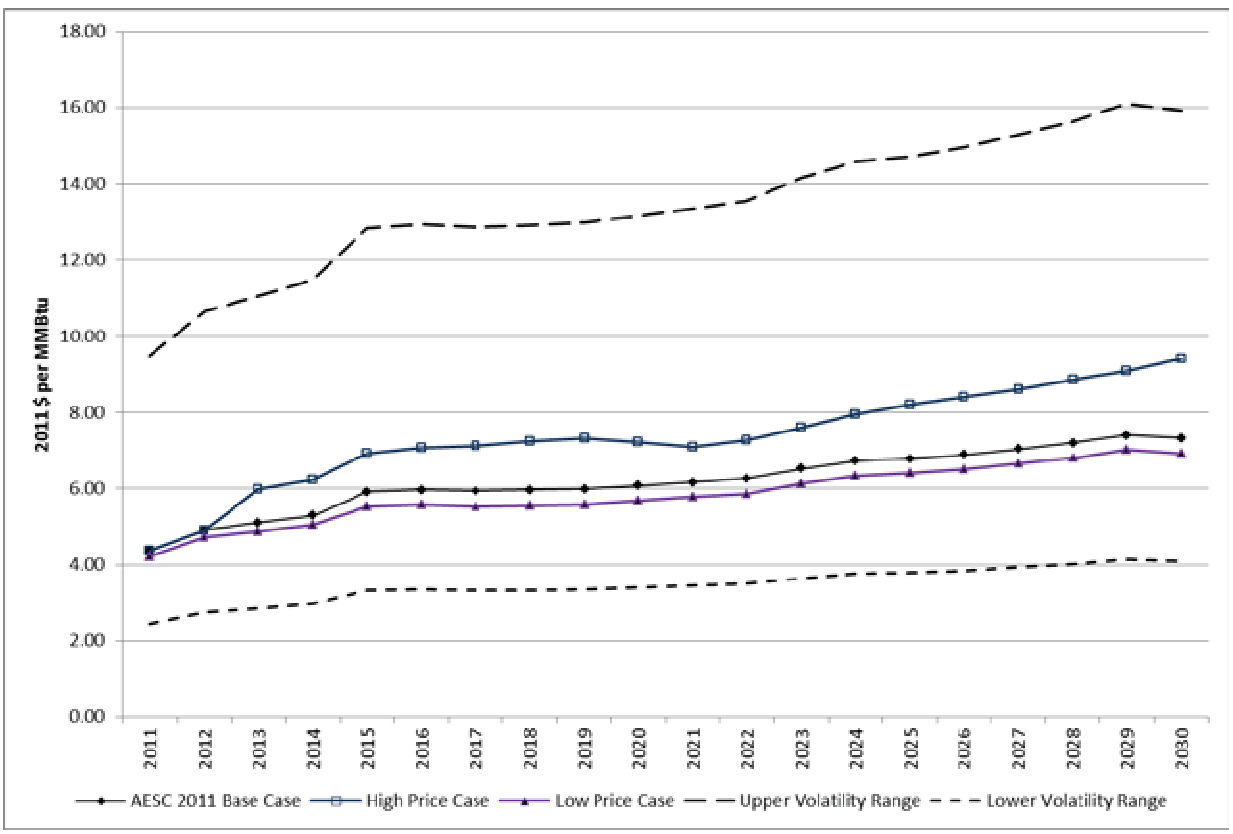
- On July 29 2005 the NYMEX gas futures contract for September 2005 delivery was priced at *$7.89* per MMBtu;
- On August 29 2005 Katrina hit the Gulf Coast;
- On December 13, 2005 the NYMEX January 2006 gas futures contract settlement price was *$15.38* per MMBtu;
- on March 1 2006, six months after Katrina struck the Gulf Coast, the April 2006 gas-futures contract was priced at *$6.73* per MMBtu;
- Subsequently 2006 experienced few hurricanes and on September 27 2006 the October 2006 gas futures contract closed at *$4.21* per MMBtu.

In this example a shock that removed 5 billion cubic feet per day of natural-gas supply produced a strong increase in prices. However, prices quickly reversed to more-typical levels and in less than a year gas futures price fell (temporarily) to a level less than one-third of the peak of December 2005. We expect such shocks and gas price volatility to continue periodically in the future. Nonetheless, the

AESC 2011 Base gas price forecast provides a reasonable estimate of average or expected Henry Hub gas prices for the purposes of this study.

We quantify Henry Hub–price volatility as follows. First we find a 105-week moving average of the weekly prices centered on the current week. This 105-week moving average is the average of the 52 previous weeks of prices, the price of the instant week, and the prices from the 52 weeks following. Then for each week we calculate the ratio of the current price to the 105 week average price. There have been four peak prices during this period of 2000 to March 2011 and the average ratio of the peak price to the 105-week moving average price as of that week is 2.17. Similarly, there were four downside bottoms in price and the average ratio of the four bottom prices is 0.56 of the 105-week moving average price. These results indicate that the actual average of daily prices in any week could range between 0.59 and 2.19 of the long-term average of Henry Hub daily prices. Exhibit 3-15 depicts this range. The range of price volatility is large, especially compared with the upper and lower range of forecast average prices.

Exhibit 3-15: Range of Potential Weekly Price Volatility versus the Forecast Base Case Annual Average Henry Hub Natural Gas Price



3.7. Forecast of Wholesale Natural-Gas Prices in New England

The forecasts of wholesale monthly natural-gas prices for New England as a region, and for each state, are presented in Exhibit 3-17.

The forecast wholesale natural-gas commodity prices each month comprise the forecast monthly commodity price at the Henry Hub plus the forecast monthly basis differential for the relevant market hub(s) in New England. Our forecasts are based on Henry Hub prices plus the following components:

- *Massachusetts, New Hampshire and Maine*–Basis differential to Tennessee Gas Pipeline (TGP) Zone 6;
- *Connecticut and Rhode Island*–Basis differential to Algonquin Gas Transmission (AGT);
- *New England region excluding Vermont*–Average of basis differential to Tennessee Gas Pipeline (TGP) Zone 6 and to Algonquin Gas Transmission (AGT).

We do not forecast a wholesale natural-gas commodity price for Vermont because there is no liquid spot market for gas in that state.

3.7.1. Forecast by Market Hub and State

Like AESC 2009, we assume that the market hubs on Tennessee Gas Pipeline (TGP) Zone 6 and Algonquin Gas Transmission (AGT) represented the majority of gas traded in wholesale markets in New England.

For AESC 2011 as in AESC 2007 and AESC 2009, we calculate historical average basis differential ratios for each of those two market hubs as a ratio of the monthly Henry Hub price and the monthly price reported at the hub. The ratios are calculated for each month over 11 years, January 2000 through December 2010. The average monthly basis-differential ratios for TGP Zone 6 and AGT is then applied to the monthly forecast of Henry Hub natural-gas prices to develop monthly prices for TGP Zone 6 and AGT over the forecast period.

The AESC 2011 average monthly basis differentials are within one percent of the AESC 2009 ratios. See Exhibit 3-16 below.

Exhibit 3-16: Monthly Basis-Differential Ratios (to Henry Hub): AESC 2011 vs. AESC 2009

	AESC 2009			AESC 2011		
	Tenn. Zone 6 Dlvd Mo	*Algonquin CG Mo*	*Average of Tenn. 6 and Algonquin*	*Tenn. Zone 6 Dlvd Mo*	*Algonquin CG Mo*	*Average of Tenn. 6 and Algonquin*
Jan	1.27	1.37	1.32	1.38	1.41	1.40
Feb	1.36	1.41	1.39	1.29	1.43	1.36
Mar	1.13	1.14	1.14	1.12	1.14	1.13
Apr	1.08	1.09	1.09	1.10	1.10	1.10
May	1.08	1.09	1.09	1.09	1.09	1.09
Jun	1.08	1.09	1.09	1.09	1.09	1.09
Jul	1.09	1.10	1.09	1.03	1.10	1.06
Aug	1.08	1.09	1.08	1.08	1.09	1.09
Sep	1.07	1.07	1.07	1.07	1.08	1.07
Oct	1.08	1.09	1.08	1.15	1.09	1.12
Nov	1.11	1.12	1.11	1.06	1.12	1.09
Dec	1.18	1.21	1.19	1.34	1.24	1.29
Average	**1.13**	**1.16**	**1.15**	**1.15**	**1.17**	**1.16**

The basis differential for New England gas market has changed little since AESC 2009, and the change was a very small increase.

3.7.2. Forecast by Region

The forecast of regional monthly spot prices, with the exception of Vermont, was calculated as the average of the forecasts for prices of spot gas delivered to market hubs TGP Zone 6 and AGT.

The average of forecast gas prices for these two zones is appropriate for several reasons. An analysis of spot gas prices delivered to TGP Zone 6 and AGT between January 2000 and March 2011shows no material difference between prices on the two pipelines in most months. This is not surprising. There is ample opportunity for price arbitrage between the two pipelines given the number of interconnections between the two and the number of participants buying and selling gas in the wholesale New England market every day. Were the price on these two pipelines to diverge by too much over a sustained time period, arbitrage would reduce the price difference. In addition, arbitration panels rely upon the average of these two price indices, TGP Zone 6 and AGT, to represent the market value of gas in New England for purposes of setting prices under gas supply contracts between gas producers and generating units.

The AESC 2011 forecasts of New England regional wholesale prices are shown in Exhibit 3-17.

Exhibit 3-17: Forecast Annual Average Wholesale Gas Commodity Prices in New England (2011 Dollar per MMBtu)

	Henry Hub	CT	RI	MA	NH	ME	New England (excluding VT)
2011	$ 4.37	$5.11	$5.11	$5.02	$5.02	$5.02	$5.07
2012	4.91	5.74	5.74	5.64	5.64	5.64	5.69
2013	5.10	5.97	5.97	5.86	5.86	5.86	5.92
2014	5.29	6.19	6.19	6.08	6.08	6.08	6.13
2015	5.91	6.92	6.92	6.80	6.80	6.80	6.86
2016	5.96	6.97	6.97	6.85	6.85	6.85	6.91
2017	5.93	6.94	6.94	6.82	6.82	6.82	6.88
2018	5.95	6.96	6.96	6.84	6.84	6.84	6.90
2019	5.98	7.00	7.00	6.88	6.88	6.88	6.94
2020	6.06	7.09	7.09	6.97	6.97	6.97	7.03
2021	6.16	7.20	7.20	7.08	7.08	7.08	7.14
2022	6.25	7.31	7.31	7.19	7.19	7.19	7.25
2023	6.52	7.63	7.63	7.50	7.50	7.50	7.56
2024	6.72	7.86	7.86	7.73	7.73	7.73	7.80
2025	6.78	7.94	7.94	7.80	7.80	7.80	7.87
2026	6.89	8.06	8.06	7.92	7.92	7.92	7.99

Notes

Connecticut and Rhode Island per basis-differential ratios to Algonquin market hub.

Massachusetts, Maine, and New Hampshire per basis differential ratio to Tennessee Zone 6 market hub.

New England, excluding Vermont, is based on the average basis-differential coefficient to Algonquin and Tennessee Zone 6.

3.7.3. Impact of New Regional Supplies on Wholesale Prices in New England

To date, increases in the quantity of supply to New England from eastern Canada and new LNG facilities have not led to major reductions in the price of gas in New England. Instead, those supplies have tended to displace gas that would otherwise have been delivered into the region from the Mid-Atlantic Region, a much larger market. In the future, as the sources of gas supply to the Eastern United States shift from the traditional Southwestern producing regions to new producing basins such as the Marcellus Shale and Rocky Mountain producing areas, the basis differential between New England and the Henry Hub may decline.

3.8. Forecast of Gas Prices for Electric Generation in New England

The price of natural gas for electric generation at any particular location can be represented as the wholesale Henry Hub price plus a basis differential representing the cost of delivering gas from the Henry Hub to that particular electric generating unit. The AESC 2011 forecast of prices of natural gas for electric generation in New England and New York thus comprises forecast monthly Henry Hub prices multiplied by a forecast differential. Because of the wide variation in natural-gas prices represented in the historical data we have normalized those relationships and presented the differentials as multipliers rather than adders. This section describes our derivation of the forecast differentials, presented below in Exhibit 3-18.

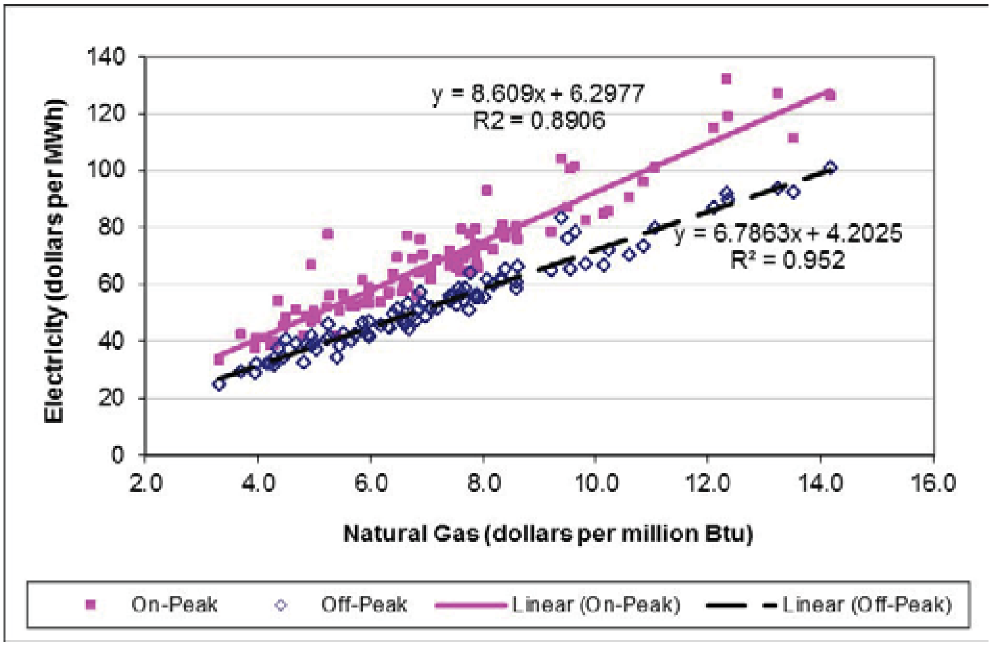
Exhibit 3-18: Monthly Natural-Gas Basis-Differential Ratios (to Henry Hub)

Month	New York	New England
January	1.357	1.354
February	1.258	1.239
March	1.240	1.187
April	1.181	1.141
May	1.145	1.107
June	1.145	1.085
July	1.218	1.126
August	1.209	1.132
September	1.164	1.086
October	1.191	1.104
November	1.235	1.136
December	1.324	1.297
Average	**1.222**	**1.166**

The forecast differentials are based on analysis of monthly prices for natural gas and electricity over the period 2003–2010. Based on the results from AESC 2009, we selected the historic monthly natural-gas prices paid by electric generators as reported to the EIA (2010c) and the corresponding monthly Henry Hub prices. From that we historic monthly differentials from the Henry Hub prices to provide the forecast of monthly prices for natural gas to electric generating units.

Exhibit 3-19 below presents a scatter plot of the monthly peak and off-period electricity prices versus the natural-gas prices as reported by EIA along with fitted trend lines. The coefficients on those lines represent average effective heat rates for the given periods.[81] For example, the implied heat rate for the peak period is 8,609 Btu/kWh representing a mix of less-efficient plants than for the off-peak period.

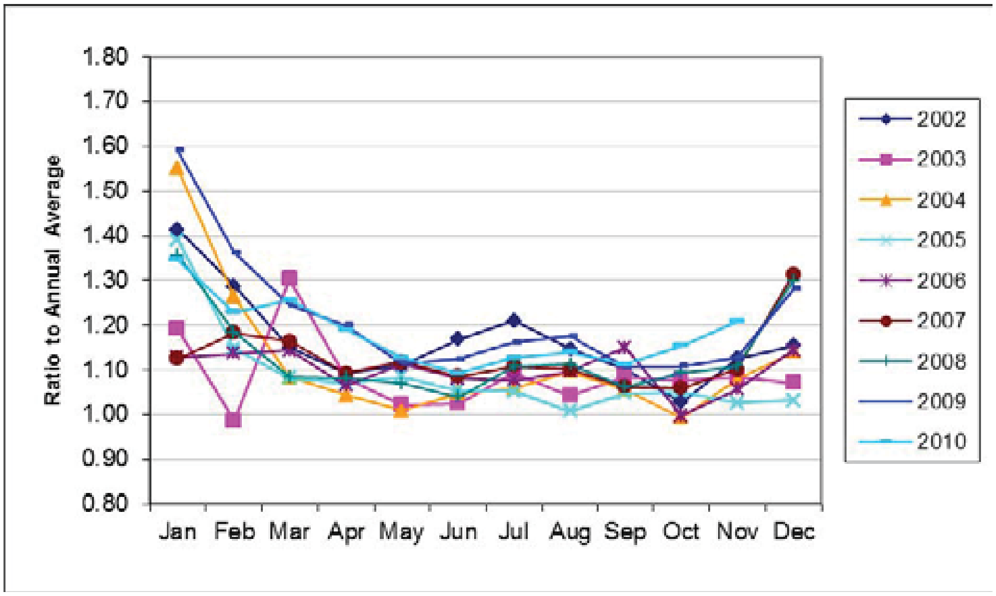
Exhibit 3-19: Monthly NE Electricity Prices vs. EIA Natural Gas Prices (2003–2010)



Based upon those analyses we developed the forecast monthly basis differentials presented in Exhibit 3-18 above. The forecast differential in each month is the average differential between the price reported to the EIA for that month and the monthly Henry Hub price over the nine-year period of 2002 to 2010. Exhibit 3-20 below shows those monthly ratios for New England. Although there are significant variations from one year to the next, there is also a consistent seasonal pattern reflecting much greater basis differentials for the winter heating season.

[81] Heat rate is a measure of the efficiency with which a generating unit converts fuel energy into electric energy. It is expressed in Btu of fuel burned per kWh of energy generated.

Exhibit 3-20: Ratio of Monthly Gas Prices Reported by New England Generating Units to Monthly Henry Hub Price



Chapter 4: Avoided Natural-Gas Costs

4.1. Introduction and Summary

The avoided cost of gas at a retail customer’s meter consists of two components:

- The avoided cost of gas delivered into the distribution systems of New England local distribution companies (LDCs), and
- The avoided cost of delivering gas on those distribution systems (‘retail margin’).

These avoided costs vary primarily according to the shape of the gas load being avoided, with some additional variation by sector due to differences in distribution service costs by sector. We have calculated avoided costs by sector and load shape for three different regions—southern New England, northern and central New England, and Vermont—because of the differences in the cost of gas supply between those three areas.

Our projected values are presented in below in Exhibit 4-1 and Exhibit 4-2, alongside the corresponding values from AESC 2009. Greater detail on the avoided costs for AESC 2011 is shown later in Exhibits 4-13 through 4-16 for Southern New England and Northern and Central New England and in Appendix D for Vermont Gas Systems (VGS).

Exhibit 4-1: Summary Table Assuming Some Avoided Retail Margin

COMPARISON OF LEVELIZED AVOIDED COSTS OF GAS DELIVERED TO RETAIL CUSTOMERS
BY END USE: AESC 2009 AND AESC 2011
ASSUMING SOME AVOIDABLE RETAIL MARGIN
(2011$/Dekatherm except where indicated as 2009$/DT

	RESIDENTIAL				COMMERCIAL & INDUSTRIAL			ALL RETAIL
	Non Heating	Hot Water	Heating	All	Non Heating	Heating	All	
Southern New England								
AESC 2009 (2009$/DT)	11.42	11.42	14.52	13.52	9.88	11.83	11.21	12.26
AESC 2009 (a)	11.63	11.63	14.79	13.77	10.07	12.05	11.42	12.49
AESC 2011	7.64	7.64	9.39	9.11	7.58	8.82	8.44	8.75
2009 to 20119 change	-34.33%	-34.33%	-36.54%	-33.82%	-24.71%	-26.84%	-26.08%	-29.92%
Northern & Central New England								
AESC 2009 (2009$/DT)	10.87	10.87	13.54	12.67	10.02	12.05	11.40	12.03
AESC 2009 (a)	11.08	11.08	13.79	12.91	10.21	12.28	11.61	12.25
AESC 2011	7.47	7.47	8.96	8.73	7.59	8.79	8.43	8.58
2009 to 2011 change	-32.57%	-32.57%	-35.03%	-32.38%	-25.64%	-28.37%	-27.41%	-29.99%
Vermont								
AESC 2009 (2009$/DT)	9.72	9.72	12.43	11.56	8.01	9.44	9.00	9.93
AESC 2009 (a)	9.90	9.90	12.66	11.77	8.16	9.62	9.17	10.12
AESC 2011	7.54	7.54	9.88	9.37	7.30	9.08	8.54	8.86
2009 to 2011 change	-23.86%	-23.86%	-21.95%	-20.36%	-10.57%	-5.67%	-6.82%	-12.44%

(a) Factor to convert 2009$ to 2011 $ 1.0186

Note: AESC 2009 levelized costs for 15 years, 2010 - 2024 at a discount rate of 2.22%.
AESC 2011 levelized costs for 15 years 2012 - 2026 at a discoiunt rate of 2.465%.

Exhibit 4-2: Summary Table Assuming No Avoided Retail Margin

COMPARISON OF LEVELIZED AVOIDED COSTS OF GAS DELIVERED TO RETAIL CUSTOMERS
BY END USE: AESC 2009 AND AESC 2011
NO AVOIDABLE RETAIL MARGIN in AESC 2011 but is in AESC 2009
(2011$/Dekatherm except where indicated as 2009$/DT

	RESIDENTIAL				COMMERCIAL & INDUSTRIAL			ALL
	Non Heating	Hot Water	Heating	All	Non Heating	Heating	All	RETAIL
Southern New England								
AESC 2009 (2009$/DT)	11.42	11.42	14.52	13.52	9.88	11.83	11.21	12.26
AESC 2009 (a)	11.63	11.63	14.79	13.77	10.07	12.05	11.42	12.49
AESC 2011	7.04	7.04	7.81	7.57	7.04	7.81	7.57	7.57
2009 to 20119 change	-39.50%	-39.50%	-47.23%	-44.98%	-30.10%	-35.24%	-33.67%	-39.34%
Northern & Central New England								
AESC 2009 (2009$/DT)	10.87	10.87	13.54	12.67	10.02	12.05	11.40	12.03
AESC 2009 (a)	11.08	11.08	13.79	12.91	10.21	12.28	11.61	12.25
AESC 2011	6.94	6.94	7.58	7.39	6.94	7.58	7.39	7.39
2009 to 2011 change	-37.32%	-37.32%	-45.04%	-42.77%	-32.01%	-38.26%	-36.37%	-39.70%
Vermont								
AESC 2009 (2009$/DT)	9.72	9.72	12.43	11.56	8.01	9.44	9.00	9.93
AESC 2009 (a)	9.90	9.90	12.66	11.77	8.16	9.62	9.17	10.12
AESC 2011	7.06	7.06	8.63	8.16	7.06	8.63	8.16	8.16
2009 to 2011 change	-28.68%	-28.68%	-31.84%	-30.70%	-13.50%	-10.32%	-11.00%	-19.38%

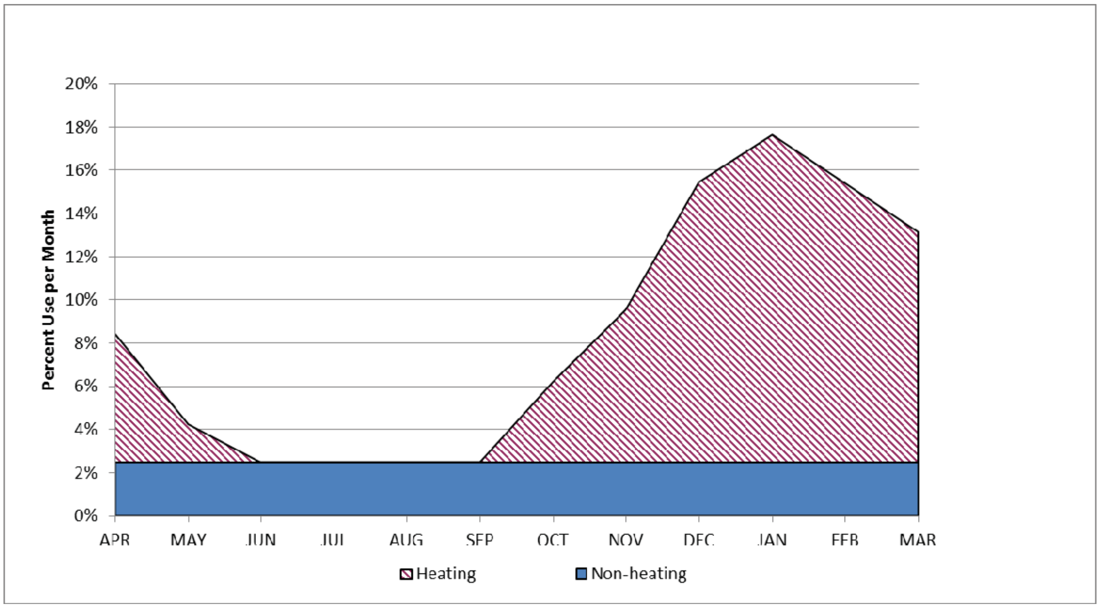
(a) Factor to convert 2009$ to 2011 $ 1.0186
Note: AESC 2009 levelized costs for 15 years, 2010 - 2024 at a discount rate of 2.22%.
AESC 2011 levelized costs for 15 years 2012 - 2026 at a discoiunt rate of 2.465%.

We project lower avoided costs for each end use compared with those projected in AESC 2009. Assuming that some retail margin is avoidable, Exhibit 4-1, the avoided costs to the end user ranges from 25 to 36 percent less than estimated in AESC 2009 for all states except Vermont. These lower avoided costs are due to a lower forecast Henry Hub price of gas and a lower estimate of the LDC retail margin that can be avoided. In Vermont the avoided costs to end users is 6 to 24 percent less. The lower price of gas at the Henry Hub and lower retail margin is offset by higher pipeline transportation and storage demand charges. When we assume that no LDC retail margin can be avoided in AESC 2011 but the avoided retail margin estimated in AESC 2009 is retained, Exhibit 4-2, the avoided cost is between 30 and 40 percent less than in estimated in AESC 2009 for states other than Vermont due to a lower forecast gas price and assuming that no retail margin is avoidable. In Vermont the avoided cost is about 10 to 32 percent less in AESC 2011 compared to AESC 2009 due to the higher pipeline and storage charges in AESC 2011.

4.2. Load Shape Is a Key Driver of Avoided Retail Gas Costs

The shape of the retail gas load being supplied has a major impact on the cost of that supply, and hence on the avoided cost of supply. The major end uses of gas by retail customers fall into two broad categories, heating and non-heating. Space-heating or winter temperature-sensitive end-uses represent the largest use in New England. As a result LDCs supply a load that has a significant swing from summer to winter and further temperature-driven variations by month throughout the winter. This variation in load by season, and month, by type of end-use are illustrated graphically in Exhibit 4-3.

Exhibit 4-3: End-Use-Load Profile

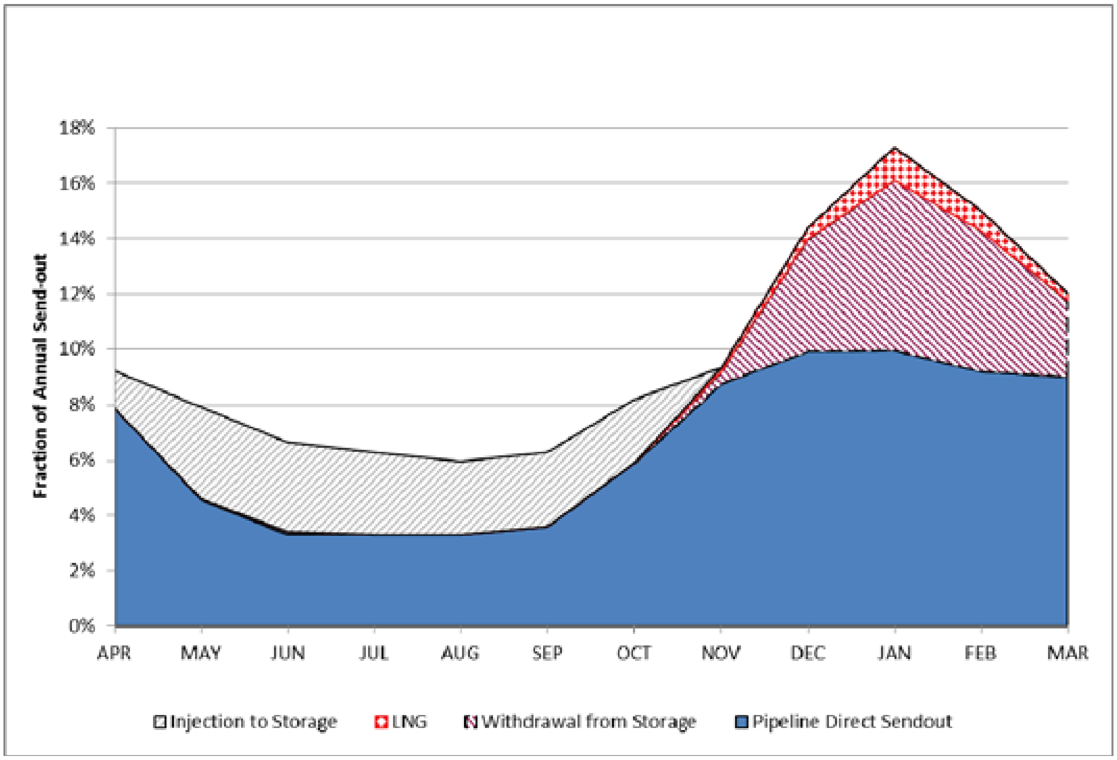


Because of the size of the gas load during the winter (defined as November through March in the gas industry) relative to the summer, and because the variation in daily load during winter months due to variation in daily temperatures, LDCs develop a portfolio of supplies in order to provide reliable service at reasonable cost over time. These portfolios comprise three major categories of delivery and storage resources: long-haul pipeline transportation, underground storage, and LNG or propane facilities.[82] We calculate the avoided cost of gas delivered into the distribution system of a New England local distribution company from the avoided cost of each resource in each month and the relative quantity of each resource that an LDC uses in each month.

[82]Local distribution companies acquire pipeline and storage services through contracts with pipeline companies whose terms and conditions are regulated by the Federal Energy Regulatory Commission.

Local distribution companies use their long-haul pipeline transportation to supply load directly in each month of the year. In addition, in summer months LDCs use a portion of that pipeline transportation capacity to deliver gas from producing areas for injection into underground storage, and sometimes for liquefaction and injection into LNG tanks.[83] In winter months LDCs meet customer load with gas delivered by pipeline directly from producing areas and from underground storage. LDCs use gas from LNG and propane facilities delivered directly into their distribution systems to meet daily peaking and seasonal requirements during the months of heaviest load, mostly December through February.[84] See Exhibit 4-4.

Exhibit 4-4: Representative New England Gas LDC Sendout by Source



Because LDCs incur fixed costs to hold pipeline transportation capacity, in the form of *demand charges* multiplied by their capacity entitlements, and because

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83 Local distribution companies may use some of their pipeline capacity to deliver gas in summer for injection into LNG tanks where there are liquefaction facilities on site.

84 The data underlying the representative LDC sendout by source is the weighted average of the recent data supplied by Yankee Gas Systems, Connecticut Natural Gas Company, Columbia Gas of Massachusetts, NSTAR and National Grid (MA).

they use long-haul pipeline transportation capacity to provide supply in three major ways, we had to determine how best to allocate those fixed costs among the three transportation applications provided using this capacity.[85] The three transportation applications are transportation of gas supply for direct supply (send-out) in winter months, transportation of gas in summer months for injection to underground storage (and subsequent withdrawal in winter months) and transportation of gas for direct supply in summer months. Our analysis of how LDCs use their long-haul capacity for each application is presented in detail below.

Based upon our analysis of LDC use of long-haul capacity, our projection of avoided costs is based on an allocation of 100 percent of pipeline demand charges incurred in winter months to avoided costs in winter months. This allocation reflects LDC use of all of their capacity to provide direct supply in those months. Allocation of pipeline demand charges incurred in summer months is somewhat complex because LDCs use only approximately 75 percent of their capacity during those months based on information provided by LDCs. Of that 75 percent, they use about 46 percent to provide direct supply and about 29 percent to deliver gas for injection into storage. Based upon our analysis of LDC use of capacity in summer months:

- 25 percent of pipeline transportation demand charges incurred in summer months are allocated to avoided costs of winter months, corresponding to the approximately 25 percent of physical capacity not being used in the summer either to refill storage or provide direct supply;
- 29 percent of pipeline demand charges in summer months are allocated to the avoided costs of gas injected into storage. (All costs of gas injected into storage are allocated to avoided costs of winter months). This is the percentage of long-haul capacity LDCs use to transport gas for injection into underground storage in summer;
- 46 percent of pipeline demand charges in summer months are not allocated to avoided costs of summer months. This is the percentage of long-haul capacity LDCs use to provide direct supply in summer. Our analysis indicates that LDCs cannot avoid those costs.

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[85] An LDC's fixed cost of capacity on a pipeline for a given month equals the pipeline's demand charge, expressed in dollars per month per dth/day of capacity, multiplied by the LDC's capacity entitlement or contract demand expressed in dth/day.

4.3. Avoided Cost of Gas to LDCs

This analysis estimates long-run avoided costs because energy efficiency improvements have long-term effects that can allow an LDC to avoid both short-run variable costs and some long-term fixed costs. We calculate the avoided cost of gas delivered into the distribution system of a New England LDC in two steps. First, we calculate the avoided cost of supply from each major resource in each month. Then we calculate the weighted average cost in each month based upon the relative quantity of each resource the LDC uses in each month. We also calculate a marginal cost (avoided cost) for the peak day.

4.3.1. Summary Results

Our estimated levelized avoided costs are 17 to 19 percent less than those of AESC 2009 mostly due to the forecasted lower cost of gas at the Henry Hub for AESC 2011 compared to AESC 2009 for the New England states other than Vermont. (See Exhibit 3-9 to compare the AESC 2009 and AESC 2011 base case Henry Hub natural gas price forecasts.) The pipeline rates were almost the same in each of the studies serving the states other than Vermont. See Exhibit 4-5. In Vermont the avoided cost of gas delivered at the city gate foe AESC 2011 is up to 6 percent greater in the winter than in AESC 2009 due to the much higher transportation and storage demand charges for AESC 2011 compared to AESC 2009. In the summer the AESC 2011 avoided cost is less that in AESC 2009 because the cost of gas is forecast to be less and there are no avoided transportation or storage demand charges in the summer.

Exhibit 4-5: Comparison of the Levelized (15 year) Avoided Cost of Gas Delivered to LDC's by Month from AESC 2009 to AESC 2011

COMPARISON OF THE LEVELIZED AVOIDED COSTS OF GAS DELIVERED TO LDCs BY MONTH
FROM AESC 2009 AND AESC 2011

	Units		APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	Annual Average
SOUTHERN NEW ENGLAND: Gas Delivered via Texas Eastern and Algonquin Pipelines															
AESC 2009	2009$/DT	(a)	7.37	7.39	7.51	7.64	7.74	7.78	7.90	9.17	9.86	10.14	9.62	9.17	8.44
AESC 2009	2011$/DT	(b)	7.51	7.53	7.65	7.78	7.88	7.93	8.04	9.35	10.04	10.33	9.80	9.34	8.60
AESC 2011	2011$/DT	(c)	6.16	6.18	6.25	6.34	6.40	6.42	6.50	7.63	8.21	8.53	8.06	7.72	7.04
Percent Difference 2009 to 2011			-17.9%	-17.8%	-18.2%	-18.6%	-18.8%	-19.0%	-19.1%	-18.3%	-18.2%	-17.4%	-17.7%	-17.3%	-18.2%
NORTHERN and CENTRAL NEW ENGLAND: Gas Delivered via Tennessee Gas Pipeline															
AESC 2009	2009$/DT	(a)	7.35	7.36	7.48	7.61	7.71	7.75	7.87	8.94	9.41	9.69	9.23	8.83	8.27
AESC 2009	2011$/DT	(b)	7.48	7.50	7.62	7.75	7.85	7.90	8.01	9.10	9.59	9.87	9.40	8.99	8.42
AESC 2011	2011$/DT	(c)	6.19	6.21	6.28	6.36	6.42	6.45	6.53	7.46	7.91	8.20	7.80	7.47	6.94
Percent Difference 2009 to 2011			-17.3%	-17.2%	-17.6%	-17.9%	-18.2%	-18.3%	-18.5%	-18.0%	-17.4%	-16.9%	-17.1%	-16.9%	-17.6%
VERMONT GAS SYSTEMS: Gas delivered via TransCanada Pipeline															
AESC 2009	2009$/DT		6.36	6.21	6.38	6.49	6.57	6.61	6.71	8.09	8.57	9.24	8.77	8.28	7.36
AESC 2009	2011$/DT		6.48	6.33	6.49	6.61	6.69	6.73	6.83	8.24	8.72	9.41	8.93	8.44	7.49
AESC 2011	2011$/DT		5.61	5.42	5.48	5.55	5.60	5.63	5.77	8.77	9.22	9.80	9.34	8.50	7.06
Percent Difference 2009 to 2011			-13.4%	-14.3%	-15.6%	-16.0%	-16.3%	-16.4%	-15.5%	6.5%	5.7%	4.2%	4.6%	0.7%	-7.2%

(a) AESC 2009 levelized costs over the 15-year period 2010 - 2024 with a discount rate of 2.218%.
(b) Factor to convert 2009$ to 2011$ 1.0186
(c) AESC 2011 levelized costs over the 15-year period 2012 - 2026 with a discount rate of 2.465%.

4.3.2. Representative New England Local Distribution Company and Resources

New England LDCs use three basic supply resources to meet the requirements of their customers. These resources are (1) gas delivered directly from producing areas via long-haul pipelines, (2) gas withdrawn from underground storage facilities (most of which are located in Pennsylvania) and delivered by pipeline, and (3) gas stored as liquefied natural gas and/or propane in tanks located in the LDC service territories throughout New England.

This avoided-cost analysis used a representative New England LDC to determine the fraction of customer requirements met from each resource each month and the fraction of storage refill in each of the summer months, April through October. The characteristics of a representative New England LDC are shown in Exhibit 4-6 below, which presents the numerical data, and Exhibit 4-4, which is a graphical representation of the typical New England LDC used in this analysis. For Vermont, which has one LDC, VGS, the characteristics of VGS were used and are shown later in this report in Section 4.5. Our analysis assumes that LDCs have optimized the mix of supply sources and thus long-term energy efficiency improvements will enable them to avoid both the fixed and the variable costs associated with their mix of supply sources.[86]

Exhibit 4-6: Representative New England LDC Monthly Characteristics of Send-out by Source, Peak-Month, and Storage Injection

AESC 2011	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	Annual
Fractions of LDC Send-out by Source Each Month													
Pipeline Deliveries, Long-haul	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	93.9%	68.8%	57.5%	61.2%	74.9%	78.8%
Underground Storage	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	4.6%	28.2%	35.6%	34.0%	23.0%	18.5%
LNG and Propane Peaking Supply	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.5%	3.0%	6.9%	4.8%	2.1%	2.7%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Fraction of Annual Sendout each Month	7.9%	4.6%	3.4%	3.3%	3.3%	3.6%	5.9%	9.3%	14.4%	17.3%	15.0%	12.0%	100.0%
Monthly Sendout as a Fraction of Peak Month	45.7%	26.6%	19.7%	19.1%	19.1%	20.8%	34.1%	53.8%	83.2%	100.0%	86.7%	69.4%	
Fraction of Underground Storage Injection by Month	7.1%	17.9%	17.6%	16.2%	14.3%	14.6%	12.3%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%

Sources: Data supplied by Yankee Gas Systems, Connecticut Natural Gas Company, Columbia of Massachusetts, NSTAR and National Grid (MA).

The fractions portraying the representative New England LDC are essentially an average of the data provided by Yankee Gas Services Company, Connecticut Natural Gas Corporation, Columbia Gas of Massachusetts, NSTAR Gas Company, and National Grid (MA).

The LDC's weighted average avoided cost in each month is a function of the avoided cost of each resource and the relative quantity of each resource used to meet the retail load each month.

4.3.3. Inputs to Avoided Costs by Resource

The cost of gas delivered to an LDC using pipeline transportation and storage facilities consists of the following four basic components:

- The unit cost of the gas commodity, which in this study is the forecast price at the Henry Hub in Louisiana;
- The demand charges for pipeline-transportation capacity, storage capacity and withdrawal capacity;
- The usage (volumetric) charges for transporting gas on a pipeline and for storage injections and withdrawals;
- The fraction (percentage) of volumes of gas received by a pipeline or storage facility that is retained by the facility for compressor fuel and losses. This fuel and loss retention increases the cost of gas above the Henry Hub price because more volumes of gas must be purchased at the Henry Hub than is delivered to the LDC. In the analysis that follows, the

[86] In a short-run marginal cost analysis only variable costs can be adjusted and thus the avoided cost is determined by the one supply source which has the highest variable cost.

fuel and loss retention is represented as the ratio of the volumes of gas purchased at the Henry Hub to the volumes of gas delivered to the LDC.

Local distribution companies generally own the LNG and/or propane tanks and accompanying liquefaction and vaporization facilities. The bulk of the New England peak gas supply comes from LNG facilities although in certain circumstances propane is the dominant peak gas source. The LDC pays for the construction, financing, operation and maintenance of the LNG facility as well as the cost of the gas that is loaded into the tank as LNG.

4.3.3.1. Commodity Costs

For this avoided-cost analysis we assume that the marginal cost of the gas commodity is the monthly price of gas at the Henry Hub. For AESC 2011, like AESC 2009, we assume that the marginal source of gas to New England LDCs from the Henry Hub is transportation and storage on either of the Tennessee Gas Pipeline (TGP), for LDCs in Northern and Central New England, or the route of Texas Eastern Transmission (TETCO) and Algonquin Gas Transmission (AGT), for LDCs in Southern New England.[87] While both the three existing LNG receiving and re-gasification terminals in New England and the terminal in New Brunswick will likely be new gas suppliers to New England, it is not likely that they will establish the avoided cost of gas supply to New England. Rather, the price of gas from these new terminals will be set by the price of gas in New England supplied by TGP and TETCO-AGT.[88]

4.3.3.2. Pipeline Rates (Charges)

As described above, we assume that the marginal source of gas to New England LDCs, other than Vermont, is transportation and storage on either of TGP or the route of TETCO and AGT. The cost for transportation and underground storage is set by the rates charged by these pipelines and their fuel and loss retention percentages, which are shown in Exhibit 4-7 and Exhibit 4-21 for Vermont Gas Systems. We assume that these rates and retention percentages will persist for the forecast period, 2011–2026; for AESC 2009 we made the same assumption.

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[87]Northern and Central New England is Massachusetts, New Hampshire and Maine; Southern New England is Connecticut and Rhode Island.

[88]Unlike in the past, the Federal Energy Regulatory Commission has decided that U.S. LNG terminals will not need to offer open access services and will be able to sell LNG at market prices. In a similar fashion the Maritimes & Northeast pipeline expansion is contracted by Repsol YPF, which is the provider of the LNG to the Canaport LNG terminal in New Brunswick. Thus this LNG will also be sold at market prices in New England.

Exhibit 4-7 shows typical rates that New England LDCs pay on the TGP and TETCO -AGP routes from the Henry Hub. These are the same rate schedules used in AESC 2007 and AESC 2009. For TGP the demand rates, in nominal dollars, and the fuel and loss retention percentages are the same as in AESC 2009.[89] The TGP usage rates are slightly higher now than in 2009. For TETCO the 2009 rates and fuel and loss retention are similar with small changes up and down. AGT's demand and usages charges are nearly identical in nominal dollars to the 2009 rates while the 2011 fuel and loss retention percentages are somewhat less.

89 Tennessee Gas Pipeline has filed with the FERC for substantially increased rates. However, these rates are not final and it is unknown what the final rates will be. Thus, for AESC 2011 we use the known and effective rates for TGP.

Exhibit 4-7: Pipeline Rates for Transportation and Storage

AESC 2011		Demand	Usage	Fuel & Loss (a)	
		$/DT/month	$/DT	Winter	Summer
				%	%
Texas Eastern Transmission, L.P. (b)					
Transportation: FT-1, WLA - M3				Dec - Mar	Apr - Nov
WLA-AAB		2.5945			
ELA-AAB		2.1471			
M1 - M3		10.8550			
Total Demand		15.5966			
WLA - M3 usage (c)			0.0371	8.10	7.12
Storage & Transportation: SS-1					
Reservation,		5.5480			
Space (d)	($/DT/year)	0.1293		0.07	0.07
Injection			0.0267	0.97	0.97
Withdrawal (c)			0.0350	3.34	3.09
Algonquin Gas Transmission LLC (e)					
				Dec - Mar	Apr - Nov
Transportation: AFT-1 (FT-1,WS-1)		6.5734			
Usage (c)			0.0131	1.02	0.72
Tennessee Gas Pipeline Company					
				Nov - Mar	Apr - Oct
Transportation FT-A (f) (g) (c)					
Zone 1 (LA) to 6		15.15	0.1522	7.82	6.67
Zone 1 (LA) to 4		na	0.1033	5.90	5.06
Zone 4 to 6		5.89	0.0853	2.17	1.92
Storage FS - Market Area (h)					
Reservation		1.15			
Space	($/DT/month)	0.0185			
Injection			0.0102	1.49	1.49
Withdrawal			0.0102		

Sources and Notes:

(a) Fuel and loss retention percentage is applied to volumes received by the pipeline.
(b) FT-1: Part 4-Statement of Rates, Section 2 FT-1, pages 1 & 2 of 16. Effective February 1, 2011.
SS-1: Part 4-Statement of Rates, Section 9, page 1. Effective February 1, 2011
Fuel and loss: Part 4-Statement of Rates, Section 16, page 1 & 2 of 3. Effective December 1, 2010.
(c) ACA charge ($0.0019) in the Algonquin and Tennessee usage rates, but not in TETCO usage rates.
Since ACA charge levied only once in a haul, the Algonquin charge is sufficient.
(d) SS-1 space charge as listed is paid at 1/12 rate per month. Fuel and loss is collected monthly.
(e) AFT-1: Part 4-Statement of Rates, Section 1, page 1. Effective May 17, 2010.
Fuel and loss: Part 4-Statement of Rates, Section 12, page 1. Effective December 1, 2010.
(f) FT-A: Tariff Sheet Nos. 14 effective July 1, 2010 and Sheet No. 15 effective April 19, 2010.
Even if the receipt point is in Zone L the rate is from Zone 1 to delivery zone. L rate is only for receipt and delivery in Zone L.
(g) Tennessee transportation fuel & loss retention percentages on Sheet No. 32 effective April 19, 2010
(h) FS: Sheet No. 61 effective July 1, 2010.

4.3.3.3. Long-Haul Pipeline “Cash” Costs

Gas is delivered to the LDC each month by pipelines from producing areas, in this analysis assumed to be the Henry Hub.[90] “Cash cost” means the avoided cost of transportation arising from pipeline usage charges, which are paid for each dekatherm of gas transported, and the demand charges allocated to that month, which pay for the reservation of pipeline capacity whether used or not. The avoided commodity cost of gas purchased was the price of gas at the Henry Hub that month multiplied by the ratio of the Henry Hub volume purchased to one dekatherm of gas delivered to the LDC. Because of the retention of gas for fuel and loss in both transportation and storage, more than one dekatherm of gas must be purchased at the Henry Hub in order to deliver one dekatherm to the LDC.

This ratio of gas volumes purchased at the Henry Hub to one dekatherm of gas delivered to the LDC was established by the fuel and loss retention percentages of the various pipeline transportation and storage services used between the Henry Hub and the LDC. For example, assume that the gas is transported by two pipelines: A and B from the Henry Hub to the LDC. The fuel and loss percentage is 6 percent for A (Fa) and 4 percent for pipeline B (Fb). The fuel and loss amount taken by the pipeline is based on the volumes received by the pipeline (R) while the demand and usage charges are based on the volume of gas delivered by the pipeline (D). In order to compute the ratio of gas received to that delivered the following equations were used:

1. $D = R – FR$
2. $D = R(1-F)$
3. $R/D = 1/(1-F)$

For pipeline A; $Ra/Da = 1/(1-.06) = 1.0638$; or $Ra = 1.0638\ Da$

For pipeline B; $Rb/Db = 1/(1-.04) = 1.0417$; or $Rb = 1.0417\ Db$

Since Db is the amount delivered to the LDC, Ra/Db or the ratio of the amount to be purchased in the field to the amount delivered to the LDC is what needs to be computed.

Since: $Rb = Da$

$Ra = 1.0638\ Da = (1.0638)Rb = (1.0638)(1.0417)Db$

Thus: $Ra/Db = (1.0638)(1.0417) = 1.1082$

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[90] Rate schedules assumed for the long-haul transportation: TETCO, FT-1 from zone WLA to zone M3; AGT, AFT-1 (FT-1) and TGP, FT-A from Zone 1 to Zone 6.

Or: 1.1082 DT of natural gas must be purchased for each DT delivered.

4.3.4. Avoided Costs of Supply (Energy) by Resource by Month

The LDC's weighted average avoided cost in each month is a function of the avoided cost of each resource and the relative quantity of *sendout* provided by each source each month. Exhibit 4-8 provides illustrative avoided costs by gas source and pipeline route for gas delivered to New England LDCs in January and June. The relative quantities of sendout, and injections into storage, by month by resource for a typical New England LDC are shown in Exhibit 4-6. Our estimates of the avoided cost of each resource by month are described below.

Exhibit 4-8: Comparison of Avoided Costs of Delivering One Dekatherm of Gas to a New England LDC from Three Sources of Natural Gas and Peak Day

		Texas Eastern & Algonquin		Tennessee Gas Pipeline	
		January	June	January	June
	units				
Pipeline Long-haul to LDC					
Total Demand Cost of Gas Delivered to LDC	2011 $/DT	$1.13	$0.00	$0.77	$0.00
Total Usage Cash Cost of Gas delivered to LDC	2011 $/DT	$0.05	$0.05	$0.15	$0.15
Ratio of Gas Purchased at HH to Gas Delivered to LDC		1.099	1.084	1.085	1.071
Delivered From Underground Storage					
Total Demand Cost of Gas Delivered to LDC from UG Storage	2011 $/DT	$1.43		$1.21	
Total Cash cost for refill + Usage Cost of Gas delivered to LD(	2011 $/DT	$0.79		$0.96	
Ratio of Gas Purchased to Gas Delivered to LDC		1.136		1.093	
LNG Regasified into LDC System					
Total Demand Cost of Gas Delivered to LDC for LNG refill	2011 $/DT	$0.91		$0.62	
Total Usage Cash Cost of Gas delivered to LDC for LNG refill	2011 $/DT	$0.06		$0.19	
Ratio of Gas Purchased at HH to Regasified Gas at the LDC		1.347		1.331	
Peak Day in January From Underground Storage					
Pipeline Cash Demand Cost of Gas Delivered to LDC	2011 $/DT	$100.13		$84.79	
Pipeline Cash Commodity Cost of Gas Delivered to LDC	2011 $/DT	$0.79		$0.96	
Ratio of Gas Purchased at HH to Gas Delivered to LDC		1.136		1.093	
Basaed on pipeline rates effective on 25 April 2011.					

4.3.4.1. Direct Long-Haul Pipeline Delivery

The analysis of a typical New England LDC send-out and storage refill shown in Exhibit 4-6 indicates that LDCs use 100 percent of their pipeline capacity to provide deliver supply in winter months. The use of the long-haul transportation capacity in the winter varies from about 90 percent in November and March to 100 percent in January. In summer months they use approximately 75 percent of this capacity. AESC 2011 allocates the winter-month pipeline-transportation-demand charges plus 25 percent of summer demand charges among the five winter months according to the quantity of capacity used each winter month. As a result, the avoided transportation demand cost varies among the five winter months with the month of heaviest use, January, receiving the largest allocation of demand charges.

Of that 75% of pipeline capacity LDCs use in the summer, they use 29% to deliver gas for injection into storage and 46 percent to provide direct supply.

- We allocate the costs of demand and usage charges and the fuel and loss fraction for pipeline transportation from the Henry Hub to refill storage to the avoided cost of underground storage and LNG peaking services.[91]
- We assume that an LDC will not avoid any capacity cost due to a reduction in summer load, because it needs to hold the capacity entitlement in order to serve its winter load and because the market value of short-term, summer releases of pipeline capacity is close to zero. This low market value is reflected in the low basis differentials in the summer between the Henry Hub and either the ALG gas spot market or the TGP Z6 spot gas market. The basis differential for each market is enough to cover the usage charges and fuel, but there is little or no amount remaining to pay for demand charges. This means that an LDC would continue to pay the full demand charge in each summer month even if the gas requirements of customers were reduced due to energy efficiency in the summer; thus the LDC would not avoid the summer pipeline demand charges.

4.3.4.2. Underground Storage

Natural gas is delivered to the LDC from underground storage during the five winter months of November through March; see Exhibit 4-4. For both TETCO and TGP, the underground storage is located in Pennsylvania. The avoided cost of underground storage supply for one dekatherm in January is shown in Exhibit 4-8.

The avoided cost of underground storage included the cost of buying gas at the Henry Hub, pipeline demand and usage charges to bring gas to the storage facility in the summer, the cost of injection, the demand cost of storage capacity, the demand and variable costs of withdrawing gas from storage and the demand and variable costs of transporting gas to the LDC from underground storage.[92]

[91] This follows the same methodology used in AESC 2009.

[92]Rate schedules used in the calculation for the TETCO-AGT route are: TETCO, FT-1 zone WLA to zone M3; storage on TETCO and transportation to AGT, SS-1; and transportation to the LDC on AGT, AFT-1 (WS-1). Rate schedules used in the Tennessee route are: TGP, FT-A zone 1 to zone 4; storage on TGP, FS–market area; and transportation to the LDC on TGP, FT-A zone 4 to zone 6.

The cost of gas injected into storage was the cost of buying gas at the Henry Hub, as adjusted for fuel and loss retention, plus the cost of transportation to underground storage including both demand and usage costs at 100 percent load factor. The cost of the gas injected into storage was less than the average cost of gas for a year, 96.9 percent of the annual cost, because gas is purchased for injection during the summer months when the price of gas is less than average.

Pipelines bill demand charges to LDCs for the capacity that LDCs hold for withdrawal of gas from storage and transportation to their system every month of the year. Because gas is withdrawn from underground storage and delivered to an LDC only during the 5 winter months, we allocated a full year of withdrawal and transportation-demand charges to the five winter months.[93] These annual demand charges were allocated among each of the five winter months according to the relative quantity of capacity the LDC used in each month to transport gas from underground storage to its city gate. January is the peak send-out month from all gas sources and from underground storage; the other winter months, especially November and March, experience less send-out as shown in Exhibit 4-6. Thus, the demand cost of unused capacity of storage withdrawal and of transportation capacity from underground storage to the LDC in November and March was assigned to the sendout during December through February based on usage each month. Similarly, the unused capacity during December and February was assigned to the cost of withdrawing and transporting gas to the LDC in January.

4.3.4.3. Liquid Natural Gas and Peak Shaving

There are 46 liquefied-natural-gas (LNG) tanks in New England in addition to the Distrigas LNG import terminal. These tanks, and to a lesser extent propane, provide peak-shaving supply for LDCs. The costs avoided by peak shaving are based only on LNG in AESC 2011. These facilities have fixed and variable costs. The estimate of avoided costs was based on the variable costs only.

The major embedded or accounting costs of LNG send-out for peaking service are the fixed costs of building the tank, vaporization and liquefaction capacity, and the fixed costs of operation and maintenance. However, these fixed costs are likely to be unaffected by reductions in gas demand due to modest-sized efficiency improvement measures. These fixed costs are sunk costs. Moreover, LNG peaking facilities have strong economies of scale and thus are lumpy investments. They are

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[93] This is true of the storage and delivery service of TETCO in rate schedule SS-1 as well at withdrawal from storage and transportation to the LDC on TGP. However, AGT has a winter service, WS, firm transportation from the interconnection with TETCO to New England LDCs which has demand charges for only the five winter months. AESC 2007 reflects AGT's five months of demand charges in its allocation and calculation.

likely to be sized to accommodate growth in gas send-out. In addition, the cost of changing the capacity of send-out is the cost of vaporization facilities, which is a small portion of the total fixed costs of the LNG peaking facility. Thus, it was assumed that the avoided cost of LNG peaking facilities due to efficiency improvements should ignore these fixed costs.

The avoided costs of LNG peaking are the variable costs of the LNG; the cost of gas at the Henry Hub, costs of pipeline transport to bring gas to the LNG facility, including pipeline demand charges, and then the variable costs of liquefaction and re-gasification.[94] The variable costs of liquefaction and vaporization are principally the gas that is used in the liquefaction stage and the vaporization stage. It was assumed that fuel use is 17 percent for liquefaction and 3% for vaporization. This is the same cost methodology used in AESC 2009.

The estimated avoided cost of LNG peaking service varies by time and pipeline; see Exhibit 4-8.

4.3.5. Avoided Costs of Peak Day Supply

The Scope of Work requests estimates of the future natural gas costs avoided by energy efficiency programs provided as all in values in $/MMBtu as well as provided as separate values for avoided energy ($/MMBtu) and avoided peak-day capacity ($/MMBtu). This section describes the calculation of an estimate of avoided peak-day capacity costs.

First, it is not clear that program administrators need an estimate of peak-day capacity costs to estimate the benefits of gas efficiency programs. Unlike electricity programs that reduce demand only during peak hours, there do not appear to be any efficiency programs that reduce gas use only on a peak day. Further, the “capacity value” of gas efficiency programs that reduce gas use over an entire year or over a heating season is incorporated in our projection of all in values of gas avoided costs in $/MMBtu. Our estimate of avoided gas cost at the city gate by month includes both avoided fixed costs (cash pipeline demand charges) and variable costs (gas commodity costs, cash pipeline usage charges and adjustments for fuel and losses in pipeline transportation and storage of gas). These avoided costs, plus avoided distribution costs, provide the full avoided cost of gas by end uses that LDCs need to evaluate gas efficiency programs. The

[94] Rate schedules used for the long-haul transportation of gas in the summer to be liquefied are the same as those cited for long-haul transportation: TETCO, FT-1 from zones WLA to zone M3; AGT, AFT-1 (FT-1) and TGP, FT-A from zone 1 to zone 6. LDC LNG tanks are also filled by hauling imported LNG from the Distrigas facility to the LNG tank by tanker truck. However, we assume that Distrigas will price this LNG at the LDC’s avoided cost of liquefaction.

avoided costs presented in Exhibit 4-5 are comprehensive and provide the full value of reductions in gas use in New England.

Second, there are differences between the gas industry and the electric industry that affect the calculation of avoided electric capacity costs versus avoided gas peak-day costs. In electricity distribution, load-serving entities (LSEs) responsible for providing firm supply of electricity to retail customers acquire a sufficient total quantity of capacity to ensure reliable service using a mix of different types of resources. The New England electric industry has separate, explicit wholesale markets for electric capacity and for electric energy. ISO-NE requires load-serving entities to hold sufficient total capacity equal to their projected summer coincident peak plus an additional reserve equal to an explicit "reserve margin multiplier." The electric reserve margin multiplier reflects the additional quantity of capacity in order to ensure reliability. It is in the range of 15 percent: LSEs are required by ISO-NE to hold capacity equal to 1.15 times their projected peak demand under normal conditions. This is a uniformly applied regulatory requirement that allows a calculation of avoided cost when the peak requirement is reduced by efficiency programs: usually assuming a gas-fired combustion turbine is the proxy for the cost of the peaking resource.

But the electricity and gas industries are different. Gas can be and is stored in substantial quantities in various ways: LNG tanks, underground storage, and line pack. In contrast, electricity, as a practical matter, cannot be stored. Furthermore, the flow of electricity in the electricity grid is controlled largely by Kirchoff's laws, which at times of stress has led to large scale blackouts. In contrast, the flow of gas in the gas grid is controlled by compressors and valves that are themselves controlled by people who follow contracts, nominations, and, occasionally, emergency protocols. These differences have led to some of the differences in regulation and operation between the gas and electricity industry.

Unlike the electricity industry, the New England gas industry LDCs buy gas largely in the wholesale markets of production areas of the U.S. Southwest, Appalachia, and Canada, and some perhaps in the New England wholesale market for gas energy. Rather LDCs buy transmission and underground storage capacity from pipelines via bilateral contracts where the prices are generally set in a FERC regulated tariff. Moreover there is no equivalent to ISO-NE that imposes explicit uniform reliability requirements to LDCs in New England. Instead, it is our understanding that each LDC determines the total physical quantity of capacity it needs to hold to ensure reliable supply service under two sets of design conditions. The first set is a *design day*, a needle peak demand during 1day of substantially colder-than-normal temperatures that occur only rarely. The second set is a *design winter*, the level of sendout in each month of a winter with colder-than-normal temperatures. LDCs must demonstrate to their state regulators that they hold sufficient capacity to ensure reliable service.

Local distribution companies acquire the capacity needed to meet design-day demands from a range of resources, according to their particular location and circumstances. For example Vermont Gas Systems relies on spot gas for peaking for normal winters under an arrangement with its supply pipeline with backup propane-air for exceptionally cold days. Many New England LDCs use local LNG storage facilities to meet peak day requirements. One New York utility appears to rely upon a large, gas-fired cogeneration power plant to switch to No. 2 fuel oil and release gas to the LDC on a few peak days in a year. Thus, there is not a common resource used to meet peak-day requirements.

However, we provide an estimate of avoided peak-day costs for those LDCs who do choose to include an avoided peak-day cost. Other LDCs may choose to adjust this estimate upward to account for their design-winter reserve margin, e.g. perhaps 10% greater than during a normal winter sendout, when computing their avoided cost. The avoided demand charges for each month of the winter will provide the number for such an addition to the avoided costs computed here.

4.3.5.1. Peak-Day Avoided Cost

Liquid-natural-gas peaking facilities are generally used to meet the peak-day requirements of New England LDCs. The fixed costs were excluded from the estimate of the avoided costs for the LNG facilities. The resulting modest cost, which excludes fixed costs, does not properly capture the high avoided costs that are expected for peak day service.

Consequently, peak-day avoided costs are estimated based on the costs of underground storage. We assume that underground storage and transportation capacity to the LDC was needed to meet a one-day peak even though the demand charges are generally paid for twelve months.[95] Thus, in calculating the peak-day avoided cost, the demand charges for all twelve months were allocated to the one-day peak.

The estimate of peak-day avoided costs is shown in Exhibit 4-8 for both the TETCO-ALG and the TGP routes. As can be seen, greater incremental demand charges, especially when several pipelines are used for transportation, produce high peak-day avoided costs.

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[95]In the case of transportation of stored gas to New England on AGT, a winter service is used for which demand charges are paid for only the five-month winter period.

An alternative estimate of the avoided cost of natural gas on a peak-day to a New England LDC is the spot market price of natural gas in New England on a peak day. The largest peak-day sendout in New England since 2002 occurred on January 15, 2004 (Leahey 2008, 62). During that day the spot price of gas in ALG was $63.42 per dekatherm, and the spot price at TGP Zone 6 was $49.81 per dekatherm.

4.3.6. Total Avoided Costs by Month

The avoided costs of natural gas were determined by month in two of the three geographic areas: Northern and Central New England (Massachusetts, New Hampshire and Maine) and Southern New England (Connecticut and Rhode Island). The avoided cost forecast for Vermont is presented later within this chapter. The avoided cost of natural gas by month is calculated as the weighted average of the avoided cost of gas delivered to the LDC from each of the three sources: long-haul pipeline, underground storage, and LNG storage.

The weightings each month are shown in Exhibit 4-6 above under the “Fraction of Annual Sendout Each Month” section of the exhibit.[96]

Like AESC 2009, we assume that the avoided cost in Southern New England is the cost of gas delivered to LDCs by the Texas Eastern and Algonquin pipeline route. Similarly, we assume that the avoided cost of gas delivered to LDCs in Northern and Central New England was provided by Tennessee Gas Pipeline.

The avoided cost forecast by month for Southern New England, Northern and Central New England, and Vermont Gas Systems are detailed in Appendix D. Also shown in the appendix is the annual Henry Hub forecast price of natural gas. Other than for the estimated peak-day avoided cost, the commodity cost of gas based on the Henry Hub price was the largest component of the avoided cost.

The levelized avoided cost is the cost for which the present value at the real rate of return of 2.465 percent has the same present value as the estimated avoided costs for the years 2012 through 2026 at the same rate of return.

[96]The summer periods, April–October, and November and December all fall within a single calendar year; thus, the commodity cost of gas for those months is based on the Henry Hub price for that calendar year. However, the winter periods, November–March, span calendar years. The majority of gas delivered in the winter is from LNG and underground storage, which was purchased during the previous summer. Thus, we assume that the commodity cost of gas from underground storage and LNG is based on the Henry Hub price from the year in which the winter delivery period begins. However, we assume that the gas supplied directly from the long-haul pipeline delivery is purchased in the month of delivery and thus January–March costs are based on the Henry Hub price for the following year.

4.3.6.1. Comparison with the AESC 2009 Avoided-Cost at an LDC City Gate

Avoided costs at the LDC city gate, excluding the cost of purchased gas, by source in AESC 2011 are very similar to those in AESC 2009, see Exhibit 4-9.[97] Rates did not change much from 2009 to 2011 in nominal terms. When comparing these costs by source in 2011 dollars the AESC 2009 costs are higher because the rates charged by TETCO, AGT, and TGP do not keep up with inflation. The major difference in the avoided costs will be due to changes in the cost of gas at Henry Hub.

Exhibit 4-9: Illustrative Comparison of AESC 2007 and AESC 2009 Avoided Costs by Source: TETCO-AGT to Southern New England

	units	AESC 2009	AESC 2009	AESC 2011
		2009$/DT	2011 $ per Dekatherm	
Pipeline Long-haul to LDC				
Total Demand Cost of Gas Delivered to LDC	$/DT	$0.99	$1.01	$1.13
Total Usage Cash Cost of Gas delivered to LDC	$/DT	$0.07	$0.08	$0.05
Ratio of Gas Purchased at HH to Gas Delivered to LDC		1.099	1.099	1.099
Delivered From Underground Storage				
Total Demand Cost of Gas Delivered to LDC from UG Storage	$/DT	$1.37	$1.40	$1.43
Total Cash cost for refill + Usage Cost of Gas delivered to LDC	$/DT	$0.83	$0.85	$0.79
Ratio of Gas Purchased to Gas Delivered to LDC		1.145	1.145	1.136
LNG Regasified into LDC System				
Total Demand Cost of Gas Delivered to LDC for LNG refill	$/DT	$0.91	$0.93	$0.91
Total Usage Cash Cost of Gas delivered to LDC for LNG refill	$/DT	$0.09	$0.09	$0.06
Ratio of Gas Purchased at HH to Regasified Gas at the LDC		1.349	1.349	1.347
Peak Day in January From Underground Storage				
Typical Rates				
Pipeline Cash Demand Cost of Gas Delivered to LDC	$/DT	$100.33	$102.20	$100.13
Pipeline Cash Commodity Cost of Gas Delivered to LDC	$/DT	$0.83	$0.85	$0.79
Ratio of Gas Purchased at HH to Gas Delivered to LDC		1.145	1.145	1.136
AESC 2009 based on pipeline rates effective May 12, 2009. AESC 2011 based on rates effective April 25, 2011				
`Convert 2009 $ to 2011 $	1.0186			

The changes in the demand charges for the long haul pipeline are due to differences in the allocation of demand charges between the two studies. The reduced fuel and loss for storage in AESC 2011 reflects the lowered AGT fuel and loss retention in AESC 2011 compared with AESC 2009.

[97] This comparison is for the pipeline route of TETCO and AGT. However, the comparison of avoided-cost estimates along the TGP route would provide similar qualitative comparisons.

4.4. Avoided Gas Costs by End Use

End uses of natural gas at retail are distinguished by the type of end-use: heating or low load factor, non-heating or high load factor and all. The costs associated with these end-uses also vary by the type of customer or sector, i.e., residential, commercial, and industrial.[98]

4.4.1. Load Shape by End Use

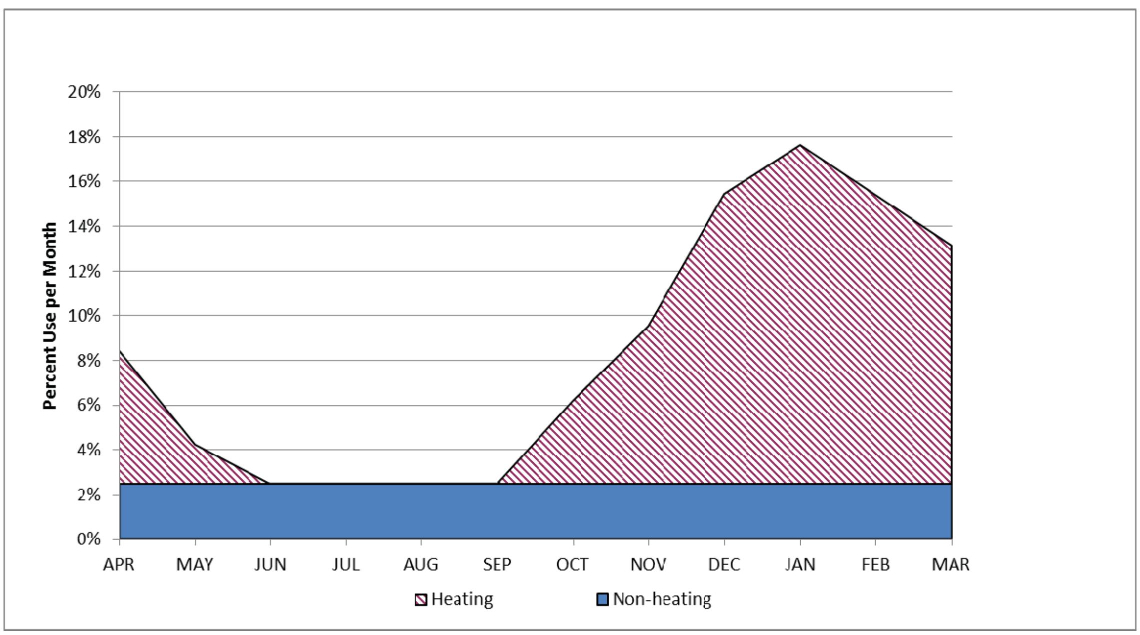
The different types of end-use have different profiles of gas use by month as shown in Exhibit 4-10 and Exhibit 4-11. Exhibit 4-10 shows the load profile of heating loads as percentages, which are graphed in Exhibit 4-11.

Exhibit 4-10: End-Use Load Profiles

		APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	ANNUAL
Non-Heating (high load factor)	(a)	8.33%	8.33%	8.33%	8.33%	8.33%	8.33%	8.33%	8.34%	8.34%	8.34%	8.34%	8.33%	100.00%
	30%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	
Heating Load (low load factor)	(b)	8.50%	2.50%	0.00%	0.00%	0.00%	0.00%	5.30%	10.00%	18.50%	21.60%	18.40%	15.20%	100.00%
	70%	5.95%	1.75%	0.00%	0.00%	0.00%	0.00%	3.71%	7.00%	12.95%	15.12%	12.88%	10.64%	
All Loads: Heating and Non-heating	(c)	8.45%	4.25%	2.50%	2.50%	2.50%	2.50%	6.21%	9.50%	15.45%	17.62%	15.38%	13.14%	100.00%

(a) Constant load all year; rounding altered in the winter months to maintain 100% use for the year.
(b) Distribution of the heating (low load factor) load among the months of the year based on data provided by National Grid (MA).
(c) Weighted average for each month at 70% heating load shape and 30% non-heating load shape. Distribution between heating load and non-heating load based on data from National Grid (MA).

Exhibit 4-11: End-Use Load Profiles Graphed



98 The electric power sector is not addressed here.

The heating loads occur October through May with a peak in January. This load profile is derived from data provided by National Grid (MA) with some slight modification using New England heating degree-day data. The non-heating load is constant year round while all loads are represented as the weighted average between the heating and the non-heating load weighted 70 percent to heating and 30 percent to non-heating.

4.4.2. Avoided Distribution Cost by Sector

The avoided cost for each end use by sector and the retail sector is the sum of the avoided cost of the gas sent out by the LDC and the avoidable distribution cost, called the avoidable LDC margin, applicable from the city gate to the burner tip.

Estimates of the portion or amount of distribution cost that is avoidable due to reductions in gas use from efficiency measures vary by LDC. Some LDCs have estimated this amount as their incremental or marginal cost of distribution; that is, the change in cost of distribution incurred as demand for gas increases or decreases. The conclusion was that the incremental cost of distribution depends upon the load type and the customer sector. For low load factor or heating loads more of the embedded cost for each sector is incremental or avoidable than for high load factor or non-heating loads. The incremental or avoidable cost is measured as a percent of the embedded costs. For AESC 2011, we measure the embedded cost as the difference between the city-gate price of gas in a state and the price charged each of the different retail customer types: residential, commercial - industrial, and all retail customers.[99] The embedded distribution cost for each of the two regions, Southern and Northern and Central, were the weighted average distribution costs among the relevant states where the weighting is the volumes of gas delivered to each sector in each state.

Exhibit 4-12 shows the estimated avoidable LDC margin percentage and avoidable costs, measured as 2011 dollars per dekatherm, by each of the end-use types and customer sectors for each region in New England.

[99]The city-gate gas prices and the prices charged to each retail customer sector are reported by the Energy Information Administration for each state each year. In AESC 2011 the cost used are the average for the 5 years 2005-2009, which is the most recent data available.

Exhibit 4-12: Avoidable LDC Margin

Estimated Avoidable LDC Margins (a)
(2011$/dekatherm)

Type of End Use	Total LDC Retail Margin & CG Price	Avoidable LDC Margin: Non-heating (High Load Factor)	Avoidable LDC Margin: Heating (Low Load Factor)	Avoidable LDC Margin: All
Avoidable Margin (percent) (b)				
Residential		8.0%	21.0%	20.4%
Commercial & Industrial		15.0%	28.0%	24.0%
All Retail				22.0%
Southern New England (c)				
Average City Gate Price	9.550			
Residential	7.527	0.60	1.58	1.54
Commercial & Industrial (e)	3.615	0.54	1.01	0.87
All Retail (f)	5.348			1.18
Northern & Central New England (d)				
Average City Gate Price	10.153			
Residential	6.576	0.53	1.38	1.34
Commercial & Industrial (e)	4.334	0.65	1.21	1.04
All Retail (f)	5.408			1.19
Vermont				
Average City Gate Price	9.312			
Residential	5.962	0.48	1.25	1.22
Commercial & Industrial (e)	1.597	0.24	0.45	0.38
All Retail (f)	3.189			0.70

Source: EIA website data sources.
(a) Average of Margins among states for 2005 - 2009 weighted by the delivered volumes in each state.
(b) Based on LDC marginal cost studies from National Grid (MA).
(c) Southern New England is Rhode Island and Connecticut
(d) Northern & Central New England is Massachusetts, New Hamshire and Maine.
(e) An average of the margins weighted by the commercial and industrial use delivered volumes.
(f) An average of residential, commercial and industrial margins weighted by associated volumes.

Other LDCs assume they will not avoid any distribution costs due to reductions in gas use from efficiency measures. The avoided cost of gas by end-use for an LDC with no avoided distribution cost is their avoided cost of gas delivered to their city-gate.

4.4.3. Avoided Costs by End-Use

Exhibits 4-13 through 4-16 and Appendix D for Vermont Gas Systems show the total avoided costs per year per Dekatherm for the retail end-uses categorized by the end-use type and customer sector for Southern New England and Northern and Central New England. The avoided cost of the gas sent out by the LDCs by load type is the weighted sum across all months of the avoided cost per dekatherm each month delivered to the city gate as detailed in Appendix D, multiplied by the percent used each month for each load type (heating, non-heating or all) plus the avoided retail margin for each retail customer sector. The levelized avoided cost is the cost for which the present value at the real rate of return of 2.465 percent has the same present value as the estimated avoided costs for the 15-year period 2012 through 2026 at the same rate of return. The resulting avoided cost each year for the different load types is shown in Appendix D.

Exhibit 4-1, which summarizes Exhibit 4-13 and Exhibit 4-14, shows the total levelized avoided costs if some retail margin is avoidable. Exhibit 4-2, which summarizes Exhibit 4-15 and Exhibit 4-16, shows the total levelized avoided costs if no retail margin is avoidable. Exhibit 4-13 and Exhibit 4-14 provide projections of avoidable cost by end-use for utilities in Southern New England and Northern and Central New England for which some LDC retail margin is avoidable.

Exhibit 4-13: Avoided Cost of Gas Delivered to an End Use Load, Assuming Some Retail Margin is Avoidable; Southern New England

AVOIDED COSTS OF GAS DELIVERED TO RETAIL CUSTOMERS
SOUTHERN NEW ENGLAND BY END USE
ASSUMING SOME AVOIDABLE RETAIL MARGIN
Gas Delivered via Texas Eastern and Algonquin Gas Pipelines
(2011$/Dekatherm)

	RESIDENTIAL				COMMERCIAL & INDUSTRIAL			ALL
Year	Non Heating	Hot Water annual	Heating	All	Non Heating	Heating	All	RETAIL END USES
2011	5.97	5.97	7.74	7.46	5.91	7.17	6.79	7.10
2012	6.49	6.49	8.21	7.94	6.43	7.64	7.27	7.58
2013	6.70	6.70	8.42	8.15	6.64	7.86	7.49	7.80
2014	6.98	6.98	8.81	8.51	6.92	8.24	7.84	8.15
2015	7.56	7.56	9.28	9.01	7.50	8.71	8.34	8.65
2016	7.59	7.59	9.30	9.04	7.53	8.74	8.37	8.68
2017	7.57	7.57	9.29	9.02	7.51	8.72	8.35	8.66
2018	7.59	7.59	9.32	9.05	7.53	8.75	8.38	8.69
2019	7.64	7.64	9.37	9.10	7.58	8.80	8.43	8.74
2020	7.73	7.73	9.47	9.20	7.67	8.90	8.53	8.84
2021	7.83	7.83	9.58	9.30	7.77	9.01	8.63	8.94
2022	7.96	7.96	9.75	9.46	7.90	9.18	8.80	9.10
2023	8.25	8.25	10.03	9.74	8.19	9.46	9.07	9.38
2024	8.44	8.44	10.20	9.92	8.38	9.63	9.25	9.56
2025	8.51	8.51	10.29	10.00	8.45	9.72	9.33	9.64
2026	8.64	8.64	10.42	10.14	8.58	9.85	9.47	9.78
Levelized (a)	7.64	7.64	9.39	9.11	7.58	8.82	8.44	8.75
Simple Average	7.70	7.70	9.45	9.17	7.64	8.88	8.50	8.81

(a) Years 2012-2026 (15 years); Real (constant $) riskless annual rate of return in %: 2.465%

Exhibit 4-14: Avoided Cost of Gas Delivered to an End Use Load, Assuming some Retail Margin is Avoidable; Northern & Central New England

AVOIDED COSTS OF GAS DELIVERED TO RETAIL CUSTOMERS
NORTHERN & CENTRAL NEW ENGLAND BY END USE
ASSUMING SOME AVOIDABLE RETAIL MARGIN
Gas Delivered via Tennassee Gas Pipeline
(2011$/Dekatherm)

Year	RESIDENTIAL				COMMERCIAL & INDUSTRIAL			ALL RETAIL END USES
	Non Heating	Hot Water annual	Heating	All	Non Heating annual	Heating	All	
2011	5.82	5.82	7.35	7.11	5.95	7.18	6.80	6.95
2012	6.34	6.34	7.80	7.58	6.46	7.64	7.28	7.43
2013	6.54	6.54	8.01	7.79	6.67	7.85	7.49	7.64
2014	6.82	6.82	8.39	8.14	6.95	8.23	7.84	7.99
2015	7.39	7.39	8.86	8.63	7.51	8.69	8.33	8.48
2016	7.42	7.42	8.88	8.66	7.55	8.71	8.36	8.51
2017	7.40	7.40	8.87	8.64	7.52	8.70	8.34	8.49
2018	7.42	7.42	8.89	8.67	7.55	8.73	8.37	8.52
2019	7.47	7.47	8.95	8.72	7.59	8.78	8.42	8.57
2020	7.56	7.56	9.04	8.82	7.68	8.88	8.51	8.66
2021	7.66	7.66	9.15	8.92	7.78	8.98	8.62	8.77
2022	7.79	7.79	9.32	9.08	7.91	9.15	8.78	8.93
2023	8.07	8.07	9.59	9.35	8.19	9.42	9.05	9.20
2024	8.26	8.26	9.76	9.53	8.38	9.59	9.22	9.37
2025	8.33	8.33	9.84	9.61	8.46	9.68	9.31	9.46
2026	8.45	8.45	9.98	9.74	8.58	9.81	9.44	9.59
Levelized (a)	7.47	7.47	8.96	8.73	7.59	8.79	8.43	8.58
Simple Average	7.53	7.53	9.02	8.79	7.65	8.86	8.49	8.64

(a) Years 2012-2026 (15 years); Real (constant $) riskless annual rate of return in 2.465%

Exhibit 4-15 and Exhibit 4-16 show the avoided cost by end-use for utilities at which it is assumed that no LDC retail margin is avoidable.

Exhibit 4-15: Avoided Cost of Gas by End Use Load Type, Southern New England

AVOIDED COSTS OF GAS DELIVERED TO LDCs
BY END-USE LOAD TYPE: ASSUMING NO AVOIDABLE RETAIL MARGIN
Southern New England
Gas Delivered via Texas Eastern and Algonquin Pipelines
(2011$/Dekatherm)

	END-USE LOAD TYPE				Annual
Year	Heating	Non-Heating	All	Annual Average	Henry Hub Price
2011	6.16	5.37	5.92	5.37	4.37
2012	6.63	5.89	6.41	5.89	4.91
2013	6.84	6.10	6.62	6.10	5.10
2014	7.23	6.38	6.97	6.38	5.29
2015	7.70	6.95	7.48	6.95	5.91
2016	7.72	6.99	7.50	6.99	5.96
2017	7.71	6.97	7.49	6.97	5.93
2018	7.74	6.99	7.51	6.99	5.95
2019	7.79	7.03	7.56	7.03	5.98
2020	7.89	7.13	7.66	7.13	6.06
2021	7.99	7.23	7.77	7.23	6.16
2022	8.17	7.36	7.93	7.36	6.25
2023	8.45	7.64	8.21	7.64	6.52
2024	8.62	7.84	8.38	7.84	6.72
2025	8.70	7.91	8.47	7.91	6.78
2026	8.84	8.04	8.60	8.04	6.89
Levelized (a)	7.81	7.04	7.57	7.04	5.97
Simple Average	7.87	7.10	7.64	7.10	6.03
(a)	15 Years (2012 - 2026) at the Real (constant $) Disco			2.465%	

Exhibit 4-16: Avoided Cost of Gas by End Use Load Type, Northern and Central New England

AVOIDED COSTS OF GAS DELIVERED TO LDCs BY END-USE LOAD TYPE: ASSUMING NO AVOIDABLE RETAIL MARGIN Northern & Central New England Gas Delivered via Tennesse Gas Pipeline (2011$/Dekatherm)					
	END-USE LOAD TYPE				Annual
Year	Heating	Non-Heating	All	Annual Average	Henry Hub Price
2011	5.96	5.30	5.76	5.30	4.37
2012	6.42	5.81	6.24	5.81	4.91
2013	6.63	6.02	6.45	6.02	5.10
2014	7.01	6.30	6.80	6.30	5.29
2015	7.48	6.86	7.29	6.86	5.91
2016	7.50	6.90	7.32	6.90	5.96
2017	7.48	6.87	7.30	6.87	5.93
2018	7.51	6.90	7.33	6.90	5.95
2019	7.57	6.94	7.38	6.94	5.98
2020	7.66	7.03	7.47	7.03	6.06
2021	7.77	7.13	7.58	7.13	6.16
2022	7.94	7.26	7.74	7.26	6.25
2023	8.21	7.54	8.01	7.54	6.52
2024	8.38	7.73	8.18	7.73	6.72
2025	8.46	7.81	8.27	7.81	6.78
2026	8.60	7.93	8.40	7.93	6.89
Levelized (a)	7.58	6.94	7.39	6.94	5.97
Simple Average	7.64	7.00	7.45	7.00	6.03
(a)	15 Years (2012 - 2026) at the Real (constant $) Discor			2.465%	

4.4.4. Comparison of Avoided Retail Gas Costs with AESC 2009

Exhibit 4-17, shows that the end use avoided costs of gas use in AESC 2011 are less than estimated in AESC 2009 for all states in New England assuming that some retail margin is avoidable.[100] There are two major reasons for this: 1) we now forecast lower gas prices at the Henry Hub than in AESC 2009 and 2) the estimates of avoided retail margin are less than in AESC 2009.

[100] Exhibit 4-17 is the same as Exhibit 4-1 and Exhibit 4-18 is the same as Exhibit 4-2.

Exhibit 4-18 shows the end use avoided costs of gas use if one assumes that no retail margin is avoidable in AESC 2011 but that the avoidable retail margin estimated in AESC 2009 remains.

Exhibit 4-17: Comparison of Avoided Cost with Those of AESC 2009 Assuming Some Retail Margin Avoided

COMPARISON OF LEVELIZED AVOIDED COSTS OF GAS DELIVERED TO RETAIL CUSTOMERS
BY END USE: AESC 2009 AND AESC 2011
ASSUMING SOME AVOIDABLE RETAIL MARGIN
(2011$/Dekatherm except where indicated as 2009$/DT

	RESIDENTIAL				COMMERCIAL & INDUSTRIAL			ALL RETAIL
	Non Heating	Hot Water	Heating	All	Non Heating	Heating	All	
Southern New England								
AESC 2009 (2009$/DT)	11.42	11.42	14.52	13.52	9.88	11.83	11.21	12.26
AESC 2009 (a)	11.63	11.63	14.79	13.77	10.07	12.05	11.42	12.49
AESC 2011	7.64	7.64	9.39	9.11	7.58	8.82	8.44	8.75
2009 to 20119 change	-34.33%	-34.33%	-36.54%	-33.82%	-24.71%	-26.84%	-26.08%	-29.92%
Northern & Central New England								
AESC 2009 (2009$/DT)	10.87	10.87	13.54	12.67	10.02	12.05	11.40	12.03
AESC 2009 (a)	11.08	11.08	13.79	12.91	10.21	12.28	11.61	12.25
AESC 2011	7.47	7.47	8.96	8.73	7.59	8.79	8.43	8.58
2009 to 2011 change	-32.57%	-32.57%	-35.03%	-32.38%	-25.64%	-28.37%	-27.41%	-29.99%
Vermont								
AESC 2009 (2009$/DT)	9.72	9.72	12.43	11.56	8.01	9.44	9.00	9.93
AESC 2009 (a)	9.90	9.90	12.66	11.77	8.16	9.62	9.17	10.12
AESC 2011	7.54	7.54	9.88	9.37	7.30	9.08	8.54	8.86
2009 to 2011 change	-23.86%	-23.86%	-21.95%	-20.36%	-10.57%	-5.67%	-6.82%	-12.44%

(a) Factor to convert 2009$ to 2011 $ 1.0186
Note: AESC 2009 levelized costs for 15 years, 2010 - 2024 at a discount rate of 2.22%.
AESC 2011 levelized costs for 15 years 2012 - 2026 at a discoiunt rate of 2.465%.

Exhibit 4-18: Comparison of Avoided Cost with Those of AESC 2009 Assuming No Retail Margin is Avoided in AESC 2011

COMPARISON OF LEVELIZED AVOIDED COSTS OF GAS DELIVERED TO RETAIL CUSTOMERS
BY END USE: AESC 2009 AND AESC 2011
NO AVOIDABLE RETAIL MARGIN in AESC 2011 but is in AESC 2009
(2011$/Dekatherm except where indicated as 2009$/DT

	RESIDENTIAL				COMMERCIAL & INDUSTRIAL			ALL RETAIL
	Non Heating	Hot Water	Heating	All	Non Heating	Heating	All	
Southern New England								
AESC 2009 (2009$/DT)	11.42	11.42	14.52	13.52	9.88	11.83	11.21	12.26
AESC 2009 (a)	11.63	11.63	14.79	13.77	10.07	12.05	11.42	12.49
AESC 2011	7.04	7.04	7.81	7.57	7.04	7.81	7.57	7.57
2009 to 20119 change	-39.50%	-39.50%	-47.23%	-44.98%	-30.10%	-35.24%	-33.67%	-39.34%
Northern & Central New England								
AESC 2009 (2009$/DT)	10.87	10.87	13.54	12.67	10.02	12.05	11.40	12.03
AESC 2009 (a)	11.08	11.08	13.79	12.91	10.21	12.28	11.61	12.25
AESC 2011	6.94	6.94	7.58	7.39	6.94	7.58	7.39	7.39
2009 to 2011 change	-37.32%	-37.32%	-45.04%	-42.77%	-32.01%	-38.26%	-36.37%	-39.70%
Vermont								
AESC 2009 (2009$/DT)	9.72	9.72	12.43	11.56	8.01	9.44	9.00	9.93
AESC 2009 (a)	9.90	9.90	12.66	11.77	8.16	9.62	9.17	10.12
AESC 2011	7.06	7.06	8.63	8.16	7.06	8.63	8.16	8.16
2009 to 2011 change	-28.68%	-28.68%	-31.84%	-30.70%	-13.50%	-10.32%	-11.00%	-19.38%

(a) Factor to convert 2009$ to 2011 $ 1.0186
Note: AESC 2009 levelized costs for 15 years, 2010 - 2024 at a discount rate of 2.22%.
AESC 2011 levelized costs for 15 years 2012 - 2026 at a discoiunt rate of 2.465%.

4.5. Avoided Gas Costs in Vermont

There is one LDC in Vermont, Vermont Gas Systems, Inc. (VGS). It receives its gas from TransCanada Pipeline at Highgate Springs, Vermont. The analysis of the avoided cost to the LDC in Vermont was performed similarly to that for the other two areas. Based on data provided by VGS, the source of gas was determined for each month of the year by the fraction contribution each month to serve firm customers.[101] Next, the avoided cost of natural gas to VGS by source for each month was computed, and then volume weighted to compute the average avoided cost of gas received at the city gate.

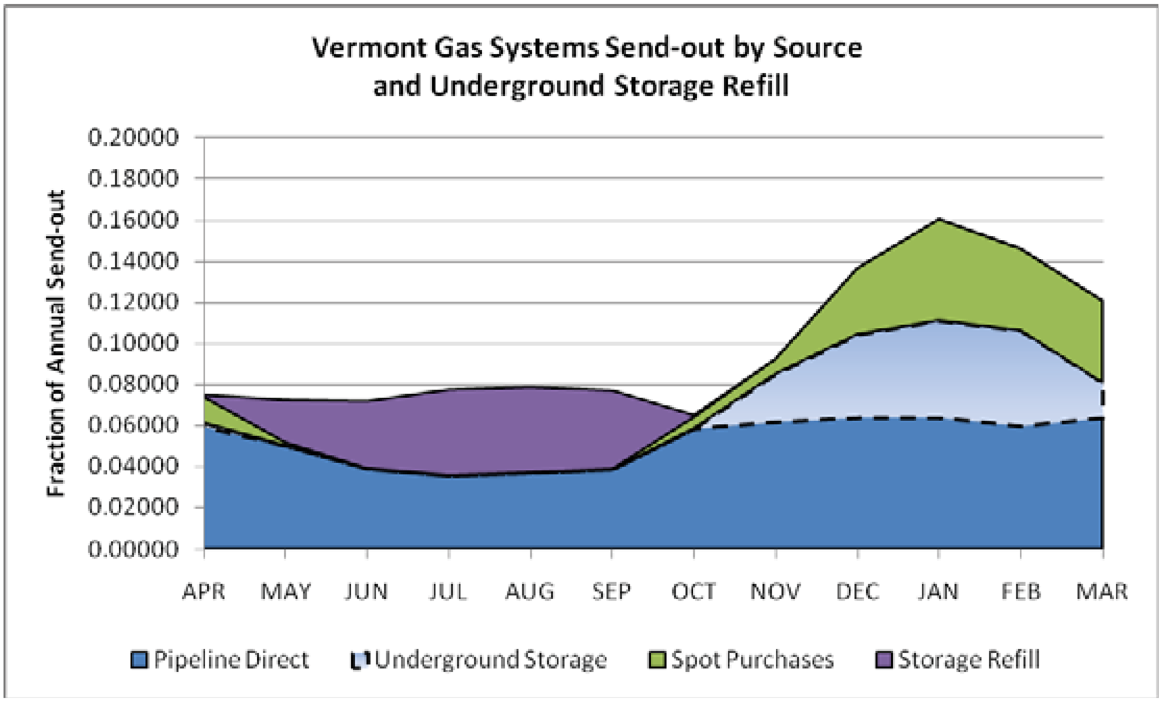
[101]This was data provided by VGS in early May 2011 supported by a recent purchased-gas-adjustment filing for 2011.

Each month, Vermont receives gas purchased in Alberta and transported by TransCanada Pipeline. During the winter months, November through March, Vermont also receives gas from underground storage and about an equal amount from purchases in spot markets. VGS has interruptible customers whom it serves using gas purchased in spot markets. During the winter, including April, when gas is needed to serve firm customers' peak loads, VGS interrupts its interruptible customers and delivers the spot gas thus released to its firm customers. Exhibit 4-19 shows the gas-supply characteristics of VGS as fractions while Exhibit 4-20 shows the gas supply by source each month and also storage refill.

Exhibit 4-19: Vermont Gas System: Monthly Sendout Fractions by Source, Peak Month, and Storage Injection

	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	Annual
Fractions of VGS Send-out by Source Each Month													
Pipeline Deliveries, Long-haul	81.1%	100.0%	100.0%	100.0%	100.0%	100.0%	91.5%	67.2%	47.0%	40.0%	41.1%	51.6%	63.6%
Underground Storage	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	25.2%	29.6%	29.4%	31.8%	15.9%	17.7%
Spot Purchases	18.9%	0.0%	0.0%	0.0%	0.0%	0.0%	8.5%	7.6%	23.4%	30.6%	27.2%	32.5%	18.7%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Fraction of Annual Sendout each Month	7.4%	5.2%	3.9%	3.6%	3.7%	3.9%	6.4%	9.3%	13.7%	16.1%	14.6%	12.1%	100.0%
Monthly Sendout as a Fraction of Peak Month	46.0%	32.3%	24.4%	22.4%	23.2%	24.3%	40.0%	57.6%	85.1%	100.0%	91.0%	75.4%	
Fraction of Underground Storage Injection by Month	0.5%	11.7%	18.5%	23.6%	23.6%	21.6%	0.5%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Basis, Parkway - HH, for spot price at Parkway	$0.50						$0.50	$0.50	$0.50	$0.50	$0.50	$0.50	
Sources:													
(a) Vermont Gas Systems.: May 2, 2011.													

Exhibit 4-20: Vermont Gas System Sendout by Source and Underground Storage Refill



Since this avoided-cost forecast was based on a forecast price of gas at the Henry Hub in Louisiana, the basis differential (price of gas in Alberta at the AECO hub minus the price at the Henry Hub) was computed from futures data on 26 May 2011 for the period June 2011 through May 2014 from the NYMEX for Henry Hub gas prices and from the Calgary based Natural Gas Exchange for the AECO-C hub prices. The exchange rate of US$ per CD$ was taken from the futures data on May 26, 2011 for June 2011 through September 2012 and averaged US$ 1.0149 per CD$. The average ratio of the Alberta gas price to the Henry Hub price in US$ is 0.899.[102]

The pipeline-transportation rates, rates for underground storage and transporting gas to VGS from underground storage, and the rates for transporting spot gas to VGS are used in the avoided cost forecasts. While the usage rates and fuel and loss percentages are about the same as in AESC 2009, the demand rates are more than twice those in AESC 2009. We assume these rates will prevail throughout the forecast period.

[102]This ratio is very similar to those in AESC 2007, winter 0.851 and summer 0.895 and in AESC 2009, winter 0.888 and summer 0.876.

Exhibit 4-21: Toll Rates of Vermont Gas Systems in 2011$

Canadian Tolls Paid by Vermont Gas Systems USD 2011 $								
			Demand (a) $/DT/Month		Usage $/DT		Fuel & Loss percent	
Firm Transportation								
	Long-Haul		$75.767	(a)	$0.171	(b)	3.14%	(c)
	From Storage		$15.957	(a)	$0.033	(b)	0.62%	(c)
Storage								
	Injection		$0.000		$0.000	(d)	2.93%	(d)
	Space		$1.229	(e)				
	Withdrawal		$0.000		$0.000	(d)	0.62%	(d)
Spot Gas Transportation								
	Parkway to Phillipsburg		$15.957	(a)	$0.033	(b)	0.62%	(c)
(a)	TransCanada Final Tolls effective Mar 1, 2011							
(b)	TransCanada Final Tolls effective Mar 1, 2011							
(c)	Average TransCanada actual fuel ratio for .Jun 2010 to May 2011							
(d)	VGS actual storage contract							
Note:	1 DT = 1 MMBtu = 1.055056 Giga Joules (GJ)							
	1 CD$ = 1.0472 US$ (3 month forward rate as of 29 April 2011)							
	Thus, US$/DT is calculated as 1.1049 of CD$/GJ							

Unlike other New England LDCs VGS uses long-haul transportation at about 100 percent load factor throughout the year with the summer refilling of underground storage and direct deliveries of gas to VGS. The increased requirements in the winter are served by underground storage and purchase and transportation of spot gas. The costs of underground storage include the costs of transportation of gas to fill storage, the cost of storage, and the cost of transportation from storage to VGS. However, demand charges for transporting stored gas in the winter are paid twelve months a year.

Purchases of gas in the spot market make up slightly more than 20 percent of the VGS gas supply. The prices of these spot purchases were estimated by VGS to be

US$0.50 greater than the Henry Hub price of gas. VGS transports spot gas with firm transportation, which means it pays demand charges 12 month a year but uses the capacity much less. Both for the transportation of spot and stored gas the demand charges are allocated by the months of higher usage to compute avoided costs by month as we have done for all the New England LDCs. The components of the avoided costs by the three sources of gas to Vermont are shown in Exhibit 4-22.

Exhibit 4-22: Avoided Cost From Three Sources of Supply

COMPARISON OF COSTS OF DELIVERING ONE DEKATHERM OF GAS			
TO VERMONT GAS SYSTEMS			
FROM THREE SOURCES OF NATURAL GAS and PEAK DAY			
		TransCanada Pipeline	
		January	June
	units		
Pipeline Long-haul to LDC			
Pipeline Demand Cost of Gas Delivered to LDC	2011 $/DT	$2.491	$0.000
Pipeline Usage Cost	2011 $/DT	$0.171	$0.171
Ratio of Gas Purchased in Alberta to Gas Delivered to LDC		1.032	1.032
Delivered From Underground Storage			
Pipeline Demand Cost of Gas Delivered to LDC	2011 $/DT	$1.915	
Pipeline Cash Variable Cost of Gas Delivered to LDC	2011 $/DT	$4.055	
Ratio of Gas Purchased to Gas Delivered to LDC		1.077	
Spot Purchases of Gas at Parkway			
Pipeline Demand Cost of Gas Delivered to LDC	2011 $/DT	2.430	
Pipeline Usage Cost	2011 $/DT	0.033	
Ratio of Gas Purchased to Gas Delivered to LDC		1.006	
Basis of Spot Gas Purchases: Parkway - HH	2011 $/DT	$0.500	
Peak Day in January From Underground Storage			
Pipeline Cash Demand Cost of Gas Delivered to LDC	2011 $/DT	$191.49	
Pipeline Cash Variable Cost of Gas Delivered to LDC	2011 $/DT	$4.055	
Ratio of Gas Purchased at HH to Gas Delivered to LDC		1.077	
Based on pipeline tolls effective April 2011.			

We used this to estimate the avoided cost of natural gas delivered to VGS by month for the forecast period as shown in Appendix D. The AESC 2009 and AESC 2011 monthly avoided costs as levelized over fifteen years are shown in Exhibit 4-5. As in the other New England sectors, the average levelized avoided costs are slightly less in AESC 2011 in 2011 dollars because the price of gas at the

Henry Hub is less in 2011 than in 2009. However, the winter avoided costs of gas delivered to the city gate at VGS are higher in AESC 2011 during the winter months than in AESC 2009 despite the lower Henry Hub price because TransCanada has more than doubled its demand charges for pipeline transportation and Union's annual storage rates have increased since 2009. These increased demand charges are concentrated in the winter months because the annual demand charges for the transportation of stored gas and spot gas are all concentrated in the winter months. That is, if a DT of gas use is reduced in the winter months then the demand charges for those months and the summer months can be avoided.

Exhibit 4-5 is shown below for clarity.

COMPARISON OF THE LEVELIZED AVOIDED COSTS OF GAS DELIVERED TO LDCs BY MONTH FROM AESC 2009 AND AESC 2011

	Units		APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	Annual Average
SOUTHERN NEW ENGLAND: Gas Delivered via Texas Eastern and Algonquin Pipelines															
AESC 2009	2009$/DT	(a)	7.37	7.39	7.51	7.64	7.74	7.78	7.90	9.17	9.86	10.14	9.62	9.17	8.44
AESC 2009	2011$/DT	(b)	7.51	7.53	7.65	7.78	7.88	7.93	8.04	9.35	10.04	10.33	9.80	9.34	8.60
AESC 2011	2011$/DT	(c)	6.16	6.18	6.25	6.34	6.40	6.42	6.50	7.63	8.21	8.53	8.06	7.72	7.04
Percent Difference															
2009 to 2011			-17.9%	-17.8%	-18.2%	-18.6%	-18.8%	-19.0%	-19.1%	-18.3%	-18.2%	-17.4%	-17.7%	-17.3%	-18.2%
NORTHERN and CENTRAL NEW ENGLAND: Gas Delivered via Tennessee Gas Pipeline															
AESC 2009	2009$/DT	(a)	7.35	7.36	7.48	7.61	7.71	7.75	7.87	8.94	9.41	9.69	9.23	8.83	8.27
AESC 2009	2011$/DT	(b)	7.48	7.50	7.62	7.75	7.85	7.90	8.01	9.10	9.59	9.87	9.40	8.99	8.42
AESC 2011	2011$/DT	(c)	6.19	6.21	6.28	6.36	6.42	6.45	6.53	7.46	7.91	8.20	7.80	7.47	6.94
Percent Difference															
2009 to 2011			-17.3%	-17.2%	-17.6%	-17.9%	-18.2%	-18.3%	-18.5%	-18.0%	-17.4%	-16.9%	-17.1%	-16.9%	-17.6%
VERMONT GAS SYSTEMS: Gas delivered via TransCanada Pipeline															
AESC 2009	2009$/DT		6.36	6.21	6.38	6.49	6.57	6.61	6.71	8.09	8.57	9.24	8.77	8.28	7.36
AESC 2009	2011$/DT		6.48	6.33	6.49	6.61	6.69	6.73	6.83	8.24	8.72	9.41	8.93	8.44	7.49
AESC 2011	2011$/DT		5.61	5.42	5.48	5.55	5.60	5.63	5.77	8.77	9.22	9.80	9.34	8.50	7.06
Percent Difference															
2009 to 2011			-13.4%	-14.3%	-15.6%	-16.0%	-16.3%	-16.4%	-15.5%	6.5%	5.7%	4.2%	4.6%	0.7%	-7.2%

(a) AESC 2009 levelized costs over the 15-year period 2010 - 2024 with a discount rate of 2.218%.
(b) Factor to convert 2009$ to 2011$ 1.0186
(c) AESC 2011 levelized costs over the 15-year period 2012 - 2026 with a discount rate of 2.465%.

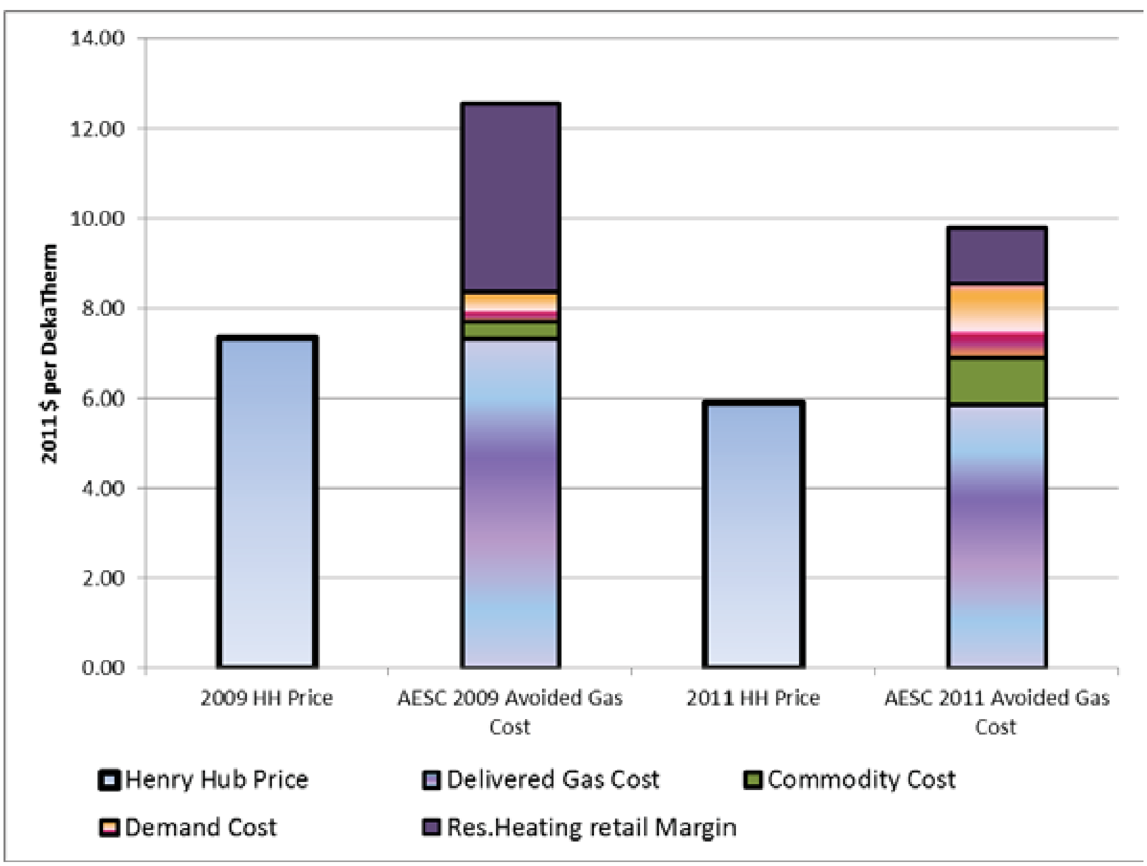
As in the other LDCs of New England, the avoided gas cost delivered to VGS's city gate by load type is shown in Appendix D. The retail avoided cost is the avoided gas cost delivered to the city gate of the LDC plus the LDC avoided margin. The LDC's avoided margin varies with load type; it is shown above in Exhibit 4-12. The avoided costs to the specified load types and customer sectors are shown in Appendix D.

The levelized avoided end use retail costs in Vermont are less than estimated in AESC 2009; see Exhibit 4-17 and Exhibit 4-18. The current retail end-use avoided cost assuming some retail margin is avoidable, in 2011 dollars, is lower than estimated in 2009 because in AESC 2011 we estimate the avoidable retail margin, if one exists, to be substantially less than in AESC 2009. The reason for this change is that the Study Group provided us with the margin costs in the LDC retail margin and it was estimated to be much less in 2011.

If one assumes that no retail margin is avoidable in AESC 2011then the avoided cost to the end user in AESC 2011 is the avoided cost at the city gate shown in Exhibit 4-18. As seen in Exhibit 4-18, with no retail margin in AESC 2011 but retaining the retail margin estimated in AESC 2009 the heating loads are reduced less than for the other states in New England or for the summer in VGS because of the much higher demand charges for transportation and for storage in 2011 compared with 2009.

Exhibit 4-23 shows the contribution to overall avoided cost to a heating customer by each of the components: cost of gas delivered to VGS, commodity costs of storing and delivering the gas, the demand cost of transporting gas, and the avoidable retail margin. This picture shows more clearly, the lower cost of gas in AESC 2011, offset by the higher commodity and demand costs of pipeline storage and transportation and the much lower avoided retail margin.

Exhibit 4-23: Comparison of the Components of the Avoided Cost to a Residential Heating Customer on Vermont Gas Systems in 2015 between AESC 2009 and AESC 2011



4.5.1. Peak Day Avoided Cost

As described above in the longer section on peak day avoided costs, we have included an estimate of peak day avoided costs, but we are unsure why such a measure applies. To the best of our knowledge, most or all efficiency improvements will reduce gas use throughout the year or the heating period. Other than interrupting interruptible load, which we understand VGS does, efficiency improvements reduce gas use whenever the equipment is in operation, not just on certain days. For this reason we estimate end-use avoided costs for base-load (high load factor) and heating load (low load factor) end use types because we assume that efficiency improvements exist whenever the equipment is in operation. But the avoided costs apply over periods of several months as seen in the load profiles of Exhibit 4-10.

Nonetheless, we have earlier in this Chapter estimated peak-day costs as the cost of taking gas from underground storage to be used only for one day while paying the relevant demand charges for 12 months. For VGS, as shown in Appendix D, the avoided cost so calculated and levelized over 15 years, 2012-2026, is $201.16 per Dekatherm.

However, this method of computing peak-day avoided costs, while useful when estimated a peak-day cost for a number of LDCs, is probably better done by examining the particular facts and circumstances of a single LDC, such as VGS. While we have not examined the method and estimates in detail, it is our understanding that because VGS is growing, VGS estimates peak-day costs as the avoided cost of transmission looping on its own system plus the associated carrying costs and upstream avoided supply costs. This appears reasonable.

Similarly, we understand that VGS estimates the avoided cost during its peak period, which is longer than one day, as the variable cost of the propane in its propane-air facilities. This seems to be reasonable as long as the cost of propane is the highest cost alternative supply during the peak period.

4.6. Value of Environmental Impacts of Natural Gas Combustion

4.6.1. Pollutants Created by Combustion of Natural Gas and their Significance

Natural gas consists of methane (generally above 85 percent) and varying amounts of ethane, propane, butane, and inert gases (typically nitrogen, carbon dioxide, and helium) (EPA 1999). In general the combustion of natural gas in boilers and furnaces generate the following pollutants (EPA 1999, 1.4-2–5):

- Oxides of nitrogen (NO_x)

- Trace levels of sulfur oxides (SO_x)[103]
- Carbon dioxide and other greenhouse gases
- Trace levels of particulates
- Volatile organic compounds
- Carbon monoxide

The most significant of these pollutants are carbon dioxide and oxides of nitrogen. These two pollutants were determined to be the most significant based on the fact that the absolute quantities of each resulting from the combustion of natural gas are large relative to the absolute quantity of each from all sources. In other words, combustion of gas is a major source of these pollutants.

To estimate the absolute quantities of each pollutant from the combustion of natural gas relative to the absolute quantity of each from all sources we began by estimating the quantity of each that is emitted per MMBtu of fuel consumed. Exhibit 4-24 provides emissions factors for NO_x and CO_2 for on three generalized boiler type categories.

Exhibit 4-24: Emission Rates of Significant Pollutants

Boiler Type	NO_x (lbs/MMBtu)	CO_2 (lbs/MMBtu)
Residential boilers	0.0922	118
Commercial boilers	0.0980	118
Industrial boilers	0.137	118

Notes:
NO_x emissions from industrial boilers without low NO_x burners would be 0.274 lb/MMBtu. We assumed these boilers were controlled in order to be conservative.
NO_x and CO_2 emissions factors for all boilers utilized conversion rate of 1,020 Btu/scf
Sources:
Environmental Protection Agency, AP-42, Volume I, Fifth Edition, January 1995, Chapter 1, External Combustion Sources. http://www.epa.gov/ttnchie1/ap42/

We apply these pollutant emission rates to the quantity of natural gas consumed, by sector, in New England in 2007. The estimated annual quantity of each of the two pollutants from natural-gas combustion, and from other sources, is presented in Exhibit 4-25.

[103] Sulfur is generally added as an odorant to natural gas, which generates trace quantities of sulfur oxides when combusted.

Exhibit 4-25: Pollutant Emissions in New England from Natural Gas

Sector	NO_x (tons)	CO_2 (tons)
Combustion of Natural Gas in R, C & I		
Residential	9,518	12,181,966
Commercial	6,858	8,257,699
Industrial	7,173	6,178,126
R, C & I Total	***23,549***	***26,617,791***
Emissions from Electric Generation		
	87,000	***38,800,000***
Notes All figures are for 2009 except emissions from electric generation, which are from 2008. **Source** Energy Information Administration http://tonto.eia.doe.gov/dnav/ng/ng_cons_sum_a_EPG0_vrs_mmcf_a.htm Environmental Protection Agency http://www.epa.gov/ttn/chief/net/2008inventory.html		

This table illustrates that combustion of natural gas is a major source of each of these pollutants. Moreover, those emissions are not currently subject to regulation, as explained below.

- *CO_2*. Regional Greenhouse Gas Initiative (RGGI) applies to electric generating units larger than 25 MW. New England CO_2 emissions for 2008 were 38.8 million tons. The total CO_2 emissions from the end-use sectors above would represent about 41 percent of the total CO_2 emissions, if such emissions were included.
- *NO_x*. The Ozone Transport Commission/EPA NO_x budget program applies to electric generating units larger than 15 MW and to industrial boilers with a heat input larger than 100 MMBtu/hour. New England NO_x emissions for 2008 were approximately 87,000 tons for just the electric generating sector[104]. The total NO_x emissions from the end use sectors above would represent about 21% of the total NO_x budget if such emissions were included.

[104] A few large sources in the industrial sector are included in the NOx budget program. These include municipal waste combustors, steel and cement plants, and large industrial boilers (such as those located at Pfizer in, New London, CT and General Electric in, Lynn, MA). However, the number of NO_x allowances used, sold, and traded for the industrial sector is very small. A few allowances in each state are allocated to non-electric generating units compared to thousands of allowances used, sold and traded for electric generating units.

4.6.2. Value Associated With Mitigation of Each Significant Pollutant

We estimate the value associated with mitigation of NO_x and CO_2 based on the 2011 emissions allowance prices per short ton presented in Exhibit 2-3.[105] This approach, which is consistent with AESC 2009, represents a consistent application of emission allowance prices across all fuels. As noted previously, natural-gas combustion is not a significant source of SO_2 emissions. Consequently we have not included an emission value for SO_2.

In addition, we provide a value of reducing CO_2 based upon the $80/ ton long-term marginal abatement cost of carbon dioxide reduction. States that have established targets for climate mitigation comparable to the targets discussed in Chapter 6, or that are contemplating such action, could view the $80/ton long-term abatement cost as a reasonable estimate of the societal cost of carbon emissions, and hence as the long-term value of reductions in carbon emissions required to achieve those targets. This value is described in greater detail in Chapter 6 (Section 6.6.4.2).

The annual pollutant-emission values by end-use sector are summarized below in Exhibit 4-26. They equal the pollutant allowance prices multiplied by the pollutant emission rates.

[105] The full externality value associated with NO_x emissions is probably not captured in the allowance price from electricity generation, however determining that externality value is beyond the scope of this project.

Exhibit 4-26: Annual Pollutant Emission Values in 2011$/MMBtu

Pollutant Emission Values by Sector and by Year in 2011$/MMBtu									
	Residential			Commercial			Industrial		
	NOx	CO2	CO2 at $80/ton	NOx	CO2	CO2 at $80/ton	NOx	CO2	CO2 at $80/ton
2011	$0.011	$0.11	$4.72	$0.011	$0.11	$4.72	$0.016	$0.11	$4.72
2012	$0.007	$0.11	$4.72	$0.007	$0.11	$4.72	$0.010	$0.11	$4.72
2013	$0.006	$0.11	$4.72	$0.007	$0.11	$4.72	$0.010	$0.11	$4.72
2014	$0.007	$0.11	$4.72	$0.007	$0.11	$4.72	$0.010	$0.11	$4.72
2015	$0.007	$0.11	$4.72	$0.007	$0.11	$4.72	$0.010	$0.11	$4.72
2016	$0.007	$0.11	$4.72	$0.007	$0.11	$4.72	$0.010	$0.11	$4.72
2017	$0.007	$0.11	$4.72	$0.007	$0.11	$4.72	$0.010	$0.11	$4.72
2018	$0.007	$0.90	$4.72	$0.007	$0.90	$4.72	$0.010	$0.90	$4.72
2019	$0.007	$1.08	$4.72	$0.008	$1.08	$4.72	$0.011	$1.08	$4.72
2020	$0.007	$1.25	$4.72	$0.008	$1.25	$4.72	$0.011	$1.25	$4.72
2021	$0.007	$1.43	$4.72	$0.008	$1.43	$4.72	$0.011	$1.43	$4.72
2022	$0.008	$1.60	$4.72	$0.008	$1.60	$4.72	$0.011	$1.60	$4.72
2023	$0.008	$1.78	$4.72	$0.008	$1.78	$4.72	$0.012	$1.78	$4.72
2024	$0.008	$1.96	$4.72	$0.008	$1.96	$4.72	$0.012	$1.96	$4.72
2025	$0.008	$2.13	$4.72	$0.009	$2.13	$4.72	$0.012	$2.13	$4.72
2026	$0.008	$2.31	$4.72	$0.009	$2.31	$4.72	$0.012	$2.31	$4.72
Levelized (2011$/MMBtu)									
5 year (2012-16)	$0.007	$0.11	$4.72	$0.007	$0.11	$4.72	$0.010	$0.11	$4.72
10 year (2012-21)	$0.007	$0.50	$4.72	$0.007	$0.50	$4.72	$0.010	$0.50	$4.72
15 year (2012-26)	$0.007	$0.93	$4.72	$0.008	$0.93	$4.72	$0.011	$0.93	$4.72

Notes

Based on Exhibit 4-24 pollution emission rates for Natural Gas combustion

Pollutant values based on emission allowance prices detailed in Exhibit 2-3 and $80/short ton long-term marginal abatement cost for CO2

The entire amount of each value is an externality. With the exception of those industrial sources subject to the EPA NO_x budget program, which represent a small fraction of the total emissions, none of these emissions are currently subject to environmental requirements. Therefore, none of these values are internalized in their market prices.

Chapter 5: Forecast of New England Regional Oil Prices and Avoided Cost of Other Fuels by Sector

5.1. Introduction

This chapter details the development of a forecast of prices for petroleum products used in electric generation as well as in the residential, commercial and industrial sectors in New England. For AESC 2011, we develop forecast prices for three fuel oil grades, i.e., No. 2, No. 4 and No. 6 and two biofuel blends, B5 and B20 (and also the projection of coal prices for the electric sector.) In addition, we develop a forecast of unit fuel oil costs that would be avoided by the installation of oil-saving energy efficiency measures in the commercial, industrial, and residential sectors.

AESC 2011 requires the development of avoided costs by state, if supported by research, and for other fuels used in residential heating applications. For AESC 2011, these other fuels are wood, wood chips or pellets, kerosene and propane.

Our proposed AESC 2011 forecasts for crude oil and fuels by sector and region are presented in detail in Appendix E.

The current forecast of fuel prices for residual oil is on average 3.2 percent lower than the AESC 2009 forecast over a fifteen-year period. All other fuels (distillate, kerosene, propane, biofuel, and wood) are on average higher than those of AESC 2009 by approximately 11.0 percent.

Exhibit 5-1: Summary of Other Fuel Prices: AESC 2011 Forecast versus AESC 2009

	No. 2 Distillate	No. 2 Distillate	No. 6 Residual (low Sulfur)	Propane	Kerosene	BioFuel	BioFuel	Wood
Sector	Res	Com	Com	Res	Res & Com	B5 Blend	B20 Blend	Res
AESC 2011 Levelized Values (2011$/MMBtu)								
2012-2026	25.37	23.53	17.26	36.00	25.50	25.37	25.37	9.47
AESC 2009 Levelized Values (2011$/MMBtu)								
2010-2024	23.25	22.09	17.85	34.66	22.59	23.25	23.25	8.38
Percent Difference from AESC 2009								
	9.1%	6.5%	-3.3%	3.9%	12.9%	9.1%	9.1%	13.0%

Notes
Res = Residential Sector
Com = Commercial Sector

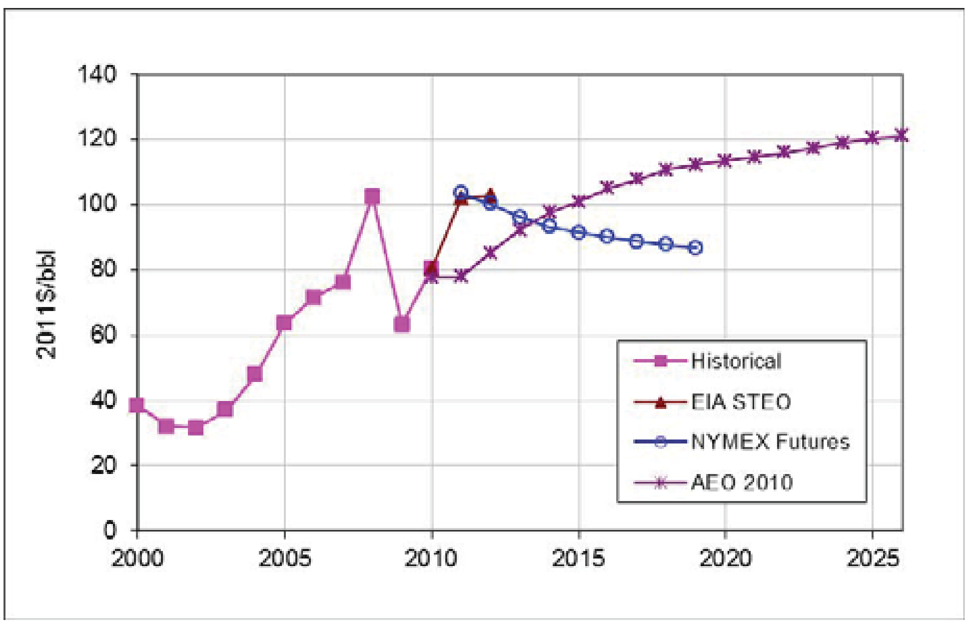
5.2. Forecast of Crude Oil Prices

Our general approach to develop the forecasts of crude-oil prices and of Henry Hub natural-gas prices is to use a set of relevant NYMEX futures prices in the near term, e.g. the first three to five years, and the relevant EIA Annual Energy Outlook forecast in the long term. This approach is based upon our view that futures market prices are the most-accurate estimates in the near term while projections from a forecasting model that reflects long-term demand and supply fundamentals, such as the EIA's National Energy Modeling System, are the most accurate estimates in the long term. As in AESC 2007 and AESC 2009, we develop our forecast of petroleum product prices based on the approach, i.e., NYMEX futures for West Texas Intermediate in the first five years and EIA's reference-case-forecast prices in following years.

Based on that general approach, our first step in developing a forecast of crude oil prices was to review the EIA Reference Case forecast (2010a). However, there is considerable uncertainty regarding the future price of crude oil.

We next compared EIA's (2010a) reference-case-forecast prices in the near term, i.e. 2011 through 2014, with current NYMEX futures prices for West Texas Intermediate (WTI).[106] This comparison revealed a significant difference between NYMEX futures for WTI in the near-term and EIA's reference-case-forecast prices in the near-term. That disparity is presented in Exhibit 5-2, which plots, in 2011 dollars per bbl, 1) actual oil prices since 2000, 2) WTI futures through 2019, and 3) EIA's (2010a) reference-case-forecast prices through 2026.

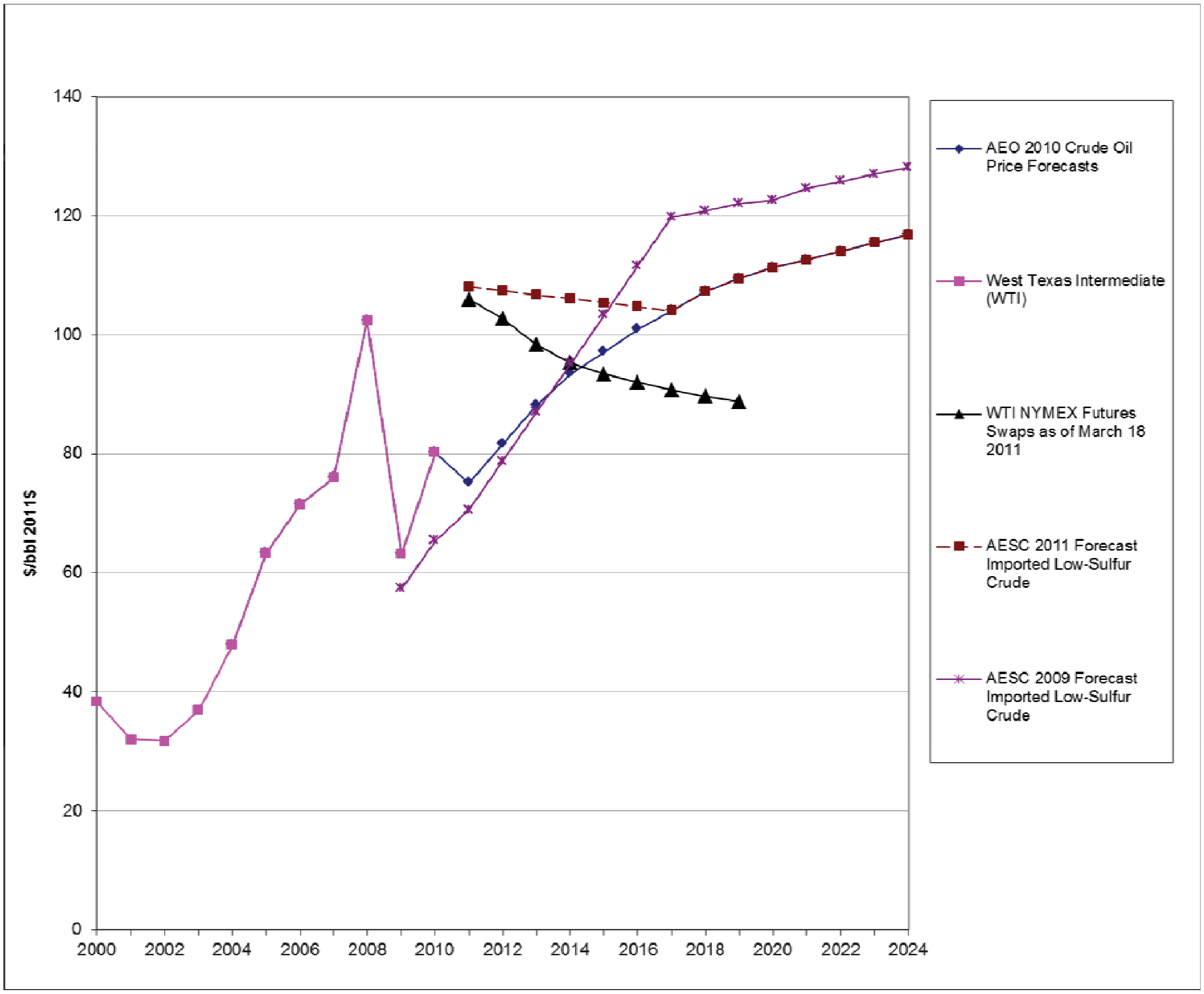
Exhibit 5-2: Low-Sulfur-Crude Prices, EIA vs. NYMEX (2011$ per bbl)



[106]NYMEX prices as of March 18, 2011. WTI was used for this comparison because it is actively traded and its price in the past has been very close to that of the low-sulfur light crude used in EIA's Reference Case.

Based on both the NYMEX futures and the latest EIA Short-Term Energy Outlook (STEO) we conclude that there have been significant changes in the oil markets that will likely continue and were not foreseen when the AEO 2010 forecast was produced in late 2009 and early 2010. The longer term forecast prices are fairly close to the current market prices. Thus, we use the EIA STEO prices for 2011 and 2012 and then transition to the AEO 2010 price in 2014 by using the NYMEX 2013 price. This forecast projects a slight dip in prices in 2013 and 2014 followed by a gradual rise. With the release of AEO 2011, we reviewed the AEO 2011 crude oil forecast and found that the only significant differences were in the first two years, after which the price forecast was more or less the same as AEO 2010. Since we do not use the near term AEO projections in our own forecast, we feel comfortable continuing to use the AEO 2010 projections. The AESC 2011 forecast is higher than the AESC 2009 forecast in the years prior to 2015, but lower thereafter. Exhibit 5-3 depicts the AESC 2011 forecast and the AESC 2009 forecast in addition to the data from Exhibit 5-2.

Exhibit 5-3: Low-Sulfur-Crude Actual and Forecast Prices (2011$ per bbl)



5.3. Forecast of Electric-Generation Fuel Prices in New England

The EIA (2010a) provides forecasts of regional prices for distillate, residual, and coal for electricity generation in New England.

5.3.1. Forecast Prices of Distillate and Residual

The EIA (2010a) provides forecasts for prices of distillate and residual for electricity generation in New England. We began by calculating the forecast unit margin implicit in EIA's (2010a) forecast of those prices as a ratio to the corresponding crude oil price forecast, and comparing those ratios to the historical unit margins. That comparison indicates that the forecast margins are generally consistent with the historical margins.

Our analysis did not identify material differences by state in the historical prices for these fuels in this sector. Therefore, we developed a forecast of these prices by multiplying the corresponding EIA (2010a) forecast price each year times the ratio of our crude-oil forecast to the EIA (2010a) crude-oil forecast.

5.3.2. Forecast Prices of Coal

The EIA (2010a, Table 78) Reference Case forecasts fairly slightly declining prices for coal in New England. We consider this reasonable. The U.S. has substantial coal resources and coal prices have been relatively stable over a long time period without the volatility seen in oil and natural gas prices. While coal at the mine mouth is relatively cheap on an energy basis, it is expensive to transport and to burn. Coal demand is also unlikely to increase significantly because of various environmental concerns. Coal is more expensive in New England because of the transportation costs and represents a smaller fraction of annual electric generation than most other parts of the U.S. Since EIA's coal prices are essentially flat and consistent with historical experience and market behavior, we use them for AESC 2011.

5.4. Forecast of Petroleum Prices in the Residential, Commercial, and Industrial Sectors

The EIA (2010) provides forecasts of regional prices for distillate and residual fuel oil in the residential, commercial, and industrial sectors in New England. The retail price of each fuel in each sector of a given state can be separated into two major components. The first component is the price of the underlying resource, crude oil. The second component is a margin, or the difference between the price of each fuel at the retail level and the crude oil price. The margin represents the aggregate unit costs of the refining process, distribution, and taxes attributed to the particular fuel by sector and state. We developed our forecast of prices for fuels in each of these sectors in the following three steps, and detailed in the following sub-sections:

- First, we calculate the forecast unit margin implicit in EIA's (2010) forecast of the New England regional price for each fuel, expressed as a ratio to the crude oil price, and compare it to the historical unit margin, calculated from historical price data. We develop a modified New England price for any fuel with an EIA (2010) forecast margin that we find unreasonable based on historical trends;
- Second, we derive regional forecasts of New England prices for each fuel by multiplying the corresponding EIA (2010) forecast, as may be modified in step one, by the ratio of our crude-oil forecast (as detailed in Section 0) to the EIA (2010) crude-oil forecast;

- Finally, we develop our forecast of prices for each fuel by New England state from the regional forecast to the extent that historical prices for that fuel have differed materially by state.

Our analysis finds material differences by state in the historical prices for some fuels in these sectors. Therefore, we adjust the corresponding EIA (2010) regional forecasts of distillate and residual by the ratio of the AESC 2011 forecast of crude oil and EIA's (2010) forecast of crude oil. We then develop a forecast of prices for each fuel by New England state from the regional forecast.

5.4.1. New England Regional Prices by Sector

The forecast of regional prices by fuel and sector in New England is presented in Appendix E.

We derive forecasts of regional petroleum product prices by adjusting the corresponding EIA (2010) forecasts of product prices in proportion to the ratio of our crude oil forecast to the EIA's (2010) crude oil forecast. This approach is based upon our conclusion that crude oil is the dominant component of petroleum product prices and that preparing a forecast of future absolute margins by product based upon historical absolute margins is beyond the scope of this project.

In summary, our proposed AESC 2011 forecasts of regional prices of petroleum and related products by sector is based on the following approaches:

- No. 2 and 6 Fuel Oil: EIA (2010) forecast of regional product price adjusted for ratio of AESC 2011 crude oil forecast to EIA (2010) crude oil forecast;
- No. 4 Oil: no projection. No. 4 is a blend of distillate and residual and we had no data on the relative proportions of that blend;
- B5 and B20: our forecast of corresponding petroleum-product prices.

For No. 2 and 6 fuels, we first calculate the forecast unit margins implicit in the EIA (2010) forecast of those prices as a ratio to the corresponding crude oil price forecast. Next, we compare the average ratio for each fuel in each sector to the corresponding historical unit margins. That comparison indicates that the forecast margins are generally consistent with the historical margins. Based upon the results of that comparison, we develop our forecast of these prices by multiplying the corresponding EIA (2010) forecast price each year by the ratio of our crude oil forecast to the EIA (2010) crude oil forecast.

The EIA (2010) does not provide a forecast of New England regional prices for biofuels B5 and B20. We therefore prepared an independent analysis. B5 and B20 are each a mix of a petroleum product, such as distillate oil or diesel, and an oil-like product derived from an agricultural source (e.g. soy beans). The number in their name is the percent of agricultural-derived component. Thus "B5" and "B20" represent products with a five percent and a 20 percent agricultural-derived component, respectively. They are both similar to No.-2 fuel oil and used primarily for heating. Each of these fuels has both advantages and disadvantages relative to No. 2 fuel oil. Their advantages include lower greenhouse-gas emissions per MMBtu of fuel consumed, more efficient operation of furnaces, and less reliance on imported crude oil. Their disadvantages include somewhat lower heat contents and concerns about the long-term supply of agricultural source feedstocks. A comparison of prices for biodiesel and regular diesel published by the DOE Alternative Fuels and Advanced Vehicles Data Center shows that, on a heat rate basis, the price differentials for these blends have varied slightly above, and slightly below, the prices for regular diesel.[107] In 2008, the premium for B2-B5 blends varied from negative three (-3) percent to five percent over regular diesel prices. In 2010, the premium for B20 has varied from three percent to five percent above diesel fuel prices. Based upon the limited experience with these fuels to date, and their premium and sub-premium attributes relative to their comparable petroleum products, we have no basis for projecting prices materially different from their competing petroleum products. Thus, we forecast the prices of biofuels to be the same on an energy basis as diesel.

Since crude oil prices do not show significant variations by month or season, we have not developed monthly or seasonal price variations for petroleum products. Storage for petroleum products is relatively inexpensive and this also tends to smooth out variations in costs relative to market prices. For these reasons, and those presented in the Chapter Three discussion of volatility in natural gas prices, our forecast does not address volatility in the prices of these fuel prices.

5.4.2. *Weighted Average Avoided Costs by Sector Based on Regional Prices*

We develop weighted average costs of avoided petroleum related fuels by sector by multiplying our projected regional prices for each fuel and sector by the relative quantities of each petroleum related fuel that EIA (2010) projects will be used in that sector. The relative quantity of each petroleum related fuel that EIA (2010) projects for each sector, expressed as percentages, are presented in

[107]The DOE stopped reporting B2-B5 as a separate fuel category after April 2009, and instead includes it in its diesel price. We therefore focus our analysis for B2-B5 fuel on the 2008 data, and for B20 on the 2010 data, with the caveat that as the 2010 diesel price data includes B2-B5 prices, a direct comparison between 2010 and 2008 is not possible. Data for B2-B5 from *Clean Cities Alternative Fuel Price Report* 1/08, 4/08, 7/08, 10/08, 1/09. Data for B20 from *Clean Cities Alternative Fuel Price Report* 1/10, 4/10, 7/10, 10/10, 1/11.

Appendix E. The resulting weighted average costs of avoided petroleum related fuels by sector are presented in Appendix E.

We estimate that the crude oil price component of these projected prices is the portion that can be avoided.

5.4.3. Prices by State by Sector

To determine if there were material differences by state in the historical prices for any of these fuels in these sectors, we analyzed the actual prices by sector in each state from 1999 through 2008 using data from the EIA State Energy Data System (SEDS). This is the most complete and consistent source of state-level energy prices.

We used Massachusetts prices as the reference point for each sector. We calculated the difference between prices in other states with the prices in Massachusetts for each year in each sector. The metric we used to determine if those differences were material was the ratio of the mean difference to the standard deviation. If that ratio was greater than 2 we concluded that the differential was material. Using that test we found material differences between some states in:

- Distillate fuel oil prices in the commercial (Rhode Island, Vermont) and residential (New Hampshire) sectors;
- Liquefied Petroleum Gas (LPG) prices in the commercial (Connecticut, New Hampshire, Rhode Island) and residential (Maine, New Hampshire, Rhode Island, Vermont) sectors;
- Residual fuel oil prices in the commercial and industrial sectors (New Hampshire).

Given the uncertainty associated with future quantities of fuel use by state by sector, and future policies on fuel taxes by state by sector, and other uncertainties, we conclude no further precision would be obtained from an estimate of avoided petroleum related fuel prices by sector by state.

5.5. Avoided Costs of Other Residential Fuels

For wood and kerosene, we determined the historical average ratio between the price of each fuel and the price of distillate in the residential sector from EIA SEDS data. These resulting ratios were 0.37 for wood and 0.99 for kerosene.[108] Then we derived the forecast of regional prices for each of those fuels by

[108] EIA State Energy Data System, http://www.eia.doe.gov/emeu/states/_seds.html (accessed 5/3/2011).

multiplying our AESC 2011 forecast price of distillate in the residential sector each year by the historical ratio.

The wood values are for cordwood.[109] Values for wood pellets would be approximately twice as high according to the limited data on wood prices.[110] Vermont publishes prices for cord wood and wood pellets, [111] but other New England states do not, relying instead upon prices reported by EIA. Based on these factors, we used the EIA SEDS data to develop prices for cordwood in New England.

For propane, we draw upon the EIA (2010) forecast of New England regional prices. The AESC 2011 forecast is derived from the EIA (2010) regional forecast by multiplying it times the ratio of the AESC 2011 crude oil forecast and the EIA (2010) crude oil forecast.

Our forecasts of prices for each fuel are presented in Appendix E. All prices are reported in constant 2011 dollars per MMBtu except where noted.

5.6. Environmental Impacts

We estimate the environmental benefit from reduced combustion of fuel oil due to energy efficiency programs with the following analyses:

- Identifying the various pollutants created by the combustion of fuel oil, assess which of them are significant and how, if at all, the impact of those pollutants is currently internalized into the cost of fuel oil.
- Finding the value associated with mitigation of each significant pollutant and portion that should be treated as an externality.

The pollutant emissions associated with the combustion of fuel oil are dependent on the fuel grade and composition, boiler characteristics and size, combustion

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[109] Residential customers can purchased either cord wood or wood pellets. Despite our attempts, we were unable to obtain a statistically valid set of historical prices for wood pellets by state other than Vermont.

[110] The Vermont cord wood price data is consistent with the EIA SEDS data, although somewhat higher. The wood pellet prices are higher than the cord wood prices but the time series of wood pellet prices is limited and the survey used to collect that data is informal.

[111] The Vermont Department of Public Service publishes prices for cordwood and wood pellets collected by the Vermont Department of Forests through an informal survey each month. http://publicservice.vermont.gov/pub/vt-fuel-price-report.html

process and sequence, and equipment maintenance (EPA 1999 1.3-2). In general, these pollutants (EPA 1999 1.3-2 to 1.3-5) are as follows:[112]

- Oxides of nitrogen (NO_x)
- Sulfur oxides
- Carbon dioxide and other greenhouse gases
- Particulates
- Trace elements
- Organic compounds
- Carbon monoxide

Of those pollutants, oxides of nitrogen, sulfur oxides, and carbon dioxide are potentially the most significant.[113] Oxides of nitrogen are precursors to the unhealthy concentrations of ozone that many areas in New England continue to experience. The region is also required to reduce NO_x and SO_x emissions by EPA programs, and the RGGI program requires mandatory reductions of CO_2 from the power sector.[114]

The value of mitigating emissions of NO_x, SO_x, and CO_2 in the electrical generation sector from the combustion of these fuels can be estimated using the forecast of emissions allowance prices presented in Exhibit 2-3 of Chapter 2.

5.6.1. Significance of Air Emissions from Combustion of Fuels by Sector

To estimate the absolute quantities of each pollutant from the combustion of fuels by sector we began by estimating the quantity of each pollutant that is emitted per MMBtu of fuel consumed.[115] The pollutant emissions associated with the

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[112] EPA, 1999. “Stationary Point and Area Sources” v. 1 of Compilation of Air Pollutant Emission Factors 5th Ed. AP-42. Triangle Partk, N.C.: U.S. Environmental Protection Agency.

[113]Wood combustion may contribute to an accumulation of unhealthy concentrations of fine particulate matter ($PM_{2.5}$). This is especially true in many valleys, where pollutants accumulate during stagnant meteorological conditions. The regulation of $PM_{2.5}$ from wood combustion is a state by state process. No comparable regionally consistent or market-based program of allowances have been established for $PM_{2.5}$, like those described above for SO_x, NO_x, and CO_2.

[114] SO_2 and NO_X emissions are regulated by the EPA under the acid rain program and the regional NOX budget trading program, as well as the new Clean Air Interstate Rule. CO_2 emissions from electrical generation sources are regulated under the Regional Greenhouse Gas Initiative (RGGI).

[115]Number-6 fuel oil has about the same rate of SO_2 emissions as distillate, about twice the rate of NO_x emissions and about seven percent higher rate of CO_2 emissions.

combustion of wood are dependent on the species of wood, moisture content, appliance used for its combustion, combustion process, and sequence and equipment maintenance. The pollutant emissions associated with the combustion of kerosene are similar to those associated with the combustion of distillate oil, and depend upon boiler characteristics and size, combustion process and sequence, and equipment maintenance (EPA 1999, 1.3-2).

Exhibit 5-4 below provides emissions factors for each fuel based on three generalized boiler-type categories.

Exhibit 5-4: Emission Rates of Significant Pollutants from Fuel Oil

Boiler type, and fuel combusted	SO_x (lbs/MMBtu)	NO_x (lbs/MMBtu)	CO_2 (lbs/MMBtu)
#2 Fuel Oil			
Residential boiler, combusting #2 oil	0.152	0.129	173
Commercial boiler, combusting #2 oil	0.152	0.171	164
Industrial boilers, combusting #2 oil	0.304	0.171	161
Kerosene—Residential heating	0.152	0.129	173
Wood—Residential heating	0.468	2.59	N/A

Notes:
For industrial boilers: assumed sulfur content = 0.3% by weight
For residential and commercial boilers: assumed sulfur content = 0.15% by weight
Kerosene same as Residential # 2 oil
Sources:
1) Energy Information Administration, Electric Power Annual with data for 2009. Table A3 *http://www.eia.doe.gov/cneaf/electricity/epa/epata3.html* (for CO_2 for industrial boilers)
2) Environmental Protection Agency, AP-42, Volume I, Fifth Edition, January 1995, Chapter 1, External Combustion Sources. *http://www.epa.gov/ttnchie1/ap42/* (for SO_x and NO_x emissions factors for all boilers)
3) Environmental Benefits of DSM in New York: Long Island Case Study; Bruce Biewald and Stephen Bernow, Tellus Institute. Proceedings from Demand-Side Management and the Global Environment, Arlington, Virginia, April 22-23, 1991. (for CO2 emissions factors for residential and commercial boilers)
4) James Houck and Brian Eagle, OMNI Environmental Services, Inc, Control Analysis and Document for Residential Wood Combustion in the MANU-VU Region, December 19, 2006. (for wood)

Emissions values for fuel oil and kerosene were based on AESC 2009 values and updated with EIA data. The values for emissions from wood remain unchanged from the AESC 2009 values. Next, we applied those pollutant emission rates to the quantity of each fuel consumed by sector in New England in 2009.[116]

[116] Distillate fuel oil consumption figures for 2009 come from the Energy Information Administration (http://www.eia.doe.gov/emeu/states/sep_fuel/html/fuel_use_df.html). No more appropriate up to date

Exhibit 5-5: Distillate Consumption, 2009 (Trillion BTU)

Residential	Commercial	Industrial
242	60	23

Combustion of No. 2 fuel oil is a major source of each of these pollutants but kerosene and wood are not, as seen Exhibit 5-6 below.

Exhibit 5-6: Pollutant Emissions in New England by Major Source

	Sector	SO_2 (tons)	NO_x (tons)	CO_2 (tons)
Emissions from Electric Generation				
A		**87,000**	**20,000**	**38,800,000**
Combustion of #2 Fuel Oil in R, C & I				
I	Residential	18,440	15,583	20,967,600
Ii	Commercial	4,526	5,100	4,879,000
Iii	Industrial	3,530	1,989	1,867,600
B = i + ii +iii	**R, C & I Total**	**26,496**	**22,672**	**27,714,200**
C	**Combustion of kerosene in Residential heating**	**1,392**	**434**	**1,104,660**
D	**Combustion of wood in Residential heating**	**556**	**3,081**	**N/A**
E = A + B + C + D		**115,444**	**46,187**	**67,618,860**
Non-electric as percent of total (B+C+D)/E		**25%**	**57%**	**43%**
Notes				
All figures are for 2009 except SO_2 and NO_x for emissions from electric generation, which are from 2008.				

5.6.2. Value of Mitigating Each Significant Pollutant

Emissions of NO_x, SO_x, and CO_2 from the combustion of these fuels are not currently subject to regulation, as explained below.

resource for kerosene or wood consumption figures could be found, and so we use the same values as in the AESC 2009 report.

- SO_2 & CO_2: The acid rain program and Regional Greenhouse Gas Initiative (RGGI) apply to electric generating units larger than 25 MW. New England SO_x emissions from electric generating units for 2008 were approximately 87,000.[117] The total SO_x emissions from the end-use sectors above would represent approximately 35 percent of the total SO_x emissions, if such emissions were included. New England electric generation CO_2 emissions for 2009 were 38.8 million tons. The calculated CO_2 emissions from the end-use sectors above would represent approximately 43 percent of the total electric generation CO_2 emissions, if such emissions were included.
- NO_x: The Ozone Transport Commission–EPA NO_x budget program applies to electric generating units larger than 15 MW and to industrial boilers with a heat input larger than 100 MMBtu per hour. New England NO_x emissions for 2008 were approximately 80,000 tons for just the electric generating sector[118]. The total NO_x emissions from the end use sectors above would represent approximately 57 percent of the total NO_x budget if such emissions were included.

We base the value associated with mitigation of NO_x, SO_x, and CO_2 on the 2011 emissions allowance prices per short ton in Exhibit 2-3 in Chapter 2 and the externality value of CO_2 shown in Exhibit 6-56 from Chapter 6. This approach, which is consistent with AESC 2009, applies the allowance prices for NO_x, SO_x, and CO_2 consistently across fuels. In addition, for CO_2 we have provided the value of pollutant emissions associated with the sustainability target value of $80/ short ton.

The pollutant-emission values for 2011 based upon these allowance prices and the pollutant emission rates, as presented in Exhibit 5-4, are presented in Exhibit 5-7.

[117] The most recent data from the EPA for New England SO_2 and NO_x emissions levels is from 2008.

[118] A few large sources in the industrial sector are included in the NO_x budget program. These include municipal waste combustors, steel and cement plants and large industrial boilers (such as those located at Pfizer in New London, Connecticut, and General Electric, in Lynn, Massachusetts). However, the number of NO_x allowances used, sold and traded for the industrial sector is very small. A few allowances in each state are allocated to non-electric generating units compared to thousands of allowances used, sold and traded for electric generating units.

Exhibit 5-7: Value of Pollutant Emissions from Fuel Oil in 2011

Generalized Boiler Type by Sector	SO_2 ($/MMBtu)	NO_x ($/MMBtu)	CO_2 ($/MMBtu)	CO_2 at $80/ton ($/MMBtu)
Residential boiler	0.0003	0.0148	0.1635	$6.92
Commercial boiler	0.0003	0.0197	0.1550	$6.56
Industrial boiler	0.0006	0.0197	0.1521	$6.44

The emission values in Exhibit 5-7 are an externality.[119] With the exception of those industrial sources subject to the EPA NO_x budget program, which represent a small fraction of the total emissions, none of the emissions shown in Exhibit 5-6 are currently subject to environmental requirements. [120] None of these values, therefore, are currently internalized in the relevant fuel's market prices. States that have established targets for climate mitigation comparable to the targets discussed in Chapter 6, or that are contemplating such action, could view the $80/ton long-term abatement cost as a reasonable estimate of the societal cost of carbon emissions, and hence as the long-term value of reductions in carbon emissions required to achieve those targets. This is discussed in greater detail in Chapter 6 (Section 6.6.4.2).

The values by year for fuel oil over the study period are presented in Appendix E.

[119] The full externality value associated with SO_x and NO_x emissions is probably not captured in the allowance price from electricity generation associated with these two pollutants, however determining that externality value is beyond the scope of this project.

[120] EPA. Factsheet: EPA's Final Air Toxics Standard Major and Area Source Boilers and Certain Incinerators Overview of Rules and Impacts. Available at http://www.epa.gov/airquality/combustion/docs/overviewfsfinal.pdf. Accessed June 20, 2011.

Chapter 6: Regional Electric-Energy-Supply Prices Avoided By Energy-Efficiency and Demand-Response Programs

This Chapter projects electricity supply costs that would be avoided by reductions in retail energy and/or demand. Sections 6-1 and 6-2 present the avoided electric capacity and energy supply costs reflected or ‘internalized” in wholesale market prices for electric capacity and electric energy respectively. Sections 6-3 onward presents avoided costs that are not internalized in those market prices, primarily demand-reduction-induced price effects, renewable-energy-credits and externalities.

Capacity Costs: The AESC 2011 projected values of avoided capacity costs are approximately 90 percent higher than those from AESC 2009 on a 15 year levelized basis. The higher values are due to ISO-NE’s decision to extend the price floor through FCA 6 and the projected need for new capacity beyond RPS requirements starting in 2020 driven by: 1) the attribution of 395 MW of passive demand reductions to energy-efficiency measures implemented in 2010 and 2011, 2) regulatory changes that result in certain capacity being treated as out-of-market resources and prohibited from setting the market price, and 3) greater levels of projected retirements of existing capacity.

The AESC 2011 projection of capacity prices is based on the FCA 4 observed supply curve and extrapolations of that curve. This was considered the best approach for AESC 2011 based on the information available and a fair representation of the impacts of projected capacity retirements and additions. That is an area that may warrant further review in future studies.

Wholesale Energy Prices: The AESC 2011 projections of wholesale electric energy costs are approximately 17 percent lower than AESC 2009 on a 15-year levelized basis.[121] This reduction is primarily attributable to a much lower projection of wholesale natural gas costs than in AESC 2009. The remaining portion of the reduction in wholesale energy prices is due to a delay in our assumption of when Federal regulation of carbon emissions would start, from 2013 for AESC 2009 to 2018 for AESC 2011. The reduction of wholesale energy prices in summer peak periods is somewhat less than the reduction in other periods due to the increased in projected retirements of existing capacity, which results in

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[121] For comparative purposes, the levelization period for AESC 2009 is 2010-2024 and AESC 2011 is 2012-2026.

less efficient generating units setting market prices in summer peak periods as compared to AESC 2009.

Avoided RPS Costs: AESC 2011 projects lower Class I REC prices through 2024 compared to AESC 2009. These results are driven by a surplus of renewable generation in the near term and projections of lower cost of new entry for renewables. For other renewable tiers, AESC 2011 projects REC prices that generally parallel Class I REC price projections for Class II RECs, or decrease with inflation for other classes. For solar RECs, AESC 2011 projects prices decreasing based on program-specific details.

Capacity DRIPE: The 2011 AESC estimates of capacity DRIPE are approximately 3.7 times greater than those from AESC 2009 on a 15-year levelized basis.[122] This increase is primarily due to the projection of higher wholesale capacity prices than in AESC 2009 as well as to the projection of a longer phase-out of capacity DRIPE effects than in AESC 2009. The AESC 2011 projections assume the phase-out or dissipation of capacity DRIPE will last up to 11 years versus four years assumed in AESC 2009. The longer projected dissipation of capacity DRIPE is based upon a detailed analysis of the various factors that tend to offset the reduction in capacity prices discussed in this chapter. Those factors include: 1) timing of new capacity additions, 2) timing of retirements of existing capacity, 3) elasticity of customer demand and 4) the portion of capacity that LSEs acquire from the FCM.

Energy DRIPE: The AESC 2011 estimates of total energy DRIPE are approximately 43 percent higher those from AESC 2009. These higher estimates are primarily due to the projection of lower wholesale energy prices than in AESC 2009. The AESC 2011 projection of an 11 year phase-out for energy DRIPE and 12 year phase-out for capacity DRIPE are within the 7 to 12 year range of other public estimates of DRIPE reviewed for AESC 2011.

Externalities: AESC 2011 uses an estimate of $80/short ton for the long-term marginal abatement cost for carbon dioxide, essentially the same as in AESC 2009. That estimate is based on the cost of limiting CO_2 emissions to a “sustainability target” level, the same approach used for AESC 2009.

[122] AESC 2009 values for 2010 Installations levelized from 2010-2024.

6.1. Forward-Capacity Auction (FCA) Prices Assuming No New Demand-Side Management

The general methodology and basic assumptions underlying our forecast of Forward Capacity Auction (FCA) prices are described in Chapter 2. This section presents additional detailed assumptions that were not presented in Chapter 2 as well as the projections based upon those assumptions.

The AESC 2011 projections of FCA prices effectively begin with FCA 7. The prices in FCA 1 through FCA 4 have already been established. The prices in FCA 5 and FCA 6 will be established in June 2011 and April 2012, however the results of FCA 4 indicate a level of surplus capacity available so large as to keep the capacity price at the floor price through FCA 6, when the floor price expires under the current ISO market rules.

The forecast of FCA prices is developed in three steps

- Forecast physical capacity requirements to be acquired in each FCA
- Forecast physical supply available to bid in each FCA
- Forecast market-clearing price in each FCA

6.1.1. Forecast Physical Capacity Requirements in each FCA

The first step in the forecast of each FCA price is to forecast the physical capacity requirements to be acquired in each FCA, which is referred to as the net installed capacity requirement (NICR). This requirement is net of the Hydro-Quebec Interconnection Capability Credit (HQ ICC) to the utilities, which has varied from 911 MW in FCA 2 to 954 MW in FCA 5. NICR is used in the FCAs, but load-serving entities need to provide capacity totaling their load share of installed capacity requirement (ICR).

- For FCA 6 through FCA 10 we forecast the NICR by multiplying the NICR in the ISO-NE 2010 Regional Supply Plan (RSP) times the ratio of the expected peak forecast in the 2011 CELT divided by the expected peak forecast in the 2010 RSP.[123]
- Beyond FCA 10, we escalate both load and NICR at the average growth rate of the last five years, FCA 6 through FCA 10.

The inputs and results are presented in Exhibit 6-1 shown below.

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[123] The FCA5 NICR is based on the ISO's March 8, 2011, filing with FERC for the FCA5 ICR values.

Exhibit 6-1: Extrapolation of Net Installed Capacity Requirement

		RSP 2010		CELT 2011			
	Year starting	**Expected Peak**	**NICR**	**Expected Peak**	**Adjusted NICR**	**NICR Reserve Margin**	**ICR Reserve Margin**
		a	B	C	d	e	f
FCA 1	2010	27,190	31,110			14.4%	19.6%
FCA 2	2011	27,660	32,528			17.6%	20.9%
FCA 3	2012	28,165	31,965			13.4%	16.6%
FCA 4	2013	28,570	32,127			12.5%	15.7%
FCA 5	2014	29,025	32,610			12.4%	15.7%
FCA 6	2015	29,450	33,178	29,380	33,099	12.7%	15.9%
FCA 7	2016	29,785	33,604	29,775	33,593	12.8%	16.0%
FCA 8	2017	30,110	34,025	30,155	34,076	13.0%	16.2%
FCA 9	2018	30,430	34,434	30,525	34,542	13.2%	16.3%
FCA 10	2019	30,730	34,818	30,875	34,982	13.3%	16.4%
FCA 11	2020			31,260	35,470	13.5%	16.5%
FCA 12	2021			31,651	35,964	13.6%	16.6%
FCA 13	2022			32,046	36,465	13.8%	16.8%
FCA 14	2023			32,446	36,973	14.0%	16.9%
FCA 15	2024			32,851	37,488	14.1%	17.0%
FCA 16	2025			33,261	38,010	14.3%	17.1%
FCA 17	2026			33,677	38,539	14.4%	17.3%
Notes:							
a.	2010 Regional System Plan, Table 4-1.						
b.	2010 Regional System Plan, Table 4-1, except FCA 2, 3, and 5 from "Summary of ICR, LSR & MCL for FCM and the Transition Period," ISO-NE, March 26, 2011. All values are based on 2010 forecast, expect FCA 1, based on 2009 forecast.						
c.	FCA 11 to FCA 17 extrapolated at growth rate FCA 6 to FCA 10.						
d.	(b÷a) × c; FCA 11 to FCA 17 extrapolated at growth rate FCA 6 to FCA 10.						
e.	FCA1 to FCA 5: b÷a – 1; FCA 6 on: d÷c – 1						
f.	e + HQ ICC÷a; HQ ICC = 1,400 MW in FCA 1, 911–916 MW in FCA 2 to 4, 954 MW in FCA 5						
Values in shaded cells have been set by ISO-NE.							

6.1.2. Forecast Physical Supply Available to Bid in each FCA

To estimate the quantity of capacity that would potentially be available to bid into FCA 5 and beyond, we begin with the 36,663 MW that cleared in FCA 4.[124] We make several adjustments to that capacity as shown in Exhibit 6-2 below.

[124] This value does not include 88 MW of real-time emergency generation in excess of the 600 MW that the ISO counts toward the NICR, or the 838 MW of Maine capacity and New Brunswick imports in excess of the capacity in Maine that the ISO counts towards the NICR.

- Remove the energy efficiency resources that cleared in FCA 4, but not in FCA 1, and were thus added after 2010, and should not be included in our Reference Case;
- Subtract capacity that our Reference Case assumes will retire during our study time horizon, as described in Chapter 2;
- Add estimated capacity from projected new renewables post FCA 4; and
- Adjust for the amount of capacity locked up in Maine.

We estimate the capacity reductions from new energy efficiency resources added after 2010 by subtracting the EE resources that cleared in FCA 1 from those that cleared in FCA 4. The on-peak and seasonal resources (i.e., passive demand resources, which are almost all energy-efficiency programs) that cleared in FCA 1 totaled 581 MW, including a 14.3% credit for avoided reserves. The reserve credit was eliminated in FCA 3, so the resources cleared in FCA 1 contributed 508 MW in FCA 3 and FCA 4 (581 ÷ 1.143 = 508). In FCA 4, a total of 1,298 MW of on-peak and seasonal resources cleared, so that auction cleared 790 MW that were not in FCA 1 (1,298 – 508 = 790). We attribute 50% of that 790 MW, 395 MW, to measures installed in 2010 that PAs, to be conservative bid into later auctions.

In this analysis, we assume that the FCM qualifying capacity from the renewables, on average, is equal to the average hourly energy production of the resources. The ratio would be somewhat higher for non-intermittent resources (e.g., biomass), and somewhat lower for much on-shore wind. The following exhibit summarizes our analysis of new renewables and retirements.

Exhibit 6-2: FCM Effects of New Renewables and Retirements

	Year Starting June	New Renewables in New England: Total GWh	New Renewables in New England: Total FCM MW	New Renewables in New England: Post-FCA 4 MW (cumulative)	Retirements: Old Peakers (MW)	Retirements: Large Units MW	Retirements: Large Units Units	Total Suppy Effect (MW) (Cumulative)
		[1]	[2]	[3]	[4]	[5]		[6]
FCA3	2012	5,921	676			600	Vermont Yankee	-600
FCA4	2013	6,464	738					-600
FCA5	2014	9,279	1,059	321	10	330	Norwalk Harbor	-619
FCA6	2015	11,343	1,295	557	10	607	Salem 3&4, Cleary 8	-1,000
FCA7	2016	12,526	1,430	692	10	807	Middletown 4, Montville 6	-1,682
FCA8	2017	13,303	1,519	781	10			-1,603
FCA9	2018	13,376	1,527	789	10	103	Wyman 1&2	-1,708
FCA10	2019	14,840	1,694	956	10			-1,551
FCA11	2020	15,523	1,772	1,034	10	143	Mt. Tom	-1,626
FCA12	2021	16,605	1,896	1,158	10			-1,512
FCA13	2022	17,315	1,977	1,239	10			-1,441
FCA14	2023	18,280	2,087	1,349	10			-1,341
FCA15	2024	18,982	2,167	1,429	10			-1,271
FCA16	2025	20,126	2,298	1,560	10			-1,150
FCA17	2026	20,649	2,357	1,619	10			-1,101
Notes:								
1	Summary_of_New_RE_Supply-Demand_AESC_2011_041811.xlsx, total minus imports							
2	[1] ÷ 8.76; assumes capacity value equals average output							
3	[2] – [2] for FCA 4							
4, 5	See Section 2.3.2.5.							
6	[3] – sum([[4] + [5]) for 2012 to current year							

The Maine adjustment shown in Exhibit 6-3reflects the fact that not all capacity in Maine is able to contribute to meeting regional reliability requirements. The ISO sets a Maximum Capacity Limit (MCL) for Maine, roughly equal to the sum of Maine's load and the transfer capability from Maine to New Hampshire.[125] In FCA 4, 838 MW of capacity in Maine could not be applied to meeting the regional capacity requirement. We assume that the locked-in capacity in Maine increases as

[125] The MCL is derived from a complex and poorly-documented reliability analysis, but the MCL has been quite close to the sum of Maine load and the Maine-New Hampshire transfer capability.

transfer capability declines and as capacity is added in Maine, and decreases as Maine load grows, using more of the Maine capacity locally.[126]

In 2014, we assume that the Maine Power Reliability Program (MPRP) will increase transmission capacity from Maine to New Hampshire. ISO-NE has not yet estimated the effect of the project on the Maine-New Hampshire transfer limit, and it also appears that relaxing that constraint may well create a new constraint at the NH export boundary. We assume that the net effect is that the MCL is increased by 500 MW, offset by a 25 MW decrease that ISO-NE expects in 2015.

Exhibit 6-3: FCM Effect of Maine Maximum Capacity Limit

	Starting June	Transmission Capacity Effect	Increased Maine Renewables	ME Expected Load	ME load growth	Net ME Locked-in MW
		[1]	[2]	[3]	[4]	[5]
FCA4	2013			2,115		
FCA5	2014	-500	120	2,150	-35	85
FCA6	2015	-475	172	2,180	-65	-368
FCA7	2016	-475	201	2,210	-95	-369
FCA8	2017	-475	175	2,240	-125	-425
FCA9	2018	-475	175	2,275	-160	-563
FCA10	2019	-475	406	2,300	-185	-357
FCA11	2020	-475	406	2,330	-215	-387
FCA12	2021	-475	199	2,361	-246	-625
FCA13	2022	-475	199	2,392	-277	-657
FCA14	2023	-475	199	2,424	-309	-688
FCA15	2024	-475	199	2,457	-342	-720
FCA16	2025	-475	199	2,489	-374	-753
FCA17	2026	-475	199	2,522	-407	-786
Notes:						
1	Exhibit 2-7					
2	SEA Forecast					
3	RSP11 ISO-NE, States, & Subarea Forecast Energy & Seasonal Peaks					
4	2,115 – [3]					
5	[1] + [2] + [3]; from FCA 9 on, -103 MW for retirement of Wyman 1 & 2.					

[126] The FCM price set for generation in Maine has been lower than the rate for the rest of the pool in most of the FCAs, but the price charged to load has been the same in throughout New England

The resulting estimates of supply and annual surplus (shortages) are summarized in Exhibit 6-4

Exhibit 6-4: Modeled FCM Capacity Surplus

	Starting June	Total Suppy Effect (MW)	Net ME Locked-in MW	Net Change from FCA 4 (MW)	Total Resources at FCA 4 Floor Price	NICR (MW)	Surplus (Shortage) at FCA 4 Floor Price
		[1]	[2]	[3]	[4]	[5]	[6]
FCA3	2012	-600			35,668	31,927	3,741
FCA4	2013	-600			35,668	32,127	3,541
FCA5	2014	-619	85	-704	35,564	33,200	2,364
FCA6	2015	-1,000	-368	-617	35,636	33,099	2,537
FCA7	2016	-1,682	-369	-1,292	34,956	33,593	1,363
FCA8	2017	-1,603	-425	-1,159	35,089	34,076	1,013
FCA9	2018	-1,708	-563	-1,233	35,123	34,542	581
FCA10	2019	-1,551	-357	-1,277	35,074	34,982	92
FCA11	2020	-1,626	-387	-1,317	35,029	35,470	-441
FCA12	2021	-1,512	-625	-971	35,381	35,964	-583
FCA13	2022	-1,441	-657	-870	35,483	36,465	-982
FCA14	2023	-1,341	-688	-737	35,615	36,973	-1,358
FCA15	2024	-1,271	-720	-633	35,717	37,488	-1,771
FCA16	2025	-1,150	-753	-479	35,871	38,010	-2,139
FCA17	2026	-1,101	-786	-395	35,953	38,539	-2,586
Notes:							
1	Exhibit 6-2						
2	Exhibit 6-3						
3	[1] – [2]						
4	36,663 cleared – 395 MW passive DR + [3]; FCA 3 and FCA 4 adjusted for retirement of Vermont Yankee						
5	Exhibit 6-1						
6	[4] – [5]						

6.1.3. Forecast Market-Clearing Price in Each FCA

The third step in the forecast of each FCA price is to forecast the price at which the FCA would clear, i.e., the intersection of demand curve and the supply curve.

Our Reference Case projects that FCA 5 and FCA 6 will clear at the floor price because of the surplus capacity indicated by FCA 4. FCA 4 ended with 36,663 MW of capacity clearing at the floor price, excluding excess Maine generation and real-time emergency generation. This represents an excess of 4,536 MW relative to the NICR.

The 4,536 MW excess included 1,527 of capacity that the ISO considered to be out-of-market capacity (OOM), i.e., capacity that the ISO found could not be supported by market revenues, and which were not allowed to set the market price in FCA 4. Of that 1,527 MW, approximately 1,227 MW are resources that FERC has grandfathered from the effects of OOM treatment in an April 2011 Order; the remaining 300 MW were new demand-response and generation resources in FCA 4 that FERC did not explicitly grandfather in that order, and thus may not be able to affect the market price.[127]. The 36,663 MW also includes about 395 MW of post-2010 energy-efficiency excluded from our analysis.[128]

There would still be an excess of 3,841 MW after excluding the 395MW from 2010 energy efficiency measures and the 300 MW of OOM capacity. That excess cleared at $2.95/kW-month (or about $2.84/kW-month in 2011 dollars). That surplus is large enough to keep the capacity price at the floor price through FCA 6, when the floor price expires under the current ISO market rules.

We forecast the prices in FCA 7 and beyond based upon the forecast annual requirements, forecast potential supply, the relationship between supply and prices bid in FCA 4, i.e. the FCA 4 observed supply or bid curve, and extrapolations of the FCA 4 supply curve. As capacity is retired and the NICR rises, we assume that the market-clearing price follows the FCA 4 bid curve. Exhibit 6-5 indicates that the FCA 4 bid curve is comparable to the FCA 3 bid curve. The FCA 3 and FCA 4 bid curves each ended at their floor price.[129]

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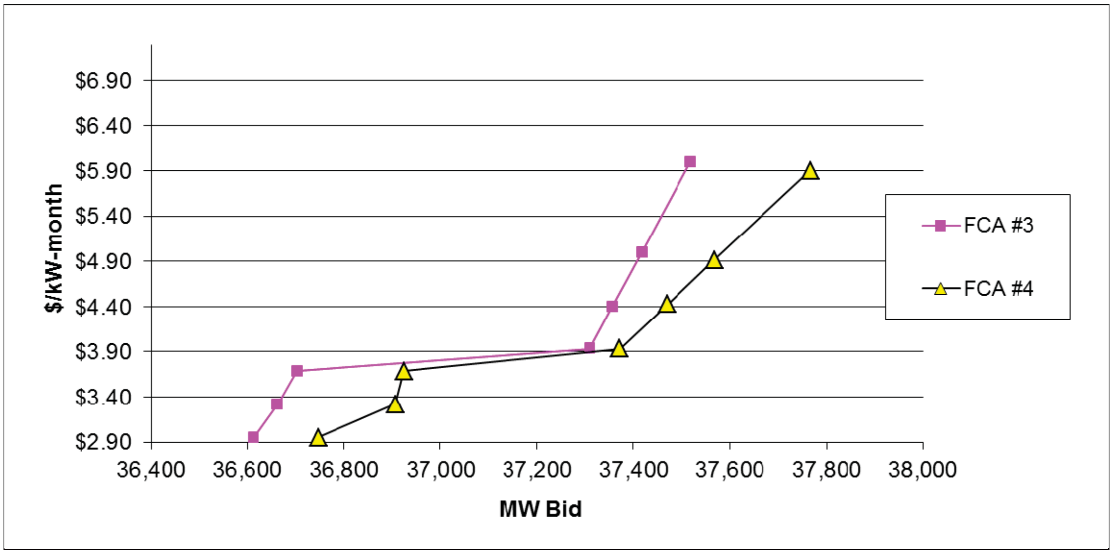
[127] FERC. Docket Nos. ER10-787-000 et al,, Order on Paper Hearing and Order on Rehearing (April 13, 2011). The ISO may remove the OOM designation from some of these resources following further information exchanges with the developers. Future resources may also be classified as OOM. If the OOM capacity does not rise much above the 300 MW level, the OOM designation is not likely to significantly affect future FCM prices.

[128] Some of the efficiency resources were classified as OOM, so these categories overlap.

[129] The shift to the right from FCA 3 to FCA 4 is less than the amount of new energy-efficiency resources that qualified in FCA 4.

Exhibit 6-5: Supply Curves in FCA 3 and 4



Below $2.90 per kw-month, the bottom of the observed supply curve, we assume that prices will continue to fall at the average slope of the FCA 4 curve from $3.90 to $2.90/kW-month, or about $0.0016/kW-month per MW of surplus. The slope of this section of the supply curve is about 2.7 times as steep as the $0.00057/kW-month per MW assumed for excess in AESC 2009. For a given amount of surplus, this assumed supply curve produces lower prices than the supply curve used in AESC 2009.

Above $5.90 per kw-month, the top of the observed supply curve, we assume that the price gradually rises to the costs of adding new generic units at a cost in the $7–$8/kW-month range, referred to as the cost of new entry (CONE). Initial estimates of CONE prepared in 2004 were $7.50/kW-month in 2010[130]. Since those analyses were prepared, costs of equipment have risen and fallen, and lenders have become more risk averse; the cost of new entry remains variable and uncertain.[131] Our specific supply-curve assumptions regarding changes in FCA prices at various increments of supply is shown in Exhibit 6-6.

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[130] See ISO-NE filing in Docket No. ER03-563-030, August 31, 2004.

[131] The costs also vary widely among locations. For example, the bids in the Connecticut peaker procurement (DPUC Docket 08-01-01 were mostly based on capital costs in the range of $1,000–$1,200/kW, but GenOn has proposed two peakers at the Canal plant for about $700/kW (Massachusetts EFSB 10-2, Testimony of Shawn Konary).

Exhibit 6-6: Assumed FCM Supply Curve, 2011 dollars

MW Required relative to the Capacity Cleared in FCA 4	Declining 20%	
	Incremental slope of FCA price	Total FCA price
	$/kW-month per MW	$/kW-month
-1000	$0.0016	$1.26
-800	$0.0016	$1.58
-600	$0.0016	$1.89
-400	$0.0016	$2.21
-200	$0.0016	$2.52
0		$2.84
200	$0.0040	$3.64
400	$0.0005	$3.74
600	$0.0005	$3.84
800	$0.0050	$4.84
1000	$0.0050	$5.84
1200	$0.0035	$6.54
1400	$0.0025	$7.03
1600	$0.0017	$7.37
1800	$0.0012	$7.61
2000	$0.0008	$7.78
2200	$0.0006	$7.90
2400	$0.0004	$7.98
2600	$0.0003	$8.04
FCA Price = Previous price + slope × capacity increment (200 MW)		

Our Reference Case assumes that the 300 MW of OOM capacity would be excluded from the computation of the market-clearing price in FCA 7 through FCA 10 because of the FERC order note earlier. Based on that assumption and our assumed supply curve, the FCM price would fall to about $1.16 in FCA 7. It would then start rising gradually through a transition period to FCA 12 by which time all existing surplus capacity is utilized. During this transition capacity prices are set by resources that did not clear in FCA 4, including at least the following:

- Demand response and incremental capacity at existing units that cleared at higher prices in FCA 1 and FCA 2, but withdrew by FCA 4;
- New demand response;
- Upgrades at existing units;
- Combined heat and power;
- Imports;
- Reactivated generation; and

- Possibly new generation units with highly favorable conditions (e.g., transmission or distribution relief, existing sites, municipal financing).

Some of those resources may be defined as new under the FCA rules, allowing some of the OOM capacity to be treated as normal capacity in each subsequent auction.

By FCA 12, the OOM capacity would all be utilized and more expensive resources would clear, resulting in a rapid rise in FCM price. For the purposes of this analysis, we have assumed 80% of OOM capacity will be treated this way.

The resulting forward capacity prices for the Reference Case are shown in Exhibit 6-7.

Exhibit 6-7: FCM Price Projection, Reference Case, AESC 2011 and AESC 2009 (2011 dollars)

	Year start	Excess including all OOM Capacity	Net of OOM	AESC 2011 FCA Price 2011$ $/kW-month	AESC 2009 FCA Price (2011$/kW-month)
FCA 1	2010				$4.46
FCA 2	2011				$3.49
FCA 3	2012			$2.89	$2.81
FCA 4	2013			$2.84	$1.32
FCA 5	2014	2,364		$2.84	$1.32
FCA 6	2015	2,537		$2.84	$1.43
FCA 7	2016	1,363	1,064	$1.16	$1.53
FCA 8	2017	1,013	714	$1.71	$1.53
FCA 9	2018	581	282	$2.39	$1.63
FCA 10	2019	92	0	$2.68	$1.63
FCA 11	2020	-441		$3.76	$1.73
FCA 12	2021	-583		$3.83	$1.83
FCA 13	2022	-982		$5.75	$1.94
FCA 14	2023	-1,358		$6.92	$2.04
FCA 15	2024	-1,771		$7.57	$2.14
FCA 16	2025	-2,139		$7.86	
FCA 17	2026	-2,586		$8.03	
			15 year Levelized	**$4.01**	**$2.10**
Notes: Excess from Exhibit 6-4.					

6.1.3.1. Comparison to AESC 2009

AS shown in Exhibit 6-7, other than in FCA 7, these values are considerably higher than the AESC 2009 projections, due to the following factors (in addition to various changes in NICR and resources bid into the latest FCA):

- The extension of the price floor through FCA 6,
- The assumption that larger amounts of capacity will retire in the next few years. In AESC 2009, we did not anticipate the retirement of the generation in Exhibit 6-2, other than Salem, or the 150 MW of other generation that delisted in FCA 4. The AESC 2009 analysis did not explicitly distinguish environmentally-driven retirements from resources that might simply offer capacity at prices above the clearing price in future auctions.
- The elimination of capacity from new energy-efficiency resources from the resources that cleared in the FCAs. The AESC 2009 analysis did not make a comparable adjustment
- The treatment of capacity trapped in Maine. The AESC 2009 analysis did not recognize that incremental capacity in Maine was not able to reduce the market-clearing price.
- The recognition that 300 MW of previously cleared resources may be treated as OOM resources and not allowed to set market prices in future auctions.

6.1.4. Avoided Capacity Costs per MW Reduction in Peak Demand

As described in Chapter 8, a kilowatt reduction from an energy-efficiency measure in a given year can avoid wholesale capacity costs through two broad categories of approaches, i.e., bidding in to FCAs as a resource or reducing the ISO-NE forecast of peak load for which capacity has to be acquired.

If the kilowatt reduction from an energy-efficiency measure in a given year is bid into FCA for that year, its avoided capacity cost is the FCA price for that year and adjusted for an ISO-NE loss factor of 8 percent.

If the load reduction from an energy-efficiency measure in a given year reduces the peak load that ISO-NE forecasts to be served in that year, its avoided capacity cost is the FCA price for that year adjusted upward by the reserve margin ISO-NE requires for that year.

The reserve margin is the ratio of the Net Installed Capacity Requirement (NICR) to forecast peak load that ISO-NE sets each year. The ISO has set NICRs through FCA 5, and has projected NICRs through FCA 10 in RSP 2010. For FCA 1 to FCA 5, Exhibit 6-1 provides the computation of the required reserve margin indicated by the latest determination of NICR for each capacity year.[132] For FCA 6

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[132] The reserve margins for FCA 1 to FCA 3 are from reconfiguration auctions, which appear to have little effect on total cost to load (and hence are not used in the rest of this analysis), but indicate the ISO's most recent view of capacity needs.

to FCA 10, the reserve margin is the value reported in the 2010 RSP. Beyond FCA 10, we escalate both load and NICR at the average growth rate in the last five years of the ISO forecast.

The resulting reserve margins are applied to the FCA prices to calculate the avoided capacity cost to load each year, and are presented in the last column of Exhibit 6-8. The forecast of avoided unit capacity cost to load does not reflect any adjustment for marginal losses on the pool transmission facilities of 1.9% and the applicable wholesale risk premium of 9%.

Exhibit 6-8: Forecast of Avoided Unit Capacity Costs

		FCA Prices 2011$				
		$kW-month	$kW-year	Required Reserve	FCA Prices Adjusted for Reserve Margin ($/kW-yr)	Avoided Capacity Cost to Load ($kW-yr)
		a	b	c	d	e
6/1/2011	FCA 2	$3.60	$43.20	21.0%	$52.26	$58.05
6/1/2012	FCA 3	$2.89	$34.72	16.6%	$40.48	$44.96
6/1/2013	FCA 4	$2.84	$34.04	15.7%	$39.37	$43.72
6/1/2014	FCA 5	$2.84	$34.04	17.7%	$40.05	$44.49
6/1/2015	FCA 6	$2.84	$34.04	15.9%	$39.45	$43.82
6/1/2016	FCA 7	$1.16	$13.98	16.0%	$16.22	$18.01
6/1/2017	FCA 8	$1.71	$20.56	16.2%	$23.89	$26.54
6/1/2018	FCA 9	$2.39	$28.72	16.3%	$33.39	$37.09
6/1/2019	FCA 10	$2.68	$32.22	16.4%	$37.50	$41.66
6/1/2020	FCA 11	$3.76	$45.08	16.5%	$52.53	$58.34
6/1/2021	FCA 12	$3.83	$45.94	16.6%	$53.58	$59.51
6/1/2022	FCA 13	$5.75	$68.95	16.8%	$80.51	$89.42
6/1/2023	FCA 14	$6.92	$83.08	16.9%	$97.11	$107.86
6/1/2024	FCA 15	$7.57	$90.89	17.0%	$106.36	$118.14
6/1/2025	FCA 16	$7.86	$94.32	17.1%	$110.49	$122.72
6/1/2026	FCA 17	$8.03	$96.38	17.3%	$113.02	$125.53

Notes:
- a From Exhibit 6-7
- b a*12
- c From Exhibit 6-1
- d b*(1+c)
- e d*(1+1.9%)*(1+WRP of 9%)

The benefit to consumers depends on four factors:

- The percentage of the projected load reduction bid into and cleared in each FCA.

- The timing of reduction in participants' ISO load tags, their share of the NICR.
- The speed with which the ISO recognizes the reduction in load due to energy-efficiency load reductions not bid into the FCAs, reducing the NICR.
- Whether the avoided cost is computed from the perspective of a particular consumer group (a utility's ratepayers, or a state's power consumers) or for all New England load. If the analysis includes DRIPE for the entire region, the avoided capacity cost would logically include only reduction in the regional total FCM charges. Once the NICR is set, load reductions only reduce that regional FCM bill by the amount of FCM revenues to the program administrators. On the other hand, if the analysis includes DRIPE benefits only for one state's consumers, it should logically include the benefits to that group from reducing their share of the FCM bill.[133]

Appendix B includes avoided capacity costs, assuming that consumers start to receive all the benefits from load reductions in the year of installation. If a regulator prefers to assume that some of the benefits will be lagged, the user may delay a portion of the avoided capacity costs.

6.2. Avoided Electric Energy Costs

6.2.1. Forecast of Energy Prices Assuming No New DSM

The projected wholesale energy prices (Reference Case) presented below are outputs from the Market Analytics simulation model for a hypothetical future in which no new energy efficiency resources are implemented after 2010. As such, they represent the wholesale price of avoided energy in a future with no new efficiency. These prices are NOT meant to be used as projections of energy prices in the most likely future, i.e., one in which there will be some level of new energy efficiency measures installed each year over the planning horizon.

Chapter 2 describes the Market Analytics model and the major input assumptions underlying these projections. In addition, that chapter discusses the structure of the electric energy market, and the model and inputs we use to represent the electric energy market for AESC 2011. These key inputs are:

- Projected loads–derived from the latest ISO-NE CELT report;

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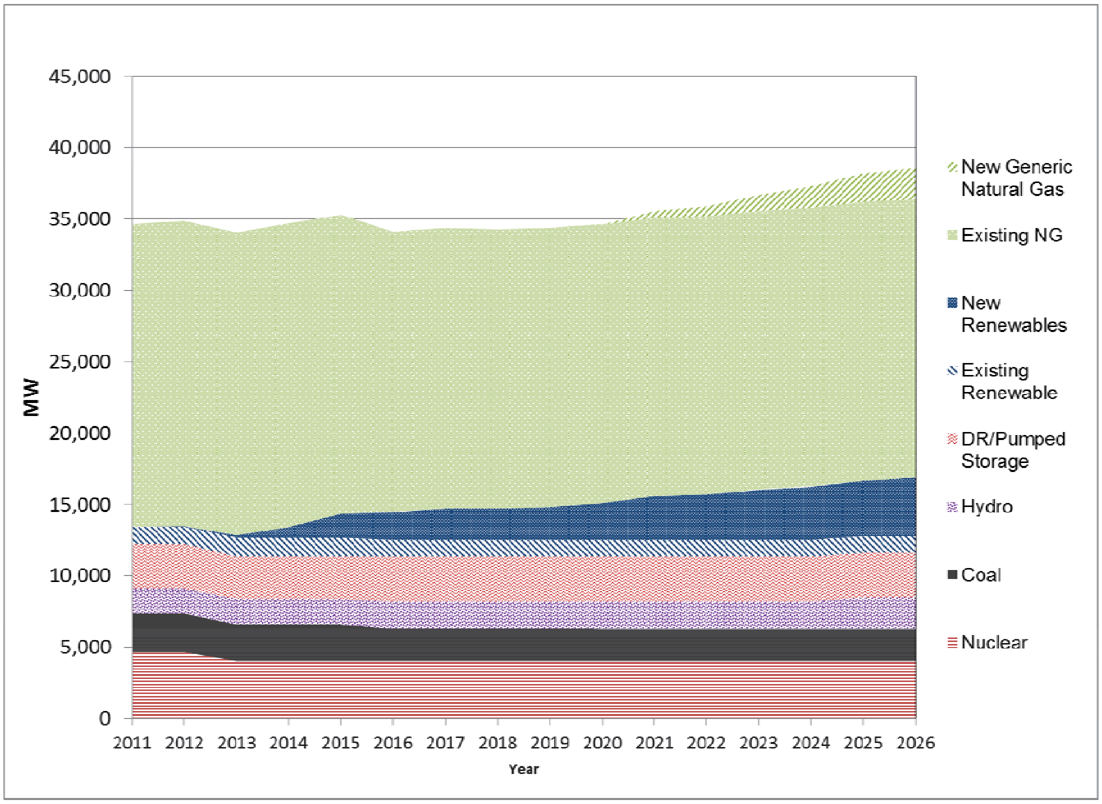
133 Various states have treated DRIPE differently: Rhode Island includes regional DRIPE, Massachusetts has included only state DRIPE, and the other states exclude DRIPE. These practices may change over time.

- Projected resources—based on available public information such as the capacity auctions and the current state RPS requirements for renewables
- Forecast prices for natural gas, coal and oil, and
- Forecast emission regulation compliance costs for CO_2, SO_2 and NO_x.

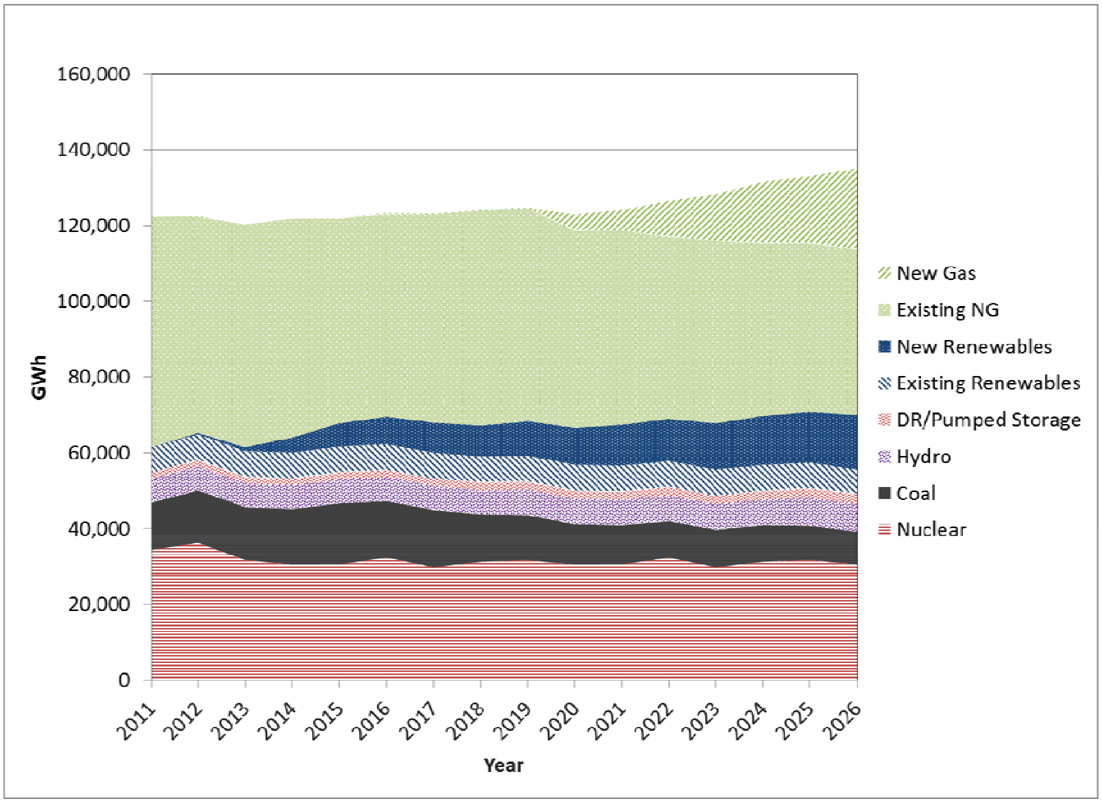
The projected level and mix of capacity in the Reference Case is presented in Exhibit 6-9 below. Most capacity additions are renewable resources, top rows, to comply with RPS requirements, but there are also some new natural gas generators added after 2019. The oil capacity are primarily peakers that get very little use, as shown by their apparent absence in the next graph that shows generation.

Exhibit 6-9: Reference-Case Capacity by Source (MW)



The projected level and mix of generation in the Reference Case is presented in Exhibit 6-10 below. Generation from nuclear declines slightly with the closure of Vermont Yankee in 2014, and coal generation also declines as some older units are retired. Generation from natural gas is the dominant resource declining slightly in the near term but rising a bit in the later years. Renewable generation increases substantially in compliance with RPS requirements.

Exhibit 6-10: Reference-Case Generation by Source (GWh)



The prices projected in the Reference Case are:

- On a levelized (2010-2024 for AESC 2009 versus 2012-2026 for AESC 2011) annual basis 17 percent below those from AESC 2009. The reductions are generally less for summer peak periods and greater for other periods as shown in Exhibit 6-11;[134]
- Within 0.4 percent of NYMEX futures for ISO NE, as of March 18, 2011, for 2011 through 2016.

6.2.1.1. Forecast of Wholesale Electric Energy Prices

For AESC 2011, we present streams of energy values for all of New England in the form of "the hub price." It requests forecasts for the following four streams—summer on-peak, summer off-peak, winter on-peak, winter off-peak.

The hub price representing the ISO-NE Control Area is located in central Massachusetts and the Central Massachusetts zone in Market Analytics model is used as the proxy for that location. Exhibit 6-11 below presents summer and

[134] All levelized values have been calculated using the AESC 2011 discount rate of 2.46 percent.

winter, on-peak and off-peak energy prices as produced by the model through 2026 for Central Massachusetts.

Exhibit 6-11: Wholesale Energy Price Forecast for Central Massachusetts

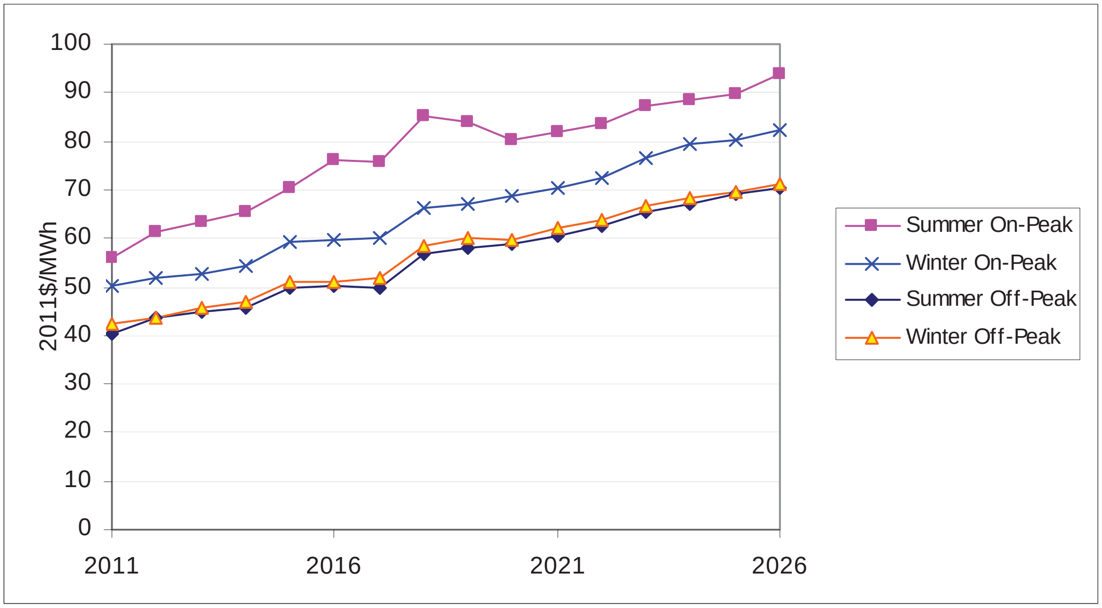


Exhibit 6-12 provides the prices in tabular form.

Exhibit 6-12: Wholesale Energy Price Forecast for Central Massachusetts

Year	Summer Off-Peak	Summer On-Peak	Summer All-Hours	Winter Off-Peak	Winter On-Peak	Winter All-Hours	Annual All-Hours
2011	40.33	55.97	47.77	42.33	50.16	46.05	46.38
2012	43.51	61.52	52.07	43.56	51.69	47.43	48.73
2013	44.94	63.19	53.62	45.53	52.84	49.01	50.27
2014	45.69	65.56	55.14	46.78	54.29	50.36	51.68
2015	49.90	70.34	59.62	50.88	59.46	54.96	56.21
2016	50.41	76.20	62.68	50.85	59.73	55.07	57.33
2017	49.87	75.78	62.19	51.96	60.03	55.80	57.64
2018	56.68	85.36	70.32	58.38	66.11	62.06	64.47
2019	57.83	83.97	70.26	60.08	66.97	63.36	65.29
2020	58.73	80.24	68.96	59.83	68.88	64.14	65.37
2021	60.43	81.81	70.60	62.07	70.51	66.09	67.19
2022	62.41	83.37	72.38	63.81	72.46	67.93	69.00
2023	65.62	87.32	75.94	66.66	76.54	71.36	72.46
2024	67.28	88.67	77.45	68.48	79.22	73.59	74.44
2025	69.32	89.86	79.09	69.38	80.26	74.56	75.61
2026	70.27	93.80	81.46	71.22	82.24	76.46	77.68
Levelized 2012-2026	55.95	78.16	66.51	57.04	65.72	61.17	62.60

All prices expressed in 2011$ per MWh.

6.2.1.2. Analysis of Forecasts of Wholesale Electric Energy Prices

The scope of work requests the following analyses of the forecast:

- Comparisons with other trends and forecasts, including comparisons to a trend of actual monthly prices (real time) from ISO-NE, a forecast as represented by the NYMEX futures market and the most recent EIA forecast;
- A high level discussion of reasons for differences identified in the comparisons; and
- Explanation of any apparent price spikes and key variables that affect the outcome, as well as identification of potential scenarios worthy of investigation.

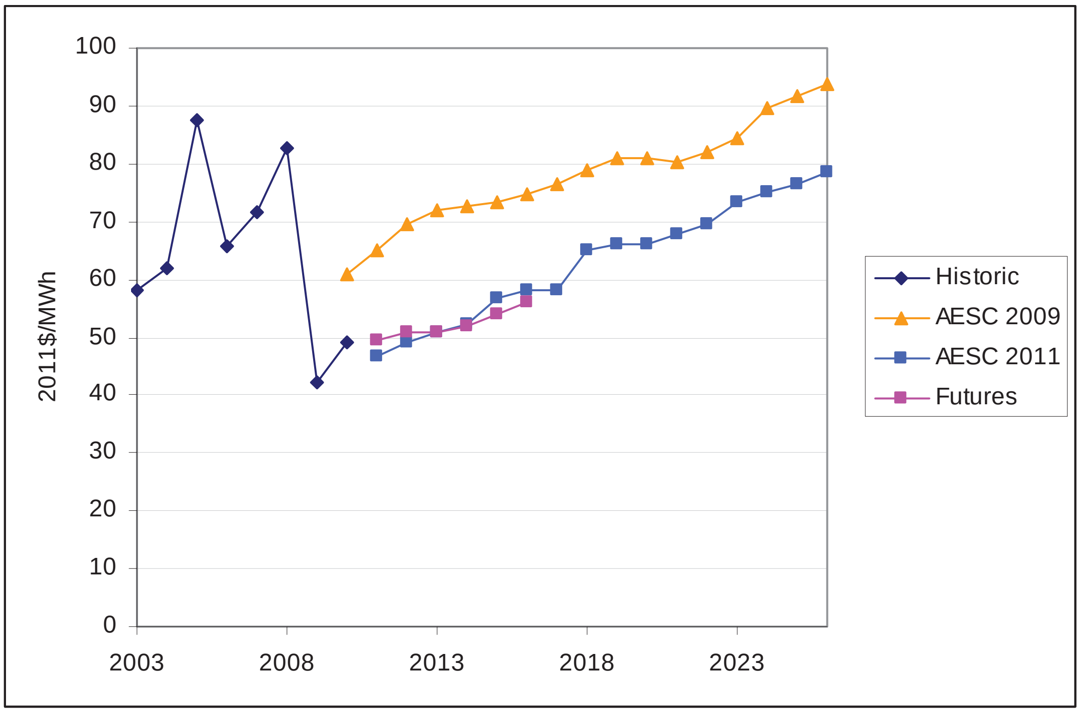
6.2.1.3. Comparison with the AESC 2009 Forecast and Historic Values

Exhibit 6-13 provides a comparison of 1) historical prices, 2) AESC 2009, and 3) AESC 2011 forecasts of the annual wholesale energy prices in the Central Massachusetts zone.

Exhibit 6-13 indicates that the AESC 2011 forecast is significantly below AESC 2009. The lower AESC 2011 forecast reflects significant reductions in the cost of natural gas which is generally the marginal generation fuel. It also reflects somewhat lower annual loads as well as lower CO_2 prices.

The AESC 2011 Reference case forecast of Henry Hub natural gas prices start in 2011 at $4.41/MMBtu, which is about $2.00 below the AESC 2009 forecast. Over time that gap narrows but still remains lower by about $1.00. The irregularities in the annual electricity price curve primarily represent the natural gas price changes, although the 2018 rise is associated with the start of CO_2 emission pricing.

Exhibit 6-13: Historic and Forecast Annual Wholesale Price Comparisons



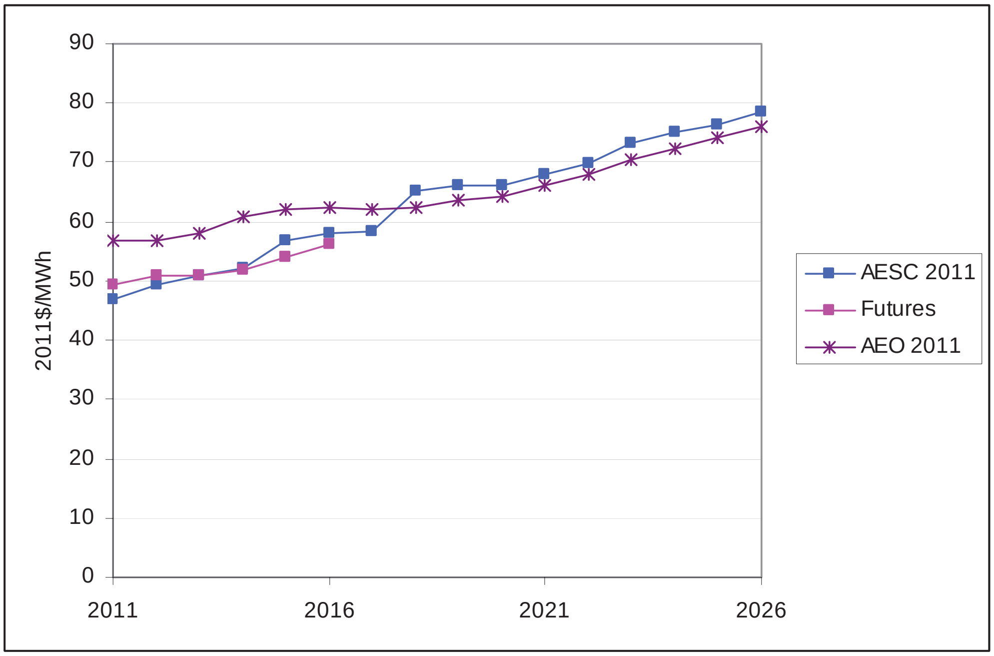
6.2.2. Comparison with Other Forecasts

The following section details comparisons of the AESC 2009 forecast with other forecasts.

6.2.2.1. Comparison with AEO 2011 Forecast

The Annual Energy Outlook is annually released by the EIA and forecasts energy usage and price for the U.S. as a whole and for its constituent regions. Table 77 of the report presents generation, capacity and prices for New England. Although the AEO does not produce a market price per se, the generation service category price comes fairly close. Exhibit 6-14 below compares that generation price with the AESC 2011 forecast.

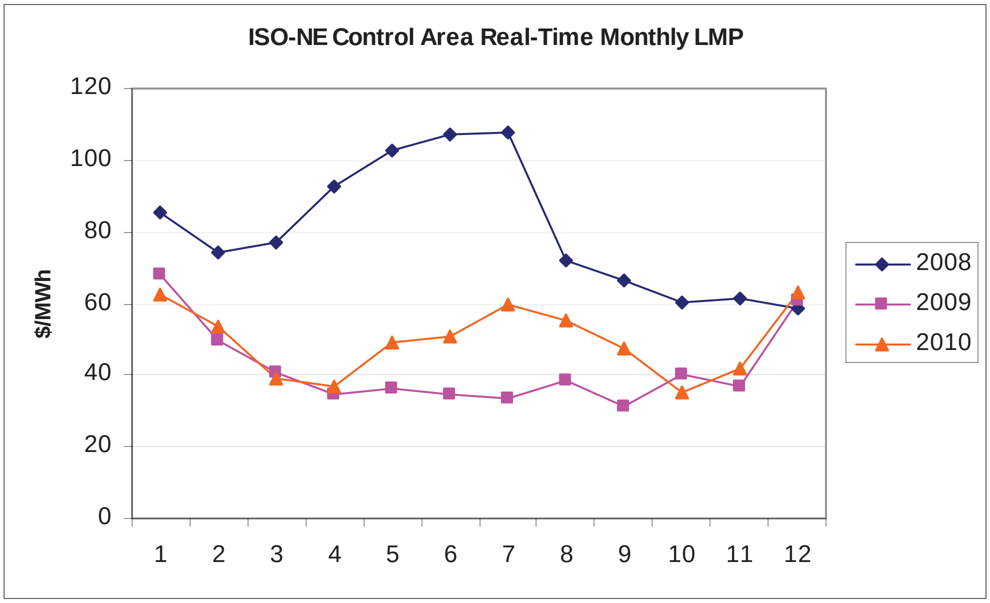
Exhibit 6-14: Forecast Comparison with AEO 2011



6.2.2.2. Comparison with Trends in ISO NE Prices

Variations in historical monthly prices in ISO-NE in 2008, 2009, and 2010 are explained by variation in monthly electricity loads and natural gas prices. Exhibit 6-15 shows the electricity monthly prices in each of the last three calendar years. The general pattern is that high loads in the summer increase prices above the spring and autumn periods. And moderately higher winter loads combined with sometimes much higher spot natural gas prices can result in even higher winter prices. In 2009, a year with generally lower loads, the winter prices were higher than the summer ones. In 2010 with higher loads, the summer and winter prices were similar. In 2008, electricity prices peaked in the summer due to what is now recognized as a natural gas price bubble that collapsed that autumn. As discussed elsewhere the primary driver of electricity prices in New England are the spot natural gas prices which tend to be low in the summer but can spike considerably during cold winter periods. The AESC 2011 forecast of monthly prices is consistent with this historical trend.

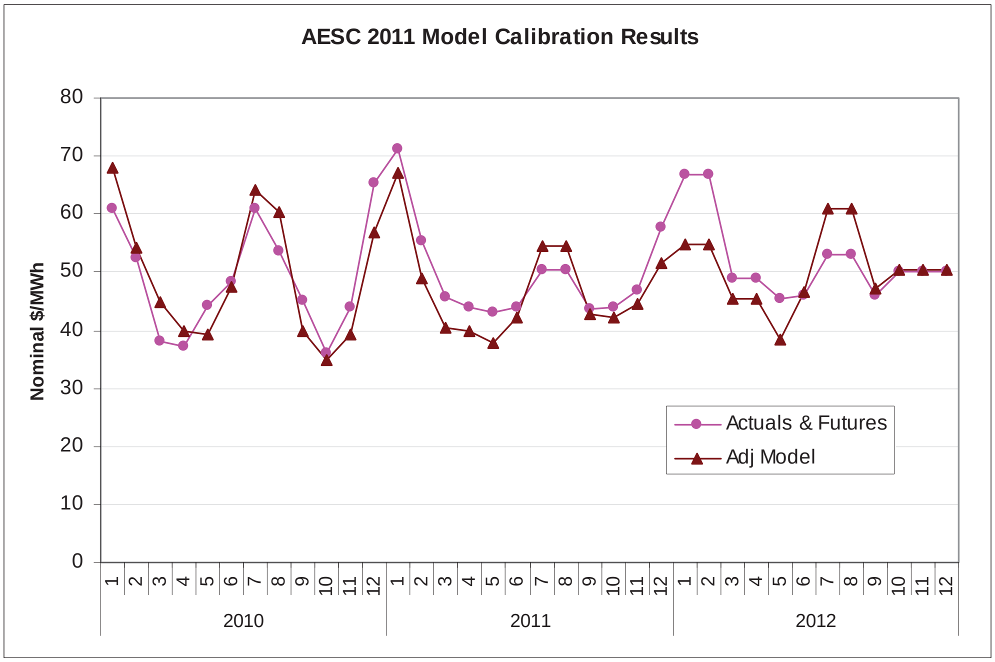
Exhibit 6-15: ISO-NE Control Area Monthly Real-Time Prices



The Chicago Mercantile Exchange (CME) maintains the NYMEX futures market for electricity prices at the New England Hub. There is a moderate amount of trading out about a year or two, but further out the market is quite thin. Nevertheless these futures prices provide one source of comparison with the AESC forecast. For this Study we use futures as of March 18, 2011.

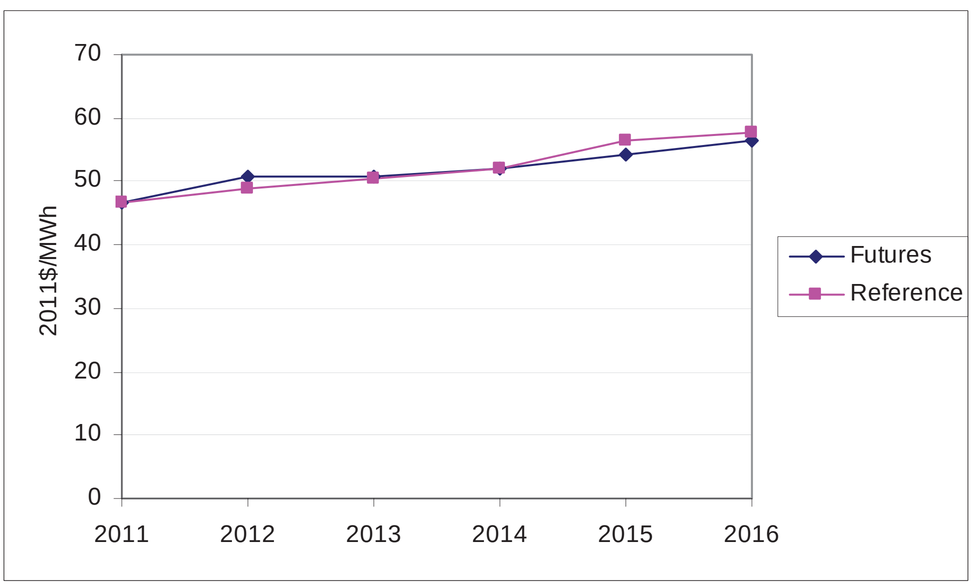
Exhibit 6-16 shows the comparisons on a monthly basis corresponding to the NYMEX products which are often based on multiple months. Considering the volatility of the futures markets the correspondence is amazingly close.

Exhibit 6-16: AESC vs. NYMEX New England Futures



The next Exhibit compares the futures and the AESC forecast energy prices on an annual average basis. The correspondence is extremely close and represents both the assumptions about natural gas prices and the calibration process that we carried out adjusting the model bidding parameters.

Exhibit 6-17: Comparison of Futures and Reference Case Annual Prices



6.2.2.3. Comparison to AESC 2009 Forecast

The following section summarizes forecast differences between AESC 2011 and AESC 2009. Exhibit 6-18 compares the two AESC forecasts on a levelized basis. Differences exist between the two forecasts occur in all years and periods in the order of 8.7 to 20.1 percent.

Exhibit 6-18: 15-Year Levelized Cost Comparison for Central Massachusetts (2011$/MWh)

	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual All-Hours Energy
AESC 2011	$65.72	$57.04	$78.16	$55.95	$62.60
AESC 2009	82.35	68.41	85.69	65.49	75.37
% Difference	-20.2%	-16.6%	-8.8%	-14.6%	-16.9%

Notes:
Levelization periods: 2010-2024 for AESC 2009; 2012-2026 for AESC 2011
Discount rate of 2.46%

There are several key factors causing the current forecast to differ from that of AESC 2009:

- Natural gas price – Natural gas prices are the primary determinant of electricity prices in the New England wholesale market. The current natural gas price forecast is significantly (17.4 percent) below the previous one.
- CO_2 price – The current forecast for a national price for CO_2 starts four years later in 2018 and on a levelized basis (2010-2024 for AESC 2009 and 2012-2026 for AESC 2011) AESC 2011 is 31 percent lower than AESC 2009.[135]
- Load Levels – the projections of peak demand used in AESC 2011, which are based on CELT 2011, are about 3 percent below those used in AESC 2009. In projections of annual electric energy used in AESC 2011 are about 3 percent greater than in AESC 2009.

The impact of each of these factors is discussed in more detail below.

[135] On levelized basis for the same period (2012-2026), the difference between AESC 2009 and AESC 2011 is 44 percent.

New England Natural Gas Price Forecast

Prices in the New England electricity energy market have been historically very volatile. This volatility is very strongly linked to the price that electric generators pay for natural gas. The graph below shows these prices on a monthly average basis for the previous five years. One thing to note is that although electricity prices closely follow natural gas prices, they tend to be proportionally higher in the summer when loads are greater.

Exhibit 6-19: Historical New England Electricity and Natural Gas Prices

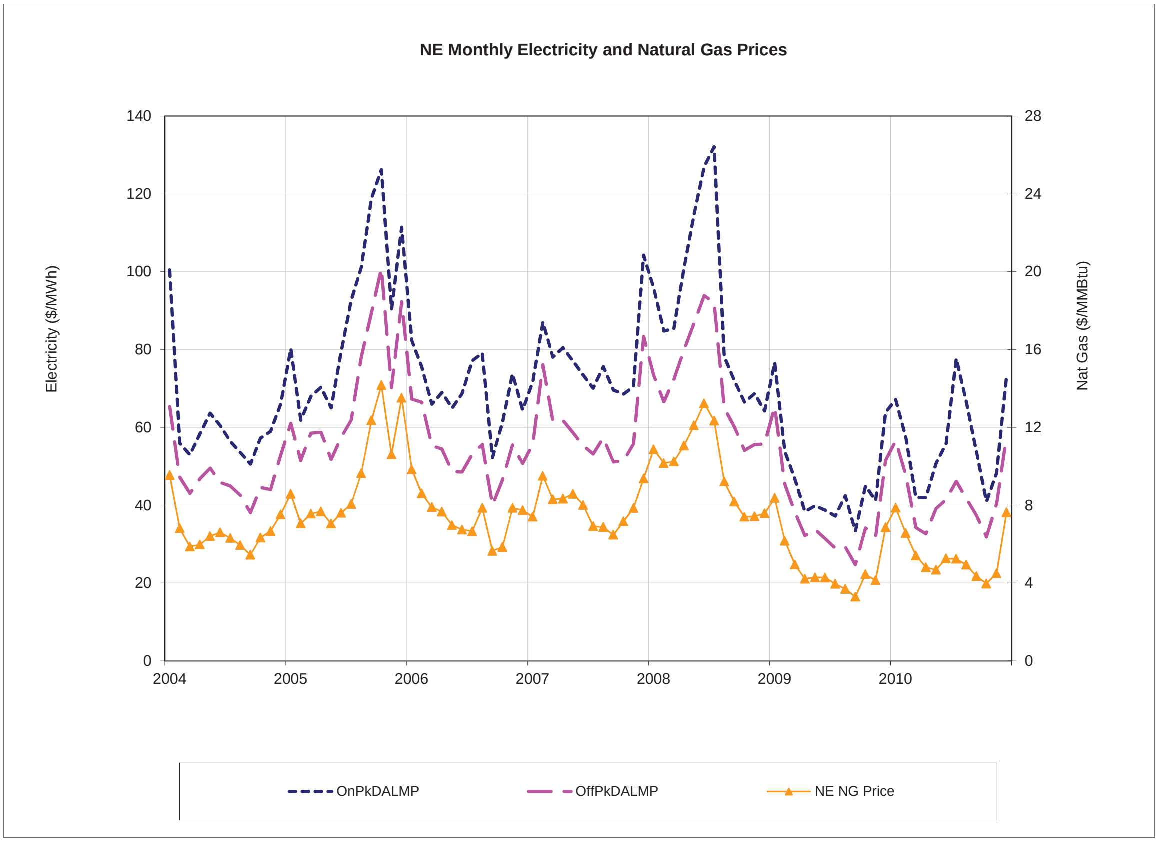
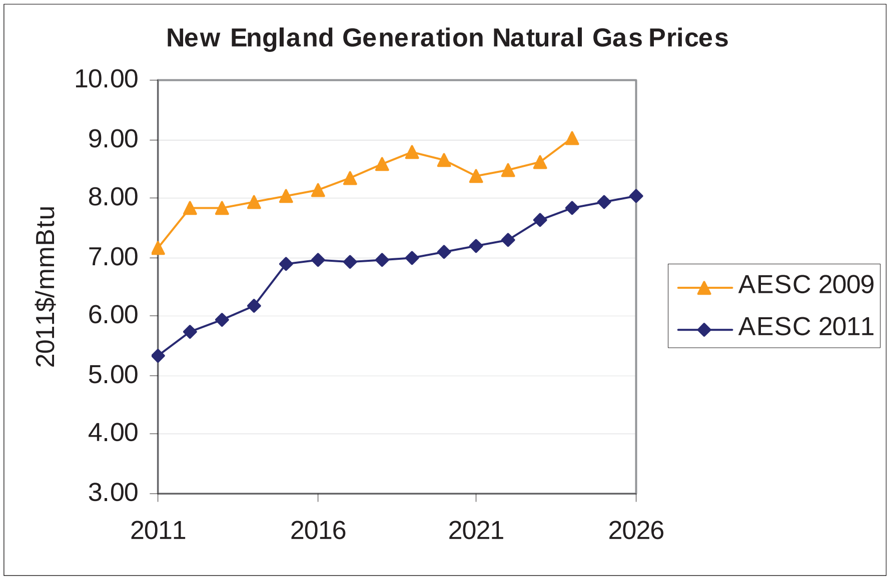


Exhibit 6-20 compares the current natural gas forecast for electric generation in New England which reflects historic margins in the spot market compared to that of AESC 2009. The AESC 2011 forecast has much lower prices in all years. On a levelized basis (2010-2024 for AESC 2009 and 2012-2026 for AESC 2011) the current natural gas price forecast is $1.12/MMBtu or 13.8 percent below AESC 2009.[136]

[136] For the same levelization period (2012-2026), the AESC 2011 New England natural gas forecast is $1.47/MMBtu or 17.4 percent lower than AESC 2009.

Exhibit 6-20: AESC 2011 vs. AESC 2009 Gas Price Forecast Comparison



In terms of the seasonal differences the winter (eight month) prices average 3.5 percent above the annual average and the summer (four month) prices average 6.9 percent below. This differs slightly from AESC 2009 where those seasonal differences were +3.2 percent and -6.4 percent respectively.

CO_2 Price Forecast

The CO_2 Price forecast used for AESC 2011 is significantly below that used in AESC 2009 reflecting expectations of significantly delayed national regulation as shown in Exhibit 6-21. The levelized (2012-2026 for AESC 2011 and 2010-2024 for AESC 2009) cost for AESC 2011is $15.69/ton compared to $22.70/ton for AESC 2009, a $7.01 or a 31 percent decrease reflecting primarily the delay from 2014 to 2018.[137] Note too that AESC 2009 had high CO_2 prices starting quite early in 2013, whereas for AESC 2011 high CO_2 prices do not start until 2018.

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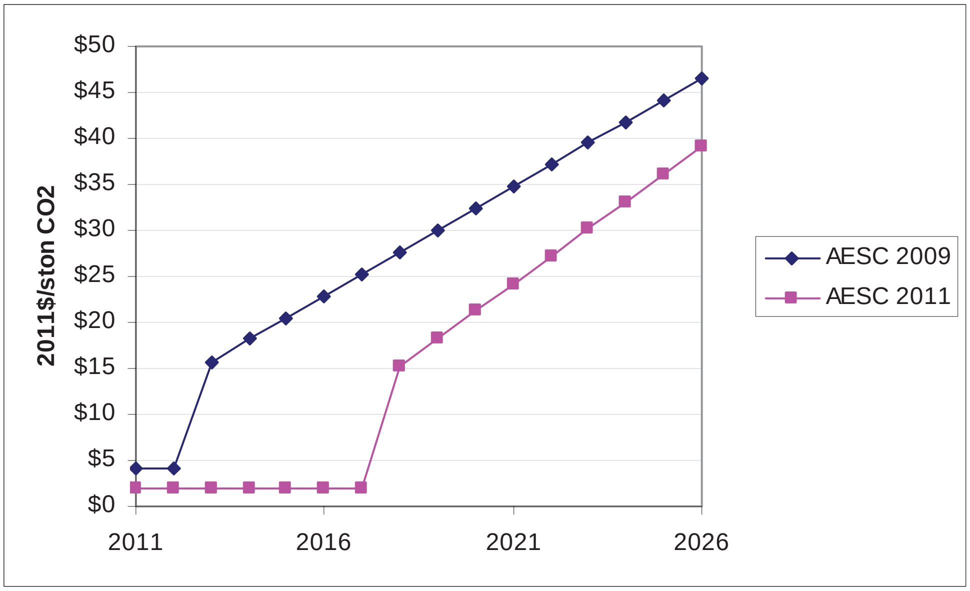
[137] Over the same levelization period (2012-2026), the difference between AESC 2011 and AESC 2009 is $12.49 or 44 percent.

Exhibit 6-21: AESC 2011 & 2009



Load Forecast

As discussed in Chapter 2, the CELT 2011 loads used for AESC 2011 are very close to those used in 2009. The summer peak loads are about three percent less, but the annual energy loads are about three percent greater. Although load levels have an effect on market prices, these types of changes would have a very minimal effect on the overall energy prices.

Analysis of Forecast Differences

There are many factors that go into the wholesale electricity price that include both fuel and environmental costs and system operation. The following exhibit focuses on a comparative analysis of the summer peak prices for AESC 2009 and AESC 2011. As noted previously the AESC 2011 summer peak price on a levelized basis was 13.2 percent below the previous one. The following exhibit presents an illustrative calculation of those two summer prices and the resulting differences keeping in mind that there are numerous year by year variations.

The table starts by showing the levelized wholesale prices over a comparable period using the same discount rate. That is followed by values for two of the key inputs - natural gas and CO_2 prices. The system parameters represent overall system behavior and are consistent with the behavior we see and expect from the dispatch modeling. A key difference with the current simulation is that there are significantly more retirements of base load resources such as Vermont Yankee and several coal plants. Those retirements shift the generation supply curve to the left which causes less efficient units to set the market price in summer peak periods, when loads are highest, as compared to AESC 2011. The result is that the decrease in summer peak period prices in AESC 2011 relative to AESC 2011 due to lower natural gas and CO_2 prices is offset somewhat by the 9.7 percent lower efficiency of the marginal units in those periods. This is why there is less of a reduction in summer peak period prices under the AESC 2011 forecast compared to AESC 2009 than for other periods of the year during which loads are generally less.

Exhibit 6-22: AESC 2011 vs. AESC 2009 Levelized Cost Comparisons

WCMA Summer On-Peak Period Price Comparison (2011$ per MWh)			
	AESC 2009	**AESC 2011**	**% Difference**
Wholesale Price from Simulation Model	**$85.69**	**$78.16**	**-8.8%**
Analysis			
Input Values			
Summer NG Price ($/MMBtu)	$7.61	$6.49	-14.7%
CO_2 Price ($/ton)	$22.70	$15.69	-30.9%
NG CO_2 (lbs/MMBtu)	118	118	
Marginal Heat Rate (Btu/kWh)	9,250	10,150	9.7%
Marginal CO_2 Rate (tons/MWh)	0.54	0.60	9.7%
Price and Heat Rate Effects			
Fuel Cost ($/MWh)	$70.35	$65.86	-6.4%
CO_2 Cost ($/MWh)	$12.39	$ 9.40	-24.2%
Other variable & bid costs ($/MWh)	$ 3.00	$ 3.00	0.0%
Wholesale Price Estimated from Price and Heat Rate effects + other variable costs	**$85.74**	**$78.25**	**-8.7%**

Notes
Values may not sum due to rounding
AESC 2009 levelized (2010-2024)
AESC 2011 levelized (2012-2026)

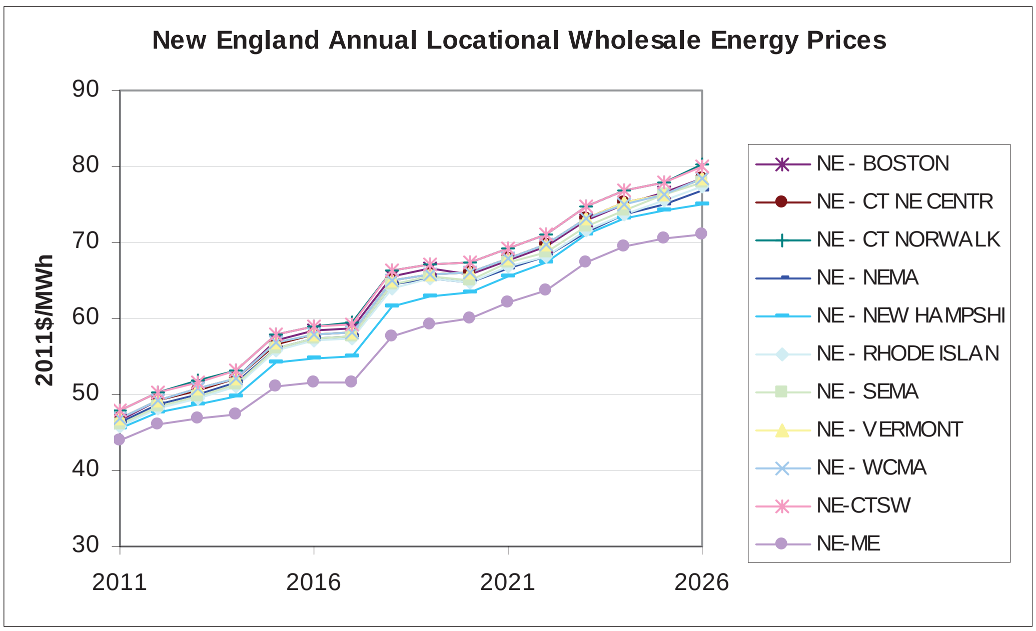
As indicated previously the AESC 2011 annual wholesale energy price forecast on a levelized basis (2012-2026) is 17 percent below that of AESC 2009. The natural gas price for New England electric generators is 18 percent lower, and the CO_2 price forecast is 31 percent lower. The changes in those two inputs explain the basic difference in the electric prices. About two-thirds of the reduction is associated with lower natural gas prices and the remaining one-third because of the lower CO_2 prices.

6.2.2.4. Forecast of Electric Energy Prices by State

The forecast of energy values by zone by year for each period i.e., summer on peak, summer off-peak, winter on-peak, winter off-peak are presented in Appendix C.

Exhibit 6-23: illustrates the summer peak period prices in descending order by model locations.[138] Note how some zones have nearly identical prices. The highest price zone is southwestern Connecticut and the lowest price zone is Maine. The price dip after 2020 is related to the underlying Henry Hub natural gas price discussed previously.

Exhibit 6-23: New England Summer Peak Locational Price Forecast



Transmission Energy Losses

Our forecast for marginal energy clearing prices includes inter-area losses for energy coming inside the load area from outside for flows across transmission links between modeling zones. These losses are not reported by the model by time of day; therefore we have presented the loss factors for summer and winter periods only. The losses are presented in Exhibit 6-24 as a percentage of imports into each zone or state.

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[138] The prices for the Bangor Hydro Area in 2024 are somewhat anomalous and will be corrected.

Exhibit 6-24: AESC 2011 Modeling Zone and State Transmission Losses

Modeling Zone Losses		
Modeling Zone	**Summer**	**Winter**
Connecticut- Northeast	8.8%	8.7%
Connecticut- Southwest	8.7%	8.7%
Connecticut- Norwalk	1.0%	1.3%
Massachusetts- Boston	4.1%	3.5%
Massachusetts- NEMA	10.0%	10.0%
Massachusetts- SEMA	2.2%	2.2%
Massachusetts- WCMA	5.1%	5.9%
Maine	10.5%	9.9%
New Hampshire	8.8%	8.7%
Rhode Island	7.5%	7.4%
Vermont	8.5%	7.8%
New England Average	6.6%	6.5%
State Losses		
State	**Summer**	**Winter**
Connecticut	6.4%	6.4%
Massachusetts	6.2%	6.2%
Maine	10.5%	9.9%
New Hampshire	8.8%	8.7%
Rhode Island	7.5%	7.4%
Vermont	8.5%	7.8%
New England Average	6.6%	6.5%

6.3. Demand-Reduction-Induced Price Effects (DRIPE) – Capacity and Energy

This section describes our estimates of capacity DRIPE and energy DRIPE.

DRIPE refers to the reduction in prices in the wholesale markets for capacity and energy, relative to the prices forecast in the Reference Case, resulting from the reduction in quantities of capacity and of energy required from those markets due to the impact of efficiency and/or demand response programs. Thus DRIPE is a measure of the value of efficiency in terms of the reductions in wholesale prices seen by all retail customers in a given period.

Our estimates indicate that the DRIPE effects are very small when expressed in terms of an impact on market prices, i.e., reductions of a fraction of a percent. However, the DRIPE impacts are significant when expressed in absolute dollar terms. Very small impacts on market prices, when applied to all energy and capacity being purchased in the market, translate into large absolute dollar amounts.

We estimate DRIPE in each wholesale market in three steps.

- First, we estimate the impact a reduction in load will have on the price in that wholesale market, assuming all else is held constant (Gross DRIPE).

We estimate this impact by analyzing the relationship between the quantity of capacity or energy required in the relevant market and the market price;

- Second, we estimate the pace at which market participants will respond to the reduction in price with actions that offset that reduction and ultimately cause the market price to eventually return to where to the level it would have been under the Reference Case (Net DRIPE). To estimate the pace of this offset or dissipation we estimate the material differences in actions that suppliers would take each year in the DRIPE case relative to the actions they are projected to take under the Reference Case. The pace of dissipation of capacity DRIPE will likely be different from the pace of energy DRIPE, because of the differences in the types of responses available to participants in those markets. Estimating the dissipation of DRIPE involves the exercise of considerable judgment and reasonable analysts may develop different estimates;
- Third, we estimate the percentage of net DRIPE that retail customers will experience based upon the portion of their supply that is acquired from wholesale capacity and energy markets.

6.3.1. Capacity DRIPE

Reductions in peak demand from energy-efficiency programs will have a downward effect on wholesale capacity prices because the lower demand will allow lower-cost resources to be at the margin—and set the price—in the FCAs. This impact is referred to as capacity DRIPE.

The timing of this impact will vary according to how, if at all, the reduction in peak demand is bid into the Forward Capacity Market.

- Reductions in peak demand that are bid into a FCA will explicitly reduce the clearing price in that FCA, potentially reducing FCM prices starting in the year the demand reduction measure is implemented;
- Reductions in peak demand that are not bid into FCAs will eventually reduce the ISO's forecast of peak load and hence of installed capacity requirement in the FCA and thereby eventually implicitly reduce FCA prices. Thus, the impact of those peak reductions may be delayed two to three years.[139]

Capacity DRIPE will not necessarily persist as long as the underlying demand reductions. The lower energy prices will tend to change the mix of generation used

[139]The ISO has not yet developed a method for explicitly recognizing energy-efficiency installations that are not bid into the market until they occur and reduce metered load.

to supply the market, which in turn will eventually lead to higher prices, erasing the effects of lower loads.

Our estimate of capacity DRIPE is based on the following three factors:

- The effect of reductions in peak demand on wholesale capacity prices, if all other capacity and Demand Response (DR) resources participating in the FCM did not change as a result of capacity DRIPE. We estimate capacity DRIPE based upon the supply curve observed in FCA 4 with extrapolations below and above the observed curve. This capacity supply curve is presented in Exhibit 1-9.
- The pace at which market participants will respond to lower wholesale capacity prices and eventually dissipate capacity DRIPE; and
- The percentage of capacity costs, and hence capacity DRIPE, that will flow through to retail customers each year.

Thus total capacity DRIPE is the product of the direct effect from the first factor, times the percent of the effect not yet eliminated by market participant adaptation from the second factor, times the percentage of capacity DRIPE that flows to retail customers from the third factor.

6.3.1.1. Estimate of Gross Capacity DRIPE

As described in Section 6.1, current ISO rules impose a floor price on FCM prices through FCA 6.[140] Under our Reference Case FCM prices increase between FCA 7 (June 2016–May 2017) and FCA 13 as increasingly expensive existing capacity resources set the price. From FCA 13 onward the Reference Case projects FCM prices will be set by increasingly expensive generic new additions.

We estimate capacity DRIPE from FCA 7 through FCA 13 based upon the supply curve observed in FCA 4 with extrapolations below and above that observed curve.

- In FCA 7 to FCA 10, peak load reductions would allow additional existing resources to delist. Based on the slope of the lower end of the supply curve from FCA 4 (i.e., below $4/kW-month, corresponding to the last 600 MW to drop out of the auction), we estimate that a load reduction that increases

[140] Docket Nos. ER10-787-000 et al., Order on Paper Hearing and Order on Rehearing (April 13, 2011) FERC has suggested that the floor may need to be extended another year or two to accommodate the ISO consultation process regarding other aspects of the FCA (Ibid, p. xx). Our analysis assumes this extension is not approved. If the floor is extended, the avoided FCM price would be higher during the applicable period and capacity DRIPE would be zero in that period.

supply or reduces NICR by 100 MW would reduce the clearing price by about 16¢/kW-month.

- In FCA 11 to FCA 13, peak load reductions would slow the increases in price by varying rates, from 5¢ to 49¢/kW-month per 100 MW, following the supply curve shown in Exhibit 1-9. The specific annual DRIPE values vary because of the variations in the slope of the capacity supply curves observed in the completed capacity auctions. In the price range just above the historical floor prices, the slope has been fairly steep for a small MW range (which we model as 40¢/kW-month per 100 MW over a range of 200 MW), followed by a very shallow stretch (5¢/kW-month per 100 MW) over the next 400 MW, followed by a steep rise (to 50¢/kW-month per 100 MW) as low-cost new resources are required to meet demand.

After FCA 13, the load reduction would slow the more gradual asymptotic rise in price toward the cost of generic new units, reducing prices by about 25¢/kW-month per 100 MW in FCA 14, gradually declining to 3¢/kW-month in FCA 17.

Exhibit 6-25 shows the supply and demand curve for FCA 7 to illustrate the capacity DRIPE effect:

Exhibit 6-25: FCA 7 Supply and Demand Curve

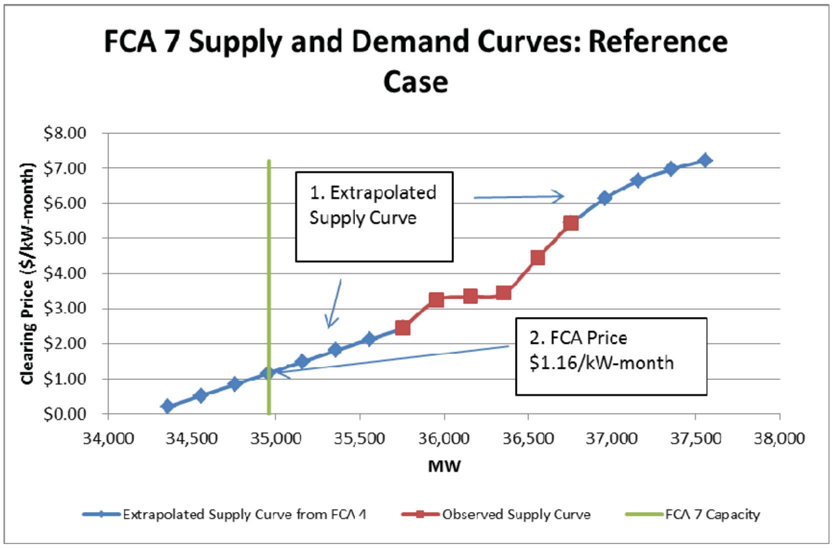

Exhibit 6-26 presents an illustrative supply and demand curve responding to decrease in capacity of 100 MW to demonstrate the gross DRIPE effect:

Exhibit 6-26: Gross Capacity DRIPE Response

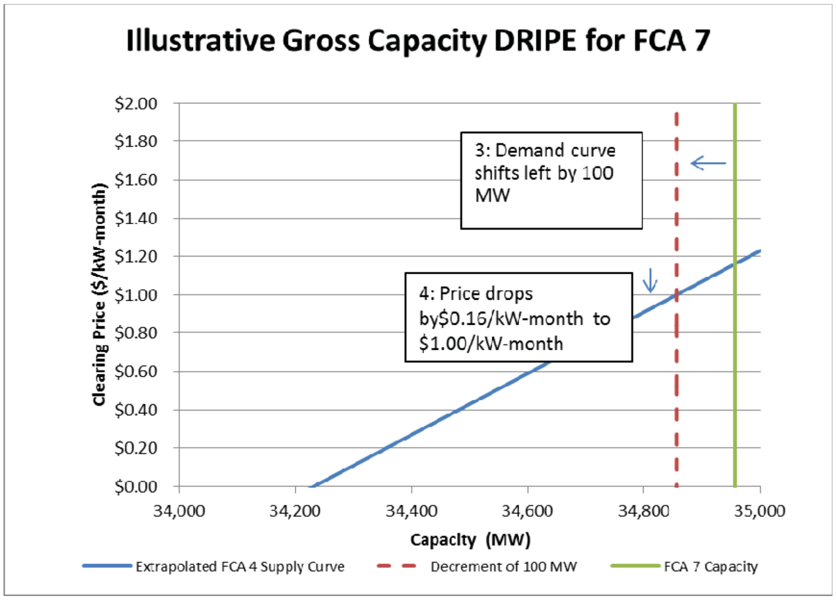

Exhibit 6-27 shows an illustrative supply and demand curve responding to the gross capacity DRIPE effect to demonstrate the net DRIPE effect:

Exhibit 6-27: Net Capacity DRIPE Response

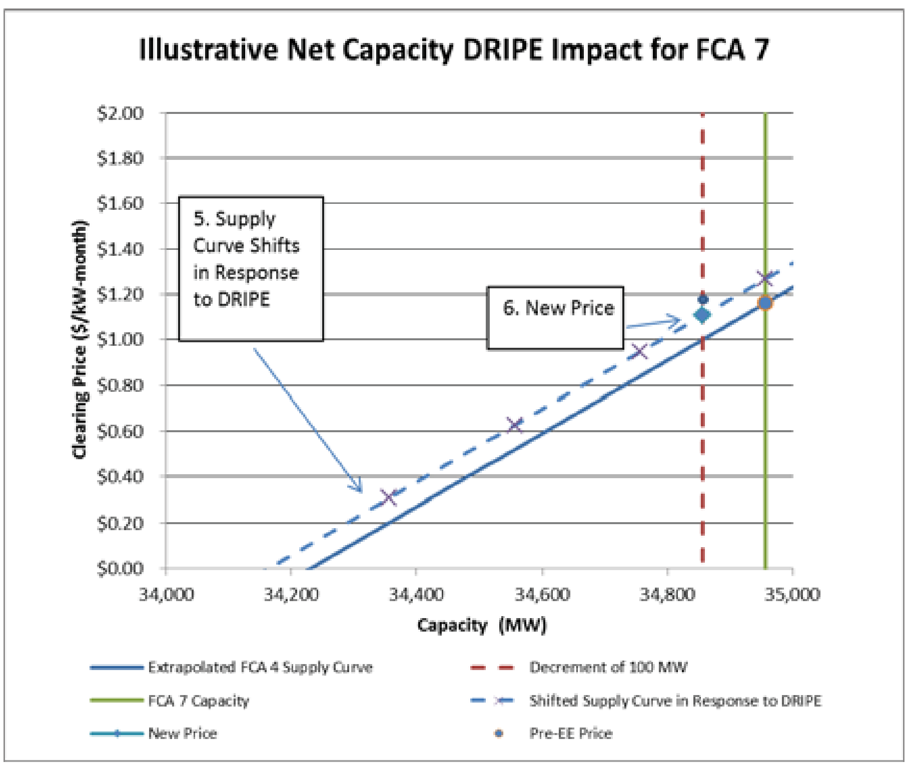

Exhibit 6-28 shows our estimates of the reduction in capacity price for a 100 MW change in the requirement for other resources due to new energy efficiency reductions starting in 2012 or in 2013. The jump in DRIPE in FCA13 reflect the point at which the supply curve transitions from keeping existing resources available to the much higher prices of bringing on new resources.

Exhibit 6-28: Capacity Prices (2011$) for the Reference Case and a 100-MW Decrement in Requirements

		FCM price to Load $/kW-month				
	Start Year	Reference Case	100 MW Reduction in Resource Need	Potential DRIPE	NICR Reserve Margin	ICR Reserve Margin
FCA2	2011	$3.60	$3.60	-		
FCA3	2012	$2.89	$2.89	-		
FCA4	2013	$2.84	$2.84	-		
FCA5	2014	$2.84	$2.84	-		
FCA6	2015	$2.84	$2.84	-		
FCA7	2016	$1.16	$1.01	$0.16	12.8%	16.0%
FCA8	2017	$1.71	$1.56	$0.16	13.0%	16.2%
FCA9	2018	$2.39	$2.24	$0.16	13.2%	16.3%
FCA10	2019	$2.68	$2.53	$0.15	13.3%	16.4%
FCA11	2020	$3.76	$3.71	$0.05	13.5%	16.5%
FCA12	2021	$3.83	$3.78	$0.05	13.6%	16.6%
FCA13	2022	$5.75	$5.25	$0.50	13.8%	16.8%
FCA14	2023	$6.92	$6.68	$0.25	14.0%	16.9%
FCA15	2024	$7.57	$7.45	$0.12	14.1%	17.0%
FCA16	2025	$7.86	$7.80	$0.06	14.3%	17.1%
FCA17	2026	$8.03	$8.00	$0.03	14.4%	17.3%

We develop estimates of intrastate and regional net capacity DRIPE by adjusting these potential Capacity DRIPE values for three factors: capacity-market response to reduced prices, utility capacity entitlements (which are not exposed to FCA prices) and reductions in renewable capacity constructed to meet RPS requirements.

6.3.1.2. Estimate of Capacity DRIPE Dissipation

As noted above, a reduction in peak load will reduce projected capacity prices relative to the levels in the Reference Case because less expensive resources will set the FCA price. Reductions in capacity prices from small reductions in peak load might continue indefinitely. However, planned energy-efficiency peak load reductions in New England are running about 300 MW annually, so the total reduction due to 2012 and 2013 installations may be on the order of 600 MW. A demand reduction of that magnitude would reduce prices by almost $1/kW-month, i.e., 600 MW * 0.16 per 100 MW for FCA 7 through FCA 10. Reductions in capacity prices of that magnitude would cause market participants to change the capacity and DR resources they bid into the FCM.

The question then is, what changes would market participants make relative to their actions in the Reference Case, and over what time period would they make these changes? One needs to project answers to those questions in order to estimate the number of years it will take for the capacity DRIPE to dissipate, i.e. for capacity prices to reach the levels forecast in the Reference Case. Estimating this dissipation or decay requires estimates of the material differences in the behavior of consumers and suppliers, relative to their actions projected under the Reference Case.

Our estimate of the dissipation of capacity DRIPE is based on our analysis of the following four factors:

1. Decisions by owners of existing capacity to accelerate the timing of delisting or retirement. We assume that accelerated retirements of existing capacity starting in 2016 will offset two-thirds of the reduction in capacity prices. Significant reductions in wholesale capacity prices, in conjunction with increased environmental costs (e.g., NOx limits under the CATR and regional haze rules, cooling-system upgrades) would almost certainly trigger additional retirements of low-capacity-factor, inefficient oil/gas steam plants.
2. Decisions by developers to change the quantity, type and/or timing of new capacity. Significant reductions in wholesale capacity prices may also cause delays in the addition of new capacity. Those delays are reflected in the supply curve in Exhibit 6-29 of the capacity section.
3. Reductions in capacity from renewable resources. Our analysis assumes that reductions in peak demand from energy efficiency measures will be accompanied by corresponding reductions in annual energy use. In turn, lower annual energy use will result in less renewable energy being required to comply with the RPS. The net result will be less new renewable resources and less new capacity from those resources. We estimate that the quantity of renewable capacity reduced by a kilowatt reduction in peak load from energy-efficiency savings will be equal to the load-weighted regional average Class-I RPS requirement percentage for energy, computed from the requirements in Chapter 2.
4. Retail customer response to lower wholesale capacity prices, increasing their electricity use and hence muting the price reduction, i.e. price elasticity.

Reductions in wholesale capacity prices will reduce retail rates, but by a very small amount, and thus should result in a minimal increase in peak load. Wholesale capacity costs are likely to be less than 20 percent of total retail electricity rates energy prices for typical load in the next couple years. Our analyses indicate that price elasticity offsets less than 5 percent of energy DRIPE which implies a price elasticity offset of capacity DRIPE of about 1 percent, which is well within the range of uncertainties.

6.3.1.3. Portion of Capacity DRIPE seen by Retail Customers: Capacity Estimate of Capacity Effect of Utility Capacity Entitlements

The effect of peak load reductions on capacity price is limited to the capacity paid the market price by load. Were all retail power supply provided under cost-of-service pricing or long-term contracts, a short-term reduction in wholesale market prices would have little effect on retail supply prices paid by customers. At the other extreme, if retail customers were being supplied 100% from the spot market and short-term contract, they would experience the benefits of short-term reductions in wholesale market prices fully and immediately. The actual mix of power supply under contract for various periods into the future varies among the states, among the utilities within some states, between municipal utilities and independently owned utilities (IOUs), and between customers on standard utility offer (standard service, default service, last-resort service, etc.) and those served by competitive suppliers. The mix also differs between capacity and energy. The standard-offer mixes are subject to legislative and/or regulatory change.

In addition, some restructured IOUs have contracts with generators for energy and capacity, which is sold into the market for the benefit of customers. These contracts include pre-restructuring contracts with independent power producers, as well as post-restructuring contracts in

- Connecticut, for:
    - A group of resources contracted to reduce Federally Mandated Congestion Costs (FMCC), including the Kleen combined-cycle plant, the Waterbury and Waterside peakers,
    - Peakers at Devon, Middletown and New Haven, and
    - Several smaller baseload renewable and fuel cell plants selected in the Project 150 process; and
- Massachusetts, for renewable purchases, currently limited to an approved National Grid contract with Cape Wind, and NStar’s purchases of wind power under its NStar Green program and proposed purchases from three

more wind plants, but potentially reaching 3% of energy requirement for the utilities other than National Grid.[141]

- Rhode Island, for renewable purchases of 90 MW of average energy, phased in from 2010 through 2013.

The non-restructured utilities in New England comprise PSNH, the Vermont utilities, and the municipal and co-op utilities in Massachusetts and Connecticut.

- For PSNH, the 2010 IRP indicates that about 61% of energy and 51% of capacity requirements over the period 2012–2015 are served from owned generation and long-term contracts, assuming no migration to retail competition.[142] We assume those percentages of long-term supply will stay constant over the study period.
- For Vermont, we estimate that 90% of energy requirements are served from owned generation and long-term contracts in 2009, including about 38% from the contract between Vermont Yankee and the Vermont utilities, which ends in March 2012.[143] About 30% of Vermont's 2009 energy came from long-term contracts with Hydro Quebec that will phase out from 2013 through 2016, but will be largely replaced by a new 225 MW contract. In addition, the Vermont utilities have been committing to renewable purchases through feed-in tariffs and contracts with larger facilities. Hence, we estimate the portion of Vermont energy supply whose price will not be affected by post-2010 DSM to be about 90% in 2011, 70% in 2012, 52% in 2013, and 50% thereafter. For capacity, we assume that these values will be higher, about 95% in 2011, 75% in 2012, and 60% thereafter.
- We have no comprehensive information about the energy supplies of the publicly-owned utilities. Various municipal utilities have wholly-owned generation (mostly peaking), shares in generators owned or co-owned by MMWEC and CMEEC, ownership interests in Seabrook and Millstone, long-term contracts for the output for particular generators, contracts for supply from the New York Power Authority, and various firm purchase arrangements. Lacking any more specific information, we assume that 95%

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[141] National Grid also owns about 6 MW of peakers on Nantucket, maintained as backup for the submarine transmission lines serving the island. This amount is within the uncertainties in the capacity of the other resources.

[142] Public Service Company of New Hampshire, Least Cost Integrated Resource Plan, September 30, 2010, Exhibits V-8 and V-9.

[143] Vermont Department of Public Service Utility Facts, March 2011.

of municipal-utility and co-op energy and capacity supply are under contract for 2011, decreasing 5% annually through 2018, and remaining at 60% thereafter.

For AESC 2011, we have updated our analysis of the energy and capacity that restructured utilities receive from pre-restructuring contracts, using data provided by NStar, utility filings with regulators, and FERC Form 1 data.

Exhibit 6-29: Capacity Entitlements of Restructured Utilities (MW)

	Old IPP Contracts		Renewables				Connecticut IOU Contracts				**Total**
Year	CL&P	NStar	NGrid RI	NGrid MA	FGE, WMECo	NStar	Peakers	FMCC	Project 150		
2011	448	384	44		-	-	376	786	23		2,061
2012	439	294	61		2	6	506	786	87		2,180
2013	427	293	78	87	2	6	506	786	150		2,334
2014	357	290	95	87	2	6	506	786	150		2,278
2015	109	290	95	87	7	28	506	786	150		2,057
2016	58	170	95	87	7	28	506	786	150		1,887
2017	32	20	95	87	7	28	506	786	150		1,711
2018	30	20	95	87	7	28	506	786	150		1,708
2019	23	20	95	87	7	28	506	786	150		1,702
2020	21	20	95	87	7	28	506	786	150		1,700
2021	1	20	95	87	7	28	506	786	150		1,680
2022	1	20	95	87	7	28	506	786	150		1,680
2023	1	7	95	87	7	28	506	786	150		1,666
2024	0	0	95	87	7	28	506	786	150		1,659
2025			95	87	7	28	506	786	150		1,659
2026			63	87	7	28	506	786	150		1,627
2027			46	87	7	28	506	786	150		1,610
2028			29	87	7	28	506	786	150		1,593
2029			12	87	7	28	506	786	150		1,575
2030			12	87	7	28	506	786	150		1,575

Exhibit 6-30 combines these long-term contracts of the restructured utilities with our estimates of the long-term capacity entitlements of the non-restructured utilities.

Exhibit 6-30: Summary of Long-Term Capacity Entitlements (MW)

Year	IOU Contracts	VT	PSNH	MA Munis	CT Munis	Total	% of ISO ICR
2011	2,061	1,195	1,218	3,029	494	7,998	25%
2012	2,180	927	1,206	2,819	459	7,592	24%
2013	2,334	746	1,219	2,682	436	7,416	23%
2014	2,278	769	1,267	2,608	424	7,346	22%
2015	2,057	767	1,270	2,442	397	6,932	21%
2016	1,887	775	1,296	2,313	375	6,646	20%
2017	1,711	783	1,320	2,179	353	6,345	19%
2018	1,708	794	1,344	2,039	330	6,215	18%
2019	1,702	802	1,368	2,064	334	6,270	18%
2020	1,700	810	1,390	2,090	337	6,327	18%
2021	1,680	819	1,414	2,118	341	6,372	18%
2022	1,680	828	1,438	2,146	345	6,438	18%
2023	1,666	837	1,463	2,173	349	6,489	18%
2024	1,659	846	1,488	2,202	353	6,548	18%
2025	1,659	856	1,514	2,230	357	6,616	18%
2026	1,627	865	1,540	2,259	362	6,652	17%
2027	1,610	874	1,565	2,287	366	6,701	17%
2028	1,593	883	1,591	2,316	370	6,752	17%
2029	1,575	892	1,618	2,345	374	6,803	17%
2030	1,575	901	1,644	2,374	378	6,872	17%

We decrease the ISO-wide capacity DRIPE by ratio of capacity entitlements to total ISO capacity.

6.3.1.4. Estimate of Net Capacity DRIPE

We estimate the net Capacity DRIPE for New England by taking the DRIPE effects in Exhibit 6-28 and reducing them first by the market effects and then by the long-term capacity entitlements. These offsets are grossed by the reserve margin to reflect the fact that one MW of load reduction results in more than one MW of avoided supply requirement. The results are presented in Exhibit 6-31.

The capacity DRIPE values are zero in 2011 through 2015, due to the price floors. The net effect of any single year's efficiency program on price would be quite small. For example, we estimate the net DRIPE effect in 2022,the year with the highest estimated DRIPE effect, of a 100 MW load reduction, or about 0.3% of ISO load, to be 15¢/kW-month, which would be about 2% of the FCA cost to load of $5.75/kW-month, including ICR reserves.

Exhibit 6-31: Final Regional Capacity DRIPE Values

Year	Gross DRIPE $/kW-Month per 100 MW	Market Response Offset	Aggregate RPS	NICR Reserve Margin	DRIPE $/kW-Mo per 100 MW Before Entitlements	Reduction for Entitlements	DRIPE Change in FCA Price $/kW-Mo per 100 MW	ISO NICR (MW)	ISO-wide Net Capacity DRIPE $/kW-yr
	a	b	c	d	e	f	g	h	i
2011			5%			25%		32,399	
2012			6%			24%		31,848	
2013			7%			23%		32,076	
2014			8%			22%		33,137	
2015			10%			21%		33,099	
2016	$0.16	67%	11%	12.8%	$0.053	20%	$0.042	33,593	$171
2017	$0.16	67%	12%	13.0%	$0.052	19%	$0.042	34,076	$174
2018	$0.16	67%	13%	13.2%	$0.052	18%	$0.042	34,542	$175
2019	$0.15	67%	14%	13.3%	$0.049	18%	$0.040	34,982	$169
2020	$0.05	67%	15%	13.5%	$0.016	18%	$0.013	35,470	$56
2021	$0.05	67%	15%	13.6%	$0.016	18%	$0.013	35,964	$57
2022	$0.50	67%	16%	13.8%	$0.160	18%	$0.131	36,452	$574
2023	$0.25	67%	16%	14.0%	$0.078	18%	$0.064	36,946	$284
2024	$0.12	67%	17%	14.1%	$0.037	18%	$0.030	37,448	$136
2025	$0.06	67%	17%	14.3%	$0.019	18%	$0.015	37,956	$70
2026	$0.03	67%	18%	14.4%	$0.008	17%	$0.007	38,471	$30

Notes: a. From Exhibit 6-28
b. See text.
c. Computed from Exhibit 6-37.
d. From Exhibit 6-28.
e [a] × [1–b] × [1–c] × [1+d]
f. From Exhibit 6-3.
g. [e] × × [1–f]
h. From 2011 CELT
i. [f] × [g] × 12 months ÷100

The DRIPE values in Exhibit 6-31 are for all ISO load. Values for capacity DRIPE in individual states are presented in Exhibit 6-32.

Exhibit 6-32: State Capacity DRIPE Values

	DRIPE $/kW-Mo per 100 MW Before Entitlements	State Peak Forecasts						State Capacity Requirement Hedged by Entitlements						State Net Capacity DRIPE $/kW-yr					
		CT	ME	MA	NH	RI	VT	CT	ME	MA	NH	RI	VT	CT	ME	MA	NH	RI	VT
2016	$0.053	7,800	2,210	13,945	2,650	2,020	1,145	21%		17%	43%	4%	60%	$44	$16	$83	$11	$14	$3
2017	$0.052	7,890	2,240	14,125	2,695	2,045	1,155	20%		15%	43%	4%	60%	$44	$16	$85	$11	$14	$3
2018	$0.052	7,975	2,275	14,300	2,740	2,070	1,170	20%		14%	43%	4%	60%	$45	$16	$87	$11	$14	$3
2019	$0.049	8,060	2,300	14,460	2,785	2,090	1,180	20%		14%	43%	4%	60%	$43	$15	$83	$11	$13	$3
2020	$0.016	8,135	2,330	14,620	2,825	2,110	1,190	20%		14%	43%	4%	60%	$14	$5	$28	$4	$4	$1
2021	$0.016	8,197	2,353	14,746	2,858	2,127	1,199	19%		14%	43%	4%	60%	$14	$5	$28	$4	$4	$1
2022	$0.160	8,260	2,376	14,874	2,892	2,143	1,208	19%		14%	43%	4%	60%	$146	$52	$280	$36	$45	$11
2023	$0.078	8,324	2,400	15,003	2,927	2,160	1,217	19%		13%	43%	4%	60%	$72	$26	$138	$18	$22	$5
2024	$0.037	8,388	2,424	15,132	2,961	2,177	1,226	19%		13%	43%	4%	60%	$34	$12	$66	$8	$11	$2
2025	$0.019	8,452	2,448	15,263	2,996	2,194	1,235	18%		13%	43%	4%	60%	$18	$6	$34	$4	$5	$1
2026	$0.008	8,517	2,472	15,395	3,032	2,211	1,244	18%		13%	43%	3%	60%	$8	$3	$14	$2	$2	$1

6.3.1.5. Comparison to AESC 2009 Capacity DRIPE Estimates

Due to the difference in timing, direct comparisons of the AESC 2011 Capacity DRIPE results to those in AESC 2009 are complex. The regional capacity DRIPE estimates, stated in 2011 dollars, are shown in Exhibit 6-33.

Exhibit 6-33: Comparison of AESC 2009 and AESC 2011 Capacity DRIPE

	Net Capacity DRIPE 2011$/kW-yr	
Year	AESC 2009	AESC 2011
2011	0	0
2012	0	0
2013	$115	0
2014	$170	0
2015	$112	0
2016	$43	$171
2017		$174
2018		$175
2019		$169
2020		$56
2021		$57
2022		$574
2023		$284
2024		$136
2025		$70
2026		$30
Levelized (2012-2026)	$32.80	$120.76

In present-value terms, the AESC 2011 Capacity DRIPE estimates total about 3.7 times those in AESC 2009. These higher estimates are primarily due to our projection of higher capacity prices and to a longer period for these impacts to dissipate.

The AESC 2009 study assumed that the change in capacity price would be about $0.05/kW-year for every 100 MW of reduced requirement, before market response and entitlements, for five years after EE implementation. That estimate was based on a high-level estimate of delists at prices below $3/kW-month. The AESC 2011 estimate is three times as high as the AESC 2009 estimate for the first five years after EE implementation. It averages about four times the AESC 2009 estimate from 2019 to 2026.

The AESC 2009 study assumed that the capacity DRIPE would dissipate linearly over the fourth and fifth years following the implementation of the energy-efficiency measures. This resulted in different DRIPE effects in 2013 (for example) from 2010 and 2011 peak load reductions. Given the extension of the price floor, we now do not expect any DRIPE effect until 2016. From 2016 onward we have modeled capacity DRIPE using a specific and reasonable supply curve.

6.3.2. Energy DRIPE

Energy-efficiency measures installed in any one year will have an immediate downward effect on energy prices because the lower load growth will allow lower-cost resources to be at the margin—and set the price—in more hours. This impact is referred to as energy DRIPE. Those price effects will not necessarily persist as long as the underlying energy savings. The lower energy prices will tend to change the mix of generation used to supply the market, which in turn will eventually lead to higher prices, erasing the effects of lower loads.

DRIPE in the energy market was estimated based on the following three factors:

- The effect of load reduction on market energy prices, if all energy traded in the spot market and the supply system did not change as a result of DRIPE effects. We estimating these effects based upon an analysis of historical data for loads and prices.
- The pace at which supply will adapt to energy-efficiency load reductions; and
- The percentage of power supply to retail customers that is subject to market prices in the current year and each future year.

Thus total energy DRIPE is the product of the direct effect from the first factor, times the percent of the effect not yet eliminated by supply adaptation from the second factor, times the percentage of power supply that is subject to market prices from the third factor. The DRIPE value may differ by month (or season) and zone.

6.3.2.1. Estimation of energy DRIPE via Analysis of Historical Data

Our estimation of gross energy DRIPE is based upon an analysis of the historical variation in locational energy market prices as a function of variation in zonal and regional loads. This approach is similar to that used in both AESC 2009 and AESC 2007.

The historical analysis is a regression of day-ahead hourly zonal price in dollars per MWh against both day-ahead load in the zone and day-ahead load in the rest of the ISO control area (rest of pool, or ROP). If one of the resulting coefficients was implausible, the zonal price was regressed based on total pool load and the resulting coefficient was then used for both the own-zone and ROP load. These analyses were performed separately for on- and off-peak hours, since we expected (and generally observed) that the slope of market price as a function of load would be higher on-peak.

To minimize the effect of changes in fuel prices,

- Each month was analyzed separately,
- We used data from December 2005 through April 2009, covering both high- and low-priced periods,
- We normalized the DRIPE coefficient for each of the 41 months by dividing the load coefficient by the average Hub price for the month, and
- We averaged the normalized DRIPE coefficient over the three or four years of regressions.

The regressions were calculated for on-peak and off-peak periods by month by state. Unlike AESC 2009, the regressions incorporated regional daily gas prices, measured as the spot price at Algonquin citygates. Where the regression of zonal price on zonal load, rest-of-pool load, and gas price was sensible (the zonal coefficient was greater than the rest-of-pool coefficient, and all coefficients were positive), we used the zonal and rest-of-pool coefficients from that regression. Otherwise, we used simpler regressions (omitting gas price and/or using ISO load, rather than separate zone and rest-of-pool loads).

The results by energy pricing zone show the change in the energy price in the zone as a result of a one-megawatt change in load in the zone or a one-megawatt change in load elsewhere in the ISO (the rest of pool or ROP). These results indicate that a reduction of one MWh of hourly load in a zone typically reduces price in that zone by between zero and 4¢/MWh. A reduction of one MWh of load elsewhere in the Pool typically reduces prices from zero and 5.2¢/MWh. In percentage terms we estimate that a 0.007% reduction in ISO average load results in a 0.010% to 0.022% reduction in prices in the zone where the reduction occurs, ratios ranging from 1.4 to 3.1, and a reduction of 0.007% in prices in other zones (a ratio of 1.0),

The effect of energy DRIPE on prices is typically higher in the on-peak period than in the off-peak period. Our estimates of gross DRIPE for intrastate reductions and rest of pool reductions are presented in Appendix B.

The total effect on the regional prices in a particular month, if all transactions moved with the day-ahead market price, would be the sum of the following two components:

- The average hourly load in the zone times the zonal effect, and
- The sum over zones of the average hourly zonal load times the effect of ROP load on that zone.

Exhibit 6-34 below summarizes our results for potential DRIPE effects, by month and annualized (using historical average ratios of monthly forwards to annual averages), expressed as a multiple of the Hub price in the corresponding period. Under each state, Exhibit 6-34 shows the price savings for consumers in that state and in the rest of the pool. For example, averaged over the year, a MWh saved on-peak in Maine would reduce Maine market energy bills by about 0.14 or 14% of the Hub price for a MWh of energy and bills in the rest of the pool about 1.13 or 113% of the Hub price.

Exhibit 6-34: Potential DRIPE as Multiple of Hub Price, in-State and Rest of Pool

	ME		NH		VT		CT		RI		MA	
	ME	ROP	NH	ROP	VT	ROP	CT	ROP	RI	ROP	MA	ROP
On-Peak												
Jan	0.18	0.96	0.29	0.95	0.08	0.98	0.70	0.72	0.18	0.98	0.77	0.64
Feb	0.20	1.25	0.24	1.24	0.10	1.28	0.66	0.96	0.21	1.27	0.71	0.74
Mar	0.15	0.94	0.09	0.93	0.10	0.97	0.35	0.71	0.17	0.96	0.51	0.56
Apr	0.08	0.59	0.10	0.58	0.08	0.60	0.29	0.38	0.24	0.60	0.39	0.40
May	0.12	0.87	0.12	0.85	0.04	0.87	0.46	0.52	0.27	0.88	0.35	0.58
Jun	0.08	1.24	0.36	1.23	0.06	1.25	0.75	0.80	0.08	1.24	0.81	0.81
Jul	0.14	1.70	0.43	1.70	0.11	1.76	1.23	1.29	0.24	1.72	1.06	1.04
Aug	0.11	1.35	0.41	1.35	0.10	1.39	0.74	0.97	0.15	1.37	0.75	0.84
Sep	0.15	1.14	0.10	1.13	0.10	1.17	0.45	0.77	0.25	1.17	0.74	0.74
Oct	0.14	1.16	0.13	1.15	0.10	1.20	0.40	0.86	0.16	1.19	0.55	0.73
Nov	0.11	0.98	0.34	0.99	0.07	1.01	0.73	0.78	0.23	1.01	0.68	0.61
Dec	0.21	1.07	0.38	1.08	0.12	1.10	0.53	0.82	0.17	1.09	0.71	0.66
Off-peak												
Jan	0.13	0.86	0.23	0.86	0.10	0.90	0.73	0.77	0.26	0.89	0.80	0.48
Feb	0.11	1.00	0.26	1.02	0.07	1.05	0.48	0.83	0.13	1.03	0.74	0.59
Mar	0.24	1.01	0.13	1.00	0.06	1.04	0.55	0.83	0.26	1.04	0.58	0.56
Apr	0.14	1.06	0.33	1.08	0.06	1.10	0.53	0.90	0.22	1.10	0.81	0.59
May	0.08	0.77	0.23	0.78	0.06	0.81	0.53	0.66	0.09	0.79	0.79	0.48
Jun	0.10	1.05	0.27	1.06	0.06	1.09	0.83	0.83	0.10	1.07	0.93	0.65
Jul	0.13	1.04	0.44	1.10	0.10	1.11	1.00	0.95	0.11	1.09	0.69	0.55
Aug	0.14	0.79	0.16	0.80	0.05	0.83	0.79	0.74	0.24	0.82	0.68	0.42
Sep	0.29	1.10	0.19	1.09	0.11	1.12	0.47	0.81	0.12	1.11	0.82	0.68
Oct	0.11	1.19	0.22	1.20	0.12	1.24	0.42	0.87	0.08	1.22	0.67	0.76
Nov	0.17	0.85	0.47	0.89	0.08	0.90	0.60	0.72	0.23	0.89	0.85	0.54
Dec	0.17	0.97	0.45	1.00	0.14	1.01	0.72	0.84	0.19	0.99	0.72	0.51
Average Annual												
On-Peak	0.14	1.13	0.26	1.13	0.09	1.15	0.64	0.83	0.19	1.16	0.69	0.71
Off-peak	0.15	0.97	0.28	0.99	0.09	1.02	0.65	0.82	0.17	1.00	0.76	0.56

These bill effects are potential values, assuming that the load reductions and price reductions have no effect on supply or demand, and that all energy is purchased from the short-term competitive market. We consider the impact of adjustments for changes in supply and demand in Sections 6.3.2.2 and 6.3.2.10, below.

6.3.2.2. Energy DRIPE Dissipation

As noted above, a reduction in load will reduce actual and projected prices relative to the levels in the Reference Case. More expensive generators will be used less often, high-prices price-responsive demand response will be called less often.

That reduction in prices will then tend to change the mix of resources available to supply the market. This response to lower prices is referred to as *supply adaptation.* One can think of this analysis of dissipation in terms of the following three steps:

- **The energy Reference Case.** This is a projection of the mix of supplies, and resulting energy prices, to meet the Reference Case load forecast. Those energy prices are influenced by a number of assumptions regarding decisions and actions by suppliers. In particular, decisions by suppliers regarding the quantity and type of new capacity that they will bring on-line each year influences the projected quantity of generation from that new capacity by year, and decisions by suppliers regarding the quantity and type of existing capacity that they will delist or retire each year influences the projected quantity of generation that will be removed from the total supply by year.
- **Gross energy DRIPE.** This is an estimate of energy prices in a future with a lower load forecast and the same supply curve, i.e., no reaction by suppliers. This step projects somewhat lower energy prices.
- **Energy DRIPE decay.** This step projects changes in the supply curve over time that offset the impact of the lower load forecast. This scenario projects the number of years it will take for the energy DRIPE to dissipate, i.e. for energy prices to reach the levels forecast in the Reference Case. Estimating this dissipation or decay requires estimates of the material differences in the behavior of consumers and suppliers, relative to their actions projected under the Reference Case. Specifically, DRIPE decay may be driven by the following four factors:

    1. Consumer feedback from the lower market prices, increasing electricity use and hence muting the price reduction, demand elasticity and income elasticity.
    2. Reductions in energy resources that are directly related to energy use. For example, lower energy use results in less renewable energy being required under the renewable portfolio standards, which results in higher energy prices than in the simple DRIPE case.
    3. Decisions by generation owners to change the quantity, type and/or timing of delisting or retirements of existing capacity.

        a. The owner of a baseload plant (such as a coal plant) with low variable production costs that faces major environmental investments may decide to retire or mothball the plant, due to the lower energy revenues from continued operation.[144]

   b. Even if the lower energy prices do not justify the retirement of a particular unit, the resulting lower energy prices reduce the incentive for the owner to maximize plant capacity, efficiency and availability, potentially shifting the supply curve upwards at some points, increasing market prices compared to the simple DRIPE case.

4. Decisions by generation developers to change the quantity, type and/or timing of new capacity. For example, the lower prices due to energy-efficiency investments may cause the following changes over time in the supply of conventional generation:

   a. A merchant developer may choose to develop a combustion turbine (CT) rather than a combined-cycle (CC) unit, if the CC's reduced energy revenues do not seem likely to cover its additional fixed costs.

   b. The developer of a potential CC unit will generally bid a higher price for its capacity (since energy revenues will cover less of the cost), resulting in selection of a CT in the FCM auction and hence construction of a CT rather than a CC.

   c. As the supply and demand changes in these and similar ways, energy prices will tend to increase back towards reference case levels. Once this supply adaptation has caused energy prices to recover from the effects of the load reduction, the future decisions by consumers, developers, owners, and the ISO should be essentially the same as they would have been without the load reduction. Thus, supply and demand adaptation ceases once the price effect has been extinguished.

Through about 2022, our forecast of energy prices are likely to affect primarily customer usage, RPS requirements, generator deactivations (and reactivations) and incremental improvements, and possibly the timing of municipally-owned generation additions. We examine those effects in order.

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[144]This is not a hypothetical concern, given the costs of upgrading existing coal (and some oil- and gas-fired steam) plants to meet tighter limits on air emissions and/or use of cooling water (see the retirements section in Chapter 2).

Estimating the extent of delay in adaptation of the energy market to efficiency-related load reductions is subject to considerable uncertainty, particularly in this period of capacity surplus.

6.3.2.3. Demand Elasticity Impacts

The 2011 ISO-NE forecast is based on an econometric model that estimates a short-run price elasticity of -0.05 and a long-run price elasticity of -0.091.[145]

The wholesale price of energy is just a portion of the total retail price of electricity (which also includes transmission, distribution, energy-efficiency and renewable charges, stranded costs, capacity, reserves, and ISO costs). As shown in Exhibit 6-35 the ratio of real-time energy costs, from the ISO's Wholesale Load Cost Reports, to average electricity prices, from the ISO's 2011 forecast documentation, has varied from under 30% to almost 70%, for various states and years. The spot energy prices are not the same as the forward energy prices included in retail prices, but have varied above and below forward prices in the last six years.

[145] The ISO's log-log regression includes coefficients of -0.050 on current real New England price (the short-term price elasticity) and 0.451 on the previous year's ISO energy load. The long-term elasticity equals the short-term elasticity divided by one minus the lag coefficient, or in this case, -0.050 ÷ (1 – 0.451) = -0.091. This value (to two significant values) is reached in about seven years.

Exhibit 6-35: Energy Prices and Total Electric Rates (¢/kWh)

	Connecticut			Maine			Massachusetts			New Hampshire			Vermont			Rhode Island		
	Total	LMP	Ratio	Total	LMP	Ratio	Total	LMP	Ratio	Total	LMP	Ratio	Total	LMP	Ratio	Total	LMP	Ratio
2005	12.1	7.7	64%	10.6	7.0	67%	12.2	7.6	63%	12.5	7.4	59%	12.0	7.7	65%	10.9	7.5	68%
2006	14.8	6.0	41%	11.8	5.6	48%	15.5	6.0	39%	13.8	5.8	42%	14.0	6.0	43%	11.4	5.8	51%
2007	16.5	6.6	40%	14.6	6.4	44%	15.2	6.6	44%	14.0	6.6	47%	13.1	6.8	52%	12.0	6.5	54%
2008	17.8	8.0	45%	13.8	7.5	54%	16.3	8.1	50%	14.7	7.9	54%	16.0	8.1	51%	12.3	7.9	64%
2009	18.2	4.2	23%	12.9	4.0	31%	15.5	4.2	27%	15.2	4.1	27%	14.2	4.2	30%	12.8	4.2	33%
2010	18.0	4.9	27%	13.0	4.7	36%	15.1	5.0	33%	15.1	4.9	32%	14.8	5.0	34%	13.4	4.9	36%

The average ratio is about 45%. In addition to the direct effect of energy prices, electric rates include losses on energy and the costs of risk, hedging and credit support related to the energy cost. Reserve prices are also increased by energy prices (since some energy payments are based on forgone energy revenue), but capacity prices are reduced by energy revenues. Overall, the ratio of energy-related costs to total rates may be roughly 55 percent. Thus, a one percent reduction in market energy prices would result in a 0.55 percent reduction in electric rates. These estimates result in the pattern of rebound in the energy price shown in Exhibit 6-36. In this computation, we assume that market energy prices anticipate the effects of planned energy savings, so market price declines and usage rebounds starting in the year of energy-efficiency implementation.

Exhibit 6-36: Price-Related Rebound in Energy DRIPE

Year	DRIPE Reduction
1	2.5%
2	3.6%
3	4.1%
4	4.3%
5	4.4%
6	4.4%
7	4.4%
8	4.4%
9	4.4%
10	4.5%

6.3.2.4. Income Elasticity

A significant literature exists on the extent to which bill reductions due to energy efficiency results in increased usage of energy services.[146] We investigated this effect for New England by assuming that the energy price reductions would be equivalent to increases in personal income in the ISO's 2009 CELT Forecast.[147] The forecast documentation for the New England energy forecast shows a short-run income elasticity of 0.223 and a long-run elasticity of 0.477.

The 2009 CELT forecast data show total regional electric revenues in 2000 dollars of $22.9 billion, or about 3.3 percent of the regional personal income of $699

[146] See Sorrell, S. 2007. The Rebound Effect: an assessment of the evidence for economy-wide energy savings from improved energy efficiency. UK Energy Research Centre.

[147] The 2010 and 2011 forecasts substitute gross state product for personal income, so this approach is not as easy to apply to these forecasts.

billion (also in 2000 dollars). Hence a one percent decrease in energy price, resulting in a 0.55 percent reduction in electric revenues, would be equivalent to a 0.018 percent increase in personal income, resulting in a 0.004 percent short-run increase in energy usage and a 0.086 percent long-run increase. These effects are far smaller than the uncertainties in our analysis.

Energy efficiency also reduces total bills to consumers, which may also result in some income-like effects on consumption. The extent of those effects will vary with the cost-effectiveness of the energy-efficiency investment, as well as the timing of benefits. For marginal energy-efficiency measures, which barely pass the screening tests, the net effect may well be higher bills in the initial year or two, followed by much smaller annual benefits for many years; considering the lag structure in the forecast model, the income effects of these marginal measures may slightly depress sales for several years.[148]

While some reductions in the cost of energy services (e.g., ¢/lumen-hour, or ¢/ºF) may result in consumers using more of the service, that effect should be estimated as part of the estimation of load reductions, and is beyond the scope of this analysis, which deals with the economic value of estimate load reductions.

6.3.2.5. Deferral of Renewables

Weighting the state Class-I RPS requirements in Exhibit 6-37by forecast state energy load, net of exempt load, produces the following offset to DRIPE due to reduced renewable additions.

[148] DRIPE effects are not likely to be important in decisions regarding non-marginal measures, which pass screening by a wide margin.

Exhibit 6-37: Regional Average RPS

	Average Regional Class-I RPS
2011	5.4%
2012	6.4%
2013	7.4%
2014	8.4%
2015	9.6%
2016	10.7%
2017	11.9%
2018	12.9%
2019	13.9%
2020	14.8%
2021	15.3%
2022	15.9%
2023	16.4%
2024	17.0%
2025	17.4%
2026	17.8%

The renewable-offset effect will vary among states; for simplicity, we used a regional average.

Some RPS requirements, other than the Class I requirements for new renewables and NH's Class II solar requirement, may also bring additional energy sources on line. The Connecticut Class III requirement can be met with cogeneration, but it is likely to be met entirely with credits from energy-efficiency projects that would proceed without the RECs. The Massachusetts APS is more difficult to assess, since the requirement can be met from gasification projects, cogeneration, flywheel storage, paper-derived fuel and (once regulations are developed) efficient steam technology. It is not clear to what extent this standard will be decisive in bringing on new generation. If the APS resources are flywheels, they will have little effect on overall energy price.

6.3.2.6. Reduced Incentive to Maintain and Improve Generator Performance

Most of the existing generators facing decisions about whether to retire operate at low capacity factors, so energy prices have limited effect on their economics and their presence or absence has limited effects on energy prices. The ratio of gas to oil prices and the level of environmental requirements will likely be more significant in retirement decisions of old steam plants than the price effect of efficiency programs.

On the other hand, generators face many decisions about performance improvements, maintenance, and the duration of outages, involving trade-offs between expenditures and various combinations of availability, heat rate, capacity and ramp rate. Lower energy prices are likely to tip some decisions toward delaying and reducing expenditures, resulting in more leisurely maintenance outages, poorer performance, and hence higher clearing prices. It is very difficult to estimate the effect of energy prices on those decisions and the resulting feedback to energy prices.

Considering the range of possible effect and the uncertainties, we combine the combined effects on existing generation as a one percent offset in the first year, rising one percent annually, plus five percent starting in 2016, reflecting the end of the FCM floor and the beginning of temporary reduction in the incentive to maximize capacity revenues.

We assume that generation owners and the power traders who set forward energy prices will model the effects of planned energy-efficiency efforts, so that the response will start in the same year as the energy-efficiency investment.

6.3.2.7. Deferral of New Units

If regional supply and demand were in balance, with growing load, and developers were adding a mix of peak, intermediate and baseload plants, then load reductions expected in (for example) 2014 would tend to shift the mix of new generation clearing in the 2011 forward capacity auction towards peakers, roughly offsetting the price effect of the efficiency.[149] These equilibrium conditions are not likely to occur for many years. No conventional generation appears to be needed until after 2022 and perhaps much later.

Municipal utilities can finance new generation less expensively than investor-owned utilities, independent power producers, and especially merchant developers, and may build generation before 2020.[150] The Massachusetts Municipal Wholesale Electric Company (MMWEC) has plans to add a 280 MW combined-cycle Stony Brook 3 plant in mid-2014,[151] but the unit did not qualify for FCA 5, suggesting that MMWEC is not expecting the plant to be on line in 2014. Taunton has recently suspended development of its Cleary-Flood Unit 10 combined-cycle plant, due to “Economic conditions and the resulting impact on

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[149] While peaking combustion turbines and intermediate combined-cycle plants can be built in three years, baseload generation (whatever that may be in the future) may have a longer lead time, resulting in some lag before the mix of new generation additions fully responds to the reduction in load.

[150] Several municipal utilities (e.g., Braintree, Vermont Public Power, CMEEC) have added generation in recent years.

[151] http://www.stonybrookunit3.org/progress-is-underway.html.

electricity usage and natural gas prices….”[152] Our Reference Case capacity prices are unlikely to support even these low-cost municipal units until at least 2020, and probably 2022 or later. Reduced energy prices could cause these utilities and their partners to delay the plants further, offsetting some DRIPE. It is not clear when these units would be constructed in the Reference Case, or how much energy prices would need to fall to change the timing of Stony Brook 3.

With all those caveats, we assume a 50 percent probability that the energy DRIPE of any particular increment of energy efficiency would be offset by delay of a municipal generator in 2020.[153] In subsequent years, we assume the probability of an offset increases by 10 percent each year, reaching 100 percent in 2025. While some new generation would likely be needed for the FCM by 2022, that capacity may be a peaker, or a combined-cycle operating at a capacity factor lower than the load factor of the energy efficiency, so the earliest new capacity may offset only part of the energy DRIPE remaining after other adjustments.

6.3.2.8. Summary of Energy DRIPE

Combining these four effects, we get the following pattern of energy DRIPE extinction. The demand elasticity in Exhibit 6-38 is for installations in 2012.[154]

152 http://www.tmlp.com/press_release/2011/Unit10OnHold.pdf.

153 That 50% probability might result from, for example, a 70% chance that the unit would be built with the base-case energy prices, and a 70% chance that it would be delayed by lower prices.

154 For installations in 2013, the demand elasticity column would be shifted down one year.

Exhibit 6-38: Energy DRIPE Decay, 2012 Installations

	Demand Elasticity	RPS	Existing Generation	New Generation	Total DRIPE Offset[a]
2011		5.4%			
2012	2.5%	6.4%	1.0%		10%
2013	3.6%	7.4%	2.0%		13%
2014	4.1%	8.4%	3.0%		15%
2015	4.3%	9.6%	4.0%		17%
2016	4.4%	10.7%	10.0%		23%
2017	4.4%	11.9%	11.0%		25%
2018	4.4%	12.9%	12.0%		27%
2019	4.4%	13.9%	13.0%		28%
2020	4.4%	14.8%	14.0%	50%	65%
2021	4.5%	15.3%	15.0%	60%	72%
2022	4.5%	15.9%	16.0%	70%	80%
2023	4.5%	16.4%	17.0%	80%	87%
2024	4.5%	17.0%	18.0%	90%	94%
2025	4.5%	17.4%	19.0%	100%	100%

Note a: Total = 1–(the product of (1-factor%) over the four factors).

6.3.2.9. Comparison to AESC 2009

This analysis of the energy DRIPE decay is similar to that in AESC 2009. It is updated for new price elasticity estimates, RPS requirements, later installation dates, and a more detailed assessment of the timing of new municipal generation being built.

6.3.2.10. Share of Retail Power Supply at Current Market Prices

As discussed in the Capacity Section of this chapter, long-term utility resource entitlements, both for vertically-integrated utilities and for the legacy and special-purpose assets of some restructured utilities. The distribution of entitlement energy is sometimes quite different from entitlement capacity; for example the Connecticut peakers are operated much less than the renewable or baseload independent power producer (IPP), and the Connecticut Federally Mandated Congestion Charge (FMCC) contracts are for capacity only.

Exhibit 6-39: Utility Energy Entitlements (GWh)

	Old IPP Contracts			Renewables				Connecticut Contracts		
Year	CL&P	NStar	MA & CT Vermont Yankee	NGrid RI	NGrid MA	FGE, WMECo	NStar	Peakers	Project 150	Total
2011	2,355	2,480	516	340		26	105	33	181	6,037
2012	2,308	1,889	123	490		42	168	44	682	5,747
2013	2,244	1,883		640	760	74	296	44	1,183	7,123
2014	1,876	1,870		788	760	74	296	133	1,183	6,980
2015	571	1,870		788	760	122	487	133	1,183	5,913
2016	307	1,082		788	760	122	487	133	1,183	4,861
2017	167	96		788	760	122	487	133	1,183	3,736
2018	156	96		788	760	122	487	222	1,183	3,814
2019	123	96		788	760	122	487	222	1,183	3,780
2020	113	96		788	760	109	434	222	1,183	3,705
2021	6	96		788	760	95	382	222	1,183	3,532
2022	6	96		788	760	95	382	222	1,183	3,532
2023	6	32		788	760	95	382	222	1,183	3,468
2024	0	0		788	760	95	382	222	1,183	3,430
2025				788	760	95	382	222	1,183	3,430
2026				549	760	95	382	222	1,183	3,191
2027				399	760	95	382	222	1,183	3,041
2028				249		95	382	222	1,183	2,131
2029				101		95	382	222	1,183	1,983
2030				101		95	382	222	1,183	1,983

Note: Connecticut peaker contracts are estimated at 1% capacity factor through 2013 as forward reserve units, gradually rising to 5% as energy units. The Project 150 resources are assumed to operate at a 90% capacity factor.

Exhibit 6-40: Summary of Long-Term Energy Entitlements (GWh)

	Entitlements						ISO Net	
Year	IOU Contracts	VT	PSNH	MA Munis	CT Munis	Total	Energy for Load	Entitlements as % of ISO
2011	6,037	6,180	5,239	12,439	1,955	31,849	135,455	24%
2012	5,747	4,961	5,365	11,996	1,885	29,953	137,955	22%
2013	7,123	4,011	5,434	11,428	1,797	29,793	139,230	21%
2014	6,980	4,053	5,518	10,874	1,712	29,137	140,830	21%
2015	5,913	4,080	5,596	10,293	1,620	27,503	142,215	19%
2016	4,861	4,101	5,675	9,702	1,525	25,864	143,585	18%
2017	3,736	4,125	5,755	9,101	1,428	24,145	144,980	17%
2018	3,814	4,149	5,833	8,489	1,329	23,613	146,390	16%
2019	3,780	4,176	5,911	8,575	1,339	23,781	147,760	16%
2020	3,705	4,200	5,989	8,662	1,350	23,906	149,145	16%
2021	3,532	4,220	6,054	8,734	1,358	23,897	150,283	16%
2022	3,532	4,240	6,119	8,805	1,367	24,063	151,429	16%
2023	3,468	4,261	6,186	8,877	1,376	24,167	152,584	16%
2024	3,430	4,281	6,253	8,950	1,385	24,299	153,748	16%
2025	3,430	4,301	6,320	9,023	1,393	24,469	154,920	16%
2026	3,191	4,322	6,389	9,097	1,402	24,402	156,102	16%
2027	3,041	4,343	6,458	9,172	1,411	24,425	157,293	16%
2028	2,131	4,363	6,528	9,247	1,420	23,690	158,492	15%
2029	1,983	4,384	6,599	9,323	1,430	23,718	159,701	15%
2030	1,983	4,405	6,671	9,399	1,439	23,896	160,919	15%

Since in many cases the load that benefits from these sales is in a different zone or even state from the zone in which the resource is located (which determines the change in price received for the contract energy), we apply the contract offset as an ISO-wide average.

Most of the utilities also receive revenues from the use of Hydro-Quebec tie lines; it is not clear how those revenues are determined, or whether they vary with energy prices in New England.

Multiplying the share of the load exposed to market prices by the portion of the price effect not yet offset by supply adaptation produces an estimate of the percent of load affected by DRIPE. This can be expressed as a formula:

$$\%\ \textit{of load subject to energy}_{\text{DRIPE}} = (1 - \textit{market response}) \times \%\ \textit{of power supply prices at market}$$

Exhibit 6-41 summarizes the combined effect of DRIPE decay and market exposure, for each of four consumer groups: PSNH, the Vermont utilities, other municipal utilities (and the Maine coops), and the restructured investor-owned utilities (and the NH Co-op). The DRIPE decay in the first column is one minus the total DRIPE offset from Exhibit 6-38, above. The Net DRIPE Effect in Exhibit

6-41 is the produce of the DRIPE Decay and the market exposure for the various customer groups.

Exhibit 6-41: Summary of Energy DRIPE Response

	DRIPE Decay	Energy Hedged by Entitlements	Effective Energy DRIPE
2012	10%	22%	71%
2013	13%	21%	69%
2014	15%	21%	68%
2015	17%	19%	67%
2016	23%	18%	64%
2017	25%	17%	63%
2018	27%	16%	62%
2019	28%	16%	60%
2020	65%	16%	30%
2021	72%	16%	23%
2022	80%	16%	17%
2023	87%	16%	11%
2024	94%	16%	6%

Applying those percentages to the potential energy DRIPE produces the energy DRIPE. In the spreadsheets accompanying the final report, we will calculate the energy DRIPE effects of a 1 MWh reduction in energy uses in each zone, by or season.

6.3.3. Comparison of Results to Other Studies of Price Suppression

Energy DRIPE and capacity DRIPE are each forms of price suppression, a market impact which has been widely studied in the context of increased power supply. A number of studies have examined these issues, mostly in the context of incremental generation. Several of those studies are summarized in Exhibit 6-42. Full citations are provided in the bibliography attached as Appendix C.

The summary metric developed in these studies is a ratio of the percentage change in energy price to the percentage change in load or supply. For our energy DRIPE results, a MWh reduction in load (about 0.007% of ISO average load) results in about 0.007% reduction in prices in other zones (a ratio of 1.0), and about 0.010% to 0.022% in the zone with the reduction (ratios of 1.4 to 3.1). These are well within the range of reported sensitivities.

The ratios of price reduction to load reduction (or additional low-cost energy) in Exhibit 6-42 are for the entire region listed in the third column, except for Charles River 2010, which produced results for both the zone with the resource (SEMA) and the entire ISO, and Stern 2009, which estimated effects in northern and western New York State (Zone 1) from installations in that area, in the Hudson Valley (Zone 2) from installations in that area, and for the state as a whole from all procured resources (mostly in Zone 1).

Exhibit 6-42: Summary of Price-Suppression Studies

					Price Effects				Ratio of Δ price to Δ supply
	Date	**Region**	**Resource**	**Position**	**Energy**	**Capacity**	**Decay?**	**Case**	
Charles River Associates	2010	ISO-NE	Cape Wind	Support	Yes	No	No	2013-27 ISO	1.9
								2013-27 SEMA	2.7
Eggers, D., et al.	2009	ISO-NE	HQ Line	Neutral	Yes	No	**Yes**	2014	0.9
								2015	0.9
								2016	0.4
								2017	0.3
								2018	0.3
Cool, E., et al.	2010	ISO-NE	Canal Unit 2	Oppose	Yes	No	No		~1.0
Cool, E., et al.	2008	ISO-NE	Conn peakers	Neutral	Yes	**Yes**	**Yes**		490
Frayer, J., et al.	2007	ISO-NE	Conn generators	Neutral	Yes	Yes	No		NRA
Frayer, J.	2009	ISO-NE	Meriden CC	Oppose	Yes	Yes	**Yes**		NRA
MacCormack, J., et al.	2010	Alberta	Wind	Neutral	Yes	N/A	No	10% capacity	5.8
								20% capacity	4.5
Munksgaard, J., & Morthorst, P.E.	2008	Denmark	Wind	Neutral	Yes	No	No	2004	0.2
								2005	0.8
								2006	0.3
New York Department of Public Service	2008	NYPP	EE	Neutral	Yes	No		2009	0.7
								2012	0.4
								2015	0.4
PJM	2009	PJM	EE	Neutral	Yes	No	No	2%	~2.0
						No	No	5%	~2.0
						No	No	10%	~2.2

Exhibit 6-42: Summary of Price-Suppression Studies Continued

					Price Effects				Ratio of Δ price to Δ supply
	Date	Region	Resource	Position	Energy	Capacity	Decay?	Case	
Saenz de Miera, et al.	2008	Spain	Wind	Neutral	Yes	No	No	2005	1.4
								2006	0.9
								2007	2.4
Senfuss, et al.	2008	Germany	Wind	Neutral	Yes	No	~		NRA
Stern, F, et al.	2009	NYPP	Wind	Support	Yes	No	No	Zone 1	1.4
								Zone 2	1.0
								State	1.1
Blossman, B., et al.	2009	ERCOT	Wind	Neutral	Yes	N/A		2008 on A	1.4
					Yes	N/A		2008 off A	1.2
					Yes	N/A		2008 on B	2.0
					Yes	N/A		2008 off B	1.2
					Yes	N/A		2013 on A	1.2
					Yes	N/A		2013 off A	0.8
					Yes	N/A		2013 on B	1.4
					Yes	N/A		2013 off B	1.3
Notes:	N/A means no capacity market exists. NA means not applicable to this study. NRA means the necessary data are not readily available. Blossman, et al., estimate effects with constraints (2008 Case A) and without (2008 Case B), and for 100% capacity factor (2013 Case A) and realistic capacity factors (2013 Case B)								

In addition to the summary information on energy DRIPE, we detail some identified studies in more detailed attention, due to their treatment of capacity prices and/or DRIPE decay. Exhibit 6-43 summarizes the length of DRIPE effects and (for studies that included energy DRIPE through the end of the analysis) the ratio of the DRIPE effect in the last year of the analysis to the effect in the first year. A "+" in the third column indicates that the DRIPE effect continues through the end of the study period. Each of these studies reduce energy DRIPE (and the Levitan study reduces capacity DRIPE) only when the resource under study delays a new unit or retires an existing unit.

Exhibit 6-43: Summary of DRIPE Decay in Price-Suppression Studies

Study	Market	Years to End of DRIPE	% of Initial DRIPE at End of Analysis
Cool, et al, 2008 (Levitan)	Energy	11	
	Capacity	7	
Frayer, 2009 (London Economics)	Energy	12+	24%
	Capacity	12+	
Eggers, 2009 (Credit Suisse)	Energy	7+	27%

AESC 2011 estimates capacity and energy DRIPE from 2012 installations to last 11 and 13 years respectively.[155] AESC 2011 estimates capacity and energy DRIPE from 2013 installations to last 11 and 12 years. These durations are consistent with the reviewed literature.

6.3.3.1. Levitan and Associates, Connecticut Peakers

The analysis of price suppression by the proposed peakers in Connecticut concentrated on the forward reserve market, which is of little relevance for future energy-efficiency screening. In addition, Cool, et al., considered the effect of the peakers on regional capacity prices, and incorporated a form of decay in the benefits.

For the capacity market, Cool, et al. had only data from FCA 1. They estimated capacity DRIPE for FCA 5 to FCA 7, since they assumed an effective price floor through FCA 4 and a need for new generic capacity at a uniform price in FCA 8. The resulting DRIPE equivalents were $0.62, $0.12, and $0.63 per kW-month (in nominal dollars) per 100 MW of supply, compared to $0.16 to $0.50 (2011 dollars) in our estimates.

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[155] For 2014 and 2015, where the potential Capacity DRIPE impact is $0 due to the FCM floor price, we do not include those years in estimate of duration for Capacity DRIPE.

In terms of DRIPE phase-out, in the capacity market Levitan terminated all DRIPE once any generic unit was needed, in FCA 8 (the summer of 2017). For energy DRIPE, Levitan continued the effect through 2020, with no obvious trend from year to year, and then ended it.

6.3.3.2. London Economics, Meriden Combined Cycle

The July 2009 testimony of Julia Frayer on behalf of Connecticut Light and Power estimated the energy and capacity market effects of adding a proposed 510 MW gas-fired combined-cycle plant in Meriden Connecticut in 2014. While many details of the analysis are difficult to extract from the public record, Frayer estimated that Meriden would reduce market prices in Connecticut by about $2.5/MWh in 2014–2016, $2.3/MWh in 2017–2018, $0.7/MWh in 2019, and $0.6 in 2020–2023. The decay of the price suppression results from the assumption that Meriden's existence would result in the retirement of an existing combined-cycle in 2017 and the delay of a small new combined-cycle in 2019.

The conclusion that the existing unit would be retired, and that the 2019 combined-cycle would have been needed in the absence of Meriden, were due to Frayer's assumption that a generator that could not cover its fixed costs over three consecutive years would retire. This might be a reasonable assumption,[156] except that Frayer included in the fixed costs debt service based on a mortgage on 60% of the plant's market value. Frayer assumes that the owner can walk away from any unit that does not cover debt payment, and that the unit will be retired. In fact, owners often cannot walk away from the debt on individual units, since the debt holders have recourse to other units owned by the operating subsidiary. More importantly, the inability to cover debt service may lead to bankruptcy and change in ownership of the unit, but does not lead to retirement. For example, Mystic and Edgar stations are now going through the second bankruptcy of an owner, but they continue to operate. PG&E National Energy Group, then owner of about 5,000 MW of New England capacity, went bankrupt in 2003; its portfolio continues to operate under other ownership. Other major merchant generators, including Calpine and Mirant, have been through bankruptcy, divested some assets, but emerged as major generators.

Despite the errors in Frayer's retirement analysis, the approach parallels parts of our treatment of DRIPE decay. Over time, DRIPE is reduced, but not eliminated, by responses of existing plants and by delay of new additions, once new capacity is required.

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[156] Other analyses, such as the Connecticut 2010 IRP, assume that owners would tolerate much longer periods of losses, so long as the unit's economics are expected to turn around.

Frayer also estimated the effect of Meriden on FCM prices (Frayer Figure 40). She assumed that lower energy prices would increase FCM bid prices by generators, probably based on her assumption that the generators prefer to retire than to bid less than required to cover hypothetical debt payments. As a result, she finds that Meriden would increase FCM prices in 2014–2016, and have almost no net effect on FCM prices in 2017 and 2019. She estimates reductions in the FCM price of about $2.2/kW-year in 2018, $1/kW-year in 2020, $4/kW-year in 2021 and 2022, and $6.5/kW-year in 2023. (The latter is equivalent to $0.08/kW-month per 100 MW in 2011 dollars.) Interestingly, Frayer estimates rising FCM price effects over time.

6.3.3.3. Credit Suisse, Hydro Quebec

A 2009 Credit Suisse analysis (Eggers 2009) compares two scenarios, a Reference Case and an adaptation case, which Eggers refers to as a new HQ import case. In his Reference Case 600 MW of combined-cycle capacity is added in 2016 and another 200 MW in 2017. In his new HQ-import case 1,125 MW of additional hydro energy is imported from HQ to ISO-NE over a new line starting in 2014. Eggers does not specify the quantity of energy that would be provided by either the HQ line or the combined-cycle units. In the new HQ capacity case the market responds by canceling the 600 MW of combined-cycle capacity planned for 2016 and the 200 MW planned for 2017 under his Reference Case.[157]

The result of the change in the supply additions, Eggers (2009) estimates that the energy price in New England would be reduced from the Reference Case by

- $5.05/MWh in 2014 and 2015 (HQ added, no supply offset).[158]
- $2.19/MWh in 2016 (600 MW of combined-cycle removed).
- $1.37/MWh in 2017–2020 (combined total of 800 MW of combined-cycle removed)

Credit Suisse's estimate of the price effect of changes in this base/intermediate capacity is essentially linear, with energy price declining about $0.0045/MWh for each MW of capacity added and rising the same amount for each MW removed. In periods with no additional offsetting changes in capacity (2014–15 and 2017–2020), the market price effect of the HQ line does not change.

[157]The Credit Suisse report refers to those combined-cycle additions, and further additions in 2018–2020 as "NE-ISO published" and references "Company information" (apparently referring to Northeast Utilities and NStar), but we are not aware of any such ISO or utility publication.

[158]The report authored by Eggers does not indicate whether these prices are real or nominal, but they appear to be real.

6.3.3.4. Senfuss, et al, German Wind

Senfuss, et al., do not estimate a decay in price suppression, but they do analyze the effect on price suppression in 2006 under a series of assumptions regarding the causation of the large retirements and deactivations that occurred in the period that wind capacity was increasing under the feed-in tariff. In the base case, they assume that the retirements were unrelated to the 52 TWh of wind penetration; in a series of steps, they re-estimate energy price suppression assuming that wind was responsible for part or all of the retirements and deactivations. The results are summarized in Exhibit 6-44.

Exhibit 6-44: Effect of on Wind-Related Price Suppression of Imputed Retirements

	Step 1	Step 2	Step 3	Step 4
Coal MW	402	1,951	2,812	4,007
Oil & gas MW	2,272	3,484	3,542	4,976
Change in Price Effect, from Base	1%	-28%	-43%	-58%

It is difficult to draw any detailed lessons from these results, other than that retirements can offset DRIPE. In Senfuss's Step 1, the loss of mostly oil and gas capacity has no effect on DRIPE. In the later steps, the decay rises mostly with coal retirements. By Step 4, assuming that the coal plants would have operated at 60% capacity factor and the oil and gas plants at 5%, the retired plants would have produced about 23 TWh of energy, or about 45% of the wind output, and the fossil plants would have operated at higher-price times than the wind. On the whole, Senfuss, et al., would weakly support the hypothesis that retirement of existing units will erode DRIPE in rough proportion to their expected energy output, with peaker energy reducing DRIPE at a faster rate than baseload energy, per MWh, but baseload retirements being much more important per MW.

6.3.4. Gas DRIPE

Gas DRIPE measures the reduction in wholesale market prices forecast in a reference case due to a reduction in the forecast quantity of gas commodity and/or gas pipeline and storage capacity underlying that reference case. The reduction in the forecast quantity of commodity and/or capacity could be caused by various factors including more efficient use of gas at the end-use, displacement of gas by other energy sources at the end-use, less use of gas for electric generation due to more efficient use of electricity at the end-use and less use of gas for electricity due to displacement of gas-fired generation by renewables.

An estimate of gas DRIPE, like electric DRIPE, has two components – magnitude and duration. The first component is the initial magnitude of the reduction in the reference case wholesale market price for a given reduction in gas usage. The second component is the duration of the reduction in price, i.e. the length of time it will take for the reduction in price to disappear. DRIPE disappears when market prices return to reference case forecast levels as a result of market participants taking actions they would not have taken in the reference case, e.g. not drilling wells they would have otherwise drilled.

Gas DRIPE, like electric energy DRIPE, has the potential to be a significant benefit of efficiency programs. Reductions in gas use from gas and/or electric efficiency in New England are likely to have very small effects on the wholesale commodity price of natural gas, particularly because commodity prices are set by demand and supply in the North American commodity market. However, the absolute value of a small reduction in the commodity price could be significant because it would apply to all of the natural gas consumed in New England. In addition, a reduction in gas use in New England has the potential to have an impact on the price of pipeline and storage capacity serving New England, particularly if the region needs new capacity.

6.3.4.1. Information Regarding the Existence of Gas DRIPE

The following studies have found that reductions in gas usage would reduce wholesale market prices for gas:

- "Natural Gas Efficiency Resource Development Potential in New York," Mosenthal, P., et al., October 31, 2006. Albany, N.Y.; New York State Energy Research and Development Authority.
- Impacts of Energy Efficiency and Renewable Energy on Natural Gas Markets in the Pacific West, William Prindle, et al., January 1, 2006, ACEEE.
- Impacts of Energy Efficiency and Renewable Energy on Natural Gas Markets: Updated and Expanded Analysis, Elliott, RN, and Shipley, AM, April 1, 2005, ACEEE.
- Examining the Potential for Energy Efficiency to Help Address the Natural Gas Crisis in the Midwest. Kushler, M, et al., January 2005, ACEEE.

The final AESC 2011 Scope of Work did **not** include either an analysis of the reports listed above to estimate gas DRIPE in New England or an analysis to estimate the impact a reduction in load will have upon the market price and then estimates the pace at which suppliers participating in that market will respond by taking a different set of actions than they would have taken in the reference case.

6.4. Avoided Transmission-and-Distribution Costs

We surveyed the sponsoring electric utilities to determine (1) the avoided T&D capacity cost estimates used in the valuation of 2009 DSM programs and (2) the methodology on which these estimates were based. Exhibit 6-45 summarizes the information provided:

Exhibit 6-45: Summary of Electric Utilities' T&D Estimates

Company	Year $	Transmission $kW-year	Distribution $kW-year	Source	Documentation
NStar	2008	14.41	85.28	NStar/ICF	Workbook provided
CL&P	2011	1.25	29.74	ICF report	PDF report
WMECo	2010	20.30	60.87	WMECo/ICF	None
National Grid MA	2010	19.95	109.25	NGrid/ICF	Workbook provided
National Grid RI	2010	19.95	87.13	NGrid/ICF	Workbook provided
UI	2011	2.54	45.96	B&V report	PDF report

Notes

Utility//ICF = the utility applied the 2005 ICF approach, sometimes with modifications.

B&V Report = United Illuminating Avoided Transmission & Distribution Cost Study Report, Black & Veatch, September 2009.

ICF Report = Assessment of Avoided Cost of Transmission and Distribution, ICF International, October 30, 2009.

CL&P and UI avoided costs in 2011$ are from 2011 Electric and Natural Gas Conservation and Load Management Plan; CL&P, UI, et al.; Dockets 10-10-03 and 10-10-04; October 1, 2010; page 331.

Unitil, and the Vermont and Maine program administrators did not respond to our inquiry.

A description of the ICF model used by NStar and National Grid was detailed in the AESC 2005 report. The AESC 2009 report included our review of the ICF model in general and in its use by the utilities.[159] We will not repeat that review here. The updated models provided by National Grid and NSTAR address several of the concerns identified in AESC 2009.

Two utilities are using T&D estimates derived from new studies performed after AESC 2009. CL&P had ICF prepare a new avoided-T&D analysis, using a different method than the 2005 ICF model, while UI had Black & Veatch estimate

[159] The avoided-cost analyses used by WMECo and NStar are the same as those reviewed in AESC 2009, using actual data only through 2008. See AESC 2009 pages 6-66 and 6-67 for a detailed critique of the components of the ICF model.

its avoided T&D. Our review of methodologies here offers some general observations and recommendations to ensure greater consistency and accuracy in the estimation of avoided T&D capacity costs across program administrators and methodologies.

6.4.1. General Methodology

The basic method in the ICF model, the ICF report for CL&P, and most other avoided-T&D estimates is to divide actual or expected investment by actual or expected load growth. The B&V report for UI uses a different approach, dividing the cost of each investment by the full capacity it could accommodate. Since T&D investments may be required by even small increases in load above the capacity of existing equipment, the B&V approach may not accurately reflect the savings from reducing load growth.[160] Since avoidable T&D costs are estimated as the ratio of actual or expected investment to actual or expected load growth, the costs used in the analysis are those not actually avoided.[161] Analysts do not generally have estimates of costs that have actually been (or are expected to be) avoided by energy-efficiency; such analysis would usually be prohibitively expensive.

Any single investment is unlikely to increase delivery capability all the way from the generators to the customer meter. Adding line transformers allows customers to draw more power from the primary distribution system; reconfiguring existing primary feeders maximizes the amount of regional available substation capacity that can be delivered to the line transformers, and so on.[162] Depending on the amount of excess capacity on the various levels of T&D equipment in a particular area, reducing load by any particular customer may avoid addition of a line transformer the next year, and contribute to delaying or avoiding the reconfiguration of feeders, the upgrading of a substation, and the construction of transmission lines in following years. At another location, load reductions may have little effect on T&D investment for many years. The basic approach to avoided cost estimates this complex relationship by computing the average ratio of all load-related investments to all load growth, rather than just the load growth that has the greatest effect on investment.

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[160] For example, the need for a new substation is not determined by an increment of MVA at one location, but by an increment of a few MVA that push load (normal or emergency) above the capacity of an existing substation.

[161] The B&V report appears to exclude some investments on the grounds that they were not avoided.

[162] B&V exclude some investments on the grounds that the projects only increase capacity on parts of the system.

6.4.2. Loads

All the T&D analyses provided in this round of review use the same system peak loads for both transmission and distribution capacity. For transmission, that assumption is a reasonable approximation. But the load growth on the utility's distribution system is lower, since many large customers provide some or all of their own distribution and are served at various transmission or primary-distribution voltages. Hence, the load used in the distribution analysis should generally be lower and the cost per kW higher (all else equal).

6.4.3. Tax Effects

The ICF model attempted to avoid the detailed computation of tax effects on revenue requirements. This simplification introduces a number of potential errors: 1) exclusion of taxes on the portion of nominal return that exceeds real return, 2) double-counting of the tax shield on debt, and 3) treating the difference between book and MACRS tax depreciation as if it were the same as the difference between sinking-fund and straight-line depreciation.[163]

We tested the effect of these simplifications by modifying the revenue requirements spreadsheet developed by NStar for its Lower SEMA 345 kV Transmission Project (filed in Massachusetts EFSB Docket No. 10-2) to use the input values (e.g., depreciation life, costs of capital, taxes, O&M) that NStar used for transmission in its ICF model of avoided T&D. The revenue requirements spreadsheet conducted all computations in nominal terms and explicitly computes the annual taxes reflecting accelerated tax depreciation. The real-levelized carrying charge is 11.0%, levelizing at the weighted average cost of capital, or 10.0%, levelizing at the weighted average cost of capital minus the tax shield on debt. The ICF model computes a levelized carrying charge of 10.4% with those same input values. The results may diverge more with alternative costs of capital or useful lives.

6.4.4. Investments Avoidable by Energy Efficiency

For any of the methodologies used, the utilities should review the specific projects (or the percentage of investments by category of T&D) that are assumed to be unavoidable by energy efficiency, and better document decisions to exclude the costs of those projects.

Among distribution investments, some asset accounts (primarily meters and services) are generally considered to be affected very little by energy-efficiency programs. Some distribution projects extend service into areas that have not

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previously been served, to connect new customers; only a small portion of those pole and wire costs are potentially avoidable by load reductions.[164] Some transmission projects are required to integrate generation, or to facilitate exports, and would be affected little, if at all, by load reductions.[165] For both distribution and transmission, investments that are simply replacements in kind due to physical deterioration or required relocation of facilities are not considered avoidable. Other than these categories, the classification of investments as unavoidable should be fully and clearly justified.

The UI and CL&P reports exclude a number of projects and categories that appear at first blush to be load-related, without adequate explanation. In order to determine that a T&D investment is not load-related and hence properly includable in the avoided-cost computation, the analysis should demonstrate that

- The investment is not motivated or required by the level of actual, anticipated or emergency load. Those considerations drive the installation of most transmission lines, new substations, additional substation transformers, new feeders, reconductoring, additions of line transformers in areas with existing service, voltage upgrades, and conversion of feeders from single-phase to multi-phase.
- The investment is not motivated by load-related energy considerations, including congestion relief and reduction of line losses.
- The investment category does not increase with load. For example, higher loads result in earlier failure of line transformers, so replacements of transformers are at least partly driven by load levels.[166]

The book costs of T&D projects generally include an allocation of overhead costs. Some of those overheads may not vary with the amount of plant under construction or in service, or the number of personnel required to design, build, maintain and operate the assets. But many categories of overheads do vary with one or more of those drivers, including office space and equipment; personnel, purchasing, and other support services; warehouses, vehicles, and equipment; and

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164 As a result of the exclusion of meters and services, as well as projects that extend the distribution system to new areas, the percentage of distribution investment that is avoidable would generally be lower than the percentage of transmission investment.

165 Generation-related transmission investments are generally charged to the generators; if these costs are avoidable, it would be through avoiding the need for the generator, and the costs should show up in market generation prices.

166 Some transformers are replaced because they rust out or are destroyed in accidents.

legal, financial and regulatory services. Any exclusion of overhead costs from avoided T&D should be carefully considered and fully justified.

In addition to increasing capital-recovery costs and taxes, most plant additions also require additional operating and maintenance costs. The ICF model and many other analyses of T&D project costs (including the NStar transmission analysis cited above) assume that the ratio of O&M cost to plant for the avoidable capacity is the same as for the existing plant mix.[167] Any assumption that O&M associated with a new transmission line, feeder, substation or transformer is less than the average O&M for similar existing equipment should be carefully considered and fully justified.

6.5. Regional Electric-Energy-Supply Prices Avoided By Energy-Efficiency and Demand-Response Programs

6.5.1. Avoided Cost of Compliance with RPS

Our estimate of avoided costs includes the expected impact of avoiding the region's five existing Renewable Portfolio Standards. AESC 2011 also assumes that Vermont establishes a binding RPS in addition to any and all of its current voluntary goals and renewable energy programs. The annual quantity of renewable energy that LSEs need to acquire in order to comply with RPS requirements is directly proportional to the annual load that the LSEs supply. All states except Vermont currently require the use and retirement of NEPOOL Generation Information System (GIS) certificates, commonly referred to as Renewable Energy Certificates (RECs), to demonstrate compliance.[168]

To the extent that the price of renewable energy exceeds the market price of electric energy, LSEs incur a cost to meet the RPS target. That incremental unit

[167] The cost ratios are often computed for transmission plant as a whole, and for distribution (or distribution net of services and meters) as a whole, although the ratios can also be disaggregated, as between substations and lines.

[168] Currently, Vermont's requirement will allow RECs to be sold off elsewhere (presumably for compliance in other states), therefore not leading to incremental renewable energy additions beyond what would be predicted in the presence of other states' requirements (although it has been argued that the Vermont requirements will support financing and therefore lead to more renewables being built, and therefore less reliance on Alternative Compliance Payments). We assume that by 2013, Vermont will adopt a binding RPS which requires the retirement of RECs for compliance, and thereby adds to the projection of total RPS additions. The year 2013 was chosen both because it is the year in which the current voluntary requirement would have become mandatory had the goals not been met, and because Vermont policy-makers are currently conducting an RPS study – the results of which are not likely to be implemented before 2013.

cost is the price of a REC. This annual compliance cost ($) equals the quantity of renewable energy purchased (kWh) multiplied by the REC price ($/kWh).

Energy-efficiency programs reduce the cost of compliance with RPS requirements by reducing the total load, or kWh, that must be supplied. Reduction in load due to DSM will reduce the RPS requirements of LSEs and therefore reduce the costs they seek to recover associated with complying with these requirements. The RPS compliance costs that retail customers avoid through reductions in their energy usage is equal to the price of renewable energy in excess of market prices, multiplied by the portion of retail load that a supplier must meet from renewable energy under the RPS. RPS targets for Connecticut, Maine, Massachusetts, New Hampshire and Rhode Island are based on state-specific legislation and regulation in effect as of April 2011. For Vermont, AESC 2011 assumes the adoption of an RPS, commencing in 2013 and requiring 5 percent eligible renewable energy by 2017, which is incremental to all goals previously described and which requires the retirement of RECs to demonstrate compliance.

This section forecasts those avoided RPS costs where the key input to the calculations is a forecast of the price of renewable energy in excess of market prices each year, i.e. the forecast price of RECs. This section presents a forecast of the expected future cost of renewable energy certificates and RPS compliance. We deduct the market price of energy from the forecast cost of renewable energy in order to calculate the forecast price of RECs for each RPS subcategory, by state and by year. For all Class 1 requirements, the forecasted price of RECs for the remainder of 2011 and all of 2012 is based on historic average broker quotations regarding short-term forward transactions consummated between January and April 2011. Beginning in 2019, Class 1 REC prices reflect the forecasted cost of new entry. Class 1 prices are interpolated for 2013 through 2018 by scrutinizing the expected balance between RPS-eligible supply and RPS demand and by including the expected impact of banked compliance[169]. For Class 2 requirements, the 2011 REC prices are based on a 12-month (May 2010 to April 2011) historic average of broker quotes and/or bid-ask spreads. These REC prices are summarized in Appendix C. Due to the differences in eligibility requirements among states, the supply and demand balance, and therefore the REC price, is expected to vary somewhat from state to state during this period. Beginning in

[169] In the event that an LSE purchases RECs in excess of its current year RPS obligation, each state allows LSEs to save and count that quantity of compliance against either of the following two compliance years. This compliance flexibility mechanism is referred to as banking. LSEs may only bank compliance within a single state, and may not transfer banked compliance credit to other entities.

2019, regional REC prices are expected to converge on the cost of new entry as all states rely on new or incremental renewable resources to meet their RPS demands.

6.5.1.1. New or Incremental Renewables Dominate Annual Additions to RPS Supply

New or *incremental* renewable resources are those that qualify as “Class I” in CT, MA, NH, ME, and as ‘new” in RI. AESC 2011 assumes that the anticipated VT RPS will include a Class 1 obligation with eligibility requirements substantially similar to those currently in effect in RI, and will therefore create incremental demand for new renewable energy. We refer to those categories in those states collectively as Class I. REC prices will be driven both by the costs of renewable resources eligible in each state and by the quantity of state-specific supply compared to state-specific demand. Because RPS eligibility criteria differ by state, REC prices continue to be differentiated by state until 2019 when regional REC prices are expected to converge because all states are relying on marginal resources to meet RPS demand.

In AESC 2011 we assume that the MA Solar Carve Out (a sub-set of MA Class I) reaches its 400 MW target in 2018 and that the target remains at this level through 2022. This is the proxy date for the point at which the last remaining "Opt-In Term" is expected to expire. Beginning in 2023, we assume that the Solar Carve-Out begins to sunset into MA Class I at the same rate as it ramped up, reaching zero carve-out shortly after the study period ends. Reductions in the installed cost of new solar facilities are assumed to drive SREC prices toward the $300 auction floor price from 2012 to 2018, with steeper declines in the early years. Beginning in 2019 (one year after the 400 MW target is reached) supply and demand dynamics may cause the market price of SRECs to drop below the auction floor price of $300, notwithstanding the fact that some SRECs are still eligible for the auction. MA DOER's SREC market structure is yet untested, and it is not clear whether an auction floor price will be able to be maintained once there is a substantial amount of supply in the market.

While Class I RPS requirements generally spur the development of new renewable resources, Class II, III and IV requirements are generally designed as “maintenance tiers.” These programs are intended to provide just enough financial incentive to keep the existing fleet of renewable resources in reliable operation. Due to their maintenance orientation, Class II, III and IV targets are generally held constant, with annual obligations varying only based on changes in the demand forecast. CT Class II, MA Class II-WTE, ME Class II, and RI "Existing" REC markets are in surplus. Therefore, REC prices in these markets are expected to remain relatively constant at levels just above the transaction cost. The MA Class II market has overlapping eligibility with CT Class I. In addition, while there is theoretically ample supply to meet MA Class II, fewer generators than expected have undertaken the steps necessary to comply with the eligibility criteria and become certified. Therefore, the MA Class II market is currently in shortage. In the long-run, MA Class II REC prices are assumed to be the lesser of CT Class I and 90% of the MA Class II Alternative Compliance Payment (ACP) rate. REC prices for MA APS are forecasted at 90% of the Alternative Compliance Payment (ACP) rate. The CT Class III market has an administratively-set REC price floor of $10. Based on the performance of this market to date, CT Class 3 compliance prices are expected to remain at $10 per MWh throughout the study period. Existing solar facilities across New England are eligible for NH Class II. As such, this market is expected to remain in balance, trend toward the MA Class I REC price between 2011 and 2014, and settle marginally above the MA Class I REC price for the remainder of the study period. The NH Class III and NH Class IV markets have overlapping eligibility with CT Class I. In the long-run, therefore, NH-III and NH-IV REC prices are assumed to be the lesser of CT Class I and 90% of their respective ACP rates.

Class I requirements will outpace the other classes on a GWh basis over time. This phenomenon is shown in Exhibit 6-46 that summarizes New England’s total renewable energy requirements by year, based on the RPS targets by state and ISO-NE’s 2011 CELT forecast, as discussed in Chapter 2. Exhibit 6-46 distinguishes between the quantity of Class I renewables that are required and the *aggregate* quantity of all other classes of renewables combined.

Exhibit 6-46: Summary of New England RPS Demand

New England Annual RPS Demand			
Year	Class 1 (GWh)	Other Classes (GWh)	Total (GWh)
2011	6,694	10,411	17,105
2012	8,066	10,607	18,673
2013	9,413	10,695	20,108
2014	10,785	10,810	21,595
2015	12,374	10,911	23,285
2016	13,990	11,013	25,003
2017	15,638	11,117	26,755
2018	17,126	11,224	28,350
2019	18,635	11,328	29,964
2020	20,034	11,435	31,469
2021	20,954	11,543	32,497
2022	21,893	11,652	33,545
2023	22,851	11,762	34,612
2024	23,827	11,873	35,700
2025	24,679	11,985	36,664
2026	25,547	12,098	37,645

Notes:
i. Class 1 includes voluntary demand.
Based on CELT 2011 and RPS targets summarized in Chapter 2.

The requirements for each RPS class were derived by multiplying the load of obligated entities (those retail LSEs subject to RPS requirements, often excluding public power) by the applicable annual class-specific RPS percentage target. The RPS requirements by class and year are listed in Appendix C. The load by state is based on CELT 2011 as detailed in Chapter 2.

The major sources of renewable supply forecast used to meet the RPS requirements by year are shown in Exhibit 6-47. These sources include wind, biomass, natural gas fuel cells, and hydro. The "other" category is included to represent the aggregate contribution of solar, landfill gas and tidal resources.

Exhibit 6-47: Cumulative Incremental Supply of Class 1 Renewable Energy Resources in New England, by Fuel Type (excludes resources already in the CELT Report)

Class 1 Renewable Energy Supply, by Fuel Type (GWh)						
Year	**Wind**	**Biomass**	**NGFC**	**Hydro**	**Other**	**Total**
	a	c	d	e	f	g = sum a to f
2012	71	47	67	50	388	**624**
2013	320	326	78	51	416	**1,192**
2014	2,419	1,005	93	55	466	**4,038**
2015	3,747	1,624	263	63	623	**6,320**
2016	4,515	2,014	310	68	678	**7,585**
2017	5,033	2,272	357	68	746	**8,476**
2018	5,107	2,272	404	68	805	**8,656**
2019	5,671	2,376	452	472	1,014	**9,984**
2020	6,532	2,381	499	472	1,014	**10,898**
2021	7,105	2,897	546	472	1,014	**12,034**
2022	7,765	2,897	594	472	1,014	**12,742**
2023	8,868	2,897	641	472	1,014	**13,891**
2024	9,321	3,051	688	472	1,015	**14,547**
2025	10,465	3,051	736	472	1,015	**15,739**
2026	10,988	3,051	783	472	1,015	**16,309**

Notes:
ii. Other includes solar, landfill gas & tidal
Based on Sustainable Energy Advantage, LLC proprietary database

The expected distribution of Class 1 RPS supplies between ISO-NE and adjacent control areas are summarized in Exhibit 6-48. Supply is categorized as follows:

- Existing eligible generation already operating (including biomass co-firing in existing facilities)
- The quantity of (energy and) RECs currently imported from RPS-eligible facilities located outside of ISO-NE
- The assumed incremental level of (energy and) RECs imported from RPS-eligible facilities located outside of ISO-NE
- The assumed incremental renewable resources by fuel type.

Exhibit 6-48: Expected Distribution of New Renewable Energy between ISO-NE and Adjacent Control Areas

	Class 1 RPS Supply					New RE Demand	
	ISO-NE Supply		Imported Supply				
Year	Operating	Incremental	Current	Expected	TOTAL	New Renewable Requirement GWh	New Renewable Energy Surplus/(Shortage)
	a	b	c	d	e = sum a to d	f	g = e-f
2012	5,803	118	1,814	656	**8,391**	**8,066**	324
2013	5,803	661	1,767	1,067	**9,298**	**9,413**	(115)
2014	5,803	3,476	1,754	1,465	**12,498**	**10,785**	1,713
2015	5,803	5,540	1,741	1,843	**14,927**	**12,374**	2,554
2016	5,803	6,723	1,728	2,220	**16,474**	**13,990**	2,484
2017	5,803	7,500	1,716	2,596	**17,614**	**15,638**	1,976
2018	5,803	7,573	1,703	2,972	**18,051**	**17,126**	925
2019	5,803	8,854	1,691	3,348	**19,695**	**18,635**	1,060
2020	5,803	9,720	1,678	3,724	**20,926**	**20,034**	892
2021	5,803	10,809	1,666	3,720	**21,998**	**20,954**	1,044
2022	5,803	11,469	1,654	3,716	**22,642**	**21,893**	749
2023	5,803	12,572	1,642	3,712	**23,728**	**22,851**	878
2024	5,803	13,179	1,629	3,708	**24,319**	**23,827**	492
2025	5,803	14,323	1,618	3,704	**25,448**	**24,679**	769
2026	5,803	14,846	1,606	3,700	**25,955**	**25,547**	407

Exhibit 6-48 also compares total Class I RPS supply to total new renewable energy demand. The combination of operating supply, projects currently under development, and resource potential from the renewable energy supply curve analysis are expected to keep supply and demand in balance through 2026.

Over time, the net requirements met by resources within ISO-New England will be further reduced by an estimate of *additional* RPS-eligible imports over existing tie lines, phased in at a rate consistent with the recent historical rate of increase in RPS-eligible imports over a ten-year period.

In addition to *new* or *incremental* renewables, several states also have minimum requirements for existing renewable energy sources, or other eligible sources. The eligibility details and target percentages are summarized in Appendix C.

6.5.1.2. Estimated Cost of Entry for New or Incremental Renewable Energy

Our general approach to estimating renewable supply is described in Chapter 2. We assume that in the long-run, the price of renewable energy certificates (and therefore the unit cost of RPS compliance) will be determined by the cost of new entry of the marginal renewable energy unit. To estimate the new or incremental REC cost of entry, we constructed a supply curve for incremental New England renewable energy potential based on various resource potential studies that sorts the supply resources from the lowest cost of entry to the highest cost of entry.[170] The resources in the supply curve model are represented by 135 blocks of supply potential from resource studies, each with total MW capacity, capacity factor, and cost of installation and operation applicable to projects installed in each year.

The supply curve consists of land-based wind, biomass, hydro, landfill gas, offshore wind and tidal resources. Land-based wind is the largest source by far, modeled as 86 blocks, varying by state, number and size of turbines in each project, wind speed and distance from transmission.

The price for each block of the supply curve is estimated for each year. For each generator, we determine the levelized REC premium, or additional revenue the project would require to attract financing, for market entry by subtracting the nominal levelized value of production consistent with the AESC 2011 projection of wholesale electric energy prices from the nominal levelized cost of marginal resources:[171]

- The nominal levelized cost of marginal resources is the amount the project needs in revenue on a levelized $/MWh basis;
- The nominal levelized value of production is the amount the project would receive from selling its commodities (energy, capacity, ancillary services) into the various wholesale markets; and
- The difference between the levelized cost and the levelized value represents the REC premium.

Unless the revenue from REC prices can make up the REC premium, a project is unlikely to be developed. Resource blocks are sorted from low to high REC price, and the intersection between incremental supply and incremental demand determines the market-clearing REC price for market entry. Our projections assume that REC prices for new renewables will not fall below $2/MWh, which is the estimated transaction cost associated with selling renewable resources into the

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[170] These assumptions are based on technology assumptions compiled by Sustainable Energy Advantage, LLC from a range of studies and interviews with market participants. Some characteristics are adapted from those used in a New England renewable energy supply curve analysis prepared by Sustainable Energy Advantage, LaCapra Associates and AWS Truewind for the Maine Governors Wind Task Force Study on behalf of the Natural Resources Council of Maine. Typical generator sizes, heat rates, availability and emission rates are consistent with technology assumptions used by ISO-New England in its scenario planning process. The resulting supply curve is proprietary to Sustainable Energy Advantage, LLC.

[171] SEA calculated these levelized analyses using discount rates representative of the cost of capital to a developer of renewable resource projects.

wholesale energy market. This estimate is consistent with market floor prices observed in various markets for renewable resources.

The estimated levelized cost of marginal resources is based on several key assumptions, including projections of capital costs, capital structure, debt terms, required minimum equity returns, and depreciation, which are combined and represented through a carrying charge. The estimated levelized cost of marginal resources also includes fixed and variable operations and maintenance costs, transmission and interconnection costs (as a function of voltage and distance from transmission), and wind integration[172] costs. The Federal Production Tax Credit is assumed to be phased out over a seven year period following 2013. Capital and operating costs were escalated over time using inflation.

The levelized commodity revenue over the life of each resource was determined based on the sum of energy and capacity prices, both utilizing preliminary AESC 2011 reference-case estimates of the FCM price and all-hour zonal LMP.

Revenues for wind resources were adjusted in three ways:

- The value of wind energy was adjusted to reflect wind's variability, production profile, and historical discount of the real-time market (in which wind plants will likely sell a significant portion of their output) versus the day-ahead market.
- Energy prices were further discounted to reflect the lower prices typical in long-term contracts, especially for wind plants, with their fluctuating energy output.[173]
- Wind generators were assumed to receive FCM revenues corresponding to only 15% of nameplate capacity, reflecting the poor performance of most on-shore wind plants on summer afternoons. This assumption may be conservative for commercial wind farms, reflecting developer, investor and lender risk-aversion regarding future capacity valuation.

Resources from the supply curve are modeled to meet net demand (as described earlier), which consists of the gross demand for new or incremental renewables, less:

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[172]We assume that reinforcement of major transmission facilities (e.g., improved connections between Maine and the rest of New England) will be socialized.

[173]Our forecast of REC prices assumes that most renewables will be financed with long-term contracts for most of their capacity and/or RECs.

a) Existing eligible generation already operating (including biomass co-firing in existing facilities);

b) The current level of RPS imports; and

c) Additional imports over existing ties to neighboring control areas.

In addition, for solar and fuel-cell resources, which tend not to be resource-constrained, we separately estimated the amounts that would be driven by various policy initiatives; these amounts were also netted from gross demand.

As previously stated, 2011 and 2012 REC prices were estimated using broker quotes. Due to the scale of expected surpluses in the near-term (which derive from new supply that has come on-line since our analysis for AESC 2009, and an increase in renewable energy imports), as well as the ability to bank RPS compliance, the cost of new entry is not expected to be determined by generic supply curve supply until roughly 2019. Until then, REC prices are estimated by scrutinizing the expected balance between RPS-eligible supply and RPS demand and by including the expected impact of banked compliance. Beginning in 2019, regional REC prices are expected to converge on the cost of new entry as all states rely on new or incremental renewable resources to meet their RPS demands. Our projection of the cost of new entry is summarized in Exhibit 6-49.

Exhibit 6-49: REC Premium for Market Entry ($/MWh)

REC Premium for Market Entry	
Year	(2011 $/MWh)
2019	$5.14
2020	$6.63
2021	$3.46
2022	$6.84
2023	$9.82
2024	$10.23
2025	$7.85
2026	$4.12

These results are highly dependent upon the forecast of wholesale electric energy market prices, including the underlying forecasts of natural gas and carbon allowance prices, as well as the forecast of inflation. A lower forecast of market energy prices would yield higher REC prices than shown, particularly in the long term. This phenomenon is demonstrated when comparing the long-run REC prices in the AESC 2011 with those from the AESC 2009 study. In the intervening period RPS supply has caught up with and surpassed RPS demand. REC prices are comparable between the two studies during the years of expected equilibrium, and then REC prices based on the cost of new entry in AESC 2011 are lower than those forecasted in AESC 2009 based primarily on the fact that equipment and raw material prices have come down from their artificial peaks of 2008 and 2009. In all cases, project developers will need to be able to secure long-term contracts and attract financing based on the aforementioned natural gas, carbon and resulting electricity price forecasts in order to create this expected REC market environment. This presents an important caveat to the projected REC prices, as such long-term electricity price forecasts (particularly to the extent that they are influenced by expected carbon regulation) are not easily taken to the bank.

In contrast to the long-term REC cost of entry, spot prices in the near term will be driven by supply and demand, but are also influenced by REC market dynamics and to a lesser extent to the expected cost of entry (through banking), as follows:

- Market shortage: Prices approach the cap or Alternative Compliance Payment
- Substantial market surplus, or even modest market surplus without banking: Prices crash to approximately $0.50 to $2/MWh, reflecting transaction and risk management costs
- Market surplus with banking: prices tend towards the cost of entry, discounted by factors including the time-value of money, the amount of banking that has taken place, expectations of when the market will return to equilibrium, and other risk management factors.

Detailed projections of REC prices by state for Class I renewables are presented in Appendix C.

6.5.1.3. Avoided RPS Compliance Cost per MWh Reduction

The RPS compliance costs that retail customers avoid through reductions in their energy usage is equal to the price of renewable energy in excess of market prices multiplied by the portion of retail load that a supplier must meet from renewable energy under the RPS. In other words,

$$\frac{\sum_{n} \mathrm{P}_{\mathrm{n,i}} \times R_{n,i}}{1-l}$$

Where:

i = year

n = RPS classes

$P_{n,i}$ = projected price of RECs for RPS class n in year i,

$R_{n,i}$ = RPS requirement for RPS class n in year i, from Exhibit 3-9 in Deliverable 3-1.

l = losses from ISO wholesale load accounts to retail meters

For example, in a year in which REC prices are \$30/MWh and the RPS percentage is 10%, the avoided RPS cost to a retail customer would be \$30 × 10% = \$3/MWh. Detailed results from Appendix C are incorporated into the Appendix B Avoided Cost Worksheets by costing period. The year-by-year RPS percentages for each RPS tier are shown in Appendix C.

The levelized RPS price impact for the 2012 to 2026 period, in 2011\$ per MWh of load, is shown below:

Exhibit 6-50: Levelized RPS Price Impact (2012-2026)

Avoided RPS Cost by Class (\$/MWh of Load) Levelized Price Impact 2012 – 2026 (2011\$)						
	CT	ME	MA	NH	RI	VT
Class I	\$1.77	\$0.87	\$1.74	\$1.31	\$1.41	\$0.50
All Other Classes	\$0.40	\$0.05	\$3.24	\$0.99	\$0.01	\$0.00
Total	**\$2.17**	**\$0.92**	**\$4.98**	**\$2.30**	**\$1.43**	**\$0.50**

6.6. Externalities

Externalities are impacts from the production of a good or service that **are not** reflected in price of that good or service, and that are **not** considered in the decision to provide that good or service.[174] Air pollution is a classic example of an externality, as pollutants released from a facility impose health impacts on a population, cause damage to the environment, or both. The costs of those health impacts and ecosystem damages are not reflected in the price of the product and are generally not borne by the owner of the pollutant source. These costs are thus external to the financial decisions pertaining to the source of the pollutant. Therefore, externalities equal the total value of the adverse impacts minus the value of those impacts reflected in market prices.

In Chapter 2, we identify the impacts of pollutants that **are** reflected in market

[174] In economics, an externality can be positive or negative; in this discussion we are focusing on negative externalities.

prices in New England. There are many significant air pollutants associated with electric generation, but NO_x, SO_x, and CO_2 are the three primary pollutants that are currently subject to federal and/or state or regional regulation. Our electric market simulation model incorporates assumptions regarding compliance costs for those emissions as part of its estimation of the market price of electricity. The simulation model includes these costs when calculating bid prices and making commitment and dispatch decisions.

The Scope of Work for AESC 2011 asks for the heat rates, fuel sources, and emissions of NO_x, and CO_2 of the marginal units during each of the energy and capacity costing periods in the 2011 base year. It also asks for the quantity of environmental benefits that would correspond to energy efficiency and demand reductions, in pounds per MWh, respectively, during each costing period.

Exhibit 6-51 and Exhibit 6-52 summarizes the marginal heat rate and marginal fuel characteristics from the model results. The results of the two exhibits are based on the marginal unit in each hour in each transmission area, as reported by the model. Once the marginal units are identified, we extracted the heat rates, fuel sources, and emission rates for the key pollutants from the database of input assumptions used in our Market Analytics simulation of the New England wholesale electricity market.

Exhibit 6-51: 2011 New England Marginal Heat Rate by Pricing Period (Btu per kWh)

	Season and Period				
	Summer		**Winter**		**Grand Total**
	Off Peak	On Peak	Off Peak	On Peak	
Average Heat Rate (BTU/kWh)	9,543	10,188	9,161	8,494	**9,183**

Exhibit 6-52: 2011 New England Marginal Fuel Type

	Season and Period				
	Summer		Winter		
Fuel Type	Off Peak	On Peak	Off Peak	On Peak	**Grand Total**
Natural gas	70%	68%	64%	83%	**71%**
Oil	0%	1%	1%	1%	**1%**
Coal	24%	29%	24%	15%	**22%**
Nuclear	5%	1%	11%	1%	**5%**
Biomass	1%	1%	0%	0%	**0%**
Other	0%	0%	0%	0%	**0%**
Renewable	0%	0%	0%	0%	**0%**
Grand Total	**100%**	**100%**	**100%**	**100%**	**100%**

Our discussion of the methodology that we employ is discussed below:

We calculate the physical environmental benefits from energy efficiency and demand reductions by calculating the emissions of each of those marginal units in terms of pounds per MWh. We do this by multiplying the quantity of fuel burned by each marginal unit by the corresponding emission rate for each pollutant for that type of unit and fuel.

The calculations for each pollutant in each hour are as follows:

$$\text{Marginal Emissions} = [\text{Fuel Burned}_{MU}\ (\text{MMBtu}) \times \text{Emission Rate}_{MU}\ (\text{lbs/MMBtu}) \times 1\ \text{ton}/2000\ \text{lbs}]/\text{Generation}_{MU}\ (\text{MWh})$$

Where:

$\textit{Fuel Burned}_{MU}$ = the fuel burned by the marginal unit in the hour in which that unit is on the margin,

$\textit{Emission Rate}_{MU}$ = the emission rate for the marginal unit, and

$\textit{Generation}_{MU}$ = generation by the marginal unit in the hour in which that unit is on the margin.

The avoided emissions values shown in the exhibits below represent the averages for each pollutant over each costing period for all of New England in pounds per MWh. The emission rates are presented by modeling zone, however differences between zones tend to be relatively insignificant.

Exhibit 6-53: 2011 New England Avoided CO_2 Emissions by Modeling Zone and Pricing Period (lbs/MWh)

CO2 (lbs/MWh)	Summer		Winter		
Transarea	Off Peak	On Peak	Off Peak	On Peak	**Grand Total**
NE - Boston	1,211	1,330	1,140	1,079	**1,163**
NE - CT Central-Northeast	1,240	1,346	1,146	1,090	**1,176**
NE - CT Norwalk	1,240	1,347	1,148	1,090	**1,177**
NE - Northeast MA	1,240	1,347	1,148	1,090	**1,177**
NE - New Hampshire	1,225	1,341	1,136	1,082	**1,167**
NE - Rhode Island	1,230	1,354	1,148	1,070	**1,170**
NE - Southeast MA	1,216	1,336	1,130	1,072	**1,159**
NE - Vermont	1,216	1,335	1,131	1,072	**1,159**
NE - West Central MA	1,230	1,347	1,143	1,086	**1,172**
NE - CT Southwest	1,229	1,350	1,143	1,090	**1,174**
NE - Maine	1,201	1,306	1,133	1,005	**1,132**
Average	**1,225**	**1,340**	**1,140**	**1,075**	**1,166**

Exhibit 6-54: 2011 New England Avoided NOx Emissions by Modeling Zone and Pricing Period (lbs/MWh)

NOx (lbs/MWh)	Summer		Winter		
Transarea	Off Peak	On Peak	Off Peak	On Peak	**Grand Total**
NE - Boston	0.646	1.076	0.635	0.477	**0.708**
NE - CT Central-Northeast	0.762	1.081	0.656	0.513	**0.753**
NE - CT Norwalk	0.757	1.084	0.656	0.514	**0.753**
NE - Northeast MA	0.708	1.094	0.640	0.491	**0.733**
NE - New Hampshire	0.698	1.100	0.647	0.452	**0.724**
NE - Rhode Island	0.664	1.083	0.634	0.461	**0.711**
NE - Southeast MA	0.664	1.083	0.634	0.461	**0.711**
NE - Vermont	0.716	1.092	0.654	0.495	**0.739**
NE - West Central MA	0.729	1.101	0.654	0.506	**0.747**
NE - CT Southwest	0.757	1.084	0.656	0.514	**0.753**
NE - Maine	0.663	1.041	0.727	0.429	**0.715**
Average	**0.706**	**1.084**	**0.654**	**0.483**	**0.732**

In this 2011 AESC report, we find that CO_2 has the most significant externality. We also conclude that the long-run marginal abatement cost of CO_2 is a practical and conservative measure of the full cost of carbon. In updating our recommendation from the 2009 AESC report, we review current literature on emissions reductions necessary to avoid the most dangerous impacts of climate change, as well as analyses of technologies available to achieve those emission reductions. We recommend that the Study Group uses a marginal abatement cost value which is based on the cost of controlling emissions.[175]

For AESC 2011, we recommend using a long-run marginal abatement cost (2011$) of $80 per short ton of CO_2. This is effectively a slight reduction in real dollars from our recommendation in AESC 2009 of $80 per short ton in 2009$ ($81.52 in 2011$). This estimate is still one-third higher than the value of $63 (2011$) per short ton recommended in AESC 2007. In 2011 approximately two percent of the $80 per ton is internalized in the market price of electricity, through RGGI, and 98 percent is an externality. By 2026, we estimate that approximately 49 percent of that amount will be internalized.

[175] This is an alternative to setting value based on monetized estimates of damages.

6.6.1. History of Environmental Externalities: Policies in New England

In the 1990's several New England states had proceedings dealing with externalities that influence current utility planning and decision-making.[176] In Massachusetts, dockets DPU 89-239 and 91-131 served as models for other states. Docket DPU 89-239 was opened to develop "Rules to Implement Integrated Resource Planning" and included consideration of many aspects of IRP including determination and application of environmental externalities values. This docket adopted a set of dollar values for air emissions, including a CO_2 value of $22 per ton of CO_2 (in 1989 dollars) (Exhibit DOER-3, Exhibit. BB-2, p. 26). Docket DPU 91-131 examined environmental externalities to develop recommendations of various approaches for quantifying the CO_2 externality value. The Department's Order in Docket DPU 91-131 was noteworthy for its foresight regarding climate change, albeit optimistic about the timing of recognition of climate change into policies and regulation in the United States.[177] Based on information in the record, the Department reaffirmed the CO_2 value it had adopted in the previous case, $22 per ton (in 1989 dollars).

6.6.2. Carbon Dioxide

Externalities associated with electricity production and uses include a wide variety of air pollutants, water pollutants, and land use impacts. The list of externalities from energy production and use is quite long, and includes the following:

- Air emissions (including SO_2, NO_x and ozone, particulates, mercury, lead, other toxins, and greenhouse gases) and the associated health and ecological damages;
- Fuel cycle impacts associated with "front end" activities such as mining and transportation, and waste disposal;
- Water use and pollution;
- Land use;
- Aesthetic impacts of power plants and related facilities;
- Radiological exposures related to nuclear power plant fuel supply and operation (routine and accident scenarios);

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[176] A more detailed description of the history of electricity generation environmental externalities and policies in New England may be found in AESC 2007 (p. 7-6–7-8).

[177] AESC 2009 provides more detail about the Massachusetts DPU Order in Docket DPU 91-131.

- Other non-environmental externalities such as economic impacts (generally focused on employment), energy security, and others.

Many of these externalities have been reduced over time, as regulations limiting emission levels have forced suppliers and buyers to consider at least a portion of those costs in their production and use decisions, thereby "internalizing" a portion of those costs.[178]

We anticipate that the "carbon externality" will continue to be the dominant externality associated with marginal electricity generation in New England. This is the case for two main reasons. First, regulations to address the greenhouse gas emissions responsible for global climate change have yet to be adopted with sufficient stringency to link scientific research and evidence with long-term policy that would enable carbon-free resources to replace fossil-based generation lag, particularly in the United States.[179] The damages from the EPA's Criteria air pollutants are relatively bounded, and to a great extent "internalized," as a result of existing regulations. In contrast, global climate change is a problem on an unprecedented scale with far-reaching and potentially catastrophic implications.

Second, New England avoided electric energy costs over the study period are likely to be dominated by natural gas-fired generation, which has minimal SO_2, mercury, and particulate emissions, as well as relatively low NO_x emissions.

Based on knowledge of the electric system and review of model runs, it is believed that the dominant environmental externality in New England over the study period will be the un-internalized cost of carbon dioxide emissions. The current RGGI

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[178] For example, the Clean Air Transport Rule, while currently in draft form, is expected to adjust the SO_2 and NO_x emissions caps downward with an ultimate effect of reducing SO_2 emissions approximately 73 percent from 2003 levels. Under the draft rule, annual emissions of SO_2 are required to decline from 4.7 million tons in 2009 to 3.9 million tons by 2012, and then to 2.5 million tons by 2014, for a cumulative reduction of 47 percent over the five-year compliance period. Annual NO_x emissions are capped at 1.4 million tons. As a result, while there will be some "external costs" associated with the residual SO_2 and NO_x pollution, these externalities are now relatively small. The EPA's proposed Air Toxics Rule governing electric utilities under section 112(d) of the Clean Air Act would do the same for emissions of mercury and other air toxics, while the proposed rule under section 316(b) of the Clean Water Act would minimize the externalities associated with the impingement and entrainment of aquatic organisms from power plant cooling water intake systems.

[179] On April 17, 2009; EPA issued a proposed finding that concluded that greenhouse gases posed an endangerment to public health and welfare under the Clean Air Act ("Proposed Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act" 74 Fed. Register 78: 18886–18910). This proposed finding initiates the process of potentially regulating greenhouse gases as an air pollutant. http://epa.gov/climatechange/endangerment.html

auctions and any federal CO_2 regulations only internalize a portion of the "greenhouse gas externality," particularly in the near term. Values were developed for the one major emission associated with avoided electricity costs for which the near-term internalized cost most significantly understates the value supported by current science.

6.6.3. General Approaches to Monetizing Environmental Externalities

There are various methods available for monetizing environmental externalities such as air pollution from power plants. These include various "damage costing" approaches that seek to value the damages associated with a particular externality, and various "control cost" approaches that seek to quantify the marginal cost of controlling a particular pollutant (thus internalizing a portion or all of the externality).

The "damage costing" methods generally rely on travel costs, hedonic pricing, and contingent valuation in the absence of market prices. These are forms of "implied" valuation, asking complex and hypothetical survey questions, or extrapolating from observed behavior. For example, data on how much people will spend on travel, subsistence, and equipment, can be used to measure the value of those fish, or more accurately the value of *not* killing fish via air or water pollution. Human lives are sometimes valued based upon wage differentials for jobs that expose workers to different risks of mortality. In other words, comparing two jobs – one with higher hourly pay rate and higher risk than the other – can serve as a measure of the compensation that someone is "willing to accept" in order to be exposed to the risk.

There are myriad problems with these approaches, two of which will be discussed here. The damage costing approaches are, in the case of global climate change, simply subject to too many problematic assumptions. We do not subscribe to the view that a reasonable economic estimate of the "damages" around the world can be developed and used as a figure for the externalities associated with carbon dioxide emissions. In other words, estimating damage is a moving target–it depends upon what concentrations we ultimately reach (or what concentrations we reach and then reduce). This is exacerbated by the fact that we do not fully understand what changes in the earth's climate might occur assuming carbon dioxide concentrations continue to increase past the current 380 parts per million, toward a projected 450 parts per million (or even higher) climate change, and cannot project with certainty the levels at which certain impacts will occur.

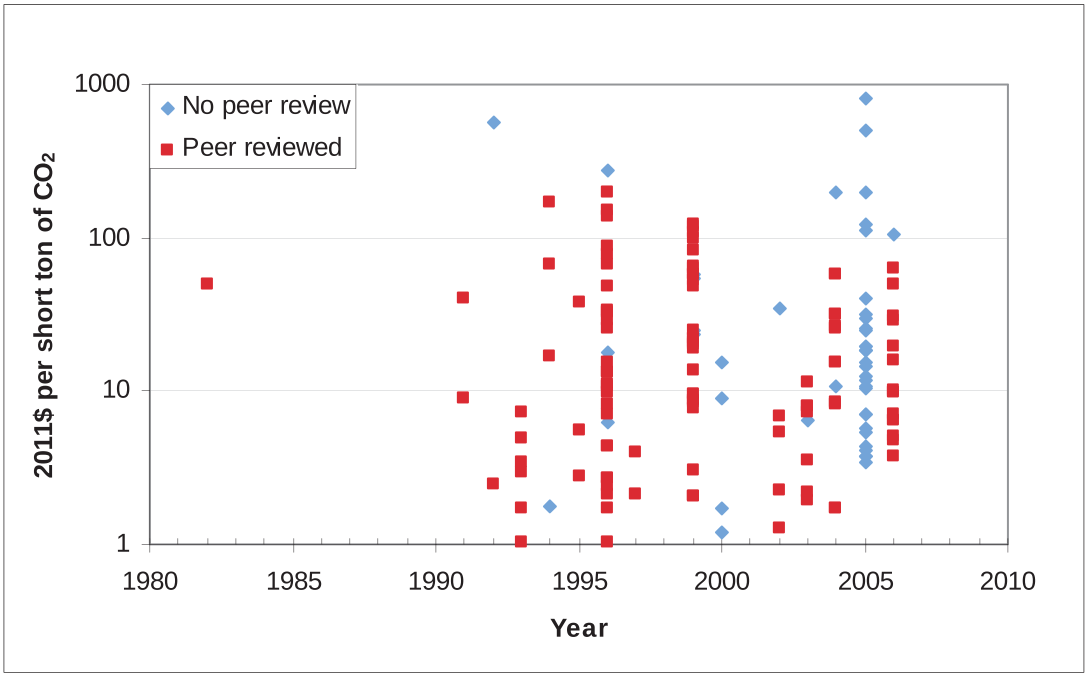
A further complicating factor is that different emissions concentrations create different damages for different regions and different groups of people. Estimating damages is fraught with difficulties including: (a) identifying the categories of changes to ecosystems and societies around the planet; (b) estimating magnitudes of impacts; (c) valuing those impacts in economic terms; (d) aggregating those values across countries with different currency exchange rates and different cultures; (e) addressing the non-linear and catastrophic aspects of the climate change damage; and (f) dealing with the paradoxes and conundrums involved in applying financial discount rates to effects stretching over centuries.

These difficulties are evident when examining various existing damage estimates. A meta-study from 2008 by author Richard Tol compares 211 estimates of this "social cost of carbon," which represents the economic costs of the damages from climate change aggregated across the globe and discounted to the present.[180] These estimates come from 47 studies done between 1982 and 2006.[181] The figure below shows a scatter plot of these estimates over time. The social cost of carbon is shown on the vertical axis, expressed in 2011 dollars per short ton of CO_2. Due to the wide range of the distribution, this value is expressed in log terms. The year of the study is shown on the horizontal axis. These studies use different methodologies, discount rates, damage functions, physical impacts of climate change, and equity weightings across individuals in different parts of the world, all of which are reflected in the resulting damage cost estimates. Hence, estimates vary across time and no particular pattern emerges when examined together.

[180] Tol, Richard S.J. *The Social cost of Carbon: Trends, Outliers and* Catastrophes. Economics E-Journal. Vol 2, 2008-25. August 12, 2008.

[181] It should be noted that many of the studies included in the meta-analysis were authored or co-authored by Richard Tol.

Exhibit 6-55: Scatter Plot of Converted Values of Tol 2009 Societal Cost of Carbon



Conversely, the “control cost” methods generally look at the *marginal* cost of control. That is, the cost of control valuations look at the last (or most expensive) unit of emissions reduction required to comply with regulations. The cost of control approach can be based upon a “regulators’ revealed preference” concept. That is, if “air regulators” are requiring a particular technology with a cost per ton of $X to be installed at power plants, then this can be taken as an indication that the value of those reductions is perceived to be at or above the cost of the controls. The fact that the “regulators’ revealed preferences” approach is unavailable, as regulators have not established relevant reference points, complicates the task of determining a carbon externality cost. The cost of control approach can also be based upon a “sustainability target” concept. With the sustainability target, we start with a level of damage or risk that is considered to be acceptable, and then estimate the marginal cost of achieving that target. It is important to note that, at this stage in our collective understanding of the science of climate change, as well as its social, economic, and physical impacts, the notion of a “sustainability target” is a construct useful for discussion, but not yet firmly established.

The “sustainability target” approach relies on the assumption that the nations of the world will not tolerate unlimited damages. It also relies partly on an expectation that policy leaders will realize that it is cheaper to reduce emissions now and achieve a sustainability target than it is not to address climate change. It is worth noting that a cost estimate based on a sustainability target will be a bit lower than a damage cost estimate because the "sustainability target" is going to be a calculus of what climate change the planet is already committed to, and what additional change we are willing to live with (again complicated by the fact that different regions will see different impacts, and have different ideas about what is dangerous and what is sustainable).

6.6.4. Estimation of CO_2 Environmental Costs

Based upon our review of the merits of those various approaches, we selected an approach that estimates the cost of controlling, or stabilizing, global carbon emissions at a "sustainable level" or sustainability target. To develop that estimate, the most recent science regarding the level of emissions that would be sustainable was reviewed, as well as the literature on costs of controlling emissions at that level.

The conceptual and practical challenges for estimating a carbon externality price include the following:

- The damages are very widely distributed in time (over many decades or even centuries) and space (across the globe);
- The "physical damages" include some impacts that are very difficult to quantify and value, such as flooding large land areas; changes to local climates; species range migration; increased risk of flood and drought; changes in the amount, intensity, frequency, and type of precipitation; changes in the type, frequency, and intensity of extreme weather events (such as hurricanes, heat waves, and heavy precipitation);
- This list of "physical damages" includes some that are extremely difficult, perhaps impossible, to reasonably express in monetary terms;
- The scientific understanding of the climate change process and climate change impacts is evolving rapidly;
- There may well be reasons (not considered here) that the environmental cost value could have a shape that starts lower and increases faster, or vice versa, having to do with periods in which rates of change are most problematic;
- The scale of the impact on the world economies associated with the impacts of climate change and/or associated with the transformations of economies to reduce greenhouse gas emissions are so large that using terms and concepts such as "marginal" can be problematic; and

The impacts of climate change are non-linear and non-continuous, including "feedback cycles" that can most reasonably be thought of in terms of thresholds beyond which there are “run away damages” such as irreversible melting of the Greenland ice sheet and the West Antarctic ice sheet, and collapse of the Atlantic thermohaline circulation—a global ocean current system that circulates warm surface waters.

Given the daunting challenge of valuing climate damages in economic terms, we propose taking a practical approach consistent with the concepts of “sustainability” and “avoidance of undue risk.” Specifically, the carbon externality can be valued by looking at the marginal costs associated with controlling total carbon emissions at, or below, the levels that avoid the major climate change risks according to current expectations.

Nonetheless, because the environmental costs of energy production and use are so significant, and because the climate change impacts associated with power plant carbon dioxide emissions are urgently important, it is worthwhile to attempt to estimate the externality price and to put it in dollar terms that can be incorporated into electric system planning.

6.6.4.1. What is Current Understanding of the Correct Level of CO_2 Emissions?

In order to determine what is currently deemed a reasonable sustainability target, we reviewed current science and predicted policy impacts that have been released since AESC 2009.

We reviewed several sources to determine reasonable assumptions about what level of concentrations are deemed likely to achieve the sustainability target and what emission reductions are necessary to reach those emissions levels. The Intergovernmental Panel on Climate Change’s most recent Assessment Report (IPCC 2007a, 15) indicates that concentrations of 445 to 490 ppm CO_2 equivalent correspond to 2^o to 2.4^oC increases above pre-industrial levels. A comprehensive assessment of the economics of climate change, Stern (2007) proposes a long-term goal to stabilize greenhouse gases at between the equivalent of 450 and 550 ppm CO_2. Recent research indicates that achieving the 2^oC goal likely requires stabilizing atmospheric concentrations of carbon dioxide and other heat-trapping gases near 400 ppm carbon dioxide equivalent (Meinshausen 2006).

The Intergovernmental Panel on Climate Change (IPCC 2007, Table SPM5) indicates that reaching concentrations of 450 to 490 ppm CO_2 equivalent requires reduction in global CO_2 emissions in 2050 of 50 to 85 percent below 2000 emissions levels. Stern (2007, xi) says that global emissions would have to be 70 percent below current levels by 2050 for stabilization at 450 ppm CO_2 equivalent. To accomplish such stabilization, the United States and other industrialized countries would have to reduce greenhouse gas emissions on the order of 80 to 90 percent below 1990 levels, and developing countries would have to achieve reductions from their baseline trajectory as soon as possible (den Elzen and Meinshausen, 2006).

In the United States, several states have adopted state greenhouse gas reduction targets of 50 percent or more reduction from a baseline of 1990 levels or then-current levels by 2050 (California, Connecticut, Illinois, Maine, New Hampshire, New Jersey, Oregon, and Vermont). The state of Massachusetts has set targets for even greater reductions of greenhouse gases. The Global Warming Solutions Act (GWSA) was signed into law by Governor Deval Patrick in August 2008. The Act calls for initial reductions in greenhouse gas emissions of between 10 percent and 25 percent below 1990 levels by 2020. In the *Massachusetts Clean Energy and Climate Plan for 2020*, released on December 29, 2010 by the Massachusetts Executive Office of Energy and Environmental Affairs, the reduction target was set at 25 percent below 1990 levels. The Global Warming Solutions Act also has emissions reduction targets for 2030 and 2040, leading to an emissions reductions target of 80 percent below 1990 levels by 2050.

6.6.4.2. Cost of Stabilizing CO_2 Emissions

There have been several efforts to estimate the costs of achieving a variety of atmospheric concentration targets. The most comprehensive effort is the work of the Intergovernmental Panel on Climate Change. The IPCC was established by the World Meteorological Organization and UNEP in 1988 to provide scientific, technical and methodological support and analysis on climate change. IPCC has issued four assessment reports on the science of climate change, climate change impacts, and on mitigation and adaptation strategies (in 1990, 1995, 2001, 2007). The IPCC’s Fifth Assessment Report is due in 2014.

IPCC (2007a) indicates that reductions on the order of 34 gigatons would be necessary to achieve an 80 percent reduction below current emission levels. [182] IPCC (2007b, p. 45) estimates that up to 31 gigatons in reductions are available for $98 per short ton of CO_2 or less (Working Group III Summary for Policy Makers) in 2011 dollars.[183]

For the 2011 AESC, we have examined other more recent studies, produced since July 2009, on the costs of achieving stabilization targets that include the following, and converted the given values to 2011$ per short ton of CO_2:

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[182] 2000 emissions levels were 43Gt CO_2-eq. IPCC (2007a).

[183] This value, expressed in Table TS.3 in 2006 dollars per metric ton, is $97 per short ton of CO_2 in 2011 dollars ($100 metric ton of $CO_2 \times 1.07$ [2006 to 2011 GDP values] $\times$ (1 metric ton/1.102 short ton)).

- In 2010 McKinsey and Company (McKinsey 2010) released an update to its second version of the Global Greenhouse Gas Abatement Cost Curve[184] in order to examine the impacts of the global financial crisis on carbon economics and emissions reductions.[185] The analysis came to the conclusion that the global financial crisis and resulting economic downturn has had a small impact on long-term emissions, and thus the size of the required emission reductions remains essentially the same. A stabilization level of 550 ppm, consistent with a temperature increase of 3°C, would result in a marginal abatement cost of $101 per short ton of CO_2. McKinsey increased its estimate from $75 per short ton in 2009 in order to include known carbon capture and storage (CCS) controls. The amount of energy necessary to run CCS controls leads to increases in the CO_2 abatement cost. Achieving a stabilization level of 450 ppm, consistent with a temperature increase of 2°C, would result in a marginal abatement cost of $126 per short ton.[186]
- In the World Energy Outlook 2010, the International Energy Agency (IEA 2010a) has modeled the implications and results of three international policy framework scenarios: (1) the Current Policies Scenario, in which country CO_2 policies are held constant as of mid-2010; (2) the New Policies Scenario, which takes into account broad policy commitments and plans that countries have announced but not yet implemented; and (3) the 450 Scenario, which stabilizes CO_2 levels at 450 ppm to limit temperature increase to 2°C. Under the Current Policies Scenario, the IEA projects carbon prices of $46 per short ton of CO_2 in 2035, and a price of $39 per short ton under the New Policies Scenario. Prices under the 450 Scenario are projected to be $111 per short ton for OECD+ countries and $83 per short ton for Other Major Economies. [187]

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[184] The original Global Greenhouse Gas Abatement Cost Curve was released in 2007. The second version was released in 2009. The 2010 update is known as Version 2.1 of the Global Greenhouse Gas Abatement Cost Curve.

[185] McKinsey and Company did not update technology projections, but rather focused on updating the macroeconomic effects on emissions in the business-as-usual (BAU) scenario, and the resulting impact on emission reduction economics. A small number of model upgrades and enhancements were also performed.

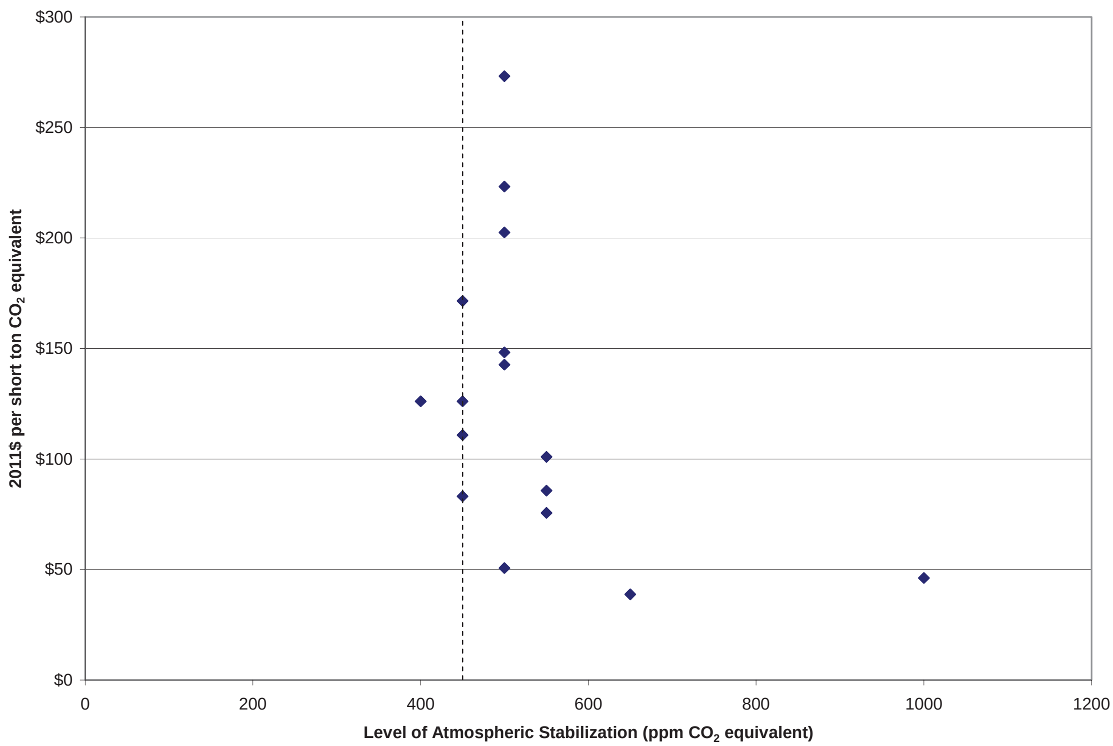
[186] The report values are expressed in 2005 Euros per metric ton of CO_2 of 80 and 100 Euros respectively.

[187] OECD+ countries include all OECD countries, as well as non-OECD countries in the European Union. Other Major Economies includes Brazil, China, the Middle East, Russia, and South Africa.

- The IEA examines four policy scenarios in its Technology Perspectives 2010, all of which reduce emissions of CO_2 by 50 percent from 2005 levels by 2050. In the Blue Map Scenario, these targets are achieved at a cost of $163 per short ton. If carbon capture and sequestration technologies are not available, the marginal cost of abatement increases to $273 per short ton. In the Blue Map case with high amounts of nuclear power, abatement cost is $148 per short ton. Finally, in the Blue Map case with high renewables, controls costs are $142 per short ton.

The results of these studies mentioned above, as well as additional studies by the same entities[188], are summarized in Exhibit 6-56. The dotted line is drawn at the value of atmospheric stabilization of 450 ppm CO_2 equivalent, which corresponds to a global temperature increase of 2^oC above pre-industrial levels.

Exhibit 6-56: Summary Chart of Marginal Abatement Cost Studies



188 These additional studies include: (1) McKinsey & Company. 2009. "Pathways to a Low-Carbon Economy: Version 2 of the Global Greenhouse Gas Abatement Cost Curve."; (2) International Energy Agency. 2008a. *World Energy Outlook 2008*. Paris: International Energy Agency.; and (3) International Energy Agency. 2008b. *Energy Technology Perspectives 2008: Scenarios and Strategies to 2050*. Paris: International Energy Agency.

We recommend that the estimated long-run marginal abatement cost be used as a practical and reasonable measure of the societal cost of carbon dioxide emissions. This can be applied to carbon dioxide emissions reductions, derived from lower electricity generation as a result of energy efficiency, in order to quantify their "full value." A portion of this value will be reflected in the allowance price for emissions, and thus internalized in the avoided costs; the balance may be referred to as an externality. Based on a review of these different sources, and our experience and judgment on the topic, we believe that it is reasonable to use an estimated long-term marginal abatement cost (LT MAC) of $80 per short tCO_2 equivalent (2011$) in evaluating the cost-effectiveness of energy efficiency measures. This estimate is essentially the same as our AESC 2009 estimate for the LT MAC of $81.52 per short tCO_2 equivalent (2011$).

Thus, states that have established targets for climate mitigation comparable to the targets discussed in this Chapter, or that are contemplating such action, could view the $80/ton long term abatement cost as a reasonable estimate of the societal cost of carbon emissions, and hence as the long-term value of reductions in carbon emissions required to achieve those targets.

Estimates of long-run marginal abatement costs include a degree of uncertainty. These reflect the underlying assumptions about a variety of effects, among them the extent of technological innovation, the selected emission reduction targets, the technical potential of certain technologies, and international and national policy initiatives, along with a variety of other influencing factors. Of course, selection of this value requires multiple assumptions and cannot be definitive given the quickly evolving combination of scientific understanding of the causes, effects and scale of climate change, international policy initiatives, and technological advances. It will be necessary to continuously review available information, and determine what value is reasonable given information available at the time of reviews. A value of $80 per short ton of CO_2 reflects our experience that actual costs tend to be lower than modeled values,[189] and is a reasonable estimate of the long-run marginal abatement costs for achieving a stabilization target that is likely to avoid temperature increases higher than 2^{o}C above pre-industrial levels.

6.6.5. Estimating CO_2 Environmental Costs for New England

Our estimates of the "external" or additional cost associated with emissions of carbon dioxide in New England are based upon the sustainability target and the

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[189] The long-run marginal abatement value of $80 per short ton CO_2 is slightly lower outside the range shown in Exhibit 6-6. The lowest value that would achieve atmospheric stabilization at 450 ppm as shown in the Exhibit is approximately $83.

forecast of carbon emission regulation in New England over the study period. The externality value for carbon dioxide in each year was calculated as the estimated long term marginal abatement cost of $80 per short ton minus the annual allowance values internalized in the projected electric energy market prices. For AESC 2011, we repeat this calculation process for the RGGI only scenario. These values are summarized in Exhibit 6-57.

Exhibit 6-57: CO_2 Externality Calculations

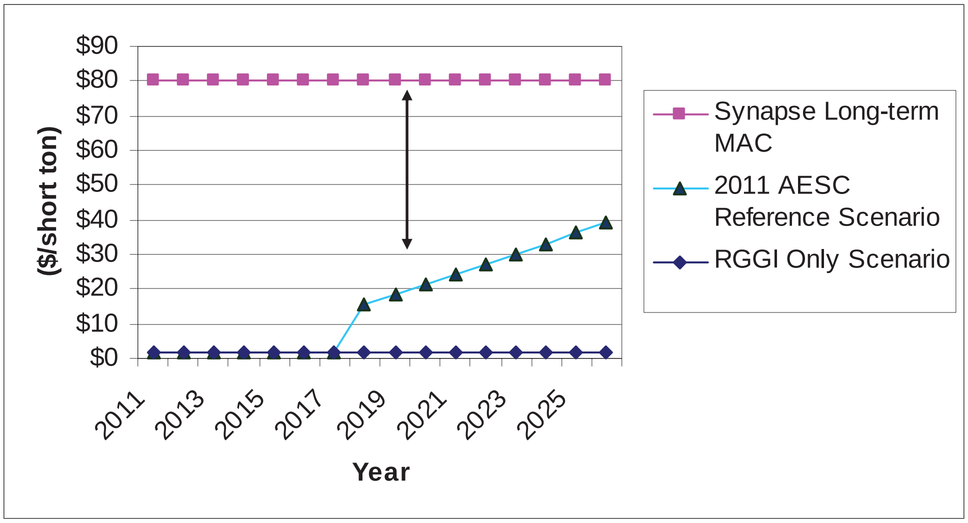
	LT MAC ($/short ton)	2011 AESC Reference Allowance Price ($/short ton)	2011 AESC Reference Externality ($/short ton)	RGGI Only Scenario Allowance Price ($/short ton)	RGGI Only Scenario Externality ($/short ton)
	a	b	c=a-b	d	e=a-d
2011	$80	$1.89	***$78.11***	$1.89	***$78.11***
2012	$80	$1.89	***$78.11***	$1.89	***$78.11***
2013	$80	$1.89	***$78.11***	$1.89	***$78.11***
2014	$80	$1.89	***$78.11***	$1.89	***$78.11***
2015	$80	$1.89	***$78.11***	$1.89	***$78.11***
2016	$80	$1.89	***$78.11***	$1.89	***$78.11***
2017	$80	$1.89	***$78.11***	$1.89	***$78.11***
2018	$80	$15.30	***$64.70***	$1.89	***$78.11***
2019	$80	$18.28	***$61.72***	$1.89	***$78.11***
2020	$80	$21.25	***$58.75***	$1.89	***$78.11***
2021	$80	$24.23	***$55.77***	$1.89	***$78.11***
2022	$80	$27.20	***$52.80***	$1.89	***$78.11***
2023	$80	$30.18	***$49.82***	$1.89	***$78.11***
2024	$80	$33.15	***$46.85***	$1.89	***$78.11***
2025	$80	$36.13	***$43.87***	$1.89	***$78.11***
2026	$80	$39.10	***$40.90***	$1.89	***$78.11***

Notes
Values expressed in 2011 Dollars
Allowance Prices from Exhibit 2-4
Inflation rate of 2%

The annual allowance values internalized in the projected electric energy market prices are shown in column b of Exhibit 6-57. The values are based upon a Synapse (Johnston 2011) forecast of the carbon trading price associated with anticipated carbon regulations starting in 2018. That carbon price was included in the dispatch model runs (in the generators' bids) and hence is embedded within the AESC 2011 avoided electricity costs. The additional value in each year is the difference between the estimate of long run marginal abatement cost ($80 per ton CO_2) and the value of the carbon trading price embedded in the projection of wholesale electric energy prices.

Exhibit 6-58 illustrates how the additional CO_2 cost was determined. The line for the allowance price is based on the forecast of carbon allowance costs, illustrating the notion that the United States will gradually move to incorporate the climate externality into policy. The "externality" is simply the difference between the estimate of the long-term marginal abatement cost (LT MAC) and the anticipated allowance cost; that is, the area above the line with triangles and below $80 per ton in the graph (shown between the double arrowed vertical line).

Exhibit 6-58: Determination of the Additional Cost of CO_2 Emissions



The carbon dioxide externality price forecast is presented above as a single simple price. This is for ease of application and because doing something more complex, such as varying the shape over time or developing a distribution to represent uncertainty, would go beyond the scope of this project and would stretch the available information upon which the externality price is based. We fully acknowledge the many complexities involved in estimating a carbon price, both conceptual and practical.

With regard to environmental costs, AESC 2011 focuses on the externality value of carbon dioxide for the purpose of screening DSM programs. There are, of course, many impacts of electric power production. A number of those impacts are listed above in Chapter 2. However, the bulk of displaced generation in New England will be from existing and future natural gas plants. For these, CO_2 emissions are the dominant non-internalized environmental cost.

6.6.6. Applying CO_2 Costs in Evaluations of DSM Programs

The externality values from Exhibit 6-57 above are incorporated in the avoided electricity cost workbooks and expressed as dollar per kWh based upon our analysis of the CO_2 emissions of the marginal generating units summarized in Exhibit 6-51.

At a minimum program administrators should calculate the costs and benefits of DSM programs with and without these values in order to assess their incremental impact on the cost-effectiveness of programs. However, we recommend the program administrators include these values in their analyses of DSM, unless specifically prohibited from doing so by state or local law or regulation.

The Massachusetts Department of Public Utilities recently clarified its policies with regard to the avoided costs of energy efficiency programs. In light of the requirement of the Green Communities Act[190] to implement all cost-effective energy efficiency resources, the Department opened an investigation to update its energy efficiency guidelines, including policies regarding the types of costs and benefits that can be included in cost-effectiveness screening in Massachusetts.

The Department affirmed the use of the Total Resource Cost test, and clarified how environmental benefits could be used in evaluating cost-effectiveness. The Department cited a Supreme Judicial Court (SJC) case that addressed the circumstances under which the Department may require Program Administrators to account for environmental impacts in evaluating energy resources. The SJC found that the Department could not require Program Administrators to consider environmental externalities in evaluating energy resources, as it did not have the statutory authority to do so.[191]

However, the SJC made it clear that the Department does have the authority to require Program Administrators to include the costs of compliance with current and reasonably foreseeable future environmental regulations, as these compliance costs would be incorporated in electricity prices over which the Department has clear jurisdiction. The Department identified the Global Warming Solutions Act and federal measures to control greenhouse gas emissions as examples of existing and reasonably anticipated future environmental regulations, and made it clear that "the Department expects Program Administrators to include estimates of such compliance costs in the calculation of future avoided energy costs."[192]

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[190] *An Act Relative to Green Communities*, Acts of 2008, Chapter 169, July 2, 2008.

[191] *Investigation by the Department of Public Utilities on its Own Motion into Updating its Energy Efficiency Guidelines Consistent with an Act Relative to Green Communities*, Order, DPU 08-50-A, March 16, 2009, pages 14 and 15.

[192] *Investigation by the Department of Public Utilities on its Own Motion into Updating its Energy Efficiency Guidelines Consistent with an Act Relative to Green Communities*, Order, DPU 08-50-A, March 16, 2009, page 17.

The next section explains why a DSM program could result in CO_2 emission reductions even under a cap and trade regulatory framework.

6.6.7. Impact of DSM on Carbon Emissions Under a Cap and Trade Regulatory Framework (RGGI)

The Regional Greenhouse Gas Initiative is a cap and trade greenhouse gas program for power plants in the northeastern United States. Participant states include Connecticut, Delaware, Maine, Massachusetts, New Hampshire, New York, Rhode Island, Vermont, Maryland and New Jersey.[193] Pennsylvania, the District of Columbia, the Eastern Canadian Provinces, and New Brunswick are official "observers" in the RGGI process. Eleven rounds of auctions have currently occurred.

As currently designed, the program:

- Stabilize CO_2 emissions from power plants at current levels for the period 2009-2015, followed by a 10 percent reduction below current levels by 2019;
- Allocate a minimum of 25 percent of allowances for consumer benefit and strategic energy purposes. Allowances allocated for consumer benefit will be auctioned and the proceeds of the auction used for consumer benefit and strategic energy purposes; and
- Include certain offset provisions that increase flexibility to include opportunities outside the capped electricity generation sector.

With carbon dioxide emissions regulated under a cap and trade system, as assumed in this market price analysis, it is conceivable that a load reduction from a DSM program will not lead to a reduction in the amount of total system carbon dioxide emissions. The annual total system emissions for the affected facilities in the relevant region are, after all, capped. In the analysis that was documented in this report, the relevant cap and trade regulation is the Regional Greenhouse Gas Initiative (RGGI) for the period 2011 to 2017 and an assumed national cap and trade system thereafter. However, there are a number of reasons why a DSM program could result in CO_2 emission reductions, specifically:

- Reduction in load that reduces the cost (marginal or total cost) of achieving an emissions cap can result in a tightening of the cap. This is a complex interaction between the energy system and political and economic systems,

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[193] New Jersey Governor Christie has announced that New Jersey will withdraw from RGGI at the end of 2011.

and is difficult or impossible to model, but the dynamic may reasonably be assumed to exist;

- Specific provisions in RGGI provide for a tightening or loosening of the cap (via adjustments to the offset provisions that are triggered at different price levels). It is unknown at this point whether and to what extent such "automatic" adjustments might be built into the US carbon regulatory system;
- It is also possible that DSM efforts will be accompanied by specific retirements or allocations of allowances that would cause them to have an impact on the overall system level of emissions (effectively tightening the cap); and
- To the extent that the cap and trade system "leaks" because of its geographic boundaries, one would expect the benefits of a carbon emissions reduction resulting from a DSM program to similarly "leak." That is, a load reduction in New York could cause reductions in generation (and emissions) at power plants in New York, Pennsylvania, and elsewhere. Because New York is in the RGGI cap and trade system, the emissions reductions realized at New York generating units may accrue as a result of increased sales of allowances from New York to other RGGI states. However, because Pennsylvania is not in the RGGI system, the emissions reductions at Pennsylvania generating units would be true reductions attributable to the DSM program.

The first three of these points, above, would also apply to a national CO_2 cap and trade program. The fourth point, about leakage and boundaries, would apply as well, but to a lesser extent.

6.7. Social Discount Rate

The Project Team surveyed Study Group members and other sources to summarize the real discount rate used in cost-effectiveness models for energy efficiency programs in the six New England States as well as California, New York, Oregon and Washington. Appendix C summarizes results from our survey of real discount rates.

Chapter 7: Sensitivity Analyses

Sensitivity analyses provide insights into the potential impacts of changes in key uncertain input assumptions. In addition they help increase the shelf life (or period of usability) of the report in the face of potential changes in market conditions over time. The latter benefit is particularly relevant to AESC 2011, which is typically revised every for two years. In the absence of sensitivity analysis results changes in market conditions between the time the report is distributed and the time avoided costs estimates are next updated might lead to questions about the robustness and usefulness of the analysis.

With this in mind, the Project Team working with the Study Group identified 1) natural gas prices and 2) carbon allowance prices as the key input assumptions for which sensitivity analyses should be prepared because of their uncertain nature and their large, direct impact on avoided electric-energy costs.

The major conclusions from the sensitivity analyses are:

- The annual average wholesale price of electric energy in New England would be approximately 14.3 percent higher ($71.58 versus $62.60 on a 15-year levelized basis) than our Reference Case forecast through 2026 under our natural gas High Price case, which has Henry Hub natural gas prices 17.6 percent higher than the Reference Case.
- The annual average wholesale price of electric energy in New England would be approximately 9.3 percent higher ($68.53 versus $62.60 on a 15 year levelized basis) than our Reference Case forecast through 2026 under our carbon High Price case, which has carbon compliance costs 90 percent higher on a 15-year levelized basis than the AESC 2011 Reference Case. This represents a change in the annual average wholesale price of electric energy of about $0.41/MWh for every $-per-ton change in the allowance price for CO_2 under the High Price Case relative to the Reference Case.

7.1. Sensitivity of Wholesale Electric Energy Prices to Changes in Natural Gas Prices at Henry Hub

As documented in previous chapters, natural-gas prices have a large, direct impact on avoided electric-energy costs.

For this sensitivity case we use our natural gas High Price case, under which wholesale natural gas prices are 17.6 percent higher at Henry Hub through 2026 on a 15 year levelized basis than those used in the Reference Case. The AESC natural gas High Price case is described in Chapter 3.

Henry Hub prices translate into a similar increase of 17.6 percent in the prices of natural gas delivered to electric generation units in New England, i.e. burner-tip prices.

The Henry Hub prices under the AESC natural gas Reference case and High Price case are shown in columns two and three of Exhibit 7-1. The last column in Exhibit 7-1 shows the impact on electricity prices using the high gas prices compared to the Reference Case Henry Hub natural gas.

Exhibit 7-1: Henry Hub Reference and Sensitivity Case Prices (2011$/million Btu)

Year	Reference NG Price	High NG Price	% Change in NG Price	% Change in Electricity Price
2012	$4.91	$4.91	-	-
2013	5.10	5.97	17.1%	14.7%
2014	5.29	6.22	17.6%	15.7%
2015	5.91	6.92	17.1%	15.7%
2016	5.96	7.07	18.6%	17.6%
2017	5.93	7.12	20.1%	18.3%
2018	5.95	7.24	21.7%	17.6%
2019	5.98	7.33	22.6%	17.6%
2020	6.06	7.23	19.3%	15.0%
2021	6.16	7.10	15.3%	11.9%
2022	6.25	7.28	16.5%	12.6%
2023	6.52	7.60	16.6%	12.7%
2024	6.72	7.95	18.3%	13.8%
2025	6.78	8.20	20.9%	15.1%
2026	6.89	8.40	21.9%	16.1%
Levelized	**$5.97**	**$7.02**	**17.6%**	**14.3%**

The gas prices in the High Price case do not represent variations in actual market prices of gas (e.g., weekly, monthly, or even annual). Instead, the High Price case provides a set of gas prices that reflect the range of upside uncertainty in gas prices in the long-term. Our expectation is that any revised forecasts of long-term avoided Henry Hub gas costs made prior to the anticipated AESC 2013 update would fall between the Reference Case and the High Case.

Exhibit 7-2 shows the impacts of the High Price Case gas prices on New England wholesale electric energy prices by costing period. The average 17.6 percent increase in the natural Henry Hub natural gas price results in an average 14.3 percent increase in annual wholesale electric energy prices. The level of increase varies by season and time period, but not dramatically.

Exhibit 7-2: Seasonal and Time Period Impacts of Henry Hub Price Changes

Season	Time of Day	High NG Price
Winter	Off-Peak	15.9%
	On-Peak	13.3%
	All-Hours	14.5%
Summer	Off-Peak	13.4%
	On-Peak	15.1%
	All-Hours	14.3%
Annual	All-Hours	14.3%

7.2. Sensitivity of Wholesale Electric-Energy Prices to Changes in Carbon-Dioxide-Allowance Prices

We tested the sensitivity of wholesale electric-energy prices to a range of possible changes in carbon-allowance prices in light of the uncertainty in long-run forecasts of those allowances. The low and high carbon forecast values are shown in Exhibit 7-3 below.

- The low carbon case provides a lower bound of CO_2 allowance prices for sensitivity analysis purposes. We draw the prices for this case from the "RGGI only" set of carbon dioxide allowance prices required under the scope of work.
- The high carbon price sensitivity case provides an upper bound estimate of CO_2 allowance prices for sensitivity analysis purposes. We draw the prices for this case from the February 2011 Synapse High Carbon price forecast. [194]

[194] Johnston (2011).

For Massachusetts, the CO_2 allowance prices from the High Carbon Price case may be a reasonable proxy for the avoided cost of carbon reductions required to comply with the GWSA in the absence of new energy efficiency programs. The AESC 2011 Reference Case projects carbon emissions for the Massachusetts electric sector will be approximately 25 percent below 1990 levels by 2020. Those projected reductions comply with the GWSA general sector-wide average target for 2020, but the Massachusetts Clean Energy and Climate Plan for 2020 calls upon the electric sector to achieve a greater than average level of carbon reductions. Further, we expect it will become increasingly difficult to meet increasingly stringent GWSA targets after 2020. Thus, in order to meet the GWSA targets, the electric sector will likely need to reduce emissions beyond the reductions reflected in the AESC 2011 Reference Case.

Exhibit 7-3: Carbon Dioxide Reference and Sensitivity Case Prices

	CO_2 (2011$/short ton)		
Year	Reference	RGGI Forecast	High Forecast
2012	$1.89	$1.89	$1.89
2013	1.89	1.89	1.89
2014	1.89	1.89	1.89
2015	1.89	1.89	15.30
2016	1.89	1.89	19.72
2017	1.89	1.89	24.14
2018	15.30	1.89	28.56
2019	18.28	1.89	32.98
2020	21.25	1.89	37.40
2021	24.23	1.89	41.82
2022	27.20	1.89	46.24
2023	30.18	1.89	50.66
2024	33.15	1.89	55.08
2025	36.13	1.89	59.50
2026	39.10	1.89	63.92
Levelized (2012-2026)	$15.64	$1.89	$29.94

Exhibit 7-4 shows the annual CO_2 price differences relative to the Reference Case and their impacts on the average annual wholesale energy prices. The average effect on energy prices is about $0.45/MWh on average for each $1/ton change in CO_2 prices.[195]

Exhibit 7-4: Energy Price Impacts of CO_2 Price Changes (2011$)

	Low CO_2 Price		High CO_2 Price				
Year	CO_2 Price Change ($/ton)	Energy Price Change ($/MWh)	CO_2 Price Change ($/ton)	Energy Price Change ($/MWh)	AESC 2011 Reference Case ($/MWh)	AESC 2011 High Carbon Sensitivity ($/MWh)	% Difference from Reference Case
2012	$0.00		$0.00		$48.73	$49.03	0.6%
2013	0.00		0.00		$50.27	$50.57	0.6%
2014	0.00		0.00		$51.68	$52.12	0.9%
2015	0.00		13.41	$6.66	56.21	62.87	11.8%
2016	0.00		17.83	8.70	57.33	66.03	15.2%
2017	0.00		22.25	10.37	57.64	68.00	18.0%
2018	-13.41	-$6.22	13.26	5.73	64.47	70.20	8.9%
2019	-16.39	-7.64	14.70	5.85	65.29	71.14	9.0%
2020	-19.36	-9.20	16.15	6.45	65.37	71.82	9.9%
2021	-22.34	-10.68	17.59	6.75	67.19	73.95	10.1%
2022	-25.31	-12.23	19.04	7.32	69.00	76.32	10.6%
2023	-28.29	-13.68	20.48	7.56	72.46	80.02	10.4%
2024	-31.26	-15.17	21.93	8.27	74.44	82.71	11.1%
2025	-34.24	-16.84	23.37	8.50	75.61	84.12	11.2%
2026	-37.21	-17.85	24.82	9.31	77.68	86.98	12.0%
Average	**-$25.31**	**-$12.17**	**$18.74**	**$7.62**	**62.60**	**68.53**	**9.3%**
Ratio: $/MWh vs. $/ton		0.48		0.41			

[195] The AESC 2011 results are quite close to the AESC 2009 calculated coefficient of $0.46/MWh on average for this effect, and the AESC 2011 result is consistent with the average marginal price being set by a natural gas plant with a heat rate slightly below 8,000 Btu/kWh.

Chapter 8: Usage Instructions

This Chapter provides instructions on how to apply the Reference Case avoided costs of electricity, how to estimate avoided costs of electricity for the High Gas Price sensitivity case and the High Carbon Price sensitivity case, and how to apply the Reference Case avoided costs of natural gas.

8.1. Reference Case Avoided Costs of Electricity

AESC 2011 provides detailed projections of avoided electricity costs for each New England state as well as for specific regions within Connecticut and Massachusetts. These projections are provided as two page tables in Appendix B. The EXCEL workbooks used to develop these tables are provided to Program Administrators.

Appendix B provides tables for the following reporting regions:

Exhibit 8-1: Appendix B Tables of Avoided Cost of Electricity

State	Table
Connecticut	Statewide
	Norwalk/Stamford
	Southwest Connecticut, excluding Norwalk/Stamford
	Southwest Connecticut, including Norwalk/Stamford
	Connecticut excluding all of Southwest Connecticut
Massachusetts	Statewide
	NEMA (Northeast Massachusetts)
	Massachusetts excluding NEMA
	SEMA (Southeast Massachusetts)
	WCMA (West-Central Massachusetts)
Maine	Statewide
New Hampshire	Statewide
Rhode Island	Statewide
Vermont	Statewide
Connecticut (nominal $)	Statewide
	Norwalk/Stamford
	Southwest Connecticut, excluding Norwalk/Stamford
	Southwest Connecticut, including Norwalk/Stamford
	Connecticut excluding all of Southwest Connecticut

The tables for each reporting region present avoided costs by year for the following ISO-NE defined costing periods:

- Summer On-Peak: The 16-hour block 6 am–10 pm, Monday–Friday (except ISO holidays), in the months of June–September (1,390 Hours, 15.9 percent of 8,760).[196]
- Summer Off-Peak: All other hours–10 pm–6 am, Monday–Friday, weekends, and ISO holidays in the months of June–September (1,530 Hours, 17.5 percent of 8,760).
- Winter On-Peak: The 16-hour block 6 am–10 pm, Monday–Friday (except ISO holidays), in the eight months of January–May and October–December (2,781 Hours, 31.7 percent of 8,760).
- Winter Off-peak: All other hours–10 pm-6 am, Monday–Friday, all day on weekends, and ISO holidays–in the months of January–May and October–December (3,059 Hours, 34.9 percent of 8,760)

The “all-hours” avoided electricity cost for a given year, or set of years, is equal to the hour-weighted average of avoided costs for each costing period of that year one.

All-hours avoided electricity cost = (15.9 percent *summer On-peak)+(17.5 percent *summer Off-peak)+ (31.7 * winter On-peak) + (34.9 percent * Winter Off-peak)

Page one of each reporting region table provides the following avoided cost components:

1. Avoided unit cost of electric energy;
2. Avoided unit cost of electric capacity by demand reduction bidding strategy;
3. Energy DRIPE and capacity DRIPE for 2012 installations;
4. Energy DRIPE and capacity DRIPE for 2013 installations; and
5. Avoided externality costs.

Page two of each reporting region table provides:

1. Wholesale avoided costs of electricity (energy and capacity)
2. Avoided REC costs to load
3. 2012 Energy DRIPE values
4. 2013 Energy DRIPE values

Each table provides illustrative levelized values for each category of avoided cost at the bottom of each cost column. These are computed using a real discount rate of 2.46 percent.

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196 ISO-NE holidays are New Year’s Day, Memorial Day, July 4th, Labor Day, Thanksgiving Day, and Christmas.

8.2. Worksheet Structure and Terminology

For each reporting region / zone there is a two page table of avoided electricity costs.

8.2.1. Page One—Avoided Cost of Electricity Results

Reading from left to right the structure of page one of each table is as follows:

8.2.1.1. User Defined Inputs

The tables have the following default values for the following three input assumptions:

1. Wholesale Risk Premium – 9 percent[197],
2. Real Discount Rate – 2.46 percent
3. Percent of Capacity Bid into the FCM – 50 percent

Users may insert their own values for any or all of those three input assumptions.

8.2.1.2. Avoided Unit Cost of Electric Energy ($/kWh) (Columns a – d)

Avoided energy costs are presented by year for each of the four energy costing periods–Winter On-Peak, Winter Off-Peak, Summer-On Peak, and Summer Off-Peak.[198]

The generalized avoided energy cost in each period is calculated as: (modeled avoided wholesale energy cost + avoided renewable energy certificate cost) * (1 + wholesale risk premium).

8.2.1.3. Avoided Unit Cost of Electric Capacity, $/kW-yr (Columns e – g)

This section provides values for a PA to calculate the avoided capacity cost based on a simplified bidding strategy consisting of x percent of demand reductions from measures in each year bid into the FCA for that year and the remaining 1-x percent not bid in to any FCA. The default value for x is 50 percent. Users can insert their own input for that value in the user-defined inputs section of Table One. (See section 8.8.1 for a discussion of energy efficiency and the capacity market).

The components of the avoided capacity cost are as follows:

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[197] The wholesale risk premium for Vermont is 11.1% per Vermont DPS.

[198] The avoided energy costs are computed for the aggregate load shape in each zone by costing period, and are applicable to DSM programs reducing load roughly in proportion to existing load. Other resources, such as load management and distributed generation, may have very different load shapes and significantly different avoided energy costs. Baseload resources, such as combined-heat-and-power (CHP) systems, would tend to have lower avoided costs per kWh. Peaking resources, such as most non-CHP distributed generation and load management, would tend to have higher avoided costs per kWh.

- The Avoided Unit Cost of Capacity of a kW bid into the FCM in column e reflects an 8 percent adjustment to reflect losses from the customer meter to the ISO-NE delivery point.
- The Avoided Unit Cost of Capacity in column f for avoided capacity not bid into an FCA reflects upward adjustments for the wholesale risk premium, the reserve margin in that year, and also a 1.9 percent adjustment to reflect PTF losses. Because FCA auctions are set three years in advance of the actual delivery year, avoided capacity *not* bid into a FCA will not impact ISO-NE's determination of forecasted peak until 2016 for measures installed in 2012.
- The Weighted Average *Capacity Value* based on % bid in column g is the *weighted average* avoided capacity of column e and f reflecting an individual PA's percent of capacity that is bid into the Forward Capacity Market. The column presents a weighted average of 50 percent bid default value that may be changed by PA's to reflect specific bidding strategies.

Under this approach the avoided capacity cost in each year is equal to the Weighted Average *Capacity Value* in column g for the relevant year multiplied by the demand reduction in that year.

8.2.1.4. Demand-Reduction-Induced Price Effects (DRIPE) (Columns h – q)

Each table provides separate projections of energy DRIPE and capacity DRIPE for measures implemented in 2012 and in 2013 respectively.

The energy DRIPE values reported in each table reflect the relevant state regulations governing treatment of energy DRIPE. For Massachusetts and Connecticut zones, the energy DRIPE values are intrastate values only. For Maine, Vermont, Rhode Island and New Hampshire, the energy DRIPE values reflect both intrastate and rest of pool values.

The AESC 2011 capacity DRIPE values start in 2016 due to floor prices set through FCA 6 as described in Chapter 6.

8.2.1.5. Carbon Dioxide Avoided Externality Costs $/kWh (Columns r – u)

This section of the worksheet table provides estimates of CO_2 externality values developed for this Study (values for RI are from the RGGI only scenario). CO_2 externality values are presented by year for each of the four energy costing periods.

8.2.2. Page Two—Inputs to Avoided Cost Calculations

Reading from left to right the structure of page two is as follows:

8.2.2.1. Wholesale Avoided Costs of Electricity Energy. $ per kWh (Columns v – y)

The wholesale electric energy prices are from the Market Analytics simulation runs described in the description of the model results in Chapter 6. Values for RI are from the

RGGI only scenario described in the Chapter 7 Sensitivity Scenarios. Users should not normally need to use the input values directly, or to modify these values.

8.2.2.2. Capacity, $ per kW-year (Column z and aa)

The wholesale electric capacity prices and reserve margin requirements are from the relevant Chapter 6 sections. Users should not normally need to use the input values directly, or to modify these values.

8.2.2.3. Avoided REC Costs to Load $/kWh (Column ab)

The avoided REC costs are calculated based on REC prices and RPS requirements that are described in detail in Chapter 6. Users should not normally need to use the input values directly, or to modify these values.

8.2.2.4. Energy DRIPE Values $/kWh (Columns ac – ar)

The energy DRIPE values are calculated based energy DRIPE factors described in detail in Chapter 6. The Appendix B workbooks present both Intrastate and Rest of Pool energy DRIPE values for 2012 and 2013 installations. Users should not normally need to use the input values directly, or to modify these values.

8.3. Guide to Applying the Avoided Costs

Users have the ability to specify certain inputs as well as to choose which of the avoided cost components to include in their analyses.

8.3.1. User-Specified Inputs

The avoided cost results are based upon default values for three inputs that users can specify. They are 1) the wholesale risk premium of 9 percent (11.1% for Vermont) , 2) the real discount rate of 2.46 percent, and 3) a percentage of capacity bid into the Forward Capacity Market of 50 percent. The Excel workbook is designed to allow Program Administrators to specify their preferred values for those three inputs in the top left section of page one of each worksheet.

If a user wishes to specify a different value for any of the inputs, the user should enter the *new* value directly in the worksheet. The calculations in the worksheet are linked to these values and new avoided costs will be calculated automatically

Program administrators are responsible for developing and applying estimates of avoided transmission and distribution costs for their own specific system that would be **separate** inputs to the values in the provided tables. An application of avoided transmission and distribution costs is described below in Section 8.3.6.

8.3.2. Avoided Costs of Energy

Calculating the quantity reduction benefits of energy reductions in a given year requires an estimate of losses from the ISO delivery points to the end use in addition to an estimate of the reduction at the meter. Each PA should obtain, or calculate, the losses applicable to its specific system as discussed below in Section 8.6.

These avoided costs should be estimated as follows:

1. Reduction in winter peak energy at the end use
× winter peak energy losses from the ISO delivery points to the end use
× the *Winter Peak Energy* value for that year by costing period;

2. Reduction in winter off-peak energy at the end use
× winter off-peak energy losses from the ISO delivery points to the end use
× the *Winter Off-Peak Energy* value for that year by costing period;

3. Reduction in summer peak energy at the end use
× summer peak energy losses from the ISO delivery points to the end use
× the *Summer Peak Energy* value for that year by costing period;

4. Reduction in summer off-peak energy at the end use
× summer peak off-energy losses from the ISO delivery points to the end use
× the *Summer Off-Peak Energy* value for that year by costing period.

8.3.3. Capacity Costs Avoided by Reductions in Peak Demand

The quantity benefit of a reduction in peak demand in a given year will depend upon the approach the PA has taken and/or will take towards bidding the reduction in demand from the efficiency program in that year into the applicable FCAs. As discussed in the Capacity section of Chapter 6, a PA may achieve avoided capacity costs from reductions in peak demand through a range of approaches.

A PA will bid some percent of demand reduction into Forward Capacity Market, and withhold the remaining percent of demand reduction since there are issues of timing and funding that may not allow a PA to bid the full quantity of demand reduction with confidence. A PA would therefore obtain a combination of the value of the capacity that is bid into the FCM (highest value) as described in Section 8.3.3.1 and the market capacity value of a reduction in peak load (lowest value) as described in Section 8.3.3.2 based on the percent of capacity that is bid into the FCM.

Following are descriptions of how a PA can calculate the avoided cost of reductions in peak demand for the two extreme approaches and the simplified user-specified bid strategy.

8.3.3.1. Value of 100% Bid of demand reduction from first program year into the first relevant FCA (Column e)

A PA will obtain the highest benefit for the reductions in peak demand from an energy efficiency program by bidding the full anticipated reduction into the FCA for the first power year in which that program would produce reductions. Thus, a PA responsible for an efficiency program that is expected to start January 2012 would have had to have bid 100% of the anticipated reduction in demand from that program into FCA 3, which was held in 2009 for the power year starting June 1, 2012. There is some financial risk associated with bidding in advance, in particular the potential a regulator may not approve the anticipated program budget and/or the possibility the program may fail to produce the anticipated level of demand reductions.

The benefit of a reduction in peak demand from either an On-Peak or a Seasonal Peak resource in a given year starting 2012 is estimated as the result of:

> Average MW reduction at the meter for the relevant period in a given year
>
> × the Avoided Unit Cost of Capacity bid if a kW bid into the FCM for that year, which incorporates the market-clearing price in the forward capacity market and an ISO-NE loss factor of 8%.

If the benefits of demand reductions are to include capacity DRIPE, the benefits calculated above should be increased by the estimate of capacity DRIPE allowed under the regulatory framework applicable to that screening zone as follows:

> Average MW reduction at the meter bid into FCA for given year
> × capacity DRIPE for that year

8.3.3.2. Value of Zero Percent Bid of demand reduction into any FCA (column f)

For an efficiency program that produces reductions starting in 2012, there is no benefit of a reduction in peak demand until 2016, at which point the annual benefit is calculated as follows:

> MW reduction at the meter during system peak in a given year
>
> × summer peak-hour losses from the ISO delivery points to the end use
> × the Avoided Unit Cost of Capacity for that year, which is the FCA price for that year adjusted upward by the reserve margin that ISO-NE requires for that year, by the PTF losses, and the wholesale risk premium.

8.3.3.3. Value of 50 Percent Bid of demand reduction into FCM (Column g)

The column reflects a 50 percent weighted average of demand reduction into Forward Capacity Market. A PA would therefore obtain 50 percent of the value of the capacity that is bid into the FCM (highest value) as described in Section 8.3.3.1 and 50 percent of the market capacity value of a reduction in peak load (lowest value) as described in Section 8.3.3.2 based on the default percentage.

8.3.4. DRIPE

The provided workbook tables include energy and capacity DRIPE values based on installation year 2012 and 2013.

8.3.4.1. Capacity DRIPE

The price benefits of demand reductions are capacity DRIPE. A PA can estimate capacity DRIPE for 2012 and 2013 installations:

MW reduction at the meter during system peak in a given year

× summer peak-hour losses from the ISO delivery points to the end use
× capacity DRIPE for that year

8.3.4.2. Avoided Cost of Energy DRIPE

The price benefits of energy reductions are energy DRIPE. A PA can estimate energy DRIPE for 2012 and 2013 installations:

1. Reduction in annual winter on peak energy at the end use
× winter peak energy losses from ISO delivery to the end use
× the Winter On Peak Energy DRIPE;
2. Reduction in annual winter off-peak energy at the end use
× winter off-peak energy losses from ISO delivery to the end use
× the Winter Off-Peak Energy DRIPE;
3. Reduction in annual summer on peak energy at the end use
× summer peak energy losses from ISO delivery to the end use
× the Summer On Peak Energy DRIPE;
4. Reduction in annual summer off-peak energy at the end use
× summer off-peak energy losses from ISO delivery to the end use
× the Summer Off-Peak Energy DRIPE;

8.3.5. Avoided Cost of Carbon Externalities

The carbon externalities can be calculated as follows:

1. Reduction in winter peak energy at the end use
× winter peak energy losses from the ISO delivery points to the end use
× the *CO_2 Externality Winter On Peak Energy* value for that year,
2. Reduction in winter off-peak energy at the end use
× winter off-peak energy losses from the ISO delivery points to the end use
× the *CO_2 Externality Winter Off-Peak Energy* value for that year,
3. Reduction in summer peak energy at the end use
× summer peak energy losses from the ISO delivery points to the end use
× the *CO_2 Externality Summer On Peak Energy* value for that year,

4. Reduction in summer off-peak energy at the end use
× summer off-peak energy losses from the ISO delivery points to the end use
× the CO_2 *Externality Summer Off-Peak Energy* value for that year

8.3.6. Local T&D Capacity Costs Avoided by Reductions in Peak Demand

Although not part of the provided tables, and should be based upon specific PA information, the benefits of peak demand reductions of avoided local transmission and distribution costs can be calculated as follows:

Reduction in the peak demand used in estimating avoided transmission and distribution costs at the end use

× the utility-specific estimate of avoided T&D costs in $/kW-year.[199]

8.4. Levelization Calculations

Illustrative levelized costs for each of the direct avoided costs are presented along the bottom of each table. These values are calculated for three periods (2012-2021, 2012-26, and 2012-41), using a 2.46 percent real discount rate assumed throughout this project.

For levelization calculations outside the three periods documented in the workbook, the following inputs are required:

- The real discount rate of 2.46 percent or other user specified discount rate
- The number or periods over the levelizing time frame. For instance, the period 2012-2021 contains 10 periods
- The avoided costs within the levelizing period

The Excel formula used to calculate levelized values in the workbook is:

$$\text{Present Value} = -PMT(Discount\_Rate, Period, (NPV(Discount\_Rate, Annual\_\text{cos}ts\_within\_period)$$

8.5. Converting Constant 2011 Dollars to Nominal Dollars

Unless specifically noted, all dollar values in AESC 2011 are presented in 2011 constant dollars. To convert constant dollars into nominal (current) dollars, a user would follow the formula:

$$\text{Nominal Value} = \frac{\text{Constant Value}_{2011\$}}{Conversion\ Factor\ to\ 2011\$}$$

[199] Most demand-response and load-management programs will not avoid transmission and distribution costs, since they are as likely to shift local loads to new hours as to reduce local peak load.

For instance, in order to convert an AESC 2011 $1 in 2012 into nominal 2012 dollars, one would use the AESC 2011 conversion factor from 2012 to 2011 of 0.98. Inserting the conversion factor into the equation above (Nominal Value_{2012} = ($\$1_{2011\$}$/0.98)) results in a value of $1.02 in nominal dollars.

The AESC 2011 conversion factors are presented in Appendix A, Exhibit A-3.

8.6. Comparisons to AESC 2009 Reference Case Avoided Costs of Electricity

A PA can prepare a comparison of the fifteen year levelized avoided costs of electricity from AESC 2011 for a given reporting location and costing period to the corresponding AESC 2009 results, such as the comparison presented in Exhibit 1-1, as follows:

- Identify the relevant reporting location and costing period
- For the relevant reporting location and costing period, obtain the yearly values of each component from AESC 2009 Appendix B. The potential components are avoided energy costs, avoided capacity costs (by type of bidding strategy), energy DRIPE, capacity DRIPE and carbon externality.
- Convert the AESC 2009 yearly values for each component from $2009 to $2011
- Calculate the 15 year levelized values of each AESC 2009 component
- For the relevant reporting location and costing period, obtain the fifteen year values of each component from AESC 2011 Appendix B.

8.7. Utility-Specific Costs to be Added/Considered by Program Administrators Not Included in Worksheets

This section details additional inputs that are not specifically included in the worksheet and not part of the AESC 2011 scope of work, but should be considered by program administrators.

8.7.1. Losses between the ISO Delivery Point and the End Use

The avoided energy and capacity costs, and the estimates of DRIPE, include energy and capacity losses on the ISO-administered pool transmission facilities (PTF), from the generator to the delivery points at which the PTF system connects to local non-PTF transmission or to distribution substations.

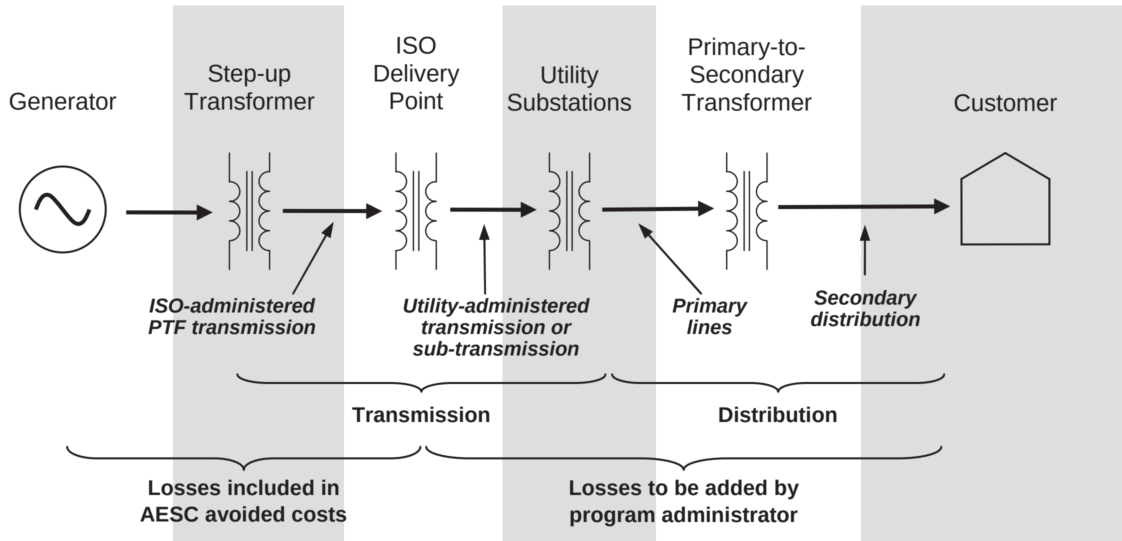
The presented values ***do not*** include the following losses:

- Losses over the non-PTF transmission substations and lines to distribution substations;
- Losses in distribution substations,

- Losses from the distribution substations to the line transformers on primary feeders and laterals,[200]
- Losses from the line transformers over the secondary lines and services to the customer meter,[201]
- Losses from the customer meter to the end use.

See Exhibit 8-2 that schematically illustrates the many types of losses on transmission and distribution systems highlighted in the list above.

Exhibit 8-2: Delivery-System Structure and Losses



In most cases, DSM program administrators measure demand savings from DSM programs at the end use. To be more comprehensive, the program administrator should estimate the losses from delivery points to the end uses. For example, if the energy delivered to the utility at the PTF is *a*, losses are *b*, and the customer received energy is *c*,

- Losses as a fraction of deliveries to the utility are $b \div a$,
- Losses as a fraction of deliveries to customers are $b \div c$.

[200] In some cases, this may involve multiple stages of transformers and distribution, as (for example) power is transformed from 115kV transmission to 34kV primary distribution and then to 14 kV primary distribution and then to 4 kV primary distribution, to which the line transformer is connected.

[201] Some customers receive their power from the utility at primary voltage. Since virtually all electricity is used at secondary voltages, these customers generally have line transformers on the customer side of the meter and secondary distribution within the customer facility.

Hence, each kilowatt or kilowatt-hour saved at the end use saves $1 + b/c$. The program administrator should estimate that ratio and multiply the end-use savings or benefits by that loss ratio. Loss ratios will be generally higher for higher-load periods than lower-load periods, since losses in wires (both within transformers and in lines) vary with the square of the load, for a given voltage and conductor type.

If the change in load does not change the capacity of the transmission and distribution system, then the losses should be computed as marginal losses, which are roughly twice the percentage as average line losses for the same load level.[202] Energy savings and/or growth do not generally result in changing the wire sizes. Hence, for energy avoided costs, losses are estimated on a marginal basis, so *a*, *b*, and *c* above are increments or derivatives, rather than total load values.

If the change in load results in a proportional change in transmission and distribution capacity, losses should be computed as the average losses for that load level. If the program administrator treats all load-carrying parts of the transmission and distribution as avoidable and varying with peak load, then only average losses should be applied to avoided capacity costs.

8.8. Energy Efficiency Programs and the Capacity Market

An energy efficiency program that produces a reduction in peak demand has the ability to avoid the wholesale capacity cost associated with that reduction. The capacity-cost amount that a particular reduction in peak demand will avoid in a given year will depend upon the approach that the program administrator responsible for that energy efficiency program takes towards bidding all, or some, of that reduction into the applicable FCAs.

A program administrator (PA) can choose an approach that ranges between bidding 100 percent of the anticipated demand reduction from the program into the relevant FCAs to bidding zero percent of the anticipated reduction into any FCA.

- A PA that wishes to bid 100 percent of the anticipated demand reduction from the program into the relevant FCA has to do so when that FCA is conducted, which can be up to three years in advance of the program implementation year. For example, a PA responsible for an efficiency program that will be implemented starting January 2012 would have had to have bid 100 percent of the forecast demand reduction for June 2012 onwards from that program into FCA 3, which was held in 2009. Since a bid is a firm financial commitment, there is an associated financial risk if the PA is unable to actually deliver the full demand

[202] In this sense, "line losses" does not include the no-load losses that result from eddy currents in the cores of transformers. These are often called "iron" losses (since transformer cores were historically made of iron), in contrast to the load-related "copper" losses of the lines and transformer windings.

reduction for whatever reason. The value of this approach is the compensation paid by ISO-NE, i.e. the quantity of peak reduction each year times the FCA price for the corresponding year.

- If a PA does not bid any of the anticipated demand reduction into any FCA, the program can still avoid some capacity costs if it has a measure life longer than three years.[203] Under this approach, a PA responsible for an efficiency program starting January 2012 simply implements that program. The customers' contribution to the ISO peak load, whenever that occurs in the summer of 2012, would be lower due to the program. This PA's customers would see some benefit from a lower capacity share starting in June 2013 (the following year). The reduced capacity requirement will reduce the capacity acquired in future FCAs, starting as early as the reconfiguration auctions for the power year starting in June 2013 and affecting all the auctions for the power years from June 2016 onward; the entire region will benefit from the reduction of capacity purchases.

Exhibit 8-3 below illustrates the various approaches that a Program Administrator could choose for avoiding wholesale capacity costs via a hypothetical energy efficiency measure that is implemented in 2012 and produces a 100 kW reduction for a five year period, 2012 to 2016. In this example, the PA considers three approaches.

The first approach is to bid 100 percent of the projected reduction, 100 kW, into each of the relevant FCAs. Under this approach the reduction avoids capacity costs roughly equals to its revenues from the FCM each year, i.e., l to 100 kW times the FCA price in each of the five years, 2012 through 2016.[204] However the PA would have had to bid that 100-kW reduction, scheduled to start in 2012, into each FCA from FCA 3 onward.

The second approach is to bid none of the projected reductions into any FCA. Under this approach the reduction avoids capacity costs equal to the value of the reduction in installed capacity it causes in 2016. That value is 100 kW increased by the reserve margin (15 percent for illustrative purposes) in 2016 and multiplied by the FCA price in 2016. The avoided capacity cost is limited to the impact in 2016 because ISO-NE sets the ICR) to be acquired in each power year three years in advance of that year. Thus, in this approach, ISO-NE would first see the 100 kW reduction as a lower actual peak load in

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[203] In many cases, the PA is a utility; in other cases it is a state agency or other entity. In any case, the reduction in load benefits the customers served by the PA, whether they pay for generation supply through a utility standard-offer supply, an aggregator, or a competitive supplier.

[204] The price paid to a capacity resource in any year can vary from the price paid by load-serving entities by various factors, including PER deductions, availability penalties, multi-year prices for new resources, local reliability costs, etc.

2012. However, 2016 is the earliest power year for which ISO-NE could reflect the actual reduction in 2012 because, by July 2013 ISO-NE will have forecast peak load for 2016, set the ICR for 2016 and run the FCA for 2016.

The third illustrated approach is to bid 50 percent of the projected reduction, 50 kW, into each of the relevant FCAs.

Other approaches, not illustrated in Exhibit 8-3, would include bidding an increasing percentage of the 2012 load reduction into FCA3 and future auctions, as the PA becomes more confident in its estimates of the demonstrable savings.

Exhibit 8-3: Illustration of Alternative Approaches to Capturing Value from Reductions in Peak Demands

Hypothetical measure installed in 2010, reduces peak by 100 kw for 5 years								
ISO-NE sets NICR and Conducts FCA			Example 1—PA bids 100% of expected demand reduction into each corresponding FCA		Example 2—PA bids zero expected demand reduction into each corresponding FCA		Example 3—PA bids 50% of expected demand reduction into each corresponding FCA	
FCA #	**Calendar year**	FCA for power year Starting	Reduction Bid into FCA	Impact of Reduction on NICR set for power year	Reduction Bid into FCA	Impact of Reduction on NICR set for power year	Reduction Bid into FCA	Impact of Reduction on NICR set for power year
			kw	kw	kw	kw	kw	kw
3	2009	6/1/2012	100		0		50	
4	2010	6/1/2013	100		0		50	
5	2011	6/1/2014	100		0		50	
6	2012	6/1/2015	100	0	0	0	50	0
7	2013	6/1/2016	100	0	0	0	50	0
8	2014	6/1/2017	0	0		0	0	0
9	2015	6/1/2018	0	0		0	0	0
10	2016	6/1/2019	0	0		**115**	0	**57.5**

8.9. Sensitivity Case Avoided Costs of Electricity

Chapter 7 provides avoided wholesale electric energy costs for a High Gas Price sensitivity case and for a High Carbon Price sensitivity case. Calculating the complete avoided cost of electricity under each of those sensitivity cases is not included in the AESC 2011 Scope of Work. However, a PA could use the results from those sensitivity cases to develop approximate estimates of the avoided costs of electricity for either, or both sensitivity cases.

The estimates developed through th**e** approach **described below** will be approximate because they **will** not reflect the changes in various components, relative to Reference Case values, that would occur with a change in wholesale electric energy costs. For example, an increase in wholesale electric energy costs under the High Gas Price would cause a decrease in the REC cost component.

8.9.1. High Gas Price Sensitivity Case

A PA could develop an approximate estimate of the fifteen year levelized avoided costs of electricity for the High Gas Price sensitivity case for a given reporting location by multiplying the wholesale avoided costs of electric energy for that location, on page two of the relevant Appendix B workbook, in each of the columns v, w, x and y, by 1.143 for each of the years 2012 through 2026. (The factor of 1.143 is the 14.3 percent increase reported in Exhibit 7-2 of Chapter 7 on an annual basis).[205]

8.9.2. High Carbon Price Sensitivity Case

A PA could develop an approximate estimate of the fifteen year levelized avoided costs of electricity for the High Carbon Price sensitivity case for a given reporting location by multiplying the wholesale avoided costs of electric energy for that location, on page two of the relevant Appendix B workbook, in each of the columns v, w, x and y, by 1.093 for each of the years 2012 through 2026. (The factor of 1.093 is the 9.3 percent average increase reported in Exhibit 7-4 of Chapter 7).[206]

8.10. Guide to Applying the Avoided Natural Gas Costs

The avoided cost for each end use by sector and the retail sector is the sum of the avoided cost of the gas sent out by the LDC and the avoidable distribution cost, called the avoidable LDC margin, applicable from the city gate to the burner tip for some LDCs. Other LDCs assume they will not avoid any distribution costs due to reductions in gas use from efficiency measures. For the LDCs with no avoided distribution cost, the avoided cost of gas by end-use is their avoided cost of gas delivered to their city-gate. Users will need to determine if the LDC has avoidable LDC margins or not.

Appendix D provides by end use of the value streams of avoided natural gas costs for both avoidable margins and no avoidable margins. These columns refer to 1) non-heating, 2) heating, and 3) all by sector.

Non-heating value streams apply to year round end-uses such as hot water where usage is generally constant over the year. As noted in Chapter 4, we find that non-heating uses represent 30 percent of usage in New England.

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[205] Exhibit 7-2 provides the impact by costing period. Using the costing period values provides a more precise approximation that accounts for seasonal differences.

[206] Exhibit 7-4 provides the annual impact of the high carbon prices through 2026.

Heating value streams apply to heating end-uses where usage is high during winter months. As noted in Chapter 4, we find that heating uses represent 70 percent of usage for New England.

All value streams are the weighted average of heating (70 percent) and non-heating (30 percent) avoided costs.

For each program and/or measure, users should choose the appropriate value stream to determine the avoided cost benefit stream in evaluating cost-effectiveness.

Appendix A: Common Financial Parameters for AESC 2011

AESC 2011 requires converting nominal dollars to constant 2011 dollars (2011$) as well as a using real discount rate for calculating illustrative levelized avoided costs, although the published workbooks in Appendix B allows users to specify their own discount rate.

AESC 2011 uses a long-term inflation rate and a real discount rate. Those values are summarized below:

Exhibit A-1: Summary of Common Financial Parameters AESC 2009 versus AESC 2011

	AESC 2009	AESC 2011
Inflation Rate	2.00%	2.00%
Real Discount Rate	2.22%	2.46%

Inflation Rate

AESC 2011 uses a forecast of long-term inflation rate of 2.00 percent. The 2.00 percent inflation is consistent with the twenty year annual average inflation rate from 1990 to 2010, of 2.16 percent, derived from the Gross Domestic Product (GDP) chain-type price index. In light of the current economic conditions, the Project Team also examined projections of long-term inflation made by the Congressional Budget Office (CBO) in January 2011. The CBO projections of long-term inflation are 2.0 percent.[1]

Real Discount Rate

AESC 2011 requires the calculation of illustrative levelized avoided costs expressed in 2011$ for intervals of 1) 10 years (2012-2021), 2) 15 years (2012-2026), and 3) 30 years (2012-2041) using an identified real discount rate.[2]

The derived the real discount rate for AESC 2011 is based upon February 2011 nominal rates of return for 30-year Treasury Bonds and the forecast long-term inflation rate (2.00 percent) according to this formula[3]:

Real discount rate = ((1+nominal long-term rate)/(1+inflation rate)-1)

This formula results a real discount rate of 2.46 percent that can be used for calculations of levelized costs through periods as long as thirty years. The AESC 2011 real discount rate is moderately higher than the rate of 2.22 percent used in AESC 2009. For comparison purposes we examined projections made by the CBO of nominal rates of

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[1] CBO, *The Budget and Economic Outlook: Fiscal Years 2011 to 2021*, Summary page xi. Available at http://www.cbo.gov/doc.cfm?index=12039. Accessed on May 17, 2011.
[2] The Excel workbooks allow members of the Study Group to input any discount rate to calculate levelized avoided costs.
[3] This approach was used in AESC 2005, 2007, and 2009.

return for 10-year Treasury notes for the 2017-2021 period.[4] The CBO projections of nominal rates of return, which are in the order of 5.4 percent, result real discount rates of over 3.3 percent based on forecast inflation of 2.0 percent. However, because we are calculating levelized costs through periods as long as thirty years we are proposing to use a real discount rate of **2.46** percent. Exhi presents a summary of the values we compared.

Conversion to Constant 2011$

AESC 2011 requires all forecasts to be expressed in real 2011$. Therefore, the project team developed a set of inflators to convert nominal dollars from prior years (pre-2011) into 2011$ and a set of deflators to convert nominal dollars from future years (post-2011) into 2011$. The inflator and deflator values are presented in Exhibit.

The inflators are calculated from the Gross Domestic Product (GDP) chain-type price index published by the US Department of Commerce's Bureau of Economic Analysis (BEA).[5] Deflators for future values use the long-term inflation rate of 2.00 percent.

Escalation Assumptions for Various Avoided Cost Components

The Project Team developed escalation assumptions used to extrapolate the forecasts from 2027 through 2041. For example, for the period from 2027 to 2041 for the annual wholesale energy prices, AESC 2011 uses an escalation assumption based on the (2021-2026) compound annual growth rate of 2.94 percent based on the Market Analytics Results. For other value streams of avoided cost components, we note the escalation assumptions.

[4] Summary Table 2, CBO (2011).
[5] BEA, Table 1.1.9 Implicit Price Deflators for Gross Domestic Product, downloaded 2/15/2011.

Exhibit A-2: Comparison of Real Discount Rate Estimates

Comparative Estimates of Financial Parameters						
Parameter / Source	**AESC 2005**	**AESC 2007**	**AESC 2009**	**AESC 2011 Proposed 2/17/11**	**Congressional Budget Office (1, 2)**	
					Jan-2009	**Jan-2011**
Long Term Nominal Rate	4.32%	4.77%	3.78%	4.51%	5.40%	5.40%
Source	30 year T-Bills as of Spring 2005	30 year T-Bills as of March 2007	30 year T-Bills as of March 2009	30 year T-Bills as of February 2011	Forecast - 10 yr T notes 2013 - 2019	Forecast - 10 yr T notes 2017-2021
Inflation Rate (GDP Deflator)	2.25%	2.50%	2.00%	**2.00%**	1.90%	2.00%
Source	Consistent with long-term historic average inflation.	Consistent with 20 year historic average inflation.	Less than 20 year historic average inflation of 2.44%, but lowered in response to economic forecasts.	Consistent with 20 year historic average inflation of 2.16%, but slightly lower to reflect economic forecasts.	Consistent with GDP price index 2013 - 2019 forecast.	Consistent with GDP price index 2015 - 2021 forecast.
Long Term Real Rate (%)	2.02%	2.22%	2.22%	**2.46%**	3.43%	3.33%
Source	Derived from nominal rate for treasuries and inflation rate.					

CBO Sources:

1 *The Budget and Economic Outlook: Fiscal Years 2009 to 2019*, Congressional Budget Office, January 2009, Table B-1

2 *The Budget and Economic Outlook: Fiscal Years 2011 to 2021*, Congressional Budget Office, January 2011, Summary introduction and Table 2.

Exhibit A-3: GDP Price Index and Inflation Rate

Year	GDP Chain-Type Price Index	Annual Inflation	Conversion from nominal $ to 2011$
1990	72.20	0.00%	1.546
1991	74.76	3.54%	1.493
1992	76.53	2.37%	1.459
1993	78.22	2.21%	1.427
1994	79.87	2.11%	1.398
1995	81.54	2.08%	1.369
1996	83.09	1.90%	1.344
1997	84.56	1.77%	1.320
1998	85.51	1.13%	1.306
1999	86.77	1.47%	1.287
2000	88.65	2.17%	1.259
2001	90.65	2.26%	1.232
2002	92.12	1.62%	1.212
2003	94.10	2.15%	1.187
2004	96.77	2.84%	1.154
2005	100.00	3.34%	1.116
2006	103.26	3.26%	1.081
2007	106.30	2.94%	1.050
2008	108.62	2.19%	1.028
2009	109.62	0.92%	1.019
2010	110.65	0.95%	1.009
2011	**111.65**	**0.90%**[6]	**1.000**
2012	113.88	2.00%	0.980
2013	116.16	2.00%	0.961
2014	118.48	2.00%	0.942
2015	120.85	2.00%	0.924
2016	123.27	2.00%	0.906
2017	125.74	2.00%	0.888
2018	128.25	2.00%	0.871
2019	130.82	2.00%	0.853
2020	133.43	2.00%	0.837
2021	136.10	2.00%	0.820
2022	138.82	2.00%	0.804
2023	141.60	2.00%	0.788
2024	144.43	2.00%	0.773
2025	147.32	2.00%	0.758
2026	150.27	2.00%	0.743
2027	153.27	2.00%	0.728
2028	156.34	2.00%	0.714
2029	159.46	2.00%	0.700
2030	162.65	2.00%	0.686

[6] Ibid, page 41: "The GDP price index will rise 0.9 percent in 2011…"

Appendix B: Avoided Electricity Cost Results

Avoided Cost of Electricity (2011$) Results :

State CT

CT
Connecticut (Statewide)

Page One of Two

User-defined Inputs			
Wholesale Risk Premium (WRP)	9%	Percent of Capacity Bid into FCM (%Bid)	50.0%
Real Discount Rate	2.46%		

	Avoided Unit Cost of Electric Energy[1]				Avoided Unit Cost of Electric Capacity[2]			DRIPE: 2012 vintage measures, Intrastate Values – Energy				DRIPE: 2012 – Capacity (See note 2)	DRIPE: 2013 vintage measures, Intrastate Values – Energy				DRIPE: 2013 – Capacity (See note 2)	Avoided Externality Costs			
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	kW bid into FCA (PA to determine quantity)[3]	kW not bid into FCM (PA to determine quantity)	Weighted Average Avoided Cost Based on Percent Capacity Bid	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kw-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e=z*1.08 for ISO-NE losses	f=z*(1+aa)*(1+PTF Loss of 1.9%)*(1+WRP)	g=(e*%Bid)+(f*(1-%Bid))	h	i	j	k	l	m	n	o	p	q	r	s	t	u
2011	0.057	0.048	0.064	0.046														0.042	0.043	0.041	0.045
2012	0.059	0.050	0.070	0.050	37.50	0.00	18.75	0.018	0.017	0.034	0.023	$0.00						0.042	0.043	0.041	0.045
2013	0.060	0.052	0.073	0.051	36.76	0.00	18.38	0.018	0.018	0.034	0.023	$0.00	0.018	0.018	0.035	0.024	$0.00	0.042	0.043	0.041	0.045
2014	0.062	0.054	0.075	0.053	36.76	0.00	18.38	0.019	0.018	0.036	0.024	$0.00	0.019	0.019	0.037	0.025	$0.00	0.042	0.043	0.041	0.045
2015	0.068	0.059	0.080	0.058	36.76	0.00	18.38	0.021	0.020	0.039	0.027	$0.00	0.021	0.021	0.040	0.028	$0.00	0.042	0.043	0.041	0.045
2016	0.069	0.059	0.087	0.059	15.09	18.01	16.55	0.020	0.019	0.040	0.026	$43.85	0.021	0.021	0.044	0.028	$43.85	0.042	0.043	0.041	0.045
2017	0.070	0.061	0.087	0.058	22.21	26.54	24.37	0.020	0.020	0.040	0.025	$44.38	0.020	0.020	0.041	0.026	$44.38	0.042	0.043	0.041	0.045
2018	0.075	0.067	0.097	0.065	31.01	37.09	34.05	0.022	0.022	0.045	0.028	$44.76	0.022	0.022	0.046	0.029	$44.76	0.035	0.036	0.034	0.037
2019	0.075	0.068	0.094	0.065	34.80	41.66	38.23	0.022	0.022	0.043	0.029	$43.11	0.022	0.023	0.044	0.029	$43.11	0.034	0.034	0.033	0.035
2020	0.078	0.068	0.091	0.067	48.69	58.34	53.52	0.011	0.011	0.020	0.014	$14.36	0.011	0.022	0.042	0.029	$14.36	0.032	0.033	0.031	0.034
2021	0.079	0.070	0.091	0.068	49.61	59.51	54.56	0.010	0.010	0.019	0.013	$14.50	0.010	0.012	0.021	0.015	$14.50	0.030	0.031	0.030	0.032
2022	0.082	0.072	0.094	0.071	74.46	89.42	81.94	0.009	0.009	0.017	0.012	$145.89	0.009	0.011	0.019	0.014	$145.89	0.029	0.029	0.028	0.030
2023	0.087	0.076	0.099	0.075	89.72	107.86	98.79	0.008	0.008	0.015	0.011	$71.93	0.009	0.010	0.018	0.013	$71.93	0.027	0.028	0.026	0.029
2024	0.090	0.078	0.101	0.077	98.16	118.14	108.15	0.007	0.007	0.013	0.010	$34.39	0.008	0.009	0.016	0.011	$34.39	0.025	0.026	0.025	0.027
2025	0.091	0.079	0.102	0.079	101.86	122.72	112.29					$17.51					$17.51	0.024	0.024	0.023	0.025
2026	0.092	0.080	0.105	0.079	104.09	125.53	114.81					$7.56					$7.56	0.022	0.023	0.022	0.023
2027	0.095	0.082	0.108	0.081	104.98	126.75	115.86											0.022	0.023	0.022	0.023
2028	0.098	0.084	0.111	0.083	105.49	127.51	116.50											0.022	0.023	0.022	0.023
2029	0.101	0.086	0.114	0.086	105.62	127.81	116.72											0.022	0.023	0.022	0.023
2030	0.104	0.089	0.117	0.088	105.75	128.11	116.93											0.022	0.023	0.022	0.023
2031	0.107	0.091	0.120	0.091	105.88	128.41	117.15											0.022	0.023	0.022	0.023
2032	0.110	0.093	0.124	0.094	105.88	128.55	117.22											0.022	0.023	0.022	0.023
2033	0.114	0.096	0.127	0.097	105.88	128.70	117.29											0.022	0.023	0.022	0.023
2034	0.117	0.099	0.131	0.099	105.88	128.84	117.36											0.022	0.023	0.022	0.023
2035	0.121	0.101	0.135	0.102	105.88	128.99	117.43											0.022	0.023	0.022	0.023
2036	0.125	0.104	0.138	0.106	105.88	129.13	117.51											0.022	0.023	0.022	0.023
2037	0.129	0.107	0.142	0.109	105.88	129.28	117.58											0.022	0.023	0.022	0.023
2038	0.133	0.110	0.146	0.112	105.88	129.43	117.65											0.022	0.023	0.022	0.023
2039	0.137	0.113	0.151	0.116	105.88	129.57	117.73											0.022	0.023	0.022	0.023
2040	0.141	0.116	0.155	0.119	105.88	129.72	117.80											0.022	0.023	0.022	0.023
2041	0.146	0.120	0.159	0.123	105.88	129.87	117.88											0.022	0.023	0.022	0.023
Levelized Costs																					
10 years (2012-2021)	0.069	0.060	0.084	0.059	34.73	22.58	28.65	0.018	0.018	0.035	0.023	19.77	0.017	0.018	0.035	0.024	20.25	0.039	0.040	0.038	0.041
15 years (2012-2026)	0.075	0.065	0.089	0.064	51.93	48.94	50.44	0.014	0.014	0.028	0.019	30.72	0.014	0.015	0.028	0.019	31.48	0.035	0.036	0.034	0.037
30 years (2012-2041)	0.092	0.079	0.106	0.078	73.99	81.60	77.80											0.030	0.030	0.029	0.031

NOTES:

General: All Avoided Costs are in Year 2011 Dollars
ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 7 AM - 11 PM; Off-Peak Hours are all other hours

1 Avoided cost of electric energy = (wholesale energy avoided cost + REC cost to load) * risk premium, e.g. A= (V + AB) * (1+Wholesale Risk Premium)

2 Absolute value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year and PA strategy about bidding that reduction into applicable FCAs, and unit values in columns e, f, l and q.

3 Proceeds from selling into the FCM include the reserve margin, in addition to the ISO-NE loss factor of 8%

Page Two: Inputs to Avoided Cost Calculations

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Zone: CT

	Wholesale Avoided Costs of Electricity						Avoided REC Costs to Load
	Energy				Capacity		
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	FCA Price	Reserve Margin	REC Costs
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	%	$/kWh
Period:	v	w	x	y	z	aa	ab
2011	0.051	0.043	0.057	0.041	43.20		0.0016
2012	0.052	0.044	0.063	0.044	34.72	16.6%	0.0019
2013	0.053	0.046	0.065	0.045	34.04	15.7%	0.0021
2014	0.055	0.047	0.066	0.046	34.04	17.7%	0.0023
2015	0.060	0.051	0.071	0.050	34.04	15.9%	0.0027
2016	0.060	0.051	0.077	0.051	13.98	16.0%	0.0030
2017	0.061	0.052	0.077	0.050	20.56	16.2%	0.0033
2018	0.067	0.059	0.086	0.057	28.72	16.3%	0.0024
2019	0.068	0.061	0.085	0.058	32.22	16.4%	0.0014
2020	0.070	0.060	0.081	0.059	45.08	16.5%	0.0018
2021	0.071	0.063	0.083	0.061	45.94	16.6%	0.0011
2022	0.073	0.064	0.084	0.063	68.95	16.8%	0.0018
2023	0.077	0.067	0.088	0.066	83.08	16.9%	0.0025
2024	0.080	0.069	0.090	0.068	90.89	17.0%	0.0026
2025	0.081	0.070	0.091	0.070	94.32	17.1%	0.0020
2026	0.083	0.072	0.095	0.071	96.38	17.3%	0.0012
2027	0.086	0.074	0.098	0.073	97.20	17.4%	0.0011
2028	0.089	0.076	0.101	0.075	97.68	17.5%	0.0010
2029	0.091	0.078	0.104	0.078	97.80	17.7%	0.0009
2030	0.094	0.080	0.107	0.080	97.92	17.8%	0.0008
2031	0.097	0.083	0.110	0.083	98.04	17.9%	0.0008
2032	0.100	0.085	0.113	0.085	98.04	18.1%	0.0008
2033	0.104	0.087	0.116	0.088	98.04	18.2%	0.0008
2034	0.107	0.090	0.119	0.090	98.04	18.3%	0.0008
2035	0.110	0.092	0.123	0.093	98.04	18.5%	0.0008
2036	0.114	0.095	0.126	0.096	98.04	18.6%	0.0008
2037	0.117	0.097	0.130	0.099	98.04	18.7%	0.0008
2038	0.121	0.100	0.133	0.102	98.04	18.9%	0.0008
2039	0.125	0.103	0.137	0.105	98.04	19.0%	0.0008
2040	0.129	0.106	0.141	0.108	98.04	19.1%	0.0008
2041	0.133	0.109	0.145	0.112	98.04	19.3%	0.0008
Levelized Cos							
10 years (2012-2021)	0.061	0.053	0.075	0.052	32.15		0.002
15 years (2012-2026)	0.066	0.058	0.079	0.056	48.09		0.002
30 years (2012-2041)	0.083	0.071	0.095	0.070	68.51		0.002

	2012 Energy DRIPE Values								2013 Energy DRIPE Values							
	Intrastate Installation				Rest of Pool Installation				Intrastate Installation				Rest of Pool Installation			
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh
Period:	ac	ad	ae	af	ag	ah	ai	aj	ak	al	am	an	ao	ap	aq	ar
2011																
2012	0.018	0.017	0.034	0.023	0.025	0.018	0.035	0.020	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2013	0.018	0.018	0.034	0.023	0.026	0.019	0.036	0.020	0.018	0.018	0.035	0.024	0.026	0.019	0.037	0.021
2014	0.019	0.018	0.036	0.024	0.026	0.019	0.037	0.020	0.019	0.019	0.037	0.025	0.027	0.020	0.038	0.021
2015	0.021	0.020	0.039	0.027	0.028	0.021	0.039	0.022	0.021	0.021	0.040	0.028	0.029	0.021	0.040	0.023
2016	0.020	0.019	0.040	0.026	0.027	0.019	0.040	0.021	0.021	0.021	0.044	0.028	0.029	0.021	0.043	0.023
2017	0.020	0.020	0.040	0.025	0.027	0.020	0.040	0.021	0.020	0.020	0.041	0.026	0.027	0.020	0.041	0.021
2018	0.022	0.022	0.045	0.028	0.030	0.022	0.044	0.024	0.022	0.022	0.046	0.029	0.030	0.023	0.045	0.024
2019	0.022	0.022	0.043	0.029	0.030	0.023	0.043	0.024	0.022	0.023	0.044	0.029	0.030	0.023	0.044	0.024
2020	0.011	0.011	0.020	0.014	0.015	0.011	0.020	0.012	0.011	0.022	0.042	0.029	0.015	0.023	0.042	0.024
2021	0.010	0.010	0.019	0.013	0.014	0.010	0.019	0.011	0.010	0.012	0.021	0.015	0.014	0.012	0.021	0.012
2022	0.009	0.009	0.017	0.012	0.012	0.009	0.017	0.010	0.009	0.011	0.019	0.014	0.013	0.011	0.019	0.011
2023	0.008	0.008	0.015	0.011	0.011	0.008	0.015	0.009	0.009	0.010	0.018	0.013	0.012	0.010	0.018	0.011
2024	0.007	0.007	0.013	0.010	0.010	0.007	0.013	0.008	0.008	0.009	0.016	0.011	0.010	0.009	0.016	0.009
2025	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.008	0.014	0.010	0.000	0.008	0.013	0.008
2026	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2027																
2028																
2029																
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2033																
2034																
2035																
2036																
2037																
2038																
2039																
2040																
2041																
Levelized Cos																
10 years (2012-2021)	0.018	0.018	0.035	0.023	0.025	0.018	0.035	0.020	0.017	0.018	0.035	0.023	0.023	0.018	0.035	0.019
15 years (2012-2026)	0.014	0.014	0.028	0.019	0.020	0.014	0.028	0.016	0.013	0.015	0.028	0.019	0.018	0.015	0.028	0.016
30 years (2012-2041)	0.008	0.008	0.016	0.011	0.012	0.009	0.016	0.009	0.008	0.009	0.017	0.011	0.011	0.009	0.017	0.009

NOTES: General — All Avoided Costs are in Year 2011 Dollars

ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are all other hours

Revised August 11, 2011

Avoided Cost of Electricity (2011$) Results :

State CT

CT-NS
Norwalk/Stamford

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User-defined Inputs			
Wholesale Risk Premium (WRP)	9%	Percent of Capacity Bid into FCM (%Bid)	50.0%
Real Discount Rate	2.46%		

	Avoided Unit Cost of Electric Energy[1]				Avoided Unit Cost of Electric Capacity[2]			DRIPE: 2012 vintage measures Intrastate Values					DRIPE: 2013 vintage measures Intrastate Values					Avoided Externality Costs			
								Energy				Capacity (See note 2)	Energy				Capacity (See note 2)				
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	kW bid into FCA (PA to determine quantity)[3]	kW not bid into FCM (PA to determine quantity)	Weighted Average Avoided Cost Based on Percent Capacity Bid	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kw-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e=z*1.08 for ISO-NE losses	f=z*(1+aa)*(1+PTF Loss of 1.9%)*(1+WRP)	g=(e*%Bid)+(f*(1-%Bid))	h	i	j	k	l	m	n	o	p	q	r	s	t	u
2011	0.058	0.049	0.065	0.047														0.042	0.043	0.041	0.045
2012	0.060	0.050	0.071	0.050	37.50	0.00	18.75	0.018	0.017	0.034	0.023	$0.00						0.042	0.043	0.041	0.045
2013	0.061	0.053	0.074	0.052	36.76	0.00	18.38	0.018	0.018	0.034	0.023	$0.00	0.018	0.018	0.035	0.024	$0.00	0.042	0.043	0.041	0.045
2014	0.063	0.055	0.076	0.053	36.76	0.00	18.38	0.019	0.018	0.036	0.024	$0.00	0.019	0.019	0.037	0.025	$0.00	0.042	0.043	0.041	0.045
2015	0.069	0.059	0.081	0.058	36.76	0.00	18.38	0.021	0.020	0.039	0.027	$0.00	0.021	0.021	0.040	0.028	$0.00	0.042	0.043	0.041	0.045
2016	0.070	0.060	0.088	0.059	15.09	18.01	16.55	0.020	0.019	0.040	0.026	$43.85	0.021	0.021	0.044	0.028	$43.85	0.042	0.043	0.041	0.045
2017	0.070	0.061	0.088	0.059	22.21	26.54	24.37	0.020	0.020	0.040	0.025	$44.38	0.020	0.020	0.041	0.026	$44.38	0.042	0.043	0.041	0.045
2018	0.076	0.068	0.098	0.065	31.01	37.09	34.05	0.022	0.022	0.045	0.028	$44.76	0.022	0.022	0.046	0.029	$44.76	0.035	0.036	0.034	0.037
2019	0.076	0.068	0.095	0.066	34.80	41.66	38.23	0.022	0.022	0.043	0.029	$43.11	0.022	0.023	0.044	0.029	$43.11	0.034	0.034	0.033	0.035
2020	0.079	0.069	0.091	0.067	48.69	58.34	53.52	0.011	0.011	0.020	0.014	$14.36	0.011	0.022	0.042	0.029	$14.36	0.032	0.033	0.031	0.034
2021	0.080	0.070	0.092	0.068	49.61	59.51	54.56	0.010	0.010	0.019	0.013	$14.50	0.010	0.012	0.021	0.015	$14.50	0.030	0.031	0.030	0.032
2022	0.083	0.073	0.095	0.071	74.46	89.42	81.94	0.009	0.009	0.017	0.012	$145.89	0.009	0.011	0.019	0.014	$145.89	0.029	0.029	0.028	0.030
2023	0.088	0.077	0.100	0.076	89.72	107.86	98.79	0.008	0.008	0.015	0.011	$71.93	0.009	0.010	0.018	0.013	$71.93	0.027	0.028	0.026	0.029
2024	0.091	0.079	0.102	0.078	98.16	118.14	108.15	0.007	0.007	0.013	0.010	$34.39	0.008	0.009	0.016	0.011	$34.39	0.025	0.026	0.025	0.027
2025	0.092	0.079	0.103	0.079	101.86	122.72	112.29					$17.51					$17.51	0.024	0.024	0.023	0.025
2026	0.093	0.081	0.106	0.080	104.09	125.53	114.81					$7.56					$7.56	0.022	0.023	0.022	0.023
2027	0.096	0.083	0.109	0.082	104.98	126.75	115.86											0.022	0.023	0.022	0.023
2028	0.099	0.085	0.112	0.084	105.49	127.51	116.50											0.022	0.023	0.022	0.023
2029	0.102	0.087	0.115	0.087	105.62	127.81	116.72											0.022	0.023	0.022	0.023
2030	0.105	0.089	0.118	0.089	105.75	128.11	116.93											0.022	0.023	0.022	0.023
2031	0.108	0.092	0.122	0.092	105.88	128.41	117.15											0.022	0.023	0.022	0.023
2032	0.111	0.094	0.125	0.095	105.88	128.55	117.22											0.022	0.023	0.022	0.023
2033	0.115	0.097	0.129	0.098	105.88	128.70	117.29											0.022	0.023	0.022	0.023
2034	0.119	0.100	0.132	0.100	105.88	128.84	117.36											0.022	0.023	0.022	0.023
2035	0.122	0.102	0.136	0.104	105.88	128.99	117.43											0.022	0.023	0.022	0.023
2036	0.126	0.105	0.140	0.107	105.88	129.13	117.51											0.022	0.023	0.022	0.023
2037	0.130	0.108	0.144	0.110	105.88	129.28	117.58											0.022	0.023	0.022	0.023
2038	0.134	0.111	0.148	0.113	105.88	129.43	117.65											0.022	0.023	0.022	0.023
2039	0.138	0.114	0.152	0.117	105.88	129.57	117.73											0.022	0.023	0.022	0.023
2040	0.143	0.117	0.156	0.120	105.88	129.72	117.80											0.022	0.023	0.022	0.023
2041	0.147	0.121	0.161	0.124	105.88	129.87	117.88											0.022	0.023	0.022	0.023
Levelized Costs																					
10 years (2012-2021)	0.070	0.061	0.085	0.060	34.73	22.58	28.65	0.018	0.018	0.035	0.023	19.77	0.017	0.018	0.035	0.024	20.25	0.039	0.040	0.038	0.041
15 years (2012-2026)	0.076	0.066	0.090	0.065	51.93	48.94	50.44	0.014	0.014	0.028	0.019	30.72	0.014	0.015	0.028	0.019	31.48	0.035	0.036	0.034	0.037
30 years (2012-2041)	0.093	0.079	0.107	0.079	73.99	81.60	77.80											0.030	0.030	0.029	0.031

NOTES:

General All Avoided Costs are in Year 2011 Dollars
ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 7 AM - 11 PM; Off-Peak Hours are all other hours

1 Avoided cost of electric energy = (wholesale energy avoided cost + REC cost to load) * risk premium, e.g. A= (V + AB) * (1+Wholesale Risk Premium)

2 Absolute value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year and PA strategy about bidding that reduction into applicable FCAs, and unit values in columns e, f, l and q.

3 Proceeds from selling into the FCM include the reserve margin, in addition to the ISO-NE loss factor of 8%

Page Two: Inputs to Avoided Cost Calculations

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Zone: CT-NS

	Wholesale Avoided Costs of Electricity: Energy				Wholesale Avoided Costs of Electricity: Capacity		Avoided REC Costs to Load	2012 Energy DRIPE Values: Intrastate Installation				2012 Energy DRIPE Values: Rest of Pool Installation				2013 Energy DRIPE Values: Intrastate Installation				2013 Energy DRIPE Values: Rest of Pool Installation			
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	FCA Price	Reserve Margin	REC Costs	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	%	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh
Period:	v	w	x	y	z	aa	ab	ac	ad	ae	af	ag	ah	ai	aj	ak	al	am	an	ao	ap	aq	ar
2011	0.051	0.043	0.058	0.041	43.20		0.0016																
2012	0.053	0.044	0.063	0.044	34.72	16.6%	0.0019	0.018	0.017	0.034	0.023	0.025	0.018	0.035	0.020	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2013	0.054	0.046	0.065	0.045	34.04	15.7%	0.0021	0.018	0.018	0.034	0.023	0.026	0.019	0.036	0.020	0.018	0.018	0.035	0.024	0.026	0.019	0.037	0.021
2014	0.055	0.048	0.067	0.047	34.04	17.7%	0.0023	0.019	0.018	0.036	0.024	0.026	0.019	0.037	0.020	0.019	0.019	0.037	0.025	0.027	0.020	0.038	0.021
2015	0.061	0.052	0.072	0.051	34.04	15.9%	0.0027	0.021	0.020	0.039	0.027	0.028	0.021	0.039	0.022	0.021	0.021	0.040	0.028	0.029	0.021	0.040	0.023
2016	0.061	0.052	0.078	0.051	13.98	16.0%	0.0030	0.020	0.019	0.040	0.026	0.027	0.019	0.040	0.021	0.021	0.021	0.044	0.028	0.029	0.021	0.043	0.023
2017	0.061	0.053	0.077	0.051	20.56	16.2%	0.0033	0.020	0.020	0.040	0.025	0.027	0.020	0.040	0.021	0.020	0.020	0.041	0.026	0.027	0.020	0.041	0.021
2018	0.068	0.060	0.087	0.058	28.72	16.3%	0.0024	0.022	0.022	0.045	0.028	0.030	0.022	0.044	0.024	0.022	0.022	0.046	0.029	0.030	0.023	0.045	0.024
2019	0.068	0.061	0.086	0.059	32.22	16.4%	0.0014	0.022	0.022	0.043	0.029	0.030	0.023	0.043	0.024	0.022	0.023	0.044	0.029	0.030	0.023	0.044	0.024
2020	0.070	0.061	0.082	0.060	45.08	16.5%	0.0018	0.011	0.011	0.020	0.014	0.015	0.011	0.020	0.012	0.011	0.022	0.042	0.029	0.015	0.023	0.042	0.024
2021	0.072	0.063	0.084	0.062	45.94	16.6%	0.0011	0.010	0.010	0.019	0.013	0.014	0.010	0.019	0.011	0.010	0.012	0.021	0.015	0.014	0.012	0.021	0.012
2022	0.074	0.065	0.085	0.064	68.95	16.8%	0.0018	0.009	0.009	0.017	0.012	0.012	0.009	0.017	0.010	0.009	0.011	0.019	0.014	0.013	0.011	0.019	0.011
2023	0.078	0.068	0.089	0.067	83.08	16.9%	0.0025	0.008	0.008	0.015	0.011	0.011	0.008	0.015	0.009	0.009	0.010	0.018	0.013	0.012	0.010	0.018	0.011
2024	0.081	0.070	0.091	0.069	90.89	17.0%	0.0026	0.007	0.007	0.013	0.010	0.010	0.007	0.013	0.008	0.008	0.009	0.016	0.011	0.010	0.009	0.016	0.009
2025	0.082	0.071	0.092	0.071	94.32	17.1%	0.0020	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.008	0.014	0.010	0.000	0.008	0.013	0.008
2026	0.084	0.073	0.096	0.072	96.38	17.3%	0.0012	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2027	0.087	0.075	0.099	0.074	97.20	17.4%	0.0011																
2028	0.090	0.077	0.102	0.076	97.68	17.5%	0.0010																
2029	0.092	0.079	0.105	0.079	97.80	17.7%	0.0009																
2030	0.095	0.081	0.108	0.081	97.92	17.8%	0.0008																
2031	0.098	0.083	0.111	0.083	98.04	17.9%	0.0008																
2032	0.101	0.086	0.114	0.086	98.04	18.1%	0.0008																
2033	0.105	0.088	0.117	0.089	98.04	18.2%	0.0008																
2034	0.108	0.091	0.121	0.091	98.04	18.3%	0.0008																
2035	0.111	0.093	0.124	0.094	98.04	18.5%	0.0008																
2036	0.115	0.096	0.128	0.097	98.04	18.6%	0.0008																
2037	0.119	0.099	0.131	0.100	98.04	18.7%	0.0008																
2038	0.122	0.101	0.135	0.103	98.04	18.9%	0.0008																
2039	0.126	0.104	0.139	0.106	98.04	19.0%	0.0008																
2040	0.130	0.107	0.143	0.110	98.04	19.1%	0.0008																
2041	0.134	0.110	0.147	0.113	98.04	19.3%	0.0008																
Levelized Cos																							
10 years (2012-2021)	0.062	0.054	0.076	0.052	32.15		0.002	0.018	0.018	0.035	0.023	0.025	0.018	0.035	0.020	0.017	0.018	0.035	0.023	0.023	0.018	0.035	0.019
15 years (2012-2026)	0.067	0.058	0.080	0.057	48.09		0.002	0.014	0.014	0.028	0.019	0.020	0.014	0.028	0.016	0.013	0.015	0.028	0.019	0.018	0.015	0.028	0.016
30 years (2012-2041)	0.084	0.071	0.096	0.071	68.51		0.002	0.008	0.008	0.016	0.011	0.012	0.009	0.016	0.009	0.008	0.009	0.017	0.011	0.011	0.009	0.017	0.009

NOTES: General — All Avoided Costs are in Year 2011 Dollars
ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are all other hours

Avoided Cost of Electricity (2011$) Results :

State CT

CT-R
Rest of Connecticut (Connecticut excluding all of Southwest Connecticut)

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User-defined Inputs			
Wholesale Risk Premium (WRP)	9%	Percent of Capacity Bid into FCM (%Bid)	50.0%
Real Discount Rate	2.46%		

	Avoided Unit Cost of Electric Energy[1]				Avoided Unit Cost of Electric Capacity[2]			DRIPE: 2012 vintage measures, Intrastate Values					DRIPE: 2013 vintage measures, Intrastate Values					Avoided Externality Costs			
								Energy				Capacity (See note 2)	Energy				Capacity (See note 2)				
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	kW bid into FCA (PA to determine quantity)[3]	kW not bid into FCM (PA to determine quantity)	Weighted Average Avoided Cost Based on Percent Capacity Bid	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kw-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e=z*1.08 for ISO-NE losses	f=z*(1+aa)*(1+PTF Loss of 1.9%)*(1+WRP)	g=(e*%Bid)+(f*(1-%Bid))	h	i	j	k	l	m	n	o	p	q	r	s	t	u
2011	0.057	0.048	0.064	0.046														0.042	0.043	0.041	0.045
2012	0.059	0.050	0.070	0.049	37.50	0.00	18.75	0.018	0.017	0.034	0.023	$0.00						0.042	0.043	0.041	0.045
2013	0.060	0.052	0.072	0.051	36.76	0.00	18.38	0.018	0.018	0.034	0.023	$0.00	0.018	0.018	0.035	0.024	$0.00	0.042	0.043	0.041	0.045
2014	0.062	0.053	0.074	0.052	36.76	0.00	18.38	0.019	0.018	0.036	0.024	$0.00	0.019	0.019	0.037	0.025	$0.00	0.042	0.043	0.041	0.045
2015	0.068	0.058	0.080	0.057	36.76	0.00	18.38	0.021	0.020	0.039	0.027	$0.00	0.021	0.021	0.040	0.028	$0.00	0.042	0.043	0.041	0.045
2016	0.068	0.059	0.087	0.058	15.09	18.01	16.55	0.020	0.019	0.040	0.026	$43.85	0.021	0.021	0.044	0.028	$43.85	0.042	0.043	0.041	0.045
2017	0.069	0.060	0.086	0.058	22.21	26.54	24.37	0.020	0.020	0.040	0.025	$44.38	0.020	0.020	0.041	0.026	$44.38	0.042	0.043	0.041	0.045
2018	0.075	0.066	0.096	0.064	31.01	37.09	34.05	0.022	0.022	0.045	0.028	$44.76	0.022	0.022	0.046	0.029	$44.76	0.035	0.036	0.034	0.037
2019	0.075	0.067	0.093	0.065	34.80	41.66	38.23	0.022	0.022	0.043	0.029	$43.11	0.022	0.023	0.044	0.029	$43.11	0.034	0.034	0.033	0.035
2020	0.077	0.067	0.090	0.066	48.69	58.34	53.52	0.011	0.011	0.020	0.014	$14.36	0.011	0.022	0.042	0.029	$14.36	0.032	0.033	0.031	0.034
2021	0.078	0.069	0.090	0.067	49.61	59.51	54.56	0.010	0.010	0.019	0.013	$14.50	0.010	0.012	0.021	0.015	$14.50	0.030	0.031	0.030	0.032
2022	0.081	0.072	0.093	0.070	74.46	89.42	81.94	0.009	0.009	0.017	0.012	$145.89	0.009	0.011	0.019	0.014	$145.89	0.029	0.029	0.028	0.030
2023	0.086	0.075	0.098	0.074	89.72	107.86	98.79	0.008	0.008	0.015	0.011	$71.93	0.009	0.010	0.018	0.013	$71.93	0.027	0.028	0.026	0.029
2024	0.089	0.077	0.100	0.076	98.16	118.14	108.15	0.007	0.007	0.013	0.010	$34.39	0.008	0.009	0.016	0.011	$34.39	0.025	0.026	0.025	0.027
2025	0.090	0.078	0.101	0.078	101.86	122.72	112.29					$17.51					$17.51	0.024	0.024	0.023	0.025
2026	0.091	0.079	0.104	0.078	104.09	125.53	114.81					$7.56					$7.56	0.022	0.023	0.022	0.023
2027	0.094	0.081	0.107	0.080	104.98	126.75	115.86											0.022	0.023	0.022	0.023
2028	0.097	0.083	0.110	0.082	105.49	127.51	116.50											0.022	0.023	0.022	0.023
2029	0.100	0.085	0.113	0.085	105.62	127.81	116.72											0.022	0.023	0.022	0.023
2030	0.103	0.088	0.116	0.087	105.75	128.11	116.93											0.022	0.023	0.022	0.023
2031	0.106	0.090	0.119	0.090	105.88	128.41	117.15											0.022	0.023	0.022	0.023
2032	0.109	0.092	0.122	0.093	105.88	128.55	117.22											0.022	0.023	0.022	0.023
2033	0.113	0.095	0.126	0.096	105.88	128.70	117.29											0.022	0.023	0.022	0.023
2034	0.116	0.098	0.130	0.098	105.88	128.84	117.36											0.022	0.023	0.022	0.023
2035	0.120	0.100	0.133	0.101	105.88	128.99	117.43											0.022	0.023	0.022	0.023
2036	0.124	0.103	0.137	0.105	105.88	129.13	117.51											0.022	0.023	0.022	0.023
2037	0.127	0.106	0.141	0.108	105.88	129.28	117.58											0.022	0.023	0.022	0.023
2038	0.131	0.109	0.145	0.111	105.88	129.43	117.65											0.022	0.023	0.022	0.023
2039	0.136	0.112	0.149	0.114	105.88	129.57	117.73											0.022	0.023	0.022	0.023
2040	0.140	0.115	0.153	0.118	105.88	129.72	117.80											0.022	0.023	0.022	0.023
2041	0.144	0.118	0.158	0.121	105.88	129.87	117.88											0.022	0.023	0.022	0.023
Levelized Costs																					
10 years (2012-2021)	0.069	0.060	0.083	0.058	34.73	22.58	28.65	0.018	0.018	0.035	0.023	19.77	0.017	0.018	0.035	0.024	20.25	0.039	0.040	0.038	0.041
15 years (2012-2026)	0.074	0.064	0.088	0.063	51.93	48.94	50.44	0.014	0.014	0.028	0.019	30.72	0.014	0.015	0.028	0.019	31.48	0.035	0.036	0.034	0.037
30 years (2012-2041)	0.091	0.078	0.105	0.078	73.99	81.60	77.80											0.030	0.030	0.029	0.031

NOTES:

General All Avoided Costs are in Year 2011 Dollars

ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 7 AM - 11 PM; Off-Peak Hours are all other hours

1 Avoided cost of electric energy = (wholesale energy avoided cost + REC cost to load) * risk premium, e.g. A= (V + AB) * (1+Wholesale Risk Premium)

2 Absolute value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year and PA strategy about bidding that reduction into applicable FCAs, and unit values in columns e, f, l and q.

3 Proceeds from selling into the FCM include the reserve margin, in addition to the ISO-NE loss factor of 8%

Page Two: Inputs to Avoided Cost Calculations

Zone: CT-R

	Wholesale Avoided Costs of Electricity						Avoided REC Costs to Load
	Energy				Capacity		
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	FCA Price	Reserve Margin	REC Costs
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	%	$/kWh
Period:	v	w	x	y	z	aa	ab
2011	0.050	0.042	0.057	0.040	43.20		0.0016
2012	0.052	0.044	0.062	0.043	34.72	16.6%	0.0019
2013	0.053	0.045	0.064	0.045	34.04	15.7%	0.0021
2014	0.054	0.047	0.066	0.046	34.04	17.7%	0.0023
2015	0.059	0.051	0.070	0.050	34.04	15.9%	0.0027
2016	0.060	0.051	0.076	0.050	13.98	16.0%	0.0030
2017	0.060	0.052	0.076	0.050	20.56	16.2%	0.0033
2018	0.066	0.058	0.085	0.056	28.72	16.3%	0.0024
2019	0.067	0.060	0.084	0.058	32.22	16.4%	0.0014
2020	0.069	0.060	0.080	0.059	45.08	16.5%	0.0018
2021	0.071	0.062	0.082	0.060	45.94	16.6%	0.0011
2022	0.072	0.064	0.083	0.062	68.95	16.8%	0.0018
2023	0.077	0.067	0.087	0.066	83.08	16.9%	0.0025
2024	0.079	0.068	0.089	0.067	90.89	17.0%	0.0026
2025	0.080	0.069	0.090	0.069	94.32	17.1%	0.0020
2026	0.082	0.071	0.094	0.070	96.38	17.3%	0.0012
2027	0.085	0.073	0.097	0.072	97.20	17.4%	0.0011
2028	0.088	0.075	0.100	0.075	97.68	17.5%	0.0010
2029	0.091	0.077	0.103	0.077	97.80	17.7%	0.0009
2030	0.093	0.080	0.105	0.079	97.92	17.8%	0.0008
2031	0.096	0.082	0.109	0.082	98.04	17.9%	0.0008
2032	0.099	0.084	0.112	0.084	98.04	18.1%	0.0008
2033	0.103	0.086	0.115	0.087	98.04	18.2%	0.0008
2034	0.106	0.089	0.118	0.090	98.04	18.3%	0.0008
2035	0.109	0.091	0.121	0.092	98.04	18.5%	0.0008
2036	0.113	0.094	0.125	0.095	98.04	18.6%	0.0008
2037	0.116	0.097	0.128	0.098	98.04	18.7%	0.0008
2038	0.120	0.099	0.132	0.101	98.04	18.9%	0.0008
2039	0.124	0.102	0.136	0.104	98.04	19.0%	0.0008
2040	0.128	0.105	0.140	0.107	98.04	19.1%	0.0008
2041	0.132	0.108	0.144	0.111	98.04	19.3%	0.0008
Levelized Cos							
10 years (2012-2021)	0.061	0.052	0.074	0.051	32.15		0.002
15 years (2012-2026)	0.066	0.057	0.078	0.056	48.09		0.002
30 years (2012-2041)	0.082	0.070	0.094	0.069	68.51		0.002

	2012 Energy DRIPE Values								2013 Energy DRIPE Values							
	Intrastate Installation				Rest of Pool Installation				Intrastate Installation				Rest of Pool Installation			
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh
Period:	ac	ad	ae	af	ag	ah	ai	aj	ak	al	am	an	ao	ap	aq	ar
2011																
2012	0.018	0.017	0.034	0.023	0.025	0.018	0.035	0.020	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2013	0.018	0.018	0.034	0.023	0.026	0.019	0.036	0.020	0.018	0.018	0.035	0.024	0.026	0.019	0.037	0.021
2014	0.019	0.018	0.036	0.024	0.026	0.019	0.037	0.020	0.019	0.019	0.037	0.025	0.027	0.020	0.038	0.021
2015	0.021	0.020	0.039	0.027	0.028	0.021	0.039	0.022	0.021	0.021	0.040	0.028	0.029	0.021	0.040	0.023
2016	0.020	0.019	0.040	0.026	0.027	0.019	0.040	0.021	0.021	0.021	0.044	0.028	0.029	0.021	0.043	0.023
2017	0.020	0.020	0.040	0.025	0.027	0.020	0.040	0.021	0.020	0.020	0.041	0.026	0.027	0.020	0.041	0.021
2018	0.022	0.022	0.045	0.028	0.030	0.022	0.044	0.024	0.022	0.022	0.046	0.029	0.030	0.023	0.045	0.024
2019	0.022	0.022	0.043	0.029	0.030	0.023	0.043	0.024	0.022	0.023	0.044	0.029	0.030	0.023	0.044	0.024
2020	0.011	0.011	0.020	0.014	0.015	0.011	0.020	0.012	0.011	0.022	0.042	0.029	0.015	0.023	0.042	0.024
2021	0.010	0.010	0.019	0.013	0.014	0.010	0.019	0.011	0.010	0.012	0.021	0.015	0.014	0.012	0.021	0.012
2022	0.009	0.009	0.017	0.012	0.012	0.009	0.017	0.010	0.009	0.011	0.019	0.014	0.013	0.011	0.019	0.011
2023	0.008	0.008	0.015	0.011	0.011	0.008	0.015	0.009	0.009	0.010	0.018	0.013	0.012	0.010	0.018	0.011
2024	0.007	0.007	0.013	0.010	0.010	0.007	0.013	0.008	0.008	0.009	0.016	0.011	0.010	0.009	0.016	0.009
2025	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.008	0.014	0.010	0.000	0.008	0.013	0.008
2026	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Levelized Cos																
10 years (2012-2021)	0.018	0.018	0.035	0.023	0.025	0.018	0.035	0.020	0.017	0.018	0.035	0.023	0.023	0.018	0.035	0.019
15 years (2012-2026)	0.014	0.014	0.028	0.019	0.020	0.014	0.028	0.016	0.013	0.015	0.028	0.019	0.018	0.015	0.028	0.016
30 years (2012-2041)	0.008	0.008	0.016	0.011	0.012	0.009	0.016	0.009	0.008	0.009	0.017	0.011	0.011	0.009	0.017	0.009

NOTES: General — All Avoided Costs are in Year 2011 Dollars
ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are all other hours

Avoided Cost of Electricity (2011$) Results :

State CT

CT-SWe
Southwest Connecticut, excluding Norwalk/Stamford

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User-defined Inputs			
Wholesale Risk Premium (WRP)	9%	Percent of Capacity Bid into FCM (%Bid)	50.0%
Real Discount Rate	2.46%		

	Avoided Unit Cost of Electric Energy[1]				Avoided Unit Cost of Electric Capacity[2]			DRIPE: 2012 vintage measures, Intrastate Values: Energy				DRIPE: 2012 Capacity (See note 2)	DRIPE: 2013 vintage measures, Intrastate Values: Energy				DRIPE: 2013 Capacity (See note 2)	Avoided Externality Costs			
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	kW bid into FCA (PA to determine quantity)[3]	kW not bid into FCM (PA to determine quantity)	Weighted Average Avoided Cost Based on Percent Capacity Bid	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kw-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e=z*1.08 for ISO-NE losses	f=z*(1+aa)*(1+PTF Loss of 1.9%)*(1+WRP)	g=(e*%Bid)+(f*(1-%Bid))	h	i	j	k	l	m	n	o	p	q	r	s	t	u
2011	0.058	0.049	0.065	0.047														0.042	0.043	0.041	0.045
2012	0.060	0.050	0.071	0.050	37.50	0.00	18.75	0.018	0.017	0.034	0.023	$0.00						0.042	0.043	0.041	0.045
2013	0.061	0.053	0.073	0.052	36.76	0.00	18.38	0.018	0.018	0.034	0.023	$0.00	0.018	0.018	0.035	0.024	$0.00	0.042	0.043	0.041	0.045
2014	0.063	0.054	0.076	0.053	36.76	0.00	18.38	0.019	0.018	0.036	0.024	$0.00	0.019	0.019	0.037	0.025	$0.00	0.042	0.043	0.041	0.045
2015	0.069	0.059	0.081	0.058	36.76	0.00	18.38	0.021	0.020	0.039	0.027	$0.00	0.021	0.021	0.040	0.028	$0.00	0.042	0.043	0.041	0.045
2016	0.070	0.060	0.088	0.059	15.09	18.01	16.55	0.020	0.019	0.040	0.026	$43.85	0.021	0.021	0.044	0.028	$43.85	0.042	0.043	0.041	0.045
2017	0.070	0.061	0.088	0.059	22.21	26.54	24.37	0.020	0.020	0.040	0.025	$44.38	0.020	0.020	0.041	0.026	$44.38	0.042	0.043	0.041	0.045
2018	0.076	0.067	0.098	0.065	31.01	37.09	34.05	0.022	0.022	0.045	0.028	$44.76	0.022	0.022	0.046	0.029	$44.76	0.035	0.036	0.034	0.037
2019	0.076	0.068	0.095	0.066	34.80	41.66	38.23	0.022	0.022	0.043	0.029	$43.11	0.022	0.023	0.044	0.029	$43.11	0.034	0.034	0.033	0.035
2020	0.079	0.068	0.091	0.067	48.69	58.34	53.52	0.011	0.011	0.020	0.014	$14.36	0.011	0.022	0.042	0.029	$14.36	0.032	0.033	0.031	0.034
2021	0.080	0.070	0.092	0.068	49.61	59.51	54.56	0.010	0.010	0.019	0.013	$14.50	0.010	0.012	0.021	0.015	$14.50	0.030	0.031	0.030	0.032
2022	0.083	0.073	0.095	0.071	74.46	89.42	81.94	0.009	0.009	0.017	0.012	$145.89	0.009	0.011	0.019	0.014	$145.89	0.029	0.029	0.028	0.030
2023	0.088	0.077	0.100	0.076	89.72	107.86	98.79	0.008	0.008	0.015	0.011	$71.93	0.009	0.010	0.018	0.013	$71.93	0.027	0.028	0.026	0.029
2024	0.091	0.079	0.102	0.078	98.16	118.14	108.15	0.007	0.007	0.013	0.010	$34.39	0.008	0.009	0.016	0.011	$34.39	0.025	0.026	0.025	0.027
2025	0.092	0.079	0.103	0.079	101.86	122.72	112.29					$17.51					$17.51	0.024	0.024	0.023	0.025
2026	0.093	0.081	0.106	0.079	104.09	125.53	114.81					$7.56					$7.56	0.022	0.023	0.022	0.023
2027	0.096	0.083	0.109	0.082	104.98	126.75	115.86											0.022	0.023	0.022	0.023
2028	0.099	0.085	0.112	0.084	105.49	127.51	116.50											0.022	0.023	0.022	0.023
2029	0.102	0.087	0.115	0.087	105.62	127.81	116.72											0.022	0.023	0.022	0.023
2030	0.105	0.089	0.118	0.089	105.75	128.11	116.93											0.022	0.023	0.022	0.023
2031	0.108	0.092	0.121	0.092	105.88	128.41	117.15											0.022	0.023	0.022	0.023
2032	0.111	0.094	0.125	0.095	105.88	128.55	117.22											0.022	0.023	0.022	0.023
2033	0.115	0.097	0.128	0.097	105.88	128.70	117.29											0.022	0.023	0.022	0.023
2034	0.118	0.100	0.132	0.100	105.88	128.84	117.36											0.022	0.023	0.022	0.023
2035	0.122	0.102	0.136	0.103	105.88	128.99	117.43											0.022	0.023	0.022	0.023
2036	0.126	0.105	0.140	0.107	105.88	129.13	117.51											0.022	0.023	0.022	0.023
2037	0.130	0.108	0.144	0.110	105.88	129.28	117.58											0.022	0.023	0.022	0.023
2038	0.134	0.111	0.148	0.113	105.88	129.43	117.65											0.022	0.023	0.022	0.023
2039	0.138	0.114	0.152	0.117	105.88	129.57	117.73											0.022	0.023	0.022	0.023
2040	0.143	0.117	0.156	0.120	105.88	129.72	117.80											0.022	0.023	0.022	0.023
2041	0.147	0.121	0.161	0.124	105.88	129.87	117.88											0.022	0.023	0.022	0.023
Levelized Costs																					
10 years (2012-2021)	0.070	0.061	0.085	0.059	34.73	22.58	28.65	0.018	0.018	0.035	0.023	19.77	0.017	0.018	0.035	0.024	20.25	0.039	0.040	0.038	0.041
15 years (2012-2026)	0.075	0.066	0.090	0.064	51.93	48.94	50.44	0.014	0.014	0.028	0.019	30.72	0.014	0.015	0.028	0.019	31.48	0.035	0.036	0.034	0.037
30 years (2012-2041)	0.093	0.079	0.107	0.079	73.99	81.60	77.80											0.030	0.030	0.029	0.031

NOTES:

General: All Avoided Costs are in Year 2011 Dollars
ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 7 AM - 11 PM; Off-Peak Hours are all other hours

1. Avoided cost of electric energy = (wholesale energy avoided cost + REC cost to load) * risk premium, e.g. A= (V + AB) * (1+Wholesale Risk Premium)
2. Absolute value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year and PA strategy about bidding that reduction into applicable FCAs, and unit values in columns e, f, l and q.
3. Proceeds from selling into the FCM include the reserve margin, in addition to the ISO-NE loss factor of 8%

Page Two: Inputs to Avoided Cost Calculations

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Zone: CT-SWe

	Wholesale Avoided Costs of Electricity: Energy				Capacity		Avoided REC Costs to Load	2012 Energy DRIPE Values: Intrastate Installation				2012 Energy DRIPE Values: Rest of Pool Installation				2013 Energy DRIPE Values: Intrastate Installation				2013 Energy DRIPE Values: Rest of Pool Installation			
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	FCA Price	Reserve Margin	REC Costs	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	%	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh
Period:	v	w	x	y	z	aa	ab	ac	ad	ae	af	ag	ah	ai	aj	ak	al	am	an	ao	ap	aq	ar
2011	0.051	0.043	0.058	0.041	43.20		0.0016																
2012	0.053	0.044	0.063	0.044	34.72	16.6%	0.0019	0.018	0.017	0.034	0.023	0.025	0.018	0.035	0.020	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2013	0.054	0.046	0.065	0.045	34.04	15.7%	0.0021	0.018	0.018	0.034	0.023	0.026	0.019	0.036	0.020	0.018	0.018	0.035	0.024	0.026	0.019	0.037	0.021
2014	0.055	0.048	0.067	0.047	34.04	17.7%	0.0023	0.019	0.018	0.036	0.024	0.026	0.019	0.037	0.020	0.019	0.019	0.037	0.025	0.027	0.020	0.038	0.021
2015	0.061	0.052	0.072	0.051	34.04	15.9%	0.0027	0.021	0.020	0.039	0.027	0.028	0.021	0.039	0.022	0.021	0.021	0.040	0.028	0.029	0.021	0.040	0.023
2016	0.061	0.052	0.078	0.051	13.98	16.0%	0.0030	0.020	0.019	0.040	0.026	0.027	0.019	0.040	0.021	0.021	0.021	0.044	0.028	0.029	0.021	0.043	0.023
2017	0.061	0.053	0.077	0.051	20.56	16.2%	0.0033	0.020	0.020	0.040	0.025	0.027	0.020	0.040	0.021	0.020	0.020	0.041	0.026	0.027	0.020	0.041	0.021
2018	0.067	0.059	0.087	0.058	28.72	16.3%	0.0024	0.022	0.022	0.045	0.028	0.030	0.022	0.044	0.024	0.022	0.022	0.046	0.029	0.030	0.023	0.045	0.024
2019	0.068	0.061	0.086	0.059	32.22	16.4%	0.0014	0.022	0.022	0.043	0.029	0.030	0.023	0.043	0.024	0.022	0.023	0.044	0.029	0.030	0.023	0.044	0.024
2020	0.070	0.061	0.082	0.060	45.08	16.5%	0.0018	0.011	0.011	0.020	0.014	0.015	0.011	0.020	0.012	0.011	0.022	0.042	0.029	0.015	0.023	0.042	0.024
2021	0.072	0.063	0.084	0.062	45.94	16.6%	0.0011	0.010	0.010	0.019	0.013	0.014	0.010	0.019	0.011	0.010	0.012	0.021	0.015	0.014	0.012	0.021	0.012
2022	0.074	0.065	0.085	0.064	68.95	16.8%	0.0018	0.009	0.009	0.017	0.012	0.012	0.009	0.017	0.010	0.009	0.011	0.019	0.014	0.013	0.011	0.019	0.011
2023	0.078	0.068	0.089	0.067	83.08	16.9%	0.0025	0.008	0.008	0.015	0.011	0.011	0.008	0.015	0.009	0.009	0.010	0.018	0.013	0.012	0.010	0.018	0.011
2024	0.081	0.070	0.091	0.069	90.89	17.0%	0.0026	0.007	0.007	0.013	0.010	0.010	0.007	0.013	0.008	0.008	0.009	0.016	0.011	0.010	0.009	0.016	0.009
2025	0.082	0.071	0.092	0.071	94.32	17.1%	0.0020	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.008	0.014	0.010	0.000	0.008	0.013	0.008
2026	0.084	0.073	0.096	0.072	96.38	17.3%	0.0012	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2027	0.087	0.075	0.099	0.074	97.20	17.4%	0.0011																
2028	0.089	0.077	0.102	0.076	97.68	17.5%	0.0010																
2029	0.092	0.079	0.105	0.078	97.80	17.7%	0.0009																
2030	0.095	0.081	0.108	0.081	97.92	17.8%	0.0008																
2031	0.098	0.083	0.111	0.083	98.04	17.9%	0.0008																
2032	0.101	0.086	0.114	0.086	98.04	18.1%	0.0008																
2033	0.105	0.088	0.117	0.089	98.04	18.2%	0.0008																
2034	0.108	0.091	0.120	0.091	98.04	18.3%	0.0008																
2035	0.111	0.093	0.124	0.094	98.04	18.5%	0.0008																
2036	0.115	0.096	0.127	0.097	98.04	18.6%	0.0008																
2037	0.118	0.098	0.131	0.100	98.04	18.7%	0.0008																
2038	0.122	0.101	0.135	0.103	98.04	18.9%	0.0008																
2039	0.126	0.104	0.139	0.106	98.04	19.0%	0.0008																
2040	0.130	0.107	0.143	0.110	98.04	19.1%	0.0008																
2041	0.134	0.110	0.147	0.113	98.04	19.3%	0.0008																
Levelized Cos																							
10 years (2012-2021)	0.062	0.054	0.076	0.052	32.15		0.002	0.018	0.018	0.035	0.023	0.025	0.018	0.035	0.020	0.017	0.018	0.035	0.023	0.023	0.018	0.035	0.019
15 years (2012-2026)	0.067	0.058	0.080	0.057	48.09		0.002	0.014	0.014	0.028	0.019	0.020	0.014	0.028	0.016	0.013	0.015	0.028	0.019	0.018	0.015	0.028	0.016
30 years (2012-2041)	0.084	0.071	0.096	0.071	68.51		0.002	0.008	0.008	0.016	0.011	0.012	0.009	0.016	0.009	0.008	0.009	0.017	0.011	0.011	0.009	0.017	0.009

NOTES: General All Avoided Costs are in Year 2011 Dollars
ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are all other hours

Avoided Cost of Electricity (2011$) Results :

State CT

CT-SWi
Southwest Connecticut, including Norwalk/Stamford

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User-defined Inputs			
Wholesale Risk Premium (WRP)	9%	Percent of Capacity Bid into FCM (%Bid)	50.0%
Real Discount Rate	2.46%		

	Avoided Unit Cost of Electric Energy[1]				Avoided Unit Cost of Electric Capacity[2]			DRIPE: 2012 vintage measures, Intrastate Values: Energy				DRIPE: 2012 Capacity (See note 2)	DRIPE: 2013 vintage measures, Intrastate Values: Energy				DRIPE: 2013 Capacity (See note 2)	Avoided Externality Costs			
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	kW bid into FCA (PA to determine quantity)[3]	kW not bid into FCM (PA to determine quantity)	Weighted Average Avoided Cost Based on Percent Capacity Bid	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kw-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e=z*1.08 for ISO-NE losses	f=z*(1+aa)*(1+PTF Loss of 1.9%)*(1+WRP)	g=(e*%Bid)+(f*(1-%Bid))	h	i	j	k	l	m	n	o	p	q	r	s	t	u
2011	0.058	0.049	0.065	0.047														0.042	0.043	0.041	0.045
2012	0.060	0.050	0.071	0.050	37.50	0.00	18.75	0.018	0.017	0.034	0.023	$0.00						0.042	0.043	0.041	0.045
2013	0.061	0.053	0.074	0.052	36.76	0.00	18.38	0.018	0.018	0.034	0.023	$0.00	0.018	0.018	0.035	0.024	$0.00	0.042	0.043	0.041	0.045
2014	0.063	0.054	0.076	0.053	36.76	0.00	18.38	0.019	0.018	0.036	0.024	$0.00	0.019	0.019	0.037	0.025	$0.00	0.042	0.043	0.041	0.045
2015	0.069	0.059	0.081	0.058	36.76	0.00	18.38	0.021	0.020	0.039	0.027	$0.00	0.021	0.021	0.040	0.028	$0.00	0.042	0.043	0.041	0.045
2016	0.070	0.060	0.088	0.059	15.09	18.01	16.55	0.020	0.019	0.040	0.026	$43.85	0.021	0.021	0.044	0.028	$43.85	0.042	0.043	0.041	0.045
2017	0.070	0.061	0.088	0.059	22.21	26.54	24.37	0.020	0.020	0.040	0.025	$44.38	0.020	0.020	0.041	0.026	$44.38	0.042	0.043	0.041	0.045
2018	0.076	0.067	0.098	0.065	31.01	37.09	34.05	0.022	0.022	0.045	0.028	$44.76	0.022	0.022	0.046	0.029	$44.76	0.035	0.036	0.034	0.037
2019	0.076	0.068	0.095	0.066	34.80	41.66	38.23	0.022	0.022	0.043	0.029	$43.11	0.022	0.023	0.044	0.029	$43.11	0.034	0.034	0.033	0.035
2020	0.079	0.069	0.091	0.067	48.69	58.34	53.52	0.011	0.011	0.020	0.014	$14.36	0.011	0.022	0.042	0.029	$14.36	0.032	0.033	0.031	0.034
2021	0.080	0.070	0.092	0.068	49.61	59.51	54.56	0.010	0.010	0.019	0.013	$14.50	0.010	0.012	0.021	0.015	$14.50	0.030	0.031	0.030	0.032
2022	0.083	0.073	0.095	0.071	74.46	89.42	81.94	0.009	0.009	0.017	0.012	$145.89	0.009	0.011	0.019	0.014	$145.89	0.029	0.029	0.028	0.030
2023	0.088	0.077	0.100	0.076	89.72	107.86	98.79	0.008	0.008	0.015	0.011	$71.93	0.009	0.010	0.018	0.013	$71.93	0.027	0.028	0.026	0.029
2024	0.091	0.079	0.102	0.078	98.16	118.14	108.15	0.007	0.007	0.013	0.010	$34.39	0.008	0.009	0.016	0.011	$34.39	0.025	0.026	0.025	0.027
2025	0.092	0.079	0.103	0.079	101.86	122.72	112.29					$17.51					$17.51	0.024	0.024	0.023	0.025
2026	0.093	0.081	0.106	0.080	104.09	125.53	114.81					$7.56					$7.56	0.022	0.023	0.022	0.023
2027	0.096	0.083	0.109	0.082	104.98	126.75	115.86											0.022	0.023	0.022	0.023
2028	0.099	0.085	0.112	0.084	105.49	127.51	116.50											0.022	0.023	0.022	0.023
2029	0.102	0.087	0.115	0.087	105.62	127.81	116.72											0.022	0.023	0.022	0.023
2030	0.105	0.089	0.118	0.089	105.75	128.11	116.93											0.022	0.023	0.022	0.023
2031	0.108	0.092	0.122	0.092	105.88	128.41	117.15											0.022	0.023	0.022	0.023
2032	0.111	0.094	0.125	0.095	105.88	128.55	117.22											0.022	0.023	0.022	0.023
2033	0.115	0.097	0.129	0.097	105.88	128.70	117.29											0.022	0.023	0.022	0.023
2034	0.118	0.100	0.132	0.100	105.88	128.84	117.36											0.022	0.023	0.022	0.023
2035	0.122	0.102	0.136	0.103	105.88	128.99	117.43											0.022	0.023	0.022	0.023
2036	0.126	0.105	0.140	0.107	105.88	129.13	117.51											0.022	0.023	0.022	0.023
2037	0.130	0.108	0.144	0.110	105.88	129.28	117.58											0.022	0.023	0.022	0.023
2038	0.134	0.111	0.148	0.113	105.88	129.43	117.65											0.022	0.023	0.022	0.023
2039	0.138	0.114	0.152	0.117	105.88	129.57	117.73											0.022	0.023	0.022	0.023
2040	0.143	0.117	0.156	0.120	105.88	129.72	117.80											0.022	0.023	0.022	0.023
2041	0.147	0.121	0.161	0.124	105.88	129.87	117.88											0.022	0.023	0.022	0.023
Levelized Costs																					
10 years (2012-2021)	0.070	0.061	0.085	0.059	34.73	22.58	28.65	0.018	0.018	0.035	0.023	19.77	0.017	0.018	0.035	0.024	20.25	0.039	0.040	0.038	0.041
15 years (2012-2026)	0.076	0.066	0.090	0.065	51.93	48.94	50.44	0.014	0.014	0.028	0.019	30.72	0.014	0.015	0.028	0.019	31.48	0.035	0.036	0.034	0.037
30 years (2012-2041)	0.093	0.079	0.107	0.079	73.99	81.60	77.80											0.030	0.030	0.029	0.031

NOTES:

General: All Avoided Costs are in Year 2011 Dollars
ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 7 AM - 11 PM; Off-Peak Hours are all other hours

1 Avoided cost of electric energy = (wholesale energy avoided cost + REC cost to load) * risk premium, e.g. A= (V + AB) * (1+Wholesale Risk Premium)

2 Absolute value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year and PA strategy about bidding that reduction into applicable FCAs, and unit values in columns e, f, l and q.

3 Proceeds from selling into the FCM include the reserve margin, in addition to the ISO-NE loss factor of 8%

Page Two: Inputs to Avoided Cost Calculations

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Zone: CT-SWi

	Wholesale Avoided Costs of Electricity: Energy				Wholesale Avoided Costs of Electricity: Capacity		Avoided REC Costs to Load
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	FCA Price	Reserve Margin	REC Costs
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	%	$/kWh
Period:	v	w	x	y	z	aa	ab
2011	0.051	0.043	0.058	0.041	43.20		0.0016
2012	0.053	0.044	0.063	0.044	34.72	16.6%	0.0019
2013	0.054	0.046	0.065	0.045	34.04	15.7%	0.0021
2014	0.055	0.048	0.067	0.047	34.04	17.7%	0.0023
2015	0.061	0.052	0.072	0.051	34.04	15.9%	0.0027
2016	0.061	0.052	0.078	0.051	13.98	16.0%	0.0030
2017	0.061	0.053	0.077	0.051	20.56	16.2%	0.0033
2018	0.067	0.059	0.087	0.058	28.72	16.3%	0.0024
2019	0.068	0.061	0.086	0.059	32.22	16.4%	0.0014
2020	0.070	0.061	0.082	0.060	45.08	16.5%	0.0018
2021	0.072	0.063	0.084	0.062	45.94	16.6%	0.0011
2022	0.074	0.065	0.085	0.064	68.95	16.8%	0.0018
2023	0.078	0.068	0.089	0.067	83.08	16.9%	0.0025
2024	0.081	0.070	0.091	0.069	90.89	17.0%	0.0026
2025	0.082	0.071	0.092	0.071	94.32	17.1%	0.0020
2026	0.084	0.073	0.096	0.072	96.38	17.3%	0.0012
2027	0.087	0.075	0.099	0.074	97.20	17.4%	0.0011
2028	0.090	0.077	0.102	0.076	97.68	17.5%	0.0010
2029	0.092	0.079	0.105	0.079	97.80	17.7%	0.0009
2030	0.095	0.081	0.108	0.081	97.92	17.8%	0.0008
2031	0.098	0.083	0.111	0.083	98.04	17.9%	0.0008
2032	0.101	0.086	0.114	0.086	98.04	18.1%	0.0008
2033	0.105	0.088	0.117	0.089	98.04	18.2%	0.0008
2034	0.108	0.091	0.120	0.091	98.04	18.3%	0.0008
2035	0.111	0.093	0.124	0.094	98.04	18.5%	0.0008
2036	0.115	0.096	0.127	0.097	98.04	18.6%	0.0008
2037	0.118	0.098	0.131	0.100	98.04	18.7%	0.0008
2038	0.122	0.101	0.135	0.103	98.04	18.9%	0.0008
2039	0.126	0.104	0.139	0.106	98.04	19.0%	0.0008
2040	0.130	0.107	0.143	0.110	98.04	19.1%	0.0008
2041	0.134	0.110	0.147	0.113	98.04	19.3%	0.0008
Levelized Cos							
10 years (2012-2021)	0.062	0.054	0.076	0.052	32.15		0.002
15 years (2012-2026)	0.067	0.058	0.080	0.057	48.09		0.002
30 years (2012-2041)	0.084	0.071	0.096	0.071	68.51		0.002

	2012 Energy DRIPE Values: Intrastate Installation				2012 Energy DRIPE Values: Rest of Pool Installation				2013 Energy DRIPE Values: Intrastate Installation				2013 Energy DRIPE Values: Rest of Pool Installation			
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh
Period:	ac	ad	ae	af	ag	ah	ai	aj	ak	al	am	an	ao	ap	aq	ar
2011																
2012	0.018	0.017	0.034	0.023	0.025	0.018	0.035	0.020	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2013	0.018	0.018	0.034	0.023	0.026	0.019	0.036	0.020	0.018	0.018	0.035	0.024	0.026	0.019	0.037	0.021
2014	0.019	0.018	0.036	0.024	0.026	0.019	0.037	0.020	0.019	0.019	0.037	0.025	0.027	0.020	0.038	0.021
2015	0.021	0.020	0.039	0.027	0.028	0.021	0.039	0.022	0.021	0.021	0.040	0.028	0.029	0.021	0.040	0.023
2016	0.020	0.019	0.040	0.026	0.027	0.019	0.040	0.021	0.021	0.021	0.044	0.028	0.029	0.021	0.043	0.023
2017	0.020	0.020	0.040	0.025	0.027	0.020	0.040	0.021	0.020	0.020	0.041	0.026	0.027	0.020	0.041	0.021
2018	0.022	0.022	0.045	0.028	0.030	0.022	0.044	0.024	0.022	0.022	0.046	0.029	0.030	0.023	0.045	0.024
2019	0.022	0.022	0.043	0.029	0.030	0.023	0.043	0.024	0.022	0.023	0.044	0.029	0.030	0.023	0.044	0.024
2020	0.011	0.011	0.020	0.014	0.015	0.011	0.020	0.012	0.011	0.022	0.042	0.029	0.015	0.023	0.042	0.024
2021	0.010	0.010	0.019	0.013	0.014	0.010	0.019	0.011	0.010	0.012	0.021	0.015	0.014	0.012	0.021	0.012
2022	0.009	0.009	0.017	0.012	0.012	0.009	0.017	0.010	0.009	0.011	0.019	0.014	0.013	0.011	0.019	0.011
2023	0.008	0.008	0.015	0.011	0.011	0.008	0.015	0.009	0.009	0.010	0.018	0.013	0.012	0.010	0.018	0.011
2024	0.007	0.007	0.013	0.010	0.010	0.007	0.013	0.008	0.008	0.009	0.016	0.011	0.010	0.009	0.016	0.009
2025	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.008	0.014	0.010	0.000	0.008	0.013	0.008
2026	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
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2034																
2035																
2036																
2037																
2038																
2039																
2040																
2041																
Levelized Cos																
10 years (2012-2021)	0.018	0.018	0.035	0.023	0.025	0.018	0.035	0.020	0.017	0.018	0.035	0.023	0.023	0.018	0.035	0.019
15 years (2012-2026)	0.014	0.014	0.028	0.019	0.020	0.014	0.028	0.016	0.013	0.015	0.028	0.019	0.018	0.015	0.028	0.016
30 years (2012-2041)	0.008	0.008	0.016	0.011	0.012	0.009	0.016	0.009	0.008	0.009	0.017	0.011	0.011	0.009	0.017	0.009

NOTES: General — All Avoided Costs are in Year 2011 Dollars

ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are all other hours

Avoided Cost of Electricity (2011$) Results :

MA
Massachusetts (Statewide)

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State MA

User-defined Inputs			
Wholesale Risk Premium (WRP)	9%	Percent of Capacity Bid into FCM (%Bid)	50.0%
Real Discount Rate	2.46%		

	Avoided Unit Cost of Electric Energy[1]				Avoided Unit Cost of Electric Capacity[2]			DRIPE: 2012 vintage measures Intrastate Values					DRIPE: 2013 vintage measures Intrastate Values					Avoided Externality Costs			
								Energy				Capacity (See note 2)	Energy				Capacity (See note 2)				
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	kW bid into FCA (PA to determine quantity)[3]	kW not bid into FCM (PA to determine quantity)	Weighted Average Avoided Cost Based on Percent Capacity Bid	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kw-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e=z*1.08 for ISO-NE losses	f=z*(1+aa)*(1+PTF Loss of 1.9%)*(1+WRP)	g=(e*%Bid)+(f*(1-%Bid))	h	i	j	k	l	m	n	o	p	q	r	s	t	u
2011	0.058	0.050	0.064	0.047														0.042	0.043	0.041	0.045
2012	0.060	0.051	0.071	0.051	37.50	0.00	18.75	0.023	0.021	0.040	0.023	$0.00						0.042	0.043	0.041	0.045
2013	0.062	0.054	0.074	0.053	36.76	0.00	18.38	0.023	0.022	0.040	0.023	$0.00	0.023	0.023	0.041	0.024	$0.00	0.042	0.043	0.041	0.045
2014	0.064	0.056	0.077	0.055	36.76	0.00	18.38	0.023	0.022	0.041	0.023	$0.00	0.024	0.023	0.043	0.024	$0.00	0.042	0.043	0.041	0.045
2015	0.071	0.062	0.083	0.060	36.76	0.00	18.38	0.026	0.024	0.044	0.025	$0.00	0.026	0.025	0.045	0.026	$0.00	0.042	0.043	0.041	0.045
2016	0.072	0.063	0.090	0.062	15.09	18.01	16.55	0.025	0.023	0.046	0.024	$83.13	0.026	0.025	0.049	0.026	$83.13	0.042	0.043	0.041	0.045
2017	0.073	0.065	0.091	0.062	22.21	26.54	24.37	0.025	0.024	0.046	0.024	$85.39	0.025	0.024	0.047	0.025	$85.39	0.042	0.043	0.041	0.045
2018	0.078	0.070	0.100	0.068	31.01	37.09	34.05	0.027	0.027	0.052	0.028	$86.75	0.028	0.027	0.053	0.028	$86.75	0.035	0.036	0.034	0.037
2019	0.078	0.071	0.097	0.068	34.80	41.66	38.23	0.027	0.027	0.050	0.028	$83.35	0.028	0.028	0.051	0.028	$83.35	0.034	0.034	0.033	0.035
2020	0.080	0.070	0.092	0.069	48.69	58.34	53.52	0.014	0.013	0.024	0.014	$27.75	0.014	0.027	0.048	0.028	$27.75	0.032	0.033	0.031	0.034
2021	0.081	0.072	0.093	0.070	49.61	59.51	54.56	0.013	0.012	0.022	0.013	$27.90	0.013	0.014	0.024	0.014	$27.90	0.030	0.031	0.030	0.032
2022	0.084	0.074	0.096	0.073	74.46	89.42	81.94	0.012	0.011	0.019	0.012	$280.47	0.012	0.013	0.022	0.013	$280.47	0.029	0.029	0.028	0.030
2023	0.089	0.078	0.100	0.077	89.72	107.86	98.79	0.011	0.010	0.018	0.011	$138.27	0.011	0.012	0.020	0.012	$138.27	0.027	0.028	0.026	0.029
2024	0.092	0.080	0.102	0.078	98.16	118.14	108.15	0.009	0.009	0.015	0.009	$66.05	0.009	0.011	0.018	0.011	$66.05	0.025	0.026	0.025	0.027
2025	0.092	0.080	0.103	0.080	101.86	122.72	112.29					$33.59					$33.59	0.024	0.024	0.023	0.025
2026	0.092	0.080	0.105	0.080	104.09	125.53	114.81					$14.49					$14.49	0.022	0.023	0.022	0.023
2027	0.095	0.082	0.108	0.082	104.98	126.75	115.86											0.022	0.023	0.022	0.023
2028	0.098	0.084	0.111	0.084	105.49	127.51	116.50											0.022	0.023	0.022	0.023
2029	0.101	0.086	0.114	0.086	105.62	127.81	116.72											0.022	0.023	0.022	0.023
2030	0.104	0.089	0.117	0.089	105.75	128.11	116.93											0.022	0.023	0.022	0.023
2031	0.107	0.091	0.121	0.091	105.88	128.41	117.15											0.022	0.023	0.022	0.023
2032	0.110	0.093	0.124	0.094	105.88	128.55	117.22											0.022	0.023	0.022	0.023
2033	0.114	0.096	0.127	0.097	105.88	128.70	117.29											0.022	0.023	0.022	0.023
2034	0.117	0.098	0.131	0.100	105.88	128.84	117.36											0.022	0.023	0.022	0.023
2035	0.121	0.101	0.135	0.103	105.88	128.99	117.43											0.022	0.023	0.022	0.023
2036	0.125	0.104	0.139	0.106	105.88	129.13	117.51											0.022	0.023	0.022	0.023
2037	0.128	0.107	0.143	0.109	105.88	129.28	117.58											0.022	0.023	0.022	0.023
2038	0.132	0.109	0.147	0.113	105.88	129.43	117.65											0.022	0.023	0.022	0.023
2039	0.137	0.112	0.151	0.116	105.88	129.57	117.73											0.022	0.023	0.022	0.023
2040	0.141	0.115	0.155	0.120	105.88	129.72	117.80											0.022	0.023	0.022	0.023
2041	0.145	0.118	0.159	0.123	105.88	129.87	117.88											0.022	0.023	0.022	0.023
Levelized Costs																					
10 years (2012-2021)	0.071	0.063	0.086	0.061	34.73	22.58	28.65	0.023	0.022	0.041	0.023	38.02	0.021	0.022	0.041	0.023	38.95	0.039	0.040	0.038	0.041
15 years (2012-2026)	0.077	0.067	0.090	0.066	51.93	48.94	50.44	0.018	0.017	0.032	0.018	59.07	0.017	0.018	0.033	0.018	60.52	0.035	0.036	0.034	0.037
30 years (2012-2041)	0.093	0.080	0.107	0.080	73.99	81.60	77.80											0.030	0.030	0.029	0.031

NOTES:

General All Avoided Costs are in Year 2011 Dollars
ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 7 AM - 11 PM; Off-Peak Hours are all other hours

1 Avoided cost of electric energy = (wholesale energy avoided cost + REC cost to load) * risk premium, e.g. A= (V + AB) * (1+Wholesale Risk Premium)

2 Absolute value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year and PA strategy about bidding that reduction into applicable FCAs, and unit values in columns e, f, l and q.

3 Proceeds from selling into the FCM include the reserve margin, in addition to the ISO-NE loss factor of 8%

Page Two: Inputs to Avoided Cost Calculations

Zone: MA

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	Wholesale Avoided Costs of Electricity						Avoided REC Costs to Load
	Energy				Capacity		
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	FCA Price	Reserve Margin	REC Costs
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	%	$/kWh
Period:	v	w	x	y	z	aa	ab
2011	0.050	0.042	0.056	0.040	43.20		0.0034
2012	0.051	0.043	0.061	0.043	34.72	16.6%	0.0038
2013	0.052	0.045	0.063	0.045	34.04	15.7%	0.0045
2014	0.054	0.047	0.065	0.045	34.04	17.7%	0.0051
2015	0.059	0.051	0.070	0.050	34.04	15.9%	0.0058
2016	0.060	0.051	0.076	0.050	13.98	16.0%	0.0065
2017	0.060	0.052	0.076	0.050	20.56	16.2%	0.0071
2018	0.066	0.059	0.086	0.057	28.72	16.3%	0.0061
2019	0.067	0.060	0.084	0.058	32.22	16.4%	0.0045
2020	0.068	0.059	0.080	0.058	45.08	16.5%	0.0047
2021	0.070	0.062	0.081	0.060	45.94	16.6%	0.0041
2022	0.072	0.063	0.083	0.062	68.95	16.8%	0.0047
2023	0.076	0.066	0.087	0.065	83.08	16.9%	0.0053
2024	0.079	0.068	0.088	0.067	90.89	17.0%	0.0051
2025	0.080	0.069	0.090	0.069	94.32	17.1%	0.0042
2026	0.082	0.071	0.094	0.070	96.38	17.3%	0.0029
2027	0.085	0.073	0.097	0.072	97.20	17.4%	0.0027
2028	0.087	0.075	0.099	0.075	97.68	17.5%	0.0025
2029	0.090	0.077	0.102	0.077	97.80	17.7%	0.0024
2030	0.093	0.079	0.105	0.079	97.92	17.8%	0.0023
2031	0.096	0.081	0.108	0.082	98.04	17.9%	0.0023
2032	0.099	0.083	0.111	0.084	98.04	18.1%	0.0023
2033	0.102	0.086	0.115	0.087	98.04	18.2%	0.0023
2034	0.105	0.088	0.118	0.089	98.04	18.3%	0.0023
2035	0.109	0.090	0.121	0.092	98.04	18.5%	0.0023
2036	0.112	0.093	0.125	0.095	98.04	18.6%	0.0023
2037	0.116	0.095	0.128	0.098	98.04	18.7%	0.0023
2038	0.119	0.098	0.132	0.101	98.04	18.9%	0.0023
2039	0.123	0.101	0.136	0.104	98.04	19.0%	0.0023
2040	0.127	0.104	0.140	0.107	98.04	19.1%	0.0023
2041	0.131	0.106	0.144	0.111	98.04	19.3%	0.0023
Levelized Cos							
10 years (2012-2021)	0.060	0.053	0.074	0.051	32.15		0.005
15 years (2012-2026)	0.065	0.057	0.078	0.056	48.09		0.005
30 years (2012-2041)	0.082	0.069	0.094	0.069	68.51		0.004

	2012 Energy DRIPE Values								2013 Energy DRIPE Values							
	Intrastate Installation				Rest of Pool Installation				Intrastate Installation				Rest of Pool Installation			
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh
Period:	ac	ad	ae	af	ag	ah	ai	aj	ak	al	am	an	ao	ap	aq	ar
2011																
2012	0.023	0.021	0.040	0.023	0.021	0.015	0.029	0.017	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2013	0.023	0.022	0.040	0.023	0.022	0.016	0.030	0.017	0.023	0.023	0.041	0.024	0.022	0.016	0.031	0.018
2014	0.023	0.022	0.041	0.023	0.022	0.016	0.031	0.017	0.024	0.023	0.043	0.024	0.023	0.017	0.032	0.018
2015	0.026	0.024	0.044	0.025	0.025	0.018	0.034	0.019	0.026	0.025	0.045	0.026	0.025	0.018	0.034	0.020
2016	0.025	0.023	0.046	0.024	0.023	0.017	0.034	0.018	0.026	0.025	0.049	0.026	0.025	0.018	0.037	0.020
2017	0.025	0.024	0.046	0.024	0.023	0.017	0.034	0.018	0.025	0.024	0.047	0.025	0.023	0.017	0.035	0.018
2018	0.027	0.027	0.052	0.028	0.025	0.019	0.038	0.020	0.028	0.027	0.053	0.028	0.025	0.019	0.038	0.021
2019	0.027	0.027	0.050	0.028	0.025	0.019	0.037	0.020	0.028	0.028	0.051	0.028	0.025	0.020	0.037	0.021
2020	0.014	0.013	0.024	0.014	0.013	0.009	0.017	0.010	0.014	0.027	0.048	0.028	0.013	0.019	0.035	0.021
2021	0.013	0.012	0.022	0.013	0.012	0.009	0.016	0.009	0.013	0.014	0.024	0.014	0.012	0.010	0.018	0.011
2022	0.012	0.011	0.019	0.012	0.011	0.008	0.014	0.009	0.012	0.013	0.022	0.013	0.011	0.009	0.016	0.010
2023	0.011	0.010	0.018	0.011	0.010	0.007	0.013	0.008	0.011	0.012	0.020	0.012	0.010	0.008	0.015	0.009
2024	0.009	0.009	0.015	0.009	0.009	0.006	0.011	0.007	0.009	0.011	0.018	0.011	0.009	0.007	0.013	0.008
2025	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.009	0.016	0.010	0.000	0.006	0.011	0.007
2026	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2027																
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2034																
2035																
2036																
2037																
2038																
2039																
2040																
2041																
Levelized Cos																
10 years (2012-2021)	0.023	0.022	0.041	0.023	0.021	0.016	0.030	0.017	0.021	0.021	0.040	0.022	0.019	0.015	0.030	0.016
15 years (2012-2026)	0.018	0.017	0.032	0.018	0.017	0.012	0.024	0.013	0.016	0.018	0.033	0.018	0.015	0.013	0.024	0.014
30 years (2012-2041)	0.011	0.010	0.019	0.011	0.010	0.007	0.014	0.008	0.010	0.011	0.019	0.011	0.009	0.007	0.014	0.008

NOTES: General All Avoided Costs are in Year 2011 Dollars
ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are all other hours

Avoided Cost of Electricity (2011$) Results :

State MA

MA-NEMA
NEMA (Northeast Massachusetts)

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User-defined Inputs			
Wholesale Risk Premium (WRP)	9%	Percent of Capacity Bid into FCM (%Bid)	50.0%
Real Discount Rate	2.46%		

	Avoided Unit Cost of Electric Energy[1]				Avoided Unit Cost of Electric Capacity[2]			DRIPE: 2012 vintage measures, Intrastate Values: Energy				DRIPE: 2012 Capacity (See note 2)	DRIPE: 2013 vintage measures, Intrastate Values: Energy				DRIPE: 2013 Capacity (See note 2)	Avoided Externality Costs			
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	kW bid into FCA (PA to determine quantity)[3]	kW not bid into FCM (PA to determine quantity)	Weighted Average Avoided Cost Based on Percent Capacity Bid	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kw-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e=z*1.08 for ISO-NE losses	f=z*(1+aa)*(1+PTF Loss of 1.9%)*(1+WRP)	g=(e*%Bid)+(f*(1-%Bid))	h	i	j	k	l	m	n	o	p	q	r	s	t	u
2011	0.058	0.049	0.064	0.047														0.042	0.043	0.041	0.045
2012	0.060	0.051	0.070	0.051	37.50	0.00	18.75	0.023	0.021	0.040	0.023	$0.00						0.042	0.043	0.041	0.045
2013	0.062	0.054	0.073	0.053	36.76	0.00	18.38	0.023	0.022	0.040	0.023	$0.00	0.023	0.023	0.041	0.024	$0.00	0.042	0.043	0.041	0.045
2014	0.064	0.056	0.076	0.055	36.76	0.00	18.38	0.023	0.022	0.041	0.023	$0.00	0.024	0.023	0.043	0.024	$0.00	0.042	0.043	0.041	0.045
2015	0.070	0.061	0.082	0.060	36.76	0.00	18.38	0.026	0.024	0.044	0.025	$0.00	0.026	0.025	0.045	0.026	$0.00	0.042	0.043	0.041	0.045
2016	0.072	0.062	0.090	0.061	15.09	18.01	16.55	0.025	0.023	0.046	0.024	$83.13	0.026	0.025	0.049	0.026	$83.13	0.042	0.043	0.041	0.045
2017	0.072	0.064	0.090	0.061	22.21	26.54	24.37	0.025	0.024	0.046	0.024	$85.39	0.025	0.024	0.047	0.025	$85.39	0.042	0.043	0.041	0.045
2018	0.078	0.070	0.099	0.067	31.01	37.09	34.05	0.027	0.027	0.052	0.028	$86.75	0.028	0.027	0.053	0.028	$86.75	0.035	0.036	0.034	0.037
2019	0.077	0.070	0.096	0.067	34.80	41.66	38.23	0.027	0.027	0.050	0.028	$83.35	0.028	0.028	0.051	0.028	$83.35	0.034	0.034	0.033	0.035
2020	0.079	0.069	0.091	0.068	48.69	58.34	53.52	0.014	0.013	0.024	0.014	$27.75	0.014	0.027	0.048	0.028	$27.75	0.032	0.033	0.031	0.034
2021	0.080	0.071	0.092	0.069	49.61	59.51	54.56	0.013	0.012	0.022	0.013	$27.90	0.013	0.014	0.024	0.014	$27.90	0.030	0.031	0.030	0.032
2022	0.083	0.073	0.094	0.072	74.46	89.42	81.94	0.012	0.011	0.019	0.012	$280.47	0.012	0.013	0.022	0.013	$280.47	0.029	0.029	0.028	0.030
2023	0.088	0.077	0.099	0.075	89.72	107.86	98.79	0.011	0.010	0.018	0.011	$138.27	0.011	0.012	0.020	0.012	$138.27	0.027	0.028	0.026	0.029
2024	0.090	0.079	0.101	0.077	98.16	118.14	108.15	0.009	0.009	0.015	0.009	$66.05	0.009	0.011	0.018	0.011	$66.05	0.025	0.026	0.025	0.027
2025	0.091	0.079	0.101	0.079	101.86	122.72	112.29					$33.59					$33.59	0.024	0.024	0.023	0.025
2026	0.091	0.079	0.104	0.078	104.09	125.53	114.81					$14.49					$14.49	0.022	0.023	0.022	0.023
2027	0.094	0.081	0.107	0.080	104.98	126.75	115.86											0.022	0.023	0.022	0.023
2028	0.097	0.083	0.110	0.082	105.49	127.51	116.50											0.022	0.023	0.022	0.023
2029	0.099	0.085	0.113	0.085	105.62	127.81	116.72											0.022	0.023	0.022	0.023
2030	0.102	0.087	0.116	0.087	105.75	128.11	116.93											0.022	0.023	0.022	0.023
2031	0.105	0.089	0.119	0.090	105.88	128.41	117.15											0.022	0.023	0.022	0.023
2032	0.109	0.092	0.122	0.092	105.88	128.55	117.22											0.022	0.023	0.022	0.023
2033	0.112	0.094	0.126	0.095	105.88	128.70	117.29											0.022	0.023	0.022	0.023
2034	0.115	0.097	0.129	0.098	105.88	128.84	117.36											0.022	0.023	0.022	0.023
2035	0.119	0.099	0.133	0.101	105.88	128.99	117.43											0.022	0.023	0.022	0.023
2036	0.123	0.102	0.137	0.104	105.88	129.13	117.51											0.022	0.023	0.022	0.023
2037	0.126	0.104	0.140	0.107	105.88	129.28	117.58											0.022	0.023	0.022	0.023
2038	0.130	0.107	0.144	0.110	105.88	129.43	117.65											0.022	0.023	0.022	0.023
2039	0.134	0.110	0.149	0.114	105.88	129.57	117.73											0.022	0.023	0.022	0.023
2040	0.139	0.113	0.153	0.117	105.88	129.72	117.80											0.022	0.023	0.022	0.023
2041	0.143	0.116	0.157	0.121	105.88	129.87	117.88											0.022	0.023	0.022	0.023
Levelized Costs																					
10 years (2012-2021)	0.071	0.062	0.085	0.061	34.73	22.58	28.65	0.023	0.022	0.041	0.023	38.02	0.021	0.022	0.041	0.023	38.95	0.039	0.040	0.038	0.041
15 years (2012-2026)	0.076	0.067	0.090	0.065	51.93	48.94	50.44	0.018	0.017	0.032	0.018	59.07	0.017	0.018	0.033	0.018	60.52	0.035	0.036	0.034	0.037
30 years (2012-2041)	0.092	0.079	0.106	0.079	73.99	81.60	77.80											0.030	0.030	0.029	0.031

NOTES:

General: All Avoided Costs are in Year 2011 Dollars

ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 7 AM - 11 PM; Off-Peak Hours are all other hours

1 Avoided cost of electric energy = (wholesale energy avoided cost + REC cost to load) * risk premium, e.g. A= (V + AB) * (1+Wholesale Risk Premium)

2 Absolute value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year and PA strategy about bidding that reduction into applicable FCAs, and unit values in columns e, f, l and q.

3 Proceeds from selling into the FCM include the reserve margin, in addition to the ISO-NE loss factor of 8%

Page Two: Inputs to Avoided Cost Calculations

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Zone: MA-NEMA

	Wholesale Avoided Costs of Electricity – Energy				Wholesale Avoided Costs of Electricity – Capacity		Avoided REC Costs to Load
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	FCA Price	Reserve Margin	REC Costs
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	%	$/kWh
Period:	v	w	x	y	z	aa	ab
2011	0.049	0.042	0.055	0.040	43.20		0.0034
2012	0.051	0.043	0.061	0.043	34.72	16.6%	0.0038
2013	0.052	0.045	0.062	0.044	34.04	15.7%	0.0045
2014	0.054	0.046	0.065	0.045	34.04	17.7%	0.0051
2015	0.059	0.050	0.070	0.049	34.04	15.9%	0.0058
2016	0.059	0.050	0.076	0.050	13.98	16.0%	0.0065
2017	0.059	0.052	0.075	0.049	20.56	16.2%	0.0071
2018	0.065	0.058	0.085	0.056	28.72	16.3%	0.0061
2019	0.066	0.060	0.084	0.057	32.22	16.4%	0.0045
2020	0.068	0.059	0.079	0.057	45.08	16.5%	0.0047
2021	0.069	0.061	0.080	0.059	45.94	16.6%	0.0041
2022	0.071	0.062	0.082	0.061	68.95	16.8%	0.0047
2023	0.075	0.065	0.085	0.064	83.08	16.9%	0.0053
2024	0.078	0.067	0.087	0.066	90.89	17.0%	0.0051
2025	0.079	0.068	0.089	0.068	94.32	17.1%	0.0042
2026	0.081	0.070	0.093	0.069	96.38	17.3%	0.0029
2027	0.083	0.071	0.095	0.071	97.20	17.4%	0.0027
2028	0.086	0.073	0.098	0.073	97.68	17.5%	0.0025
2029	0.089	0.075	0.101	0.075	97.80	17.7%	0.0024
2030	0.092	0.077	0.104	0.078	97.92	17.8%	0.0023
2031	0.094	0.080	0.107	0.080	98.04	17.9%	0.0023
2032	0.097	0.082	0.110	0.083	98.04	18.1%	0.0023
2033	0.100	0.084	0.113	0.085	98.04	18.2%	0.0023
2034	0.104	0.086	0.116	0.088	98.04	18.3%	0.0023
2035	0.107	0.089	0.120	0.090	98.04	18.5%	0.0023
2036	0.110	0.091	0.123	0.093	98.04	18.6%	0.0023
2037	0.114	0.093	0.127	0.096	98.04	18.7%	0.0023
2038	0.117	0.096	0.130	0.099	98.04	18.9%	0.0023
2039	0.121	0.099	0.134	0.102	98.04	19.0%	0.0023
2040	0.125	0.101	0.138	0.105	98.04	19.1%	0.0023
2041	0.129	0.104	0.142	0.108	98.04	19.3%	0.0023
Levelized Cos							
10 years (2012-2021)	0.060	0.052	0.073	0.051	32.15		0.005
15 years (2012-2026)	0.065	0.056	0.077	0.055	48.09		0.005
30 years (2012-2041)	0.081	0.068	0.093	0.068	68.51		0.004

	2012 Energy DRIPE Values – Intrastate Installation				2012 Energy DRIPE Values – Rest of Pool Installation			
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh
Period:	ac	ad	ae	af	ag	ah	ai	aj
2011								
2012	0.023	0.021	0.040	0.023	0.021	0.015	0.029	0.017
2013	0.023	0.022	0.040	0.023	0.022	0.016	0.030	0.017
2014	0.023	0.022	0.041	0.023	0.022	0.016	0.031	0.017
2015	0.026	0.024	0.044	0.025	0.025	0.018	0.034	0.019
2016	0.025	0.023	0.046	0.024	0.023	0.017	0.034	0.018
2017	0.025	0.024	0.046	0.024	0.023	0.017	0.034	0.018
2018	0.027	0.027	0.052	0.028	0.025	0.019	0.038	0.020
2019	0.027	0.027	0.050	0.028	0.025	0.019	0.037	0.020
2020	0.014	0.013	0.024	0.014	0.013	0.009	0.017	0.010
2021	0.013	0.012	0.022	0.013	0.012	0.009	0.016	0.009
2022	0.012	0.011	0.019	0.012	0.011	0.008	0.014	0.009
2023	0.011	0.010	0.018	0.011	0.010	0.007	0.013	0.008
2024	0.009	0.009	0.015	0.009	0.009	0.006	0.011	0.007
2025	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2026	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
10 years (2012-2021)	0.023	0.022	0.041	0.023	0.021	0.016	0.030	0.017
15 years (2012-2026)	0.018	0.017	0.032	0.018	0.017	0.012	0.024	0.013
30 years (2012-2041)	0.011	0.010	0.019	0.011	0.010	0.007	0.014	0.008

	2013 Energy DRIPE Values – Intrastate Installation				2013 Energy DRIPE Values – Rest of Pool Installation			
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh
Period:	ak	al	am	an	ao	ap	aq	ar
2011								
2012	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2013	0.023	0.023	0.041	0.024	0.022	0.016	0.031	0.018
2014	0.024	0.023	0.043	0.024	0.023	0.017	0.032	0.018
2015	0.026	0.025	0.045	0.026	0.025	0.018	0.034	0.020
2016	0.026	0.025	0.049	0.026	0.025	0.018	0.037	0.020
2017	0.025	0.024	0.047	0.025	0.023	0.017	0.035	0.018
2018	0.028	0.027	0.053	0.028	0.025	0.019	0.038	0.021
2019	0.028	0.028	0.051	0.028	0.025	0.020	0.037	0.021
2020	0.014	0.027	0.048	0.028	0.013	0.019	0.035	0.021
2021	0.013	0.014	0.024	0.014	0.012	0.010	0.018	0.011
2022	0.012	0.013	0.022	0.013	0.011	0.009	0.016	0.010
2023	0.011	0.012	0.020	0.012	0.010	0.008	0.015	0.009
2024	0.009	0.011	0.018	0.011	0.009	0.007	0.013	0.008
2025	0.000	0.009	0.016	0.010	0.000	0.006	0.011	0.007
2026	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
10 years (2012-2021)	0.021	0.021	0.040	0.022	0.019	0.015	0.030	0.016
15 years (2012-2026)	0.016	0.018	0.033	0.018	0.015	0.013	0.024	0.014
30 years (2012-2041)	0.010	0.011	0.019	0.011	0.009	0.007	0.014	0.008

NOTES: General All Avoided Costs are in Year 2011 Dollars
ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are all other hours

Avoided Cost of Electricity (2011$) Results :

State MA

MA-R
Rest of Massachusetts (Massachusetts excluding NEMA)

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User-defined Inputs			
Wholesale Risk Premium (WRP)	9%	Percent of Capacity Bid into FCM (%Bid)	50.0%
Real Discount Rate	2.46%		

	Avoided Unit Cost of Electric Energy[1]				Avoided Unit Cost of Electric Capacity[2]			DRIPE: 2012 vintage measures, Intrastate Values: Energy				DRIPE: 2012 vintage measures, Intrastate Values: Capacity (See note 2)	DRIPE: 2013 vintage measures, Intrastate Values: Energy				DRIPE: 2013 vintage measures, Intrastate Values: Capacity (See note 2)	Avoided Externality Costs			
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	kW bid into FCA (PA to determine quantity)[3]	kW not bid into FCM (PA to determine quantity)	Weighted Average Avoided Cost Based on Percent Capacity Bid	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kw-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e=z*1.08 for ISO-NE losses	f=z*(1+aa)*(1+PTF Loss of 1.9%)*(1+WRP)	g=(e*%Bid)+(f*(1-%Bid))	h	i	j	k	l	m	n	o	p	q	r	s	t	u
2011	0.058	0.050	0.064	0.047														0.042	0.043	0.041	0.045
2012	0.060	0.051	0.071	0.051	37.50	0.00	18.75	0.023	0.021	0.040	0.023	$0.00						0.042	0.043	0.041	0.045
2013	0.062	0.054	0.074	0.053	36.76	0.00	18.38	0.023	0.022	0.040	0.023	$0.00	0.023	0.023	0.041	0.024	$0.00	0.042	0.043	0.041	0.045
2014	0.064	0.057	0.077	0.055	36.76	0.00	18.38	0.023	0.022	0.041	0.023	$0.00	0.024	0.023	0.043	0.024	$0.00	0.042	0.043	0.041	0.045
2015	0.071	0.062	0.083	0.061	36.76	0.00	18.38	0.026	0.024	0.044	0.025	$0.00	0.026	0.025	0.045	0.026	$0.00	0.042	0.043	0.041	0.045
2016	0.072	0.063	0.090	0.062	15.09	18.01	16.55	0.025	0.023	0.046	0.024	$83.13	0.026	0.025	0.049	0.026	$83.13	0.042	0.043	0.041	0.045
2017	0.073	0.065	0.091	0.062	22.21	26.54	24.37	0.025	0.024	0.046	0.024	$85.39	0.025	0.024	0.047	0.025	$85.39	0.042	0.043	0.041	0.045
2018	0.079	0.071	0.100	0.068	31.01	37.09	34.05	0.027	0.027	0.052	0.028	$86.75	0.028	0.027	0.053	0.028	$86.75	0.035	0.036	0.034	0.037
2019	0.078	0.071	0.097	0.068	34.80	41.66	38.23	0.027	0.027	0.050	0.028	$83.35	0.028	0.028	0.051	0.028	$83.35	0.034	0.034	0.033	0.035
2020	0.080	0.070	0.092	0.069	48.69	58.34	53.52	0.014	0.013	0.024	0.014	$27.75	0.014	0.027	0.048	0.028	$27.75	0.032	0.033	0.031	0.034
2021	0.081	0.072	0.093	0.070	49.61	59.51	54.56	0.013	0.012	0.022	0.013	$27.90	0.013	0.014	0.024	0.014	$27.90	0.030	0.031	0.030	0.032
2022	0.084	0.074	0.096	0.073	74.46	89.42	81.94	0.012	0.011	0.019	0.012	$280.47	0.012	0.013	0.022	0.013	$280.47	0.029	0.029	0.028	0.030
2023	0.089	0.078	0.100	0.077	89.72	107.86	98.79	0.011	0.010	0.018	0.011	$138.27	0.011	0.012	0.020	0.012	$138.27	0.027	0.028	0.026	0.029
2024	0.092	0.080	0.102	0.079	98.16	118.14	108.15	0.009	0.009	0.015	0.009	$66.05	0.009	0.011	0.018	0.011	$66.05	0.025	0.026	0.025	0.027
2025	0.092	0.080	0.103	0.080	101.86	122.72	112.29					$33.59					$33.59	0.024	0.024	0.023	0.025
2026	0.093	0.081	0.106	0.080	104.09	125.53	114.81					$14.49					$14.49	0.022	0.023	0.022	0.023
2027	0.095	0.082	0.108	0.082	104.98	126.75	115.86											0.022	0.023	0.022	0.023
2028	0.098	0.084	0.111	0.084	105.49	127.51	116.50											0.022	0.023	0.022	0.023
2029	0.101	0.087	0.114	0.087	105.62	127.81	116.72											0.022	0.023	0.022	0.023
2030	0.104	0.089	0.117	0.089	105.75	128.11	116.93											0.022	0.023	0.022	0.023
2031	0.107	0.091	0.121	0.092	105.88	128.41	117.15											0.022	0.023	0.022	0.023
2032	0.111	0.094	0.124	0.095	105.88	128.55	117.22											0.022	0.023	0.022	0.023
2033	0.114	0.096	0.128	0.097	105.88	128.70	117.29											0.022	0.023	0.022	0.023
2034	0.117	0.099	0.131	0.100	105.88	128.84	117.36											0.022	0.023	0.022	0.023
2035	0.121	0.101	0.135	0.103	105.88	128.99	117.43											0.022	0.023	0.022	0.023
2036	0.125	0.104	0.139	0.106	105.88	129.13	117.51											0.022	0.023	0.022	0.023
2037	0.129	0.107	0.143	0.110	105.88	129.28	117.58											0.022	0.023	0.022	0.023
2038	0.133	0.110	0.147	0.113	105.88	129.43	117.65											0.022	0.023	0.022	0.023
2039	0.137	0.113	0.151	0.116	105.88	129.57	117.73											0.022	0.023	0.022	0.023
2040	0.141	0.116	0.155	0.120	105.88	129.72	117.80											0.022	0.023	0.022	0.023
2041	0.146	0.119	0.160	0.124	105.88	129.87	117.88											0.022	0.023	0.022	0.023
Levelized Costs																					
10 years (2012-2021)	0.071	0.063	0.086	0.062	34.73	22.58	28.65	0.023	0.022	0.041	0.023	38.02	0.021	0.022	0.041	0.023	38.95	0.039	0.040	0.038	0.041
15 years (2012-2026)	0.077	0.068	0.091	0.066	51.93	48.94	50.44	0.018	0.017	0.032	0.018	59.07	0.017	0.018	0.033	0.018	60.52	0.035	0.036	0.034	0.037
30 years (2012-2041)	0.093	0.080	0.107	0.080	73.99	81.60	77.80											0.030	0.030	0.029	0.031

NOTES:

General: All Avoided Costs are in Year 2011 Dollars

ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 7 AM - 11 PM; Off-Peak Hours are all other hours

1 Avoided cost of electric energy = (wholesale energy avoided cost + REC cost to load) * risk premium, e.g. A= (V + AB) * (1+Wholesale Risk Premium)

2 Absolute value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year and PA strategy about bidding that reduction into applicable FCAs, and unit values in columns e, f, l and q.

3 Proceeds from selling into the FCM include the reserve margin, in addition to the ISO-NE loss factor of 8%

Page Two: Inputs to Avoided Cost Calculations

Zone: MA-R

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	Wholesale Avoided Costs of Electricity						
	Energy				Capacity		Avoided REC Costs to Load
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	FCA Price	Reserve Margin	REC Costs
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	%	$/kWh
Period:	v	w	x	y	z	aa	ab
2011	0.050	0.042	0.056	0.040	43.20		0.0034
2012	0.051	0.043	0.061	0.043	34.72	16.6%	0.0038
2013	0.052	0.045	0.063	0.045	34.04	15.7%	0.0045
2014	0.054	0.047	0.065	0.046	34.04	17.7%	0.0051
2015	0.059	0.051	0.070	0.050	34.04	15.9%	0.0058
2016	0.060	0.051	0.076	0.050	13.98	16.0%	0.0065
2017	0.060	0.052	0.076	0.050	20.56	16.2%	0.0071
2018	0.066	0.059	0.086	0.057	28.72	16.3%	0.0061
2019	0.067	0.061	0.084	0.058	32.22	16.4%	0.0045
2020	0.068	0.060	0.080	0.058	45.08	16.5%	0.0047
2021	0.070	0.062	0.082	0.060	45.94	16.6%	0.0041
2022	0.072	0.063	0.083	0.062	68.95	16.8%	0.0047
2023	0.076	0.066	0.087	0.065	83.08	16.9%	0.0053
2024	0.079	0.068	0.088	0.067	90.89	17.0%	0.0051
2025	0.080	0.069	0.090	0.069	94.32	17.1%	0.0042
2026	0.082	0.071	0.094	0.070	96.38	17.3%	0.0029
2027	0.085	0.073	0.097	0.072	97.20	17.4%	0.0027
2028	0.087	0.075	0.100	0.075	97.68	17.5%	0.0025
2029	0.090	0.077	0.103	0.077	97.80	17.7%	0.0024
2030	0.093	0.079	0.105	0.079	97.92	17.8%	0.0023
2031	0.096	0.081	0.109	0.082	98.04	17.9%	0.0023
2032	0.099	0.084	0.112	0.084	98.04	18.1%	0.0023
2033	0.102	0.086	0.115	0.087	98.04	18.2%	0.0023
2034	0.106	0.088	0.118	0.090	98.04	18.3%	0.0023
2035	0.109	0.091	0.122	0.093	98.04	18.5%	0.0023
2036	0.112	0.093	0.125	0.095	98.04	18.6%	0.0023
2037	0.116	0.096	0.129	0.098	98.04	18.7%	0.0023
2038	0.120	0.098	0.133	0.101	98.04	18.9%	0.0023
2039	0.123	0.101	0.136	0.105	98.04	19.0%	0.0023
2040	0.127	0.104	0.140	0.108	98.04	19.1%	0.0023
2041	0.131	0.107	0.144	0.111	98.04	19.3%	0.0023
Levelized Cos							
10 years (2012-2021)	0.060	0.053	0.074	0.051	32.15		0.005
15 years (2012-2026)	0.066	0.057	0.078	0.056	48.09		0.005
30 years (2012-2041)	0.082	0.070	0.094	0.070	68.51		0.004

	2012 Energy DRIPE Values								2013 Energy DRIPE Values							
	Intrastate Installation				Rest of Pool Installation				Intrastate Installation				Rest of Pool Installation			
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh
Period:	ac	ad	ae	af	ag	ah	ai	aj	ak	al	am	an	ao	ap	aq	ar
2011																
2012	0.023	0.021	0.040	0.023	0.021	0.015	0.029	0.017	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2013	0.023	0.022	0.040	0.023	0.022	0.016	0.030	0.017	0.023	0.023	0.041	0.024	0.022	0.016	0.031	0.018
2014	0.023	0.022	0.041	0.023	0.022	0.016	0.031	0.017	0.024	0.023	0.043	0.024	0.023	0.017	0.032	0.018
2015	0.026	0.024	0.044	0.025	0.025	0.018	0.034	0.019	0.026	0.025	0.045	0.026	0.025	0.018	0.034	0.020
2016	0.025	0.023	0.046	0.024	0.023	0.017	0.034	0.018	0.026	0.025	0.049	0.026	0.025	0.018	0.037	0.020
2017	0.025	0.024	0.046	0.024	0.023	0.017	0.034	0.018	0.025	0.024	0.047	0.025	0.023	0.017	0.035	0.018
2018	0.027	0.027	0.052	0.028	0.025	0.019	0.038	0.020	0.028	0.027	0.053	0.028	0.025	0.019	0.038	0.021
2019	0.027	0.027	0.050	0.028	0.025	0.019	0.037	0.020	0.028	0.028	0.051	0.028	0.025	0.020	0.037	0.021
2020	0.014	0.013	0.024	0.014	0.013	0.009	0.017	0.010	0.014	0.027	0.048	0.028	0.013	0.019	0.035	0.021
2021	0.013	0.012	0.022	0.013	0.012	0.009	0.016	0.009	0.013	0.014	0.024	0.014	0.012	0.010	0.018	0.011
2022	0.012	0.011	0.019	0.012	0.011	0.008	0.014	0.009	0.012	0.013	0.022	0.013	0.011	0.009	0.016	0.010
2023	0.011	0.010	0.018	0.011	0.010	0.007	0.013	0.008	0.011	0.012	0.020	0.012	0.010	0.008	0.015	0.009
2024	0.009	0.009	0.015	0.009	0.009	0.006	0.011	0.007	0.009	0.011	0.018	0.011	0.009	0.007	0.013	0.008
2025	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.009	0.016	0.010	0.000	0.006	0.011	0.007
2026	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Levelized Cos																
10 years (2012-2021)	0.023	0.022	0.041	0.023	0.021	0.016	0.030	0.017	0.021	0.021	0.040	0.022	0.019	0.015	0.030	0.016
15 years (2012-2026)	0.018	0.017	0.032	0.018	0.017	0.012	0.024	0.013	0.016	0.018	0.033	0.018	0.015	0.013	0.024	0.014
30 years (2012-2041)	0.011	0.010	0.019	0.011	0.010	0.007	0.014	0.008	0.010	0.011	0.019	0.011	0.009	0.007	0.014	0.008

NOTES: General All Avoided Costs are in Year 2011 Dollars
ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are all other hours

Avoided Cost of Electricity (2011$) Results :

State MA

MA-SEMA
SEMA (Southeast Massachusetts)

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User-defined Inputs			
Wholesale Risk Premium (WRP)	9%	Percent of Capacity Bid into FCM (%Bid)	50.0%
Real Discount Rate	2.46%		

	Avoided Unit Cost of Electric Energy[1]				Avoided Unit Cost of Electric Capacity[2]			DRIPE: 2012 vintage measures Intrastate Values					DRIPE: 2013 vintage measures Intrastate Values					Avoided Externality Costs			
								Energy				Capacity (See note 2)	Energy				Capacity (See note 2)				
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	kW bid into FCA (PA to determine quantity)[3]	kW not bid into FCM (PA to determine quantity)	Weighted Average Avoided Cost Based on Percent Capacity Bid	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kw-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e=z*1.08 for ISO-NE losses	f=z*(1+aa)*(1+PTF Loss of 1.9%)*(1+WRP)	g=(e*%Bid)+(f*(1-%Bid))	h	i	j	k	l	m	n	o	p	q	r	s	t	u
2011	0.057	0.050	0.063	0.047														0.042	0.043	0.041	0.045
2012	0.059	0.051	0.070	0.051	37.50	0.00	18.75	0.023	0.021	0.040	0.023	$0.00						0.042	0.043	0.041	0.045
2013	0.061	0.054	0.072	0.053	36.76	0.00	18.38	0.023	0.022	0.040	0.023	$0.00	0.023	0.023	0.041	0.024	$0.00	0.042	0.043	0.041	0.045
2014	0.063	0.056	0.075	0.055	36.76	0.00	18.38	0.023	0.022	0.041	0.023	$0.00	0.024	0.023	0.043	0.024	$0.00	0.042	0.043	0.041	0.045
2015	0.070	0.062	0.081	0.060	36.76	0.00	18.38	0.026	0.024	0.044	0.025	$0.00	0.026	0.025	0.045	0.026	$0.00	0.042	0.043	0.041	0.045
2016	0.071	0.063	0.089	0.061	15.09	18.01	16.55	0.025	0.023	0.046	0.024	$83.13	0.026	0.025	0.049	0.026	$83.13	0.042	0.043	0.041	0.045
2017	0.072	0.065	0.089	0.062	22.21	26.54	24.37	0.025	0.024	0.046	0.024	$85.39	0.025	0.024	0.047	0.025	$85.39	0.042	0.043	0.041	0.045
2018	0.077	0.070	0.098	0.068	31.01	37.09	34.05	0.027	0.027	0.052	0.028	$86.75	0.028	0.027	0.053	0.028	$86.75	0.035	0.036	0.034	0.037
2019	0.077	0.071	0.095	0.067	34.80	41.66	38.23	0.027	0.027	0.050	0.028	$83.35	0.028	0.028	0.051	0.028	$83.35	0.034	0.034	0.033	0.035
2020	0.079	0.070	0.091	0.069	48.69	58.34	53.52	0.014	0.013	0.024	0.014	$27.75	0.014	0.027	0.048	0.028	$27.75	0.032	0.033	0.031	0.034
2021	0.080	0.072	0.092	0.070	49.61	59.51	54.56	0.013	0.012	0.022	0.013	$27.90	0.013	0.014	0.024	0.014	$27.90	0.030	0.031	0.030	0.032
2022	0.083	0.074	0.095	0.072	74.46	89.42	81.94	0.012	0.011	0.019	0.012	$280.47	0.012	0.013	0.022	0.013	$280.47	0.029	0.029	0.028	0.030
2023	0.088	0.078	0.099	0.077	89.72	107.86	98.79	0.011	0.010	0.018	0.011	$138.27	0.011	0.012	0.020	0.012	$138.27	0.027	0.028	0.026	0.029
2024	0.091	0.080	0.101	0.078	98.16	118.14	108.15	0.009	0.009	0.015	0.009	$66.05	0.009	0.011	0.018	0.011	$66.05	0.025	0.026	0.025	0.027
2025	0.092	0.080	0.102	0.080	101.86	122.72	112.29					$33.59					$33.59	0.024	0.024	0.023	0.025
2026	0.092	0.080	0.105	0.080	104.09	125.53	114.81					$14.49					$14.49	0.022	0.023	0.022	0.023
2027	0.095	0.082	0.108	0.082	104.98	126.75	115.86											0.022	0.023	0.022	0.023
2028	0.097	0.084	0.111	0.084	105.49	127.51	116.50											0.022	0.023	0.022	0.023
2029	0.100	0.086	0.114	0.087	105.62	127.81	116.72											0.022	0.023	0.022	0.023
2030	0.103	0.089	0.117	0.089	105.75	128.11	116.93											0.022	0.023	0.022	0.023
2031	0.106	0.091	0.120	0.092	105.88	128.41	117.15											0.022	0.023	0.022	0.023
2032	0.110	0.094	0.124	0.095	105.88	128.55	117.22											0.022	0.023	0.022	0.023
2033	0.113	0.096	0.128	0.098	105.88	128.70	117.29											0.022	0.023	0.022	0.023
2034	0.117	0.099	0.131	0.101	105.88	128.84	117.36											0.022	0.023	0.022	0.023
2035	0.120	0.101	0.135	0.104	105.88	128.99	117.43											0.022	0.023	0.022	0.023
2036	0.124	0.104	0.139	0.107	105.88	129.13	117.51											0.022	0.023	0.022	0.023
2037	0.128	0.107	0.143	0.111	105.88	129.28	117.58											0.022	0.023	0.022	0.023
2038	0.132	0.110	0.147	0.114	105.88	129.43	117.65											0.022	0.023	0.022	0.023
2039	0.136	0.113	0.152	0.118	105.88	129.57	117.73											0.022	0.023	0.022	0.023
2040	0.140	0.116	0.156	0.121	105.88	129.72	117.80											0.022	0.023	0.022	0.023
2041	0.145	0.119	0.161	0.125	105.88	129.87	117.88											0.022	0.023	0.022	0.023
Levelized Costs																					
10 years (2012-2021)	0.071	0.063	0.085	0.061	34.73	22.58	28.65	0.023	0.022	0.041	0.023	38.02	0.021	0.022	0.041	0.023	38.95	0.039	0.040	0.038	0.041
15 years (2012-2026)	0.076	0.067	0.089	0.066	51.93	48.94	50.44	0.018	0.017	0.032	0.018	59.07	0.017	0.018	0.033	0.018	60.52	0.035	0.036	0.034	0.037
30 years (2012-2041)	0.093	0.080	0.106	0.080	73.99	81.60	77.80											0.030	0.030	0.029	0.031

NOTES:

General All Avoided Costs are in Year 2011 Dollars

ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 7 AM - 11 PM; Off-Peak Hours are all other hours

1 Avoided cost of electric energy = (wholesale energy avoided cost + REC cost to load) * risk premium, e.g. A= (V + AB) * (1+Wholesale Risk Premium)

2 Absolute value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year and PA strategy about bidding that reduction into applicable FCAs, and unit values in columns e, f, l and q.

3 Proceeds from selling into the FCM include the reserve margin, in addition to the ISO-NE loss factor of 8%

Page Two: Inputs to Avoided Cost Calculations

Zone: MA-SEMA

	Wholesale Avoided Costs of Electricity						Avoided REC Costs to Load
	Energy				Capacity		
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	FCA Price	Reserve Margin	REC Costs
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	%	$/kWh
Period:	v	w	x	y	z	aa	ab
2011	0.049	0.042	0.055	0.040	43.20		0.0034
2012	0.051	0.043	0.060	0.043	34.72	16.6%	0.0038
2013	0.052	0.045	0.062	0.044	34.04	15.7%	0.0045
2014	0.053	0.047	0.064	0.045	34.04	17.7%	0.0051
2015	0.058	0.051	0.069	0.049	34.04	15.9%	0.0058
2016	0.059	0.051	0.075	0.050	13.98	16.0%	0.0065
2017	0.059	0.052	0.075	0.049	20.56	16.2%	0.0071
2018	0.065	0.058	0.084	0.056	28.72	16.3%	0.0061
2019	0.066	0.060	0.083	0.057	32.22	16.4%	0.0045
2020	0.068	0.059	0.079	0.058	45.08	16.5%	0.0047
2021	0.070	0.062	0.081	0.060	45.94	16.6%	0.0041
2022	0.071	0.063	0.082	0.062	68.95	16.8%	0.0047
2023	0.076	0.066	0.086	0.065	83.08	16.9%	0.0053
2024	0.078	0.068	0.087	0.067	90.89	17.0%	0.0051
2025	0.080	0.069	0.089	0.069	94.32	17.1%	0.0042
2026	0.082	0.071	0.093	0.070	96.38	17.3%	0.0029
2027	0.084	0.073	0.096	0.073	97.20	17.4%	0.0027
2028	0.087	0.075	0.099	0.075	97.68	17.5%	0.0025
2029	0.090	0.077	0.102	0.077	97.80	17.7%	0.0024
2030	0.092	0.079	0.105	0.080	97.92	17.8%	0.0023
2031	0.095	0.081	0.108	0.082	98.04	17.9%	0.0023
2032	0.098	0.084	0.111	0.085	98.04	18.1%	0.0023
2033	0.102	0.086	0.115	0.088	98.04	18.2%	0.0023
2034	0.105	0.088	0.118	0.090	98.04	18.3%	0.0023
2035	0.108	0.091	0.122	0.093	98.04	18.5%	0.0023
2036	0.112	0.093	0.125	0.096	98.04	18.6%	0.0023
2037	0.115	0.096	0.129	0.099	98.04	18.7%	0.0023
2038	0.119	0.098	0.133	0.102	98.04	18.9%	0.0023
2039	0.123	0.101	0.137	0.106	98.04	19.0%	0.0023
2040	0.127	0.104	0.141	0.109	98.04	19.1%	0.0023
2041	0.131	0.107	0.145	0.113	98.04	19.3%	0.0023
Levelized Cos							
10 years (2012-2021)	0.060	0.052	0.073	0.051	32.15		0.005
15 years (2012-2026)	0.065	0.057	0.077	0.055	48.09		0.005
30 years (2012-2041)	0.081	0.069	0.094	0.070	68.51		0.004

	2012 Energy DRIPE Values								2013 Energy DRIPE Values							
	Intrastate Installation				Rest of Pool Installation				Intrastate Installation				Rest of Pool Installation			
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh
Period:	ac	ad	ae	af	ag	ah	ai	aj	ak	al	am	an	ao	ap	aq	ar
2011																
2012	0.023	0.021	0.040	0.023	0.021	0.015	0.029	0.017	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2013	0.023	0.022	0.040	0.023	0.022	0.016	0.030	0.017	0.023	0.023	0.041	0.024	0.022	0.016	0.031	0.018
2014	0.023	0.022	0.041	0.023	0.022	0.016	0.031	0.017	0.024	0.023	0.043	0.024	0.023	0.017	0.032	0.018
2015	0.026	0.024	0.044	0.025	0.025	0.018	0.034	0.019	0.026	0.025	0.045	0.026	0.025	0.018	0.034	0.020
2016	0.025	0.023	0.046	0.024	0.023	0.017	0.034	0.018	0.026	0.025	0.049	0.026	0.025	0.018	0.037	0.020
2017	0.025	0.024	0.046	0.024	0.023	0.017	0.034	0.018	0.025	0.024	0.047	0.025	0.023	0.017	0.035	0.018
2018	0.027	0.027	0.052	0.028	0.025	0.019	0.038	0.020	0.028	0.027	0.053	0.028	0.025	0.019	0.038	0.021
2019	0.027	0.027	0.050	0.028	0.025	0.019	0.037	0.020	0.028	0.028	0.051	0.028	0.025	0.020	0.037	0.021
2020	0.014	0.013	0.024	0.014	0.013	0.009	0.017	0.010	0.014	0.027	0.048	0.028	0.013	0.019	0.035	0.021
2021	0.013	0.012	0.022	0.013	0.012	0.009	0.016	0.009	0.013	0.014	0.024	0.014	0.012	0.010	0.018	0.011
2022	0.012	0.011	0.019	0.012	0.011	0.008	0.014	0.009	0.012	0.013	0.022	0.013	0.011	0.009	0.016	0.010
2023	0.011	0.010	0.018	0.011	0.010	0.007	0.013	0.008	0.011	0.012	0.020	0.012	0.010	0.008	0.015	0.009
2024	0.009	0.009	0.015	0.009	0.009	0.006	0.011	0.007	0.009	0.011	0.018	0.011	0.009	0.007	0.013	0.008
2025	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.009	0.016	0.010	0.000	0.006	0.011	0.007
2026	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2027–2041																
Levelized Cos																
10 years (2012-2021)	0.023	0.022	0.041	0.023	0.021	0.016	0.030	0.017	0.021	0.021	0.040	0.022	0.019	0.015	0.030	0.016
15 years (2012-2026)	0.018	0.017	0.032	0.018	0.017	0.012	0.024	0.013	0.016	0.018	0.033	0.018	0.015	0.013	0.024	0.014
30 years (2012-2041)	0.011	0.010	0.019	0.011	0.010	0.007	0.014	0.008	0.010	0.011	0.019	0.011	0.009	0.007	0.014	0.008

NOTES: General — All Avoided Costs are in Year 2011 Dollars
ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are all other hours

Avoided Cost of Electricity (2011$) Results :

MA-WCMA

WCMA (West-Central Massachusetts)

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State MA

User-defined Inputs			
Wholesale Risk Premium (WRP)	9%	Percent of Capacity Bid into FCM (%Bid)	50.0%
Real Discount Rate	2.46%		

	Avoided Unit Cost of Electric Energy[1]				Avoided Unit Cost of Electric Capacity[2]			DRIPE: 2012 vintage measures, Intrastate Values: Energy				DRIPE: 2012 vintage measures, Intrastate Values: Capacity (See note 2)	DRIPE: 2013 vintage measures, Intrastate Values: Energy				DRIPE: 2013 vintage measures, Intrastate Values: Capacity (See note 2)	Avoided Externality Costs			
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	kW bid into FCA (PA to determine quantity)[3]	kW not bid into FCM (PA to determine quantity)	Weighted Average Avoided Cost Based on Percent Capacity Bid	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kw-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e=z*1.08 for ISO-NE losses	f=z*(1+aa)*(1+PTF Loss of 1.9%)*(1+WRP)	g=(e*%Bid)+(f*(1-%Bid))	h	i	j	k	l	m	n	o	p	q	r	s	t	u
2011	0.058	0.050	0.065	0.048														0.042	0.043	0.041	0.045
2012	0.060	0.052	0.071	0.052	37.50	0.00	18.75	0.023	0.021	0.040	0.023	$0.00						0.042	0.043	0.041	0.045
2013	0.062	0.055	0.074	0.054	36.76	0.00	18.38	0.023	0.022	0.040	0.023	$0.00	0.023	0.023	0.041	0.024	$0.00	0.042	0.043	0.041	0.045
2014	0.065	0.057	0.077	0.055	36.76	0.00	18.38	0.023	0.022	0.041	0.023	$0.00	0.024	0.023	0.043	0.024	$0.00	0.042	0.043	0.041	0.045
2015	0.071	0.062	0.083	0.061	36.76	0.00	18.38	0.026	0.024	0.044	0.025	$0.00	0.026	0.025	0.045	0.026	$0.00	0.042	0.043	0.041	0.045
2016	0.072	0.062	0.090	0.062	15.09	18.01	16.55	0.025	0.023	0.046	0.024	$83.13	0.026	0.025	0.049	0.026	$83.13	0.042	0.043	0.041	0.045
2017	0.073	0.064	0.090	0.062	22.21	26.54	24.37	0.025	0.024	0.046	0.024	$85.39	0.025	0.024	0.047	0.025	$85.39	0.042	0.043	0.041	0.045
2018	0.079	0.070	0.100	0.068	31.01	37.09	34.05	0.027	0.027	0.052	0.028	$86.75	0.028	0.027	0.053	0.028	$86.75	0.035	0.036	0.034	0.037
2019	0.078	0.070	0.096	0.068	34.80	41.66	38.23	0.027	0.027	0.050	0.028	$83.35	0.028	0.028	0.051	0.028	$83.35	0.034	0.034	0.033	0.035
2020	0.080	0.070	0.093	0.069	48.69	58.34	53.52	0.014	0.013	0.024	0.014	$27.75	0.014	0.027	0.048	0.028	$27.75	0.032	0.033	0.031	0.034
2021	0.081	0.072	0.094	0.070	49.61	59.51	54.56	0.013	0.012	0.022	0.013	$27.90	0.013	0.014	0.024	0.014	$27.90	0.030	0.031	0.030	0.032
2022	0.084	0.075	0.096	0.073	74.46	89.42	81.94	0.012	0.011	0.019	0.012	$280.47	0.012	0.013	0.022	0.013	$280.47	0.029	0.029	0.028	0.030
2023	0.089	0.078	0.101	0.077	89.72	107.86	98.79	0.011	0.010	0.018	0.011	$138.27	0.011	0.012	0.020	0.012	$138.27	0.027	0.028	0.026	0.029
2024	0.092	0.080	0.102	0.079	98.16	118.14	108.15	0.009	0.009	0.015	0.009	$66.05	0.009	0.011	0.018	0.011	$66.05	0.025	0.026	0.025	0.027
2025	0.092	0.080	0.103	0.080	101.86	122.72	112.29					$33.59					$33.59	0.024	0.024	0.023	0.025
2026	0.093	0.081	0.105	0.080	104.09	125.53	114.81					$14.49					$14.49	0.022	0.023	0.022	0.023
2027	0.095	0.083	0.108	0.082	104.98	126.75	115.86											0.022	0.023	0.022	0.023
2028	0.098	0.085	0.111	0.084	105.49	127.51	116.50											0.022	0.023	0.022	0.023
2029	0.101	0.087	0.114	0.086	105.62	127.81	116.72											0.022	0.023	0.022	0.023
2030	0.104	0.089	0.117	0.089	105.75	128.11	116.93											0.022	0.023	0.022	0.023
2031	0.107	0.092	0.120	0.092	105.88	128.41	117.15											0.022	0.023	0.022	0.023
2032	0.110	0.094	0.123	0.094	105.88	128.55	117.22											0.022	0.023	0.022	0.023
2033	0.114	0.097	0.126	0.097	105.88	128.70	117.29											0.022	0.023	0.022	0.023
2034	0.117	0.099	0.130	0.100	105.88	128.84	117.36											0.022	0.023	0.022	0.023
2035	0.121	0.102	0.133	0.103	105.88	128.99	117.43											0.022	0.023	0.022	0.023
2036	0.124	0.105	0.137	0.106	105.88	129.13	117.51											0.022	0.023	0.022	0.023
2037	0.128	0.108	0.141	0.109	105.88	129.28	117.58											0.022	0.023	0.022	0.023
2038	0.132	0.110	0.144	0.112	105.88	129.43	117.65											0.022	0.023	0.022	0.023
2039	0.136	0.113	0.148	0.116	105.88	129.57	117.73											0.022	0.023	0.022	0.023
2040	0.140	0.117	0.152	0.119	105.88	129.72	117.80											0.022	0.023	0.022	0.023
2041	0.145	0.120	0.157	0.123	105.88	129.87	117.88											0.022	0.023	0.022	0.023
Levelized Costs																					
10 years (2012-2021)	0.072	0.063	0.086	0.062	34.73	22.58	28.65	0.023	0.022	0.041	0.023	38.02	0.021	0.022	0.041	0.023	38.95	0.039	0.040	0.038	0.041
15 years (2012-2026)	0.077	0.068	0.091	0.066	51.93	48.94	50.44	0.018	0.017	0.032	0.018	59.07	0.017	0.018	0.033	0.018	60.52	0.035	0.036	0.034	0.037
30 years (2012-2041)	0.093	0.080	0.106	0.080	73.99	81.60	77.80											0.030	0.030	0.029	0.031

NOTES:

General: All Avoided Costs are in Year 2011 Dollars

ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 7 AM - 11 PM; Off-Peak Hours are all other hours

1 Avoided cost of electric energy = (wholesale energy avoided cost + REC cost to load) * risk premium, e.g. A= (V + AB) * (1+Wholesale Risk Premium)

2 Absolute value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year and PA strategy about bidding that reduction into applicable FCAs, and unit values in columns e, f, l and q.

3 Proceeds from selling into the FCM include the reserve margin, in addition to the ISO-NE loss factor of 8%

Page Two: Inputs to Avoided Cost Calculations

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Zone: MA-WCMA

	Wholesale Avoided Costs of Electricity						Avoided REC Costs to Load	2012 Energy DRIPE Values								2013 Energy DRIPE Values							
	Energy				Capacity			Intrastate Installation				Rest of Pool Installation				Intrastate Installation				Rest of Pool Installation			
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	FCA Price	Reserve Margin	REC Costs	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	%	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh
Period:	v	w	x	y	z	aa	ab	ac	ad	ae	af	ag	ah	ai	aj	ak	al	am	an	ao	ap	aq	ar
2011	0.050	0.042	0.056	0.040	43.20		0.0034																
2012	0.052	0.044	0.062	0.044	34.72	16.6%	0.0038	0.023	0.021	0.040	0.023	0.021	0.015	0.029	0.017	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2013	0.053	0.046	0.063	0.045	34.04	15.7%	0.0045	0.023	0.022	0.040	0.023	0.022	0.016	0.030	0.017	0.023	0.023	0.041	0.024	0.022	0.016	0.031	0.018
2014	0.054	0.047	0.066	0.046	34.04	17.7%	0.0051	0.023	0.022	0.041	0.023	0.022	0.016	0.031	0.017	0.024	0.023	0.043	0.024	0.023	0.017	0.032	0.018
2015	0.059	0.051	0.070	0.050	34.04	15.9%	0.0058	0.026	0.024	0.044	0.025	0.025	0.018	0.034	0.019	0.026	0.025	0.045	0.026	0.025	0.018	0.034	0.020
2016	0.060	0.051	0.076	0.050	13.98	16.0%	0.0065	0.025	0.023	0.046	0.024	0.023	0.017	0.034	0.018	0.026	0.025	0.049	0.026	0.025	0.018	0.037	0.020
2017	0.060	0.052	0.076	0.050	20.56	16.2%	0.0071	0.025	0.024	0.046	0.024	0.023	0.017	0.034	0.018	0.025	0.024	0.047	0.025	0.023	0.017	0.035	0.018
2018	0.066	0.058	0.085	0.057	28.72	16.3%	0.0061	0.027	0.027	0.052	0.028	0.025	0.019	0.038	0.020	0.028	0.027	0.053	0.028	0.025	0.019	0.038	0.021
2019	0.067	0.060	0.084	0.058	32.22	16.4%	0.0045	0.027	0.027	0.050	0.028	0.025	0.019	0.037	0.020	0.028	0.028	0.051	0.028	0.025	0.020	0.037	0.021
2020	0.069	0.060	0.080	0.059	45.08	16.5%	0.0047	0.014	0.013	0.024	0.014	0.013	0.009	0.017	0.010	0.014	0.027	0.048	0.028	0.013	0.019	0.035	0.021
2021	0.071	0.062	0.082	0.060	45.94	16.6%	0.0041	0.013	0.012	0.022	0.013	0.012	0.009	0.016	0.009	0.013	0.014	0.024	0.014	0.012	0.010	0.018	0.011
2022	0.072	0.064	0.083	0.062	68.95	16.8%	0.0047	0.012	0.011	0.019	0.012	0.011	0.008	0.014	0.009	0.012	0.013	0.022	0.013	0.011	0.009	0.016	0.010
2023	0.077	0.067	0.087	0.066	83.08	16.9%	0.0053	0.011	0.010	0.018	0.011	0.010	0.007	0.013	0.008	0.011	0.012	0.020	0.012	0.010	0.008	0.015	0.009
2024	0.079	0.068	0.089	0.067	90.89	17.0%	0.0051	0.009	0.009	0.015	0.009	0.009	0.006	0.011	0.007	0.009	0.011	0.018	0.011	0.009	0.007	0.013	0.008
2025	0.080	0.069	0.090	0.069	94.32	17.1%	0.0042	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.009	0.016	0.010	0.000	0.006	0.011	0.007
2026	0.082	0.071	0.094	0.070	96.38	17.3%	0.0029	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2027	0.085	0.073	0.096	0.072	97.20	17.4%	0.0027																
2028	0.087	0.075	0.099	0.075	97.68	17.5%	0.0025																
2029	0.090	0.077	0.102	0.077	97.80	17.7%	0.0024																
2030	0.093	0.080	0.105	0.079	97.92	17.8%	0.0023																
2031	0.096	0.082	0.108	0.082	98.04	17.9%	0.0023																
2032	0.099	0.084	0.111	0.084	98.04	18.1%	0.0023																
2033	0.102	0.086	0.114	0.087	98.04	18.2%	0.0023																
2034	0.105	0.089	0.117	0.089	98.04	18.3%	0.0023																
2035	0.108	0.091	0.120	0.092	98.04	18.5%	0.0023																
2036	0.112	0.094	0.123	0.095	98.04	18.6%	0.0023																
2037	0.115	0.096	0.127	0.098	98.04	18.7%	0.0023																
2038	0.119	0.099	0.130	0.101	98.04	18.9%	0.0023																
2039	0.123	0.102	0.134	0.104	98.04	19.0%	0.0023																
2040	0.127	0.105	0.138	0.107	98.04	19.1%	0.0023																
2041	0.130	0.108	0.141	0.110	98.04	19.3%	0.0023																
Levelized Cos																							
10 years (2012-2021)	0.061	0.053	0.074	0.051	32.15		0.005	0.023	0.022	0.041	0.023	0.021	0.016	0.030	0.017	0.021	0.021	0.040	0.022	0.019	0.015	0.030	0.016
15 years (2012-2026)	0.066	0.057	0.078	0.056	48.09		0.005	0.018	0.017	0.032	0.018	0.017	0.012	0.024	0.013	0.016	0.018	0.033	0.018	0.015	0.013	0.024	0.014
30 years (2012-2041)	0.082	0.070	0.094	0.069	68.51		0.004	0.011	0.010	0.019	0.011	0.010	0.007	0.014	0.008	0.010	0.011	0.019	0.011	0.009	0.007	0.014	0.008

NOTES: General — All Avoided Costs are in Year 2011 Dollars
ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are all other hours

Avoided Cost of Electricity (2011$) Results :

ME
Maine

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State ME

User-defined Inputs			
Wholesale Risk Premium (WRP)	9%	Percent of Capacity Bid into FCM (%Bid)	50.0%
Real Discount Rate	2.46%		

	Avoided Unit Cost of Electric Energy[1]				Avoided Unit Cost of Electric Capacity[2]			DRIPE: 2012 vintage measures, Intrastate Values: Energy				Capacity (See note 2)	DRIPE: 2013 vintage measures, Intrastate Values: Energy				Capacity (See note 2)	Avoided Externality Costs			
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	kW bid into FCA (PA to determine quantity)[3]	kW not bid into FCM (PA to determine quantity)	Weighted Average Avoided Cost Based on Percent Capacity Bid	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kw-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e=z*1.08 for ISO-NE losses	f=z*(1+aa)*(1+PTF Loss of 1.9%)*(1+WRP)	g=(e*%Bid)+(f*(1-%Bid))	h	i	j	k	l	m	n	o	p	q	r	s	t	u
2011	0.052	0.046	0.054	0.042														0.042	0.043	0.041	0.045
2012	0.054	0.047	0.059	0.046	37.50	0.00	18.75	0.007	0.006	0.008	0.007	$0.00						0.042	0.043	0.041	0.045
2013	0.055	0.049	0.058	0.047	36.76	0.00	18.38	0.007	0.006	0.008	0.007	$0.00	0.007	0.006	0.008	0.007	$0.00	0.042	0.043	0.041	0.045
2014	0.055	0.049	0.059	0.047	36.76	0.00	18.38	0.007	0.006	0.008	0.007	$0.00	0.007	0.006	0.008	0.007	$0.00	0.042	0.043	0.041	0.045
2015	0.060	0.053	0.064	0.052	36.76	0.00	18.38	0.008	0.006	0.008	0.007	$0.00	0.008	0.006	0.008	0.008	$0.00	0.042	0.043	0.041	0.045
2016	0.061	0.053	0.066	0.052	15.09	18.01	16.55	0.007	0.006	0.008	0.007	$15.79	0.008	0.006	0.009	0.008	$15.79	0.042	0.043	0.041	0.045
2017	0.061	0.054	0.065	0.052	22.21	26.54	24.37	0.007	0.006	0.008	0.007	$15.85	0.007	0.006	0.008	0.007	$15.85	0.042	0.043	0.041	0.045
2018	0.067	0.060	0.072	0.058	31.01	37.09	34.05	0.008	0.007	0.009	0.008	$15.95	0.008	0.007	0.009	0.008	$15.95	0.035	0.036	0.034	0.037
2019	0.068	0.062	0.073	0.059	34.80	41.66	38.23	0.008	0.007	0.009	0.008	$15.32	0.008	0.007	0.009	0.008	$15.32	0.034	0.034	0.033	0.035
2020	0.070	0.061	0.075	0.060	48.69	58.34	53.52	0.004	0.003	0.004	0.004	$5.11	0.004	0.007	0.008	0.008	$5.11	0.032	0.033	0.031	0.034
2021	0.071	0.064	0.077	0.062	49.61	59.51	54.56	0.004	0.003	0.004	0.004	$5.14	0.004	0.003	0.004	0.004	$5.14	0.030	0.031	0.030	0.032
2022	0.074	0.065	0.079	0.065	74.46	89.42	81.94	0.003	0.003	0.003	0.003	$51.76	0.003	0.003	0.004	0.004	$51.76	0.029	0.029	0.028	0.030
2023	0.079	0.069	0.084	0.068	89.72	107.86	98.79	0.003	0.002	0.003	0.003	$25.52	0.003	0.003	0.004	0.003	$25.52	0.027	0.028	0.026	0.029
2024	0.082	0.071	0.086	0.071	98.16	118.14	108.15	0.003	0.002	0.003	0.003	$12.20	0.003	0.003	0.003	0.003	$12.20	0.025	0.026	0.025	0.027
2025	0.082	0.072	0.087	0.072	101.86	122.72	112.29					$6.21					$6.21	0.024	0.024	0.023	0.025
2026	0.083	0.072	0.087	0.071	104.09	125.53	114.81					$2.68					$2.68	0.022	0.023	0.022	0.023
2027	0.087	0.075	0.089	0.074	104.98	126.75	115.86											0.022	0.023	0.022	0.023
2028	0.089	0.077	0.091	0.076	105.49	127.51	116.50											0.022	0.023	0.022	0.023
2029	0.092	0.078	0.094	0.078	105.62	127.81	116.72											0.022	0.023	0.022	0.023
2030	0.095	0.080	0.096	0.080	105.75	128.11	116.93											0.022	0.023	0.022	0.023
2031	0.098	0.082	0.098	0.083	105.88	128.41	117.15											0.022	0.023	0.022	0.023
2032	0.101	0.084	0.100	0.085	105.88	128.55	117.22											0.022	0.023	0.022	0.023
2033	0.104	0.087	0.103	0.088	105.88	128.70	117.29											0.022	0.023	0.022	0.023
2034	0.107	0.089	0.105	0.090	105.88	128.84	117.36											0.022	0.023	0.022	0.023
2035	0.111	0.091	0.107	0.093	105.88	128.99	117.43											0.022	0.023	0.022	0.023
2036	0.114	0.093	0.110	0.095	105.88	129.13	117.51											0.022	0.023	0.022	0.023
2037	0.118	0.096	0.112	0.098	105.88	129.28	117.58											0.022	0.023	0.022	0.023
2038	0.122	0.098	0.115	0.101	105.88	129.43	117.65											0.022	0.023	0.022	0.023
2039	0.125	0.101	0.118	0.104	105.88	129.57	117.73											0.022	0.023	0.022	0.023
2040	0.129	0.103	0.121	0.107	105.88	129.72	117.80											0.022	0.023	0.022	0.023
2041	0.133	0.106	0.123	0.110	105.88	129.87	117.88											0.022	0.023	0.022	0.023
Levelized Costs																					
10 years (2012-2021)	0.062	0.055	0.066	0.053	34.73	22.58	28.65	0.007	0.006	0.007	0.007	7.06	0.006	0.006	0.007	0.006	7.23	0.039	0.040	0.038	0.041
15 years (2012-2026)	0.067	0.059	0.072	0.058	51.93	48.94	50.44	0.005	0.004	0.006	0.005	10.93	0.005	0.004	0.006	0.005	11.20	0.035	0.036	0.034	0.037
30 years (2012-2041)	0.083	0.071	0.085	0.071	73.99	81.60	77.80											0.030	0.030	0.029	0.031

NOTES:

General All Avoided Costs are in Year 2011 Dollars
ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 7 AM - 11 PM; Off-Peak Hours are all other hours

1 Avoided cost of electric energy = (wholesale energy avoided cost + REC cost to load) * risk premium, e.g. A= (V + AB) * (1+Wholesale Risk Premium)

2 Absolute value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year and PA strategy about bidding that reduction into applicable FCAs, and unit values in columns e, f, l and q.

3 Proceeds from selling into the FCM include the reserve margin, in addition to the ISO-NE loss factor of 8%

Page Two: Inputs to Avoided Cost Calculations

Zone: ME

	Wholesale Avoided Costs of Electricity						Avoided REC Costs to Load	2012 Energy DRIPE Values								2013 Energy DRIPE Values							
	Energy				Capacity			Intrastate Installation				Rest of Pool Installation				Intrastate Installation				Rest of Pool Installation			
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	FCA Price	Reserve Margin	REC Costs	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	%	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh
Period:	v	w	x	y	z	aa	ab	ac	ad	ae	af	ag	ah	ai	aj	ak	al	am	an	ao	ap	aq	ar
2011	0.047	0.042	0.049	0.038	43.20		0.0004																
2012	0.049	0.043	0.053	0.041	34.72	16.6%	0.0007	0.007	0.006	0.008	0.007	0.033	0.024	0.046	0.026	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2013	0.050	0.044	0.052	0.042	34.04	15.7%	0.0008	0.007	0.006	0.008	0.007	0.034	0.025	0.047	0.027	0.007	0.006	0.008	0.007	0.035	0.026	0.048	0.028
2014	0.050	0.044	0.053	0.043	34.04	17.7%	0.0010	0.007	0.006	0.008	0.007	0.035	0.025	0.049	0.027	0.007	0.006	0.008	0.007	0.035	0.026	0.050	0.028
2015	0.054	0.048	0.057	0.046	34.04	15.9%	0.0012	0.008	0.006	0.008	0.007	0.038	0.028	0.052	0.030	0.008	0.006	0.008	0.008	0.039	0.028	0.054	0.031
2016	0.054	0.047	0.060	0.047	13.98	16.0%	0.0013	0.007	0.006	0.008	0.007	0.036	0.026	0.054	0.029	0.008	0.006	0.009	0.008	0.039	0.028	0.058	0.031
2017	0.055	0.048	0.059	0.046	20.56	16.2%	0.0015	0.007	0.006	0.008	0.007	0.036	0.027	0.053	0.028	0.007	0.006	0.008	0.007	0.037	0.028	0.055	0.029
2018	0.060	0.054	0.065	0.052	28.72	16.3%	0.0010	0.008	0.007	0.009	0.008	0.040	0.030	0.060	0.032	0.008	0.007	0.009	0.008	0.040	0.031	0.061	0.033
2019	0.061	0.056	0.066	0.054	32.22	16.4%	0.0006	0.008	0.007	0.009	0.008	0.040	0.030	0.058	0.032	0.008	0.007	0.009	0.008	0.040	0.031	0.059	0.033
2020	0.063	0.055	0.068	0.055	45.08	16.5%	0.0008	0.004	0.003	0.004	0.004	0.020	0.015	0.027	0.016	0.004	0.007	0.008	0.008	0.021	0.031	0.056	0.033
2021	0.065	0.058	0.070	0.056	45.94	16.6%	0.0004	0.004	0.003	0.004	0.004	0.019	0.014	0.025	0.015	0.004	0.003	0.004	0.004	0.019	0.016	0.028	0.017
2022	0.067	0.059	0.072	0.059	68.95	16.8%	0.0008	0.003	0.003	0.003	0.003	0.017	0.013	0.022	0.014	0.003	0.003	0.004	0.004	0.017	0.014	0.026	0.016
2023	0.071	0.062	0.076	0.061	83.08	16.9%	0.0011	0.003	0.002	0.003	0.003	0.015	0.011	0.020	0.012	0.003	0.003	0.004	0.003	0.016	0.013	0.024	0.014
2024	0.074	0.064	0.078	0.064	90.89	17.0%	0.0012	0.003	0.002	0.003	0.003	0.014	0.010	0.018	0.011	0.003	0.003	0.003	0.003	0.014	0.012	0.021	0.013
2025	0.075	0.065	0.079	0.065	94.32	17.1%	0.0009	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.002	0.003	0.003	0.000	0.010	0.018	0.011
2026	0.076	0.066	0.079	0.065	96.38	17.3%	0.0005	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2027	0.078	0.068	0.081	0.067	97.20	17.4%	0.0010																
2028	0.081	0.069	0.083	0.069	97.68	17.5%	0.0010																
2029	0.083	0.071	0.085	0.071	97.80	17.7%	0.0010																
2030	0.086	0.073	0.087	0.073	97.92	17.8%	0.0009																
2031	0.089	0.075	0.089	0.075	98.04	17.9%	0.0009																
2032	0.092	0.077	0.091	0.077	98.04	18.1%	0.0009																
2033	0.095	0.079	0.093	0.079	98.04	18.2%	0.0009																
2034	0.098	0.081	0.095	0.082	98.04	18.3%	0.0009																
2035	0.101	0.083	0.098	0.084	98.04	18.5%	0.0009																
2036	0.104	0.085	0.100	0.087	98.04	18.6%	0.0009																
2037	0.107	0.087	0.102	0.089	98.04	18.7%	0.0009																
2038	0.111	0.089	0.105	0.092	98.04	18.9%	0.0009																
2039	0.114	0.091	0.107	0.094	98.04	19.0%	0.0009																
2040	0.118	0.094	0.110	0.097	98.04	19.1%	0.0009																
2041	0.122	0.096	0.112	0.100	98.04	19.3%	0.0009																
Levelized Cos																							
10 years (2012-2021)	0.056	0.049	0.060	0.048	32.15		0.001	0.007	0.006	0.007	0.007	0.033	0.025	0.047	0.026	0.006	0.005	0.007	0.006	0.030	0.024	0.046	0.026
15 years (2012-2026)	0.061	0.053	0.065	0.052	48.09		0.001	0.005	0.004	0.006	0.005	0.026	0.019	0.037	0.021	0.005	0.004	0.006	0.005	0.024	0.020	0.038	0.021
30 years (2012-2041)	0.076	0.064	0.077	0.064	68.51		0.001	0.003	0.003	0.003	0.003	0.016	0.011	0.022	0.012	0.003	0.003	0.003	0.003	0.014	0.012	0.022	0.013

NOTES: General — All Avoided Costs are in Year 2011 Dollars
ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are all other hours

Avoided Cost of Electricity (2011$) Results :

State NH

NH
New Hampshire

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User-defined Inputs			
Wholesale Risk Premium (WRP)	9%	Percent of Capacity Bid into FCM (%Bid)	50.0%
Real Discount Rate	2.46%		

	Avoided Unit Cost of Electric Energy[1]				Avoided Unit Cost of Electric Capacity[2]			DRIPE: 2012 vintage measures, Intrastate Values – Energy				DRIPE: 2012 – Capacity (See note 2)	DRIPE: 2013 vintage measures, Intrastate Values – Energy				DRIPE: 2013 – Capacity (See note 2)	Avoided Externality Costs			
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	kW bid into FCA (PA to determine quantity)[3]	kW not bid into FCM (PA to determine quantity)	Weighted Average Avoided Cost Based on Percent Capacity Bid	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kw-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e=z*1.08 for ISO-NE losses	f=z*(1+aa)*(1+PTF Loss of 1.9%)*(1+WRP)	g=(e*%Bid)+(f*(1-%Bid))	h	i	j	k	l	m	n	o	p	q	r	s	t	u
2011	0.055	0.048	0.060	0.045														0.042	0.043	0.041	0.045
2012	0.057	0.049	0.065	0.049	37.50	0.00	18.75	0.006	0.007	0.011	0.006	$0.00						0.042	0.043	0.041	0.045
2013	0.059	0.051	0.064	0.051	36.76	0.00	18.38	0.006	0.007	0.011	0.007	$0.00	0.006	0.007	0.012	0.007	$0.00	0.042	0.043	0.041	0.045
2014	0.061	0.053	0.066	0.052	36.76	0.00	18.38	0.006	0.007	0.012	0.007	$0.00	0.006	0.007	0.012	0.007	$0.00	0.042	0.043	0.041	0.045
2015	0.067	0.058	0.071	0.056	36.76	0.00	18.38	0.006	0.008	0.012	0.007	$0.00	0.006	0.008	0.013	0.007	$0.00	0.042	0.043	0.041	0.045
2016	0.067	0.058	0.074	0.057	15.09	18.01	16.55	0.006	0.007	0.012	0.007	$10.72	0.006	0.008	0.014	0.007	$10.72	0.042	0.043	0.041	0.045
2017	0.068	0.060	0.073	0.057	22.21	26.54	24.37	0.006	0.007	0.012	0.007	$10.80	0.006	0.007	0.013	0.007	$10.80	0.042	0.043	0.041	0.045
2018	0.073	0.065	0.080	0.063	31.01	37.09	34.05	0.006	0.008	0.014	0.007	$10.88	0.006	0.008	0.014	0.008	$10.88	0.035	0.036	0.034	0.037
2019	0.072	0.066	0.079	0.063	34.80	41.66	38.23	0.006	0.008	0.013	0.007	$10.51	0.007	0.008	0.014	0.008	$10.51	0.034	0.034	0.033	0.035
2020	0.074	0.065	0.081	0.064	48.69	58.34	53.52	0.003	0.004	0.006	0.004	$3.51	0.003	0.008	0.013	0.008	$3.51	0.032	0.033	0.031	0.034
2021	0.076	0.067	0.083	0.065	49.61	59.51	54.56	0.003	0.004	0.006	0.003	$3.54	0.003	0.004	0.007	0.004	$3.54	0.030	0.031	0.030	0.032
2022	0.079	0.070	0.086	0.068	74.46	89.42	81.94	0.003	0.003	0.005	0.003	$35.69	0.003	0.004	0.006	0.004	$35.69	0.029	0.029	0.028	0.030
2023	0.084	0.074	0.092	0.073	89.72	107.86	98.79	0.003	0.003	0.005	0.003	$17.63	0.003	0.004	0.006	0.003	$17.63	0.027	0.028	0.026	0.029
2024	0.087	0.076	0.093	0.075	98.16	118.14	108.15	0.002	0.003	0.004	0.003	$8.45	0.002	0.003	0.005	0.003	$8.45	0.025	0.026	0.025	0.027
2025	0.088	0.077	0.094	0.076	101.86	122.72	112.29					$4.31					$4.31	0.024	0.024	0.023	0.025
2026	0.088	0.076	0.093	0.076	104.09	125.53	114.81					$1.86					$1.86	0.022	0.023	0.022	0.023
2027	0.091	0.078	0.094	0.078	104.98	126.75	115.86											0.022	0.023	0.022	0.023
2028	0.093	0.080	0.096	0.080	105.49	127.51	116.50											0.022	0.023	0.022	0.023
2029	0.096	0.082	0.098	0.082	105.62	127.81	116.72											0.022	0.023	0.022	0.023
2030	0.099	0.084	0.100	0.084	105.75	128.11	116.93											0.022	0.023	0.022	0.023
2031	0.102	0.086	0.102	0.086	105.88	128.41	117.15											0.022	0.023	0.022	0.023
2032	0.105	0.088	0.105	0.089	105.88	128.55	117.22											0.022	0.023	0.022	0.023
2033	0.108	0.090	0.107	0.092	105.88	128.70	117.29											0.022	0.023	0.022	0.023
2034	0.112	0.092	0.109	0.094	105.88	128.84	117.36											0.022	0.023	0.022	0.023
2035	0.115	0.095	0.111	0.097	105.88	128.99	117.43											0.022	0.023	0.022	0.023
2036	0.118	0.097	0.114	0.100	105.88	129.13	117.51											0.022	0.023	0.022	0.023
2037	0.122	0.100	0.116	0.103	105.88	129.28	117.58											0.022	0.023	0.022	0.023
2038	0.126	0.102	0.119	0.106	105.88	129.43	117.65											0.022	0.023	0.022	0.023
2039	0.130	0.105	0.121	0.109	105.88	129.57	117.73											0.022	0.023	0.022	0.023
2040	0.134	0.107	0.124	0.112	105.88	129.72	117.80											0.022	0.023	0.022	0.023
2041	0.138	0.110	0.126	0.115	105.88	129.87	117.88											0.022	0.023	0.022	0.023
Levelized Costs																					
10 years (2012-2021)	0.067	0.059	0.073	0.057	34.73	22.58	28.65	0.005	0.007	0.011	0.006	4.82	0.005	0.007	0.011	0.006	4.94	0.039	0.040	0.038	0.041
15 years (2012-2026)	0.072	0.064	0.078	0.062	51.93	48.94	50.44	0.004	0.005	0.009	0.005	7.51	0.004	0.005	0.009	0.005	7.70	0.035	0.036	0.034	0.037
30 years (2012-2041)	0.088	0.075	0.091	0.075	73.99	81.60	77.80											0.030	0.030	0.029	0.031

NOTES:

General All Avoided Costs are in Year 2011 Dollars

ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 7 AM - 11 PM; Off-Peak Hours are all other hours

1 Avoided cost of electric energy = (wholesale energy avoided cost + REC cost to load) * risk premium, e.g. A= (V + AB) * (1+Wholesale Risk Premium)

2 Absolute value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year and PA strategy about bidding that reduction into applicable FCAs, and unit values in columns e, f, l and q.

3 Proceeds from selling into the FCM include the reserve margin, in addition to the ISO-NE loss factor of 8%

Page Two: Inputs to Avoided Cost Calculations

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Zone: NH

	Wholesale Avoided Costs of Electricity						Avoided REC Costs to Load	2012 Energy DRIPE Values								2013 Energy DRIPE Values							
	Energy				Capacity			Intrastate Installation				Rest of Pool Installation				Intrastate Installation				Rest of Pool Installation			
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	FCA Price	Reserve Margin	REC Costs	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	%	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh
Period:	v	w	x	y	z	aa	ab	ac	ad	ae	af	ag	ah	ai	aj	ak	al	am	an	ao	ap	aq	ar
2011	0.049	0.042	0.053	0.039	43.20		0.0019																
2012	0.050	0.043	0.057	0.042	34.72	16.6%	0.0021	0.006	0.007	0.011	0.006	0.035	0.025	0.048	0.027	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2013	0.051	0.045	0.056	0.044	34.04	15.7%	0.0026	0.006	0.007	0.011	0.007	0.035	0.026	0.049	0.028	0.006	0.007	0.012	0.007	0.036	0.027	0.050	0.029
2014	0.053	0.046	0.057	0.045	34.04	17.7%	0.0029	0.006	0.007	0.012	0.007	0.036	0.026	0.051	0.028	0.006	0.007	0.012	0.007	0.037	0.027	0.052	0.029
2015	0.058	0.050	0.062	0.048	34.04	15.9%	0.0033	0.006	0.008	0.012	0.007	0.040	0.029	0.054	0.031	0.006	0.008	0.013	0.007	0.040	0.030	0.056	0.032
2016	0.058	0.050	0.064	0.049	13.98	16.0%	0.0037	0.006	0.007	0.012	0.007	0.038	0.027	0.056	0.030	0.006	0.008	0.014	0.007	0.040	0.030	0.060	0.032
2017	0.058	0.051	0.063	0.049	20.56	16.2%	0.0040	0.006	0.007	0.012	0.007	0.038	0.028	0.055	0.029	0.006	0.007	0.013	0.007	0.038	0.029	0.057	0.030
2018	0.064	0.057	0.070	0.055	28.72	16.3%	0.0026	0.006	0.008	0.014	0.007	0.042	0.031	0.062	0.033	0.006	0.008	0.014	0.008	0.042	0.032	0.064	0.034
2019	0.065	0.059	0.072	0.057	32.22	16.4%	0.0010	0.006	0.008	0.013	0.007	0.041	0.032	0.060	0.033	0.007	0.008	0.014	0.008	0.042	0.032	0.062	0.034
2020	0.067	0.059	0.073	0.057	45.08	16.5%	0.0013	0.003	0.004	0.006	0.004	0.021	0.016	0.028	0.017	0.003	0.008	0.013	0.008	0.021	0.032	0.058	0.034
2021	0.069	0.061	0.076	0.059	45.94	16.6%	0.0007	0.003	0.004	0.006	0.003	0.019	0.014	0.026	0.015	0.003	0.004	0.007	0.004	0.020	0.016	0.029	0.017
2022	0.071	0.063	0.077	0.061	68.95	16.8%	0.0015	0.003	0.003	0.005	0.003	0.017	0.013	0.023	0.014	0.003	0.004	0.006	0.004	0.018	0.015	0.027	0.016
2023	0.075	0.065	0.082	0.064	83.08	16.9%	0.0023	0.003	0.003	0.005	0.003	0.016	0.012	0.021	0.013	0.003	0.004	0.006	0.003	0.016	0.014	0.025	0.015
2024	0.078	0.067	0.083	0.066	90.89	17.0%	0.0025	0.002	0.003	0.004	0.003	0.014	0.010	0.018	0.011	0.002	0.003	0.005	0.003	0.014	0.012	0.022	0.013
2025	0.079	0.068	0.084	0.068	94.32	17.1%	0.0020	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.003	0.004	0.003	0.000	0.011	0.019	0.012
2026	0.080	0.069	0.084	0.068	96.38	17.3%	0.0011	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2027	0.082	0.071	0.086	0.070	97.20	17.4%	0.0009																
2028	0.085	0.073	0.088	0.072	97.68	17.5%	0.0007																
2029	0.088	0.074	0.090	0.074	97.80	17.7%	0.0006																
2030	0.090	0.076	0.091	0.077	97.92	17.8%	0.0005																
2031	0.093	0.078	0.093	0.079	98.04	17.9%	0.0005																
2032	0.096	0.080	0.095	0.081	98.04	18.1%	0.0005																
2033	0.099	0.082	0.097	0.083	98.04	18.2%	0.0005																
2034	0.102	0.084	0.100	0.086	98.04	18.3%	0.0005																
2035	0.105	0.086	0.102	0.088	98.04	18.5%	0.0005																
2036	0.108	0.089	0.104	0.091	98.04	18.6%	0.0005																
2037	0.111	0.091	0.106	0.094	98.04	18.7%	0.0005																
2038	0.115	0.093	0.108	0.096	98.04	18.9%	0.0005																
2039	0.118	0.095	0.111	0.099	98.04	19.0%	0.0005																
2040	0.122	0.098	0.113	0.102	98.04	19.1%	0.0005																
2041	0.126	0.100	0.115	0.105	98.04	19.3%	0.0005																

Levelized Cos																							
10 years (2012-2021)	0.059	0.052	0.065	0.050	32.15		0.002	0.005	0.007	0.011	0.006	0.035	0.026	0.049	0.027	0.005	0.007	0.011	0.006	0.032	0.025	0.048	0.027
15 years (2012-2026)	0.064	0.056	0.070	0.055	48.09		0.002	0.004	0.005	0.009	0.005	0.027	0.020	0.039	0.022	0.004	0.006	0.009	0.005	0.025	0.021	0.040	0.022
30 years (2012-2041)	0.079	0.067	0.082	0.067	68.51		0.002	0.003	0.003	0.005	0.003	0.016	0.012	0.023	0.013	0.002	0.003	0.005	0.003	0.015	0.012	0.023	0.013

NOTES: General All Avoided Costs are in Year 2011 Dollars
ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are all other hours

Avoided Cost of Electricity (2011$) Results :

RI
Rhode Island

Page One of Two

State RI

User-defined Inputs			
Wholesale Risk Premium (WRP)	9%	Percent of Capacity Bid into FCM (%Bid)	50.0%
Real Discount Rate	2.46%		

	Avoided Unit Cost of Electric Energy[1]				Avoided Unit Cost of Electric Capacity[2]			DRIPE: 2012 vintage measures, Intrastate Values					DRIPE: 2013 vintage measures, Intrastate Values					Avoided Externality Costs			
								Energy				Capacity (See note 2)	Energy				Capacity (See note 2)				
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	kW bid into FCA (PA to determine quantity)[3]	kW not bid into FCM (PA to determine quantity)	Weighted Average Avoided Cost Based on Percent Capacity Bid	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kw-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e=z*1.08 for ISO-NE losses	f=z*(1+aa)*(1+PTF Loss of 1.9%)*(1+WRP)	g=(e*%Bid)+(f*(1-%Bid))	h	i	j	k	l	m	n	o	p	q	r	s	t	u
2011	0.054	0.046	0.059	0.043														0.042	0.043	0.041	0.045
2012	0.056	0.048	0.066	0.047	37.50	0.00	18.75	0.009	0.007	0.010	0.005	$0.00						0.042	0.043	0.041	0.045
2013	0.057	0.050	0.068	0.049	36.76	0.00	18.38	0.009	0.007	0.010	0.005	$0.00	0.009	0.007	0.010	0.006	$0.00	0.042	0.043	0.041	0.045
2014	0.059	0.052	0.071	0.051	36.76	0.00	18.38	0.009	0.007	0.010	0.005	$0.00	0.009	0.007	0.010	0.005	$0.00	0.042	0.043	0.041	0.045
2015	0.066	0.057	0.077	0.056	36.76	0.00	18.38	0.010	0.008	0.010	0.006	$0.00	0.010	0.008	0.011	0.006	$0.00	0.042	0.043	0.041	0.045
2016	0.066	0.058	0.084	0.057	15.09	18.01	16.55	0.009	0.007	0.011	0.005	$13.79	0.010	0.008	0.011	0.006	$13.79	0.042	0.043	0.041	0.045
2017	0.067	0.059	0.084	0.057	22.21	26.54	24.37	0.009	0.007	0.010	0.005	$13.83	0.009	0.007	0.011	0.005	$13.83	0.042	0.043	0.041	0.045
2018	0.066	0.058	0.085	0.056	31.01	37.09	34.05	0.009	0.007	0.010	0.005	$13.89	0.009	0.007	0.011	0.005	$13.89	0.042	0.043	0.041	0.045
2019	0.064	0.057	0.081	0.055	34.80	41.66	38.23	0.009	0.007	0.010	0.005	$13.33	0.009	0.007	0.010	0.005	$13.33	0.042	0.043	0.041	0.045
2020	0.065	0.054	0.074	0.055	48.69	58.34	53.52	0.004	0.003	0.005	0.003	$4.43	0.004	0.007	0.009	0.005	$4.43	0.042	0.043	0.041	0.045
2021	0.065	0.055	0.074	0.055	49.61	59.51	54.56	0.004	0.003	0.004	0.002	$4.46	0.004	0.003	0.005	0.003	$4.46	0.042	0.043	0.041	0.045
2022	0.066	0.055	0.074	0.055	74.46	89.42	81.94	0.003	0.003	0.004	0.002	$44.79	0.004	0.003	0.004	0.002	$44.79	0.042	0.043	0.041	0.045
2023	0.069	0.057	0.076	0.058	89.72	107.86	98.79	0.003	0.002	0.003	0.002	$22.05	0.003	0.003	0.004	0.002	$22.05	0.042	0.043	0.041	0.045
2024	0.071	0.057	0.078	0.059	98.16	118.14	108.15	0.003	0.002	0.003	0.002	$10.53	0.003	0.002	0.003	0.002	$10.53	0.042	0.043	0.041	0.045
2025	0.070	0.056	0.077	0.059	101.86	122.72	112.29					$5.35					$5.35	0.042	0.043	0.041	0.045
2026	0.071	0.056	0.079	0.059	104.09	125.53	114.81					$2.34					$2.34	0.042	0.043	0.041	0.045
2027	0.072	0.057	0.082	0.060	104.98	126.75	115.86											0.042	0.043	0.041	0.045
2028	0.075	0.059	0.084	0.062	105.49	127.51	116.50											0.042	0.043	0.041	0.045
2029	0.077	0.060	0.086	0.064	105.62	127.81	116.72											0.042	0.043	0.041	0.045
2030	0.079	0.062	0.089	0.065	105.75	128.11	116.93											0.042	0.043	0.041	0.045
2031	0.081	0.064	0.091	0.067	105.88	128.41	117.15											0.042	0.043	0.041	0.045
2032	0.083	0.066	0.094	0.069	105.88	128.55	117.22											0.042	0.043	0.041	0.045
2033	0.086	0.068	0.097	0.071	105.88	128.70	117.29											0.042	0.043	0.041	0.045
2034	0.088	0.070	0.100	0.073	105.88	128.84	117.36											0.042	0.043	0.041	0.045
2035	0.091	0.072	0.102	0.076	105.88	128.99	117.43											0.042	0.043	0.041	0.045
2036	0.094	0.074	0.105	0.078	105.88	129.13	117.51											0.042	0.043	0.041	0.045
2037	0.096	0.076	0.109	0.080	105.88	129.28	117.58											0.042	0.043	0.041	0.045
2038	0.099	0.078	0.112	0.082	105.88	129.43	117.65											0.042	0.043	0.041	0.045
2039	0.102	0.081	0.115	0.085	105.88	129.57	117.73											0.042	0.043	0.041	0.045
2040	0.105	0.083	0.118	0.087	105.88	129.72	117.80											0.042	0.043	0.041	0.045
2041	0.108	0.085	0.122	0.090	105.88	129.87	117.88											0.042	0.043	0.041	0.045
Levelized Costs																					
10 years (2012-2021)	0.063	0.055	0.076	0.053	34.73	22.58	28.65	0.008	0.006	0.009	0.005	6.15	0.008	0.006	0.009	0.005	6.30	0.042	0.043	0.041	0.045
15 years (2012-2026)	0.065	0.055	0.076	0.055	51.93	48.94	50.44	0.006	0.005	0.007	0.004	9.48	0.006	0.005	0.007	0.004	9.72	0.042	0.043	0.041	0.045
30 years (2012-2041)	0.074	0.061	0.086	0.062	73.99	81.60	77.80											0.042	0.043	0.041	0.045

NOTES:

General: All Avoided Costs are in Year 2011 Dollars
ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 7 AM - 11 PM; Off-Peak Hours are all other hours

1 Avoided cost of electric energy = (wholesale energy avoided cost + REC cost to load) * risk premium, e.g. A= (V + AB) * (1+Wholesale Risk Premium)

2 Absolute value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year and PA strategy about bidding that reduction into applicable FCAs, and unit values in columns e, f, l and q.

3 Proceeds from selling into the FCM include the reserve margin, in addition to the ISO-NE loss factor of 8%

Page Two: Inputs to Avoided Cost Calculations

Zone: RI

	Wholesale Avoided Costs of Electricity: Energy				Capacity		Avoided REC Costs to Load
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	FCA Price	Reserve Margin	REC Costs
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	%	$/kWh
Period:	v	w	x	y	z	aa	ab
2011	0.049	0.042	0.054	0.039	43.20		0.0006
2012	0.050	0.043	0.060	0.042	34.72	16.6%	0.0009
2013	0.051	0.045	0.061	0.044	34.04	15.7%	0.0013
2014	0.053	0.046	0.064	0.045	34.04	17.7%	0.0016
2015	0.058	0.051	0.068	0.049	34.04	15.9%	0.0020
2016	0.058	0.051	0.074	0.050	13.98	16.0%	0.0024
2017	0.059	0.052	0.074	0.049	20.56	16.2%	0.0028
2018	0.059	0.051	0.076	0.050	28.72	16.3%	0.0019
2019	0.058	0.052	0.074	0.050	32.22	16.4%	0.0008
2020	0.058	0.049	0.067	0.049	45.08	16.5%	0.0010
2021	0.059	0.050	0.068	0.050	45.94	16.6%	0.0005
2022	0.059	0.049	0.067	0.050	68.95	16.8%	0.0010
2023	0.062	0.051	0.069	0.051	83.08	16.9%	0.0015
2024	0.063	0.051	0.070	0.052	90.89	17.0%	0.0016
2025	0.063	0.050	0.070	0.053	94.32	17.1%	0.0012
2026	0.064	0.051	0.072	0.053	96.38	17.3%	0.0006
2027	0.066	0.052	0.074	0.055	97.20	17.4%	0.0005
2028	0.068	0.054	0.076	0.056	97.68	17.5%	0.0004
2029	0.070	0.055	0.079	0.058	97.80	17.7%	0.0004
2030	0.072	0.057	0.081	0.060	97.92	17.8%	0.0003
2031	0.074	0.058	0.083	0.061	98.04	17.9%	0.0003
2032	0.076	0.060	0.086	0.063	98.04	18.1%	0.0003
2033	0.079	0.062	0.088	0.065	98.04	18.2%	0.0003
2034	0.081	0.064	0.091	0.067	98.04	18.3%	0.0003
2035	0.083	0.066	0.094	0.069	98.04	18.5%	0.0003
2036	0.086	0.068	0.096	0.071	98.04	18.6%	0.0003
2037	0.088	0.070	0.099	0.073	98.04	18.7%	0.0003
2038	0.091	0.072	0.102	0.075	98.04	18.9%	0.0003
2039	0.093	0.074	0.105	0.077	98.04	19.0%	0.0003
2040	0.096	0.076	0.108	0.080	98.04	19.1%	0.0003
2041	0.099	0.078	0.111	0.082	98.04	19.3%	0.0003
Levelized Cos							
10 years (2012-2021)	0.056	0.049	0.068	0.048	32.15		0.002
15 years (2012-2026)	0.058	0.049	0.069	0.049	48.09		0.001
30 years (2012-2041)	0.067	0.055	0.078	0.056	68.51		0.001

	2012 Energy DRIPE Values: Intrastate Installation				2012 Rest of Pool Installation				2013 Energy DRIPE Values: Intrastate Installation				2013 Rest of Pool Installation			
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh
Period:	ac	ad	ae	af	ag	ah	ai	aj	ak	al	am	an	ao	ap	aq	ar
2011																
2012	0.009	0.007	0.010	0.005	0.034	0.025	0.047	0.027	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2013	0.009	0.007	0.010	0.005	0.035	0.026	0.048	0.028	0.009	0.007	0.010	0.006	0.036	0.026	0.050	0.029
2014	0.009	0.007	0.010	0.005	0.036	0.026	0.051	0.028	0.009	0.007	0.010	0.005	0.036	0.027	0.052	0.029
2015	0.010	0.008	0.010	0.006	0.039	0.029	0.054	0.031	0.010	0.008	0.011	0.006	0.040	0.029	0.055	0.032
2016	0.009	0.007	0.011	0.005	0.037	0.027	0.055	0.029	0.010	0.008	0.011	0.006	0.040	0.029	0.060	0.032
2017	0.009	0.007	0.010	0.005	0.037	0.028	0.055	0.029	0.009	0.007	0.011	0.005	0.038	0.028	0.056	0.030
2018	0.009	0.007	0.010	0.005	0.037	0.027	0.056	0.029	0.009	0.007	0.011	0.005	0.038	0.028	0.057	0.030
2019	0.009	0.007	0.010	0.005	0.036	0.027	0.054	0.029	0.009	0.007	0.010	0.005	0.037	0.028	0.055	0.029
2020	0.004	0.003	0.005	0.003	0.018	0.013	0.024	0.014	0.004	0.007	0.009	0.005	0.018	0.026	0.050	0.029
2021	0.004	0.003	0.004	0.002	0.016	0.012	0.022	0.013	0.004	0.003	0.005	0.003	0.017	0.013	0.025	0.014
2022	0.003	0.003	0.004	0.002	0.015	0.010	0.019	0.011	0.004	0.003	0.004	0.002	0.015	0.012	0.022	0.013
2023	0.003	0.002	0.003	0.002	0.013	0.009	0.017	0.010	0.003	0.003	0.004	0.002	0.013	0.011	0.020	0.012
2024	0.003	0.002	0.003	0.002	0.011	0.008	0.015	0.009	0.003	0.002	0.003	0.002	0.012	0.009	0.018	0.010
2025	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.002	0.003	0.002	0.000	0.008	0.015	0.009
2026	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Levelized Cos																
10 years (2012-2021)	0.008	0.006	0.009	0.005	0.033	0.024	0.047	0.026	0.007	0.006	0.009	0.005	0.030	0.023	0.046	0.025
15 years (2012-2026)	0.006	0.005	0.007	0.004	0.026	0.019	0.036	0.020	0.006	0.005	0.007	0.004	0.023	0.019	0.037	0.020
30 years (2012-2041)	0.004	0.003	0.004	0.002	0.015	0.011	0.021	0.012	0.003	0.003	0.004	0.002	0.014	0.011	0.022	0.012

NOTES: General All Avoided Costs are in Year 2011 Dollars
ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are all other hours

Avoided Cost of Electricity (2011$) Results :

VT
Vermont

Page One of Two

State VT

User-defined Inputs			
Wholesale Risk Premium (WRP)	11%	Percent of Capacity Bid into FCM (%Bid)	50.0%
Real Discount Rate	2.46%		

	Avoided Unit Cost of Electric Energy[1]				Avoided Unit Cost of Electric Capacity[2]			DRIPE: 2012 vintage measures Intrastate Values					DRIPE: 2013 vintage measures Intrastate Values					Avoided Externality Costs			
								Energy				Capacity (See note 2)	Energy				Capacity (See note 2)				
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	kW bid into FCA (PA to determine quantity)[3]	kW not bid into FCM (PA to determine quantity)	Weighted Average Avoided Cost Based on Percent Capacity Bid	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kw-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e=z*1.08 for ISO-NE losses	f=z*(1+aa)*(1+PTF Loss of 1.9%)*(1+WRP)	g=(e*%Bid)+(f*(1-%Bid))	h	i	j	k	l	m	n	o	p	q	r	s	t	u
2011	0.056	0.047	0.062	0.045														0.042	0.043	0.041	0.045
2012	0.057	0.048	0.068	0.048	37.50	0.00	18.75	0.001	0.001	0.002	0.001	$0.00						0.042	0.043	0.041	0.045
2013	0.059	0.051	0.070	0.050	36.76	0.00	18.38	0.002	0.001	0.003	0.001	$0.00	0.002	0.002	0.003	0.002	$0.00	0.042	0.043	0.041	0.045
2014	0.061	0.053	0.073	0.051	36.76	0.00	18.38	0.002	0.001	0.003	0.001	$0.00	0.002	0.002	0.003	0.001	$0.00	0.042	0.043	0.041	0.045
2015	0.067	0.057	0.079	0.056	36.76	0.00	18.38	0.002	0.002	0.003	0.002	$0.00	0.002	0.002	0.003	0.002	$0.00	0.042	0.043	0.041	0.045
2016	0.068	0.058	0.086	0.057	15.09	18.36	16.73	0.002	0.001	0.003	0.001	$3.27	0.002	0.002	0.003	0.002	$3.27	0.042	0.043	0.041	0.045
2017	0.068	0.059	0.086	0.057	22.21	27.05	24.63	0.002	0.001	0.003	0.001	$3.27	0.002	0.002	0.003	0.001	$3.27	0.042	0.043	0.041	0.045
2018	0.074	0.066	0.096	0.064	31.01	37.81	34.41	0.002	0.002	0.003	0.002	$3.28	0.002	0.002	0.003	0.002	$3.28	0.035	0.036	0.034	0.037
2019	0.075	0.067	0.094	0.065	34.80	42.46	38.63	0.002	0.002	0.003	0.002	$3.14	0.002	0.002	0.003	0.002	$3.14	0.034	0.034	0.033	0.035
2020	0.077	0.067	0.090	0.066	48.69	59.47	54.08	0.001	0.001	0.001	0.001	$1.04	0.001	0.002	0.003	0.002	$1.04	0.032	0.033	0.031	0.034
2021	0.079	0.069	0.091	0.067	49.61	60.66	55.13	0.001	0.001	0.001	0.001	$1.05	0.001	0.001	0.001	0.001	$1.05	0.030	0.031	0.030	0.032
2022	0.081	0.071	0.093	0.070	74.46	91.14	82.80	0.001	0.001	0.001	0.001	$10.52	0.001	0.001	0.001	0.001	$10.52	0.029	0.029	0.028	0.030
2023	0.086	0.075	0.098	0.074	89.72	109.94	99.83	0.001	0.001	0.001	0.001	$5.18	0.001	0.001	0.001	0.001	$5.18	0.027	0.028	0.026	0.029
2024	0.089	0.077	0.099	0.075	98.16	120.41	109.29	0.001	0.001	0.001	0.001	$2.47	0.001	0.001	0.001	0.001	$2.47	0.025	0.026	0.025	0.027
2025	0.090	0.078	0.100	0.078	101.86	125.08	113.47					$1.25					$1.25	0.024	0.024	0.023	0.025
2026	0.092	0.079	0.104	0.078	104.09	127.95	116.02					$0.54					$0.54	0.022	0.023	0.022	0.023
2027	0.094	0.081	0.107	0.081	104.98	129.19	117.08											0.022	0.023	0.022	0.023
2028	0.097	0.084	0.110	0.083	105.49	129.97	117.73											0.022	0.023	0.022	0.023
2029	0.100	0.086	0.113	0.085	105.62	130.27	117.95											0.022	0.023	0.022	0.023
2030	0.103	0.088	0.116	0.088	105.75	130.58	118.17											0.022	0.023	0.022	0.023
2031	0.107	0.091	0.119	0.091	105.88	130.88	118.38											0.022	0.023	0.022	0.023
2032	0.110	0.093	0.123	0.093	105.88	131.03	118.46											0.022	0.023	0.022	0.023
2033	0.113	0.096	0.126	0.096	105.88	131.17	118.53											0.022	0.023	0.022	0.023
2034	0.117	0.098	0.130	0.099	105.88	131.32	118.60											0.022	0.023	0.022	0.023
2035	0.120	0.101	0.133	0.102	105.88	131.47	118.68											0.022	0.023	0.022	0.023
2036	0.124	0.104	0.137	0.105	105.88	131.62	118.75											0.022	0.023	0.022	0.023
2037	0.128	0.106	0.141	0.108	105.88	131.77	118.83											0.022	0.023	0.022	0.023
2038	0.132	0.109	0.145	0.112	105.88	131.92	118.90											0.022	0.023	0.022	0.023
2039	0.136	0.112	0.149	0.115	105.88	132.07	118.98											0.022	0.023	0.022	0.023
2040	0.140	0.115	0.153	0.119	105.88	132.22	119.05											0.022	0.023	0.022	0.023
2041	0.145	0.119	0.157	0.122	105.88	132.37	119.13											0.022	0.023	0.022	0.023
Levelized Costs																					
10 years (2012-2021)	0.068	0.059	0.083	0.058	34.73	23.01	28.87	0.002	0.001	0.002	0.001	1.45	0.001	0.001	0.002	0.001	1.49	0.039	0.040	0.038	0.041
15 years (2012-2026)	0.074	0.064	0.087	0.063	51.93	49.88	50.91	0.001	0.001	0.002	0.001	2.23	0.001	0.001	0.002	0.001	2.29	0.035	0.036	0.034	0.037
30 years (2012-2041)	0.091	0.078	0.104	0.077	73.99	83.17	78.58											0.030	0.030	0.029	0.031

NOTES:

General: All Avoided Costs are in Year 2011 Dollars

ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 7 AM - 11 PM; Off-Peak Hours are all other hours

1 Avoided cost of electric energy = (wholesale energy avoided cost + REC cost to load) * risk premium, e.g. A= (V + AB) * (1+Wholesale Risk Premium)

2 Absolute value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year and PA strategy about bidding that reduction into applicable FCAs, and unit values in columns e, f, l and q.

3 Proceeds from selling into the FCM include the reserve margin, in addition to the ISO-NE loss factor of 8%

Page Two: Inputs to Avoided Cost Calculations

Zone: VT

	Wholesale Avoided Costs of Electricity: Energy				Capacity		Avoided REC Costs to Load
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	FCA Price	Reserve Margin	REC Costs
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	%	$/kWh
Period:	v	w	x	y	z	aa	ab
2011	0.050	0.042	0.056	0.040	43.20		0.0000
2012	0.052	0.044	0.061	0.043	34.72	16.6%	0.0000
2013	0.053	0.046	0.063	0.045	34.04	15.7%	0.0002
2014	0.054	0.047	0.066	0.046	34.04	17.7%	0.0005
2015	0.059	0.051	0.070	0.050	34.04	15.9%	0.0007
2016	0.060	0.051	0.076	0.050	13.98	16.0%	0.0010
2017	0.060	0.052	0.076	0.050	20.56	16.2%	0.0013
2018	0.066	0.058	0.085	0.057	28.72	16.3%	0.0008
2019	0.067	0.060	0.084	0.058	32.22	16.4%	0.0003
2020	0.069	0.060	0.080	0.059	45.08	16.5%	0.0004
2021	0.071	0.062	0.082	0.060	45.94	16.6%	0.0002
2022	0.073	0.064	0.083	0.062	68.95	16.8%	0.0004
2023	0.077	0.067	0.087	0.066	83.08	16.9%	0.0005
2024	0.079	0.068	0.089	0.067	90.89	17.0%	0.0006
2025	0.080	0.069	0.090	0.069	94.32	17.1%	0.0004
2026	0.082	0.071	0.094	0.070	96.38	17.3%	0.0002
2027	0.085	0.073	0.096	0.072	97.20	17.4%	0.0002
2028	0.087	0.075	0.099	0.075	97.68	17.5%	0.0002
2029	0.090	0.077	0.102	0.077	97.80	17.7%	0.0001
2030	0.093	0.079	0.105	0.079	97.92	17.8%	0.0001
2031	0.096	0.081	0.107	0.082	98.04	17.9%	0.0001
2032	0.099	0.084	0.110	0.084	98.04	18.1%	0.0001
2033	0.102	0.086	0.113	0.087	98.04	18.2%	0.0001
2034	0.105	0.088	0.117	0.089	98.04	18.3%	0.0001
2035	0.108	0.091	0.120	0.092	98.04	18.5%	0.0001
2036	0.112	0.093	0.123	0.095	98.04	18.6%	0.0001
2037	0.115	0.096	0.126	0.097	98.04	18.7%	0.0001
2038	0.119	0.098	0.130	0.100	98.04	18.9%	0.0001
2039	0.122	0.101	0.134	0.103	98.04	19.0%	0.0001
2040	0.126	0.104	0.137	0.107	98.04	19.1%	0.0001
2041	0.130	0.107	0.141	0.110	98.04	19.3%	0.0001
Levelized Cos							
10 years (2012-2021)	0.061	0.053	0.074	0.051	32.15		0.001
15 years (2012-2026)	0.066	0.057	0.078	0.056	48.09		0.000
30 years (2012-2041)	0.082	0.070	0.094	0.069	68.51		0.000

	2012 Energy DRIPE Values: Intrastate Installation				2012 Energy DRIPE Values: Rest of Pool Installation				2013 Energy DRIPE Values: Intrastate Installation				2013 Energy DRIPE Values: Rest of Pool Installation			
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh
Period:	ac	ad	ae	af	ag	ah	ai	aj	ak	al	am	an	ao	ap	aq	ar
2011																
2012	0.001	0.001	0.002	0.001	0.036	0.026	0.050	0.029	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2013	0.002	0.001	0.003	0.001	0.036	0.027	0.051	0.029	0.002	0.002	0.003	0.002	0.037	0.028	0.052	0.030
2014	0.002	0.001	0.003	0.001	0.037	0.027	0.052	0.029	0.002	0.002	0.003	0.001	0.038	0.028	0.054	0.030
2015	0.002	0.002	0.003	0.002	0.041	0.030	0.056	0.032	0.002	0.002	0.003	0.002	0.042	0.031	0.058	0.033
2016	0.002	0.001	0.003	0.001	0.039	0.028	0.058	0.031	0.002	0.002	0.003	0.002	0.042	0.031	0.062	0.033
2017	0.002	0.001	0.003	0.001	0.039	0.029	0.057	0.030	0.002	0.002	0.003	0.001	0.040	0.030	0.059	0.031
2018	0.002	0.002	0.003	0.002	0.043	0.032	0.064	0.034	0.002	0.002	0.003	0.002	0.043	0.033	0.066	0.035
2019	0.002	0.002	0.003	0.002	0.043	0.033	0.062	0.034	0.002	0.002	0.003	0.002	0.043	0.033	0.064	0.035
2020	0.001	0.001	0.001	0.001	0.022	0.016	0.029	0.017	0.001	0.002	0.003	0.002	0.022	0.033	0.060	0.035
2021	0.001	0.001	0.001	0.001	0.020	0.015	0.027	0.016	0.001	0.001	0.001	0.001	0.020	0.017	0.030	0.018
2022	0.001	0.001	0.001	0.001	0.018	0.014	0.024	0.015	0.001	0.001	0.001	0.001	0.018	0.016	0.028	0.017
2023	0.001	0.001	0.001	0.001	0.017	0.012	0.022	0.013	0.001	0.001	0.001	0.001	0.017	0.014	0.026	0.015
2024	0.001	0.001	0.001	0.001	0.015	0.011	0.019	0.012	0.001	0.001	0.001	0.001	0.015	0.013	0.023	0.014
2025	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.001	0.001	0.001	0.000	0.011	0.019	0.012
2026	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2027–2041																
Levelized Cos																
10 years (2012-2021)	0.002	0.001	0.002	0.001	0.036	0.026	0.051	0.028	0.001	0.001	0.002	0.001	0.033	0.026	0.050	0.028
15 years (2012-2026)	0.001	0.001	0.002	0.001	0.028	0.021	0.040	0.022	0.001	0.001	0.002	0.001	0.026	0.022	0.041	0.023
30 years (2012-2041)	0.001	0.001	0.001	0.001	0.017	0.012	0.024	0.013	0.001	0.001	0.001	0.001	0.015	0.013	0.024	0.014

NOTES: General — All Avoided Costs are in Year 2011 Dollars
ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are all other hours

Avoided Cost of Electricity (Nominal $) Results :

State CT

CT
Connecticut (Statewide)

Page One of Two

User-defined Inputs			
Wholesale Risk Premium (WRP)	9%	Percent of Capacity Bid into FCM (%Bid)	50.0%
Nominal Discount Rate	4.51%	Real Discount Rate	2.46%

	Avoided Unit Cost of Electric Energy[1]				Avoided Unit Cost of Electric Capacity[2]			DRIPE: 2012 vintage measures Intrastate Values — Energy				DRIPE: 2012 vintage measures — Capacity (See note 2)	DRIPE: 2013 vintage measures Intrastate Values — Energy				DRIPE: 2013 vintage measures — Capacity (See note 2)	Avoided Externality Costs			
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	kW bid into FCA (PA to determine quantity)[3]	kW not bid into FCM (PA to determine quantity)	Weighted Average Avoided Cost Based on Percent Capacity Bid	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kw-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e=z*1.08 for ISO-NE losses	f=z*(1+aa)*(1+PTF Loss of 1.9%)*(1+WRP)	g=(e*%Bid)+(f*(1-%Bid))	h	i	j	k	l	m	n	o	p	q	r	s	t	u
2011	0.057	0.048	0.064	0.046														0.042	0.043	0.041	0.045
2012	0.060	0.051	0.072	0.051	38.24		19.12	0.018	0.018	0.035	0.024	$0.00	0.000	0.000	0.000	0.000		0.043	0.044	0.042	0.046
2013	0.063	0.054	0.076	0.053	38.24		19.12	0.019	0.018	0.036	0.024	$0.00	0.019	0.019	0.037	0.025	$0.00	0.044	0.045	0.043	0.047
2014	0.066	0.057	0.079	0.056	39.01		19.50	0.020	0.019	0.038	0.025	$0.00	0.020	0.020	0.039	0.026	$0.00	0.045	0.046	0.044	0.047
2015	0.074	0.064	0.087	0.063	39.79		19.90	0.023	0.022	0.043	0.029	$0.00	0.023	0.023	0.044	0.030	$0.00	0.046	0.047	0.045	0.048
2016	0.076	0.065	0.096	0.065	16.67	19.89	18.28	0.022	0.021	0.045	0.028	$48.41	0.024	0.023	0.048	0.031	$48.41	0.047	0.048	0.046	0.049
2017	0.078	0.068	0.098	0.066	25.01	29.88	27.45	0.022	0.022	0.045	0.028	$49.98	0.023	0.023	0.046	0.029	$49.98	0.048	0.049	0.047	0.050
2018	0.087	0.077	0.111	0.074	35.62	42.61	39.12	0.025	0.025	0.051	0.033	$51.41	0.025	0.026	0.052	0.033	$51.41	0.040	0.041	0.039	0.043
2019	0.088	0.079	0.110	0.076	40.77	48.81	44.79	0.026	0.026	0.051	0.034	$50.52	0.026	0.027	0.052	0.034	$50.52	0.039	0.040	0.038	0.041
2020	0.093	0.081	0.108	0.080	58.19	69.73	63.96	0.013	0.013	0.024	0.017	$17.16	0.013	0.027	0.050	0.035	$17.16	0.038	0.039	0.037	0.040
2021	0.096	0.085	0.111	0.083	60.48	72.55	66.51	0.012	0.012	0.023	0.016	$17.67	0.013	0.014	0.026	0.018	$17.67	0.037	0.038	0.036	0.039
2022	0.102	0.090	0.117	0.088	92.59	111.18	101.89	0.011	0.012	0.021	0.015	$181.39	0.012	0.013	0.024	0.017	$181.39	0.036	0.036	0.035	0.038
2023	0.110	0.097	0.126	0.095	113.79	136.80	125.29	0.011	0.011	0.019	0.014	$91.23	0.011	0.012	0.023	0.016	$91.23	0.034	0.035	0.034	0.036
2024	0.117	0.101	0.131	0.099	126.98	152.82	139.90	0.010	0.010	0.017	0.013	$44.48	0.010	0.011	0.020	0.015	$44.48	0.033	0.034	0.032	0.035
2025	0.120	0.104	0.134	0.104	134.40	161.93	148.17					$23.10					$23.10	0.031	0.032	0.031	0.033
2026	0.124	0.107	0.142	0.106	140.09	168.95	154.52					$10.17					$10.17	0.030	0.030	0.029	0.031
2027	0.130	0.112	0.148	0.111	144.11	174.00	159.05											0.031	0.031	0.030	0.032
2028	0.137	0.118	0.155	0.117	147.72	178.55	163.13											0.031	0.032	0.030	0.033
2029	0.144	0.123	0.163	0.122	150.86	182.54	166.70											0.032	0.032	0.031	0.033
2030	0.151	0.129	0.171	0.129	154.06	186.63	170.35											0.032	0.033	0.032	0.034
2031	0.159	0.135	0.179	0.135	157.34	190.81	174.07											0.033	0.034	0.032	0.035
2032	0.167	0.142	0.188	0.142	160.48	194.84	177.66											0.034	0.034	0.033	0.035
2033	0.176	0.148	0.197	0.149	163.69	198.96	181.33											0.034	0.035	0.034	0.036
2034	0.185	0.156	0.206	0.157	166.97	203.17	185.07											0.035	0.036	0.034	0.037
2035	0.195	0.163	0.216	0.165	170.31	207.46	188.89											0.036	0.036	0.035	0.038
2036	0.205	0.171	0.227	0.173	173.71	211.85	192.78											0.036	0.037	0.036	0.038
2037	0.215	0.179	0.238	0.182	177.19	216.34	196.76											0.037	0.038	0.036	0.039
2038	0.227	0.188	0.250	0.191	180.73	220.91	200.82											0.038	0.039	0.037	0.040
2039	0.238	0.197	0.262	0.201	184.35	225.59	204.97											0.039	0.039	0.038	0.041
2040	0.251	0.207	0.275	0.211	188.03	230.37	209.20											0.039	0.040	0.039	0.042
2041	0.264	0.216	0.288	0.222	191.79	235.24	213.52											0.040	0.041	0.039	0.042
Levelized Costs																					
10 years (2012-2021)	0.069	0.060	0.084	0.059	34.73	26.94	28.65	0.018	0.018	0.035	0.023	19.77	0.017	0.018	0.035	0.023	20.66	0.039	0.040	0.038	0.041
15 years (2012-2026)	0.075	0.065	0.089	0.064	51.93	58.38	50.44	0.014	0.014	0.028	0.019	30.72	0.013	0.014	0.028	0.019	32.11	0.035	0.036	0.034	0.037
30 years (2012-2041)	0.092	0.079	0.106	0.078	73.99	97.34	77.80											0.030	0.030	0.029	0.031

NOTES:
General — All Avoided Costs are in Nominal Dollars
ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 7 AM - 11 PM; Off-Peak Hours are all other hours
1 Avoided cost of electric energy = (wholesale energy avoided cost + REC cost to load) * risk premium, e.g. A= (V + AB) * (1+Wholesale Risk Premium)
2 Absolute value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year and PA strategy about bidding that reduction into applicable FCAs, and unit values in columns e, f, l and q.
3 Proceeds from selling into the FCM include the reserve margin, in addition to the ISO-NE loss factor of 8%

Page Two: Inputs to Avoided Cost Calculations

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Zone: CT

	Wholesale Avoided Costs of Electricity: Energy				Capacity		Avoided REC Costs to Load
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	FCA Price	Reserve Margin	REC Costs
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	%	$/kWh
Period:	v	w	x	y	z	aa	ab
2011	0.051	0.043	0.057	0.041	43.20		0.0016
2012	0.053	0.045	0.064	0.045	35.41	16.6%	0.0019
2013	0.055	0.047	0.067	0.047	35.41	15.7%	0.0022
2014	0.058	0.050	0.070	0.049	36.12	17.7%	0.0025
2015	0.065	0.056	0.077	0.055	36.84	15.9%	0.0029
2016	0.067	0.057	0.085	0.056	15.43	16.0%	0.0033
2017	0.068	0.059	0.086	0.057	23.16	16.2%	0.0037
2018	0.077	0.068	0.099	0.065	32.99	16.3%	0.0028
2019	0.079	0.071	0.099	0.068	37.75	16.4%	0.0017
2020	0.083	0.072	0.097	0.071	53.88	16.5%	0.0022
2021	0.087	0.076	0.101	0.074	56.00	16.6%	0.0014
2022	0.091	0.080	0.105	0.078	85.73	16.8%	0.0023
2023	0.098	0.085	0.112	0.084	105.36	16.9%	0.0032
2024	0.104	0.090	0.117	0.088	117.58	17.0%	0.0033
2025	0.107	0.092	0.120	0.092	124.45	17.1%	0.0027
2026	0.112	0.097	0.128	0.096	129.71	17.3%	0.0017
2027	0.118	0.102	0.134	0.100	133.43	17.4%	0.0015
2028	0.124	0.107	0.141	0.106	136.78	17.5%	0.0014
2029	0.131	0.112	0.148	0.111	139.68	17.7%	0.0013
2030	0.137	0.117	0.155	0.117	142.65	17.8%	0.0012
2031	0.145	0.123	0.163	0.123	145.68	17.9%	0.0012
2032	0.152	0.129	0.171	0.129	148.60	18.1%	0.0012
2033	0.160	0.135	0.179	0.136	151.57	18.2%	0.0012
2034	0.169	0.142	0.188	0.143	154.60	18.3%	0.0012
2035	0.177	0.148	0.197	0.150	157.69	18.5%	0.0012
2036	0.187	0.156	0.207	0.158	160.85	18.6%	0.0013
2037	0.196	0.163	0.217	0.166	164.06	18.7%	0.0013
2038	0.207	0.171	0.228	0.174	167.34	18.9%	0.0013
2039	0.217	0.179	0.239	0.183	170.69	19.0%	0.0013
2040	0.229	0.188	0.251	0.193	174.10	19.1%	0.0014
2041	0.241	0.197	0.263	0.203	177.59	19.3%	0.0014
Levelized Cos							
10 years (2012-2021)	0.061	0.053	0.075	0.052	32.15		0.002
15 years (2012-2026)	0.066	0.058	0.079	0.056	48.09		0.002
30 years (2012-2041)	0.083	0.071	0.095	0.070	68.51		0.002

	2012 Energy DRIPE Values: Intrastate Installation				2012 Energy DRIPE Values: Rest of Pool Installation				2013 Energy DRIPE Values: Intrastate Installation				2013 Energy DRIPE Values: Rest of Pool Installation			
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh
Period:	ac	ad	ae	af	ag	ah	ai	aj	ak	al	am	an	ao	ap	aq	ar
2011																
2012	0.018	0.018	0.035	0.024	0.026	0.018	0.035	0.020	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2013	0.019	0.018	0.036	0.024	0.027	0.020	0.037	0.021	0.019	0.019	0.037	0.025	0.027	0.020	0.038	0.022
2014	0.020	0.019	0.038	0.025	0.028	0.020	0.039	0.022	0.020	0.020	0.039	0.026	0.028	0.021	0.040	0.022
2015	0.023	0.022	0.043	0.029	0.031	0.022	0.042	0.024	0.023	0.023	0.044	0.030	0.031	0.023	0.043	0.025
2016	0.022	0.021	0.045	0.028	0.030	0.022	0.044	0.023	0.024	0.023	0.048	0.031	0.032	0.023	0.048	0.025
2017	0.022	0.022	0.045	0.028	0.031	0.022	0.045	0.024	0.023	0.023	0.046	0.029	0.031	0.023	0.046	0.024
2018	0.025	0.025	0.051	0.033	0.034	0.026	0.051	0.027	0.025	0.026	0.052	0.033	0.034	0.026	0.052	0.028
2019	0.026	0.026	0.051	0.034	0.035	0.026	0.050	0.028	0.026	0.027	0.052	0.034	0.035	0.027	0.052	0.029
2020	0.013	0.013	0.024	0.017	0.018	0.013	0.024	0.014	0.013	0.027	0.050	0.035	0.018	0.027	0.050	0.029
2021	0.012	0.012	0.023	0.016	0.017	0.013	0.023	0.013	0.013	0.014	0.026	0.018	0.017	0.014	0.026	0.015
2022	0.011	0.012	0.021	0.015	0.016	0.012	0.021	0.012	0.012	0.013	0.024	0.017	0.016	0.013	0.024	0.014
2023	0.011	0.011	0.019	0.014	0.015	0.011	0.019	0.012	0.011	0.012	0.023	0.016	0.015	0.012	0.022	0.013
2024	0.010	0.010	0.017	0.013	0.013	0.010	0.017	0.010	0.010	0.011	0.020	0.015	0.013	0.011	0.020	0.012
2025	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.010	0.018	0.013	0.000	0.010	0.018	0.011
2026	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
10 years (2012-2021)	0.018	0.018	0.035	0.023	0.025	0.018	0.035	0.020	0.017	0.018	0.035	0.023	0.023	0.018	0.035	0.019
15 years (2012-2026)	0.014	0.014	0.028	0.019	0.020	0.014	0.028	0.016	0.013	0.015	0.028	0.019	0.018	0.015	0.028	0.016
30 years (2012-2041)	0.008	0.008	0.016	0.011	0.012	0.009	0.016	0.009	0.008	0.009	0.017	0.011	0.011	0.009	0.017	0.009

NOTES: General — All Avoided Costs are in Nominal Dollars

ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are all other hours

Avoided Cost of Electricity (Nominal $) Results :

CT-NS
Norwalk/Stamford

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State CT

User-defined Inputs			
Wholesale Risk Premium (WRP)	9%	Percent of Capacity Bid into FCM (%Bid)	50.0%
Nominal Discount Rate	4.51%	Real Discount Rate	2.46%

	Avoided Unit Cost of Electric Energy[1]				Avoided Unit Cost of Electric Capacity[2]			DRIPE: 2012 vintage measures, Intrastate Values: Energy				DRIPE: 2012 Capacity (See note 2)	DRIPE: 2013 vintage measures, Intrastate Values: Energy				DRIPE: 2013 Capacity (See note 2)	Avoided Externality Costs			
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	kW bid into FCA (PA to determine quantity)[3]	kW not bid into FCM (PA to determine quantity)	Weighted Average Avoided Cost Based on Percent Capacity Bid	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kw-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e=z*1.08 for ISO-NE losses	f=z*(1+aa)*(1+PTF Loss of 1.9%)*(1+WRP)	g=(e*%Bid)+(f*(1-%Bid))	h	i	j	k	l	m	n	o	p	q	r	s	t	u
2011	0.058	0.049	0.065	0.047														0.042	0.043	0.041	0.045
2012	0.061	0.052	0.073	0.051	38.24		19.12	0.018	0.018	0.035	0.024	$0.00	0.000	0.000	0.000	0.000		0.043	0.044	0.042	0.046
2013	0.063	0.055	0.077	0.054	38.24		19.12	0.019	0.018	0.036	0.024	$0.00	0.019	0.019	0.037	0.025	$0.00	0.044	0.045	0.043	0.047
2014	0.067	0.058	0.080	0.057	39.01		19.50	0.020	0.019	0.038	0.025	$0.00	0.020	0.020	0.039	0.026	$0.00	0.045	0.046	0.044	0.047
2015	0.075	0.064	0.088	0.063	39.79		19.90	0.023	0.022	0.043	0.029	$0.00	0.023	0.023	0.044	0.030	$0.00	0.046	0.047	0.045	0.048
2016	0.077	0.066	0.097	0.066	16.67	19.89	18.28	0.022	0.021	0.045	0.028	$48.41	0.024	0.023	0.048	0.031	$48.41	0.047	0.048	0.046	0.049
2017	0.079	0.069	0.099	0.066	25.01	29.88	27.45	0.022	0.022	0.045	0.028	$49.98	0.023	0.023	0.046	0.029	$49.98	0.048	0.049	0.047	0.050
2018	0.088	0.078	0.112	0.075	35.62	42.61	39.12	0.025	0.025	0.051	0.033	$51.41	0.025	0.026	0.052	0.033	$51.41	0.040	0.041	0.039	0.043
2019	0.089	0.080	0.111	0.077	40.77	48.81	44.79	0.026	0.026	0.051	0.034	$50.52	0.026	0.027	0.052	0.034	$50.52	0.039	0.040	0.038	0.041
2020	0.094	0.082	0.109	0.080	58.19	69.73	63.96	0.013	0.013	0.024	0.017	$17.16	0.013	0.027	0.050	0.035	$17.16	0.038	0.039	0.037	0.040
2021	0.097	0.086	0.113	0.083	60.48	72.55	66.51	0.012	0.012	0.023	0.016	$17.67	0.013	0.014	0.026	0.018	$17.67	0.037	0.038	0.036	0.039
2022	0.103	0.091	0.118	0.089	92.59	111.18	101.89	0.011	0.012	0.021	0.015	$181.39	0.012	0.013	0.024	0.017	$181.39	0.036	0.036	0.035	0.038
2023	0.112	0.098	0.127	0.096	113.79	136.80	125.29	0.011	0.011	0.019	0.014	$91.23	0.011	0.012	0.023	0.016	$91.23	0.034	0.035	0.034	0.036
2024	0.118	0.102	0.132	0.100	126.98	152.82	139.90	0.010	0.010	0.017	0.013	$44.48	0.010	0.011	0.020	0.015	$44.48	0.033	0.034	0.032	0.035
2025	0.121	0.105	0.135	0.105	134.40	161.93	148.17					$23.10					$23.10	0.031	0.032	0.031	0.033
2026	0.125	0.109	0.143	0.107	140.09	168.95	154.52					$10.17					$10.17	0.030	0.030	0.029	0.031
2027	0.132	0.114	0.150	0.112	144.11	174.00	159.05											0.031	0.031	0.030	0.032
2028	0.138	0.119	0.157	0.118	147.72	178.55	163.13											0.031	0.032	0.030	0.033
2029	0.145	0.124	0.164	0.124	150.86	182.54	166.70											0.032	0.032	0.031	0.033
2030	0.153	0.130	0.172	0.130	154.06	186.63	170.35											0.032	0.033	0.032	0.034
2031	0.161	0.136	0.181	0.136	157.34	190.81	174.07											0.033	0.034	0.032	0.035
2032	0.169	0.143	0.190	0.143	160.48	194.84	177.66											0.034	0.034	0.033	0.035
2033	0.178	0.150	0.199	0.151	163.69	198.96	181.33											0.034	0.035	0.034	0.036
2034	0.187	0.157	0.209	0.158	166.97	203.17	185.07											0.035	0.036	0.034	0.037
2035	0.197	0.165	0.219	0.167	170.31	207.46	188.89											0.036	0.036	0.035	0.038
2036	0.207	0.173	0.229	0.175	173.71	211.85	192.78											0.036	0.037	0.036	0.038
2037	0.218	0.181	0.241	0.184	177.19	216.34	196.76											0.037	0.038	0.036	0.039
2038	0.229	0.190	0.252	0.193	180.73	220.91	200.82											0.038	0.039	0.037	0.040
2039	0.241	0.199	0.265	0.203	184.35	225.59	204.97											0.039	0.039	0.038	0.041
2040	0.254	0.209	0.278	0.214	188.03	230.37	209.20											0.039	0.040	0.039	0.042
2041	0.267	0.219	0.291	0.225	191.79	235.24	213.52											0.040	0.041	0.039	0.042
Levelized Costs																					
10 years (2012-2021)	0.070	0.061	0.085	0.060	34.73	26.94	28.65	0.018	0.018	0.035	0.023	19.77	0.017	0.018	0.035	0.023	20.66	0.039	0.040	0.038	0.041
15 years (2012-2026)	0.076	0.066	0.090	0.065	51.93	58.38	50.44	0.014	0.014	0.028	0.019	30.72	0.013	0.014	0.028	0.019	32.11	0.035	0.036	0.034	0.037
30 years (2012-2041)	0.093	0.079	0.107	0.079	73.99	97.34	77.80											0.030	0.030	0.029	0.031

NOTES:

General All Avoided Costs are in Nominal Dollars

ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 7 AM - 11 PM; Off-Peak Hours are all other hours

1 Avoided cost of electric energy = (wholesale energy avoided cost + REC cost to load) * risk premium, e.g. A= (V + AB) * (1+Wholesale Risk Premium)

2 Absolute value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year and PA strategy about bidding that reduction into applicable FCAs, and unit values in columns e, f, l and q.

3 Proceeds from selling into the FCM include the reserve margin, in addition to the ISO-NE loss factor of 8%

Page Two: Inputs to Avoided Cost Calculations

Zone: CT-NS

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	Wholesale Avoided Costs of Electricity						Avoided REC Costs to Load	2012 Energy DRIPE Values								2013 Energy DRIPE Values							
	Energy				Capacity			Intrastate Installation				Rest of Pool Installation				Intrastate Installation				Rest of Pool Installation			
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	FCA Price	Reserve Margin	REC Costs	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	%	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh
Period:	v	w	x	y	z	aa	ab	ac	ad	ae	af	ag	ah	ai	aj	ak	al	am	an	ao	ap	aq	ar
2011	0.051	0.043	0.058	0.041	43.20		0.0016																
2012	0.054	0.045	0.065	0.045	35.41	16.6%	0.0019	0.018	0.018	0.035	0.024	0.026	0.018	0.035	0.020	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2013	0.056	0.048	0.068	0.047	35.41	15.7%	0.0022	0.019	0.018	0.036	0.024	0.027	0.020	0.037	0.021	0.019	0.019	0.037	0.025	0.027	0.020	0.038	0.022
2014	0.059	0.051	0.071	0.049	36.12	17.7%	0.0025	0.020	0.019	0.038	0.025	0.028	0.020	0.039	0.022	0.020	0.020	0.039	0.026	0.028	0.021	0.040	0.022
2015	0.066	0.056	0.078	0.055	36.84	15.9%	0.0029	0.023	0.022	0.043	0.029	0.031	0.022	0.042	0.024	0.023	0.023	0.044	0.030	0.031	0.023	0.043	0.025
2016	0.067	0.057	0.086	0.057	15.43	16.0%	0.0033	0.022	0.021	0.045	0.028	0.030	0.022	0.044	0.023	0.024	0.023	0.048	0.031	0.032	0.023	0.048	0.025
2017	0.069	0.060	0.087	0.057	23.16	16.2%	0.0037	0.022	0.022	0.045	0.028	0.031	0.022	0.045	0.024	0.023	0.023	0.046	0.029	0.031	0.023	0.046	0.024
2018	0.078	0.068	0.100	0.066	32.99	16.3%	0.0028	0.025	0.025	0.051	0.033	0.034	0.026	0.051	0.027	0.025	0.026	0.052	0.033	0.034	0.026	0.052	0.028
2019	0.080	0.072	0.100	0.069	37.75	16.4%	0.0017	0.026	0.026	0.051	0.034	0.035	0.026	0.050	0.028	0.026	0.027	0.052	0.034	0.035	0.027	0.052	0.029
2020	0.084	0.073	0.098	0.072	53.88	16.5%	0.0022	0.013	0.013	0.024	0.017	0.018	0.013	0.024	0.014	0.013	0.027	0.050	0.035	0.018	0.027	0.050	0.029
2021	0.088	0.077	0.102	0.075	56.00	16.6%	0.0014	0.012	0.012	0.023	0.016	0.017	0.013	0.023	0.013	0.013	0.014	0.026	0.018	0.017	0.014	0.026	0.015
2022	0.092	0.081	0.106	0.079	85.73	16.8%	0.0023	0.011	0.012	0.021	0.015	0.016	0.012	0.021	0.012	0.012	0.013	0.024	0.017	0.016	0.013	0.024	0.014
2023	0.099	0.086	0.113	0.085	105.36	16.9%	0.0032	0.011	0.011	0.019	0.014	0.015	0.011	0.019	0.012	0.011	0.012	0.023	0.016	0.015	0.012	0.022	0.013
2024	0.105	0.090	0.118	0.089	117.58	17.0%	0.0033	0.010	0.010	0.017	0.013	0.013	0.010	0.017	0.010	0.010	0.011	0.020	0.015	0.013	0.011	0.020	0.012
2025	0.108	0.093	0.122	0.093	124.45	17.1%	0.0027	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.010	0.018	0.013	0.000	0.010	0.018	0.011
2026	0.113	0.098	0.130	0.097	129.71	17.3%	0.0017	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2027	0.119	0.103	0.136	0.102	133.43	17.4%	0.0015																
2028	0.125	0.108	0.143	0.107	136.78	17.5%	0.0014																
2029	0.132	0.113	0.150	0.112	139.68	17.7%	0.0013																
2030	0.139	0.118	0.157	0.118	142.65	17.8%	0.0012																
2031	0.146	0.124	0.165	0.124	145.68	17.9%	0.0012																
2032	0.154	0.130	0.173	0.130	148.60	18.1%	0.0012																
2033	0.162	0.136	0.181	0.137	151.57	18.2%	0.0012																
2034	0.170	0.143	0.190	0.144	154.60	18.3%	0.0012																
2035	0.179	0.150	0.199	0.152	157.69	18.5%	0.0012																
2036	0.189	0.157	0.209	0.159	160.85	18.6%	0.0013																
2037	0.198	0.165	0.219	0.168	164.06	18.7%	0.0013																
2038	0.209	0.173	0.230	0.176	167.34	18.9%	0.0013																
2039	0.220	0.181	0.242	0.185	170.69	19.0%	0.0013																
2040	0.231	0.190	0.253	0.195	174.10	19.1%	0.0014																
2041	0.243	0.199	0.266	0.205	177.59	19.3%	0.0014																
Levelized Cos																							
10 years (2012-2021)	0.062	0.054	0.076	0.052	32.15		0.002	0.018	0.018	0.035	0.023	0.025	0.018	0.035	0.020	0.017	0.018	0.035	0.023	0.023	0.018	0.035	0.019
15 years (2012-2026)	0.067	0.058	0.080	0.057	48.09		0.002	0.014	0.014	0.028	0.019	0.020	0.014	0.028	0.016	0.013	0.015	0.028	0.019	0.018	0.015	0.028	0.016
30 years (2012-2041)	0.084	0.071	0.096	0.071	68.51		0.002	0.008	0.008	0.016	0.011	0.012	0.009	0.016	0.009	0.008	0.009	0.017	0.011	0.011	0.009	0.017	0.009

NOTES: General All Avoided Costs are in Nominal Dollars
ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are all other hours

Avoided Cost of Electricity (Nominal $) Results :

State CT

CT-R
Rest of Connecticut (Connecticut excluding all of Southwest Connecticut)

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User-defined Inputs			
Wholesale Risk Premium (WRP)	9%	Percent of Capacity Bid into FCM (%Bid)	50.0%
Nominal Discount Rate	4.51%	Real Discount Rate	2.46%

	Avoided Unit Cost of Electric Energy[1]				Avoided Unit Cost of Electric Capacity[2]			DRIPE: 2012 vintage measures, Intrastate Values					DRIPE: 2013 vintage measures, Intrastate Values					Avoided Externality Costs			
								Energy				Capacity (See note 2)	Energy				Capacity (See note 2)				
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	kW bid into FCA (PA to determine quantity)[3]	kW not bid into FCM (PA to determine quantity)	Weighted Average Avoided Cost Based on Percent Capacity Bid	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kw-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e=z*1.08 for ISO-NE losses	f=z*(1+aa)*(1+PTF Loss of 1.9%)*(1+WRP)	g=(e*%Bid)+(f*(1-%Bid))	h	i	j	k	l	m	n	o	p	q	r	s	t	u
2011	0.057	0.048	0.064	0.046														0.042	0.043	0.041	0.045
2012	0.060	0.050	0.071	0.050	38.24		19.12	0.018	0.018	0.035	0.024	$0.00	0.000	0.000	0.000	0.000		0.043	0.044	0.042	0.046
2013	0.062	0.054	0.075	0.053	38.24		19.12	0.019	0.018	0.036	0.024	$0.00	0.019	0.019	0.037	0.025	$0.00	0.044	0.045	0.043	0.047
2014	0.066	0.057	0.079	0.055	39.01		19.50	0.020	0.019	0.038	0.025	$0.00	0.020	0.020	0.039	0.026	$0.00	0.045	0.046	0.044	0.047
2015	0.073	0.063	0.086	0.062	39.79		19.90	0.023	0.022	0.043	0.029	$0.00	0.023	0.023	0.044	0.030	$0.00	0.046	0.047	0.045	0.048
2016	0.076	0.065	0.096	0.064	16.67	19.89	18.28	0.022	0.021	0.045	0.028	$48.41	0.024	0.023	0.048	0.031	$48.41	0.047	0.048	0.046	0.049
2017	0.078	0.068	0.097	0.065	25.01	29.88	27.45	0.022	0.022	0.045	0.028	$49.98	0.023	0.023	0.046	0.029	$49.98	0.048	0.049	0.047	0.050
2018	0.086	0.076	0.110	0.074	35.62	42.61	39.12	0.025	0.025	0.051	0.033	$51.41	0.025	0.026	0.052	0.033	$51.41	0.040	0.041	0.039	0.043
2019	0.087	0.078	0.109	0.076	40.77	48.81	44.79	0.026	0.026	0.051	0.034	$50.52	0.026	0.027	0.052	0.034	$50.52	0.039	0.040	0.038	0.041
2020	0.092	0.080	0.107	0.079	58.19	69.73	63.96	0.013	0.013	0.024	0.017	$17.16	0.013	0.027	0.050	0.035	$17.16	0.038	0.039	0.037	0.040
2021	0.095	0.084	0.110	0.082	60.48	72.55	66.51	0.012	0.012	0.023	0.016	$17.67	0.013	0.014	0.026	0.018	$17.67	0.037	0.038	0.036	0.039
2022	0.101	0.089	0.116	0.087	92.59	111.18	101.89	0.011	0.012	0.021	0.015	$181.39	0.012	0.013	0.024	0.017	$181.39	0.036	0.036	0.035	0.038
2023	0.109	0.096	0.124	0.094	113.79	136.80	125.29	0.011	0.011	0.019	0.014	$91.23	0.011	0.012	0.023	0.016	$91.23	0.034	0.035	0.034	0.036
2024	0.115	0.100	0.129	0.098	126.98	152.82	139.90	0.010	0.010	0.017	0.013	$44.48	0.010	0.011	0.020	0.015	$44.48	0.033	0.034	0.032	0.035
2025	0.119	0.103	0.133	0.103	134.40	161.93	148.17					$23.10					$23.10	0.031	0.032	0.031	0.033
2026	0.123	0.106	0.140	0.105	140.09	168.95	154.52					$10.17					$10.17	0.030	0.030	0.029	0.031
2027	0.129	0.111	0.147	0.110	144.11	174.00	159.05											0.031	0.031	0.030	0.032
2028	0.135	0.116	0.154	0.115	147.72	178.55	163.13											0.031	0.032	0.030	0.033
2029	0.142	0.122	0.161	0.121	150.86	182.54	166.70											0.032	0.032	0.031	0.033
2030	0.150	0.128	0.169	0.127	154.06	186.63	170.35											0.032	0.033	0.032	0.034
2031	0.157	0.134	0.177	0.134	157.34	190.81	174.07											0.033	0.034	0.032	0.035
2032	0.165	0.140	0.186	0.141	160.48	194.84	177.66											0.034	0.034	0.033	0.035
2033	0.174	0.147	0.195	0.148	163.69	198.96	181.33											0.034	0.035	0.034	0.036
2034	0.183	0.154	0.204	0.155	166.97	203.17	185.07											0.035	0.036	0.034	0.037
2035	0.193	0.161	0.214	0.163	170.31	207.46	188.89											0.036	0.036	0.035	0.038
2036	0.203	0.169	0.225	0.171	173.71	211.85	192.78											0.036	0.037	0.036	0.038
2037	0.213	0.177	0.236	0.180	177.19	216.34	196.76											0.037	0.038	0.036	0.039
2038	0.224	0.186	0.247	0.189	180.73	220.91	200.82											0.038	0.039	0.037	0.040
2039	0.236	0.195	0.259	0.199	184.35	225.59	204.97											0.039	0.039	0.038	0.041
2040	0.248	0.204	0.272	0.209	188.03	230.37	209.20											0.039	0.040	0.039	0.042
2041	0.261	0.214	0.285	0.220	191.79	235.24	213.52											0.040	0.041	0.039	0.042
Levelized Costs																					
10 years (2012-2021)	0.069	0.060	0.083	0.058	34.73	26.94	28.65	0.018	0.018	0.035	0.023	19.77	0.017	0.018	0.035	0.023	20.66	0.039	0.040	0.038	0.041
15 years (2012-2026)	0.074	0.064	0.088	0.063	51.93	58.38	50.44	0.014	0.014	0.028	0.019	30.72	0.013	0.014	0.028	0.019	32.11	0.035	0.036	0.034	0.037
30 years (2012-2041)	0.091	0.078	0.105	0.078	73.99	97.34	77.80											0.030	0.030	0.029	0.031

NOTES:

General All Avoided Costs are in Nominal Dollars
ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 7 AM - 11 PM; Off-Peak Hours are all other hours

1 Avoided cost of electric energy = (wholesale energy avoided cost + REC cost to load) * risk premium, e.g. A= (V + AB) * (1+Wholesale Risk Premium)

2 Absolute value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year and PA strategy about bidding that reduction into applicable FCAs, and unit values in columns e, f, l and q.

3 Proceeds from selling into the FCM include the reserve margin, in addition to the ISO-NE loss factor of 8%

Appendix B: CT-R_Nominal

Page Two: Inputs to Avoided Cost Calculations

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Zone: CT-R

	Wholesale Avoided Costs of Electricity						Avoided REC Costs to Load	2012 Energy DRIPE Values								2013 Energy DRIPE Values							
	Energy				Capacity			Intrastate Installation				Rest of Pool Installation				Intrastate Installation				Rest of Pool Installation			
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	FCA Price	Reserve Margin	REC Costs	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	%	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh
Period:	v	w	x	y	z	aa	ab	ac	ad	ae	af	ag	ah	ai	aj	ak	al	am	an	ao	ap	aq	ar
2011	0.050	0.042	0.057	0.040	43.20		0.0016																
2012	0.053	0.044	0.063	0.044	35.41	16.6%	0.0019	0.018	0.018	0.035	0.024	0.026	0.018	0.035	0.020	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2013	0.055	0.047	0.067	0.046	35.41	15.7%	0.0022	0.019	0.018	0.036	0.024	0.027	0.020	0.037	0.021	0.019	0.019	0.037	0.025	0.027	0.020	0.038	0.022
2014	0.058	0.050	0.070	0.048	36.12	17.7%	0.0025	0.020	0.019	0.038	0.025	0.028	0.020	0.039	0.022	0.020	0.020	0.039	0.026	0.028	0.021	0.040	0.022
2015	0.064	0.055	0.076	0.054	36.84	15.9%	0.0029	0.023	0.022	0.043	0.029	0.031	0.022	0.042	0.024	0.023	0.023	0.044	0.030	0.031	0.023	0.043	0.025
2016	0.066	0.056	0.084	0.056	15.43	16.0%	0.0033	0.022	0.021	0.045	0.028	0.030	0.022	0.044	0.023	0.024	0.023	0.048	0.031	0.032	0.023	0.048	0.025
2017	0.068	0.058	0.085	0.056	23.16	16.2%	0.0037	0.022	0.022	0.045	0.028	0.031	0.022	0.045	0.024	0.023	0.023	0.046	0.029	0.031	0.023	0.046	0.024
2018	0.076	0.067	0.098	0.065	32.99	16.3%	0.0028	0.025	0.025	0.051	0.033	0.034	0.026	0.051	0.027	0.025	0.026	0.052	0.033	0.034	0.026	0.052	0.028
2019	0.078	0.070	0.098	0.068	37.75	16.4%	0.0017	0.026	0.026	0.051	0.034	0.035	0.026	0.050	0.028	0.026	0.027	0.052	0.034	0.035	0.027	0.052	0.029
2020	0.082	0.071	0.096	0.070	53.88	16.5%	0.0022	0.013	0.013	0.024	0.017	0.018	0.013	0.024	0.014	0.013	0.027	0.050	0.035	0.018	0.027	0.050	0.029
2021	0.086	0.076	0.100	0.074	56.00	16.6%	0.0014	0.012	0.012	0.023	0.016	0.017	0.013	0.023	0.013	0.013	0.014	0.026	0.018	0.017	0.014	0.026	0.015
2022	0.090	0.079	0.104	0.078	85.73	16.8%	0.0023	0.011	0.012	0.021	0.015	0.016	0.012	0.021	0.012	0.012	0.013	0.024	0.017	0.016	0.013	0.024	0.014
2023	0.097	0.085	0.111	0.083	105.36	16.9%	0.0032	0.011	0.011	0.019	0.014	0.015	0.011	0.019	0.012	0.011	0.012	0.023	0.016	0.015	0.012	0.022	0.013
2024	0.103	0.089	0.115	0.087	117.58	17.0%	0.0033	0.010	0.010	0.017	0.013	0.013	0.010	0.017	0.010	0.010	0.011	0.020	0.015	0.013	0.011	0.020	0.012
2025	0.106	0.092	0.119	0.091	124.45	17.1%	0.0027	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.010	0.018	0.013	0.000	0.010	0.018	0.011
2026	0.111	0.096	0.127	0.095	129.71	17.3%	0.0017	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2027	0.117	0.101	0.133	0.099	133.43	17.4%	0.0015																
2028	0.123	0.105	0.140	0.105	136.78	17.5%	0.0014																
2029	0.129	0.111	0.146	0.110	139.68	17.7%	0.0013																
2030	0.136	0.116	0.154	0.116	142.65	17.8%	0.0012																
2031	0.143	0.122	0.161	0.121	145.68	17.9%	0.0012																
2032	0.151	0.127	0.169	0.128	148.60	18.1%	0.0012																
2033	0.158	0.134	0.177	0.134	151.57	18.2%	0.0012																
2034	0.167	0.140	0.186	0.141	154.60	18.3%	0.0012																
2035	0.176	0.147	0.195	0.148	157.69	18.5%	0.0012																
2036	0.185	0.154	0.205	0.156	160.85	18.6%	0.0013																
2037	0.194	0.161	0.215	0.164	164.06	18.7%	0.0013																
2038	0.205	0.169	0.226	0.173	167.34	18.9%	0.0013																
2039	0.215	0.178	0.237	0.181	170.69	19.0%	0.0013																
2040	0.226	0.186	0.248	0.191	174.10	19.1%	0.0014																
2041	0.238	0.195	0.260	0.200	177.59	19.3%	0.0014																
Levelized Cos																							
10 years (2012-2021)	0.061	0.052	0.074	0.051	32.15		0.002	0.018	0.018	0.035	0.023	0.025	0.018	0.035	0.020	0.017	0.018	0.035	0.023	0.023	0.018	0.035	0.019
15 years (2012-2026)	0.066	0.057	0.078	0.056	48.09		0.002	0.014	0.014	0.028	0.019	0.020	0.014	0.028	0.016	0.013	0.015	0.028	0.019	0.018	0.015	0.028	0.016
30 years (2012-2041)	0.082	0.070	0.094	0.069	68.51		0.002	0.008	0.008	0.016	0.011	0.012	0.009	0.016	0.009	0.008	0.009	0.017	0.011	0.011	0.009	0.017	0.009

NOTES: General All Avoided Costs are in Nominal Dollars
ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are all other hours

Avoided Cost of Electricity (Nominal $) Results :

State CT

CT-SWe
Southwest Connecticut, excluding Norwalk/Stamford

Page One of Two

User-defined Inputs			
Wholesale Risk Premium (WRP)	9%	Percent of Capacity Bid into FCM (%Bid)	50.0%
Nominal Discount Rate	4.51%	Real Discount Rate	2.46%

	Avoided Unit Cost of Electric Energy[1]				Avoided Unit Cost of Electric Capacity[2]			DRIPE: 2012 vintage measures Intrastate Values					DRIPE: 2013 vintage measures Intrastate Values					Avoided Externality Costs			
								Energy				Capacity (See note 2)	Energy				Capacity (See note 2)				
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	kW bid into FCA (PA to determine quantity)[3]	kW not bid into FCM (PA to determine quantity)	Weighted Average Avoided Cost Based on Percent Capacity Bid	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kw-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e=z*1.08 for ISO-NE losses	f=z*(1+aa)*(1+PTF Loss of 1.9%)*(1+WRP)	g=(e*%Bid)+(f*(1-%Bid))	h	i	j	k	l	m	n	o	p	q	r	s	t	u
2011	0.058	0.049	0.065	0.047														0.042	0.043	0.041	0.045
2012	0.061	0.051	0.072	0.051	38.24		19.12	0.018	0.018	0.035	0.024	$0.00	0.000	0.000	0.000	0.000		0.043	0.044	0.042	0.046
2013	0.063	0.055	0.076	0.054	38.24		19.12	0.019	0.018	0.036	0.024	$0.00	0.019	0.019	0.037	0.025	$0.00	0.044	0.045	0.043	0.047
2014	0.067	0.058	0.080	0.056	39.01		19.50	0.020	0.019	0.038	0.025	$0.00	0.020	0.020	0.039	0.026	$0.00	0.045	0.046	0.044	0.047
2015	0.075	0.064	0.088	0.063	39.79		19.90	0.023	0.022	0.043	0.029	$0.00	0.023	0.023	0.044	0.030	$0.00	0.046	0.047	0.045	0.048
2016	0.077	0.066	0.097	0.066	16.67	19.89	18.28	0.022	0.021	0.045	0.028	$48.41	0.024	0.023	0.048	0.031	$48.41	0.047	0.048	0.046	0.049
2017	0.079	0.069	0.099	0.066	25.01	29.88	27.45	0.022	0.022	0.045	0.028	$49.98	0.023	0.023	0.046	0.029	$49.98	0.048	0.049	0.047	0.050
2018	0.087	0.077	0.112	0.075	35.62	42.61	39.12	0.025	0.025	0.051	0.033	$51.41	0.025	0.026	0.052	0.033	$51.41	0.040	0.041	0.039	0.043
2019	0.089	0.080	0.111	0.077	40.77	48.81	44.79	0.026	0.026	0.051	0.034	$50.52	0.026	0.027	0.052	0.034	$50.52	0.039	0.040	0.038	0.041
2020	0.094	0.082	0.109	0.080	58.19	69.73	63.96	0.013	0.013	0.024	0.017	$17.16	0.013	0.027	0.050	0.035	$17.16	0.038	0.039	0.037	0.040
2021	0.097	0.086	0.112	0.083	60.48	72.55	66.51	0.012	0.012	0.023	0.016	$17.67	0.013	0.014	0.026	0.018	$17.67	0.037	0.038	0.036	0.039
2022	0.103	0.091	0.118	0.089	92.59	111.18	101.89	0.011	0.012	0.021	0.015	$181.39	0.012	0.013	0.024	0.017	$181.39	0.036	0.036	0.035	0.038
2023	0.111	0.097	0.127	0.096	113.79	136.80	125.29	0.011	0.011	0.019	0.014	$91.23	0.011	0.012	0.023	0.016	$91.23	0.034	0.035	0.034	0.036
2024	0.118	0.102	0.132	0.100	126.98	152.82	139.90	0.010	0.010	0.017	0.013	$44.48	0.010	0.011	0.020	0.015	$44.48	0.033	0.034	0.032	0.035
2025	0.121	0.105	0.135	0.105	134.40	161.93	148.17					$23.10					$23.10	0.031	0.032	0.031	0.033
2026	0.125	0.108	0.143	0.107	140.09	168.95	154.52					$10.17					$10.17	0.030	0.030	0.029	0.031
2027	0.131	0.113	0.150	0.112	144.11	174.00	159.05											0.031	0.031	0.030	0.032
2028	0.138	0.119	0.157	0.118	147.72	178.55	163.13											0.031	0.032	0.030	0.033
2029	0.145	0.124	0.164	0.124	150.86	182.54	166.70											0.032	0.032	0.031	0.033
2030	0.153	0.130	0.172	0.130	154.06	186.63	170.35											0.032	0.033	0.032	0.034
2031	0.160	0.136	0.181	0.136	157.34	190.81	174.07											0.033	0.034	0.032	0.035
2032	0.169	0.143	0.189	0.143	160.48	194.84	177.66											0.034	0.034	0.033	0.035
2033	0.178	0.150	0.199	0.151	163.69	198.96	181.33											0.034	0.035	0.034	0.036
2034	0.187	0.157	0.208	0.158	166.97	203.17	185.07											0.035	0.036	0.034	0.037
2035	0.196	0.165	0.219	0.166	170.31	207.46	188.89											0.036	0.036	0.035	0.038
2036	0.207	0.173	0.229	0.175	173.71	211.85	192.78											0.036	0.037	0.036	0.038
2037	0.217	0.181	0.240	0.184	177.19	216.34	196.76											0.037	0.038	0.036	0.039
2038	0.229	0.190	0.252	0.193	180.73	220.91	200.82											0.038	0.039	0.037	0.040
2039	0.241	0.199	0.265	0.203	184.35	225.59	204.97											0.039	0.039	0.038	0.041
2040	0.253	0.208	0.277	0.213	188.03	230.37	209.20											0.039	0.040	0.039	0.042
2041	0.266	0.218	0.291	0.224	191.79	235.24	213.52											0.040	0.041	0.039	0.042
Levelized Costs																					
10 years (2012-2021)	0.070	0.061	0.085	0.059	34.73	26.94	28.65	0.018	0.018	0.035	0.023	19.77	0.017	0.018	0.035	0.023	20.66	0.039	0.040	0.038	0.041
15 years (2012-2026)	0.075	0.066	0.090	0.064	51.93	58.38	50.44	0.014	0.014	0.028	0.019	30.72	0.013	0.014	0.028	0.019	32.11	0.035	0.036	0.034	0.037
30 years (2012-2041)	0.093	0.079	0.107	0.079	73.99	97.34	77.80											0.030	0.030	0.029	0.031

NOTES:

General All Avoided Costs are in Nominal Dollars
ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 7 AM - 11 PM; Off-Peak Hours are all other hours
1 Avoided cost of electric energy = (wholesale energy avoided cost + REC cost to load) * risk premium, e.g. A= (V + AB) * (1+Wholesale Risk Premium)
2 Absolute value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year and PA strategy about bidding that reduction into applicable FCAs, and unit values in columns e, f, l and q.
3 Proceeds from selling into the FCM include the reserve margin, in addition to the ISO-NE loss factor of 8%

Page Two: Inputs to Avoided Cost Calculations

Zone: CT-SWe

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	Wholesale Avoided Costs of Electricity							2012 Energy DRIPE Values								2013 Energy DRIPE Values							
	Energy				Capacity		Avoided REC Costs to Load	Intrastate Installation				Rest of Pool Installation				Intrastate Installation				Rest of Pool Installation			
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	FCA Price	Reserve Margin	REC Costs	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	%	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh
Period:	v	w	x	y	z	aa	ab	ac	ad	ae	af	ag	ah	ai	aj	ak	al	am	an	ao	ap	aq	ar
2011	0.051	0.043	0.058	0.041	43.20		0.0016																
2012	0.054	0.045	0.065	0.045	35.41	16.6%	0.0019	0.018	0.018	0.035	0.024	0.026	0.018	0.035	0.020	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2013	0.056	0.048	0.068	0.047	35.41	15.7%	0.0022	0.019	0.018	0.036	0.024	0.027	0.020	0.037	0.021	0.019	0.019	0.037	0.025	0.027	0.020	0.038	0.022
2014	0.059	0.051	0.071	0.049	36.12	17.7%	0.0025	0.020	0.019	0.038	0.025	0.028	0.020	0.039	0.022	0.020	0.020	0.039	0.026	0.028	0.021	0.040	0.022
2015	0.066	0.056	0.078	0.055	36.84	15.9%	0.0029	0.023	0.022	0.043	0.029	0.031	0.022	0.042	0.024	0.023	0.023	0.044	0.030	0.031	0.023	0.043	0.025
2016	0.067	0.057	0.086	0.057	15.43	16.0%	0.0033	0.022	0.021	0.045	0.028	0.030	0.022	0.044	0.023	0.024	0.023	0.048	0.031	0.032	0.023	0.048	0.025
2017	0.069	0.060	0.087	0.057	23.16	16.2%	0.0037	0.022	0.022	0.045	0.028	0.031	0.022	0.045	0.024	0.023	0.023	0.046	0.029	0.031	0.023	0.046	0.024
2018	0.077	0.068	0.100	0.066	32.99	16.3%	0.0028	0.025	0.025	0.051	0.033	0.034	0.026	0.051	0.027	0.025	0.026	0.052	0.033	0.034	0.026	0.052	0.028
2019	0.080	0.072	0.100	0.069	37.75	16.4%	0.0017	0.026	0.026	0.051	0.034	0.035	0.026	0.050	0.028	0.026	0.027	0.052	0.034	0.035	0.027	0.052	0.029
2020	0.084	0.073	0.098	0.072	53.88	16.5%	0.0022	0.013	0.013	0.024	0.017	0.018	0.013	0.024	0.014	0.013	0.027	0.050	0.035	0.018	0.027	0.050	0.029
2021	0.088	0.077	0.102	0.075	56.00	16.6%	0.0014	0.012	0.012	0.023	0.016	0.017	0.013	0.023	0.013	0.013	0.014	0.026	0.018	0.017	0.014	0.026	0.015
2022	0.092	0.081	0.106	0.079	85.73	16.8%	0.0023	0.011	0.012	0.021	0.015	0.016	0.012	0.021	0.012	0.012	0.013	0.024	0.017	0.016	0.013	0.024	0.014
2023	0.099	0.086	0.113	0.085	105.36	16.9%	0.0032	0.011	0.011	0.019	0.014	0.015	0.011	0.019	0.012	0.011	0.012	0.023	0.016	0.015	0.012	0.022	0.013
2024	0.105	0.090	0.118	0.089	117.58	17.0%	0.0033	0.010	0.010	0.017	0.013	0.013	0.010	0.017	0.010	0.010	0.011	0.020	0.015	0.013	0.011	0.020	0.012
2025	0.108	0.093	0.121	0.093	124.45	17.1%	0.0027	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.010	0.018	0.013	0.000	0.010	0.018	0.011
2026	0.113	0.098	0.129	0.096	129.71	17.3%	0.0017	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2027	0.119	0.103	0.136	0.101	133.43	17.4%	0.0015																
2028	0.125	0.108	0.142	0.107	136.78	17.5%	0.0014																
2029	0.132	0.113	0.149	0.112	139.68	17.7%	0.0013																
2030	0.139	0.118	0.157	0.118	142.65	17.8%	0.0012																
2031	0.146	0.124	0.164	0.124	145.68	17.9%	0.0012																
2032	0.154	0.130	0.173	0.130	148.60	18.1%	0.0012																
2033	0.162	0.136	0.181	0.137	151.57	18.2%	0.0012																
2034	0.170	0.143	0.190	0.144	154.60	18.3%	0.0012																
2035	0.179	0.150	0.199	0.151	157.69	18.5%	0.0012																
2036	0.188	0.157	0.209	0.159	160.85	18.6%	0.0013																
2037	0.198	0.165	0.219	0.167	164.06	18.7%	0.0013																
2038	0.209	0.173	0.230	0.176	167.34	18.9%	0.0013																
2039	0.220	0.181	0.241	0.185	170.69	19.0%	0.0013																
2040	0.231	0.190	0.253	0.194	174.10	19.1%	0.0014																
2041	0.243	0.199	0.266	0.204	177.59	19.3%	0.0014																
Levelized Cos																							
10 years (2012-2021)	0.062	0.054	0.076	0.052	32.15		0.002	0.018	0.018	0.035	0.023	0.025	0.018	0.035	0.020	0.017	0.018	0.035	0.023	0.023	0.018	0.035	0.019
15 years (2012-2026)	0.067	0.058	0.080	0.057	48.09		0.002	0.014	0.014	0.028	0.019	0.020	0.014	0.028	0.016	0.013	0.015	0.028	0.019	0.018	0.015	0.028	0.016
30 years (2012-2041)	0.084	0.071	0.096	0.071	68.51		0.002	0.008	0.008	0.016	0.011	0.012	0.009	0.016	0.009	0.008	0.009	0.017	0.011	0.011	0.009	0.017	0.009

NOTES: General All Avoided Costs are in Nominal Dollars

ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are all other hours

Avoided Cost of Electricity (Nominal $) Results :

CT-SWi
Southwest Connecticut, including Norwalk/Stamford

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State CT

User-defined Inputs			
Wholesale Risk Premium (WRP)	9%	Percent of Capacity Bid into FCM (%Bid)	50.0%
Nominal Discount Rate	4.51%	Real Discount Rate	2.46%

	Avoided Unit Cost of Electric Energy[1]				Avoided Unit Cost of Electric Capacity[2]			DRIPE: 2012 vintage measures Intrastate Values: Energy				DRIPE: 2012 vintage measures Intrastate Values: Capacity (See note 2)	DRIPE: 2013 vintage measures Intrastate Values: Energy				DRIPE: 2013 vintage measures Intrastate Values: Capacity (See note 2)	Avoided Externality Costs			
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	kW bid into FCA (PA to determine quantity)[3]	kW not bid into FCM (PA to determine quantity)	Weighted Average Avoided Cost Based on Percent Capacity Bid	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Annual Value	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kw-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e=z*1.08 for ISO-NE losses	f=z*(1+aa)*(1+PTF Loss of 1.9%)*(1+WRP)	g=(e*%Bid)+(f*(1-%Bid))	h	i	j	k	l	m	n	o	p	q	r	s	t	u
2011	0.058	0.049	0.065	0.047														0.042	0.043	0.041	0.045
2012	0.061	0.051	0.072	0.051	38.24		19.12	0.018	0.018	0.035	0.024	$0.00	0.000	0.000	0.000	0.000		0.043	0.044	0.042	0.046
2013	0.063	0.055	0.076	0.054	38.24		19.12	0.019	0.018	0.036	0.024	$0.00	0.019	0.019	0.037	0.025	$0.00	0.044	0.045	0.043	0.047
2014	0.067	0.058	0.080	0.057	39.01		19.50	0.020	0.019	0.038	0.025	$0.00	0.020	0.020	0.039	0.026	$0.00	0.045	0.046	0.044	0.047
2015	0.075	0.064	0.088	0.063	39.79		19.90	0.023	0.022	0.043	0.029	$0.00	0.023	0.023	0.044	0.030	$0.00	0.046	0.047	0.045	0.048
2016	0.077	0.066	0.097	0.066	16.67	19.89	18.28	0.022	0.021	0.045	0.028	$48.41	0.024	0.023	0.048	0.031	$48.41	0.047	0.048	0.046	0.049
2017	0.079	0.069	0.099	0.066	25.01	29.88	27.45	0.022	0.022	0.045	0.028	$49.98	0.023	0.023	0.046	0.029	$49.98	0.048	0.049	0.047	0.050
2018	0.088	0.078	0.112	0.075	35.62	42.61	39.12	0.025	0.025	0.051	0.033	$51.41	0.025	0.026	0.052	0.033	$51.41	0.040	0.041	0.039	0.043
2019	0.089	0.080	0.111	0.077	40.77	48.81	44.79	0.026	0.026	0.051	0.034	$50.52	0.026	0.027	0.052	0.034	$50.52	0.039	0.040	0.038	0.041
2020	0.094	0.082	0.109	0.080	58.19	69.73	63.96	0.013	0.013	0.024	0.017	$17.16	0.013	0.027	0.050	0.035	$17.16	0.038	0.039	0.037	0.040
2021	0.097	0.086	0.113	0.083	60.48	72.55	66.51	0.012	0.012	0.023	0.016	$17.67	0.013	0.014	0.026	0.018	$17.67	0.037	0.038	0.036	0.039
2022	0.103	0.091	0.118	0.089	92.59	111.18	101.89	0.011	0.012	0.021	0.015	$181.39	0.012	0.013	0.024	0.017	$181.39	0.036	0.036	0.035	0.038
2023	0.112	0.097	0.127	0.096	113.79	136.80	125.29	0.011	0.011	0.019	0.014	$91.23	0.011	0.012	0.023	0.016	$91.23	0.034	0.035	0.034	0.036
2024	0.118	0.102	0.132	0.100	126.98	152.82	139.90	0.010	0.010	0.017	0.013	$44.48	0.010	0.011	0.020	0.015	$44.48	0.033	0.034	0.032	0.035
2025	0.121	0.105	0.135	0.105	134.40	161.93	148.17					$23.10					$23.10	0.031	0.032	0.031	0.033
2026	0.125	0.108	0.143	0.107	140.09	168.95	154.52					$10.17					$10.17	0.030	0.030	0.029	0.031
2027	0.131	0.113	0.150	0.112	144.11	174.00	159.05											0.031	0.031	0.030	0.032
2028	0.138	0.119	0.157	0.118	147.72	178.55	163.13											0.031	0.032	0.030	0.033
2029	0.145	0.124	0.164	0.124	150.86	182.54	166.70											0.032	0.032	0.031	0.033
2030	0.153	0.130	0.172	0.130	154.06	186.63	170.35											0.032	0.033	0.032	0.034
2031	0.160	0.136	0.181	0.136	157.34	190.81	174.07											0.033	0.034	0.032	0.035
2032	0.169	0.143	0.189	0.143	160.48	194.84	177.66											0.034	0.034	0.033	0.035
2033	0.178	0.150	0.199	0.151	163.69	198.96	181.33											0.034	0.035	0.034	0.036
2034	0.187	0.157	0.208	0.158	166.97	203.17	185.07											0.035	0.036	0.034	0.037
2035	0.197	0.165	0.219	0.166	170.31	207.46	188.89											0.036	0.036	0.035	0.038
2036	0.207	0.173	0.229	0.175	173.71	211.85	192.78											0.036	0.037	0.036	0.038
2037	0.218	0.181	0.240	0.184	177.19	216.34	196.76											0.037	0.038	0.036	0.039
2038	0.229	0.190	0.252	0.193	180.73	220.91	200.82											0.038	0.039	0.037	0.040
2039	0.241	0.199	0.265	0.203	184.35	225.59	204.97											0.039	0.039	0.038	0.041
2040	0.253	0.208	0.278	0.214	188.03	230.37	209.20											0.039	0.040	0.039	0.042
2041	0.267	0.219	0.291	0.224	191.79	235.24	213.52											0.040	0.041	0.039	0.042
Levelized Costs																					
10 years (2012-2021)	0.070	0.061	0.085	0.059	34.73	26.94	28.65	0.018	0.018	0.035	0.023	19.77	0.017	0.018	0.035	0.023	20.66	0.039	0.040	0.038	0.041
15 years (2012-2026)	0.076	0.066	0.090	0.065	51.93	58.38	50.44	0.014	0.014	0.028	0.019	30.72	0.013	0.014	0.028	0.019	32.11	0.035	0.036	0.034	0.037
30 years (2012-2041)	0.093	0.079	0.107	0.079	73.99	97.34	77.80											0.030	0.030	0.029	0.031

NOTES:

General All Avoided Costs are in Nominal Dollars
ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 7 AM - 11 PM; Off-Peak Hours are all other hours

1 Avoided cost of electric energy = (wholesale energy avoided cost + REC cost to load) * risk premium, e.g. A= (V + AB) * (1+Wholesale Risk Premium)

2 Absolute value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year and PA strategy about bidding that reduction into applicable FCAs, and unit values in columns e, f, l and q.

3 Proceeds from selling into the FCM include the reserve margin, in addition to the ISO-NE loss factor of 8%

Page Two: Inputs to Avoided Cost Calculations

Zone: CT-SWi

	Wholesale Avoided Costs of Electricity						
	Energy				Capacity		Avoided REC Costs to Load
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	FCA Price	Reserve Margin	REC Costs
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	%	$/kWh
Period:	v	w	x	y	z	aa	ab
2011	0.051	0.043	0.058	0.041	43.20		0.0016
2012	0.054	0.045	0.065	0.045	35.41	16.6%	0.0019
2013	0.056	0.048	0.068	0.047	35.41	15.7%	0.0022
2014	0.059	0.051	0.071	0.049	36.12	17.7%	0.0025
2015	0.066	0.056	0.078	0.055	36.84	15.9%	0.0029
2016	0.067	0.057	0.086	0.057	15.43	16.0%	0.0033
2017	0.069	0.060	0.087	0.057	23.16	16.2%	0.0037
2018	0.077	0.068	0.100	0.066	32.99	16.3%	0.0028
2019	0.080	0.072	0.100	0.069	37.75	16.4%	0.0017
2020	0.084	0.073	0.098	0.072	53.88	16.5%	0.0022
2021	0.088	0.077	0.102	0.075	56.00	16.6%	0.0014
2022	0.092	0.081	0.106	0.079	85.73	16.8%	0.0023
2023	0.099	0.086	0.113	0.085	105.36	16.9%	0.0032
2024	0.105	0.090	0.118	0.089	117.58	17.0%	0.0033
2025	0.108	0.093	0.121	0.093	124.45	17.1%	0.0027
2026	0.113	0.098	0.129	0.097	129.71	17.3%	0.0017
2027	0.119	0.103	0.136	0.101	133.43	17.4%	0.0015
2028	0.125	0.108	0.142	0.107	136.78	17.5%	0.0014
2029	0.132	0.113	0.149	0.112	139.68	17.7%	0.0013
2030	0.139	0.118	0.157	0.118	142.65	17.8%	0.0012
2031	0.146	0.124	0.165	0.124	145.68	17.9%	0.0012
2032	0.154	0.130	0.173	0.130	148.60	18.1%	0.0012
2033	0.162	0.136	0.181	0.137	151.57	18.2%	0.0012
2034	0.170	0.143	0.190	0.144	154.60	18.3%	0.0012
2035	0.179	0.150	0.199	0.151	157.69	18.5%	0.0012
2036	0.188	0.157	0.209	0.159	160.85	18.6%	0.0013
2037	0.198	0.165	0.219	0.167	164.06	18.7%	0.0013
2038	0.209	0.173	0.230	0.176	167.34	18.9%	0.0013
2039	0.220	0.181	0.241	0.185	170.69	19.0%	0.0013
2040	0.231	0.190	0.253	0.195	174.10	19.1%	0.0014
2041	0.243	0.199	0.266	0.205	177.59	19.3%	0.0014
Levelized Cos							
10 years (2012-2021)	0.062	0.054	0.076	0.052	32.15		0.002
15 years (2012-2026)	0.067	0.058	0.080	0.057	48.09		0.002
30 years (2012-2041)	0.084	0.071	0.096	0.071	68.51		0.002

	2012 Energy DRIPE Values								2013 Energy DRIPE Values							
	Intrastate Installation				Rest of Pool Installation				Intrastate Installation				Rest of Pool Installation			
	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak	Winter On Peak	Winter Off-Peak	Summer On Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh
Period:	ac	ad	ae	af	ag	ah	ai	aj	ak	al	am	an	ao	ap	aq	ar
2011																
2012	0.018	0.018	0.035	0.024	0.026	0.018	0.035	0.020	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2013	0.019	0.018	0.036	0.024	0.027	0.020	0.037	0.021	0.019	0.019	0.037	0.025	0.027	0.020	0.038	0.022
2014	0.020	0.019	0.038	0.025	0.028	0.020	0.039	0.022	0.020	0.020	0.039	0.026	0.028	0.021	0.040	0.022
2015	0.023	0.022	0.043	0.029	0.031	0.022	0.042	0.024	0.023	0.023	0.044	0.030	0.031	0.023	0.043	0.025
2016	0.022	0.021	0.045	0.028	0.030	0.022	0.044	0.023	0.024	0.023	0.048	0.031	0.032	0.023	0.048	0.025
2017	0.022	0.022	0.045	0.028	0.031	0.022	0.045	0.024	0.023	0.023	0.046	0.029	0.031	0.023	0.046	0.024
2018	0.025	0.025	0.051	0.033	0.034	0.026	0.051	0.027	0.025	0.026	0.052	0.033	0.034	0.026	0.052	0.028
2019	0.026	0.026	0.051	0.034	0.035	0.026	0.050	0.028	0.026	0.027	0.052	0.034	0.035	0.027	0.052	0.029
2020	0.013	0.013	0.024	0.017	0.018	0.013	0.024	0.014	0.013	0.027	0.050	0.035	0.018	0.027	0.050	0.029
2021	0.012	0.012	0.023	0.016	0.017	0.013	0.023	0.013	0.013	0.014	0.026	0.018	0.017	0.014	0.026	0.015
2022	0.011	0.012	0.021	0.015	0.016	0.012	0.021	0.012	0.012	0.013	0.024	0.017	0.016	0.013	0.024	0.014
2023	0.011	0.011	0.019	0.014	0.015	0.011	0.019	0.012	0.011	0.012	0.023	0.016	0.015	0.012	0.022	0.013
2024	0.010	0.010	0.017	0.013	0.013	0.010	0.017	0.010	0.010	0.011	0.020	0.015	0.013	0.011	0.020	0.012
2025	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.010	0.018	0.013	0.000	0.010	0.018	0.011
2026	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2027																
2028																
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2033																
2034																
2035																
2036																
2037																
2038																
2039																
2040																
2041																
Levelized Cos																
10 years (2012-2021)	0.018	0.018	0.035	0.023	0.025	0.018	0.035	0.020	0.017	0.018	0.035	0.023	0.023	0.018	0.035	0.019
15 years (2012-2026)	0.014	0.014	0.028	0.019	0.020	0.014	0.028	0.016	0.013	0.015	0.028	0.019	0.018	0.015	0.028	0.016
30 years (2012-2041)	0.008	0.008	0.016	0.011	0.012	0.009	0.016	0.009	0.008	0.009	0.017	0.011	0.011	0.009	0.017	0.009

NOTES: General All Avoided Costs are in Nominal Dollars
ISO NE periods: Summer is June through September, Winter is all other months. On Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are all other hours

Appendix C: Selected Input Assumptions to Avoided Cost Analyses

Table of Exhibits

Discussion of EPA Regulations

The EPA is in the process of numerous rulemakings, many of them court-ordered, which implement statutory requirements under the Clean Air Act, Clean Water Act and Resource Conservation and Recovery Act (RCRA). Several of these rules will regulate the power sector directly. These include revisions of Clean Air Act new source performance standards for power plants, regulation of interstate pollutant emissions from power plants, regulation of hazardous air pollutant emissions from power plants, haze regulations, new standards governing cooling intake water, and new effluent limitation guidelines for wastewater discharges from power plants. In addition, EPA has proposed to regulate the disposal of coal combustion wastes for the first time. Finally, the EPA is in the process of revising several National Ambient Air Quality Standards (NAAQS) for pollutants including particulate matter (PM), ozone, sulfur dioxide, and nitrogen oxides. Revised NAAQS will result in the designation of additional nonattainment areas, which in turn will obligate states to require emissions reductions from major pollution sources including power plants.

When considered individually, these rules to varying extents will require retrofits and associated outages and may result in retirements and/or the repowering of existing electric generating units across the United States. Taken together, these rules will have a significant effect on the generating fleet. The following sections describe what are anticipated to be the most economically consequential rules, and summarize the analysis undertaken to date on the costs of these future regulations and associated impacts on the power sector. A summary of the timeline of regulations is provided in Appendix C.

Clean Air Transport Rule (CATR)

The Clean Air Transport Rule, proposed in July 2010, will reduce emissions that contribute to non-attainment of National Ambient Air Quality Standards or that interfere with maintenance of those standards by downwind states.[1] Based on the current proposal, emissions of sulfur dioxide and nitrogen oxide from electric generating units in 31 eastern states and the District of Columbia will be capped to help enable downwind states to comply with the NAAQS, including the annual $PM_{2.5}$ NAAQS (promulgated in 1997) and the 24 hour $PM_{2.5}$ NAAQS (promulgated in 2006).[2] Connecticut is covered for summer NOx emissions (for ozone) and year-round particulates, NOx and SO_2 (for $PM_{2.5}$), while Massachusetts is covered only for $PM_{2.5}$, and the other four New England

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[1] U.S. EPA, *Federal Implementation Plans To Reduce Interstate Transport of Fine Particulate Matter and Ozone*, Federal Register / Vol. 75, No. 147 / Monday, August 2, 2010 / Proposed Rules, pp. 45210 ff.

[2] US EPA, Office of Air and Radiation. *Proposed Air Pollution Transport Rule*. July 26, 2010. Slide 4. Available at: http://www.epa.gov/airtransport/pdfs/FactsheetTR7-6-10.pdf.

states are not covered.[3] Compliance with the transport rule will require substantial investments in scrubbers and other control devices at many generation stations.

The CATR sets limits on the emission of sulfur dioxide and nitrogen oxide that will become effective in two phases. Sulfur dioxide emissions are required to decline from 4.7 million tons in 2009 to 3.9 million tons by 2012, and then to 2.5 million tons by 2014, for a cumulative reduction of 47% over the five-year compliance period. The Rule is likely to have a minimal effect on nitrogen oxide emissions, however, because the rule's emission caps (1.4 million tons per year) are slightly higher than the actual nitrogen oxide emissions in the covered states in 2009.

In the July 2010 proposal, the EPA identified a "preferred approach" for the new regulations, but also took comments on two alternatives. All three approaches would cover the same geographic area, set a pollution limit (or budget) for each state, and obtain the mandated reductions from power plants. The EPA's preferred approach and the first alternative would both allow trading of emissions allowances among power plants within a state, with the preferred approach also allowing some limited trading among states. The third approach would allow averaging among a power plant owner's in-state generating units.[4]

To achieve the required emissions reductions, the EPA expects that power plants will "fuel switch" to lower-sulfur coal, operate already installed emissions control equipment more frequently, or install new pollution control equipment.[5] The EPA anticipates that a final rule will be issued in the spring of 2011.

The EPA estimates that the costs of compliance with the CATR are $2.8 billion in 2014. Estimates of the expected benefits from the proposed rule range between $120 and $290 billion in 2014. The EPA expects that electricity prices will increase by less than 2%, natural gas prices will increase by less than 1%, and coal use will be reduced by less than 1%.[6]

The EPA has also begun assessing the transport of air pollution across state boundaries that would interfere with attainment of the 2010 ozone standard. The Second Clean Air Transport Rule will address the responsibility of upwind states to downwind state ozone

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[3] Of the excluded states, only Maine and New Hampshire have power plants of the sort that would be affected by the rule.

[4] US EPA. *Proposed Transport Rule Would Reduce Interstate Transport of Ozone and Fine Particle Pollution*. Clean Air Transport Rule Fact Sheet. July 6, 2010. Available at: http://www.epa.gov/airtransport/pdfs/FactsheetTR7-6-10.pdf

[5] US EPA, Office of Air and Radiation. *Reducing Air Pollution from Power Plants*. September 24, 2010. Slide 10. Available at: http://www.naruc.org/Domestic/EPA-Rulemaking/Docs/EPA%20AIR%20Presentation%20Sept%2024%202010%20_%20Sam%20Napolitano.pdf

[6] US EPA, Office of Air and Radiation. *Proposed Air Pollution Transport Rule*. July 26, 2010. Slide 13. Available at: http://www.epa.gov/airtransport/pdfs/FactsheetTR7-6-10.pdf

problems under the Clean Air Act. The EPA is expected to propose the Second Clean Air Transport Rule in summer 2011, and promulgate a final rule in summer 2012.[7]

Air Toxics Standards (MACT Rule)

The EPA is under court order to set emission limits for hazardous air pollutant emissions from electric generating units under section 112(d) of the Clean Air Act. More than 180 hazardous air pollutants are listed under the Clean Air Act, and those most relevant to the electric power industry include mercury, dioxins, and acid gases. This "air toxics rule" would require that sources meet emission limits based on EPA's assessment of "Maximum Achievable Control Technology" or "MACT." For existing sources, this means that the level of control achieved must be in line with the average of the top twelve percent of top-performing power plants. Requirements for new sources are at least as stringent as the single best performing source, reflecting the maximum emissions reductions achievable with state-of-the-art pollution controls. Existing units will have three years to comply with the final rule once it is issued, while new sources will have to comply immediately upon issuance of the rule.[8] The EPA issued the new proposed rule in March 2011 and is expected to finalize the rule in November 2011.[9] New standards must be implemented within three years after the rule is finalized, so compliance by 2014 is implied.

The EPA has not yet released an analysis of costs and benefits of the MACT rule. However, as discussed below, several recent analyses assess their impact on the power sector.

Coal Combustion Residuals

Coal combustion residuals are byproducts from the combustion of coal that include fly ash, bottom ash, boiler slag, and flue gas materials. In 2008, annual production of these residuals was 136 million tons.[10] The spill of coal ash at the Tennessee Valley Authority's containment facility prompted the EPA in June 2010 to propose two approaches to regulating the disposal of coal combustion residuals under RCRA. The EPA's long-term objective is to phase out the wet handling of coal ash and the use of surface impoundments (ash ponds) in favor of dry ash handling and disposal in lined

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[7] *Id.* Slide 14.

[8] Bryson, Joe. US EPA, Office of Air and Radiation. *Key EPA Power Sector Rulemakings*. Eastern Interconnection States' Planning Council. August 26, 2010. Slide 17. Available at: http://communities.nrri.org/c/document_library/get_file?folderId=107847&name=DLFE-3419.pdf.

[9] US EPA, Office of Air and Radiation. *Reducing Air Pollution from Power Plants*. September 24, 2010. Slide 7. Available at: http://www.naruc.org/Domestic/EPA-Rulemaking/Docs/EPA%20AIR%20Presentation%20Sept%2024%202010%20_%20Sam%20Napolitano.pdf.

[10] Bryson, Joe. US EPA, Office of Air and Radiation. *Key EPA Power Sector Rulemakings*. Eastern Interconnection States' Planning Council. August 26, 2010. Slide 19. Available at: http://communities.nrri.org/c/document_library/get_file?folderId=107847&name=DLFE-3419.pdf.

landfills. Approximately one-third of the coal capacity in the United States uses wet ash handling and storage systems.[11]

The first proposal would regulate coal ash under subtitle C of RCRA and would create a program imposing federally enforceable requirements for waste management and disposal, including the phase-out of wet handling and existing surface impoundments. If EPA pursues the implementation of a coal ash rule under subtitle C, states would be required to adopt the new federal requirements.[12]

The second proposal would regulate coal ash under subtitle D of RCRA, and would apply to coal combustion residuals that are disposed of in landfills or surface impoundments. Under subtitle D, the federal government sets national criteria that are used by the states to issue waste management permits, but states are not required to adopt the federal standards. Utilities would likely continue operating surface impoundments, but states and citizens could seek to enforce new federal requirements through citizen suits in the event of environmental damage.

The Edison Electric Institute (EEI) estimates that the costs to convert bottom ash handling systems to dry ash handling systems are $20 million per unit, while costs to convert fly ash handling systems are $10-$15 million per unit.[13] Costs of new landfills for dry ash are between $30 and $50 million.[14]

A date for release of the final coal combustion residuals rule has yet to be determined. If the subtitle C proposal were adopted, implementation would depend on the timing of the approvals from each of the states, which is expected to take at least two years. A subtitle D rule would become effective six months after promulgation of the rule for most of the provisions, but specific provisions would have a longer effective date.[15]

Clean Water Act § 316(b)

Thermal power plants using water for cooling purposes use one of three types of cooling systems: once-through, recirculating, and dry cooling. Once-through systems withdraw water in large volumes and then discharge it back into the same water body at elevated temperatures. Recirculating systems withdraw water in smaller volumes, and continuously circulate the cooling water through a plant's heat exchangers with the aid of

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[11] Bernstein Research. *U.S. Utilities: Coal-Fired Generation Is Squeezed in the Vice of EPA Regulation; Who Wins and Who Loses?* October 2010. Page 66.

[12] US EPA. *Coal Combustion Residuals – Key Differences Between Subtitle C and Subtitle D Options*. Available at: http://www.epa.gov/epawaste/nonhaz/industrial/special/fossil/ccr-rule/ccr-table.htm.

[13] Edison Electric Institute estimates taken from: Bernstein Research. *U.S. Utilities: Coal-Fired Generation Is Squeezed in the Vice of EPA Regulation; Who Wins and Who Loses?* October 2010. Page 66.

[14] *Id*.

[15] US EPA. *Coal Combustion Residuals – Key Differences Between Subtitle C and Subtitle D Options*. Available at: http://www.epa.gov/epawaste/nonhaz/industrial/special/fossil/ccr-rule/ccr-table.htm.

cooling towers. Dry cooling systems are closed-loop systems that do not rely on cooling water, but instead on forced draft air flow.

Section 316(b) of the Clean Water Act requires that new power plants use the best available cooling water intake technologies for minimizing adverse environmental impacts. Adverse environmental impacts include the intake of aquatic organisms with cooling water when using once-through systems.

The EPA promulgated a 316(b) rule in 2004 that covered large existing power plants with water intake in excess of 50 million gallons per day. In 2007, the Second Circuit Court of Appeals remanded this rule to the EPA. Absent federal regulations, states have begun to consider and adopt rules governing the retrofit of existing power plants with closed-loop cooling systems. On March 10, 2010, New York's Department of Environmental Conservation proposed a policy that would set a closed-cycle cooling performance goal at all of the state's power plants.[16] The California State Water Resources Control Board issued regulations on May 4, 2010 that would require many steam generators to replace once-through systems with closed-loop systems, reducing cooling water intake by 93%.[17] EPA is developing revised national regulatory standards implementing Section 316(b) for existing power plants and manufacturing facilities, and plans to publish a Notice of Proposed Rulemaking in March 2011. The EPA already has taken comments on an Information Collection Request, and issued proposed rules on March 16, 2011, including specific rules for limiting impingement, which will generally require only advanced screens, and a process for determining best available technology for entrainment for large water users.[18] The entrainment analyses may require some existing plants to retrofit closed-loop systems, such as cooling towers.[19]

Regional Haze Rule

The Clean Air Act defines as a national goal the remedying of existing visibility impairment that results from manmade air pollution in all "Class I" areas (e.g., most

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[16] New York State Department of Environmental Conservation. *CP-nn/Best Technology Available (BTA) for Cooling Water Intake Structures.* March 10, 2010. Available at: http://www.dec.ny.gov/docs/fish_marine_pdf/drbtapolicy1.pdf.

[17] California State Water Resources Control Board. *Statewide Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling*. May 4, 2010. Available at: http://www.swrcb.ca.gov/water_issues/programs/npdes/docs/cwa316may2010/otcpolicy_final050410.pdf.

[18] US EPA. *Fact Sheet: Proposed Information Collection Request for a General Population Survey to Allow the Estimation of Benefits for the Clean Water Act Section 316(b) Cooling Water Intake Structures Rulemaking.* July 2010. Available at: http://water.epa.gov/lawsregs/lawsguidance/cwa/316b/phase2/upload/316factsheet2010.pdf.

[19] There are 651 generating units with water intake above 50 million gallons per day. Of these 651 generators, there are 404 that are not currently equipped with closed-loop cooling systems.
Bernstein Research. *U.S. Utilities: Coal-Fired Generation Is Squeezed in the Vice of EPA Regulation; Who Wins and Who Loses?* October 2010. Page 72.

national parks and wilderness areas). See 42 U.S.C. § 7491(a)(1). EPA's implementing rules require states to create plans to achieve natural visibility conditions by 2064 with enforceable reductions in haze-causing pollution from individual sources and other measures to meet "reasonable further progress" milestones. See generally 40 C.F.R. §51.308-309.

The Clean Air Act's Regional Haze Rule was promulgated in 1999, and revised in 2005. A key component of the haze rule is the imposition of air pollution controls on certain existing facilities that impact visibility in Class I areas. Specifically, the rules require emissions limits on haze-causing pollutants; these limits are represented by "best available retrofit technology" (BART). BART limits are established for air pollutants that impact visibility in our national parks and wilderness areas – namely, SO_2, NO_x, and PM.

Under the Clean Air Act, States have the primary responsibility for developing these requirements, but EPA must determine that a state's plan to achieve natural visibility, including its imposition of BART limits on certain sources, comply with the Clean Air Act's requirements. If EPA finds the plans do not fully meet its regulations, EPA must adopt a federal plan and BART requirements that comply with its regulations. Affected facilities must achieve BART emissions limitations as expeditiously as practicable, but no later than five years from the date EPA approves the state plan or adopts a federal plan.

Exhibit C-1: EPA Regulations Schedule by Year

	2008	2009	2010	2011	2012	2013	2014	2015
Ozone	Revised Ozone NAAQS		Reconsidered Ozone NAAQS	Final EPA Nonattainment Designations			Next Ozone NAAQS Revision	
SO_2/NO_x			NO_x Primary NAAQS SO_2 Primary NAAQS		NO_x/SO_2 Secondary NAAQS			
Clean Air Transport Rule	CAIR Vacated CAIR Remanded	Begin CAIR Phase I Annual NO_x Cap Begin CAIR Phase I Seasonal NO_x Cap	Begin CAIR Phase I Annual SO_2 Cap Proposed CATR Rule	Final CATR Rule Expected	Beginning CATR Phase I Annual SO_2 & NO_x caps Beginning CATR Phase I Seasonal SO_2 & NO_x Caps		Compliance with CATR Rule Beginning CATR Phase II Annual SO_2 & NO_x Caps	
Hg/HAPS Air Toxics Rule	CAMR & Delisting Rule Vacated			HAPS MACT Proposed Rule in March HAPS MACT Final Rule Expected in November				HAPS MACT Compliance Three Years After Final Rule

Exhibit C-1: EPA Regulations Schedule (Continued)

	2008	2009	2010	2011	2012	2013	2014	2015
Water			316(b) Proposed Rule Expected	Effluent Guidelines Proposed Rule	316(b) Final Rule Expected	Effluent Guidelines Final Rule Expected	316(b) Compliance Three to Four Years After Final Rule	Effluent Guidelines Compliance Three to Five Years After Final Rule
PM 2.5	PM-2.5 SIPS due			Next PM-2.5 NAAQS Revision	Next PM-2.5 SIPs due	New PM-2.5 NAAQS Designations		
Coal Ash			Proposed Rule for CCBs Management	Final Rule for CCBs Management		Begin Compliance Requirements Under final CCB Rule (Ground Water Monitoring, Double Monitors, Closure, Dry Ash Conversion)		

Notes

NAAQS	National Ambient Air Quality Standards
NO_x	Nitrogen oxide
SO_2	Sulfur dioxide
$PM_{2.5}$	Particulate matter less than 2.5 microns in diameter
CAIR	Clean Air Interstate Rule
CATR	Clean Air Transport Rule
HAPs	Hazardous Air Pollutants
CAMR	Clean Air Mercury Rule
MACT	Maximum Achievable Control Technology
CCBs	Coal Combustion By-products
SIPs	State Implementation Plans

Exhibit C-2: Renewable Requirements and Qualifying Technologies

	Connecticut[1]			Maine		Massachusetts[2,3]				New Hampshire				Rhode Island		Vermont
	I	II	III	I	II	I	I - Solar[4]	II	II - WTE	I	II	III	IV	New	New or Existing	New
First Compliance Year	2004	2004	2007	2008	2000	2003	2010	2009	2009	2009	2009	2009	2009	2007	2007	2013[5]
Vintage Requirement	See hydro; otherwise none.		post-1/06	post-9/05	none	post-1/98	post-1/08	pre-1/98	pre-1/98	post-1/06	post-1/06	pre-1/06	pre-1/06	post-1/98	pre-1/98	post-1/05
Fuel Type / Technology																
Biomass	NOx limit = 0.075 lbs/MMBtu	NOx limit = 0.2 lbs/MMBtu		< 100 MW	< 100 MW	Advanced Conversion Technology; emissions per DEP		emissions per DEP		NOx limit = 0.075 lbs/MMBtu. PM limit = 0.02 lbs/MMBtu.		<= 25 MW w/ same emissions limits at Class I		High st'd for clean wood fuel.	High st'd for clean wood fuel.	✓
Biomass Thermal										✓						
Fuel Cells	✓	✓		< 100 MW	< 100 MW	✓ if run on RE fuel		✓ if run on RE fuel		✓ if run on RE fuel				✓ if run on RE fuel	✓ if run on RE fuel	✓ if run on RE fuel
Geothermal				< 100 MW	< 100 MW	✓		✓		✓				✓	✓	✓
Hydro	<= 5 MW, ROR, post-1/03	<= 5 MW ROR		< 100 MW	< 100 MW	New + incremental hydro < 25 MW		<= 5 MW		incremental MWh over historic baseline			<= 5 MW	< 30 MW	< 30 MW	<= 200 MW
Methane: includes landfill gas, anerobic digestion, sewage plant wastes	Yes + LFG by NG pipeline from outside ISO-NE also eligible.	Yes + LFG by NG pipeline from outside ISO-NE also eligible.		< 100 MW	< 100 MW	✓		✓		✓		✓		✓	✓	✓
MSW & WTE		✓			✓ w/ recycling			✓	✓							
Ocean Thermal	✓	✓				✓		✓		✓				✓	✓	
Solar Photovoltaic	✓	✓		< 100 MW	< 100 MW	✓	≤ 6 MW per parcel; in MA; BTM	✓		✓	✓			✓	✓	✓
Solar Thermal Electric	✓	✓				✓	≤ 6 MW per parcel; in MA; BTM	✓		✓	✓			✓	✓	✓
Tidal	✓	✓		< 100 MW	< 100 MW	✓		✓		✓				✓	✓	
Wave	✓	✓		< 100 MW	< 100 MW	✓		✓		✓				✓	✓	
Wind	✓	✓		✓	< 100 MW	✓		✓		✓				✓	✓	✓

Exhibit C-2: Renewable Requirements and Qualifying Technologies (Continued)

	Connecticut[1]			Maine		Massachusetts[2,3]				New Hampshire				Rhode Island		Vermont
	I	II	III	I	II	I	I - Solar[4]	II	II - WTE	I	II	III	IV	New	New or Existing	New
First Compliance Year	2004	2004	2007	2008	2000	2003	2010	2009	2009	2009	2009	2009	2009	2007	2007	2013[5]
Vintage Requirement	See hydro; otherwise none.		post-1/06	post-9/05	none	post-1/98	post-1/08	pre-1/98	pre-1/98	post-1/06	post-1/06	pre-1/06	pre-1/06	post-1/98	pre-1/98	post-1/05
Fuel Type / Technology																
Combined Heat & Power			w/ min operating efficiency of 50%		< 100 MW											if run on qualifying RE fuel
Waste Heat or Pressure			✓ post 4/07													
Energy Efficiency																
Conservation & Load Management			✓													
Obligated Entities	Includes investor-owned utilities and competitive LSEs, but excludes municipal and cooperative utilities.									Includes IOUs, Cooperatives and competitive LSEs.				Narragansett Electric & competitive LSEs		All retail LSEs
Geographic Eligibility	Within ISO-NE; or imported from adjacent control areas if the energy is delivered and settleed in the market settlement system.															Within VT[6]
Verification Mechanism	NEPOOL Generation Information System															None
Compliance Period	Annual. January 1 to December 31.															
Alternative Compliance Payment	Penalty Payment is fixed at $55/MWh, all years	Penalty Payment is fixed at $55/MWh, all years	Penalty Payment is fixed at $55/MWh, all years	$62.13/MWh in 2011; adj. annually by CPI.		$62.13/MWh in 2011; adj. annually by CPI.	$550/MWh in 2011; DOER may reduce by up to 10% annually	$25.50/MWh in 2011; adj. annually by CPI.	$10.20Wh in 2011; adj. annually by CPI.	$62.13/MWh in 2011; adj. annually by CPI.	$159.98/MWh in 2009; adj. annually by CPI.	$29.87/MWh in 2009; adj. annually by CPI.	$29.87/MWh in 2009; adj. annually by CPI.	$62.13/MWh in 2011; adj. annually by CPI.	$62.13/MWh in 2011; adj. annually by CPI.	
Banking	Compliance with Class I/New RPS requirements is bankable for 2 years; annual bankable quantity capped at 30% of current year's obligation.															

(1) Revisions to the Connecticut RPS are the subject of discussion in the 2011 Legislature. Reductions to RPS targets and the eligibility of all hydropower for Class 1 have been proposed.

(2) Massachusetts' RPS regulations are currently subject to revisions related to the eligibility of both proposed and existing biomass facilities.

(3) Massachusetts' RPS also includes an Alternate Energy Portfolio Standard (APS), which governs the utilization of certain non-renewable resources, and is therefore not included in this analysis.

(4) Solar projects receiving funding from the MA Clean Energy Center prior to 1/1/2010, or more than 67% of total funding through the American Reinvestment and Recovery Act are not eligible.

Governor's office is compiling a comprehensive energy plan.

(6) Out-of-state projects owned by, or under contract to, Vermont retail providers may also qualify - with PSB approval.

Exhibit C-3: Summary of Annual State RPS Requirements

	Connecticut[1]			Maine		Massachusetts				New Hampshire				Rhode Island		Vermont[2]
Year	I	I or II	III	I	II	I	I - Solar[3,4]	II	II-WTE	I	II	III	IV	New	New or Existing	New
2009	6.00%	3.00%	3.00%	2.00%	30.00%	4.00%	0.00%	3.60%	3.50%	0.50%	0.00%	4.50%	1.00%	2.00%	2.00%	0.00%
2010	7.00%	3.00%	4.00%	3.00%	30.00%	5.00%	0.0679%	3.60%	3.50%	1.00%	0.04%	5.50%	1.00%	2.50%	2.00%	0.00%
2011	8.00%	3.00%	4.00%	4.00%	30.00%	6.00%	per DOER	3.60%	3.50%	2.00%	0.08%	6.50%	1.00%	3.50%	2.00%	0.00%
2012	9.00%	3.00%	4.00%	5.00%	30.00%	7.00%	per DOER	3.60%	3.50%	3.00%	0.15%	6.50%	1.00%	4.50%	2.00%	0.00%
2013	10.00%	3.00%	4.00%	6.00%	30.00%	8.00%	per DOER	3.60%	3.50%	4.00%	0.20%	6.50%	1.00%	5.50%	2.00%	1.00%
2014	11.00%	3.00%	4.00%	7.00%	30.00%	9.00%	per DOER	3.60%	3.50%	5.00%	0.30%	6.50%	1.00%	6.50%	2.00%	2.00%
2015	12.50%	3.00%	4.00%	8.00%	30.00%	10.00%	per DOER	3.60%	3.50%	6.00%	0.30%	6.50%	1.00%	8.00%	2.00%	3.00%
2016	14.00%	3.00%	4.00%	9.00%	30.00%	11.00%	per DOER	3.60%	3.50%	7.00%	0.30%	6.50%	1.00%	9.50%	2.00%	4.00%
2017	15.50%	3.00%	4.00%	10.00%	30.00%	12.00%	per DOER	3.60%	3.50%	8.00%	0.30%	6.50%	1.00%	11.00%	2.00%	5.00%
2018	17.00%	3.00%	4.00%	10.00%	30.00%	13.00%	per DOER	3.60%	3.50%	9.00%	0.30%	6.50%	1.00%	12.50%	2.00%	5.00%
2019	18.50%	3.00%	4.00%	10.00%	30.00%	14.00%	per DOER	3.60%	3.50%	10.00%	0.30%	6.50%	1.00%	14.00%	2.00%	5.00%
2020	20.00%	3.00%	4.00%	10.00%	30.00%	15.00%	per DOER	3.60%	3.50%	11.00%	0.30%	6.50%	1.00%	14.00%	2.00%	5.00%
2021	20.00%	3.00%	4.00%	10.00%	30.00%	16.00%	per DOER	3.60%	3.50%	12.00%	0.30%	6.50%	1.00%	14.00%	2.00%	5.00%
2022	20.00%	3.00%	4.00%	10.00%	30.00%	17.00%	per DOER	3.60%	3.50%	13.00%	0.30%	6.50%	1.00%	14.00%	2.00%	5.00%
2023	20.00%	3.00%	4.00%	10.00%	30.00%	18.00%	per DOER	3.60%	3.50%	14.00%	0.30%	6.50%	1.00%	14.00%	2.00%	5.00%
2024	20.00%	3.00%	4.00%	10.00%	30.00%	19.00%	per DOER	3.60%	3.50%	15.00%	0.30%	6.50%	1.00%	14.00%	2.00%	5.00%

(1) Revisions to the Connecticut RPS are the subject of discussion in the 2011 Legislature. Proposals include reducing the RPS target to 11.5% by 2020.
(2) This study assumes the adoption of a new RPS, commencing in 2013, of 5% by 2017 which is incremental to all previously enacted goals and requires REC retirement.
(3) The MA Solar Carve-Out represents a portion of the Class 1 requirement, not an additional requirement. The annual Solar Carve-Out target is calculated each year by MA DOER.
(4) The goal of the Massachusetts Solar Carve-Out is the installation and operation of 400 MW of solar generating capacity.

Exhibit C-4: AESC 2011 Renewable Portfolio Standards, REC Price Forecast, and Avoided RPS Costs by State (2011$)

AESC 2011: Renewable Portfolio Standard (RPS) Targets, Renewable Energy Credit (REC) Price Forecasts, and Avoided RPS Costs in $/MWh of Load

(all values in 2011 dollars)

State	Item	Class	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
CONNECTICUT	RPS Targets (%)	Class 1	8.0%	9.0%	10.0%	11.0%	12.5%	14.0%	15.5%	17.0%	18.5%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%
		Class 2	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
		Class 3	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%
	REC Prices ($/MWh)	Class 1	$ 13.48	$ 14.60	$ 15.23	$ 16.04	$ 16.76	$ 17.29	$ 17.08	$ 10.99	$ 5.14	$ 6.63	$ 3.46	$ 6.84	$ 9.82	$ 10.23	$ 7.85	$ 4.12
		Class 2	$ 0.91	$ 0.89	$ 0.87	$ 0.86	$ 0.84	$ 0.82	$ 0.81	$ 0.79	$ 0.78	$ 0.76	$ 0.75	$ 0.73	$ 0.72	$ 0.70	$ 0.69	$ 0.68
		Class 3	$ 10.00	$ 9.80	$ 9.61	$ 9.42	$ 9.24	$ 9.06	$ 8.88	$ 8.71	$ 8.53	$ 8.37	$ 8.20	$ 8.04	$ 7.88	$ 7.73	$ 7.58	$ 7.43
		Loss Adjustment	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%
	Avoided RPS Cost: $/MWh of Load	Class 1	$1.16	$1.42	$1.64	$1.91	$2.26	$2.61	$2.86	$2.02	$1.03	$1.43	$0.75	$1.48	$2.12	$2.21	$1.70	$0.89
		Class 2	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02
		Class 3	$0.43	$0.42	$0.42	$0.41	$0.40	$0.39	$0.38	$0.38	$0.37	$0.36	$0.35	$0.35	$0.34	$0.33	$0.33	$0.32
MAINE	RPS Targets (%)	Class 1	4.0%	5.0%	6.0%	7.0%	8.0%	9.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
		Class 2	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%
	REC Prices ($/MWh)	Class 1	$ 9.00	$ 11.64	$ 11.68	$ 12.30	$ 12.85	$ 13.26	$ 13.10	$ 9.04	$ 5.14	$ 6.63	$ 3.46	$ 6.84	$ 9.82	$ 10.23	$ 7.85	$ 4.12
		Class 2	$ 0.18	$ 0.18	$ 0.17	$ 0.17	$ 0.17	$ 0.16	$ 0.16	$ 0.16	$ 0.15	$ 0.15	$ 0.15	$ 0.14	$ 0.14	$ 0.14	$ 0.14	$ 0.13
		Loss Adjustment	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%
	Avoided RPS Cost: $/MWh of Load	Class 1	$0.39	$0.63	$0.76	$0.93	$1.11	$1.29	$1.41	$0.98	$0.55	$0.72	$0.37	$0.74	$1.06	$1.11	$0.85	$0.44
		Class 2	$0.06	$0.06	$0.06	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.04	$0.04

Exhibit C-4: AESC 2011 Renewable Portfolio Standards, REC Price Forecast, and Avoided RPS Costs by State (2011$) (Continued)

AESC 2011: Renewable Portfolio Standard (RPS) Targets, Renewable Energy Credit (REC) Price Forecasts, and Avoided RPS Costs in $/MWh of Load

(all values in 2011 dollars)

State			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
MASSACHUSETTS	RPS Targets (%)	Class 1	5.84%	6.78%	7.73%	8.65%	9.54%	10.41%	11.24%	12.10%	13.10%	14.10%	15.10%	16.10%	17.16%	18.33%	19.56%	20.83%
		Solar Carve-Out	0.1627%	0.22%	0.27%	0.35%	0.46%	0.59%	0.76%	0.90%	0.90%	0.90%	0.90%	0.90%	0.84%	0.67%	0.44%	0.17%
		Class 2	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%
		Class 2-WTE	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
		APS	2.00%	2.50%	3.00%	3.50%	3.75%	4.00%	4.25%	4.50%	4.75%	5.00%	5.25%	5.50%	5.75%	6.00%	6.25%	6.50%
	REC Prices ($/MWh)	Class 1	$ 14.95	$ 17.05	$ 22.44	$ 23.63	$ 24.69	$ 25.48	$ 25.17	$ 14.96	$ 5.14	$ 6.63	$ 3.46	$ 6.84	$ 9.82	$ 10.23	$ 7.85	$ 4.12
		Solar Carve-Out	$ 525.00	$ 435.42	$ 381.68	$ 355.49	$ 331.09	$ 308.37	$ 287.21	$ 267.50	$ 249.14	$ 232.04	$ 222.87	$ 207.57	$ 199.19	$ 190.97	$ 182.95	$ 175.13
		Class 2	$ 22.88	$ 20.52	$ 18.24	$ 16.04	$ 16.76	$ 17.29	$ 17.08	$ 10.99	$ 5.14	$ 6.63	$ 3.46	$ 6.84	$ 9.82	$ 10.23	$ 7.85	$ 4.12
		Class 2-WTE	$ 5.27	$ 5.17	$ 5.07	$ 4.97	$ 4.87	$ 4.77	$ 4.68	$ 4.59	$ 4.50	$ 4.41	$ 4.32	$ 4.24	$ 4.16	$ 4.07	$ 3.99	$ 3.92
		APS	$ 19.00	$ 18.79	$ 18.57	$ 18.36	$ 18.36	$ 18.36	$ 18.36	$ 18.36	$ 18.36	$ 18.36	$ 18.36	$ 18.36	$ 18.36	$ 18.36	$ 18.36	$ 18.36
		Loss Adjustment	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%
	Avoided RPS Cost: $/MWh of Load	Class 1	$0.94	$1.25	$1.87	$2.21	$2.54	$2.86	$3.05	$1.95	$0.73	$1.01	$0.56	$1.19	$1.82	$2.03	$1.66	$0.93
		Solar Carve-Out	$0.92	$1.05	$1.12	$1.35	$1.64	$1.97	$2.36	$2.61	$2.43	$2.26	$2.17	$2.03	$1.80	$1.38	$0.88	$0.33
		Class 2	$0.89	$0.80	$0.71	$0.62	$0.65	$0.67	$0.66	$0.43	$0.20	$0.26	$0.13	$0.27	$0.38	$0.40	$0.31	$0.16
		Class 2-WTE	$0.20	$0.20	$0.19	$0.19	$0.18	$0.18	$0.18	$0.17	$0.17	$0.17	$0.16	$0.16	$0.16	$0.15	$0.15	$0.15
		APS	$0.41	$0.51	$0.60	$0.69	$0.74	$0.79	$0.84	$0.89	$0.94	$0.99	$1.04	$1.09	$1.14	$1.19	$1.24	$1.29
NEW HAMPSHIRE	RPS Targets (%)	Class 1	2.0%	3.0%	4.0%	5.0%	6.0%	7.0%	8.0%	9.0%	10.0%	11.0%	12.0%	13.0%	14.0%	15.0%	16.0%	16.0%
		Class 2	0.08%	0.15%	0.20%	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%
		Class 3	6.5%	6.5%	6.5%	6.5%	6.5%	6.5%	6.5%	6.5%	6.5%	6.5%	6.5%	6.5%	6.5%	6.5%	6.5%	6.5%
		Class 4	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
	REC Prices ($/MWh)	Class 1	$ 15.71	$ 17.41	$ 26.21	$ 27.60	$ 28.84	$ 29.76	$ 29.39	$ 17.03	$ 5.14	$ 6.63	$ 3.46	$ 6.84	$ 9.82	$ 10.23	$ 7.85	$ 4.12
		Class 2	$ 25.00	$ 18.75	$ 24.13	$ 24.81	$ 25.93	$ 26.76	$ 26.42	$ 15.70	$ 5.39	$ 6.96	$ 3.63	$ 7.18	$ 10.32	$ 10.75	$ 8.24	$ 4.32
		Class 3	$ 18.75	$ 17.82	$ 16.91	$ 16.04	$ 16.76	$ 17.29	$ 17.08	$ 10.99	$ 5.14	$ 6.63	$ 3.46	$ 6.84	$ 9.82	$ 10.23	$ 7.85	$ 4.12
		Class 4	$ 24.47	$ 21.56	$ 18.74	$ 16.04	$ 16.76	$ 17.29	$ 17.08	$ 10.99	$ 5.14	$ 6.63	$ 3.46	$ 6.84	$ 9.82	$ 10.23	$ 7.85	$ 4.12
		Loss Adjustment	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%
	Avoided RPS Cost: $/MWh of Load	Class 1	$0.34	$0.56	$1.13	$1.49	$1.87	$2.25	$2.54	$1.65	$0.55	$0.79	$0.45	$0.96	$1.49	$1.66	$1.36	$0.71
		Class 2	$0.02	$0.03	$0.05	$0.08	$0.08	$0.09	$0.09	$0.05	$0.02	$0.02	$0.01	$0.02	$0.03	$0.03	$0.03	$0.01
		Class 3	$1.32	$1.25	$1.19	$1.13	$1.18	$1.21	$1.20	$0.77	$0.36	$0.47	$0.24	$0.48	$0.69	$0.72	$0.55	$0.29
		Class 4	$0.26	$0.23	$0.20	$0.17	$0.18	$0.19	$0.18	$0.12	$0.06	$0.07	$0.04	$0.07	$0.11	$0.11	$0.08	$0.04

Exhibit C-4: AESC 2011 Renewable Portfolio Standards, REC Price Forecast, and Avoided RPS Costs by State (2011$) (Continued)

AESC 2011: Renewable Portfolio Standard (RPS) Targets, Renewable Energy Credit (REC) Price Forecasts, and Avoided RPS Costs in $/MWh of Load

(all values in 2011 dollars)

State	Item		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
RHODE ISLAND	RPS Targets (%)	New	3.5%	4.5%	5.5%	6.5%	8.0%	9.5%	11.0%	12.5%	14.0%	14.0%	14.0%	14.0%	14.0%	14.0%	14.0%	14.0%
		Existing	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
	REC Prices ($/MWh)	New	$ 15.28	$ 17.41	$ 20.83	$ 21.93	$ 22.92	$ 23.65	$ 23.35	$ 14.07	$ 5.14	$ 6.63	$ 3.46	$ 6.84	$ 9.82	$ 10.23	$ 7.85	$ 4.12
		Existing	$ 0.76	$ 0.75	$ 0.73	$ 0.72	$ 0.70	$ 0.69	$ 0.67	$ 0.66	$ 0.65	$ 0.64	$ 0.62	$ 0.61	$ 0.60	$ 0.59	$ 0.58	$ 0.56
		Loss Adjustment	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%
	Avoided RPS Cost:	New	$0.58	$0.85	$1.24	$1.54	$1.98	$2.43	$2.77	$1.90	$0.78	$1.00	$0.52	$1.03	$1.49	$1.55	$1.19	$0.62
	$/MWh of Load	Existing	$0.02	$0.02	$0.02	$0.02	$0.02	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01
VERMONT	RPS Targets (%)	New	0%	0%	1%	2%	3%	4%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%
	REC Prices ($/MWh)	New	$ -	$ -	$ 20.83	$ 21.93	$ 22.92	$ 23.65	$ 23.35	$ 14.07	$ 5.14	$ 6.63	$ 3.46	$ 6.84	$ 9.82	$ 10.23	$ 7.85	$ 4.12
		Loss Adjustment	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%
	Avoided RPS Cost:	New	$0.00	$0.00	$0.22	$0.47	$0.74	$1.02	$1.26	$0.76	$0.28	$0.36	$0.19	$0.37	$0.53	$0.55	$0.42	$0.22

Exhibit C-4: AESC 2011 Renewable Portfolio Standards, REC Price Forecast, and Avoided RPS Costs by State (2011$) (Continued)

Assumptions:

1 *RPS Targets for CT, ME, MA, NH & RI are based on state-specific legislation and regulation in effect as of April 15, 2011*

2 *Vermont currently has a non-binding goal of 20 percnet by 2017. VT's minimum obligation is to meet incremental load growth from 2005 - 2012 with qualifying resources. A minimum goal of generating 5 percent of VT's 2005 sales is also included in the current law. No F is required. This AESC 2011 study assumes adoption of an RPS, commencing in 2013, of 5 percent by 2017 which is incremental to all goals previously described and requires REC retirement.*

3 *For Class I requirements, 2011 & 2012 REC prices are based on historic average broker quotes from January to April 2011. For Class II requirements, 2011 REC prices are based on a 12-month (May 2010 to April 2011) historic average of broker quotes and/or bid-ask spread*

4 *Prices for MA Class I, CT Class I, NH Class I, ME Class I, and RI "New" are assumed to reflect the new renewables cost of entry beginning in 2019. Prices are interpolated between 2013 and 2018.*

5 *The incremental VT RPS requirement (described in Note 2) is assumed to have eligibility criteria similar enough to RI Class 1 that VT REC prices will approximately the levels expected in this market.*

6 *The MA Solar Carve Out (a sub-set of MA Class I) is assumed to reach its 400 MW target in 2018. The target is assumed to remain at this level through 2022. This is the proxy date for the point at which the last remaining "Opt-In Term" is expected to expire. Beginning in Carve-Out is assumed to begin to sunset into MA Class I at the same rate as it ramped up, reaching zero carve-out shortly after the study period ends. Reductions in the installed cost of new solar facilities are asumed to drive SREC prices toward the $300 auction floor pr to 2018, with steeper declines in the early years. Beginning in 2019 (one year after the 400 MW target is reached) supply and demand dynamics may cause the market price of SRECs to drop below the auction floor price of $300, notwithstanding the fact that some SRECs for the auction. MA DOER's SREC market structure is yet untested, and it is not clear whether an auction floor price will be able to be maintained once there is a substantial amount of supply in the market.*

7 *CT Class II, MA Class II-WTE, ME Class II, and RI "Existing" REC markets are in surplus. Therefore, REC prices in these markets are expected to remain relatively constant.*

8 *The MA Class II market has overlapping eligibility with CT Class I. In addition, while there is theoretically ample supply to meet MA Class II, fewer generators than expected have undertaken the steps necessary to comply with the eligibility criteria and become certified. MA Class II market is currently in shortage. In the long-run, MA Class II REC prices are assumed to be the lesser of CT Class I and 90 percent of the MA Class II Alternative Compliance Payment (ACP) rate.*

9 *REC prices for MA APS are forecasted at 90 percent of the Alternative Compliance Payment (ACP) rate.*

10 *The CT Class III market has an administratively-set REC price floor of $10 per MWh. Based on the performance of this market to date, CT Class 3 compliance prices are expected to remain at $10 per MWh throughout the study period.*

11 *Existing solar facilities across New England are eligible for NH Class II. As such, this market is expected to remain in balance, trend toward the MA Class I REC price between 2011 and 2014, and settle marginally above the MA Class I REC price for the remainder of the stud*

12 *The NH Class III and NH CLass IV markets have overlapping eligibility with CT Class I. In the long-run, therefore, NH-III and NH-IV REC prices are assumed to be the lesser of CT Class I and 90 percent of their respective Alternative Compliance Payment (ACP) rates.*

Exhibit C-5: Market Analytics Locational Prices by Zone

Zone	Maine					
	Winter			Summer		
Year	On-Peak	Off-Peak	All-Hours	On-Peak	Off-Peak	All-Hours
2011	47.11	41.77	44.3	48.96	38.00	43.2
2012	48.78	42.84	45.7	53.19	41.07	46.8
2013	49.59	43.73	46.5	52.26	41.99	46.9
2014	49.81	44.27	46.9	53.18	42.59	47.6
2015	54.30	47.63	50.8	57.21	46.35	51.5
2016	54.40	47.17	50.6	59.57	46.59	52.8
2017	54.79	47.98	51.2	58.59	46.37	52.2
2018	60.43	54.17	57.2	65.22	52.33	58.5
2019	61.39	56.11	58.6	66.40	53.70	59.7
2020	63.10	55.49	59.1	68.02	54.68	61.0
2021	64.89	58.07	61.3	70.35	56.27	63.0
2022	66.86	58.97	62.7	71.93	58.82	65.1
2023	71.19	62.10	66.4	76.41	61.44	68.6
2024	74.04	64.28	68.9	77.79	63.56	70.3
2025	74.74	65.19	69.7	79.05	64.80	71.6
2026	75.92	65.86	70.7	79.09	64.96	71.7

Zone	Vermont					
	Winter			Summer		
Year	On-Peak	Off-Peak	All-Hours	On-Peak	Off-Peak	All-Hours
2011	50.10	42.29	46.0	55.88	40.24	47.7
2012	51.65	43.50	47.4	61.41	43.41	52.0
2013	52.90	45.57	49.1	63.19	44.96	53.6
2014	54.33	46.83	50.4	65.54	45.70	55.1
2015	59.48	50.92	55.0	70.28	49.86	59.6
2016	59.75	50.86	55.1	76.15	50.36	62.6
2017	60.08	51.99	55.8	75.74	49.84	62.2
2018	66.18	58.43	62.1	85.33	56.69	70.3
2019	67.02	60.12	63.4	83.93	57.83	70.3
2020	68.92	59.85	64.2	80.24	58.76	69.0
2021	70.57	62.12	66.1	81.81	60.48	70.6
2022	72.53	63.84	68.0	83.37	62.46	72.4
2023	76.59	66.67	71.4	87.32	65.66	76.0
2024	79.30	68.49	73.6	88.68	67.33	77.5
2025	80.34	69.35	74.6	89.89	69.35	79.1
2026	82.23	71.10	76.4	93.75	70.21	81.4

Zone	New Hampshire					
	Winter			Summer		
Year	On-Peak	Off-Peak	All-Hours	On-Peak	Off-Peak	All-Hours
2011	48.81	41.89	45.2	52.70	39.42	45.7
2012	50.47	42.97	46.5	57.13	42.47	49.5
2013	51.37	44.62	47.8	56.38	43.86	49.8
2014	52.74	45.98	49.2	57.39	44.63	50.7
2015	57.78	49.94	53.7	61.72	48.45	54.8
2016	58.03	49.72	53.7	64.26	48.93	56.2
2017	58.40	51.00	54.5	63.19	48.54	55.5
2018	64.39	57.47	60.8	70.47	55.28	62.5
2019	65.36	59.19	62.1	71.55	56.60	63.7
2020	66.97	58.57	62.6	72.94	57.40	64.8
2021	68.81	61.06	64.8	75.55	59.15	67.0
2022	70.60	62.52	66.4	77.05	61.23	68.8
2023	74.73	65.39	69.8	81.88	64.36	72.7
2024	77.58	67.34	72.2	82.96	66.02	74.1
2025	78.60	68.21	73.2	84.15	68.15	75.8
2026	79.99	69.12	74.3	84.00	68.27	75.8

Zone	Connecticut					
	Winter			Summer		
Year	On-Peak	Off-Peak	All-Hours	On-Peak	Off-Peak	All-Hours
2011	50.80	42.61	46.5	57.36	40.70	48.6
2012	52.35	43.99	48.0	62.71	43.95	52.9
2013	53.31	45.65	49.3	64.72	44.99	54.4
2014	54.86	47.18	50.8	66.36	46.07	55.7
2015	60.08	51.32	55.5	71.07	50.41	60.2
2016	60.35	51.31	55.6	77.12	50.91	63.4
2017	60.64	52.44	56.3	76.59	50.34	62.8
2018	66.80	58.92	62.7	86.28	57.00	70.9
2019	67.68	60.60	64.0	84.85	58.38	71.0
2020	69.67	60.45	64.8	81.22	59.32	69.8
2021	71.26	62.71	66.8	82.74	61.03	71.4
2022	73.25	64.47	68.6	84.35	63.02	73.2
2023	77.42	67.34	72.1	88.35	66.29	76.8
2024	80.14	69.19	74.4	90.17	67.98	78.5
2025	81.19	70.10	75.4	91.14	70.04	80.1
2026	83.28	71.98	77.4	95.24	71.00	82.5

Exhibit C-5: Market Analytics Locational Prices by Zone (Continued)

Zone	Massachusetts					
	Winter			Summer		
Year	On-Peak	Off-Peak	All-Hours	On-Peak	Off-Peak	All-Hours
2011	49.64	42.25	45.8	55.65	39.92	47.4
2012	51.33	43.34	47.1	61.31	43.07	51.8
2013	52.45	45.31	48.7	62.96	44.51	53.3
2014	53.83	46.74	50.1	65.23	45.48	54.9
2015	59.15	51.04	54.9	70.09	49.72	59.4
2016	59.58	51.03	55.1	76.24	50.25	62.6
2017	59.89	52.20	55.9	75.98	49.77	62.2
2018	65.89	58.52	62.0	85.64	56.51	70.4
2019	66.99	60.46	63.6	84.38	57.68	70.4
2020	68.26	59.46	63.6	79.72	58.34	68.5
2021	70.10	61.84	65.8	81.43	60.20	70.3
2022	71.92	63.34	67.4	82.92	62.00	72.0
2023	76.02	66.06	70.8	86.64	65.06	75.3
2024	78.82	68.01	73.2	88.25	66.87	77.0
2025	80.30	69.18	74.5	89.95	69.11	79.0
2026	81.96	70.82	76.1	93.90	70.11	81.4

Zone	Rhode Island					
	Winter			Summer		
Year	On-Peak	Off-Peak	All-Hours	On-Peak	Off-Peak	All-Hours
2011	48.50	41.86	45.0	53.72	39.31	46.2
2012	50.16	43.04	46.4	59.58	42.42	50.6
2013	51.31	44.85	47.9	61.15	43.71	52.0
2014	52.71	46.30	49.4	64.04	44.83	54.0
2015	58.13	50.63	54.2	68.43	48.99	58.2
2016	58.39	50.52	54.3	74.43	49.60	61.4
2017	58.54	51.62	54.9	73.91	49.11	60.9
2018	58.52	51.28	54.7	75.90	49.65	62.1
2019	58.29	51.61	54.8	73.98	49.55	61.2
2020	58.38	48.79	53.4	67.30	49.19	57.8
2021	58.99	49.60	54.1	67.51	49.83	58.2
2022	59.25	49.24	54.0	66.59	49.85	57.8
2023	61.79	50.69	56.0	68.63	51.45	59.6
2024	63.23	50.63	56.6	69.66	52.34	60.6
2025	63.43	50.01	56.4	69.59	52.72	60.8
2026	64.09	50.54	57.0	72.16	53.17	62.2

Zone	CT Norwalk/Stamford					
	Winter			Summer		
Year	On-Peak	Off-Peak	All-Hours	On-Peak	Off-Peak	All-Hours
2011	51.33	43.05	47.0	57.96	41.12	49.1
2012	52.90	44.46	48.5	63.37	44.41	53.4
2013	53.87	46.13	49.8	65.40	45.46	55.0
2014	55.44	47.66	51.4	67.06	46.55	56.3
2015	60.71	51.85	56.1	71.82	50.94	60.9
2016	60.98	51.84	56.2	77.93	51.45	64.1
2017	61.28	52.99	56.9	77.39	50.87	63.5
2018	67.51	59.53	63.3	87.19	57.60	71.7
2019	68.39	61.24	64.6	85.74	58.99	71.7
2020	70.40	61.08	65.5	82.08	59.95	70.5
2021	72.01	63.37	67.5	83.62	61.67	72.1
2022	74.02	65.15	69.4	85.24	63.68	73.9
2023	78.23	68.04	72.9	89.28	66.99	77.6
2024	80.99	69.92	75.2	91.12	68.69	79.4
2025	82.05	70.83	76.2	92.10	70.78	80.9
2026	84.15	72.74	78.2	96.25	71.75	83.4

Zone	CT Southwest Including Norwalk/Stamford					
	Winter			Summer		
Year	On-Peak	Off-Peak	All-Hours	On-Peak	Off-Peak	All-Hours
2011	51.30	43.02	47.0	57.92	41.10	49.1
2012	52.87	44.43	48.4	63.33	44.38	53.4
2013	53.83	46.10	49.8	65.36	45.43	54.9
2014	55.41	47.63	51.3	67.01	46.52	56.3
2015	60.67	51.82	56.0	71.77	50.90	60.8
2016	60.94	51.81	56.2	77.88	51.42	64.0
2017	61.24	52.96	56.9	77.34	50.84	63.5
2018	67.47	59.49	63.3	87.13	57.56	71.6
2019	68.35	61.20	64.6	85.69	58.95	71.7
2020	70.35	61.04	65.5	82.03	59.91	70.4
2021	71.96	63.33	67.4	83.56	61.63	72.1
2022	73.97	65.11	69.3	85.19	63.64	73.9
2023	78.18	68.00	72.8	89.22	66.94	77.6
2024	80.93	69.87	75.1	91.06	68.65	79.3
2025	81.99	70.79	76.1	92.04	70.73	80.9
2026	84.10	72.69	78.1	96.19	71.71	83.4

Exhibit C-5: Market Analytics Locational Prices by Zone (Continued)

Zone	CT Southwest Excluding Norwalk/Stamford					
	Winter			Summer		
Year	On-Peak	Off-Peak	All-Hours	On-Peak	Off-Peak	All-Hours
2011	51.28	43.01	46.9	57.90	41.09	49.1
2012	52.85	44.41	48.4	63.31	44.37	53.4
2013	53.82	46.08	49.8	65.34	45.41	54.9
2014	55.39	47.61	51.3	66.99	46.50	56.3
2015	60.65	51.80	56.0	71.74	50.89	60.8
2016	60.92	51.79	56.1	77.85	51.40	64.0
2017	61.21	52.94	56.9	77.32	50.82	63.4
2018	67.44	59.47	63.3	87.10	57.54	71.6
2019	68.33	61.18	64.6	85.66	58.93	71.7
2020	70.33	61.02	65.5	82.00	59.89	70.4
2021	71.94	63.31	67.4	83.53	61.61	72.0
2022	73.94	65.08	69.3	85.16	63.61	73.9
2023	78.16	67.98	72.8	89.19	66.92	77.5
2024	80.91	69.85	75.1	91.03	68.62	79.3
2025	81.96	70.76	76.1	92.01	70.71	80.9
2026	84.07	72.67	78.1	96.15	71.68	83.3

Zone	CT Rest of State					
	Winter			Summer		
Year	On-Peak	Off-Peak	All-Hours	On-Peak	Off-Peak	All-Hours
2011	50.27	42.18	46.0	56.77	40.28	48.1
2012	51.81	43.54	47.5	62.07	43.50	52.3
2013	52.76	45.18	48.8	64.05	44.53	53.8
2014	54.30	46.71	50.3	65.68	45.60	55.2
2015	59.46	50.80	54.9	70.34	49.89	59.6
2016	59.73	50.78	55.0	76.33	50.39	62.7
2017	60.01	51.90	55.8	75.80	49.82	62.2
2018	66.12	58.33	62.0	85.39	56.42	70.2
2019	66.99	59.99	63.3	83.98	57.78	70.3
2020	68.95	59.82	64.2	80.39	58.72	69.0
2021	70.53	62.06	66.1	81.90	60.40	70.6
2022	72.49	63.81	67.9	83.48	62.37	72.4
2023	76.62	66.65	71.4	87.44	65.61	76.0
2024	79.32	68.48	73.6	89.24	67.28	77.7
2025	80.36	69.38	74.6	90.21	69.32	79.3
2026	82.42	71.25	76.6	94.27	70.27	81.7

Zone	SEMA					
	Winter			Summer		
Year	On-Peak	Off-Peak	All-Hours	On-Peak	Off-Peak	All-Hours
2011	48.92	42.10	45.3	54.72	39.51	46.8
2012	50.64	43.07	46.7	60.37	42.67	51.1
2013	51.70	45.10	48.2	61.90	44.03	52.5
2014	53.04	46.58	49.7	64.08	45.13	54.2
2015	58.44	51.00	54.5	68.81	49.38	58.6
2016	58.81	50.89	54.7	74.92	49.87	61.8
2017	59.09	52.11	55.4	74.72	49.40	61.5
2018	64.94	58.33	61.5	84.22	56.09	69.5
2019	66.20	60.42	63.2	83.12	57.23	69.6
2020	67.58	59.36	63.3	78.60	58.25	67.9
2021	69.68	61.99	65.6	80.69	60.21	70.0
2022	71.17	63.11	66.9	82.07	61.75	71.4
2023	75.72	65.93	70.6	85.78	64.93	74.9
2024	78.20	67.87	72.8	87.45	66.85	76.7
2025	80.43	69.38	74.6	89.46	69.29	78.9
2026	81.52	70.98	76.0	93.46	70.41	81.4

Zone	WCMA					
	Winter			Summer		
Year	On-Peak	Off-Peak	All-Hours	On-Peak	Off-Peak	All-Hours
2011	50.16	42.33	46.1	55.97	40.33	47.8
2012	51.69	43.56	47.4	61.52	43.51	52.1
2013	52.84	45.53	49.0	63.19	44.94	53.6
2014	54.29	46.78	50.4	65.56	45.69	55.2
2015	59.46	50.88	55.0	70.34	49.90	59.6
2016	59.73	50.85	55.1	76.20	50.41	62.7
2017	60.03	51.96	55.8	75.78	49.87	62.2
2018	66.11	58.38	62.1	85.36	56.68	70.3
2019	66.97	60.08	63.4	83.97	57.83	70.3
2020	68.88	59.83	64.1	80.24	58.73	69.0
2021	70.51	62.07	66.1	81.81	60.43	70.6
2022	72.46	63.81	67.9	83.37	62.41	72.4
2023	76.54	66.66	71.4	87.32	65.62	76.0
2024	79.22	68.48	73.6	88.67	67.28	77.5
2025	80.26	69.38	74.6	89.86	69.32	79.1
2026	82.24	71.22	76.5	93.80	70.27	81.5

Exhibit C-5: Market Analytics Locational Prices by Zone (Continued)

Zone	NEMA					
	Winter			Summer		
Year	On-Peak	Off-Peak	All-Hours	On-Peak	Off-Peak	All-Hours
2011	49.48	41.94	45.5	55.23	39.58	47.0
2012	51.15	43.03	46.9	60.84	42.71	51.3
2013	52.17	44.87	48.3	62.43	44.09	52.8
2014	53.54	46.27	49.7	64.68	44.95	54.3
2015	58.71	50.47	54.4	69.53	49.12	58.8
2016	59.14	50.44	54.6	75.64	49.63	62.0
2017	59.41	51.57	55.3	75.39	49.15	61.6
2018	65.34	57.84	61.4	85.00	55.80	69.7
2019	66.42	59.73	62.9	83.72	56.97	69.7
2020	67.59	58.55	62.9	78.89	57.41	67.6
2021	69.28	60.87	64.9	80.44	59.24	69.3
2022	71.16	62.41	66.6	81.92	61.05	71.0
2023	74.98	64.96	69.7	85.49	63.96	74.2
2024	77.87	66.94	72.1	87.13	65.75	75.9
2025	79.14	68.04	73.3	88.84	67.93	77.9
2026	80.89	69.60	75.0	92.69	68.88	80.2

Zone	Rest of MA					
	Winter			Summer		
Year	On-Peak	Off-Peak	All-Hours	On-Peak	Off-Peak	All-Hours
2011	49.66	42.30	45.8	55.72	39.97	47.5
2012	51.36	43.39	47.2	61.38	43.13	51.8
2013	52.49	45.38	48.8	63.04	44.57	53.4
2014	53.88	46.82	50.2	65.32	45.56	55.0
2015	59.22	51.13	55.0	70.18	49.81	59.5
2016	59.65	51.12	55.2	76.34	50.35	62.7
2017	59.96	52.29	55.9	76.07	49.87	62.3
2018	65.98	58.63	62.1	85.74	56.63	70.5
2019	67.09	60.58	63.7	84.48	57.79	70.5
2020	68.37	59.60	63.8	79.85	58.48	68.7
2021	70.23	61.99	65.9	81.58	60.36	70.5
2022	72.04	63.49	67.6	83.08	62.15	72.1
2023	76.18	66.23	71.0	86.83	65.23	75.5
2024	78.97	68.18	73.3	88.42	67.05	77.2
2025	80.49	69.36	74.7	90.13	69.29	79.2
2026	82.13	71.01	76.3	94.09	70.30	81.6

Exhibit C-6: AESC 2011 Reference Case: Avoided Externality Costs

	AESC Long-term Cost	AESC Allowance Price		Winter On Peak	Winter Off-Peak	Summer On Peak Energy	Summer Off-Peak
	$/ton (2011$)	$/ton (2011$)	$/ton externality	$/kWh externality			
	a	b	c=a-b	d=c* winter on peak emission rate	e=c* winter off peak emission rate	f=c* summer on peak emission rate	g=c* summer off emission rate
2011	*$80.00*	*$1.89*	*$78.11*	0.042	0.043	0.041	0.045
2012	*$80.00*	*$1.89*	*$78.11*	0.042	0.043	0.041	0.045
2013	*$80.00*	*$1.89*	*$78.11*	0.042	0.043	0.041	0.045
2014	*$80.00*	*$1.89*	*$78.11*	0.042	0.043	0.041	0.045
2015	*$80.00*	*$1.89*	*$78.11*	0.042	0.043	0.041	0.045
2016	*$80.00*	*$1.89*	*$78.11*	0.042	0.043	0.041	0.045
2017	*$80.00*	*$1.89*	*$78.11*	0.042	0.043	0.041	0.045
2018	*$80.00*	*$15.30*	*$64.70*	0.035	0.036	0.034	0.037
2019	*$80.00*	*$18.28*	*$61.73*	0.034	0.034	0.033	0.035
2020	*$80.00*	*$21.25*	*$58.75*	0.032	0.033	0.031	0.034
2021	*$80.00*	*$24.23*	*$55.78*	0.030	0.031	0.030	0.032
2022	*$80.00*	*$27.20*	*$52.80*	0.029	0.029	0.028	0.030
2023	*$80.00*	*$30.18*	*$49.83*	0.027	0.028	0.026	0.029
2024	*$80.00*	*$33.15*	*$46.85*	0.025	0.026	0.025	0.027
2025	*$80.00*	*$36.13*	*$43.88*	0.024	0.024	0.023	0.025
2026	*$80.00*	*$39.10*	*$40.90*	0.022	0.023	0.022	0.023
2027	*$80.00*	*$39.10*	*$40.90*	0.022	0.023	0.022	0.023
2028	*$80.00*	*$39.10*	*$40.90*	0.022	0.023	0.022	0.023
2029	*$80.00*	*$39.10*	*$40.90*	0.022	0.023	0.022	0.023
2030	*$80.00*	*$39.10*	*$40.90*	0.022	0.023	0.022	0.023
2031	*$80.00*	*$39.10*	*$40.90*	0.022	0.023	0.022	0.023
2032	*$80.00*	*$39.10*	*$40.90*	0.022	0.023	0.022	0.023
2033	*$80.00*	*$39.10*	*$40.90*	0.022	0.023	0.022	0.023
2034	*$80.00*	*$39.10*	*$40.90*	0.022	0.023	0.022	0.023
2035	*$80.00*	*$39.10*	*$40.90*	0.022	0.023	0.022	0.023
2036	*$80.00*	*$39.10*	*$40.90*	0.022	0.023	0.022	0.023
2037	*$80.00*	*$39.10*	*$40.90*	0.022	0.023	0.022	0.023
2038	*$80.00*	*$39.10*	*$40.90*	0.022	0.023	0.022	0.023
2039	*$80.00*	*$39.10*	*$40.90*	0.022	0.023	0.022	0.023
2040	*$80.00*	*$39.10*	*$40.90*	0.022	0.023	0.022	0.023
2041	*$80.00*	*$39.10*	*$40.90*	0.022	0.023	0.022	0.023
			Emission Values (tons/MWh)	0.544	0.554	0.530	0.572

Data taken from long term carbon abatement costs and emission rates from Chapter 6 and from Exhibit 2-4

Exhibit C-7: AESC 2011 RGGI Only Case: Avoided Externality Costs

	AESC Long-term Cost	**AESC Allowance Price**		Winter On Peak	Winter Off-Peak	Summer On Peak Energy	Summer Off-Peak
	$/ton (2011$)	$/ton (2011$)	$/ton externality	$/kWh externality			
	a	b	c=a-b	d=c* winter on peak emission rate	e=c* winter off peak emission rate	f=c* summer on peak emission rate	g=c* summer off emission rate
2011	***$80.00***	***$1.89***	***$78.11***	0.042	0.043	0.041	0.045
2012	***$80.00***	***$1.89***	***$78.11***	0.042	0.043	0.041	0.045
2013	***$80.00***	***$1.89***	***$78.11***	0.042	0.043	0.041	0.045
2014	***$80.00***	***$1.89***	***$78.11***	0.042	0.043	0.041	0.045
2015	***$80.00***	***$1.89***	***$78.11***	0.042	0.043	0.041	0.045
2016	***$80.00***	***$1.89***	***$78.11***	0.042	0.043	0.041	0.045
2017	***$80.00***	***$1.89***	***$78.11***	0.042	0.043	0.041	0.045
2018	***$80.00***	***$1.89***	***$78.11***	0.042	0.043	0.041	0.045
2019	***$80.00***	***$1.89***	***$78.11***	0.042	0.043	0.041	0.045
2020	***$80.00***	***$1.89***	***$78.11***	0.042	0.043	0.041	0.045
2021	***$80.00***	***$1.89***	***$78.11***	0.042	0.043	0.041	0.045
2022	***$80.00***	***$1.89***	***$78.11***	0.042	0.043	0.041	0.045
2023	***$80.00***	***$1.89***	***$78.11***	0.042	0.043	0.041	0.045
2024	***$80.00***	***$1.89***	***$78.11***	0.042	0.043	0.041	0.045
2025	***$80.00***	***$1.89***	***$78.11***	0.042	0.043	0.041	0.045
2026	***$80.00***	***$1.89***	***$78.11***	0.042	0.043	0.041	0.045
2027	***$80.00***	***$1.89***	***$78.11***	0.042	0.043	0.041	0.045
2028	***$80.00***	***$1.89***	***$78.11***	0.042	0.043	0.041	0.045
2029	***$80.00***	***$1.89***	***$78.11***	0.042	0.043	0.041	0.045
2030	***$80.00***	***$1.89***	***$78.11***	0.042	0.043	0.041	0.045
2031	***$80.00***	***$1.89***	***$78.11***	0.042	0.043	0.041	0.045
2032	***$80.00***	***$1.89***	***$78.11***	0.042	0.043	0.041	0.045
2033	***$80.00***	***$1.89***	***$78.11***	0.042	0.043	0.041	0.045
2034	***$80.00***	***$1.89***	***$78.11***	0.042	0.043	0.041	0.045
2035	***$80.00***	***$1.89***	***$78.11***	0.042	0.043	0.041	0.045
2036	***$80.00***	***$1.89***	***$78.11***	0.042	0.043	0.041	0.045
2037	***$80.00***	***$1.89***	***$78.11***	0.042	0.043	0.041	0.045
2038	***$80.00***	***$1.89***	***$78.11***	0.042	0.043	0.041	0.045
2039	***$80.00***	***$1.89***	***$78.11***	0.042	0.043	0.041	0.045
2040	***$80.00***	***$1.89***	***$78.11***	0.042	0.043	0.041	0.045
2041	***$80.00***	***$1.89***	***$78.11***	0.042	0.043	0.041	0.045
			Emission Values (tons/MWh)	0.544	0.554	0.530	0.572

Data taken from long term carbon abatement costs and emission rates from Chapter 6 and from Exhibit 2-4

Exhibit C-8: DRIPE Research Bibliography

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Exhibit C-9: Social Discount Rate Summary Table

Table: Summary of Real Discount Rates from Selected Jurisdictions			
Jurisdiction	**Real Discount Rate**	**Citation**	**Rationale**
Connecticut	4.68%	Connecticut Natural Gas Commercial and Industrial Energy-Efficiency Potential Study, Final Report, May 7, 2009. Rate converted from nominal rate of 7.09% to real rate using given inflation rate of 2.3%. http://www.ctsavesenergy.org/files/ CTNGPotential090508FINAL.pdf	None Given
Maine	Based on US Treasuries	"The discount rate used for present value calculations shall be the current yield of long-term (10 years or longer) U.S. Treasury securities, adjusted for inflation." Main PUC 65-407, Chapter 380: Electric Energy Conservation Programs. http://www.efficiencymaine.com/docs/AgencyRules/Chapter%20380.pdf	None given
Massachusetts	Based on US Treasuries	**"**The discount rate used for the Total Resource Cost test should be equal to the historic twelve-month average of the yields of ten-year United States Treasury notes." Investigation by the Department of Public Utilities on its own Motion into Updating its Energy Efficiency Guidelines Consistent with An Act Relative to Green Communities, D.P.U. 08-50-A, March 16, 2009	None given
New Hampshire	5.0%	Additional Opportunities for Energy Efficiency in New Hampshire, Final Report, January 2009. http://www.puc.state.nh.us/Electric/GDS%20Report/NH%20Additional%20EE%20Opportunities%20Study%202-19-09%20-%20Final.pdf	None given
Rhode Island	7.0%	Rhode Island Energy Efficiency and Resources Management Council (EERMC): Opportunity Report – Phase I, July 15, 2008 http://www.rieermc.ri.gov/documents/OER-EERMC-OpportunityRept(7-15-08).pdf	"The discount rate of seven percent is the federally accepted rate used for a CBA and also takes into account the inflation rate (NOAA)"
Vermont	5.7%	Efficiency Vermont Annual Plan 2011, November 1, 2010. http://www.efficiencyvermont.com/docs/about_efficiency_vermont/annual_plans/EVT_AnnualPlan2011.pdf	None given
California	8.15%	Following E3's development of an avoided cost calculation methodology in R.04-04-025, E3 developed the "E3 Calculator," used by all California investor-owned utilities to compute the cost-effectiveness of energy efficiency programs. The calculator is updated periodically (last update 8/13/2010) and is available at: http://www.ethree.com/public_projects/cpuc4.html	
New York	5.5%	New York's System Benefits Charge Programs Evaluation and Status Report, May 2010, http://www.nyserda.org/publications/ first_quarter_report_sbc_rev.pdf	None given
Oregon	5.2%	Energy Trust of Oregon. "4.06.000-P: Cost Effectiveness Policy and General Methodology for Energy Trust of Oregon." February 13, 2008. Available at: http://energytrust.org/library/policies/4.06.000.pdf	None given
Washington (1)	Based on utility WACC	*Washington Administrative Code. Chapter 194-37 WAC: Energy Independence. Last updated March 18, 2008. Available at: http://apps.leg.wa.gov/wac/default.aspx?cite=194-37&full=true*	

(1) The Northwest Power and Conservation Council (NWPCC) used a 5% real discount rate in its Sixth Annual "Northwest Power Plan," released February 2010. Utility conservation targets are based on resource potential identified by the NWPCC.

Appendix D: Avoided Natural Gas Cost Results

Table of Exhibits

Exhibit D-1: Avoided Cost of Natural Gas Delivered to Retail Customers by End Use for Northern Central New England Assuming Some Avoidable Retail Margin (2011$/MMBtu)

	RESIDENTIAL				COMMERCIAL & INDUSTRIAL			ALL
Year	Non Heating	Hot Water annual	Heating	All	Non Heating annual	Heating	All	RETAIL END USES
2011	5.82	5.82	7.35	7.11	5.95	7.18	6.80	6.95
2012	6.34	6.34	7.80	7.58	6.46	7.64	7.28	7.43
2013	6.54	6.54	8.01	7.79	6.67	7.85	7.49	7.64
2014	6.82	6.82	8.39	8.14	6.95	8.23	7.84	7.99
2015	7.39	7.39	8.86	8.63	7.51	8.69	8.33	8.48
2016	7.42	7.42	8.88	8.66	7.55	8.71	8.36	8.51
2017	7.40	7.40	8.87	8.64	7.52	8.70	8.34	8.49
2018	7.42	7.42	8.89	8.67	7.55	8.73	8.37	8.52
2019	7.47	7.47	8.95	8.72	7.59	8.78	8.42	8.57
2020	7.56	7.56	9.04	8.82	7.68	8.88	8.51	8.66
2021	7.66	7.66	9.15	8.92	7.78	8.98	8.62	8.77
2022	7.79	7.79	9.32	9.08	7.91	9.15	8.78	8.93
2023	8.07	8.07	9.59	9.35	8.19	9.42	9.05	9.20
2024	8.26	8.26	9.76	9.53	8.38	9.59	9.22	9.37
2025	8.33	8.33	9.84	9.61	8.46	9.68	9.31	9.46
2026	8.45	8.45	9.98	9.74	8.58	9.81	9.44	9.59
2027	8.58	8.58	10.11	9.87	8.70	9.94	9.57	9.72
2028	8.71	8.71	10.25	10.00	8.83	10.08	9.70	9.85
2029	8.84	8.84	10.38	10.13	8.96	10.21	9.83	9.98
2030	8.97	8.97	10.52	10.27	9.09	10.35	9.97	10.12
2031	9.10	9.10	10.66	10.41	9.23	10.49	10.11	10.26
2032	9.24	9.24	10.80	10.55	9.36	10.63	10.25	10.40
2033	9.38	9.38	10.94	10.69	9.50	10.78	10.39	10.54
2034	9.52	9.52	11.09	10.83	9.64	10.92	10.53	10.68
2035	9.66	9.66	11.23	10.97	9.78	11.07	10.68	10.82
2036	9.80	9.80	11.38	11.12	9.92	11.22	10.83	10.97
2037	9.95	9.95	11.53	11.27	10.07	11.37	10.97	11.12
2038	10.10	10.10	11.69	11.42	10.22	11.52	11.13	11.27
2039	10.25	10.25	11.84	11.57	10.37	11.68	11.28	11.42
2040	10.40	10.40	12.00	11.73	10.52	11.84	11.44	11.58
2041	10.56	10.56	12.16	11.88	10.67	12.00	11.59	11.74
Levelized (2012-2021) (a)	7.17	7.17	8.66	8.43	7.30	8.49	8.13	8.28
Levelized (2012-2026)	7.47	7.47	8.96	8.73	7.59	8.79	8.43	8.58
Levelized (2012-2041) (b)	8.29	8.29	9.81	9.57	8.41	9.65	9.27	9.42

(a) Real (constant $) riskless annual rate of return in %: 2.465%
(b) Values from 2027-2041 extrapolated from Compound Annual Growth Rate (2017-2026)

Exhibit D-2: Avoided Cost of Natural Gas Delivered to Retail Customers by End Use for Southern New England Assuming Some Avoidable Retail Margin (2011$/MMBtu)

	RESIDENTIAL				COMMERCIAL & INDUSTRIAL			ALL RETAIL END USES
Year	Non Heating	Hot Water annual	Heating	All	Non Heating annual	Heating	All	
2011	5.97	5.97	7.74	7.46	5.91	7.17	6.79	7.10
2012	6.49	6.49	8.21	7.94	6.43	7.64	7.27	7.58
2013	6.70	6.70	8.42	8.15	6.64	7.86	7.49	7.80
2014	6.98	6.98	8.81	8.51	6.92	8.24	7.84	8.15
2015	7.56	7.56	9.28	9.01	7.50	8.71	8.34	8.65
2016	7.59	7.59	9.30	9.04	7.53	8.74	8.37	8.68
2017	7.57	7.57	9.29	9.02	7.51	8.72	8.35	8.66
2018	7.59	7.59	9.32	9.05	7.53	8.75	8.38	8.69
2019	7.64	7.64	9.37	9.10	7.58	8.80	8.43	8.74
2020	7.73	7.73	9.47	9.20	7.67	8.90	8.53	8.84
2021	7.83	7.83	9.58	9.30	7.77	9.01	8.63	8.94
2022	7.96	7.96	9.75	9.46	7.90	9.18	8.80	9.10
2023	8.25	8.25	10.03	9.74	8.19	9.46	9.07	9.38
2024	8.44	8.44	10.20	9.92	8.38	9.63	9.25	9.56
2025	8.51	8.51	10.29	10.00	8.45	9.72	9.33	9.64
2026	8.64	8.64	10.42	10.14	8.58	9.85	9.47	9.78
2027	8.77	8.77	10.56	10.27	8.71	9.99	9.60	9.91
2028	8.90	8.90	10.69	10.40	8.84	10.13	9.74	10.04
2029	9.03	9.03	10.83	10.54	8.97	10.26	9.87	10.18
2030	9.16	9.16	10.97	10.67	9.10	10.40	10.01	10.32
2031	9.30	9.30	11.11	10.81	9.24	10.55	10.15	10.46
2032	9.43	9.43	11.25	10.95	9.37	10.69	10.29	10.60
2033	9.57	9.57	11.40	11.10	9.51	10.84	10.44	10.74
2034	9.71	9.71	11.55	11.24	9.66	10.99	10.58	10.89
2035	9.86	9.86	11.69	11.39	9.80	11.14	10.73	11.03
2036	10.00	10.00	11.85	11.54	9.95	11.29	10.88	11.18
2037	10.15	10.15	12.00	11.69	10.09	11.44	11.03	11.34
2038	10.30	10.30	12.15	11.84	10.24	11.60	11.19	11.49
2039	10.45	10.45	12.31	11.99	10.40	11.76	11.35	11.64
2040	10.61	10.61	12.47	12.15	10.55	11.92	11.50	11.80
2041	10.77	10.77	12.63	12.31	10.71	12.08	11.67	11.96
Levelized (2012-2021) (a)	7.34	7.34	9.08	8.80	7.28	8.51	8.14	8.45
Levelized (2012-2026)	7.64	7.64	9.39	9.11	7.58	8.82	8.44	8.75
Levelized (2012-2041) (b)	8.47	8.47	10.25	9.96	8.41	9.69	9.30	9.61

(a) Real (constant $) riskless annual rate of return in %: 2.465%
(b) Values from 2027-2041 extrapolated from Compound Annual Growth Rate (2017-2026)

Exhibit D-3: Avoided Cost of Natural Gas Delivered to Retail Customers by End Use for Vermont Gas Systems Assuming Some Avoidable Retail Margin (2011$/MMBtu)

	RESIDENTIAL				COMMERCIAL & INDUSTRIAL			ALL RETAIL END USES
Year	Non Heating	Hot Water annual	Heating	All	Non Heating annual	Heating	All	
2011	6.11	6.11	8.48	7.97	5.87	7.68	7.14	7.45
2012	6.55	6.55	8.87	8.37	6.31	8.06	7.54	7.85
2013	6.73	6.73	9.05	8.55	6.49	8.25	7.72	8.04
2014	6.99	6.99	9.41	8.88	6.75	8.61	8.05	8.37
2015	7.46	7.46	9.78	9.28	7.23	8.98	8.45	8.77
2016	7.49	7.49	9.80	9.30	7.26	8.99	8.47	8.79
2017	7.47	7.47	9.79	9.29	7.24	8.98	8.46	8.78
2018	7.50	7.50	9.81	9.31	7.26	9.01	8.48	8.80
2019	7.53	7.53	9.86	9.36	7.30	9.06	8.53	8.85
2020	7.61	7.61	9.95	9.45	7.38	9.14	8.61	8.93
2021	7.70	7.70	10.04	9.54	7.46	9.24	8.70	9.02
2022	7.82	7.82	10.20	9.68	7.58	9.40	8.85	9.17
2023	8.06	8.06	10.44	9.92	7.82	9.63	9.09	9.41
2024	8.22	8.22	10.58	10.07	7.99	9.77	9.23	9.55
2025	8.29	8.29	10.65	10.14	8.05	9.85	9.31	9.63
2026	8.40	8.40	10.77	10.26	8.16	9.97	9.42	9.74
2027	8.51	8.51	10.89	10.37	8.27	10.09	9.54	9.86
2028	8.62	8.62	11.01	10.49	8.38	10.20	9.65	9.97
2029	8.73	8.73	11.12	10.60	8.49	10.32	9.77	10.09
2030	8.84	8.84	11.24	10.72	8.61	10.44	9.89	10.21
2031	8.96	8.96	11.36	10.84	8.72	10.56	10.01	10.33
2032	9.07	9.07	11.49	10.96	8.84	10.69	10.13	10.45
2033	9.19	9.19	11.61	11.08	8.96	10.81	10.25	10.57
2034	9.31	9.31	11.73	11.20	9.08	10.94	10.38	10.69
2035	9.43	9.43	11.86	11.33	9.20	11.06	10.50	10.82
2036	9.56	9.56	11.99	11.45	9.32	11.19	10.63	10.94
2037	9.68	9.68	12.11	11.58	9.45	11.32	10.76	11.07
2038	9.81	9.81	12.24	11.70	9.57	11.45	10.89	11.20
2039	9.93	9.93	12.38	11.83	9.70	11.59	11.02	11.33
2040	10.06	10.06	12.51	11.97	9.83	11.72	11.15	11.46
2041	10.19	10.19	12.64	12.10	9.97	11.86	11.29	11.60
Levelized (2012-2021) (a)	7.28	7.28	9.61	9.11	7.04	8.81	8.28	8.60
Levelized (2012-2026)	7.54	7.54	9.88	9.37	7.30	9.08	8.54	8.86
Levelized (2012-2041) (b)	8.25	8.25	10.62	10.10	8.01	9.82	9.28	9.59

(a) Real (constant $) riskless annual rate of return in %: 2.465%

(b) Values from 2027-2041 extrapolated from Compound Annual Growth Rate (2017-2026)

Exhibit D-4: Avoided Cost of Natural Gas Delivered to Retail Customers by End Use for Northern and Central New England Assuming No Avoidable Retail Margin (2011$/MMBtu)

Year	END-USE LOAD TYPE Heating	Non-Heating	All	Annual Average	Annual Henry Hub Price
2011	5.96	5.30	5.76	5.30	4.37
2012	6.42	5.81	6.24	5.81	4.91
2013	6.63	6.02	6.45	6.02	5.10
2014	7.01	6.30	6.80	6.30	5.29
2015	7.48	6.86	7.29	6.86	5.91
2016	7.50	6.90	7.32	6.90	5.96
2017	7.48	6.87	7.30	6.87	5.93
2018	7.51	6.90	7.33	6.90	5.95
2019	7.57	6.94	7.38	6.94	5.98
2020	7.66	7.03	7.47	7.03	6.06
2021	7.77	7.13	7.58	7.13	6.16
2022	7.94	7.26	7.74	7.26	6.25
2023	8.21	7.54	8.01	7.54	6.52
2024	8.38	7.73	8.18	7.73	6.72
2025	8.46	7.81	8.27	7.81	6.78
2026	8.60	7.93	8.40	7.93	6.89
2027	8.73	8.05	8.53	8.05	7.04
2028	8.87	8.18	8.66	8.18	7.20
2029	9.01	8.31	8.80	8.31	7.41
2030	9.15	8.45	8.94	8.45	7.33
2031	9.29	8.58	9.08	8.58	7.34
2032	9.43	8.72	9.22	8.72	7.49
2033	9.58	8.86	9.36	8.86	7.63
2034	9.73	9.00	9.51	9.00	7.66
2035	9.88	9.14	9.66	9.14	7.83
2036	10.03	9.29	9.81	9.29	7.96
2037	10.19	9.44	9.96	9.44	8.10
2038	10.35	9.59	10.12	9.59	8.24
2039	10.51	9.74	10.28	9.74	8.37
2040	10.67	9.90	10.44	9.90	8.52
2041	10.84	10.06	10.60	10.06	8.66
Levelized (2012-2021)	7.28	6.65	7.09	6.65	5.70
Levelized (2012-2026)	7.58	6.94	7.39	6.94	5.97
Levelized (2012-2041)	8.44	7.77	8.24	7.77	6.69

15 Years (2012 - 2026) at the Real (constant $) Discont Rate 2.465%
Values for 2027-2041, extrapolated from CAGR of 2017-2026.
Henry Hub Price for 2036-2041, extrapolated from CAGR of 2017-2026

Exhibit D-5: Avoided Cost of Natural Gas Delivered to Retail Customers by End Use for Southern New England Assuming No Avoidable Retail Margin (2011$/MMBtu)

Year	END-USE LOAD TYPE Heating	Non-Heating	All	Annual Average	Annual Henry Hub Price
2011	6.16	5.37	5.92	5.37	4.37
2012	6.63	5.89	6.41	5.89	4.91
2013	6.84	6.10	6.62	6.10	5.10
2014	7.23	6.38	6.97	6.38	5.29
2015	7.70	6.95	7.48	6.95	5.91
2016	7.72	6.99	7.50	6.99	5.96
2017	7.71	6.97	7.49	6.97	5.93
2018	7.74	6.99	7.51	6.99	5.95
2019	7.79	7.03	7.56	7.03	5.98
2020	7.89	7.13	7.66	7.13	6.06
2021	7.99	7.23	7.77	7.23	6.16
2022	8.17	7.36	7.93	7.36	6.25
2023	8.45	7.64	8.21	7.64	6.52
2024	8.62	7.84	8.38	7.84	6.72
2025	8.70	7.91	8.47	7.91	6.78
2026	8.84	8.04	8.60	8.04	6.89
2027	8.96	8.15	8.72	8.15	7.04
2028	9.08	8.26	8.83	8.26	7.20
2029	9.20	8.37	8.95	8.37	7.41
2030	9.33	8.49	9.07	8.49	7.33
2031	9.45	8.61	9.20	8.61	7.34
2032	9.58	8.73	9.32	8.73	7.49
2033	9.70	8.85	9.45	8.85	7.63
2034	9.83	8.97	9.58	8.97	7.66
2035	9.97	9.09	9.70	9.09	7.83
2036	10.10	9.22	9.84	9.22	7.95
2037	10.23	9.35	9.97	9.35	8.06
2038	10.37	9.48	10.10	9.48	8.18
2039	10.51	9.61	10.24	9.61	8.30
2040	10.65	9.74	10.38	9.74	8.42
2041	10.79	9.88	10.52	9.88	8.54
Levelized (2012-2021)	7.50	6.74	7.27	6.74	5.70
Levelized (2012-2026)	7.81	7.04	7.57	7.04	5.97
Levelized (2012-2041)	8.62	7.81	8.38	7.81	6.68

15 Years (2012 - 2026) at the Real (constant $) Discont Rate 2.465%
Values for 2027-2041, extrapolated from CAGR of 2017-2026.
Henry Hub Price for 2036-2041, extrapolated from CAGR of 2017-2026

Exhibit D-6: Avoided Cost of Natural Gas Delivered to Retail Customers by End Use for Vermont Gas System Assuming No Avoidable Retail Margin (2011$/MMBtu)

Year	END-USE LOAD TYPE Heating	Non-Heating	All	Annual Average	Annual Henry Hub Price
2011	7.23	5.63	6.75	5.63	4.37
2012	7.62	6.07	7.15	6.07	4.91
2013	7.80	6.25	7.34	6.25	5.10
2014	8.16	6.51	7.66	6.51	5.29
2015	8.53	6.99	8.07	6.99	5.91
2016	8.55	7.02	8.09	7.02	5.96
2017	8.54	7.00	8.08	7.00	5.93
2018	8.56	7.02	8.10	7.02	5.95
2019	8.61	7.06	8.15	7.06	5.98
2020	8.70	7.14	8.23	7.14	6.06
2021	8.79	7.22	8.32	7.22	6.16
2022	8.95	7.34	8.47	7.34	6.25
2023	9.18	7.58	8.70	7.58	6.52
2024	9.32	7.75	8.85	7.74	6.72
2025	9.40	7.81	8.92	7.81	6.78
2026	9.52	7.92	9.04	7.92	6.89
2027	9.64	8.03	9.16	8.03	7.04
2028	9.76	8.14	9.27	8.14	7.20
2029	9.88	8.25	9.39	8.25	7.41
2030	10.00	8.37	9.51	8.37	7.33
2031	10.12	8.48	9.63	8.48	7.34
2032	10.24	8.60	9.75	8.60	7.49
2033	10.37	8.72	9.87	8.72	7.63
2034	10.49	8.84	10.00	8.84	7.66
2035	10.62	8.96	10.12	8.96	7.83
2036	10.75	9.09	10.25	9.09	7.96
2037	10.88	9.21	10.38	9.21	8.10
2038	11.02	9.34	10.51	9.34	8.24
2039	11.15	9.47	10.65	9.47	8.37
2040	11.29	9.60	10.78	9.60	8.52
2041	11.42	9.74	10.92	9.73	8.66
Levelized (2012-2021)	8.36	6.80	7.89	6.80	5.70
Levelized (2012-2026)	8.63	7.06	8.16	7.06	5.97
Levelized (2012-2041)	9.37	7.77	8.89	7.77	6.69

15 Years (2012 - 2026) at the Real (constant $) Discont Rate 2.465%
Values for 2027-2041, extrapolated from CAGR of 2017-2026.
Henry Hub Price for 2036-2041, extrapolated from CAGR of 2017-2026

Exhibit D-7: Avoided Cost of Gas Delivered to LDC's by Month: Northern and Central New England via Tennessee Gas Pipeline ($2011/Dekatherm)

	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	PEAK DAY (a)	Annual Henry Hub Price (2011$)
Demand Cash Cost (b)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.565	$0.680	$0.917	$0.667	$0.541	$84.786	
Variable Cash Cost (c)	$0.152	$0.152	$0.152	$0.152	$0.152	$0.152	$0.152	$0.190	$0.380	$0.441	$0.428	$0.338	$0.957	
Ratio of Gas Purchased to Delivered	1.071	1.071	1.071	1.071	1.071	1.071	1.071	1.089	1.095	1.105	1.099	1.092	1.093	
2011	4.572	4.587	4.637	4.698	4.741	4.760	4.819	5.664	6.076	6.653	6.293	6.056	90.370	4.37
2012	5.115	5.133	5.189	5.257	5.305	5.327	5.393	6.268	6.693	7.031	6.651	6.358	90.940	4.91
2013	5.310	5.328	5.386	5.457	5.507	5.530	5.599	6.484	6.914	7.246	6.861	6.563	91.143	5.10
2014	5.500	5.519	5.580	5.653	5.705	5.728	5.800	6.695	7.130	7.748	7.368	7.122	91.343	5.29
2015	6.132	6.153	6.220	6.303	6.360	6.387	6.466	7.397	7.847	8.071	7.664	7.331	92.004	5.91
2016	6.181	6.202	6.270	6.353	6.411	6.437	6.518	7.451	7.902	8.073	7.663	7.318	92.055	5.96
2017	6.149	6.170	6.238	6.320	6.378	6.404	6.484	7.415	7.866	8.072	7.664	7.327	92.022	5.93
2018	6.171	6.191	6.260	6.342	6.401	6.427	6.507	7.440	7.891	8.102	7.694	7.357	92.044	5.95
2019	6.201	6.222	6.290	6.373	6.432	6.458	6.539	7.473	7.925	8.172	7.764	7.434	92.076	5.98
2020	6.286	6.307	6.377	6.461	6.520	6.547	6.629	7.568	8.021	8.273	7.863	7.533	92.165	6.06
2021	6.381	6.402	6.473	6.559	6.619	6.646	6.729	7.673	8.129	8.378	7.966	7.633	92.264	6.16
2022	6.474	6.496	6.568	6.655	6.716	6.743	6.828	7.777	8.235	8.601	8.191	7.879	92.362	6.25
2023	6.749	6.772	6.846	6.937	7.001	7.030	7.118	8.082	8.547	8.861	8.442	8.116	92.650	6.52
2024	6.951	6.975	7.052	7.145	7.211	7.241	7.332	8.307	8.777	8.996	8.569	8.221	92.862	6.72
2025	7.014	7.038	7.116	7.210	7.277	7.307	7.398	8.377	8.848	9.095	8.668	8.324	92.928	6.78
2026	7.122	7.146	7.225	7.321	7.388	7.418	7.512	8.496	8.970	9.246	8.817	8.476	93.040	6.89
Levelized 2012-2026(d)	6.191	6.212	6.281	6.364	6.422	6.448	6.529	7.463	7.914	8.202	7.795	7.474	92.066	
Simple Average (2012-2026)	6.249	6.270	6.339	6.423	6.482	6.509	6.590	7.527	7.980	8.264	7.856	7.533	92.126	

(a) Peak day avoided cost is calculated based on currently effective rates, which are the basis for the monthly avoided costs.
(b) The cash costs paid to pipelines as demand charges to reserve transportation and storage capacity.
(c) The variable cash cost is primarily the cash paid to pipelines for using the pipelines to transport and store natural gas plus the demand charges at 100% load factor to move gas into storage.
(d) Real (constant $) riskless annual rate of return in %: 2.465%

Exhibit D-8: Avoided Cost of Gas Delivered to LDC's by Month: Southern New England via Texas Eastern and Algonquin Gas Pipelines ($2011/Dekatherm)

	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	PEAK DAY (a)	Annual Henry Hub Price (2011$)
Demand Cash Cost (b)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.831	$0.960	$1.225	$0.910	$0.777	$100.126	
Variable Cash Cost (c)	$0.050	$0.050	$0.050	$0.050	$0.050	$0.050	$0.050	$0.085	$0.260	$0.315	$0.303	$0.221	$0.792	
Ratio of Gas Purchased to Delivered	1.084	1.084	1.084	1.084	1.084	1.084	1.084	1.091	1.117	1.130	1.124	1.113	1.136	
2011	4.523	4.539	4.590	4.651	4.694	4.714	4.774	5.831	6.338	6.949	6.522	6.272	105.729	4.37
2012	5.074	5.091	5.148	5.217	5.266	5.288	5.355	6.436	6.967	7.337	6.890	6.582	106.321	4.91
2013	5.271	5.289	5.348	5.420	5.470	5.493	5.563	6.653	7.193	7.557	7.105	6.791	106.533	5.10
2014	5.464	5.482	5.544	5.618	5.671	5.694	5.767	6.865	7.413	8.068	7.620	7.359	106.740	5.29
2015	6.103	6.124	6.192	6.275	6.334	6.360	6.441	7.567	8.144	8.401	7.926	7.574	107.427	5.91
2016	6.152	6.173	6.242	6.326	6.385	6.412	6.493	7.621	8.201	8.403	7.925	7.561	107.481	5.96
2017	6.120	6.141	6.210	6.293	6.352	6.378	6.459	7.586	8.164	8.402	7.926	7.570	107.446	5.93
2018	6.142	6.163	6.232	6.316	6.375	6.401	6.483	7.610	8.189	8.433	7.956	7.601	107.470	5.95
2019	6.172	6.193	6.263	6.347	6.406	6.433	6.515	7.643	8.224	8.504	8.028	7.679	107.502	5.98
2020	6.258	6.280	6.350	6.436	6.496	6.523	6.606	7.738	8.323	8.607	8.129	7.780	107.595	6.06
2021	6.354	6.376	6.448	6.534	6.596	6.623	6.707	7.844	8.432	8.715	8.234	7.882	107.698	6.16
2022	6.449	6.471	6.544	6.632	6.694	6.721	6.807	7.948	8.540	8.942	8.463	8.132	107.800	6.25
2023	6.727	6.750	6.826	6.918	6.982	7.011	7.101	8.253	8.858	9.208	8.720	8.373	108.099	6.52
2024	6.932	6.956	7.034	7.128	7.195	7.225	7.317	8.478	9.093	9.346	8.851	8.481	108.319	6.72
2025	6.996	7.020	7.099	7.194	7.261	7.292	7.384	8.549	9.166	9.448	8.952	8.586	108.388	6.78
2026	7.104	7.129	7.209	7.306	7.374	7.405	7.499	8.668	9.290	9.601	9.103	8.741	108.505	6.89
Levelized 2012-2026 (d)	6.163	6.184	6.253	6.337	6.397	6.423	6.505	7.633	8.213	8.534	8.060	7.719	107.492	
Simple Average (2012-2026)	6.221	6.243	6.313	6.397	6.457	6.484	6.566	7.697	8.280	8.598	8.122	7.779	107.555	

(a) Peak day avoided cost is calculated based on the Legacy Rates, which are the basis for the monthly avoided costs.
(b) The cash costs paid to pipelines as demand charges to reserve transportation and storage capacity.
(c) The variable cash cost is primarily the cash paid to pipelines for using the pipelines to transport and store natural gas plus the demand charges at 10% load factor to move gas into storage.
(d) Real (constant $) Discount Rate %: 2.465%

Exhibit D-9: Avoided Cost of Gas Delivered to LDCs by Month: Vermont Gas System via TransCanada Gas Pipelines ($2011/Dekatherm)

	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	PEAK DAY (a) Rates	Annual Henry Hub Price
Demand Cash Cost (b)	$0.059	$0.000	$0.000	$0.000	$0.000	$0.000	$0.009	$1.848	$1.796	$2.303	$1.931	$1.757	$191.489	
Variable Cash Cost (c)	$0.145	$0.171	$0.171	$0.171	$0.171	$0.171	$0.160	$1.141	$1.288	$1.271	$1.367	$0.745	$4.055	
Ratio of Gas Purchased to Delivered	1.027	1.032	1.032	1.032	1.032	1.032	1.030	1.042	1.039	1.037	1.039	1.031	1.077	
2011	4.189	4.013	4.056	4.109	4.146	4.163	4.283	7.232	7.605	8.483	8.046	7.280	$199.65	4.369
2012	4.667	4.486	4.534	4.594	4.635	4.654	4.784	7.749	8.146	8.771	8.337	7.516	$200.16	4.907
2013	4.838	4.655	4.706	4.767	4.810	4.830	4.963	7.934	8.340	8.960	8.521	7.697	$200.34	5.099
2014	5.006	4.820	4.873	4.937	4.981	5.002	5.138	8.115	8.530	9.463	8.998	8.229	$200.51	5.287
2015	5.562	5.369	5.428	5.499	5.549	5.572	5.720	8.716	9.159	9.671	9.217	8.361	$201.10	5.912
2016	5.605	5.412	5.471	5.543	5.593	5.616	5.765	8.762	9.208	9.661	9.210	8.343	$201.15	5.960
2017	5.577	5.384	5.443	5.514	5.565	5.587	5.736	8.732	9.176	9.668	9.215	8.356	$201.12	5.928
2018	5.596	5.403	5.462	5.534	5.584	5.607	5.756	8.753	9.198	9.695	9.241	8.383	$201.14	5.950
2019	5.622	5.429	5.488	5.560	5.611	5.634	5.783	8.781	9.228	9.764	9.307	8.455	$201.16	5.980
2020	5.697	5.503	5.563	5.636	5.688	5.711	5.862	8.862	9.313	9.856	9.396	8.543	$201.24	6.064
2021	5.781	5.586	5.647	5.721	5.773	5.797	5.949	8.953	9.407	9.948	9.486	8.632	$201.33	6.158
2022	5.863	5.667	5.729	5.804	5.857	5.881	6.035	9.041	9.500	10.170	9.696	8.865	$201.42	6.250
2023	6.104	5.905	5.970	6.049	6.104	6.129	6.288	9.303	9.774	10.390	9.912	9.067	$201.67	6.521
2024	6.283	6.081	6.148	6.229	6.286	6.312	6.475	9.495	9.976	10.490	10.014	9.148	$201.86	6.722
2025	6.338	6.136	6.204	6.285	6.343	6.369	6.533	9.555	10.039	10.584	10.104	9.243	$201.92	6.784
2026	6.433	6.230	6.298	6.381	6.439	6.466	6.632	9.657	10.145	10.723	10.238	9.381	$202.02	6.890
Levelized (d)	5.614	5.421	5.480	5.552	5.603	5.626	5.775	8.772	9.218	9.800	9.340	8.496	$201.16	
Simple Average	5.665	5.471	5.531	5.604	5.655	5.678	5.828	8.827	9.276	9.854	9.393	8.548	$201.21	

(a) Peak day avoided cost is calculated based using gas stored in underground storage for one peak day. Thus, the annual demand charges for transporting gas from storage to Phillipsburg are charged to that one peak day.
(b) The cash costs paid to pipelines as demand charges to reserve transportation and storage capacity.
(c) The variable cash cost is primarily the cash paid to pipelines for using the pipelines to transport and store natural gas, usage charges, plus the demand charges at 100% load factor to move gas into storage.
(d) Real (constant $) riskless annual rate of return i 2.465% (2012-2026)

Appendix E: Avoided Costs of Other Fuels

Table of Exhibits

Exhibit E-1: AESC 2011 Forecast Weighted Average Avoided Cost of Petroleum Fuels by Sector and Other Fuels

	Fuel Oils							Other Fuels		
	Residential	Commercial			Industrial			Residential		
Year	Distillate Fuel Oil/ Biofuel	Distillate Fuel Oil/ Biofuel	Residual Fuel	Sum	Distillate Fuel Oil/ Biofuel	Residual Fuel Oil	Sum	Wood	Kerosene	Propane
	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu
	2011$	2011$	2011$	2011$	2011$	2011$	2011$	2011$	2011$	2011$
2011	$27.00	$19.85	$3.06	$22.90	$10.27	$9.48	$19.75	10.08	26.75	41.28
2012	$26.22	$18.74	$3.55	$22.29	$10.62	$9.24	$19.86	9.78	25.97	39.36
2013	$25.44	$18.17	$3.66	$21.83	$10.87	$8.95	$19.82	9.49	25.20	37.77
2014	$24.69	$17.58	$3.72	$21.30	$10.98	$8.61	$19.60	9.21	24.46	36.55
2015	$24.18	$17.14	$3.82	$20.95	$10.97	$8.40	$19.37	9.02	23.96	35.61
2016	$24.14	$17.22	$3.73	$20.96	$11.05	$8.29	$19.34	9.01	23.92	34.74
2017	$23.94	$17.03	$3.77	$20.80	$11.03	$8.21	$19.24	8.93	23.72	34.07
2018	$24.64	$17.49	$3.95	$21.44	$11.43	$8.44	$19.88	9.19	24.41	34.68
2019	$25.09	$17.76	$4.15	$21.91	$11.73	$8.70	$20.43	9.36	24.86	34.95
2020	$25.47	$17.96	$4.28	$22.24	$11.96	$8.79	$20.75	9.50	25.23	35.19
2021	$25.62	$18.03	$4.37	$22.41	$12.06	$8.91	$20.96	9.56	25.38	35.44
2022	$25.83	$18.23	$4.45	$22.68	$12.19	$9.06	$21.25	9.64	25.59	35.65
2023	$26.17	$18.38	$4.55	$22.92	$12.28	$9.19	$21.47	9.76	25.92	35.95
2024	$26.36	$18.44	$4.64	$23.08	$12.34	$9.30	$21.64	9.84	26.11	36.23
2025	$26.67	$18.62	$4.74	$23.35	$12.53	$9.39	$21.92	9.95	26.42	36.50
2026	$26.95	$18.75	$4.81	$23.56	$12.68	$9.42	$22.10	10.06	26.70	36.66
2027	$27.31	$18.95	$4.94	$23.89	$12.88	$9.57	$22.44	10.19	27.06	36.96
2028	$27.67	$19.16	$5.08	$24.23	$13.08	$9.71	$22.79	10.33	27.41	37.26
2029	$28.04	$19.36	$5.22	$24.56	$13.28	$9.86	$23.15	10.46	27.78	37.57
2030	$28.41	$19.57	$5.36	$24.91	$13.49	$10.02	$23.50	10.60	28.14	37.88
2031	$28.79	$19.78	$5.51	$25.25	$13.70	$10.17	$23.87	10.74	28.52	38.19
2032	$29.17	$20.00	$5.66	$25.61	$13.91	$10.33	$24.24	10.88	28.90	38.50
2033	$29.55	$20.21	$5.81	$25.96	$14.13	$10.49	$24.62	11.03	29.28	38.81
2034	$29.95	$20.43	$5.97	$26.33	$14.35	$10.65	$25.00	11.17	29.67	39.13
2035	$30.34	$20.65	$6.13	$26.69	$14.57	$10.81	$25.39	11.32	30.06	39.45
2036	$30.74	$20.87	$6.30	$27.06	$14.80	$10.98	$25.78	11.47	30.46	39.77
2037	$31.15	$21.10	$6.47	$27.44	$15.03	$11.15	$26.18	11.62	30.86	40.10
2038	$31.56	$21.33	$6.65	$27.82	$15.27	$11.32	$26.59	11.78	31.27	40.43
2039	$31.98	$21.56	$6.83	$28.21	$15.51	$11.50	$27.00	11.93	31.68	40.76
2040	$32.41	$21.79	$7.02	$28.61	$15.75	$11.67	$27.42	12.09	32.10	41.09
2041	$32.83	$22.02	$7.21	$29.01	$15.99	$11.85	$27.85	12.25	32.53	41.43
Levelized Costs										
2012-2021	$24.95	$17.72	$3.88	$21.60	$11.24	$8.66	$19.90	$9.31	$24.71	$35.92
2012-2026	$25.37	$17.94	$4.10	$22.05	$11.58	$8.84	$20.42	$9.47	$25.13	$36.00
2012-2041	$27.19	$18.93	$4.86	$23.75	$12.69	$9.56	$22.25	$10.15	$26.94	$37.23

Notes

Calculation based on fuel oil forecast percentages by sector multiplied by fuel oil forecast price by sector

2027-2041 costs extrapolated based on 2017-2026 compound annual growth rate

Exhibit E-2: Crude Oil and Fuel Prices by Sector in New England - AESC 2009 Forecast (2011$)

	Crude Oil Prices				Fuel Prices for Electric Generation in New England			Residential			Commercial			Industrial		
Year	AEO 2010 Forecast Imported Low Sulfur Crude	WTI NYMEX Futures Swaps as of March 18 2011	AESC 2011 Forecast Imported Low-Sulfur Crude	AESC 2011 Forecast Imported Low-Sulfur Crude	Distillate Fuel Oil	Residual Fuel Oil	Steam Coal	Distillate Fuel Oil	Kerosene	Cord Wood	Distillate Fuel Oil	Residual Fuel	Kerosene	Distillate Fuel Oil	Residual Fuel Oil	Kerosene
	$/bbl	$/bbl	$/bbl	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu
	2011$	2011$	2011$	2011$	2011$	2011$	2011$	2011$	2011$	2011$	2011$	2011$	2011$	2011$	2011$	2011$
2011	75.10	105.96	108.07	18.63	21.19	13.22	3.16	27.00	26.75	10.08	24.43	16.30	26.84	24.55	16.30	24.02
2012	81.62	102.67	107.40	18.52	20.83	13.56	3.13	26.22	25.97	9.78	23.84	16.60	26.20	23.97	16.60	23.45
2013	88.13	98.31	106.73	18.40	20.42	13.75	3.08	25.44	25.20	9.49	23.25	16.73	25.56	23.39	16.73	22.88
2014	93.45	95.31	106.06	18.29	19.94	13.78	3.05	24.69	24.46	9.21	22.65	16.62	24.89	22.79	16.62	22.30
2015	97.15	93.40	105.39	18.17	19.62	13.58	3.05	24.18	23.96	9.02	22.38	16.30	24.59	22.63	16.30	22.14
2016	100.98	92.01	104.72	18.06	19.74	13.53	2.97	24.14	23.92	9.01	22.38	16.21	24.59	22.61	16.21	22.12
2017	104.05	90.69	104.05	17.94	19.67	13.49	2.99	23.94	23.72	8.93	22.22	16.15	24.42	22.43	16.15	21.95
2018	107.32	89.64	107.32	18.50	20.33	13.98	2.91	24.64	24.41	9.19	22.91	16.70	25.18	23.13	16.70	22.63
2019	109.44	88.71	109.44	18.87	20.77	14.34	2.92	25.09	24.86	9.36	23.36	17.32	25.67	23.57	17.32	23.06
2020	111.30		111.30	19.19	21.13	14.48	2.77	25.47	25.23	9.50	23.74	17.55	26.10	23.97	17.55	23.45
2021	112.58		112.58	19.41	21.27	14.72	2.76	25.62	25.38	9.56	23.92	17.77	26.29	24.17	17.77	23.65
2022	114.02		114.02	19.66	21.47	14.91	2.73	25.83	25.59	9.64	24.21	18.01	26.61	24.53	18.01	24.00
2023	115.45		115.45	19.91	21.79	15.13	2.72	26.17	25.92	9.76	24.48	18.25	26.90	24.74	18.25	24.21
2024	116.80		116.80	20.14	21.98	15.35	2.71	26.36	26.11	9.84	24.62	18.47	27.06	24.85	18.47	24.32
2025	118.30		118.30	20.40	22.27	15.55	2.71	26.67	26.42	9.95	24.94	18.69	27.41	25.17	18.69	24.63
2026	119.87		119.87	20.67	22.55	15.62	2.72	26.95	26.70	10.06	25.21	18.78	27.71	25.44	18.78	24.90
Levelized Costs																
2012-2016				18.29	20.12	13.64	3.06	24.96	24.73	9.31	22.92	16.50	25.19	23.09	16.50	22.60
2012-2021				18.51	20.35	13.90	2.97	24.95	24.71	9.31	23.06	16.77	25.34	23.25	16.77	22.75
2012-2026				18.99	20.84	14.31	2.90	25.37	25.13	9.47	23.53	17.26	25.86	23.75	17.26	23.24

Notes
Crude Oil forecasts based on EIA historical and projected values from AEO 2009 Table A12; West Texas Intermediate NYMEX prices as of March 18, 2011
Electric Generation Forecast based on AEO 2011 Table S11; Sector fuel price forecast based on low-sulfur fuel price ratios relative to historic and forecast crude oil prices

Exhibit E-3: Percentage of AESC 2011 Forecast Mix of Petroleum Related Fuels by Grade by Sector

	Residential	Commercial		Industrial	
Year	Distillate Fuel Oil	Distillate Fuel Oil	Residual Fuel	Distillate Fuel Oil	Residual Fuel Oil
	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu
	Percent	Percent	Percent	Percent	Percent
2011	100%	81%	19%	42%	58%
2012	100%	79%	21%	44%	56%
2013	100%	78%	22%	46%	54%
2014	100%	78%	22%	48%	52%
2015	100%	77%	23%	48%	52%
2016	100%	77%	23%	49%	51%
2017	100%	77%	23%	49%	51%
2018	100%	76%	24%	49%	51%
2019	100%	76%	24%	50%	50%
2020	100%	76%	24%	50%	50%
2021	100%	75%	25%	50%	50%
2022	100%	75%	25%	50%	50%
2023	100%	75%	25%	50%	50%
2024	100%	75%	25%	50%	50%
2025	100%	75%	25%	50%	50%
2026	100%	74%	26%	50%	50%

Notes

Calculations based on AEO 2010 Supplemental Table One for New England Fuel and Sector Consumption
Percentages based on 2010 fuel oil forecast of consumption by sector

Exhibit E-4: Pollutant Emission Values (2011$/MMBtu)

	Residential				Commercial				Industrial			
	SO_2	NO_x	CO_2	CO_2 at $80/ton	SO_2	NO_x	CO_2	CO_2 at $80/ton	SO_2	NO_x	CO_2	CO_2 at $80/ton
2011	$0.0003	$0.0148	$0.1635	$6.92	$0.0003	$0.0197	$0.1550	$6.56	$0.0006	$0.0197	$0.1521	$6.44
2012	$0.0002	$0.0095	$0.1635	$6.92	$0.0002	$0.0127	$0.1550	$6.56	$0.0005	$0.0127	$0.1521	$6.44
2013	$0.0001	$0.0089	$0.1635	$6.92	$0.0001	$0.0119	$0.1550	$6.56	$0.0003	$0.0119	$0.1521	$6.44
2014	$0.0001	$0.0091	$0.1635	$6.92	$0.0001	$0.0121	$0.1550	$6.56	$0.0002	$0.0121	$0.1521	$6.44
2015	$0.0001	$0.0092	$0.1635	$6.92	$0.0001	$0.0123	$0.1550	$6.56	$0.0002	$0.0123	$0.1521	$6.44
2016	$0.0001	$0.0094	$0.1635	$6.92	$0.0001	$0.0125	$0.1550	$6.56	$0.0002	$0.0125	$0.1521	$6.44
2017	$0.0001	$0.0096	$0.1635	$6.92	$0.0001	$0.0128	$0.1550	$6.56	$0.0002	$0.0128	$0.1521	$6.44
2018	$0.0001	$0.0098	$1.3235	$6.92	$0.0001	$0.0130	$1.2546	$6.56	$0.0002	$0.0130	$1.2317	$6.44
2019	$0.0001	$0.0100	$1.5808	$6.92	$0.0001	$0.0133	$1.4986	$6.56	$0.0002	$0.0133	$1.4711	$6.44
2020	$0.0001	$0.0102	$1.8381	$6.92	$0.0001	$0.0135	$1.7425	$6.56	$0.0002	$0.0135	$1.7106	$6.44
2021	$0.0001	$0.0104	$2.0955	$6.92	$0.0001	$0.0138	$1.9865	$6.56	$0.0002	$0.0138	$1.9501	$6.44
2022	$0.0001	$0.0106	$2.3528	$6.92	$0.0001	$0.0141	$2.2304	$6.56	$0.0002	$0.0141	$2.1896	$6.44
2023	$0.0001	$0.0108	$2.6101	$6.92	$0.0001	$0.0144	$2.4744	$6.56	$0.0002	$0.0144	$2.4291	$6.44
2024	$0.0001	$0.0110	$2.8675	$6.92	$0.0001	$0.0147	$2.7183	$6.56	$0.0002	$0.0147	$2.6686	$6.44
2025	$0.0001	$0.0113	$3.1248	$6.92	$0.0001	$0.0150	$2.9623	$6.56	$0.0002	$0.0150	$2.9081	$6.44
2026	$0.0001	$0.0114	$3.3822	$6.92	$0.0001	$0.0153	$3.2062	$6.56	$0.0002	$0.0153	$3.1476	$6.44
Levelized (2011$/MMBtu)												
5 year (2012-16)	$0.0001	$0.0092	$0.1635	$6.92	$0.0001	$0.0123	$0.1550	$6.56	$0.0003	$0.0123	$0.1521	$6.44
10 year (2012-21)	$0.0001	$0.0096	$0.7343	$6.92	$0.0001	$0.0128	$0.6961	$6.56	$0.0003	$0.0128	$0.6834	$6.44
15 year (2012-26)	$0.0001	$0.0100	$1.3572	$6.92	$0.0001	$0.0133	$1.2866	$6.56	$0.0003	$0.0133	$1.2631	$6.44

Notes

Based on pollution emission rates for Number 2 fuel oil

Pollutant values based on emission allowance prices detailed in Exhibit 2-4 and Exhibit 6-56.

Appendix 5

EVALUATION STUDIES

STUDY NUMBER	STUDY NAME
2.	Residential and Low-Income Non-Energy Impacts (NEI) Evaluation

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Massachusetts Program Administrators

Massachusetts Special and Cross-Sector Studies Area, Residential and Low-Income Non-Energy Impacts (NEI) Evaluation

FINAL

August 15, 2011

Prepared by: NMR Group, Inc.

Massachusetts Program Administrators

Massachusetts Special and Cross-Sector Studies Area, Residential and Low-Income Non-Energy Impacts (NEI) Evaluation

FINAL

August 15, 2011

Prepared for: Massachusetts Program Administrators

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List of Acronyms

AESC	Avoided Energy Supply Costs
AWWA	American Water Works Association
CA	Conjoint Analysis
CDC	Centers for Disease Control and Prevention
CFC	Chlorofluorocarbon
CHP	Scottish Central Heating Programme
CO2e	Carbon dioxide equivalent
CV	Contingent Valuation
DHW	Domestic Hot Water
DRIPE	Demand Reduction Induced Price Effect
EPA	Environmental Protection Agency
GPM	Gallons per Minute
GWP	Global warming potential
HCFC	Hydrochlorofluorocarbon
HES	Home Energy Solutions
HWAP	Home Weatherization Assistance Program
IAQ	Indoor air quality
IEQ	Indoor environmental quality
IIFB	Insurance Institute Fact Book
LIHEAP	Low Income Home Energy Assistance Program
LIPPT	Low Income Public Purpose Test (California)
NATCEN	the United Kingdom's National Center for Social Research
NEB	Non-energy benefit
NEI	Non-energy impact
NSWMA	National Solid Wastes Management Association
ORNL	Oak Ridge National Laboratory
PCB	Polychlorinated biphenyls
RAD	Responsible Appliance Disposal
RV	Relative Valuation
T&D	Transmission and distribution
TRC	Total Resource Cost
TRM	Technical Reference Manual
VPP	Venture Partners Pilot
VSL	Value of a statistical life
WAP	Weatherization Assistance Program
WARM	Waste Reduction Model
WHO	World Health Organization
WRAP	Weatherization Residential Assistance Partnership
WTP	Willingness to Pay

1. EXECUTIVE SUMMARY

This report presents the findings of the Massachusetts Cross-Cutting Non-Energy Benefits [NEBs] Evaluation. It incorporates findings from a review of the Non-Energy Impacts (NEI) literature, in-depth interviews, and telephone surveys with program participants. It uses these to quantify non-energy benefits, including NEBs for low-income programs. To account for the fact both positive (benefits) and negative impacts can result from energy efficiency programs, we use the term non-energy impacts (NEIs) in this report.

NEIs are a widely recognized but difficult to quantify affect of energy efficiency programs. The impacts of efficiency programs extend beyond electric demand and electricity, gas, and oil consumption energy savings. NEIs have traditionally been characterized by the perspective of the party a particular NEI accrues to, including utilities, participants, and society. For example, utilities can realize a number of financial savings because program participants often have lower energy bills, which can decrease the likelihood that customers experience difficulties with paying their utility bills. Program participants may benefit through reduced water usage from water saving measures or experience increased comfort after a retrofit. Finally, society may realize environmental benefits and positive economic impacts from energy efficiency programs.

NEIs may also be characterized by ease of estimation. Relatively easy to quantify NEIs have engineering estimates that are fairly well established, such as water savings from an energy-efficient dish washer. Some NEIs can be quantified with more effort and less certainty, while other, less tangible NEIs are difficult to quantify.

This evaluation had several objectives. First and foremost, this evaluation sought to reliably quantify NEIs associated with the Program Administrators' (PAs) programs.[1] Through the literature review, this report classifies NEIs in terms of the perspective of the party a particular NEI accrues to (i.e., utility, participant, society) and specifies whether an NEI applies to low-income households, non-low-income households, or both.[2]

Second, the evaluation assesses the reliability of the NEI values found in the literature and the extent to which they apply to the PAs' low-income and residential programs. Classifying and assessing the reliability of the NEIs found in the literature allowed NMR to recommend NEI quantification methods that include deriving values from the literature, from engineering estimates and algorithms, and from data collection through surveys of program participants.

Third, the evaluation quantifies NEIs that apply to the PAs' residential and low-income programs. When possible, NEIs values were derived from the existing literature or by developing modified algorithms from the literature. For residential and low-income program participants, including owners of low-income rental housing, select NEI values were derived by surveys of program participants.[3] In some cases, the evaluation team does not recommend quantifying an NEI. NEIs were not recommended for quantification for one of several reasons:

- The NEI is too hard to quantify meaningfully
- Quantifying the NEI would amount to double counting as the NEI is already accounted for

[1] It is up to the Program Administrators and regulatory bodies to determine the applicability and use of the NEI values in the cost effectiveness tests used by the relevant jurisdictions.

[2] In some cases, the value of the NEI may vary by type of participant.

[3] The following NEIs were examined in the residential and low-income surveys: thermal comfort, reduced noise, property value, equipment maintenance, durability of the home, lighting life and quality, health impacts. The following NEIs were examined in the surveys of owners and managers of low-income rental housing: marketing, equipment maintenance, tenant complaints, tenant turnover, property value, lighting maintenance, durability of the property.

- There is insufficient evidence in the literature for its existence
- The NEI is too intangible

1.1 NEI QUANTIFICATION IN THE LITERATURE

NEIs have been quantified in the literature for a variety of programs by a variety of methods. However, most monetized NEI values reported have been based on low-income weatherization and retrofit programs. Since many of the NEIs are difficult to measure, quantification of these impacts must balance the minimization of uncertainty with evaluation costs. A key consideration in the quantification of NEIs is to ensure that the impacts do not overlap with other benefits that have already been accounted for elsewhere, in order to avoid double-counting of values. For many of the monetized NEI values found in the literature, the authors have attempted to determine whether or not the quantified benefits are overlapping.

The persistence of NEIs is another key consideration. The persistence of benefits is commonly assumed to be equal to the measure life of the installed efficiency measures.[4] When NEIs are estimated in terms of net present value, the NEI reported are sensitive to the assumed benefit horizon (measure life) and discount rates employed in the calculation.

An issue regarding the quantification of NEI values that is not well-addressed in the literature is the portioning out of NEIs over multiple measures. Most programs studied include multiple measures, with NEIs attributed to the installed measures as a group rather than individually. Therefore, NEIs have generally been examined at the program level rather than at the measure level, with notable exceptions of studies that have examined NEIs associated with appliance programs.[5] While most NEIs are attributable to a program, to the extent possible, NMR has recommended NEI values applicable to individual measures.

Finally, when comparing various values for a give NEI reported in the literature, it is important to recognize the variation in program elements, the type and quantity of measures installed, and geographic/climatic differences amongst the programs from which the values were derived, since these factors can influence the reported NEI values.

1.1.1 Utility-Perspective NEIs

Utilities can realize a number of NEIs from their energy efficiency programs in the form of financial savings. Energy-efficient technologies installed by PA programs often result in reduced energy bills for participants, which can decrease the likelihood that customers experience difficulties with paying their utility bills. In turn, utilities realize financial savings through reduced costs associated with arrearages and late payments, uncollectible bills and bad debt write-offs, service terminations and reconnections, bill-related customer calls, and the bill collections process. In addition, utilities may realize savings from their efficiency programs due to a reduction in safety-related emergency calls and reductions in energy that is eligible for a rate discount. Theoretically, most of these benefits could apply to some extent to all PA programs and customers, but the NEI literature has rarely quantified these benefits for non-low-income customers and programs.

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[4] A benefit horizon of ten or 20 years is commonly assumed in the literature (see, for example, Schweitzer and Tonn, 2002; TecMarket Works, SERA and Megdal Associates, 2001; Riggert et al., 1999; and Skumatz and Nordeen, 2002).

[5] Other exceptions would include a study conducted by Smith-McClain, Skumatz and Gardener which examined the impacts of individual weatherization measures on NEI values and found that presence of insulation was the only measure to have a significant impact on NEI values. Other exceptions include several studies that examined NEI values associated with individual appliances (see Fuchs et al., 2005; Skumatz et al, 2005; Stoecklein & Skumatz, 2007)

As utility-perspective NEIs represent tangible benefits in the form of direct monetary savings, they tend to be relatively easy to quantify, compared to Participant- and Societal- perspective NEIs.

1.1.2 Participant-Perspective NEIs – Occupants

Participants can also realize a variety of NEIs from energy efficiency programs. These NEIs are generally considered less tangible and therefore are much more difficult to measure than those from the utility perspective. Some of the participant NEIs are due to subjective, non-material impacts, such as “increased comfort” or “sense of doing good for the environment,” while others, though very tangible—such as improved health or increased property value—are difficult to measure and monetize. When measured and monetized, participant NEIs have often been found to be quite valuable, often exceeding the value of energy savings and NEIs from the societal and utility perspectives.

1.1.3 Societal-Perspective NEIs

A number of NEIs from energy efficiency programs may also accrue to society. NEIs from the societal perspective are indirect program effects not realized solely by utilities or by program participants, but rather by society at large. Much of the latest literature on societal-perspective NEIs focuses on environmental and economic impacts; however, these two societal NEIs are not included in this review because the environmental and economic impacts of the PAs’ programs have been included in the PAs’ three year energy efficiency plans (National Grid et al., 2009; NSTAR et al., 2009). Many of the remaining societal NEIs are sparsely reported and quantified. Examples include equity benefits or reduced societal disparity for the low-income populations, and cost savings to social service agencies resulting from low-income weatherization. When equity benefits associated with low-income programs have been addressed in the literature, improving the economic status of the low-income participants is often the primary program goal. Therefore, these programs tend to emphasize program elements that are not part of the PA programs, such as education, counseling, financial assistance, and job training. Societal NEIs tend to be moderately to very difficult to quantify. Other societal benefits examined by this report include benefits from appliance recycling programs and potential reductions in the costs of medical care due to improved health of program participants.

1.1.4 Participant Perspective NEIs – Owners of Low-Income Housing

A portion of the PAs’ program participants consists of property owners of low-income rental housing, particularly within the multifamily programs. Our review of the literature found no mention of non-energy impacts pertaining to participating owners of low-income rental housing. However, interviews with PA staff identified several potential NEIs, including reduced maintenance pertaining to lighting (attributed to the longer life of a CFL, thus reducing labor costs), reduced maintenance associated with heating and cooling systems, improved marketing of rental property (i.e., a more energy-efficient rental unit is easier to market and rent), and reduced tenant turnover.

1.2 SUMMARY OF NEIs

The NEIs we assessed in this study are summarized in Table 1-1. In general, for utility-perspective NEIs, NMR recommends using values in the literature, or algorithms in the literature using inputs of PA-specific data. For some of the participant-perspective NEIs, NMR recommends values derived from the participant surveys. For other participant-perspective NEIs, NMR recommends using engineering estimates, values in the literature, algorithms in the literature, or not valuing a particular NEI. For societal-perspective NEIs, NMR recommends a mixture of not valuing, using new survey data, or using engineering algorithms. If different NEI values are recommended for low-income and non-low-income programs, the values are designated with an LI (low-income) and NLI (non-low-income) in the table.

When estimating NEIs, it is important to note that free-ridership and spillover should be accounted for in all calculations and estimates for NEIs that apply to non-low-income participants. The summary tables, algorithms, and body of the report do not contain free ridership and spillover factors, as it is assumed that these will be applied to each NEI at the program level, from free ridership and spillover factors derived from other evaluations.

In addition, NMR recommends that the duration of the NEI correspond with the expected life of the corresponding measures associated with each NEI, as reported in the current TRM (Massachusetts Electric and Gas Energy Efficiency Program Administrators, 2010). For NEIs that are estimated on a per participant basis and derived from multiple measures, NMR recommends adopting the methodology used in the current TRM for determining the measure life for the gas weatherization program, whereby the measure life is weighted based on the mix of measures installed. (Massachusetts Electric and Gas Energy Efficiency Program Administrators, 2010).

1.2.1 Utility-Perspective NEIs

Nearly all utility-perspective NEIs arise from programs targeted to low-income customers, wherein the programs reduce energy bills for participants. As a result of reduced energy bills, program participants are less likely to experience difficulties with paying their utility bills and the PAs' realize financial savings. In addition, utilities may realize savings due to a reduction in safety-related emergency calls and insurance costs, due to reduced fires and other emergencies. In general, the utility-perspective NEIs are relatively low in value, typically ranging from less than a dollar to nearly $9 per participant. Most of the NEIs found in the literature apply to the PAs' low-income programs and can be monetized relatively easily from the literature or from algorithms using inputs from the PAs.

1.2.2 Participant-Perspective NEIs - Occupants

Participant-perspective NEIs accrue to participants in both low-income and non-low-income programs, although some participant NEIs are specific to low-income participants. Most of the participant-perspective NEIs found in the literature apply to the PAs' programs. In general, the participant-perspective NEIs are relatively high in value, although the ranges of values found in the literature for many of these NEIs vary considerably. Some of these NEIs are quantifiable with some effort, using data from the PAs, secondary data, and algorithms found in the literature. However, most of the participant-perspective NEIs are difficult to quantify and require primary data collection through participant surveys. In this study NMR quantified a number of these less tangible participant-perspective NEIs, though it should be noted that they can be quantified with only limited certainty.

For some of the participant-perspective NEIs, NMR recommends using values derived from the recently completed NEI surveys. For other participant-perspective NEIs, NMR recommends using engineering estimates, values in the literature, algorithms in the literature, or not valuing a particular NEI.

It is important to note that a number of participant perspective NEIs commonly found in the literature and currently included in the TRM report are derived from customer bill savings. These bill savings partially overlap with avoided costs accounted for in the Avoided Energy Supply Costs (AESC) in New England (Hornby et al., 2011) and included in the TRC calculations. The AESC study estimates a number of avoided costs, including avoided costs of electricity to retail customers and avoided costs to natural gas retail customers. Each set of avoided costs is comprised of several individual costs. For example, avoided costs of electricity to retail customers includes avoided energy costs, avoided capacity costs, avoided environmental regulation compliance costs, demand reduction induced price effects, and avoided costs of local transmission and distribution infrastructure (Hornby et al, 2011). While bill savings and avoided costs partially overlap, they typically differ in part because bill savings are based on average retail savings to participants while avoided costs are based on marginal energy supply costs that are avoided because of the PAs' energy efficiency programs. Theoretically, a participant NEI of bill savings, based on the difference between the avoided energy and capacity costs and participant energy bill savings, could be added to the TRC. However, according to traditional TRC calculation methods, including participant bill savings as a benefit would require including a similar cost in the form of lost PA revenues, thus negating the bill savings benefit.[6] Therefore, there is no additional NEI of participant bill savings.

In addition, NMR does not recommend including any NEIs that are derived from participant bill savings because it would amount to double counting of benefits. To count benefits that derive from bill savings would amount to valuing the additional disposable income (i.e., bill savings) and the ways in which the participants spend the disposable income. For example, a participant may spend the bill savings on food or medicine, leading to improved health. Similarly, participants may use their bill savings to pay energy bills, reducing the incidence of service terminations and the costs associated with service termination and reconnection. But to count both the bill savings and the health benefits or the benefit of reduced service terminations that are derived entirely from the way bill savings are spent is to count the same benefit twice. Other examples of NEIs derived from bill savings include reduced bill-related calls and reduced need to move or forced mobility.

1.2.3 Participant-Perspective NEIs - Owners and Managers of Low-income Rental Housing

Participant Perspective NEIs (Owners of Low-income Rental Housing) were derived from the recently completed NEI surveys.

Table 1-1 provides an overview of all NEIs reviewed in this report, including NMR's recommendation to quantify or not quantify the NEI, the method of quantification, and the recommended value of the NEI (if available). NEI values are reported on a per-housing unit basis. More detailed presentations of the NEI values, including reasons for not quantifying an NEI, can be found in the body of the report.

1.2.4 Societal-Perspective NEIs

The societal-perspective NEIs of interest to the PAs for this literature review (i.e. the non-economic and non-environmental societal NEIs) generally arise from programs targeted to low-income customers. Little work has been done in the area of quantifying these NEIs, and quantification methods are not well-established in the literature. Societal NEIs are generally quantifiable with some effort using secondary data, but the values are of limited certainty.

1.2.5 Non-Resource Benefits

NMR has developed several values for non-resource benefits that pertain to waste reduction attributable to the PAs' Appliance Turn-in Program.

Table 1-1. Summary of Recommended NEI Values

NEI	Quantify (Yes/No)	Method of Quantification	Recommended Value[7]	Duration
UTILITY PERSPECTIVE				
Arrearages	Yes	Literature	$2.61	Annual
Bad debt write-offs	Yes	Literature	$3.74	Annual

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[6] As defined in the *California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects,* the TRC takes into consideration program benefits and costs in terms of the participants and the ratepayers: "In a sense, it is the summation of the benefit and cost terms in the Participant and the Ratepayer Impact Measure tests, where the revenue (bill) change and the incentive terms intuitively cancel (CPUC, 2001, p. 18)."

[7] Recommended values derived from the literature represent the median of the values reported in the recent NEI literature. Values were adjusted to 2010 dollars using an inflation rate of 2.5 percent per year, the same inflation rate used in the PAs' three-year plans.

NEI	Quantify (Yes/No)	Method of Quantification	Recommended Value[7]	Duration
Terminations and reconnections	Yes	Literature	$0.43	Annual
Rate discounts	Yes	Algorithm & PA data	Algorithm	Annual
Complaints and payment plans	No	None for now	None	—
Customer calls	Yes	Literature	$0.58	Annual
Collections notices	Yes	Literature	$0.34	Annual
Safety-related emergency calls	Yes	Literature	$8.43	Annual
Increased electricity system reliability	No	Quantified Elsewhere	None	—
Transmission and distribution savings	No	Quantified Elsewhere	None	—
Insurance savings	Yes	Literature	National WAP Evaluation (2011)	—
PARTICIPANT PESPECTIVE (OCCUPANT)				
Higher comfort levels	Yes	Survey	$125 (NLI retrofits); $77 (NLI new construction) / $101 (LI)	Annual
Improved sense of environmental responsibility	No	Quantified Elsewhere	None	Annual
Quieter interior environment	Yes	Survey	$31 (NLI retrofits); $40 (NLI new construction) / $30 (LI)	Annual
Reduced noise (dishwashers)	No	None for now	None	Annual
Lighting quality & lifetime	Yes	TRM Report	$3.50/CFL fixture; $3.00 per CFL bulb	One time
Increased housing property value	Yes	Survey	$1,998 (NLI retrofits); $72 (NLI RNC/$949 (LI)	One time (Annual for NLI RNC)
Buffers energy price increase	No	Quantified Elsewhere	None	—
Reducing energy expenses, making more money available for other uses, such as health care	No	Quantified Elsewhere	None	—
Reduced need to move and costs of moving, including homelessness	No	Quantified Elsewhere	None	—
Reduced detergent usage (dishwashers)	No	None	None	Annual

NEI	Quantify (Yes/No)	Method of Quantification	Recommended Value[7]	Duration
Reduced water usage and sewer costs (dishwashers)	Yes	Algorithm from literature	$3.70	Annual
Reduced water usage and sewer costs (tankless water heaters)	No	None	—	—
Reduced water usage and sewer costs (faucet aerators)	Yes	Algorithm from literature	Algorithm	Annual
Reduced water usage and sewer costs (low flow showerheads)	Yes	Algorithm from literature	Algorithm	Annual
More durable home and less maintenance	Yes	Survey	$149 (NLI retrofits)/$35 (LI)	Annual
Equipment and appliance maintenance requirements	Yes	Survey	$124 (NLI retrofits)/$54 (LI)	Annual
Health related NEIs	Yes	Survey	$4 (NLI retrofits)/$19 (LI)	Annual
Improved safety (heating system, ventilation, carbon monoxide, fires)	Yes	Algorithm & PA data	$37.40 (avoided fire deaths); $0.03 (avoided fire injuries); $1.24 (avoided fire property damage); $6.38 (avoided CO poisonings; all LI	Annual
Improved safety (lighting)	No	None for now	None	—
Heat (or lack thereof) generated	No	None	None	—
Warm up delay	No	None for now	None	—
Product lifetime	No	None	None	—
Availability of hot water	No	None for now	None	—
Product performance	No	None for now	None	—
Window AC NEIs	Yes	Literature	$49.50	Annual
Bill-related calls	No	Quantified Elsewhere	None	—
Termination and reconnection	No	Quantified Elsewhere	None	—
Reduced transaction costs	No	None	None	—
Education	No	None	None	—
SOCIETAL PERSPECTIVE				

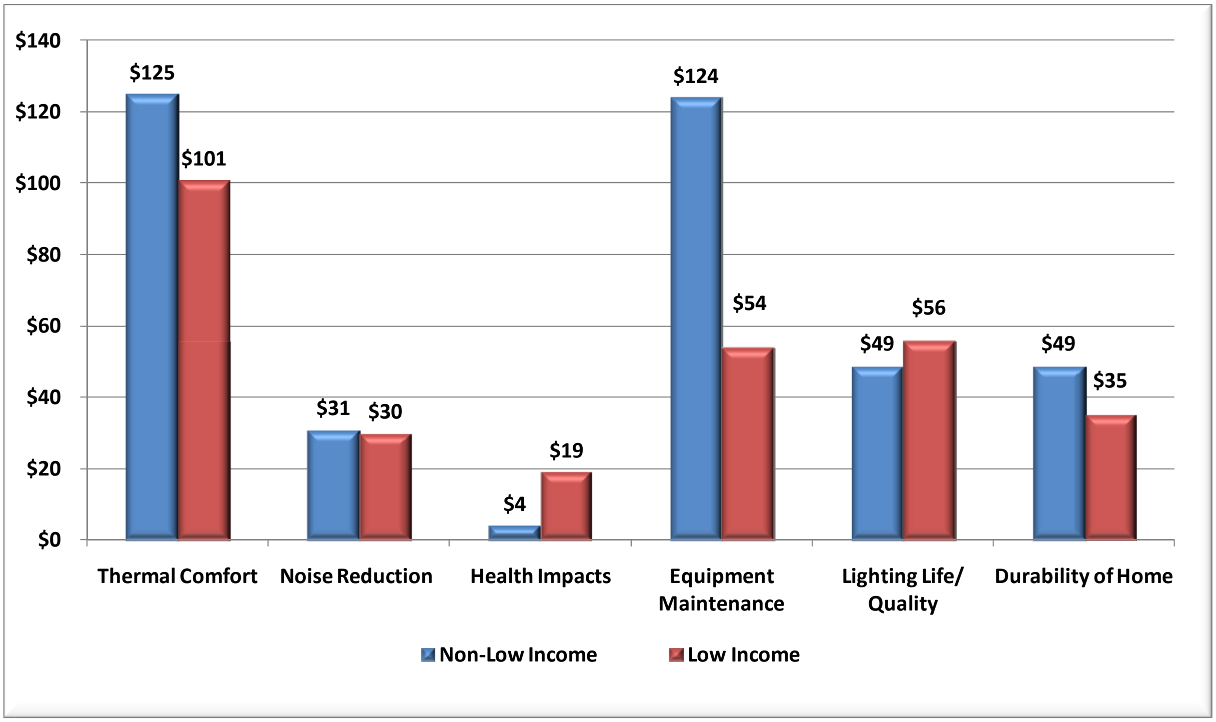
NEI	Quantify (Yes/No)	Method of Quantification	Recommended Value[7]	Duration
Weatherization by utility programs saves costs of inspections and upgrades by other agencies	No	None for now	None	—
Equity and Hardship	No	None	None	—
Improved Health	No	None for now	None	—
Improved Safety	No	None for now	None	—
Water	No	None for now	None	—
National Security	Yes	Algorithm from literature	Algorithm	Annual
PARTICIPANT PERSPECTIVE (OWNERS OF LOW-INCOME RENTAL HOUSING), PER HOUSING UNIT				
Marketability/ease of finding renters	Yes	Survey	$0.96	Annual
Reduced tenant turnover	Yes	Survey	$0	Annual
Property value	Yes	Survey	$17.03	One time
Equipment maintenance (heating and cooling systems)	Yes	Survey	$3.91	Annual
Reduced maintenance (lighting)	Yes	Survey	$66.73	Annual
Durability of property	Yes	Survey	$36.85	Annual
Tenant complaints	Yes	Survey	$19.61	Annual
NON-RESOURCE BENEFITS				
Appliance Recycling – Avoided landfill space	Yes	Algorithm from literature	$1.06	One time
Appliance Recycling – Reduced emissions due to recycling plastic and glass, reduced emissions	Yes	Algorithm from literature	$1.25	One time
Appliance Recycling – Reduced emissions due to incineration of insulating foam	Yes	Algorithm from literature	$170.22	One time

1.3 NEIS QUANTIFIED THROUGH PARTICIPANT SURVEYS

NMR estimated the value of several NEIs through surveys of program participants, using a *Relative Valuation* method, by which respondents were asked to assign a monetary value to various NEIs, compared to the amount of energy savings yielded by the measures they had installed. To correct for the common finding that the sum of individual NEI values exceeds the overall value reported by participants of the NEIs together, NMR included a question about overall NEI values, then took the conservative approach of scaling the individual NEI values to the overall value.

The survey results for non-low-income and low-income respondents are summarized in Figure 1-1. The values shown for each NEI are the per participant annual averages of each NEI. In general, non-low-income (NLI) respondents placed a higher value than did the low-income (LI) respondents on the NEIs that provide annual benefits (i.e., all the NEIs except increase in property value), except for health impacts and lighting life and quality. NLI respondents valued thermal comfort and equipment maintenance the most ($125 and $124 per year, respectively), while LI respondents valued thermal comfort, lighting life and quality, and equipment maintenance the most ($101, $56, and $54, respectively).

Figure 1-1. Valuation of Annual NEIs per Participant
Non-low-income and Low-income Respondents

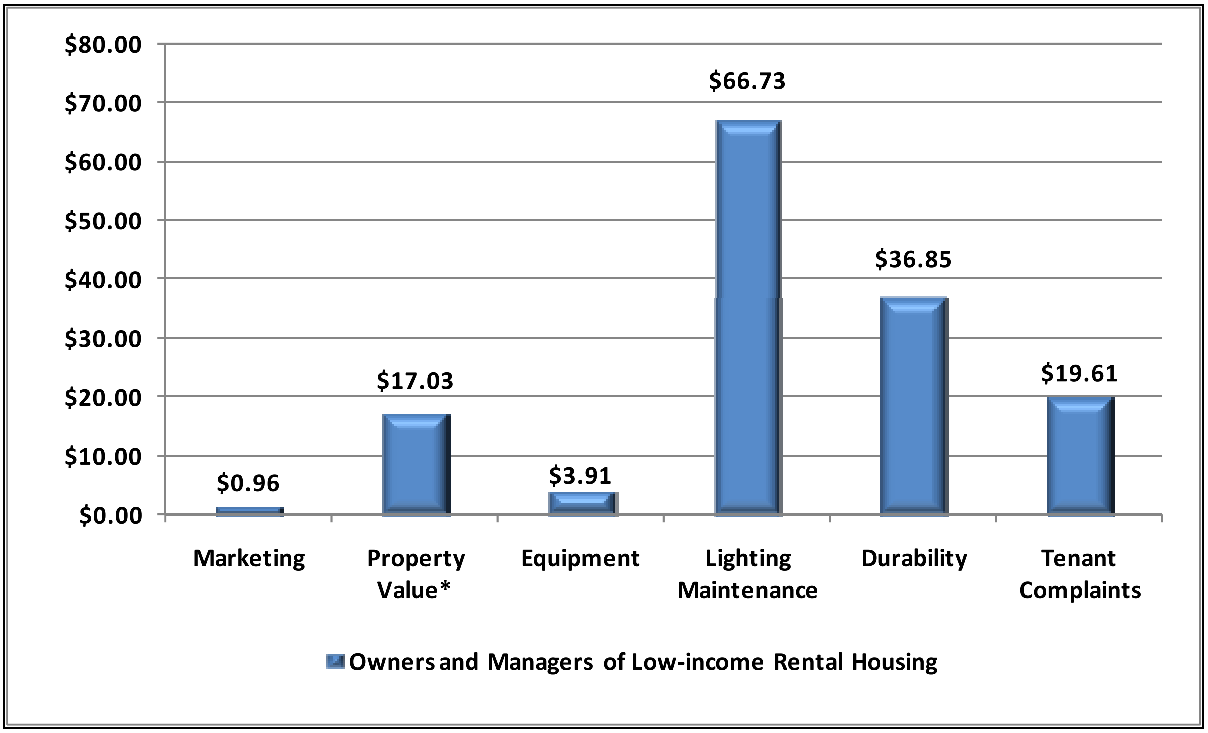


Non-low-income respondents also estimated a substantially higher one-time property value increase attributable to the energy efficiency retrofits than did low-income respondents ($1,998 and $949, respectively).

In addition to the NEIs assessed through the relative valuation method, this survey included questions related to participant perspective health benefits—via reductions in sick days attributed to the energy efficiency retrofits—as well as societal benefits via reduced medical costs due to reductions in incidences of heat stress, hypothermia and asthma. Because of the extremely small number of respondents reporting program induced changes in health, NMR does not recommend using results from this method. Findings are reported in Section 9.5. However, health benefits are also being examined in the current evaluation of the national WAP; values might be derived from these findings once the study is complete (Ternes et al., 2007)

Survey results for owners and managers of low-income rental housing are summarized in Figure 1-2. The most highly valued NEI was reduced costs associated with lighting maintenance, with a mean annual value of $66.73 per housing unit, followed by increased durability of the building or property, with a mean annual value of $36.85 per housing unit. Improved marketing, reduced equipment maintenance, expected increase in property value (one-time benefit), and reduced tenant complaints were all valued at $20 a year or less per housing unit. One NEI, reduced tenant turnover, was valued at $0 for all respondents.

Figure 1-2. Valuation of NEIs per Housing Unit
Owners and Managers of Low-income Rental Housing



*Property Value is a one-time benefit while the remaining NEIs are annual benefits.

2. INTRODUCTION AND OVERVIEW OF NEI VALUES

This report presents the findings of the Massachusetts Cross-Cutting Non-Energy Benefits Evaluation. It incorporates findings from a review of the NEI literature, in-depth interviews, and telephone surveys with program participants, and uses these to quantify non-energy benefits, including NEBs for low-income programs. To account for the fact both positive and negative impacts can result from energy efficiency programs, we use the term non-energy impacts (NEIs) in this report.

Overall, more than 125 reports and academic papers were reviewed for this report. As a complement to the literature review, NMR conducted 13 interviews with Project Administrator (PA) staff members responsible for residential retrofit programs, low-income retrofit programs, and residential new construction programs. Nine in-depth interviews were also conducted with administrators of low-income and residential retrofit energy efficiency programs in other states, health and safety experts, and social service providers familiar with low-income weatherization programs.

NEI values were derived in several ways. When possible, NEIs values were derived from the existing literature or by developing modified algorithms from the literature. For residential and low-income program participants, including owners of low-income rental housing, select NEIs values were estimated with surveys of program participants. NEIs estimated from surveys relied on the following three sources:

- A survey of 213 low-income households whose homes were retrofitted by the PAs programs between July 1, 2009 and June 30, 2010
- A survey of 209 non-low-income households whose homes were retrofitted by the PAs programs between July 1, 2009 and June 30, 2010
- A survey of 21 owners and managers of low-income rental housing

The following participant NEIs were addressed via the surveys:

- Thermal comfort in terms of temperature and draftiness
- Noise levels in terms of the amount of outdoor noise the home's occupants can hear inside the house
- Health in terms of the frequency or intensity of colds, flus or other illnesses, such as asthma
- Expected increase in property value (homeowners only)
- Reliability and maintenance requirements of heating and cooling equipment
- Lighting quality combined with longer lighting life, given the use of CFLs and fluorescent fixtures
- Durability of home and need for repairs
- In addition, the surveys examined in more detail a number of health related NEIs that may accrue to the participant and to society. These include changes in the number of sick days experienced by program participants, with the resulting impacts on societal costs for medical care, as measured by the number of times medical care was sought for heat exposure, hypothermia and asthma or other chronic conditions.

Lastly, the surveys addressed the following NEIs that may be experienced by the owners and managers of retrofitted low-income rental housing:

- Marketability and ease of finding renters
- Reduced maintenance of heating and cooling equipment

- Reduced maintenance for lighting
- Reduced tenant turnover
- Reduced tenant complaints
- Expected increase in property value
- Improved durability of property

Table 2-1(Utility-perspective), Table 2-2 (Participant-perspective – Occupants), Table 2-3 (Societal-perspective), and Table 2-5 (Participant-perspective – Owners of Low-income Rental Housing) provide details for each NEI. In the tables, for each NEI, we present the following:

- The range of values reported in the recent literature (and indicate if no values have been reported in the literature)
- Recommendation for quantification
- Method of quantification
- The recommended value of the NEI, the recommended algorithm for quantifying the NEI, or the justification for not quantifying the NEI.
- The basis of the NEI (per participant or per measure)
- The time frame of the NEI (annual benefit or one-time benefit)
- The relevant PA programs

When estimating NEIs, it is important to note that free-ridership and spillover should be accounted for in all calculations and estimates for NEIs that apply to non-low-income participants. The summary tables, algorithms, and body of the report do not contain free ridership and spillover factors, as it is assumed that these will be applied to each NEI at the program level, from free ridership and spillover factors derived from impact evaluations.

In addition, NMR recommends that the duration of the NEI correspond with the expected life of the corresponding measures associated with each NEI as reported in the current TRM (Massachusetts Electric and Gas Energy Efficiency Program Administrators, 2010). For NEIs that are estimated on a per participant basis and derived from multiple measures, NMR recommends adopting the methodology used in the current TRM for determining the measure life for the gas weatherization program, whereby the measure life is weighted based on the mix of measures installed. (Massachusetts Electric and Gas Energy Efficiency Program Administrators, 2010).

Utility-perspective NEIs are summarized below in Table 2-1 Nearly all utility-perspective NEIs arise from programs targeted to low-income customers, wherein the programs reduce energy bills for participants. As a result, program participants are less likely to experience difficulties with paying their utility bills and the PAs realize financial savings. In addition, utilities may realize savings due to a reduction in safety-related emergency calls and insurance costs, due to reduced fires and other emergencies. In general, the utility-perspective NEIs are relatively low in value, typically ranging from less than a dollar to nearly $9 per participant. Most of the NEIs found in the literature apply to the PAs' low-income programs and can be monetized relatively easily from the literature or from algorithms using inputs from the PAs. An overview of the studies used to estimate utility-perspective NEI values is provided in Appendix D.[8]

[8] Values were derived from the literature published since 1997 and were adjusted into 2010 dollars using an inflation rate of 2.5 percent per year, the same inflation rate used in the PAs' three-year plans (see National Grid et al., 2009; NSTAR et al., 2009).

In addition, NMR estimated NEI values at the measure level (Table 2-6, Table 2-7, and Table 2-8). To do so, NMR assigned a portion of a given NEI value to an individual measure based on the average energy bill savings for which the measure is responsible. This method has also been used for the *2001 California Low Income Public Purpose Test (LIPPT) report for the Reporting Requirements Manual (RRM) Working Group Cost Effectiveness Committee* (TecMarket Works, SERA and Megdal Associates, 2001).

Table 2-1. Summary of Utility-Perspective NEI Values

NEI	Range of Reported Values ($)[9]	Quantify	Method of Quantification	Recommended Value, Algorithm, or Justification for not quantifying[10]	Basis	Duration	Relevant PA Programs[11]
Arrearages	0.50–7.50[12]	Yes	Literature	$2.61	Per participant	Annual	1,2
Bad debt write-offs	0.48–7.00	Yes	Literature	$3.74	Per participant	Annual	1,2
Terminations and reconnections	0.02–7.00	Yes	Literature	$0.43	Per participant	Annual	1,2
Rate discounts	2.61–23.57	Yes	Algorithm & PA data	Estimated energy savings per installed measure * [(full rate per unit energy ($) – discounted rate per unit energy ($)][13]	Per measure	Annual	1,2
Complaints and payment plans	No monetized values reported	No	None for now	Insufficient data in the literature to derive a reliable value	—	—	—
Customer Calls	0.00–1.58	Yes	Literature	$0.58	Per participant	Annual	1,2

[9] Values in the table reported as per participant, per year

[10] Recommended values derived from the literature represent the median of the values reported in the recent NEI literature. Values were adjusted to 2010 dollars using an inflation rate of 2.5 percent per year, the same inflation rate used in the PAs' three-year plans.

[11] The following numbers correspond to the following PA Programs: 1 Low-income retrofit programs; 2 = Low-income new construction programs; 3 = Residential new construction; 4 = Residential cooling and heating; 5 = Residential heating and hot water; 6 = Non-low-income retrofit programs (i.e., MassSAVE, multi-family retrofit programs); 7 = ENERGY STAR lighting; 8= ENEGY STAR appliances

[12] A previous draft reported a maximum value of $32 reported in the NEI literature. The $32 value was an annual value reported in the 1993 evaluation of the national WAP program (Brown et al., 1993). This same benefit was estimated to have an net present value (NPV) of $57 (or roughly $3.90 annual value) in the 2002 evaluation of the same program (Schweitzer and Tonn, 2002), so we relied on the more recent value to report the range of values.

[13] Alternatively, the NEI of rate discounts could also be estimated at the participant level rather than at the measure level The rate discount benefit can be calculated either by individual PAs, according to their individual PA rate discount, or it can be calculated statewide using the population weighted rate discounts of $0.0424 per kWh and $0.2663 per therm.

NEI	Range of Reported Values ($)[9]	Quantify	Method of Quantification	Recommended Value, Algorithm, or Justification for not quantifying[10]	Basis	Duration	Relevant PA Programs[11]
Collections notices	0.00–1.49	Yes	Literature	$0.34	Per participant	Annual	1,2
Safety-related emergency calls	0.07–15.58[14]	Yes	Literature	$8.43	Per participant	Annual	1[15]
Increased electricity system reliability	No monetized values reported	No	Quantified Elsewhere	The PAs currently receive credit for contributing to increased system reliability due to the load reductions attributable to energy efficiency measures (Hornby et al., 2011).	—	—	—
Transmission and distribution savings	0.13–4.33	No	Quantified Elsewhere	Avoided transmission and distribution losses are already accounted for in the Total Resource Cost (TRC) test	—	—	—
Insurance savings	0.00–0.15	Yes	Literature	Derive value from National WAP Evaluation (2011)	—	—	1

[14] A previous draft reported a maximum value of $22.67 reported in the NEI literature The $22.57 was reported in a study by Magouirk (1995) as first-year savings value attributable to the 1993 Colorado Public Service's energy savings partners program (a low-income weatherization program). It was an overall safety value comprised of several individual safety NEIs: $15.58 (emergency calls excluding flex connectors); $1.98 (for gas flex connectors), & $5.01 (incremental cost of having the flex connector replaced by emergency services instead of weatherization agency). Because gas flex connectors were not included in the PAs' programs, we removed the benefits associated with the flex connectors and report the value of $15.58 (emergency calls excluding flex connectors).

[15] This NEI only applies to participants with replaced or repaired space and water heating equipment, gas appliances, and gas connectors

Participant-perspective NEIs are summarized below in Table 2-2. Participant-perspective NEIs accrue to participants in both low-income and non-low-income programs, although some participant NEIs are specific to low-income participants. Most of the participant-perspective NEIs found in the literature apply to the PAs' programs. In general, the participant-perspective NEIs are relatively high in value, although the ranges of values found in the literature for many of these NEIs are large. Some of these NEIs are quantifiable with some effort: with data from the PAs, secondary data and algorithms found in the literature. However, most of the participant-perspective NEIs are difficult to quantify and require primary data collection through participant surveys. Due to the less tangible nature of many participant-perspective NEIs, they can be quantified with only limited certainty.

For some of the participant-perspective NEIs, NMR recommends using values derived from the recently completed NEI surveys. For other participant-perspective NEIs, NMR recommends using engineering estimates, values in the literature, algorithms in the literature, or not valuing a particular NEI

For the PAs' residential new construction program, NMR recommends scaling the values of individual NEIs to 100% of estimated bill savings.[16] Because the NMR survey did not include a question asking respondents to estimate the overall value of the NEIs combined, this would represent a more conservative valuation of these NEIs.

It is important to note that a number of participant perspective NEIs commonly found in the literature and currently included in the TRM report are derived from customer bill savings. These bill savings partially overlap with avoided costs accounted for in the Avoided Energy Supply Costs (AESC) in New England (Hornby et al., 2011) and included in the TRC calculations. The AESC study estimates a number of avoided costs, including avoided costs of electricity to retail customers and avoided costs to natural gas retail customers. Each set of avoided costs is comprised of several individual costs. For example, avoided costs of electricity to retail customers includes avoided energy costs, avoided capacity costs, avoided environmental regulation compliance costs, demand reduction induced price effects, and avoided costs of local transmission and distribution infrastructure (Hornby et al, 2011). While bill savings and avoided costs partially overlap, they typically differ in part because bill savings are based on average retail savings to participants while avoided costs are based on marginal energy supply costs that are avoided because of the PAs' energy efficiency programs. Theoretically, a participant NEI of bill savings, based on the difference between the avoided energy and capacity costs and participant energy bill savings, could be added to the TRC. However, according to traditional TRC calculation methods, including participant bill savings as a benefit would require including a similar cost in the form of lost PA revenues, thus negating the bill savings benefit.[17] Therefore, there is no additional NEI of participant bill savings.

In addition, NMR does not recommend including any NEIs that are derived from participant bill savings because it would amount to double counting of benefits. To count benefits that derive from bill savings would amount to valuing the additional disposable income (i.e., bill savings) and the ways in which the participants spend the disposable income. For example, a participant may spend the bill savings on food or medicine, leading to improved health.Similarly, participants may use their bill savings to pay energy bills, reducing the incidence of service terminations and the costs associated with service termination and

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[16] Our recommendation of scaling to 100% of bill savings represents a higher percentage of bill savings than the average non-low-income respondent from this study (total NEIs were, on average, 77% of bill savings for non-low-income respondents). However, we believe that 100% of bill savings is reasonable because the NEIs for a new home may be different than a retrofit. Further, the sum of the individual NEIs for the residential new construction program were substantially higher than the retrofit NEIs found in this study, both in dollar value and as a percentage of savings (NMR and Conant, 2009). For the ENERGY STAR homes evaluation, the sum of the individual NEIs ($1,445) was a much higher percentage of bill savings (361% of bill savings, based on estimate of $400 annual bill savings) than the non-low-income respondents from this study (the sum of the individual NEIs was equal to 132% of bill savings).

[17] As defined in the *California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects,* the TRC takes into consideration program benefits and costs in terms of the participants and the ratepayers: "In a sense, it is the summation of the benefit and cost terms in the Participant and the Ratepayer Impact Measure tests, where the revenue (bill) change and the incentive terms intuitively cancel (CPUC, 2001, p. 18)."

reconnection. But to count both the bill savings and the health benefits or the benefit of reduced service terminations that are derived entirely from the way bill savings are spent is to count the same benefit twice. Other examples of NEIs derived from bill savings include reduced bill-related calls and reduced need to move or forced mobility.

Table 2-2. Summary of Participant-Perspective (Occupants) NEI Values

NEI	Range of Reported Values ($)[18]	Quantify	Method of Quantification	Recommended Value, Algorithm, or Justification for not quantifying	Basis	Duration	Relevant PA Programs[19]
Higher comfort levels	27.13–279.00	Yes	Survey	$125 (NLI) / $101 (LI)	Per participant	Annual	1,2,4,5,6[20]
			Survey	$77	Per participant	Annual	3
Improved sense of environmental responsibility	4.00–220.00	No	Quantified Elsewhere	Environmental benefits have already been estimated in the *Avoided Energy Supply Costs in New England: 2011 Report* (AESC 2011) and included in PA's 3-year energy efficiency plans and the benefit is too intangible to quantify	Per participant	Annual	—
Quieter interior environment	13.00–252.00	Yes	Survey	$31 (NLI) / $30 (LI)	Per participant	Annual	1,2,4 5,6 [20]
			Survey	$40	Per participant	Annual	3
Reduced noise (dishwashers)	No monetized values reported	No	None for now	Insufficient data in the literature to derive a reliable value	—	—	—
Lighting quality	19.00–25.00[21]	Yes	TRM Report	$3.50 / CFL fixture; $3.00 per CFL bulb; combined value for lighting lifetime and quality.	Per fixture / bulb	One time	1,2, 3,6,7 (lighting measures only)
Longer lighting life	1.80		TRM Report				

[18] Values in the table reported as per participant, per year

[19] The following numbers correspond to the following PA Programs: 1 Low-income retrofit programs; 2 = Low-income new construction programs; 3 = Residential new construction; 4 = Residential cooling and heating; 5 = Residential heating and hot water; 6 = Non-low-income retrofit programs (i.e., MassSAVE, multi-family retrofit programs); 7 = ENERGY STAR lighting; 8= ENEGY STAR appliances

[20] This NEI only applies to participants that installed shell measures &/or HVAC equipment

[21] This range excludes the value of $144 estimated for the MA ENERGY STAR Homes program by NMR and Conant (2009) which was based on lighting quality combined with longer lighting life for all CFLs and fluorescent fixtures in the home.

NEI	Range of Reported Values ($)[18]	Quantify	Method of Quantification	Recommended Value, Algorithm, or Justification for not quantifying	Basis	Duration	Relevant PA Programs[19]
Increased housing property value	2.57 – 22.00	Yes	Survey	$1,998 (NLI) / $949 (LI)	Per participant	One time	1,2,4,5,6 [20]
Anticipated ease of selling or leasing home	170.00 – 348.00		Survey	$72 for combined increased property value/anticipated ease of selling or leasing home	Per participant	Annual	3
Buffers energy price increase	161.00 – 611.00	No	Quantified Elsewhere	The value of Demand Reduction Induced Price Effect (DRIPE) has been estimated in AESC 2011 report and included in the TRC test	—	—	—
Reducing energy expenses, making more money available for other uses	No monetized values reported	No	Quantified Elsewhere	Benefit derived entirely from energy savings, which are already included in the TRC test	—	—	—
Reduced need to move and costs of moving, including homelessness	0.65 – 100.00	No	Quantified Elsewhere	Benefit derived entirely from energy savings, which are already included in the TRC test	—	—	—
Reduced detergent usage (dishwashers)	No monetized values reported	No	None	Insufficient data in the literature to derive a reliable value	—	—	—
Reduced water usage and sewer costs (dishwashers)	1.65	Yes	Algorithm from literature	$3.70	Per measure	Annual	3 (dishwashers)
Reduced water usage and sewer costs (tankless water heaters)	No monetized values reported	No	None	Insufficient data in the literature to derive a reliable value	—	—	—

NEI	Range of Reported Values ($)[18]	Quantify	Method of Quantification	Recommended Value, Algorithm, or Justification for not quantifying	Basis	Duration	Relevant PA Programs[19]
Reduced water usage and sewer costs (low flow showerheads)	4.89 – 13.38	Yes	Algorithm from literature	(3696 gallons water saved per low flow showerhead per year) * √average number of showerheads installed per site * [$0.0036 (average cost of water per gallon) + $0.0050 (average cost of sewerage per gallon)]	Per participant	Annual	1, 2,6 [22]
Reduced water usage and sewer costs (faucet aerators)		Yes	Algorithm from literature	(332 gallons water saved per faucet aerator per year * √average number of faucet aerator installed per site * [$0.0036 (average cost of water per gallon) + $0.0050 (average cost of sewerage per gallon)]	Per participant	Annual	1,2,6 [22]
More durable home and less maintenance	90.00 – 202.00	Yes	Survey	$149 (NLI retrofits) / $35 (LI)	Per participant	Annual	1,2,4,5,6 [20]
Equipment & appliance maintenance	17.00 – 150.00	Yes	Survey	$124 (NLI retrofits) / $54 (LI)	Per participant	Annual	1,2,4,5,6 [20]
Health related NEIs	1.00 – 330.00	Yes	Survey	$4 (NLI retrofits) / $19 (LI)	Per participant	Annual	1,2,4,5,6 [20]
Improved safety (heating system, ventilation, carbon monoxide, fires)	0.00 – 105.00	Yes	Algorithm & PA data	Avoided fire deaths: $37.40	Per measure	Annual	1 [23]
			Algorithm & PA data	Avoided fire-related injuries: $0.03	Per measure	Annual	
			Algorithm & PA data	Avoided fire-related property damage: $1.24	Per measure	Annual	
			Algorithm & PA data	Avoided deaths attributable to CO poisonings: $6.38	Per measure	Annual	
Improved safety (lighting)	No monetized values reported	No	None for now	Insufficient data in the literature to derive a reliable value	—	—	—

[22] This NEI only applies to participants that installed low flow showerheads and faucet aerators

[23] This NEI only applies to replaced and/or repaired heating systems.

NEI	Range of Reported Values ($)[18]	Quantify	Method of Quantification	Recommended Value, Algorithm, or Justification for not quantifying	Basis	Duration	Relevant PA Programs[19]
Heat (or lack thereof) generated	0.92	No	None	Energy-related impact	—	—	—
Warm up delay	0.29 – 0.77	No	None for now	Insufficient data in the literature to derive a reliable value	—	—	—
Product lifetime	No monetized values reported	No	None	Insufficient data in the literature to derive a reliable value	—	—	—
Availability of hot water	No monetized values reported	No	None for now	Insufficient data in the literature to derive a reliable value	—	—	—
Product performance	14.00 – 18.00	No	None for now	Insufficient data in the literature to derive a reliable value	—	—	—
Window AC NEIs	$109	Yes	Literature	$49.50	Per participant	Annual	1
Bill-related calls	0.18 – 8.00	No	Quantified Elsewhere	Benefit derived entirely from energy savings, which are already included in the TRC test	—	—	—
Termination and reconnection	0.03 – 86.93	No	Quantified Elsewhere	Benefit derived entirely from energy savings, which are already included in the TRC test	—	—	—
Reduced transaction costs	0.00 – 5.00	No	None	Insufficient data in the literature to derive a reliable value	—	—	—
Education	No monetized values reported	No	None	Insufficient data in the literature to derive a reliable value	—	—	—

Societal-perspective NEIs are summarized below in Table 2-3. The societal-perspective NEIs of interest to the PAs for this literature review (i.e. the non-economic and non-environmental societal NEIs) generally arise from programs targeted to low-income customers. Little work has been done in the area of quantifying these NEIs, and quantification methods are not well-established in the literature. Societal NEIs are generally difficult to quantify or quantifiable with some effort, but limited certainty, using secondary data.

Table 2-3. Summary of Societal-Perspective NEI Values

NEI	Range of Reported Values ($)[24]	Quantify	Method of Quantification	Recommended Value, Algorithm, or Justification for not quantifying	Basis	Time Frame	Relevant PA Programs[25]
Weatherization by utility programs saves costs of inspections and upgrades by other agencies	No monetized values reported	No	None for now	Insufficient data in the literature to derive a reliable value	—	—	—
Equity and Hardship	No monetized values reported	No	None	Insufficient data in the literature to derive a reliable value	—	—	—
Improved Health	No monetized values reported	No	None for now	Heat Stress: Insufficient data from surveys; Algorithm if data can be derived from National WAP Evaluation (2011) [(Reductions in visits to hospital, emergency room, or urgent care facilities for heat stress (participant surveys) * $1,469.79 (Cost of general injury emergency room visit, adjusted for inflation)) / Total number of participants]	Per participant	Annual	1,4,5 6[26]
			None for now	Cold exposure: Insufficient data from surveys; Algorithm if data can be derived from National WAP Evaluation (2011 [(Reductions in visits to hospital, emergency room, or urgent care facilities for cold exposure (participant surveys) * $1,469.79 (Cost of general injury emergency room visit, adjusted for inflation)) / Total number of participants]	Per participant	Annual	

[24] Values in the table reported as per participant, per year

[25] The following numbers correspond to the following PA Programs: 1 Low-income retrofit programs; 2 = Low-income new construction programs; 3 = Residential new construction; 4 = Residential cooling and heating; 5 = Residential heating and hot water; 6 = Non-low-income retrofit programs (i.e., MassSAVE, multi-family retrofit programs); 7 = ENERGY STAR lighting; 8= ENEGY STAR appliances

[26] This NEI only applies to participants that installed shell measures &/or HVAC equipment

NEI	Range of Reported Values ($)[24]	Quantify	Method of Quantification	Recommended Value, Algorithm, or Justification for not quantifying	Basis	Time Frame	Relevant PA Programs[25]
			None for now	Asthma: Insufficient data from surveys; Algorithm if data can be derived from National WAP Evaluation (2011 [(Reductions in visits to hospital, emergency room, or urgent care facilities for asthma (participant surveys) * $737.74 (Cost of treating asthma at emergency room, adjusted for inflation)) / Total number of participants]	Per participant	Annual	
Improved Safety	0.00 – 0.29	No	None for now	Insufficient data in the literature to derive a reliable value	—	—	—
Water	0.00	No	None for now	Insufficient data in the literature to derive a reliable value	—	—	—
National Security	$202	Yes	Algorithm from literature	[(Estimated annual savings in fuel oil and kerosene, MMBtu, per measure * $1.83 (10% adder for cost of relying on imported oil or kerosene, per MMBtu) * number of homes that use fuel oil or kerosene as the primary heating fuel)] / all program participants	Per measure	Annual	1,5,6 (heating related measures only)

Table 2-4 presents the non-resource benefits that pertain to waste reduction attributable to the PAs' Appliance Turn-in Program.

Table 2-4. Summary of Non-Resource Benefits

NEI	Range of Reported Values ($)	Quantify	Method of Quantification	Recommended Value, Algorithm, or Justification for not quantifying	Basis	Time Frame	Relevant PA Programs
NEIs derived from refrigerator/freezer turn-in programs	No monetized values reported	Yes	Algorithm from literature	Avoided landfill space: $1.06 per unit, one-time benefit	Per measure	One time	Massachusetts Appliance Turn-in Program
				Recycling of plastics and glass: $1.25 per unit, one-time benefit	Per measure	One time	
				Incineration insulating foam: $170.22 per unit, one-time benefit	Per measure	One time	

Participant Perspective NEIs (Owners of Low-income Rental Housing) are summarized below in Table 2-5. Our review of the literature found no mention of non-energy impacts pertaining to participating owners of low-income rental housing. However, interviews with PA staff identified several potential NEIs, including reduced maintenance pertaining to lighting (attributed to the longer life of a CFL, thus reducing labor costs), improved sense of environmental responsibility, improved marketing of rental property (i.e., a more energy-efficient rental unit is easier to market and rent), and reduced tenant turnover. All values for the NEIs were derived from surveys of owners and managers of low-income rental housing and estimated on a per housing unit basis.

Table 2-5. Summary of Participant-Perspective NEI Values (Owners of Low-income Rental Housing)

NEI	Range of Reported Values ($)	Quantify	Method of Quantification	Recommended Value, Algorithm, or Justification for not quantifying	Basis	Time Frame	Relevant PA Programs
Marketability/ease of finding renters	No monetized values reported	Yes	Survey	$0.96	Per housing unit	Annual	MF Low-income retrofit programs
Reduced tenant turnover	No monetized values reported	Yes	Survey	$0	Per housing unit	Annual	MF Low-income retrofit programs
Property value	No monetized values reported	Yes	Survey	$17.03	Per housing unit	One time	MF Low-income retrofit programs
Equipment maintenance (heating and cooling systems)	No monetized values reported	Yes	Survey	$3.91	Per housing unit	Annual	MF Low-income retrofit programs[27]
Reduced maintenance (lighting)	No monetized values reported	Yes	Survey	$66.73	Per housing unit	Annual	MF Low-income retrofit programs[28]
Durability of property	No monetized values reported	Yes	Survey	$36.85	Per housing unit	Annual	MF Low-income retrofit programs
Tenant complaints	No monetized values reported	Yes	Survey	$19.61	Per housing unit	Annual	MF Low-income retrofit programs

[27] This NEI only applies to participants that installed programmable thermostats.
[28] This NEI only applies to participants that installed energy efficient lighting.

In addition, NMR estimated NEI values at the measure level (Table 2-6, Table 2-7, and Table 2-8). To do so, NMR assigned a portion of a given NEI value to an individual measure based on the average energy bill savings for which the measure is responsible. This method has also been used for the *2001 California Low Income Public Purpose Test (LIPPT) report for the Reporting Requirements Manual (RRM) Working Group Cost Effectiveness Committee* (TecMarket Works, SERA and Megdal Associates, 2001).

Computation of dollar values for a specific NEI begins with calculating the average portion of bill savings attributed to each measure for an individual NEI. As a first step, the NMR team made a determination whether a measure reasonably contributes to an individual NEI. For example, air sealing, cooling equipment, door, insulation, window, and weatherization measures contribute to changes in outside noise heard inside the home. [29] Next, the team calculated the average percentage of bill savings for each measure that contributes to an NEI. For example, for the NLI sample air sealing represents, on average, 8% of the bill savings of measures that contribute to Thermal Comfort, while heating systems represent 39% of those bill savings; combined, all of the measures sum to 100% of the bill savings associated with each NEI. Last, the team multiplied the average percentage of bill savings by the average NEI value to estimate an NEI value for each measure (Table 2-6).

As illustrated in Table 2-6 and Table 2-7, the attribution of NEI values to measures by non- and low-income participants reveals that several measures typically account for the bulk of dollar benefits for a particular NEI: heating systems, insulation, weatherization measures,[30] and air sealing. Heating systems, air sealing, insulation, and various weatherization programs have the greatest impact, a benefit to the thermal comfort NEI in both samples. Heating system measures provide the greatest benefit in the equipment maintenance NEI.

The low-income sample exhibits a similar distribution of NEI benefits with some notable exceptions (Table 2-7). For example, air sealing measures generally represent the highest percentage of bill savings, followed by insulation measures. Air sealing represents the largest percentage of bill savings for noise reduction at 55% of the NEI or valued at $16 annually. Another marked difference from non-low-income participants is the contribution of the lighting measure to the property value NEI. Lighting accounts for 24% of the total property value NEI and $226 one-time benefit for the low-income sample while the non-low-income sample only derives 5% of total benefit from lighting (or $97 in dollar terms).

Compared to the occupant sample, the sample of owners and managers of multi-family rental housing had fewer types of measures installed: refrigerators and freezers, hot water systems and other water saving measures, lighting, programmable thermostats, and air sealing. Not surprisingly, with fewer types of measures installed, the total value of NEIs to owners and managers was a much smaller percentage of bill savings (36%) than for occupants – 62% for low-income and 57% for others. As illustrated in the tables, energy efficient lighting has the greatest percentage contribution to the NEIs for owners and managers, at 46% of estimated energy savings and in turn 46% of each individual NEI (except for reduced lighting maintenance). Refrigerators and freezers provide the second largest percentage contribution to multi-family owner NEIs, at 35% of estimated bill savings.

[29] For the NLI sample, the following measures were not included in this analysis: doors, heating controls, pipe wrap, hot water tank wrap, pool timer and faucet aerators. For the LI sample, the following measures were not included in the analysis: cooling systems, heating and cooling systems, heating and hot water systems, heating controls, AC system sizing, pool timer, and hot water tank wrap. While these measures reasonably contribute to several NEIs, such as comfort or property value, the measures were either not installed in any homes included in this study or savings data at the measure level were not available.

[30] The 'Weatherization' measure represents the program level savings for National Grid and Berkshire Gas customers; savings data for the individual measures installed were not available for these programs

Table 2-6. Attribution of NEI Values to Energy Efficiency Measures, Non-low-income Participants, Dollars per Measure[31] (Weighted mean value of all respondents)

	Thermal Comfort		Noise Reduction		Health Impacts		Property Value		Equipment Maintenance		Lighting Quality		Durability of Home	
	% bill savings	$[32]	% bill savings	$	% bill savings	$	% bill savings	$	% bill savings	$	% bill savings	$	% bill savings	$
Sample size, by NEI[33]	*209*	*180*	*147*	*187*	*209*	*190*	*209*	*171*	*139*	*125*	*47*	*41*	*209*	*188*
Air sealing	8%	$10.13	16%	$4.88	8%	$0.32	7%	$135.83	-	-	-	-	8%	$3.95
Appliance (refrigerators and freezers)	-	-	-	-	-	-	<1%	$1.44	-	-	-	-	-	-
Cooling systems	3%	$3.92	9%	$2.83	3%	$0.13	3%	$62.65	6%	$7.54	-	-	3%	$1.54
Duct sealing	<1%	$0.16	-	-	<1%	$0.01	<1%	$2.51	-	-	-	-	<1%	$0.06
Heating & cooling syst.	4%	$5.05	-	-	4%	$0.16	4%	$80.69	8%	$9.42	-	-	4%	$1.98
Heating & hot water sys.	1%	$1.83	-	-	1%	$0.06	1%	$29.17	3%	$3.41	-	-	1%	$0.72
Heating system	39%	$48.63	-	-	39%	$1.56	34%	$678.52	83%	$102.40	-	-	36%	$17.42
Hot water system	-	-	-	-	-	-	4%	$82.56	-	-	-	-	4%	$2.13
Insulation	20%	$25.15	37%	$11.54	20%	$0.80	19%	$378.05	-	-	-	-	20%	$9.82
Lighting	-	-	-	-	-	-	5%	$96.61	-	-	100%	$49.00	-	-
Service to heating or cooling system	<1%	$0.47	-	-	<1%	$0.01	<1%	$7.44	1%	$0.87	-	-	<1%	$0.18
Low flow showerhead	-	-	-	-	-	-	<1%	$0.03	-	-	-	-	-	-
AC system sizing	<1%	$0.19	-	-	<1%	$0.01	<1%	$3.01	<1%	$0.37	-	-	<1%	$0.07
Programmable thermo.	3%	$3.99	-	-	3%	$0.13	3%	$51.49	-	-	-	-	3%	$1.33
Window	1%	$0.68	2%	$0.54	1%	$0.02	<1%	$6.72	-	-	-	-	<1%	$0.21
Weatherization[34]	20%	$25.00	36%	$11.22	20%	$0.79	19%	$381.28	-	-	-	-	19%	$9.57
Total Value	100%	$125	100%	$31	100%	$4	100%	$1,998	100%	$124	100%	$49	100%	$49

[31] For the purpose of attributing NEI values to individual measure, the evaluation team only included measures that reasonably have an impact on an individual NEI. For example, heating, cooling and shell measures are included in the NEI for thermal comfort. A cell with a '-' indicates that the measure does not reasonably impact the individual NEI. The following measures were not included in this analysis: doors, heating controls and pipe wrap. While these measures reasonably contribute to several NEIs, such as comfort or property value, the measures were either not installed or savings data at the measure level were not available for the respondents in this sample.

[32] The values in the table are reported as dollars per measure.

[33] The sample size for each individual NEI varies because analysis is limited to those respondents who had specific measures installed.

[34] The 'Weatherization' measure represents the program level savings for National Grid and Berkshire Gas customers; savings data for the individual measures installed were not available for these programs.

Table 2-7. Attribution of NEI Values to Energy Efficiency Measures, Low-income Participants, Dollars per Measure[35]

(Weighted mean value of all respondents)

	Thermal Comfort		Noise Reduction		Health Impacts		Property Value		Equipment Maintenance		Lighting Quality		Durability of Home	
	% bill savings	$[36]	% bill savings	$	% bill savings	$	% bill savings	$	% bill savings	$	% bill savings	$	% bill savings	$
Sample size, by NEI[37]	*211*	*177*	*141*	*191*	*211*	*199*	*213*	*147*	*140*	*122*	*108*	*89*	*212*	*189*
Aerator	-	-	-	-	-	-	3%	$26.61	-	-	-	-	-	-
Air sealing	30%	$30.23	55%	$16.39	30%	$5.69	15%	$144.93	-	-	-	-	30%	$10.61
Appliance (refrigerators and freezers)	-	-	-	-	-	-	3%	$26.61	-	-	-	-	-	-
Door	<1%	$0.01	<1%	$0.01	<1%	$0.01	<1%	$0.04	-	-	-	-	<1%	$0.01
Duct sealing	1%	$0.68	-	-	1%	$0.13	1%	$5.11	-	-	-	-	1%	$0.23
Heating system	28%	$28.01	-	-	28%	$5.27	26%	$249.20	51%	$27.43	-	-	28%	$9.72
Hot water system	-	-	-	-	-	-	<1%	$1.65	-	-	-	-	1%	$0.20
Insulation	25%	$25.38	45%	$13.56	25%	$4.77	24%	$223.63	-	-	-	-	25%	$8.76
Lighting	-	-	-	-	-	-	24%	$226.31	-	-	100%	$56.00	-	-
Pipe wrap	6%	$5.56	-	-	6%	$1.05	1%	$5.00	-	-	-	-	-	-
Service to heating or cooling system	6%	$6.18	-	-	6%	$1.16	<1%	$3.52	49%	$26.57	-	-	11%	$3.77
Low flow showerhead	-	-	-	-	-	-	<1%	$1.72	-	-	-	-	-	-
Programmable thermostat	5%	$4.87	-	-	5%	$0.92	4%	$34.47	-	-	-	-	5%	$1.68
Window	<1%	$0.08	<1%	$0.04	<1%	$0.01	<1%	$0.19	-	-	-	-	<1%	$0.03
Total Value	100%	$101	100%	$30	100%	$19	100%	$949	100%	$54	100%	$56	100%	$35

[35] For the purpose of attributing NEI values to individual measure, the evaluation team only included measures that reasonably have an impact on an individual NEI. For example, heating, cooling and shell measures are included in the NEI for thermal comfort. A cell with a '-' indicates that the measure does not reasonably impact the individual NEI. The following measures were not included in the analysis: cooling systems, heating and cooling systems, heating controls, AC system sizing, and pool timer. While these measures reasonably contribute to several NEIs, such as comfort or property value, the measures were either not installed or savings data at the measure level were not available. for the respondents in this sample

[36] The values in the table are reported as dollars per measure.

[37] The sample size for each individual NEI varies because analysis is limited to those respondents having specific measures installed.

Table 2-8. Attribution of NEI Values to Energy Efficiency Measures, Multi Family Owners, Per Housing Unit

	Marketing		Reduced Tenant Turnover		Increased Property Value		Equipment Maintenance and Reliability		Reduced Lighting Maintenance		Durability		Tenant Complaints	
	% bill savings	$	% bill savings	$	% bill savings	$	% bill savings	$	% bill savings	$	% bill savings	$	% bill savings	$
Sample size	*27*	*21*	*27*	*25*	*27*	*22*	*0*	*4*	*19*	*12*	*27*	*22*	*27*	*20*
Refrigerators or Freezers	35%	$0.34	35%	$0	35%	$5.96	-	-	-	-	35%	$12.90	35%	$6.86
Hot Water System or Water Saving Measures	1%	$0.01	1%	$0	1%	$0.17	-	-	-	-	1%	$0.37	1%	$0.20
Energy Efficient Lighting	46%	$0.44	46%	$0	46%	$7.83	-	-	100%	$66.73	46%	$16.95	46%	$9.02
Thermostats	11%	$0.11	11%	$0	11%	$1.87	100%	$3.91	-	-	11%	$4.05	11%	$2.16
Air Sealing	7%	$0.07	7%	$0	7%	$1.19	-	-	-	-	7%	$2.58	7%	$1.37
Total Value	100%	$0.96	100%	$0	100%	$17.03	100%	$3.91	100%	$66.73	100%	$36.85	100%	$19.61

3. METHODOLOGY

This report presents the findings of the Massachusetts Cross-Cutting Non-Energy Benefits Evaluation and incorporates findings from a review of the NEI literature, in-depth interviews, and telephone surveys with program participants. To account for the fact both positive and negative impacts can result from energy efficiency programs, we use the term non-energy impacts (NEIs) in this report.

3.1 LITERATURE REVIEW

NMR conducted an extensive review of the non-energy benefits (NEBs) literature, in order to identify and review methods used to quantify non-energy benefits, particularly NEBs for low-income programs. Overall, more than 125 reports and academic papers were reviewed for this report

3.2 IN-DEPTH INTERVIEWS

As a complement to the literature review, NMR conducted 13 interviews with Project Administrator (PA) staff members responsible for residential retrofit programs, low-income retrofit programs, and residential new construction programs. Nine in-depth interviews were also conducted with administrators of low-income and residential retrofit energy efficiency programs in other states, health and safety experts, and social service providers familiar with low-income weatherization programs.

During September and October of 2010, NMR conducted in-depth interviews with PA staff members responsible for residential retrofit programs, low-income retrofit programs, and residential new construction programs. The 13 PA program implementers that were interviewed represented the following programs: Mass Save, Multifamily Retrofit, Low Income Multifamily Retrofit, Low Income 1- to 4-Family Retrofit, Weatherization, Residential New Construction, Low Income Residential New Construction, and Residential Heating and Cooling. During the interviews PA staff members were asked to review NEIs found in the literature to be associated with the programs and provide suggestions for additional NEIs not identified in the literature. Findings specific to individual NEIs resulting from these interviews have been included in the discussion of the corresponding NEIs within the body of this report. When asked about the NEIs associated with their programs and the program measures, many interviewees expressed two common viewpoints: that bill savings and increased comfort were the most important benefits of their programs, and that their programs take a whole-house approach wherein the individual measures can have synergistic effects, so that estimating NEIs for individual measures was difficult.[38]

Administrators of low-income and residential retrofit energy efficiency programs in other states were also targeted for in-depth interviews. The purpose of these interviews was to understand how NEIs are considered and treated in other states. Five out-of-state interviewees were targeted. However, due to a low response rate, only two out-of-state interviews could be completed. Relevant findings resulting from these interviews have been included in the discussion of the body of this report were appropriate.

NMR targeted two additional groups for in-depth interviews: health and safety experts and social service providers. The goal was to complete four interviews each for these two groups. NMR was able to complete four in-depth interviews with health and safety experts, and three in-depth interviews with social service providers. These interviewees provided NMR with research studies and reports outside of the evaluation literature that are relevant to particular NEIs, such as health and safety. Findings specific to

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[38] The “whole-house approach” concept arose during interviews with PA Staff responsible for the following programs: residential new construction, MassSAVE, low-income multi-family and low-income one to four family. PA staff emphasized that their programs consider the whole house as a system and attempt to address energy efficiency at the house level rather than at the measure level. For example, one PA staff summarized their approach as follows: “When we go through this process we look at the house as a whole. We don’t look at it as measure by measure, but what does the measure have an affect on the house as a whole,”

certain NEIs resulting from these interviews have been included in the discussion of the corresponding NEIs within the body of this report.

3.3 SURVEYS OF PROGRAM PARTICIPANTS

The study relied on two different surveys. First, we conducted an occupant survey of households that had taken part in various PA programs. Second, we performed surveys with owners and managers of low-income rental housing that had received PA program services. We discuss each method below.

3.3.1 Occupant Surveys

We surveyed 213 low-income households and 209 non-low-income households via computer-assisted telephone interviewing (CATI) from April 11, 2011 through May 10, 2011. The sample was developed from data provided by the PAs for the following programs:

- Low-income retrofit programs (single and multi-family programs)
- Residential cooling and heating program
- Residential heating and hot water program
- Non-low-income retrofit programs (i.e., Mass Save, weatherization, multi-family retrofit programs)

In order to examine potential differences in participant NEI values due to the types of measures installed, the NMR team stratified the residential and low-income residential samples according to the measures installed in their homes, with the three strata representing homes retrofitted with shell measures, or with heating and cooling measures, or with shell plus heating and cooling measures.[39]

Classifying participants into one of the strata required several steps. First, because of the large number of measure types installed by the programs, individual measures were categorized into broader groups of similar measures. For example, we grouped furnaces and boilers together as heating systems and the variety of CFL bulbs and fixtures installed through the programs as lighting, and so on. These efforts yielded the following measure categories:

- Air sealing
- Appliance (refrigerators and freezers)
- Cooling systems
- Door
- Duct sealing
- Faucet Aerator
- Heating and cooling system
- Heating and hot water system
- Heating system

[39] To be included in the shell stratum, a respondent had to have air sealing or insulation installed. To be included in the heating and cooling stratum, a respondent had to have a heating system, such as furnaces or boilers, or an air conditioning system installed. To be included in the shell plus heating and cooling stratum, a respondent had to have at least one shell measure and one heating and cooling measure installed. Installed measures that were neither shell nor heating and cooling did not affect classification of respondents into strata.

- Heating controls[40]
- Hot water system
- Insulation
- Lighting
- Pipe wrap
- Service to heating or cooling system[41]
- Low flow showerhead
- AC system sizing
- Programmable thermostat
- Pool timer
- Hot water tank wrap
- Window
- Weatherization[42]

The measure categories were further grouped into three broader groups of measures: 1) Shell measures, 2) Heating and cooling measures, and 3) Other measures (Table 3-1). The three strata into which participants were classified (i.e., Shell, Heating and Cooling, and Shell plus Heating and Cooling) were derived from these categories. As all participants had at least one shell or heating and cooling measure installed, any measures participants may have installed that are in the *Other Measures* group did not affect respondents' classification into the strata.

[40] The following types of measures were defined as heating controls: boiler reset controls, heat recovery ventilator, weather responsive control, ECM motor.

[41] The following types of measures were defined as service to heating and cooling systems: HVAC service, AC digital tune-up, AC QIV, CoolSmart AC Digital check-up / tune-up.

[42] The 'Weatherization' measure represents the program level savings for National Grid and Berkshire Gas customers; savings data for the individual measures installed were not available for these programs.

Table 3-1. Measure Categories and Strata

Shell Measures	Heating and Cooling Measures	Other Measures
Air sealing	Heating and cooling system	Appliance (refrigerators and freezers)
Insulation	Heating and hot water system	Door
Weatherization[43]	Heating system	Duct sealing
		Heating controls[44]
		Hot water system
		Lighting
		Pipe wrap
		Service to heating or cooling system[45]
		Low flow showerhead
		AC system sizing
		Programmable thermostat
		Pool timer
		Hot water tank wrap
		Window

Second, because program participants can participate in multiple programs with the same PA or across multiple PAs, we developed a unique ID in order to identify participants across programs and PAs.[46] Using the unique ID, NMR aggregated all measures installed in a participant's home by the PAs' programs, plus the energy savings associated with the measures.

Third, using PA data of the estimated energy savings associated with each efficiency measure installed, NMR estimated annual bill savings for the sample. Bill savings were estimated by using a population weighted average of gas and electric rates reported on the Web site of the Executive Office of Energy and Environmental Affairs of Massachusetts.[47] Table 3-2 displays the estimated average annual energy bill savings for the survey respondents, by population and strata. Overall, low-income respondents are expected to save $473 annually and non-low-income respondents are expected to save $673 annually. For the low-income respondents, the shell stratum has the highest average annual energy savings ($583)

[43] The 'Weatherization' measure represents the program level savings for National Grid and Berkshire Gas customers; savings data for the individual measures installed were not available for these programs.

[44] The following types of measures were defined as heating controls: boiler reset controls, heat recovery ventilator, weather responsive control, ECM motor.

[45] The following types of measures were defined as service to heating and cooling systems: HVAC service, AC digital tune-up, AC QIV, CoolSMart AC Digital check-up / tune-up.

[46] A participant who receives gas service from one PA and electric service from a different PA can participate in programs from both PAs. In addition, participants may enroll in multiple programs within the same PA.

[47] http://www.mass.gov/?pageID=eoeeaterminal&L=5&L0=Home&L1=Energy%2c+Utilities+%26+Clean+Technologies&L2=Electric+Power&L3=Electric+Market+Information&L4=Basic%26%2347%3bDefault+Service&sid=Eoeea&b=terminalcontent&f=dpu_restruct_default_service_fixed_defaul

while for the non-low-income respondents the shell plus heating and cooling stratum has the highest average annual energy savings ($1,275).[48]

Table 3-2. Estimated Average Annual Energy Bill Savings

Strata	Low-income	Non-low-income
Sample size	213	209
Shell	$583	$380
Heating and Cooling	$392	$347
Shell plus Heating and Cooling	$445	$1,275
Overall Population	$473	$673

Fourth, we classified participants into strata according to the program measures installed in their homes. To be included in the shell stratum, a respondent had to have air sealing or insulation installed. To be included in the heating and cooling stratum, a respondent had to have a heating system, such as furnaces or boilers, or an air conditioning system installed. To be included in the shell plus heating and cooling stratum, a respondent had to have at least one shell measure and one heating and cooling measure installed. Other measures installed by participants did not affect classification. Next, we removed from the sample all program participants who had been included in the sample frame for other surveys recently conducted for the residential retrofit evaluations (i.e., Mass Save and low-income retrofit programs) to avoid burdening program participants with multiple survey requests.

Table 3-3 shows the final sample population, sample sizes, and associated expected error margin at the 90% confidence level, assuming a 50/50 break in responses. In addition, because program participants who received both shell measures and heating and cooling measures were oversampled, we developed weights so that results could be extrapolated to the population of program participants that met at least one of the strata criteria[49].

[48] Estimated annual bill savings ranged from a low of $13.93 to a high of $4,910.74 for non-low-income respondents and from a low of $3.15 to a high of $2,150.81 for low-income respondents.

[49] The shell plus heating and cooling strata had a wider range of measures installed in their homes, which may result in different levels of NEIs for these participants. Weights were applied so that results could generalized to all program participants who installed shell measures or heating and cooling measures.

Table 3-3. Sample Size, Sampling Error, and Weight: Occupants

		Population (households)	Sample Size	Sampling Error at 90% Confidence Interval	Weight*
Non-low-income	Heating & Cooling	13,313	68	±10.0%	1.53
	Shell	12,574	70	±9.9%	1.40
	Shell plus Heating & Cooling	944	71	±9.5%	0.10
	Total	26,831	209	±9.9%	-
Low-income	Heating & Cooling	1,087	72	±9.4%	1.22
	Shell	869	72	±9.3%	0.98
	Shell plus Heating & Cooling	672	69	±9.4%	0.79
	Total	2,628	213	±9.4%	-

*Weights were calculated as follows: (strata population / total population) * (total sample size / class sample size)

The occupant survey addressed the following issues:

- Whether the participant believed their home, because of the energy efficiency improvements, provides a particular NEI
- Annual value placed on each NEI in relation to energy bill savings. Values could be expressed in dollars or as a percentage of bill savings.
- Total value of the NEIs
- Changes in household health since the energy efficiency improvements were installed
- Demographic and housing characteristics

A copy of the survey instrument is found in Appendix F: NEI Survey: Low-income and Non-low-income Retrofits.

3.3.2 Owners and Managers of Low-income Rental Housing Survey

Twenty-one owners and managers of low-income rental housing were surveyed about 27 low-income rental facilities via computer-assisted telephone interviewing (CATI) from April 26, 2011 through May 10, 2011.

The sample was developed from multi-family retrofit program data provided by the PAs. As with the occupant survey sample, we took several steps to prepare the program data for the sample, including categorizing measures, aggregating installed measures and related energy savings by owner or manager and by facility, and estimating bill savings for each facility. All of the sample processing procedures used for the occupant survey sample were followed except for the step of classifying by strata.

Table 3-4 shows the final sample population, sample sizes, and the associated error margin at the 90% confidence level, assuming a 50/50 break in responses.

Table 3-4. Sample Size, Sampling Error, and Weight: Owners and Managers of Low-income Rental Housing

	Population (Buildings/Facilities)	Sample Size	Sampling Error at 90% Confidence Interval
Owners & Managers of Low-income Rental Housing	196	27	+15.0%

4. UTILITY-PERSPECTIVE NEIs—LITERATURE REVIEW

Utilities can realize a number of non-energy impacts (NEIs) from their energy efficiency programs in the form of financial savings. Energy-efficient technologies installed by Project Administrators' (PA) programs often result in reduced energy bills for participants, which can decrease the likelihood that customers experience difficulties with paying their utility bills. In turn, utilities realize financial savings through reduced costs associated with arrearages and late payments, uncollectible bills and bad debt write-offs, service terminations and reconnections, bill-related customer calls, and the bill collections process. In addition, utilities may realize savings from their efficiency programs due to a reduction in safety-related emergency calls and reductions in the costs of energy that receives a rate discount. Program induced energy savings among low-income participants reduces the amount of energy receiving a rate discount. These financial savings are generally passed on to ratepayers, and therefore are sometimes referred to as ratepayer benefits in the literature. Theoretically, these benefits could apply to some extent to all PA programs and customers, but the NEI literature has rarely quantified this benefit for non-low-income customers and programs. Therefore, NMR recommends limiting the utility-perspective NEIs to low-income programs.

The majority of early NEI literature focused on utility-perspective NEIs arising from programs targeted to low-income customers. A wide range of positive impacts to utilities were reported, based on a variety of programs. The variability in the magnitude of impacts reported in the literature is due to several reasons. First, the programs on which the analyses are based incorporated different approaches. While some low-income programs provided only weatherization measures to participants, others included or relied entirely upon education or cash assistance components. For programs that included energy efficiency measures, the type and quantity of measures varied between programs and often are not specified in the analyses. Secondly, utility data on participant characteristics and certain collection-related costs are often nonexistent or extremely expensive to collect. Absent accurate data, various assumptions have been made in the estimation of utility perspective NEIs. Lastly, the calculation of many utility-perspective NEIs includes marginal costs to the utility such as the cost per customer call, late payment notice, or service termination. It is apparent from the literature that these costs vary among utilities, due to differences in utility cost structures and policies. Table 4-1 provides an overview of recent NEI evaluations of low-income programs, illustrating the range of program elements and efficiency measures installed by the programs as well as the estimated bill savings realized by the programs.

Table 4-1. Recent NEI Studies of Low-Income Programs

Year of Study	Author	Location	Program Type	Measures Installed[50]	Estimated Annual Energy Bill Savings, per Participant[51]
1997	Skumatz & Dickerson	California	Low-income Weatherization & Education Pilot Program	Outreach; on-site audit & education; weatherization[52]; & follow-up education visit	$85
1999	Skumatz & Dickerson	California	Low-income Weatherization Program	Attic insulation, water heater blankets, efficient showerheads, door weather-stripping, caulking, minor home repairs that affect infiltration, refrigerators, & education	$44
1999	Riggert et al.	Vermont	Low-income Weatherization Program	Water heater wrap, water conservation devices, pipe insulation, CFLs, water bed insulation covers, insulation, windows, air sealing, weather-stripping, heating system replacement or repair	$276
2002	Skumatz & Nordeen	Connecticut	Low-income Weatherization Program	CFLs, lighting fixtures, water heater wraps, low flow showerheads & faucet aerators, waterbed insulated covers, door sweeps, thermostats, caulking &insulation, energy efficient refrigerators & freezers, minor repairs, burner & furnace replacement	$67
2005	Skumatz & Gardner	Wisconsin	Low-income Weatherization Program	CFLs, air sealing, CO detectors, attic insulation, insulation of hot water heater pipes, smoke detectors	$220

Table 4-2 provides a summary of the utility-perspective NEIs for which NMR recommends deriving values from the literature, including reductions in arrearage carrying costs, bad debt write-offs, terminations and reconnections, customer calls, notices, and safety-related emergency calls. NMR's review of the literature found eight reports containing utility-perspective NEI values based on programs comparable to the PAs' programs with respect to program components[53], energy efficient measures[54], and target populations.[55] [56]

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[50] Most programs installed wide variety of measures. This list includes the most commonly installed measures as reported in the literature.

[51] Dollar values have not been adjusted for inflation.

[52] Specific weatherization measures were not defined in the study.

[53] The low-income energy efficiency programs in the literature incorporated different program elements, including different combinations of energy efficiency measures, educational and counseling components, and in some cases payment assistance. NMR considered programs comparable to the PAs' programs to be those relying primarily on energy efficiency measures. Programs relying primarily or entirely on education, counseling, or payment assistance components were not considered comparable to the PAs' programs.

[54] In determining whether an NEI value from the literature was applicable to the PAs' programs, NMR reviewed the measures implemented by the programs in each study. Next, NMR compared the measures in the literature to measures implemented through the PAs' programs (the PAs provided lists of measures implemented through their programs). With the exception of low-income programs relying primarily on education, counseling, or payment assistance components, the majority of low-income weatherization and retrofit programs in the NEI literature offer similar measures as the PAs' low-income programs, such as insulation, air sealing, heating system repairs/replacements, lighting, and DHW measures.

[55] NMR considers low-income programs that are open to all low-income customers to be comparable to the PAs' low-income programs. Studies of programs that targeted only a subset of low-income customers, such as high-arrearage low-income customers, were not considered comparable to the PAs' programs.

The table does not include NEI values from evaluations of programs that were not comparable to the PAs' programs. For example, the 2008 evaluations of the Oregon HEAT and REACH Programs (Drakos et al., 2008) and the 2005 evaluation of the Utah HELP program (Khawaja and Wiley, 2005) were excluded because these programs relied heavily or entirely on payment assistance, counseling, and educational components, program elements not included in the PAs' low-income programs.

Table 4-2. Reported NEI Values (Dollars per Participant per Year) from Recent NEI Studies of Low-Income Programs

Study	Reported NEI Value, $/year/participant					
	Carrying Cost on Arrearages	Bad Debt Write-Offs	Terminations and Reconnections	Customer Calls	Notices	Safety-Related Emergency Calls
WI Low-income Weatherization (Skumatz and Gardner, 2005)	1.37	--	0.13	0.43	0.30	--
National Low-income Weatherization NEBs Study (Schweitzer and Tonn, 2002)	--	6.09	0.55	--	--	6.91
MA Low-income Weatherization (Skumatz Economic Research) Associates, 2002)	1.71	3.62	--	0.59	--	0.40
CT Low-income Weatherization (Skumatz and Nordeen, 2002)	2.03	2.24	0.10	0.55	1.16	0.21
CA Low-income Public Purpose Test (TecMarket Works, Skumatz Economic Research Inc, and Megdal Associates, 2001)	3.76	0.48	0.07	1.58	1.49	0.07
VT Low-income Weatherization (Riggert et al., 1999)	--	--	7.00	--	--	15.58
CA Low-income Weatherization (Skumatz and Dickerson, 1999)	2.09	2.34	0.33	0.07	0.04	7.91
Venture Partners Pilot Program (Skumatz and Dickerson, 1997)	4.00	4.50	0.63	0.13	0.08	15.00

4.1 ARREARAGES

Arrearages accumulate when customers are unable to pay their bills on time. The carrying cost associated with arrearages is borne by the utilities. The magnitude of arrearage carrying cost is dependent on the dollar value of arrears, the utility's interest rate for carrying short-term debt,[57] and the duration that arrears are outstanding.

The value of the NEI of reduced arrearage carrying costs ranges from $0.50 to $7.50 per participant per year in recent studies.

Energy efficiency programs that reduce customers' energy consumption also reduce customers' energy bills, making it easier for low-income customers to pay their bills and therefore less likely to be in arrears.

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[56] An empty cell in Table 4-1 signifies one of two things: either an NEI value was not estimated for a particular study, or the NEI value reported was based on an NEI from another report included in the table. An example of the latter scenario is the NEI of reduced carrying cost on arrearages reported for the national low-income WAP (Schweitzer and Tonn, 2002), in which the NEI value was estimated by taking the midpoint of the values reported for the Venture Partners Pilot and CA low-income weatherization programs (Skumatz and Dickerson, 1997 and 1999).

[57] The interest rate for carrying short-term debt refers to the interest expense associated with arrears. Accounts in arrear represent a lost opportunity to the utility to earn a return on customer's bill payment. The relevant time period for a dollar in late payments is the amount of time that that dollar is late and not earning a return for the utility.

The NEI value to utilities from reduced arrearages can be calculated by multiplying the program-induced reduction in arrearages by the utility's interest rate for carrying short-term debt. Studies measuring the impact on arrearages of energy efficiency programs date back to the early 1990's. A review of the literature indicates that programs targeting high-arrearage or payment-troubled customers tend to have a larger impact in arrears than those that do not. The most rigorous arrearage studies in the literature employ a quasi-experimental design, with one year each of pre- and post-program billing data for both a treatment and a comparison group. More recent studies quantifying arrearage NEIs often substitute pre/post treatment/control measured impacts with assumed percentage arrearage reductions taken from previous studies.

Howat and Oppenheim (1999) summarized much of the earlier arrearage literature. Many of the arrearage estimates reported in the early literature were not reported in conjunction with pre-program arrearage balances. Therefore, while they demonstrate that energy efficiency programs affect arrearages, they do not demonstrate the magnitude of program impacts. A 1995 study conducted for the Boston Edison Settlement Board by the Tellus Institute found an arrearage reduction of $0 to $469 per household (Biewald et al., 1995), and a 1998 study by Skumatz and Dickerson reported a reduction of $4 to $63 per household. The Oak Ridge National Laboratory (ORNL) reported the average reduction in arrearages for the year following weatherization to be $32 in its 1993 evaluation of the national Weatherization Assistance Program (WAP) (Brown et al., 1993), though a follow-up study of the national WAP study estimated a smaller benefit of $3.90 per year (Schweitzer and Tonn, 2002).

One complication in comparing arrearage impact estimates across different reports is that the literature does not consistently report program design elements and the energy efficiency measures employed, both of which vary across programs. The national 1993 WAP evaluation published by ORNL, however, did specify commonly employed measures, which included caulking and weather stripping around doors and windows, sealing unnecessary openings to reduce air infiltration, installing attic, wall, and floor insulation, and wrapping water heaters and pipes with insulating material. Another report that identified installed measures, thereby allowing for the meaningful comparison of arrearage impacts across programs, is Blasnik's 1997 evaluation of Ohio's low-income Home Weatherization Assistance Program (HWAP). The HWAP measures included dense-pack cellulose wall insulation, attic insulation, blower-door guided air sealing, duct sealing, energy-related home repairs, energy education, and heating and water heating system safety testing, minor tune-ups and occasional replacements. Additionally, it was noted in the 1997 HWAP evaluation report that the gas savings for HWAP participants were 70% larger than the average national WAP gas savings (Blasnik, 1997). The HWAP analysis reported both average arrearage reductions and original arrearage balances, allowing program impacts to be interpreted in percentage terms. The HWAP arrearage impact evaluation employed a pre/post treatment/comparison approach and found that average payment shortfalls declined by 63% after HWAP, while the comparison group's shortfall actually increased by 7%.

Program-induced arrearage reductions are generally estimated as an annual benefit with the annual program-induced arrearage reductions multiplied by a utility's interest rate associated with short-term debt in order to estimate the benefit to the utility in the form of reduced carrying costs.

Skumatz and Dickerson (1997)

Skumatz and Dickerson (1997) estimated a range of $0.50-$7.50 in reduced arrearage carrying costs per participant, based on the Venture Partners Pilot (VPP) Program, a low-income weatherization and education program in California. The VPP estimate was based on an assumed reduction in arrearages of 26%, taken from Magouirk (1995), and utility data on the percentage of customers in arrears and arrearage balances for customers eligible to participate in the program.

Skumatz and Dickerson (1999)

A different low-income weatherization program in California evaluated by Skumatz and Dickerson (1999) yielded a smaller benefit range of $0.26-$3.91. Weatherization measures for the VPP program were not reported, but they were for the 1999 California weatherization program and included energy education services, energy-efficient refrigerators, attic insulation, water heater blankets, energy-efficient showerheads, door weather-stripping, caulking, and minor home repairs affecting infiltration. A key differentiating factor between the two California programs is that the average bill savings per participant from the VPP program were approximately twice as much as the average bill savings from the weatherization program.

Skumatz and Nordeen (2002)

A 2002 report evaluating the NEIs associated with the Connecticut Weatherization Residential Assistance Partnership (WRAP) program reported a reduction in arrearage balances of 32%, resulting in carrying cost savings to the utility of $2.03 per participant (Skumatz and Nordeen, 2002). WRAP measures included weather stripping, caulking, CFLs, low-flow showerheads, faucet aerators, refrigerators, furnaces, thermostats, and on-site energy discussion and education. Identifying eligible nonparticipants for a control group in the WRAP evaluation proved challenging, because the utility's database was not designed to differentiate between low-income and non-low-income customers. As cited in Skumatz, Khawaja, and Krop (2010), Skumatz has been involved in the estimation of several other arrearage-carrying-cost NEI values, including $1.37 per household per year for a Wisconsin low-income program and $1.71 per household per year for a Massachusetts program.

Riggert et al. (1999)

Many of the more recent NEI valuations of reduced arrearage carrying costs are based partially or entirely on values published in the literature estimated for other programs. A comprehensive summary of arrearage analyses in the literature is provided in Riggert et al.'s 1999 Evaluation of the Energy and Non-energy impacts of Vermont's Weatherization Assistance. Rather than calculating an NEI value for the benefit from reduced carrying cost of arrearages based on Vermont WAP data, Riggert et al. selected an NEI value of $4.00 per household per year from their literature review. Assuming a 20-year benefit duration, a net present value of $57.25 per household in reduced arrearage carrying costs was estimated for the 1999 Vermont WAP evaluation.

TecMarket Works, SERA, and Megdal Associates (2001)

A literature review was also conducted for the 2001 California Low-income Public Purpose Test (LIPPT) report for the Reporting Requirements Manual (RRM) Working Group Cost Effectiveness Committee (TecMarket Works, SERA, and Megdal Associates, 2001). This literature review identified over 30 arrearage estimates, most of which employed a pre/post treatment/comparison methodology. The range of arrearage reductions, excluding studies which targeted customers with bill payment difficulties, was 0%-90%. The LIPPT estimated an NEI value of $3.76 per participant per year based on the average percentage reduction in arrearages from the literature review of 28%. This NEI valuation assumes a ten-year benefit duration and a utility interest rate of 8.15%. The magnitude of the arrearage benefit relative to other utility NEIs is illustrated in the LIPPT report, which found reduced arrearage carrying costs to represent 36% of the total utility perspective NEIs quantified in the report.

4.1.1 Assessment of the NEI Literature

Out of all of the NEIs that have been recognized in relation to energy efficiency programs, arrearage impacts are the most studied. The literature on arrearage impacts of low-income programs extends back two decades. The impact evaluations in the earlier literature were frequently performed using a rigorous evaluation design, which included pre- and post-program billing data for both a treatment and a comparison group. The majority of recent NEI valuations for the utility benefit of reduced arrearage carrying costs borrow arrearage reduction percentages from previous studies, rather than conducting a pre/post treatment/comparison arrearage impact evaluation in order to calculate the relevant program-induced impact on arrearages. NEI valuations estimated in this way avoid the costs associated with collecting primary data, which can be expensive and, particularly when it is necessary to distinguish between low-income and non-low-income participants, extremely difficult to collect. Energy efficiency programs targeting customers with bill payment difficulties have resulted in higher arrearage reductions, though even when these results are ignored, the range of arrearage reduction percentages from the literature is 0%-90%. Caution should be used when making generalizations based on the literature, because the programs studied incorporated different program elements, including different combinations of measures, educational and counseling components, and in some cases payment assistance[58] and because the relative impact of each program element on arrearage reductions is not examined in the literature.[59]. Arrearage impact estimates found in the literature are sensitive to underlying assumptions, including the duration of savings to the utility, the discount rate used to calculate annual benefits, the utility interest rate used to calculate the carrying cost savings, and substitute values that have been used when data is unavailable.

4.1.2 Relevant PA Programs

All of the arrearage estimates in the literature have been based on information from low-income programs, the majority of which were weatherization programs. Therefore, NMR recommends applying this NEI to participants in the PAs' low-income programs.

4.1.3 Recommendations

Based on our review of the literature, NMR recommends a value of $2.61 per participant per year, based on the median of the values reported in the literature.[60] An overview of the studies used to estimate this value is provided in Appendix D.[61]

Because PA data were not available for average arrearage balances for eligible low-income customers before and after program participation, it is not possible to derive an estimated value from PA data. If such data becomes available, an alternative method of quantifying the annual cost savings to utilities from reduced arrearage carrying costs is as follows:

- Average arrearage balance per eligible low-income customer before program (PA data) * 28% (average reduction in arrearages, derived from the literature[62]) * utility interest rate associated with short-term debt (PA data).

Greater precision would require the collection of primary data on pre- and post-program arrearages of program participants. However, because of the relatively low value of this NEI, NMR does not recommend primary data collection at this time.

4.2 BAD DEBT WRITE-OFFS

Utilities incur the cost of bad debt write-offs (or uncollectables) when customers fail to pay their bills and utilities are unable to collect unpaid balances. Bad debt write-offs are accounted for separately from arrearages by utilities and represent a different cost from the carrying costs of arrearages. Low-income energy efficiency programs can reduce this utility cost by making energy bills more affordable to customers. The NEI value to utilities from reduced bad debt write-offs is a simple calculation, equal to the difference between pre-program bad debt write-offs and post-program bad debt write-offs. A couple of

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[58] It is NMRs understanding that none of the PA programs include cash assistance. Therefore, we excluded all analyses based on cash assistance programs. It is possible, however, that program impact values that are based on point estimates from literature reviews did not exclude cash assistance programs.

[59] In other words, if the educational and counseling component of a program in the literature review is responsible for a significant amount of the total arrearage reduction and the PAs' programs do not include an educational and counseling component, than deriving an average program-induced reduction in arrearages from the literature would result in an inflated estimate of arrearage reductions

[60] The current TRM reports a one-time arrearage benefit of $70 per household (Massachusetts Electric and Gas Energy Efficiency Program Administrators, 2010). Because the evaluation team was not provided the study used to estimate and justify this value, we relied on the existing literature to estimate a value.

[61] Values were derived from the literature published since 1997 and were adjusted into 2010 dollars using an inflation rate of 2.5 percent per year, the same inflation rate used in the PAs' three-year plans (see National Grid et al., 2009; NSTAR et al., 2009).

[62] Data source for average reduction in arrearages: TecMarket Works, SERA and Megdal Associates, 2001.

studies in the literature examined the impact of low-income energy efficiency programs on bad debt write-offs, using a pre/post impact evaluation design. However, most bad debt write-off NEI valuations found in the literature are based on assumed rates of program-induced decreases in bad debt write-offs, as opposed to rates calculated based on program billing data.

The NEI value of reduced bad debt write-offs ranges from $0.48 to $7.00 per participant per year in the literature.

Magouirk (1995)

One of the pre/post impact evaluations of bad debt write-offs frequently cited in the literature is that of a low-income weatherization program in Colorado by Magouirk (1995), which found that write-offs dropped 18% at weatherized homes during the year following weatherization.

Skumatz and Dickerson (1997 and 1999)

Skumatz and Dickerson (1997 and 1999) applied the 18% reduction reported by Magouirk in the calculation of the value of avoided bad debt write-offs for the VPP and low-income weatherization programs in California.

TecMarket Works, SERA, and Megdal Associates (2001)

In a review of the literature, the 2001 California LIPPT found that the average reduction in write-offs associated with energy efficiency programs ranged from 8% to 36%, based on a variety of low-income programs. The average percentage reduction of bad debt write-offs found in the literature was multiplied by the average bad debt per low-income customer for four California utilities, in order to calculate the per participant NEI value of $0.48[63] for the LIPPT report (TecMarket Works, SERA and Megdal Associates, 2001). Bad debt write-offs were estimated to represent 5% of total utility NEIs in the LIPPT report.

Skumatz and Nordeen (2002)

The percentage reduction in arrearages was employed as a proxy for percentage reduction in bad debt write-offs in the bad debt write-off NEI estimation for Connecticut's WRAP program (Skumatz and Nordeen, 2002).

[63] Assumes ten-year benefit duration and 8.15% interest rate.

Skumatz, Khawaja, and Krop (2010)

Based on a review of the literature, Skumatz, Khawaja and Krop (2010) noted that the impact values for reduced bad-debt range from 20-35%, that few studies have specifically examined program impacts on bad debt, and that the values for this NEI are approximately $2 when averaged across participants.

4.2.1 Assessment of the Literature

While the literature for bad debt write-off impacts is less extensive than that for arrearages, estimation methods and impact results are similar for these two NEIs. Many of the recent studies have applied assumed rates of decrease in bad debt write-offs, such as the percent decrease in arrearages or a point estimate taken from the literature, as opposed to embarking on a pre/post bad debt write-offs impact analysis. There is moderate variability in the range of estimates of the NEI for bad debt write-offs; however, the magnitude of this NEI is small relative to other NEIs.

4.2.2 Relevant PA Programs

All of the bad debt write-off estimates in the literature have been based in information from low-income programs, the majority of which were weatherization programs. Therefore, NMR recommends applying this NEI to participants in the PAs' low-income programs.

4.2.3 Recommendations

Based on our review of the literature, NMR recommends a value of $3.74 per participant per year, based on the median value reported in the literature.[64]

Because PA data were not available for average bad debt write-offs for eligible low-income customers before and after program participation, it is not possible to derive an estimated value from PA data. If such data becomes available, an alternative method of quantifying the annual cost savings to utilities from reduced bad debt write-offs is as follows:

- Average amount of bad debt per eligible low-income customer before program (PA data) * 20.7% (average reduction in bad debt write-offs, derived from the literature[65]).

Greater precision would require primary data collection on pre- and post-program bad debt write-offs of program participants. However, because of the relatively low value of this NEI, NMR does not recommend primary data collection at this time.

4.3 TERMINATIONS AND RECONNECTIONS

Energy efficiency programs that make energy bills more affordable for low-income customers can decrease the likelihood of service termination due to non-payment. Terminations and subsequent reconnections represent a cost to utilities. The NEI value to utilities from avoided termination costs can be estimated by multiplying the number of avoided terminations times the marginal cost per termination. The NEI value for avoided reconnections is calculated in a similar manner.

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[64] Values were derived from the literature published since 1997 and were adjusted into 2010 dollars using an inflation rate of 2.5 percent per year, the same inflation rate used in the PAs' three-year plans (see National Grid et al., 2009; NSTAR et al., 2009). For more details, see Appendix D.

[65] Data source for average reduction in bad debt write-offs: TecMarket Works, SERA and Megdal Associates, 2001.

The NEI value of decreased terminations and reconnections ranges from $0.02 to $7.00 per participant per year in the literature.

Termination and reconnection costs vary between utilities. Howat and Oppenheim (1999) cited costs from Colton (1994) to Columbia Gas Company, including $21.92 per termination and $43.84 per reconnection. The 2007 Low Income Arrearage Study found a wide range in disconnection and reconnection service fees in PacifiCorp's service territory, ranging from $19.75 to $112.15. The study authors noted that fees varied by state for a variety of reasons, including the personnel assigned, the associated time, and hourly rates (Khawaja et al., 2007).

Blasnik (1997 & 1999)

The ideal way to measure the impact of energy efficiency programs on frequency of terminations and reconnections is to conduct a pre/post treatment/comparison impact evaluation. Using the pre/post treatment/comparison method, Blasnik (1997) found that the service disconnection rate for HWAP participants declined 39.3%, from 3.7% to 2.3% of the participating population, while the comparison group experienced an increase of 28.5% over the same period. Blasnik reported a net reduction of 67.8% in service disconnections resulting from the HWAP program. As cited in the 2001 California LIPPT report, Blasnik's 1999 study of Ohio's WAP found a reduction in service terminations of 5.4%, and his 1999 evaluation of Louisville Gas and Electric reported a reduction of 23% (TecMarket Works, SERA and Megdal Associates, 2001)

Skumatz and Nordeen (2002)

A reduction in service terminations of 16% was reported for the 2002 Connecticut WRAP program analysis (Skumatz and Nordeen, 2002).

TecMarket Works, SERA, and Megdal Associates (2001)

A literature review for the 2001 California LIPPT report revealed a range of 1% to 84% reduction in service terminations resulting from low-income weatherization programs, some of which included education components. The authors selected the value of 23% from Blasnik's 1999 evaluation of Louisville Gas and Electric in estimating the NEI value for the LIPPT report. The assumed 23% impact was multiplied by the average shutoff per low-income customer per year (0.0279) and the utility's marginal cost per shutoff ($8.29) to derive an NEI value of $0.05 per participant. The value of decreased reconnections was calculated similarly in the LIPPT report: average reconnects per low-income customer were estimated to be 0.0192 and marginal cost per reconnect was found to be $22.70, yielding an NEI value of $0.02 per participant. The value of reduced terminations and reconnections represented only 1% of total utility NEIs considered in this report (TecMarket Works, SERA, and Megdal Associates, 2001).

4.3.1 Assessment of the Literature

A few early studies of program impacts on terminations and reconnections employed pre/post treatment/comparison methods. These early studies examined impacts on service terminations, but did not quantify impacts on reconnections. In addition, some of the literature assumes that customers who experience a service termination will likely have service reconnected; thus the cost to the utility per termination incident includes the cost per termination plus the cost per reconnection. Most of the recent literature that monetizes program-induced utility cost savings does not directly measure program impacts, but instead assumes an impact percentage reduction in terminations and reconnections based on findings from past research. Termination and reconnection costs represent a minor portion of utility avoided costs associated with energy efficiency programs.

4.3.2 Relevant PA Programs

The literature on service terminations and reconnections is based entirely on low-income customers. Therefore, NMR recommends applying this NEI to participants in the PAs' low-income programs.

4.3.3 Recommendations

Based on our review of the literature, NMR recommends a value of $0.43 per participant per year, based on the median value reported in the literature.[66]

Because PA data were not available for PA costs of terminations and reconnections, it is not possible to derive an estimated value from PA data. If such data becomes available, an alternative method of quantifying the annual cost savings to utilities from reduced terminations and reconnections is as follows:

- Average number of terminations per eligible low-income customer before program (PA data) * 23% (conservative reduction in terminations, derived from the literature[67]) * marginal cost per termination (PA data).
- Average number of reconnections per eligible low-income customer before program (PA data) * 23% (conservative reduction in reconnections, derived from the literature[68]) * marginal cost per reconnection (PA data).

Greater precision would require the collection of primary data on pre- and post-program terminations and reconnections of program participants. However, because of the relatively low value of this NEI, NMR does not recommend primary data collection at this time.

4.4 RATE DISCOUNTS

Rate discounts are offered to low-income customers and are subsidized by utilities and ratepayers. Energy efficiency programs that reduce the amount of energy consumed by low-income customers can decrease the quantity of energy sold at the discounted rate. Utilities realize financial savings because a smaller portion of energy is sold at the discounted rate. The financial savings to utilities is equal to the expected energy savings of low-income participants times the difference between the full residential rate and the discounted rate for eligible low-income participants.

The NEI value of rate discounts ranges from $2.61 to $23.57 per participant per year in the literature.

Skumatz and Dickerson (1997 & 1999)

One of the earlier estimates of rate discount NEIs was by Skumatz and Dickerson (1997), who estimated the utility benefit from avoided rate subsidies attributable to the VPP program to be $5-$32 annually per participant. This NEI value was calculated based on the annual subsidy per-participant and the expected percentage energy savings from the program. The same authors estimated a benefit range of $2.61-$16.68 for a California low-income weatherization program (1999).

Skumatz, Khawaja, and Krop (2010)

The annual per participant NEI value estimated in the 2001 California LIPPT report was $2.77, which was calculated by multiplying the following: 1) average annual bill savings per participant; 2) rate subsidy percentage; 3) percent of participants paying the subsidized rate. Intuitively, average bill savings is dependent on average energy savings. The LIPPT report authors found a range of 4% to 22% for average energy savings in the literature, noting that programs that included an education component tended to produce greater energy savings. Skumatz, Khawaja, and Krop (2010) reported a range from the

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[66] Values were derived from the literature published since 1997 and were adjusted into 2010 dollars using an inflation rate of 2.5 percent per year, the same inflation rate used in the PAs' three-year plans (see National Grid et al., 2009; NSTAR et al., 2009). For more details, see Appendix D.

[67] Data source for reduction in terminations: TecMarket Works, SERA and Megdal Associates, 2001.

[68] Data source for reduction in reconnections: TecMarket Works, SERA and Megdal Associates, 2001.

literature of $3.32-$23.57 for this NEI, noting that the value is directly related to energy savings and the utility's discount rate.

4.4.1 Assessment of the Literature

The calculation of the NEI associated with rate discounts is relatively straightforward. Estimation methods in the literature are consistent, although it is not always clear from the literature whether the energy savings input has been calculated based on actual program data, or whether energy savings have been assumed based on previous study results. The cost savings to a utility from avoided rate discounts is particularly sensitive to individual rate discount percentages and the level of program-induced energy savings.

4.4.2 Relevant PA Programs

NMR recommends applying this NEI to programs in which low-income participants pay discounted rates.

4.4.3 Recommendations

Based on our review of the literature, NMR recommends quantifying the cost savings to utilities from reduced rate discounts as follows:

- Estimated energy savings per installed measure (PA data) * Number of measures installed * [(full rate per unit energy ($) – discounted rate per unit energy ($)]

Alternatively, this could also be estimated at the participant level rather than at the measure level using the following formula:

- Average program energy savings per low-income eligible customer (PA data) * [(full rate per unit energy ($) – discounted rate per unit energy ($)]

The rate discount benefit can be calculated either by individual PAs, according to their individual PA rate discount, or it can be calculated statewide using the following population weighted rate discounts of $0.0424 per kWh and $0.2663 per therm.[69]

4.5 CUSTOMER CALLS AND COLLECTIONS ACTIVITIES

Timely customer bill payments can result in fewer customer calls, late payment notices, shut-off notices, and other collection activities. The PAs realize savings in staff time and materials. As with all other payment-related utility NEIs addressed in the literature, customer calls and collection activities have been examined only within the context of low-income programs. Oftentimes the data required to estimate program impacts for low-income customers are extremely difficult or impossible to collect; utilities do not usually track whether individual telephone calls, notices, and other collection-related activities involve low-income or non-low-income customers. Therefore, program-induced changes in incidence rates of these activities involve assumptions in the proportion of activities involving low-income customers. Some studies examining collection-related NEIs investigate each cost individually, while others examine various combinations. In this section we review each collection-related avoided cost separately.

[69] The population weighted average rate discount was estimated using data reported on the Web site of the Executive Office of Energy and Environmental Affairs of Massachusetts: (http://www.mass.gov/?pageID=eoeeaterminal&L=5&L0=Home&L1=Energy%2c+Utilities+%26+Clean+Technologies&L2=Electric+Power&L3=Electric+Market+Information&L4=Basic%26%2347%3bDefault+Service&sid=Eoeea&b=terminalcontent&f=dpu_restruct_default_service_fixed_default)

4.5.1 Customer Calls

Reduced incidence of customer calls is widely recognized as a non-energy benefit to utilities. Bill-related calls from customers represent a cost to utilities, as do calls made by utilities in order to collect on delinquent accounts. The general approach to quantifying the average per-participant savings due to reduced customer calls is easy to calculate, and is done so by multiplying the percentage reduction in calls as a result of the program by the utility's marginal cost for calls. Quantifications in the literature of the value of this NEI have not been based on pre/post program changes in customer calls, but instead employ substitute impact values, such as the percentage decrease in arrears or bad debt. Because utility costs are a component of the calculation, this NEI is inherently sensitive to each individual utility's costs.

The NEI value of reduced incidence of customer calls ranges from $0.00 to $1.58 per participant per year in recent studies.

Skumatz and Dickerson (1997 and 1999)

Some of the first estimates of the utility NEI from reduced customer calls were reported by Skumatz and Dickerson, who estimated a value range for reduced customer calls of $0.00-$0.25 per participant per year for the VPP program (1997) and $0.00-$0.13 for the California weatherization program (1999). These ranges were calculated by multiplying the reduction in write-offs and arrearages by utility data on cost of customer calls. A key assumption in the estimation of these benefit ranges is that low-income customers are more likely to call the utility regarding late payments and notices than other customers. The authors noted that the actual percentage of customer calls from eligible customers was unavailable from the utility data; therefore, the estimated benefit ranges were based on an assumed proportion of calls from low-income customers.

TecMarket Works, SERA, and Megdal Associates (2001)

The authors of the California LIPPT report suggested that the preferred calculation method for the NEI associated with decreased customer calls is to multiply the average number of pre-program bill-related calls from eligible low-income customers by the percent reduction in participant bill-related calls, by the utility marginal cost per bill-related call (TecMarket Works, SERA, and Megdal Associates, 2001). They also recognized that the literature did not contain any studies with estimates of reductions in customer calls. The proxy value used in quantifying the NEI value for the LIPPT report, in place of percent reduction in customer calls, was a point estimate based on an assortment of bill payment behavior and collection activity impact studies. The NEI value of $1.58 per participant per year was calculated by multiplying the average customer calls per year (1.865) by the proxy value (24.7%) and the utility's marginal cost per call ($3.42). Reduced customer calls represented 15% of total utility NEIs quantified in the LIPPT report.

Skumatz and Gardner (2005)

An NEI value of $0.43 per participant per year was estimated for a 2005 report on Wisconsin's low-income weatherization program (Skumatz and Gardner, 2005). This calculation was not based on any of Wisconsin's program data, but instead employed estimates from the literature for average calls per low-income customer pre-program, average program-induced reduction in calls, and utility marginal cost per call.

Skumatz, Khawaja, and Krop (2010)

In a review of the literature that includes the California LIPPT report, Wisconsin low-income weatherization, and Skumatz and Dickerson estimates above, Skumatz, Khawaja and Krop (2010) report that values for the NEI of reduced customer calls are on the order of $0.50 annually per participant.

4.5.2 Assessment of the Literature

Standard practice in the literature is to assume that energy efficiency programs reduce telephone calls involving low-income customers, in proportion to low-income bill payment improvement. Where data on the proportion of calls that are bill-related calls from low-income customers have been unavailable, NEI calculations have relied on data for all customer calls. All of the quantifications of the value to utilities of reduced customer calls are based on assumed impact values for payment-related behavior from the literature, rather than on data about program-induced changes in customer calls. Therefore, by relying on decreases in arrears or bad debt as a proxy value for reduced customer calls, previous studies have assumed that the decrease in customer calls from the program is exactly the same as the decrease in arrears or bad debt. The accuracy of this assumption is not addressed in the literature. Another, more overarching assumption that is not addressed in the literature is that energy efficiency programs will lead to a reduction the number of customer calls to utilities.

4.5.3 Relevant PA Programs

All of the estimates of customer call NEIs have been based on low-income programs. Therefore, NMR recommends applying this NEI to participants in the PAs' low-income programs.

4.5.4 Recommendations

Based on our review of the literature, NMR recommends a value of $0.58 per participant per year, based on the median value reported in the literature.[70]

Because PA data were not available for PA costs of fielding customer calls, it is not possible to derive an estimated value from PA data. If such data becomes available, an alternative method of quantifying the annual cost savings to utilities from reduced incidence of customer calls is as follows:

- Average number of bill-related calls per low-income customer before program (PA data) * the percentage decrease in bill-related calls from low-income customers (PA data) * marginal cost per call (PA data).[71]

4.6 NOTICES

A reduction in late payment and termination notices is widely recognized as a non-energy benefit to utilities. Utilities realize savings in the form of reduced paper, ink, and postage. These savings are realized for reductions in past due, collection, and termination notices, which are sent separately from ordinary billing statements. The value of these savings is easy to calculate, provided that the necessary data is available. Quantifying the value of reduced notices involves multiplying the program-induced reduction in notices by the marginal cost per notice. Few studies have actually measured the program-induced impact on notices;[72] thus most estimates of this NEI value are based on assumed impact values. Because utility costs are a component of the calculation, this NEI is inherently sensitive to each individual utility's costs.

The value of the NEI of reduced late payment and termination notices ranges from $0.00 to $1.49 per participant per year in recent studies.

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[70] Values were derived from the literature published since 1997 and were adjusted into 2010 dollars using an inflation rate of 2.5 percent per year, the same inflation rate used in the PAs' three-year plans (see National Grid et al., 2009; NSTAR et al., 2009). For more details, see Appendix D.

[71] Alternatively, if PA data on the marginal cost of a bill-related low-income customer call are available, an NEI value could be derived from the following formula: average number of low-income customer calls (PA data) * 25% (average reduction in bad debt and arrearages, derived from the literature) * marginal cost per call (PA data). The assumed 25% reduction in calls is from \TecMarket Works, SERA and Megdal Associates, 2001.

[72] Skumatz (2002) is an exception and the authors measured the impact on reminder notices associated with Connecticut's WRAP program. However, rather than finding a reduction in notices the authors found a 20% increase in notices for the participant group (Skumatz, 2002).

Skumatz and Dickerson (1999) & Skumatz and Gardner (2005)

In place of the percentage reduction in late payment notices, Skumatz and Dickerson used the reduction in write-offs and arrearages to estimate a value range for fewer late payment notices of $0.00-$0.15 per participant per year for the VPP program, and $0.00-$0.08 for the California weatherization program (1999). An NEI value of $0.30 per participant per year was estimated for the 2005 report on Wisconsin's low-income WAP program, based on an assumed percent reduction in late payment notices taken from the literature (Skumatz and Gardner, 2005).

TecMarket Works, SERA, and Megdal Associates (2001)

The cost savings resulting from reduced notices is estimated in the California LIPPT report in the same manner as reduced customer calls. In place of an actual program-induced impact value for reduced notices, a point estimate, based on an assortment of bill payment behavior and collection activity impact studies, is employed. The NEI value of $1.49 per participant per year was calculated by multiplying the average notices per customer per year (1.1) by the proxy value (24.7%) and the utility's marginal cost per notice ($5.50). The LIPPT report found reduced notices to represent 15% of total utility NEIs quantified (TecMarket Works, SERA, and Megdal Associates, 2001).[73]

4.6.1 Assessment of the Literature

Standard practice in the literature is to assume that energy efficiency programs reduce the number of past due, collection, and termination notices in proportion to low-income bill payment improvement. This is a reasonable assumption, considering the relationship between bill payment and notices. When data on the proportion of notices sent to low-income customers have been unavailable, NEI calculations have relied on data for all customer notices.

4.6.2 Relevant PA Programs

All of the estimates of reduced notice NEIs have been based on low-income programs. Therefore, NMR recommends applying this NEI to participants in the PAs' low-income programs.

4.6.3 Recommendations

Based on our review of the literature, NMR recommends a value of $0.34 per participant per year, based on the median value reported in the literature.[74]

Because PA data were not available for PA costs of customer notices, it is not possible to derive an estimated value from PA data. If such data becomes available, an alternative method of quantifying the annual cost savings to utilities from reduced late payment and termination notices is as follows:

- Average number of notices per low-income customer before program (PA data) * 25% (average reduction in bad debt and arrearages, derived from the literature[75]) * marginal cost per notice (PA data).[76]

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[73] Some studies have combined reduced notices with avoided credit and collection expenses associated with unpaid utility bills, and it is therefore difficult to make a reliable estimate of the individual components of the NEI, and to compare these estimates with estimated values of reduced notices alone (see Colton, 1994; Riggert et al., 1999; Schweitzer and Tonn, 2002; Tellus, 1995).

[74] Values were derived from the literature published since 1997 and were adjusted into 2010 dollars using an inflation rate of 2.5 percent per year, the same inflation rate used in the PAs' three-year plans (see National Grid et al., 2009; NSTAR et al., 2009). For more details, see Appendix D.

[75] Data source for average reduction in bad debt and arrearages: TecMarket Works, SERA and Megdal Associates, 2001.

[76] If the marginal cost for late payment notices differs from the cost for termination notices, then NMR recommends quantifying these values separately.

4.7 OTHER COLLECTION ACTIVITIES

Improved participant payment behavior can lead to additional reductions in collections-related costs, such as establishing payment plans or contracting with collections agencies. These costs have rarely been quantified, though they are worth reviewing briefly, in case the PAs wish to capture these potential benefits through primary data collection.

For example, Colton (1994) quantified an additional benefit due to the decreases in negotiating payment plans with customers. Colton (1994) estimated a value of $14.64 for each individual payment plan negotiation avoided. Riggert et al. (1999) cite a 1995 study by the Tellus Institute that estimates the benefit of reduced credit and collection expenses between $65 and $85 per participant.

However, without further primary data collection, NMR does not recommend including this as an NEI.

4.8 SAFETY RELATED EMERGENCY CALLS

The NEI of reductions in safety related emergency calls has been limited to natural gas programs in the literature. Low-income households are more prone than other customers to have old or damaged space and water heating systems, and therefore are more likely to experience fires from gas leaks. Energy efficiency programs that repair space and water heating appliances can potentially reduce the likelihood of an emergency call to the gas utility. NEI estimates in the literature vary, due to differences in assumptions regarding incidence of emergencies, portion of emergencies obviated by programs, and gas utility costs per emergency. Because utility costs are a component of the calculation, this NEI is inherently sensitive to each individual utility's costs.

The value of the NEI of reduced safety related emergency calls ranges from $0.07 to $15.58 per participant per year in recent studies.

Skumatz and Dickerson (1997 & 1999)

Skumatz and Dickerson (1997) quantified three components of savings to gas utilities arising from a reduction in emergency situations: 1) fewer emergency gas calls, valued at $10-$20 per participant per year; 2) flex connector replacements, valued one time at $0-$5; and 3) fewer emergency calls from replaced flex connectors, valued at $0-$2 per participant per year. The VPP program checked and replaced gas appliances and gas connectors on appliances as needed. The NEI value range for reduced emergency gas calls was based on the utility's cost per emergency gas call, and an assumed percent reduction of 20% in emergency calls, taken from Magouirk's 1995 analysis of a low-income weatherization program in Colorado. The flex connector value ranges were also taken from Magouirk (1995), although they did not apply directly to the VPP program. Skumatz and Dickerson reported a value range of $5.27-$10.54 for reduced emergency gas calls, for the California weatherization program in their 1999 report.

Riggert et al. (1999)

The 1999 Vermont WAP evaluation applied the dollar savings estimated by Magouirk (1995) of $22.57 per home, representing the summed estimated savings from reduced emergency calls ($15.58), gas flex connector replacements ($1.98), and the incremental avoided cost of having a gas flex connector replaced by an emergency crew ($5.01), as opposed to during weatherization (Riggert et al., 1999).

Schweitzer and Tonn (2002)

Reduction in emergency gas service calls was quantified by Schweitzer and Tonn (2002) for the national WAP, by selecting a midpoint from the range of estimates presented in the literature (including those listed above), and then adjusting the value down in order to accurately reflect the proportion of U.S. households fueled by natural gas (50.9% at the time the report was published).

Ternes et al., (2007)

In the upcoming evaluation of the national WAP, ORNL intends to monetize the value of reduced emergency gas service calls via the following formula (Ternes et al., 2007):

Number of households weatherized	*	Average reduction in number of emergency service calls made per weatherized household	*	Average cost to utility per service call

TecMarket Works, SERA, and Megdal Associates (2001)

Quantification of the non-energy benefit associated with reduced emergency calls for the California LIPPT report required estimation of several variables, including the proportion of total participants who have gas checks or gas appliances in place, the percentage of those needing appliance repairs or maintenance, the total potential emergencies avoided, and the marginal cost per emergency call (TecMarket Works, SERA and Megdal Associates, 2001). Impact values for the percentage of participants needing appliance repairs or maintenance, and the total potential emergencies avoided, were selected from the literature review. An annualized NEI value of $0.07 per participant was calculated from the following formula:

10% Participants Receiving Gas Services	*	23% Eligible Customers Needing Gas Appliances Fixed	*	25.9% Emergencies Avoided Through Program Activities[77]	*	$76.08 Marginal Cost Per Emergency Call Avoided	*	0.15 Adjustment Factor (horizon and discount assumptions)[78]

The non-energy benefit associated with fewer emergency gas calls was found to represent 1% of total utility NEIs considered in the LIPPT report.

4.8.1 Assessment of the Literature

Weatherization programs that identify and repair potential gas leaks undoubtedly prevent some quantity of emergency calls to gas utilities. Few studies have measured actual program impacts on the frequency of emergency gas calls, which is dependent on the fuel source of a given home, the condition of the heating system, and the safety-related measures included in the program. The majority of estimates for the value of this NEI are based on assumed impact values taken from the literature. The value to gas utilities of reduced emergency calls is relatively low, compared to the value of other utility NEIs.

4.8.2 Relevant PA Programs

The NEI derived from avoided safety-related emergency calls should be limited to the PAs' low-income programs that repair or replace space and water heating appliances, gas appliances, and gas connectors.

[77] The California LIPPT applied the 25.9% reduction in emergency calls reported by Magourik (1995) (TecMarket Works, SERA and Megdal Associates, 2001).

[78] Assumes a ten year benefit stream and applies a 8.15% discount rate (TecMarket Works, SERA and Megdal Associates, 2001).

4.8.3 Recommendations

Based on our review of the literature, NMR recommends a value of $8.43 per participant per year, based on the median value reported in the literature.[79]

Because PA data were not available for the marginal cost of a safety-related emergency call and for decreases in emergency calls among program participants, it is not possible to derive an estimated value from PA data. If such data becomes available, an alternative method of quantifying the savings to the PAs from reduced emergency gas calls is as follows:

- Average number of safety-related emergency calls per customer before program (PA data) * the percentage decrease in emergency calls per customers (PA data) * marginal cost per emergency (PA data). [80]

4.9 INCREASED ELECTRICITY SYSTEM RELIABILITY

The nation's electricity system has a maximum limit of electricity it can supply at any given point in time, based on installed capacity and infrastructure. Blackouts can occur when electric demand in a particular geographic region exceeds the maximum capacity of the system in that region. By reducing the demand for electricity, energy efficiency programs can potentially increase the reliability of the system, by preventing demand from exceeding maximum capacity when it otherwise would have, thereby preventing a blackout from occurring. Total electricity demand is expected to grow at a rate of 1% annually through 2035.[81] Therefore, by reducing electricity consumption (and consequently slowing demand growth), energy efficiency programs can, to some extent, prolong the need to build additional infrastructure to meet growing demand. Financial savings are realized when expenses are pushed further into the future, due to the time value of money. Theoretically, the financial savings derived from delaying investments in electricity system infrastructure represent the non-energy impact of energy efficiency programs on the electricity system.

According to the *Avoided Energy Supply Costs in New England: 2011 Report* the PAs currently receive credit for contributing to increased system reliability due to the load reductions attributable to energy efficiency measures (Hornby et al., 2011).

Interestingly, NMR's review of the NEI literature did not uncover any valuation of increased electricity system reliability as an NEI associated with energy efficiency programs. Skumatz, Khawaja, and Krop (2010) identify "power quality/reliability" as a potential utility-perspective NEI arising from low-income programs, but state that no studies quantifying its value have been performed to date.

4.9.1 Recommendation

Because the PAs currently receive credit for contributing to increased system reliability due to the load reductions attributable to energy efficiency measures, NMR does not recommend attempting to quantify an NEI value above and beyond what has already been accounted for in *Avoided Energy Supply Costs in New England: 2011 Report* (Hornby et al., 2011).

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[79] Values were derived from the literature published since 1997 and were adjusted into 2010 dollars using an inflation rate of 2.5 percent per year, the same inflation rate used in the PAs' three-year plans (see National Grid et al., 2009; NSTAR et al., 2009). For more details, see Appendix D.

[80] Data source for the percentage decrease in emergency calls: Magouirk (1995) as cited in Skumatz and Dickerson (1997).

[81] http://www.eia.doe.gov/oiaf/aeo/electricity.html

4.10 ADDITIONAL UTILITY NEIS FOUND IN THE LITERATURE

NMR's review of the literature found additional utility-perspective NEIs commonly mentioned in the literature, but not identified in the work plan or during the kick-off meeting. These additional NEIs include insurance savings and transmission and distribution savings.

4.10.1 Transmission and Distribution Savings

Transmission and distribution (T&D) line loss reduction is often recognized as a non-energy benefit in the NEI literature. By reducing the use of electricity, energy efficiency programs eliminate the line losses, which would have occurred during transmission and distribution of the electricity which would have been generated absent the programs.

Because the PAs currently receive credit for avoided transmission and distribution losses, NMR does not recommend attempting to quantify an NEI value above and beyond what has already been accounted for in *Avoided Energy Supply Costs in New England: 2011 Report* (Hornby et al., 2011) and applied to the Total Resource Cost (TRC) test for the PAs' electric energy efficiency plan (National Grid et al., 2009; NSTAR et al., 2009).[82]

4.10.2 Insurance Savings

Energy efficiency programs that fix gas leaks and replace faulty equipment can reduce the risk of explosions and fires in participants' homes, which in turn can lead to lower insurance costs for utilities. The NEI of insurance savings is primarily applicable to gas utilities, due to the higher risk of fires from gas equipment. The most accurate way to quantify the NEI of insurance savings is to perform a pre/post impact evaluation to assess the reduction in explosions and fires resulting from the program, in order to determine the impact on the utility's insurance costs, which depends on whether a utility self-insures or buys coverage from an insurer. Insurance savings to utilities has been identified as an NEI associated with energy efficiency programs several times in the literature, but has rarely been quantified. When NEI values have been quantified for utility insurance savings, they have not been based on actual program impact data, but rather proxy values for reduced risk of explosions and fires.

The value of the NEI of insurance savings ranges from $0.00 to $0.15 per participant per year in recent studies.

Schweitzer and Tonn (2002); Ternes et al. (2007)

Insurance savings are recognized as a non-energy benefit to utilities by the evaluators of the national WAP program at the Oak Ridge National Laboratory (ORNL). According to the 2002 non-energy benefit report prepared for the national WAP, reduced risk of fires and explosions is expected to lower utility insurance costs, regardless of whether the utility self-insures or buys coverage from an insurer (Schweitzer and Tonn, 2002). In the current national WAP evaluation, the evaluators at ORNL plan to calculate a monetized value of insurance savings to utilities, by multiplying the number of weatherized households by the average reduction in utility's cost for insurance to cover household fires and explosions per weatherized household. Relative to all other NEIs that these evaluators plan to measure in the upcoming WAP evaluation, both the magnitude and uncertainty surrounding the monetized value are expected to be medium, on a scale of low, medium and high (Ternes et al., 2007).

Skumatz and Dickerson (1997 and 1999)

Estimates of the non-energy benefit of insurance savings to utilities are provided by Skumatz and Dickerson (1997, 1999). The authors estimated a NEI range of zero to fifteen cents annually per

[82] A brief review of other studies that have estimated a value for transmission and distribution savings is presented in Appendix A.

participant, based on two low-income weatherization programs. The NEI estimates were calculated based on insurance claims per household for an average year and an assumed reduction in risk from the program. Because the actual reduction in risk was unknown, the authors used the reduction in gas emergency calls of 75% from Magouirk (1995) as a proxy for the actual reduction in risk. The authors noted that the NEI of utility insurance savings applies primarily to gas utilities and that the quantified NEI values reported were applicable only to self-insuring utilities.

a. Assessment of the Literature

Although insurance savings are recognized as a non-energy benefit, the impact of energy efficiency programs on utility insurance costs has rarely been investigated. The few values that have been reported in the literature are not based on actual program impacts, but instead rely on proxy measures such as reductions in emergency calls. Additionally, they are extremely low in value, indicating that the value of this NEI compared to other utility NEIs is relatively insignificant.

b. Relevant PA Programs

The utility-perspective NEI of insurance savings potentially applies to all PA programs that reduce the risk of fires and explosions by repairing or replacing faulty gas equipment.

c. Recommendation

Due to the scarcity of studies examining the impact of energy efficiency programs on utility insurance costs in the literature, NMR does not recommend quantifying a value for insurance savings at this time.

Upon completion of the national WAP evaluation in 2011, an estimate of insurance savings could be derived from the national evaluation and applied to the PAs' low-income programs.

5. PARTICIPANT-PERSPECTIVE NEIs—LITERATURE REVIEW

Participants can also realize a number of non-energy impacts. When measured and monetized, participant NEIs have been found to be quite substantial, often exceeding the value of energy savings and NEIs from the societal and utility perspectives. However, participant NEIs are generally much more difficult to measure than NEIs from the utility perspective and some are considered less tangible. For example, some of the less tangible participant NEIs include “increased comfort” or “sense of doing good for the environment,” while others, though very tangible—such as improved health or increased property value—are difficult to measure and monetize.

It is important to note that a number of participant perspective NEIs commonly found in the literature and currently included in the TRM report are derived from customer bill savings. These bill savings partially overlap with avoided costs accounted for in the Avoided Energy Supply Costs (AESC) in New England (Hornby et al., 2011) and included in the TRC calculations. The AESC study estimates a number of avoided costs, including avoided costs of electricity to retail customers and avoided costs to natural gas retail customers. Each set of avoided costs is comprised of several individual costs. For example, avoided costs of electricity to retail customers includes avoided energy costs, avoided capacity costs, avoided environmental regulation compliance costs, demand reduction induced price effects, and avoided costs of local transmission and distribution infrastructure (Hornby et al, 2011). While bill savings and avoided costs partially overlap, they typically differ in part because bill savings are based on average retail savings to participants while avoided costs are based on marginal energy supply costs that are avoided because of the PAs’ energy efficiency programs. Theoretically, a participant NEI of bill savings, based on the difference between the avoided energy and capacity costs and participant energy bill savings, could be added to the TRC. However, according to traditional TRC calculation methods, including participant bill savings as a benefit would require including a similar cost in the form of lost PA revenues, thus negating the bill savings benefit.[83] Therefore, there is no additional NEI of participant bill savings.

In addition, NMR does not recommend including any NEIs that are derived from participant bill savings because it would amount to double counting of benefits. To count benefits that derive from bill savings would amount to valuing the additional disposable income (i.e., bill savings) and the ways in which the participants spend the disposable income. For example, a participant may spend the bill savings on food or medicine, leading to improved health.Similarly, participants may use their bill savings to pay energy bills, reducing the incidence of service terminations and the costs associated with service termination and reconnection. But to count both the bill savings and the health benefits or the benefit of reduced service terminations that are derived entirely from the way bill savings are spent is to count the same benefit twice. Other examples of NEIs derived from bill savings include reduced bill-related calls and reduced need to move or forced mobility.

Table 5-1 below provides a summary of recent studies that have measured and monetized a number of participant perspective NEIs, especially the less tangible NEIs such as higher comfort levels and quieter interior environments. The studies have used a variety of survey methods, including relative valuation methods and conjoint analysis (described in more details in section 5.1. Methods Used to Measure Participant NEIs). Several NEIs, such as higher comfort levels, quieter interior environment and health impacts, are frequently valued highly by program participants. However, there is also wide variation in the values reported by survey respondents, either in dollars or as a percentage of bill savings. For example, higher comfort levels have been estimated to range from $44 to $280 per participant per year and from 2% of bill savings to 70% of bill savings.

[83] As defined in the *California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects,* the TRC takes into consideration program benefits and costs in terms of the participants and the ratepayers: “In a sense, it is the summation of the benefit and cost terms in the Participant and the Ratepayer Impact Measure tests, where the revenue (bill) change and the incentive terms intuitively cancel (CPUC, 2001, p. 18).”

Table 5-1. Summary of the Value of Participant NEIs Reported in the Literature

NEI	Savings	Studies							
		MA ES Homes (NMR & Conant, 2009)	NYSERDA ES Homes, Relative Valuation (Barkett et al., 2006)	NYSERDA ES Homes and CFLs, Conjoint Analysis (Barkett et al., 2006)	Various MF Retrofit Programs (Myers & Skumatz, 2006)	LI MF Retrofit Program (Myers & Skumatz, 2006)	Wisconsin LI Weatherization (Skumatz &Gardner, 2005)	NYSERDA ES CFLs, Relative Valuation (Barkett et al., 2006)	Various ENERGY STAR Programs84 (Fuchs et al., 2004)
Higher Comfort Levels	% Bill Savings	70%	42%	—	2-4%	3%	20-25%	—	2-7%
	$	$280	$252	$191	—	—	$44-56	—	—
Improved Sense of Environmental Responsibility	% Bill Savings	—	—	—	7-18%	29%	2-3%	70%	15-18%
	$	—	—	—	—	—	$4-6	$10	—
Quieter Interior Environment	% Bill Savings	37%	42%	—	0%	9%	7-9%	—	1-11%
	$	$146	$252	$72	—	—	$14-19	—	—
Reduced Noise Dishwashers	% Bill Savings	—	—	—	—	—	—	—	6%
	$	—	—	—	—	—	—	—	—
Longer Lighting Life	% Bill Savings	36%[85]	—	—	—	—	—	55%	12%[86]
	$	$144	—	$1.80[87]	—	—	—	$8	—
Anticipated Ease of	% Bill Savings	65%	62%	—	4-11%	18%	—	—	3-5%

[84] NEI values reported for the following ENERGY STAR products: refrigerators, dishwashers, room air conditioners, CFLs, and lighting fixtures.

[85] The NEI value for Massachusetts represents the combined value of lighting life and lighting quality.

[86] Applies to CFLs only.

[87] One-time benefit for bulb lifetime.

NEI	Savings	Studies: MA ES Homes (NMR & Conant, 2009)	NYSERDA ES Homes, Relative Valuation (Barkett et al., 2006)	NYSERDA ES Homes and CFLs, Conjoint Analysis (Barkett et al., 2006)	Various MF Retrofit Programs (Myers & Skumatz, 2006)	LI MF Retrofit Program (Myers & Skumatz, 2006)	Wisconsin LI Weatherization (Skumatz &Gardner, 2005)	NYSERDA ES CFLs, Relative Valuation (Barkett et al., 2006)	Various ENERGY STAR Programs84 (Fuchs et al., 2004)
Selling or Leasing Home	$	$259	$372	—	—	—	—	—	—
Buffers Energy Price Increase	% Bill Savings	97%	—	—	—	—	—	—	—
	$	$386	—	—	—	—	—	—	—
Reduced Need to Move	% Bill Savings	—	—	—	—	5%	<1%	—	1-6%
	$	—	—	—	—	—	$1	—	—
More Durable Home	% Bill Savings	—	15%	—	—	—	—	—	—
	$	—	$90	$202	—	—	—	—	—
Equipment and Appliance Maintenance	% Bill Savings	—	25%	—	4-9%	-14%	9-11%	—	2-7%
	$	—	$150	—	—	—	$19-24	—	—
Health Impacts[88]	% Bill Savings	32%	55%	—	—	—	0-5%	—	—
	$	$126	$330	$156	—	—	$1-12	—	—
Improved Safety	% Bill Savings	26%	35%	—	1-3%	5%	10-12%	—	1-6%
	$	$105	$210	$181	—	—	$20-$26	—	—
Warm up Delay	% Bill Savings	—	—	—	—	—	—	-15-0%	—

[88] The NEI values reported for the Massachusetts and New York ENERGY STAR Homes programs represent participant valuation of perceived improved indoor air quality. The NEI values reported for the Wisconsin Low Income Weatherization program represent the range of valuations for numerous health-related impacts measured in the participant survey, including frequency or intensity of chronic conditions such as asthma, frequency or intensity of other illnesses, headaches, doctor or hospital visits and related costs, and medication costs.

NEI	Savings	Studies							
		MA ES Homes (NMR & Conant, 2009)	NYSERDA ES Homes, Relative Valuation (Barkett et al., 2006)	NYSERDA ES Homes and CFLs, Conjoint Analysis (Barkett et al., 2006)	Various MF Retrofit Programs (Myers & Skumatz, 2006)	LI MF Retrofit Program (Myers & Skumatz, 2006)	Wisconsin LI Weatherization (Skumatz &Gardner, 2005)	NYSERDA ES CFLs, Relative Valuation (Barkett et al., 2006)	Various ENERGY STAR Programs84 (Fuchs et al., 2004)
	$	—	—	-$0.29	—	—	—	-$2	—
Product Lifetime	% Bill Savings	—	—	—	—	3%	—	—	2-6%[89]
	$	—	—	—	—	—	—	—	—
Product Performance	% Bill Savings	—	—	—	2-4%	15%	6-8%	—	4-9%
	$	—	—	—	—	—	$14-$18	—	—
Total NEIs[90]	% Bill Savings	—	47%	—	44-110%	108%	122-156%	60%	29-90%[91]

[89] Applies to ENERGY STAR refrigerators, dishwashers, room air conditioners, and lighting fixtures (excludes CFLs).

[90] Total NEIs reflect participant valuation of all NEIs experienced as a percentage of energy bill savings. Participants were asked to value all NEIs experienced in relation to bill savings as a separate question from the valuation of individual NEIs, so that the sum of participant reported individual NEI valuations could be compared with participant reports of total NEIs experienced.

[91] 29% of energy bill savings for refrigerators, 65% of energy bill savings for dishwashers, 71% of energy bill savings for room air conditioners, 90% of energy bill savings for CFLs, and 30% of energy bill savings for lighting fixtures.

5.1 METHODS USED TO MEASURE PARTICIPANT NEIS

Much of the research on participant NEIs has relied on participant self-reports garnered from surveys. For many participant NEIs, self-report is the only possible source of data, as their values are based on the participants' own perceptions. These perceptual, less tangible, NEIs represent the extent to which participants experience a particular intangible impact of a program, such as "increased comfort" or "sense of doing good for the environment," as well as how important that impact is to them.

On the other hand, there are many participant NEIs, such as "increased property value" and "fewer colds and viruses" that could be estimated using non-survey data (e.g., by tracking sales data, interviewing real estate experts, checking employers' office data for participants' sick days before and after the program, etc.), but are often addressed in surveys for practical reasons, such as the lack of available data and the relative ease and low cost of including questions on surveys that are already being used to measure the perceptually-based NEIs.

In some cases, values for these more tangible NEIs are derived entirely from a participant survey, while in other cases data collected from the participant survey is combined with secondary data to estimate a value for the NEI. For example, in some studies, improved health has been measured by combining survey data—in this case reductions in the number of sick days—and multiplying that value by an assumed wage rate for the participant from secondary data.

In addition, some participant NEIs are derived entirely from secondary sources and computations. For example, increases in property values from low-income weatherization programs have been estimated by using program expenditures on repairs made to homes before weatherization measures are installed.

5.1.1 Survey Methods

Several different types of survey methods have been used since researchers began monetizing participant NEIs as part of program evaluations in the 1990's. These methods are loosely based on methods used in behavioral economic research that were developed in order to gauge the value of non-market goods (i.e., goods or attributes of goods that are not ordinarily directly exchanged for money, such as the value of the existence of a wilderness area or the value of the preservation of endangered species). Lisa Skumatz has been a central figure in the adapting these methods to NEI research from the late 1990's to the present. Her work is cited throughout this literature review.

In this section, we briefly review the survey methods most frequently used in NEI evaluations, by describing each method and discussing its advantages and disadvantages. The terminology of the methods is somewhat confusing, because different researchers tend to use different terms for the same method and, in some cases, the same term for different concepts, when describing the methods. We attempt to clarify the terminology by specifying the various terms used for each method and labeling them consistently throughout this report. Following that we discuss other aspects of survey methods that are important to consider and make recommendations regarding developing surveys used for evaluating the PAs' programs.

a. Contingent Valuation (Willingness to Pay)

One of the most direct methods of monetizing an NEI is *Willingness to Pay (WTP)*, by which respondents are asked how much they would pay to obtain an NEI or a group of NEIs. For example, to quantify the value of *reduced noise in the home*, respondents who reported that a program resulted in reduced noise would be asked, "How much would you be willing to pay to go from the previous noise level in your home to the present noise level, if everything else were the same?"[92] A variant on this method is to ask respondents how much they would pay to get a group of NEIs back if they disappeared.

The advantage of this method is its directness. However, although a question asking what someone would be willing to pay for something is relatively easy to understand, it has proven to be quite difficult for people to answer accurately and consistently. This method tends to result in high non-response rates, wildly divergent values across respondents, and much higher values than are typically obtained by other methods. For example, a survey used in an evaluation of the Northeast Utilities Weatherization Residential Assistance Partnership (Skumatz and Nordeen, 2002) asked respondents to value overall NEIs using *WTP* and two other types of questions, allowing the results from the different methods to be compared directly. Only 39% of respondents answered the *WTP* question, and the average value obtained through the *WTP* questions was roughly ten times that obtained through the other methods. Across respondents, *WTP* values ranged from $0 to $70,000. For these reasons, this method is rarely used in current evaluations of NEIs.

b. Relative Valuation

The *Relative Valuation* (*RV)* method involves asking respondents the value of the NEI relative to the bill savings from a program, either in terms of a verbally labeled scale (*Labeled Magnitude Scaling)* or in percentage or dollar terms (*direct scaling* or *self-reported percentages)*. For example, an *RV* survey might ask respondents whether they have experienced changes in the noise level in their home as a result of the program, whether these changes are positive or negative, and whether the value of these changes is higher than, lower than, or about the same as the bill savings from the program (or, for negative changes, how much the value detracts from the bill savings). A follow-up question would ask *how much* more or less than the bill savings, expressed either as a percentage of bill savings (i.e., *self-reported percentages*) or as "somewhat" or "very much" more or less than bill savings (i.e., *labeled magnitude scaling*). Respondents answer *labeled magnitude scaling* questions more quickly than the *self-reported percentage*, but analyzing the data requires an extra step of translating the verbal labels into values using standard equivalence equations. When both methods have been used in a single survey, the results have been similar.

Respondents generally find *RV* questions easier to answer than *WTP* questions. The results tend to be more consistent within and across studies (although the ranges of values obtained by this method are still quite wide both within and across studies and programs). A disadvantage is that, across programs, NEI values tend to be correlated with the value of bill savings, which might reflect the fact that higher "anchors" in such survey questions tend to result in higher values, a robust finding in recent survey research (Kahneman and Sugden, 2005). Thus, it is not clear whether higher bill savings results in higher NEI values or whether instead the effect of bill savings on NEI values is an artifact of the survey method, and not reliable evidence that programs with higher bill savings tend to result in more valuable NEIs. Also, when studies have asked respondents to value NEIs relative to bill savings without telling them the average savings amount for the program, results have been less consistent across participants, possibly because different respondents were assuming different levels of bill savings, thus using different values as an anchor with which to decide the value of NEIs. Nevertheless, because this method yields higher response rates and more consistent results than the other methods that have been used, *Relative Valuation* is the most frequently used method in NEI research.

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[92] In WTP surveys, respondents are generally asked to estimate how much they would pay for a good or service, without reference to any other price, good or service.

c. Conjoint Analysis

The *Conjoint Analysis (CA)* survey method, commonly used in marketing research, essentially involves assessing the value of various hypothetical attributes of a product, through multiple questions asking respondents to choose between two hypothetical products, or scenarios with different combinations of the attributes in question. In some of these pairs, a monetary value replaces one of the attribute bundles. These preferences are then analyzed to obtain the monetary value of each of the attributes.[93]

The *CA* approach occasionally has been used in NEI research. For example, Summit Blue's evaluation of the NYSERDA ENERGY STAR Homes programs included *CA* questions in addition to *RV* questions (Barkett et al., 2006). To illustrate, one question asked respondents to choose between two different homes. Home 1 was described as having very little noise, standard ventilation (worse air quality), and best installation and construction practices (more durable); home 2 had some noise (less quiet), improved ventilation (better air quality) and standard installation and construction practices (less durable).

The main advantage of *CA* is that it does not require respondents to directly place a value on each of the NEIs. Rather, this method simply asks respondents about their preferences, which arguably is closer to how people evaluate intangibles in their everyday lives. The primary disadvantage of this method for NEI research is that the results reflect the value of NEIs under hypothetical, idealized circumstances, as opposed to value of the NEIs as actually experienced. Another disadvantage of the *CA* method is that it requires a more lengthy and complex set of survey questions, reducing the number of NEIs that can be evaluated. In addition, the values obtained tend to be substantially higher than those using *RV* methods. The evaluation of NYSERDA ES Homes (Barkett et al., 2006) found that the average value of overall NEIs from the *CV* questions was about $300 (50% of bill savings), whereas the value from the *CA* questions was about $800 (over 130% of bill savings).

d. Overall versus Individual NEI Values

Recent NEI research has found that if participants are asked to estimate the value of individual NEIs (i.e., thermal comfort, sense of environmental responsibility, etc.) and then asked to estimate the overall value of all of the individual NEIs together, the sum of the individual values often exceeds the overall value of the NEIs substantially. For example, in Summit Blue's evaluation of NYSERDA ES Homes program (Barkett et al., 2006), the sum of the individual NEI values is about 250% of bill savings, five times the average value obtained from the question about the overall value of all the NEIs (roughly 50% of bill savings).

Some reports have corrected for this divergence between the sum of the NEI values and the overall NEI value by presenting NEI values that are scaled down proportionately, so that they sum to the overall NEI value (e.g., Skumatz and Gardner, 2005). This correction is meant to adjust for potential overlap and overestimation of NEIs. Potential overlap and overestimation can be conceptualized in two ways. First, when asking respondents to valuate non-market goods with multiple parts or components, the stated value of the whole is often less than the value of the sum of the parts. This is often referred to as 'part-whole bias' when the values of the individual parts are not adjusted for the value of the whole (Bateman et al., 1996; Brown and Duffield, 1995). Second, when valuating several related things, the stated value of the total is often less than that of the sum of the individual items, often referred to as an "embedding effect" (Baron and Greene, 1996; Brown et al, 1995). There could be any number of explanations for this, but in the case of NEIs it is likely that there is "overlap" among the various NEIs asked about, such that respondents do not conceptualize the individual NEIs as being completely distinct and therefore their values are not additive.

[93] For a thorough review of *Conjoint Analysis* see Wobus, et al. (2009).

Overlap could be occurring among NEIs in a few different possible ways. One way is if there is an implied causal relationship in the respondent's mind between two NEIs, so that it would be redundant to "pay for" each separately. For example, if a respondent thinks that fewer drafts lead to fewer colds and viruses, the respondent might think that both NEIs are valuable, but when combined, the NEIs are less valuable in total because when the respondent 'pays' for fewer drafts the respondent also benefits from fewer colds/viruses. Alternatively, two or more NEIs could be conceptually or experientially similar, so that they share at least some of their perceived meaning. For example, a respondent might perceive comfort, fewer illnesses, and reduced noise as all being different but somewhat overlapping aspects of an overall sense of "well-being," such that the various aspects, when taken separately, add up to more than the overall sense. Finally, one NEI can be considered a subset of another NEI, such that the value of one "contains" the value of another. For example, longer lighting life and even durable home could be perceived as part of "reduced equipment maintenance," such that the value of equipment maintenance includes the value of the other two.

5.2 IMPLICATIONS AND RECOMMENDATIONS FOR SURVEY METHODS

NMR recommends that surveys used in evaluating the PAs' programs use a *Relative Valuation* method, with *self-reported percentages*. To limit survey length and reduce respondent burden and fatigue, surveys should include fewer than eight NEIs (NMR and Conant, 2009). To correct for the commonly found disparity between the sum of individual NEI values and the overall value of the NEIs together, we recommend including a question about overall NEI values, then taking the conservative approach of scaling the individual NEI values to the overall value.

As noted earlier, several of the non-energy impacts of energy efficiency programs are intangible effects on participants' subjective quality of life. As such, they can only be measured through the reports of the participants themselves. They include increased thermal comfort, sense of environmental responsibility, lighting quality, and perceived reduction in noise levels. Although these NEIs are often highly valued by participants, because of methodological and theoretical difficulties with their measurement, they are often either not measured or their estimated values are reported separately from those of the other NEIs, instead of being incorporated into total NEI values for a program. Values for "soft" NEIs have been used primarily for marketing, designing, and targeting programs. They currently are rarely used for regulatory purposes.

Among the several published studies measuring soft NEIs, resulting values have varied by orders of magnitude, depending on survey method and other factors, including the type and comprehensiveness of the program, number of NEIs asked about in the survey, geographical area of the program, whether participants give an estimate of the sum of NEIs to which individual NEI values are scaled, and the value of energy savings for the program. For these reasons, it is not possible to come up with a reliable point estimate for any of these intangible NEIs based on values derived from these past studies. Collecting primary data from program participants through telephone surveys is far more reliable, as doing so controls for the variation among programs, participant sectors, and geographical area.

In addition, many of these intangible NEIs tend to be most relevant to whole-house programs, particularly those that include weatherization or other HVAC measures, rather than those with only one or two measures such as appliance rebate programs. Previous studies indicate that these NEIs tend to be equally important to low-income and general populations, and are relevant to both retrofit and new construction programs.

If the PAs wish to apply point estimates for the NEI values from the Evaluation of the Massachusetts New Homes with ENERGY STAR Program (NMR and Conant, 2009) to similar new construction programs, NMR recommends scaling the values of individual NEIs to 100% of estimated bill savings. Because the NMR survey did not include a question asking respondents to estimate the overall value of the NEIs combined, this would represent a more conservative valuation of these NEIs. This would be consistent with values found in a similar study conducted for NYSERDA's ENERGY STAR Homes program, which found participants valued all NEIs at 47% of estimated bill savings (Barkett et al., 2006).

In the following sections we indicate whether an NEI is being estimated via surveys of program participants.

5.2.1 Higher Comfort Levels

Participants in energy efficiency programs that include HVAC components and weatherization measures commonly experience greater perceived comfort, due to fewer drafts and more even temperatures throughout the home. The literature provides strong evidence that participants experience increased thermal comfort as a result of programs that affect the heating and cooling of the home, and that they consider these increased comfort levels to be a very important program benefit, both in general terms and in relation to other perception-based NEIs.

5.2.2 Non-low-income Programs

Myers and Skumatz (2006)

Several studies show that participants in non-low-income retrofit and new construction programs highly value thermal comfort relative to bill savings as well as relative to other NEIs, although some of the reported monetary valuations are probably overestimates because of methodological issues (as discussed in more detail throughout this section). For example, Myers and Skumatz (2006) performed an analysis of NEIs from multi-family retrofit programs, estimating the value of various NEIs across studies. The resulting estimated average value for comfort was 4% of the value for all NEIs combined. It should be noted, however, that this value reflects not only how much participant's value comfort, but also the frequency with which the various surveys include questions about comfort. The individual studies included in the analysis varied widely in the number and combination of NEIs assessed, and for surveys that did not include a particular NEI, the value was estimated to be 0%.

Barkett et al. (2006)

An assessment of NEIs from a New York ENERGY STAR Homes program using a *Relative Valuation* survey method (Barkett et al., 2006) found that 92% of participants reported positive changes in thermal comfort relative to their previous homes, compared to 67% of non-participants who had purchased non-ES (standard efficiency) new homes. Participants valued comfort at 42% of energy savings for the program. However, this result is difficult to interpret in terms of attributing the impact to the program, as non-participants valued increased comfort relative to their previous homes at an even higher rate, at 55% of bill savings. Further, participants estimated the value of all the NEIs combined (asked in the same way as the individual NEIs) at 47% of bill savings, which was just slightly higher than the average value of the individual NEI of comfort. Scaling the values for comfort and the other NEIs relative to the total NEI value would have resulted in far lower estimates. It should also be noted that the value of 42% of energy savings for thermal comfort derived from Summit Blue's survey was calculated from the nine participants who reported positive changes in that attribute (Barkett et al., 2006). The three participants who said either "same (no impact)" or "don't know" were not included in calculating the average valuation. If these participants had been included in the analysis and assigned a value of zero and averaged with the positive valuations, as was done in many other studies, including NMR's evaluation of MA ES Homes, the value of comfort would have been lower (NMR and Conant, 2009). Therefore, the value of 42% of energy savings is somewhat higher than the average value per participant.

The same New York ENERGY STAR Homes survey also assessed the NEIs using *Conjoint Analysis* questions, which yielded a comfort value of $191 annually per participating household, or 32% of estimated annual bill savings (Barkett et al., 2006).

NMR and Conant (2009)

Another *RV* survey evaluating NEIs from a similar ENERGY STAR program in MA (NMR and Conant, 2009) found that 86% of participants said that their homes provided more thermal comfort than they thought a non-ENERGY STAR new home would provide, and valued comfort at 70% of their bill savings, or $280. Again, although this value is not scaled relative to participants' estimates of the total value of all the NEIs in the survey, it does provide further evidence that thermal comfort is quite valuable to participants of energy efficiency programs.

5.2.3 Low-income Programs

Participants of low-income programs also experience increased thermal comfort and perceive it to be a particularly important benefit. In 1999, Skumatz and Dickerson conducted a study evaluating NEIs across several low-income weatherization programs. Participants from each program were asked to rate the importance of several NEIs. For programs with insulation, thermal comfort (phrased as "less drafty" in the survey) received the highest average importance rating, and for programs with caulking and weather-stripping, comfort and lower bills were judged to be equally important. Also, 52% of respondents in a survey evaluating NEIs from the CT Weatherization Residential Assistance Program said the thermal comfort in their homes was "better" or "much better" than before the program, while 34% of these participants said comfort was of greater value than their bill savings (Skumatz and Nordeen, 2002).

5.2.4 Assessment of the Literature

The literature provides strong evidence that participants experience increased thermal comfort as a result of programs that affect the heating and cooling of the home, and that they consider these increased comfort levels to be a very important program benefit, both in general terms and in relation to other perception-based NEIs. As illustrated above, due to methodological issues and the wide range of values obtained for increased thermal comfort across studies, the literature does not allow for a reliable estimate of increased comfort value for any of the PA programs, either in terms of dollars per participant or percent of energy savings. Instead, *increased* thermal comfort should be measured through surveys of program participants for programs that affect the heating and cooling of the home.

5.2.5 Relevant PA Programs

Based on the findings from the literature, increased thermal comfort is likely to be experienced and considered important by participants of a number of the PAs' programs that install weatherization measures, shell measures, and heating and cooling equipment, including low-income programs, retrofit and new construction programs, residential new construction and retrofit programs, as well as residential heating and hot water and residential cooling and heating programs.

5.2.6 Recommendations

Based on the surveys of program participants, NMR recommends an annual value of $125 for NLI participants and $101 for LI participants who installed shell and weatherization measures or heating and cooling equipment. The NEI applies to the PAs' low income-retrofit programs, low-income new construction programs, residential cooling and heating programs, residential heating and hot water programs, and non-low-income retrofit programs (i.e., Mass Save, multi-family retrofit programs).

For the PAs' residential new construction programs (non-low-income), NMR recommends using a value of $77 per participant, the scaled value from the Evaluation of the Massachusetts New Homes with ENERGY STAR Program (NMR and Conant, 2009).[94]

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[94] Thermal comfort was estimated to be equal to $279 per participant, or 19% of the $1,445 in total NEI benefits from the Evaluation of the Massachusetts New Homes with ENERGY STAR Program (NMR and Conant, 2009). Energy savings from a new ENERGY STAR rated home

5.3 IMPROVED SENSE OF ENVIRONMENTAL RESPONSIBILITY

Participants are generally aware that reducing their own energy consumption has a positive effect on the environment, and programs that increase the energy efficiency of their homes can result in a sense of satisfaction from being environmentally responsible. When *sense of environmental responsibility* (or, as expressed in some surveys, participants' perceptions of the value of the "environmental impact" of their participation in the program) is included in NEI studies, it tends to be one of the most highly valued participant NEIs for both all-income and low-income whole-house programs, possibly second only to comfort (for example, Myers and Skumatz, 2006; NMR and Conant, 2009; Skumatz and Dickerson, 1999; Skumatz and Nordeen, 2001; for a review of these studies, see Appendix A).

While sense of environmental responsibility has been shown to be commonly experienced and considered important by participants of a variety of program types, the environmental benefits of the PAs' programs have been estimated in the *Avoided Energy Supply Costs in New England: 2011 Report* (Hornby et al, 2011) and included in the PAs' three year energy efficiency plans (National Grid et al., 2009; NSTAR et al., 2009). Therefore, NMR does not recommend including the NEI of sense of environmental responsibility, as this would amount to double counting of the same benefit.

5.3.1 Recommendations

NMR does not recommend including the NEI of sense of environmental responsibility for two reasons. First, because the environmental benefits of the PAs' programs have been estimated in the *Avoided Energy Supply Costs in New England: 2011 Report* (Hornby et al, 2011) and included in the PAs' three year energy efficiency plans (National Grid et al., 2009; NSTAR et al., 2009), this would potentially amount to double counting of the same benefit. In other words, this would count both the material environmental benefit and the psychic benefit of how program participants feel about the material environmental benefit. Second, because sense of environmental benefit is so intangible, NMR does not recommend counting this benefit. ,

5.4 QUIETER INTERIOR ENVIRONMENT

Energy efficiency programs can reduce the noise in participants' homes by installing insulation and sealing doors and windows, thus reducing the extent to which outside noise can be heard inside the home. Also, some of the measures installed such as furnaces, can themselves be quieter than the standard, often older, equipment that was replaced. This NEI is sometimes included in evaluations of whole-house programs. It is perceived by participants of both all-income and low-income programs to be of moderate to high value, relative to other participant NEIs.

5.4.1 Non-low-income Programs

Barkett et al. (2006)

In the evaluation of the NY ENERGY STAR Homes program described earlier (Barkett et al., 2006), 75% of participants surveyed reported a positive change in noise levels in their home relative to their previous home, compared to 67% of non-participants (who had recently purchased a non-ENERGY STAR home). Participants and non-participants both valued reduced noise levels at 42% of energy savings, a value equal to that of thermal comfort. Again, although the NEI values were not scaled proportionately to the overall value, and the equivalence of the participants' and non-participant results is difficult to interpret, it is notable that such a large proportion of participants experienced reduced noise levels and that the value was as high as that of thermal comfort. The C*onjoint Analysis* questions in the survey, which measure the

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were estimated to be $400 per home per year. Scaling thermal comfort to 100% of the estimated bill savings results in an NEI estimate of $77 per participant (i.e., 19% * $400=$77). NMR recommends considering adjusting the scaling of the residential new construction NEI values upon completion of the analysis of the current NEI surveys of participants in the PAs' residential retrofit programs.

value to participants of noise level and other attributes in the abstract (as opposed to actually experienced), yielded an annual value of $72 per participant household. Although this is far lower than the $191 obtained for comfort, it is still high relative to the other NEIs, showing that participants prefer lower noise levels and (at least in hypothetical scenarios) would be willing to exchange a substantial amount of money for a reduction in noise.

NMR and Conant (2009)

NMR's Massachusetts New Homes ENERGY STAR program evaluation (NMR and Conant, 2009) found that 67% of participants perceived that their homes were quieter than they thought an equivalent non-ENERGY STAR home would be, and they valuated this NEI at 37% of bill savings, or $146. Although this value should be interpreted in light of the fact that it was not scaled to an overall NEI value, the study provides further evidence that reduced noise is clearly experienced and valued by many program participants.

5.4.2 Low-income Programs

The literature suggests that participants in low-income programs also consider reduced noise levels to be of moderate to high importance relative to other participant NEIs, but the evidence that such programs result in a significant reduction in noise levels is somewhat mixed. Skumatz and Dickerson's study on NEIs from various low-income weatherization programs (1999) found that, for the programs with caulking/weather-stripping, reduced noise was rated as the second most important NEI (after "less drafty"), equivalent in importance to "lower bills." However, fewer than 10% of participants in the CT WRAP program said that the noise level in their house was "better" or "much better" than before the program (Skumatz and Nordeen, 2002), indicating that not all programs are successful in reducing noise levels to a noticeable degree. Nevertheless, on the whole it appears that low-income programs do have a net positive impact on noise levels; in a recent review of NEIs from hundreds of different low-income programs, Skumatz, Khawaja, and Krop (2010) estimates that reduced noise values for such programs are $13 to $20 annually per participant household.

5.4.3 Assessment of the Literature

Quieter interior environment NEI is sometimes included in evaluations of whole-house programs and is perceived by participants of both all-income and low-income programs to be of moderate to high value relative to other participant NEIs. NMR does not consider the range of values reported by Skumatz, Khawaja and Krop (2010)—$13 to $20 annually—to be readily applicable to the PAs' programs, as the values in the review vary widely by type of program, measures installed, survey method, geographical region, and other factors.

5.4.4 Relevant PA Programs

Quieter interior environment is often found to be a moderate- to low-value participant NEI and it is potentially applicable to all-income and low-income programs that include insulation and other weatherization and shell measures.

5.4.5 Recommendations

Based on the surveys of program participants, NMR recommends an annual value of $31 for NLI participants and $30 for LI participants who installed shell and weatherization measures or heating and cooling equipment. The NEI applies to the PAs' low income-retrofit programs, low-income new construction programs, residential cooling and heating programs, residential heating and hot water programs, and non-low-income retrofit programs (i.e., Mass Save, multi-family retrofit programs).

For the PAs' residential new construction program (non-low-income), NMR recommends using a value of $40 per participant, the scaled value from the Evaluation of the Massachusetts New Homes with ENERGY STAR Program (NMR and Conant, 2009).[95]

5.5 REDUCED NOISE (DISHWASHERS)

A potential non-energy impact associated with ENERGY STAR dishwashers is reduced noise.[96] Some dishwashers, particularly older models, can be loud. The NEI of reduced noise from dishwashers has rarely been measured in the literature. In fact, NMR's review of the literature identified only one study quantifying this benefit. A survey conducted for the New York Energy $mart programs found that respondents valued the NEI of "noise levels" for dishwashers at 9% of total NEIs (Fuchs et al., 2004). This survey employed the relative valuation method, in which respondents were asked if the appliance had a positive, negative, or no impact with regards to each of 13 NEIs. When respondents indicated that there was an impact (positive or negative), they were then asked for the relative value of the impact. Monetized NEI values were not computed in this report.

5.5.1 Assessment of the Literature

The literature on participant valuation of reduced noise from dishwashers is virtually nonexistent.

5.5.2 Relevant PA Programs

The NEI of reduced noise from dishwashers is relevant to PA programs that implement ENERGY STAR dishwashers. These programs include the RNC programs.

5.5.3 Recommendation

Due to the lack of research on reduced noise from dishwashers and its relative low and non-monetized value in the single study in which it was measured, NMR does not recommend quantifying the value of this NEI at this time.[97]

5.6 LIGHTING QUALITY

Our review of the literature found few studies assessing participants' perceptions of the lighting quality of CFLs. When it has been examined, it has sometimes been combined with lifespan of CFLs provided through the program. However, the results are mixed and difficult to interpret. Lighting lifespan is discussed in more detail in Section 5.7.

In a study evaluating NEIs from several NY Energy $mart programs, ten participants of a CFL marketing program (CFL users) and ten non-participants (CFL non-users) were asked a series of questions about their experiences or perceptions of CFL bulbs compared to incandescent bulbs (Barkett et al., 2006). While the majority (72%) of respondents perceived the longer lifetime of CFLs to be positive, more respondents perceived the lighting quality of CFLs to be worse than incandescents (about 35%) than perceived it to be better (less than 30%). Combining quality and lifetime in a single question, NMR's

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[95] Noise reduction was estimated to be equal to $146 per participant, or 10% of the $1,445 in total NEI benefits from the Evaluation of the Massachusetts New Homes with ENERGY STAR Program (NMR and Conant, 2009). Energy savings from a new ENERGY STAR rated home were estimated to be $400 per home per year. Scaling noise reduction to 100% of the estimated bill savings results in an NEI estimate of $40 per participant (i.e., 10% * $400 = $40). NMR recommends considering adjusting the scaling of the residential new construction NEI values upon completion of the analysis of the current NEI surveys of participants in the PAs' residential retrofit programs.

[96] Reduced noise may also apply to energy efficient clothes washers.

[97] Reduced noise from dishwashers could be quantified through the surveys of the PAs' program participants, but priority was placed on NEIs that derive from shell, heating and cooling measures rather than appliances.

survey evaluating NEIs from the MA ENERGY STAR Homes program found that 61% of participants considered the combination to be positive overall, compared to what they thought they would experience in a new standard-efficiency home, whereas 20% said it was overall negative (NMR and Conant, 2009).

5.6.1 Assessment of the Literature

Few studies have assessed participants' perceptions of the lighting quality of CFLs and when it has been examined, it has sometimes been combined with lifespan of CFLs provided through the program. Results from the literature are mixed and difficult to interpret.

5.6.2 Relevant PA Programs

Lighting quality applies to PA programs that install CFLs and LEDs, including the RNC programs, Mass Save, ENERGY STAR Lighting, the Multifamily Retrofit programs, and the Low-Income retrofit programs.

5.6.3 Recommendations

We recommend a single benefit for both lighting quality and lifetime and recommends using the one-time operation and maintenance (O&M) benefit presented in the Massachusetts Statewide Technical Reference Manual (TRM) for Estimating Savings from Energy Efficiency Measures for the 2011 program year, provided by the Massachusetts Department of Energy Resources (Massachusetts Electric and Gas Energy Efficiency Program Administrators, 2010). The one-time benefit per CFL bulb or CFL fixture installed through programs that ranges from $3.00 to $3.50 per CFL bulb or fixture, depending on the type of bulb or fixture. This applies to all of the PAs' programs that install energy efficient lighting (i.e., RNC programs, Mass Save, ENERGY STAR Lighting, the Multifamily Retrofit programs, Low-Income retrofit programs, and low-income new construction programs)

While the surveys of program participants found that respondents assign a positive value to the lighting quality and lifetime of program sponsored energy efficient lighting ($49 for NLI participants and $56 for LI participants), the O&M benefit is a more reliable and straightforward estimate of lighting NEIs.

5.7 LONGER LIGHTING LIFETIME

Energy-efficient lighting technologies such as CFLs and LEDs have longer lifetimes than incandescent lighting. ENERGY STAR CFL bulbs last up to ten times longer than incandescent bulbs, while LED bulbs last at least 15 times longer than incandescent bulbs.[98] In addition to energy bill savings, participants realize financial savings from CFLs in the form of fewer bulb purchases due to their longer lighting life. Additionally, participants benefit because they need to spend less time changing light bulbs. The value of financial savings to participants in the form of fewer bulb purchases and maintenance can be derived via an engineering estimate that includes the following variables: purchase price per bulb, bulb lifetime, installation labor hours, and labor cost per hour (i.e. the value of participant time spent changing out light bulbs). Purchase price, bulb lifetime, and installation labor hours are straightforward to quantify and likely do not vary significantly from one participant to another. Labor cost per hour, however, does vary from one participant to another.

[98] http://www.energystar.gov/index.cfm?c=products.pr_find_es_products

Barkett et al., (2006)

Participant valuation of the longer lifetime associated with CFLs has been investigated in the literature via participant surveys. In the 2006 Non-Energy Impacts Evaluation for New York Energy $mart programs, for example, respondents who owned CFLs were asked if they experienced a positive, zero, or negative impact with regards to bulb lifetime compared to incandescent light bulbs (n=10) (Barkett et al., 2006). Over 70% of respondents reported a positive impact, around 10% reported zero impact, and the remainder answered “don’t know.” When asked to value the positive impact of bulb lifetime relative to energy savings, those who indicated a positive impact reported an average of 55% of energy savings. Conjoint analysis questions asked in the same survey of all respondents (both CFL users and non-users) resulted in an annual participant valuation of $1.80 for bulb lifetime (n=21).

NMR and Conant (2009)

Another study investigating participant valuation of longer lighting life is the 2008 Evaluation of Massachusetts New Homes with ENERGY STAR Program (NMR and Conant, 2009). Eighty-one percent of respondents believed that their ENERGY STAR home provided the NEI of “lighting life/quality,” while 61% reported a positive impact with regard to “lighting life/quality” for all CFLs in their home. Via the relative valuation method, an annual NEI value of $144 (or 36% of bill savings) was reported for “lighting life/quality” (n=63). This NEI value accounts for both positive and negative valuations reported by respondents.

5.7.1 Assessment of the Literature

Several studies in the literature have examined participant valuation of longer lighting lifetime via participant surveys. While this NEI has been investigated for programs promoting CFLs, there are no studies in the literature specific to LED lighting. Monetized values of this NEI have been estimated via relative valuation and conjoint analysis methods. Relative to other participant NEIs, the NEI of lighting life is well suited for an engineering estimate approach, because light bulbs have well-documented estimated useful lifetimes and bulb prices. Therefore, the NEI of lighting life could likely be measured reliably via an engineering estimate, as opposed to the survey methods with which it has been estimated in the NEI literature.

5.7.2 Relevant PA Programs

Longer lighting lifetime applies to PA programs that install CFLs and LEDs, including the RNC programs, Mass Save, ENERGY STAR Lighting, the Multifamily Retrofit programs, and the Low-Income retrofit programs.

5.7.3 Recommendations

NMR recommends a single benefit for both lighting quality and lifetime and recommends using the one-time operation and maintenance (O&M) benefit presented in the Massachusetts Statewide Technical Reference Manual (TRM) for Estimating Savings from Energy Efficiency Measures for the 2011 program year, provided by the Massachusetts Department of Energy Resources (Massachusetts Electric and Gas Energy Efficiency Program Administrators, 2010). The one-time benefit per CFL bulb or CFL fixture installed through programs that ranges from $3.00 to $3.50 per CFL bulb or fixture, depending on the type of bulb or fixture. This applies to all of the PAs’ programs that install energy efficient lighting (i.e., RNC programs, Mass Save, ENERGY STAR Lighting, the Multifamily Retrofit programs, and the Low-Income retrofit programs)

While the surveys of program participants found that respondents assign a positive value to the lighting quality and lifetime of program sponsored energy efficient lighting ($49 for NLI participants and $56 for LI participants), the O&M benefit is a more reliable and straightforward estimate of lighting NEIs.

5.8 INCREASED HOUSING PROPERTY VALUE AND ANTICIPATED EASE OF SELLING OR LEASING HOME

Increased home property value is frequently recognized as a non-energy benefit associated with low-income weatherization programs and has also been estimated for non-low-income programs. Energy-efficient homes are generally more desirable than less efficient homes, particularly because energy bills are lower in energy-efficient homes. The benefit of increased property value has been estimated through the value of the anticipated ease of selling or renting or, in some cases, increased resale or rental value.

5.8.1 Low-income Programs

Several methods for estimating the participant benefit of increased home property value have been employed in the literature. The most commonly employed estimation method, particularly in the recent literature, is to value the structural repairs made to homes during low-income weatherization programs. Home repairs generally increase a property's value, which represents a participant benefit separate from and in addition to energy bill savings. While the benefit of increased home property value could theoretically apply to all PA programs and customers, the NEI literature has rarely quantified this benefit for non-low-income customers and programs.

The majority of NEI valuations for increased property value found in the literature are based on structural repairs made to homes through low-income weatherization programs. Home repairs are often required before weatherization measures can be installed. Examples of home repairs include repairing or replacing windows and doors, ventilating attics, and incidental roof, wall, and floor repairs.

Brown et al. (1993)

The 1993 national WAP program evaluation estimated the value of the increased property values to be equal to the weighted national average spent on materials for structural repairs, which was $126 for the program year under evaluation (Brown et al., 1993). The authors of the report noted that the quantity of home repairs performed through the national WAP varied depending on climate region, primary heating fuel, and dwelling type. In particular, structural repairs occurred most frequently to homes found in hot regions, to homes heated by gas, and to single-family detached homes.

TecMarket Works, SERA, and Megdal Associates (2001)

The LIPPT report estimated a value of $17.80 per household per year based on the cost of structural repairs made to a participant's home (TecMarket Works, SERA, and Megdal Associates, 2001). This annual NEI value assumes a ten-year benefit horizon and a participant discount rate of 18%.

Skumatz, Khawaja, and Krop (2010)

A recent review of the literature found annual participant benefits ranging from a few dollars to more than $20 per participant (Skumatz, Khawaja, and Krop, 2010).

Nevin and Watson (1998)

One study frequently cited in the literature that examined the relationship between energy efficiency and property values is that of Nevin and Watson (1998). This study employed regression models to estimate the relationship between fuel expenditures and home values. Property value data for the study incorporated a variety of home types and home heating fuels. The model results confirmed the hypothesis that homebuyers were willing to pay more for energy-efficient homes; a $10-$25 increase in property value for every $1 decrease in annual fuel bills was reported. While this particular study is often cited in low-income NEI literature, it addressed neither PA-sponsored energy efficiency programs nor the low-income population.

Riggert et al. (1999)

The property value NEI of $5,413 per home presented in the 1999 Vermont WAP evaluation was estimated by multiplying the average dollar increase reported by Nevin and Watson by the average energy savings from the Vermont WAP (Riggert et al., 1999). This NEI estimation method assumes that weatherization increases a home's value in proportion to the energy savings.

Dalhoff (2007)

A subsequent Vermont WAP report, however, stated that, for several reasons, it was not appropriate to use Nevin and Watson's regression model to quantify increased property values for the Vermont WAP (Dalhoff, 2007). Because Nevin and Watson's analysis was based on the correlation between fuel costs and property value in a national sample, the 2007 Vermont WAP evaluators argued that the analysis did not account for the fact that energy usage tends to be lower in milder climates and that people place value on numerous benefits of residing in a mild climate (not just lower fuel expenditures). Furthermore, the analysis did not directly measure the change in property value following the installation of energy efficiency measures. Consequently, the property value NEI for the 2007 Vermont WAP was valued at average program expenditures per weatherized household. The reasoning for this estimation method was that other homes in the same market could be improved by a similar expenditure.

Skumatz and Dickerson (1999)

Skumatz and Dickerson's analysis of NEIs from various low-income weatherization programs (1999) found that participants rated increased selling price as the third most important NEI from the programs that included insulation, after comfort and environmental impact. In Myers and Skumatz' evaluation of multi-family programs, participants in all-income multifamily programs gave anticipated ease of selling the third highest NEI value, again following comfort and environmental impact (Myers and Skumatz, 2006). Participants in low-income multifamily retrofit programs valued anticipated ease of selling or renting to an even higher degree, at 17% of the total NEI value, second only to environmental impact.

5.8.2 Non-low-income Programs

A high degree of energy efficiency in a home tends to be an attractive feature for homebuyers and renters. Therefore, homes with energy-efficient equipment, or homes that are built to be energy-efficient, can command a higher selling or rental price, and can be easier to sell or rent than similar homes with standard efficiency, resulting in a higher property value.

Studies show that participants of a variety of programs consider anticipated ease of selling or renting or, in some surveys, increased resale or rental value to be an important benefit.

For the two major evaluations of NEIs from new construction programs included in our literature review, homeowners were asked about the value per year of anticipating these resale benefits.

Barkett et al. (2006)

The *RV/DS* survey employed in Summit Blue's NYSERDA evaluation of NEIs from a NY ENERGY STAR Homes program (Barkett et al., 2006) asked 12 participants and 12 non-participants whether they anticipated that their new home would be easier or harder to sell than their previous home. Six participants and four non-participants indicated that it would be easier to sell. The other six participant respondents either thought it would be the same or did not know if it would be easier or harder to sell.

NMR and Conant (2009)

NMR's survey on NEIs from MA ENERGY STAR Homes (NMR and Conant, 2009) asked whether participants expected that their homes would have a higher or lower rental or resale value, compared to similar, standard-efficiency new homes. Eighty percent of the respondents said they expected it to be higher.

While these results suggest that at least some owners of ES Homes do anticipate greater ease in selling the home because of the program, estimating the annual value of that anticipation per participant is not straightforward. Summit Blue's evaluation of NY ES Homes (Barkett et al., 2006) reported a value of 62% of energy savings for anticipated ease of selling ($399), while surveyed participants in the NMR evaluation of MA ES Homes valued the increased resale or rental value at 65% of bill savings, or $259.

Although the two studies obtained similar results for this NEI, both values are likely to be overestimated, for several reasons. First, as mentioned in other sections, the survey does not account for the fact that when respondents are asked the total combined value of all the NEIs in the survey, this average value is invariably far lower than the sum of the values given individually for the NEIs, both in this survey and other similar surveys (e.g., Skumatz, 2002). In fact, the value Summit Blue (Barkett et al., 2006) reported for estimated ease of selling (62% of bill savings) is *higher* than the average value given by participants for *all the NEIs combined* (47%).

Also, the value of 62% of energy savings derived from Summit Blue's survey was calculated only from the five participants who had said they expected their new home to be easier to sell than their previous home (Barkett et al., 2006). The six participants who said either "same (no impact)" or "don't know" were not included in calculating the average valuation. Therefore, the value of 62% of energy savings does not reflect the average value per participant. Further, because four non-participants (with standard-energy homes) thought their new homes would sell more easily than their previous homes, and because they valued this anticipation to a greater extent (75% of bill savings) than did participants, interpretation of the results is difficult.

5.8.3 Assessment of the Literature

Home property valuation depends on a multitude of factors. Holding all other factors constant, an energy-efficient property is more valuable than a less efficient one. However, the magnitude by which specific energy efficiency measures increase a property's value has not been examined extensively in the NEI literature. Instead, most property value NEI estimations found in the literature are based on low-income weatherization programs; they are estimated as the average cost of materials required for minor improvements performed during home weatherizations. It is reasonable to assume that needed structural repairs improve a home's value.

For non-low-income programs, increases in property values have been measured through surveys of program participants as their valuation of the anticipated ease of selling/renting their home. This has been found to be a fairly important subjective benefit for participating homeowners for a variety of program types, including multifamily retrofit programs, as well as new construction.

5.8.4 Relevant PA Programs

NMR recommends applying this NEI to the PAs' low-income and non-low-income retrofit programs.

5.8.5 Recommendations

Based on the surveys of program participants, NMR recommends one-time value of $1,998 for NLI participants and $949 for LI participants who installed shell and weatherization measures or heating and cooling equipment. The NEI applies to the PAs' low income-retrofit programs, low-income new construction programs, residential cooling and heating programs, residential heating and hot water programs, and non-low-income retrofit programs (i.e., Mass Save, multi-family retrofit programs).

For the PAs' residential new construction program (non-low-income), NMR recommends using an annual value of $72 per participant, the scaled value from the Evaluation of the Massachusetts New Homes with ENERGY STAR Program (NMR and Conant, 2009).[99]

The evaluation team recommends replacing the current NEI value used in the TRM report with the values estimated in this report. The TRM reports a one-time property value benefit of $20.70 for every dollar in energy savings, based on the Nevin and Watson (1998) study, and the evaluation team does not recommend continuing to use this value.[100]

5.9 BUFFERS ENERGY PRICE INCREASES

Energy prices fluctuate over time, with short term fluctuations and longer-term (expected upwards) trends. This is particularly true for prices of residential home heating fuels. Energy efficiency programs mitigate the impact of energy price fluctuations that affect customers' energy bills, by reducing the amount of energy that customers consume. Program participants derive value from minimizing their exposure to price increases.[101]

According to the PAs' three-year electric plans, the TRC benefit-cost test includes Demand Reduction Induced Price Effect (DRIPE). DRIPE is a benefit realized by consumers from the response of the supply market to lowered demand attributable to energy efficiency measures. The three-year plans define DRIPE as a reduction of prices of wholesale energy and capacity market prices that result from reductions in demand as a result of energy efficiency efforts (National Grid et al, 2009). The value of DRIPE was estimated in the *Avoided Energy Supply Costs in New England: 2011 Report* (Hornby et al., 2011) and used in the TRC benefit-cost test.

5.9.1 Recommendations

Because the PAs' three-year electric plans and the TRC benefit-cost test includes DRIPE, NMR does not recommend attempting to quantify an NEI value above and beyond what has already been accounted for in the *Avoided Energy Supply Costs in New England: 2011 Report* (Hornby et al., 2011). NMR believes that DRIPE provides the best estimate of the price effects realized by consumers.

5.10 REDUCED NEED TO MOVE AND COSTS OF MOVING, INCLUDING HOMELESSNESS

High energy costs have been linked with increased rates of mobility among low-income households. High energy bills leave less money available for other necessities. When a household's income is insufficient to cover all expenses, the household is more likely to fall behind on rent and be evicted. Utility service terminations due to non-payment can render a home uninhabitable, forcing its inhabitants to move.

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[99] Resale or rental value was estimated to be equal to $259 per participant, or 18% of the $1,445 in total NEI benefits from the Evaluation of the Massachusetts New Homes with ENERGY STAR Program (NMR and Conant, 2009). Energy savings from a new ENERGY STAR rated home were estimated to be $400 per home per year. Scaling resale or rental value to 100% of the estimated bill savings results in an NEI estimate of $72 per participant (i.e., 18% * $400 = $72).

[100] According to the Nevin and Watson's study, the increase in the property value for an energy efficient home is derived from the expected energy savings. The one time increase in property value represents the current value of the stream of expected energy savings. To quote the authors: "These findings provide strong evidence that the market value of energy- efficient homes reflects projected fuel savings discounted at the average home buyer's after-tax mortgage interest rate (Nevin and Watson, 1998, p. 407)." Because energy savings are already accounted for, to count the increase in property value that is attributed to the same energy savings would be double counting of benefits.

[101] See Appendix C: Additional Literature Reviewed for Select NEIs for a review of studies that have examined participant valuation of buffering future energy price increases.

Frequent relocation results in direct and indirect costs to low-income families. Direct costs include the time, effort, and expenses incurred in moving. An indirect cost identified in the literature is the disruption in children's education associated with frequent relocation. As cited in Khawaja et al. (1999), a 1984 National Science and Law Center study in Pennsylvania found that low-income households were three times as likely to move as non-low-income households, and that the high school drop-out rate of frequent movers was four times the average. Howat and Oppenheim (1999) identify three ways in which energy efficiency programs can help reduce mobility, including freeing up funds to pay rent and other required housing costs, decreasing the likelihood of service terminations, and resolving dangerous problems with heating systems or building structures that might otherwise force a household to move.

Research linking increased mobility and/or homelessness with unaffordable energy costs indicates that decreasing the energy burden of low-income households makes more funds available within the household budget for rent and energy bills, therefore helping low-income households stay in their current homes. Because the energy savings from the programs are already counted as a benefit by the PAs, to count additional benefits that derive from these energy savings would amount to double counting. Therefore, NMR does not recommend quantifying the benefits of reduced rates of mobility and homelessness. This is not to say that low-income households do not benefit from reduced energy burdens, but rather that the benefits are already accounted for. A review of the literature linking energy costs with mobility and homelessness can be found in Appendix C: Additional Literature Reviewed for Select NEIs.

5.10.1 Recommendation

The primary mechanism by which energy efficiency programs reduce the incidence of low-income mobility and/or homelessness is through the energy bill savings. The energy bill savings represent additional dollars that can be put toward rent and energy bills. However, participant energy bill savings are already accounted for by the PAs in the AESC study and TRC test. Valuing the NEI of reduced mobility and homelessness attributable to energy efficiency programs is effectively double counting the energy bill savings. Therefore, NMR does not recommend quantifying the value of this NEI. [102]

5.11 REDUCED WATER USAGE AND SEWER COSTS (DISHWASHERS AND TANKLESS WATER HEATERS)[103]

To the extent that ENERGY STAR dishwashers and tankless water heaters use less water than conventional alternatives, participants can benefit from a decrease in their water and sewer bills. For dishwashers, the magnitude of water bill savings to a given participant depends on whether a non-ENERGY STAR dishwasher would have been installed without the program, and if so, the difference in the amount of water used between the ENERGY STAR dishwasher and the non-ENERGY STAR dishwasher that would have been installed in the absence of the program. Estimating the annual value of this NEI for dishwashers is a straightforward engineering estimate involving the following variables: annual dishwasher cycles, the quantity of water saved per cycle by the new dishwasher, and the cost of water. Sewer costs use a similar algorithm of annual dishwasher cycles, the quantity of water saved per cycle by the new dishwasher, and the sewer costs.

For water savings attributable to water heaters, water usage is likely to be related to the distance between the water heater and the faucet or appliance to which it supplies hot water. If participants do not have to run a hot faucet tap and wait for the water to warm up, then they can potentially cut down on their water bills.

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[102] If energy bill savings are not counted, we recommend that bill savings be counted rather than counting the benefits that derive from bill savings.

[103] Because clothes washers are not among the measures included in the PAs' programs, this literature review does not include a discussion of water savings attributable to energy-efficient clothes washers.

Many studies have examined the participant value of water savings from measures such as low-flow showerheads and faucet aerators, but few have focused on ENERGY STAR dishwashers. One study analyzing the non-energy benefits arising from ENERGY STAR appliances in California estimated that the value of annual water savings from ENERGY STAR dishwashers was $1.65 per participant (Equipoise Consulting, 2001). This NEI value was obtained by multiplying estimates of the following: water savings (in gallons) between conventional and ENERGY STAR dishwashers; dishwasher cycles per year; and cost of water per gallon. An important consideration noted in the report is that ENERGY STAR dishwashers do not necessarily use less water than conventional models, due to the soil sensors they contain. For example, the authors noted that soil-sensing dishwashers use between 4.9 and 8.5 gallons per load, depending on how soiled the dishes are. In order to quantify the NEI value, average water usage data for ENERGY STAR and conventional dishwashers was obtained from the Department of Energy. The estimated number of cycles per year used to estimate the program-level energy savings was applied in the formula for estimating the NEI of participant water savings. The last component to the NEI calculation, residential water rates, was estimated by averaging the rates from the water utilities within the relevant service territory.

Non-energy impacts of tankless hot water heaters have seldom been discussed in the literature. To our knowledge they have never been monetized. A 2006 survey of participants in a Massachusetts tankless water heater program found that satisfaction with tankless water heaters may be associated with the distance between the water heater and the primary faucet or appliance to which it supplies hot water (NMR, 2006). For example, respondents who reported that their tankless water heater was either closer to or the same distance from the primary faucet or appliance than their old water heater were more likely to be satisfied with the amount of time it took hot water to come out of the faucet (100% and 85%, respectively, were satisfied or extremely satisfied, versus 56% among those whose water heaters are farther away). Participants were also asked if they used more, less, or the same amount of hot water than before participating in the program. Approximately three-quarters of respondents estimated that they used the same amount of hot water as when they had a storage tank water heater, while approximately 12% reported using more hot water and 12% reported using less hot water. NEI values were not quantified in this report.

5.11.1 Assessment of the Literature

The value to participants of reduced water usage can be calculated using a straightforward engineering calculation. NEI valuations in the literature for reduced water usage from ENERGY STAR dishwashers have been estimated via this method. The non-energy impact of reduced water usage resulting from tankless hot water heaters has rarely been investigated. One study on water usage of ENERGY STAR versus non-ENERGY STAR dishwashers found that the former did not necessarily use less water than the later. As of August 2009, however, ENERGY STAR qualified dishwashers are required to use 5.8 gallons of water per cycle or less.[104] Data on water usage of the new and old dishwashers for rebate and retrofit programs is expensive to collect; therefore, NEI estimates have generally been based on average water usage for relevant dishwasher models. Because participant water rates are a component in the formula, the value of this NEI is sensitive to local water rates and pricing structures.

5.11.2 Relevant PA Programs

The non-energy benefit of reduced water usage from dishwashers and tankless hot water heaters applies to PA programs that implement ENERGY STAR dishwashers and tankless water heaters. These programs include the RNC programs and the residential heating and hot water equipment program.

[104] http://energystar.custhelp.com/cgi-bin/energystar.cfg/php/enduser/std_adp.php?p_faqid=2539&p_created=1147982777

5.11.3 Recommendations

a. Dishwashers

NMR recommends quantifying participant water savings by using the annual water savings value from the 2010 Massachusetts Technical Reference Manual (TRM) for Estimating Savings from Energy Efficiency Measures for an ENEGY STAR dishwasher of 430 gallons per year[105] and multiplying by the average cost of water per gallon in Massachusetts reported in Massachusetts Joint Statewide Three-Year Electric Energy Efficiency Plan ($0.0036 per gallon) for an annual NEI value of $1.55 per dishwasher. The algorithm is as follows:

- 430 gallons (estimated annual water savings per ENERGY STAR dishwasher) * $0.0036 (average cost of water per gallon in Massachusetts reported in Massachusetts Joint Statewide Three-Year Electric Energy Efficiency Plan)

NMR recommends using the same formula for sewer savings and using an average sewer rate of $0.0050 per gallon as reported in the Massachusetts Joint Statewide Three-Year Electric Energy Efficiency Plan for an annual NEI value of $2.15 per dishwasher. The algorithm is as follows:

- 430 gallons (estimated annual water savings per ENERGY STAR dishwasher) * $0.0050 (average cost of sewerage per gallon in Massachusetts reported in Massachusetts Joint Statewide Three-Year Electric Energy Efficiency Plan)

b. Tankless Water Heaters

Due to the lack of information in the literature, it is unclear how significant the NEI of water usage associated with tankless water heaters might be. The quantity of water reduced is zero, more or less, depending on the location of the new water heater compared to the old one. Further, because of the relatively low cost of water (average Massachusetts cost of $0.0036 per gallon); this NEI is likely to be low in value and likely does not warrant the costs of primary data collection. If the PAs are interested in quantifying its value, NMR recommends the following algorithms:

- (average number of gallons of water flowing down the drain waiting for hot from traditional water heaters - average number of gallons of water flowing down the drain waiting for hot from tankless water heaters) * $0.0036 (average cost of water per gallon in Massachusetts reported in Massachusetts Joint Statewide Three-Year Electric Energy Efficiency Plan)
- (average number of gallons of water flowing down the drain waiting for hot from traditional water heaters - average number of gallons of water flowing down the drain waiting for hot from tankless water heaters) $0.0050 (average cost of sewerage per gallon in Massachusetts reported in Massachusetts Joint Statewide Three-Year Electric Energy Efficiency Plan)

Because the quantity of water flowing down the drain while participants are waiting for the water to become hot depends on the distance between the water heater and the point of use, these data are likely to be extremely difficult to collect.

5.12 REDUCED DETERGENT USAGE (DISHWASHERS)

While reduced detergent usage associated with ENERGY STAR clothes washers has been addressed in the NEI literature, detergent usage associated with ENERGY STAR dishwashers has not. In fact, there is

[105] The annual water savings from an ENEGY STAR dishwasher was derived from the Environmental Protection Agency (2010). Life Cycle Cost Estimate for ENERGY STAR Residential Dishwasher. Interactive Excel Spreadsheet found at

http://www.energystar.gov/ia/business/bulk_purchasing/bpsavings_calc/CalculatorConsumerDishwasher.xls no evidence in the literature that ENERGY STAR dishwashers require less detergent than non-ENERGY STAR dishwashers. Where detergent savings have been investigated for clothes washers, it has been found that the NEI associated with detergent usage can be either positive or negative. For example, one study found that participants who continued to use conventional clothes detergent in their new ENERGY STAR clothes washers benefited because they used less detergent per load and therefore saved on the cost of detergent (Equipoise, 2001). However, the same study found that participants that switched to high efficiency (HE) detergent actually spent more money because the HE detergent was more expensive per load than conventional detergents.

5.12.1 Assessment of the Literature

Detergent usage for energy-efficient dishwashers has not been addressed in the NEI literature. It is unclear whether detergent usage associated with energy-efficient dishwashers differs from that of non-energy-efficient dishwashers. Determining the financial impact to participants from a difference in detergent use requires determining not only the recommended detergent dosages and associated costs for both ENERGY STAR and non-ENERGY STAR dishwashers, but also determining the extent to which participants actually follow the recommended detergent dosages.

5.12.2 Relevant PA Programs

Dishwasher detergent usage is relevant to the RNC programs that install dishwashers.

5.12.3 Recommendation

Due to the lack of information in the literature, it is unclear whether detergent usage differs between ENERGY STAR and non-ENERGY STAR dishwashers, and if it does, how significant the NEI of detergent usage associated with ENERGY STAR dishwashers might be. Furthermore, because the only PA program promoting the installation of ENERGY STAR dishwashers is the residential new construction program, the baseline comparison for detergent usage would be a new, non-ENERGY STAR dishwasher. While the difference in detergent requirements between an older unit and a new ENERGY STAR dishwasher may be significant enough to warrant investigation, it is unlikely that the difference in detergent usage between a new, non-ENERGY STAR dishwasher and a new ENERGY STAR dishwasher would warrant the cost of investigation. NMR does not recommend quantifying the NEI of dishwasher detergent at this time.

5.13 REDUCED WATER USAGE AND SEWER COSTS (LOW FLOW SHOWERHEADS AND FAUCET AERATORS)

Domestic hot water (DHW) measures such as low flow showerheads and faucet aerators reduce the amount of water that flows through showerheads and faucets. Therefore, in addition to the energy savings derived from DHW measures, participants can benefit from a decrease in their water and sewer bills. A straightforward engineering algorithm can be used to estimate the value of the NEI of water and sewer bill savings from low flow showerheads and faucet aerators. The requisite variables for quantifying the annual NEI value for low flow showerheads include the pre- and post-retrofit showerhead flow rates, the amount of time the shower is in use per year, and the costs of water and sewer. Similarly, the variables required to quantify the annual NEI value for faucet aerators are the pre- and post-retrofit faucet flow rates, the amount of time the faucet is in use per year, and water and sewer costs. It is important to note that for filling applications, such as filling bathtubs for bathing or pots to cook with, a fixed quantity of water is required and therefore no post-retrofit water bill savings will be achieved.

Skumatz and Dickerson (1997 and 1999)

Earlier estimates of the participant-perspective NEI of water savings from DHW measures are provided by Skumatz and Dickerson (1997 and 1999). Skumatz and Dickerson (1997) estimated a range of $8.00-$110.00 per year in water and sewer bill savings per household from showerhead and faucet aerator retrofits based on the low-income Venture Partners Pilot (VPP) Program in California. The VPP estimate was based on estimates of reduced water use from showerheads and faucet aerators, the number of showerheads and aerators installed per dwelling, and water and sewer rates for San Francisco and San Jose, CA. The authors noted that the wide range they presented for the value of this NEI illustrates its potential variability given alternative assumptions, and the that the high end of the range reflects the fact that local water rates can vary by a factor of ten across the nation. A different low-income weatherization program in California evaluated by Skumatz and Dickerson (1999) yielded a smaller benefit range of $4.22-$57.97.

Riggert et al. (1999)

The evaluation of the energy and non-energy impacts of Vermont's Weatherization Assistance Program derived a water and sewer savings benefit of $10 per participant per year based on the estimates developed by the evaluation of the VPP program (Riggert et al., 1999).

TecMarket Works, SERA, and Megdal Associates (2001)

An annual NEI value of $11.67 per household in water cost savings from low flow showerheads and faucet aerators was estimated in the 2001 California LIPPT report (TecMarket Works, SERA, and Megdal Associates, 2001). This NEI value was based on estimates of the annual water savings per showerhead and faucet aerator, the number of showerheads and faucet aerators installed, and the cost of water. Estimates of the quantity of water saved per showerhead and faucet aerator were obtained from water conservation and utility literature. The information used to estimate the cost of water per unit was gathered via surveys of California water utilities. In addition to water rates, the authors collected information on wastewater rates and discussed the potential for wastewater rates to be included in the estimation of this NEI. However, wastewater savings associated with water-saving measures were excluded from the LIPPT NEI estimate due to the fact that many wastewater utilities in California charge fixed rates that do not vary with consumption. Results from survey information collected to determine net water savings from installed faucet aerators and low flow showerheads indicated that these measures are left in place an average of three years. Therefore, the assumed benefit period for the NEI of water cost savings from low flow showerheads and faucet aerators in the LIPPT report is three years.

Skumatz and Nordeen (2002)

A 2002 report evaluating the NEIs associated with the Connecticut WRAP program reported an annual NEI value of $13.38 per household in water and sewer bill savings from low flow showerheads and faucet aerators (Skumatz and Nordeen, 2002). The quantity of water saved per DHW measure was derived from past research by the evaluators. A cost of $0.0051 per gallon of water and an assumed benefit horizon of 6 years were used to estimate this NEI value.

Skumatz and Gardner (2005)

Two separate NEI values were estimated for reduced water bill costs resulting from DHW measures installed in the Wisconsin low-income WAP: one via an engineering estimate and the other via a participant survey (Skumatz and Gardner, 2005). An annual NEI value of $4.89 per household was estimated via an engineering estimate assuming a water cost of $1.71 per hundred cubic feet ($0.0023 per gallon) derived from a survey of 10 indicator communities within the state. In addition, an NEI value range of $8-$10 per household per year was estimated for the same program via the relative verbal scaling method from a survey of program participants.

Skumatz, Khawaja, and Krop (2010)

In a recent review of the literature, Skumatz, Khawaja, and Krop (2010) reported a range of $5-$12 per household per year for water bill savings. These authors pointed out that water saved per measure is reliable and well-known, but that behavioral impacts can affect savings estimates as some studies have revealed behavior changes such as participants taking longer showers following the installation of low flow showerheads.

Algorithms and assumptions for estimating the quantity of water saved from faucet aerators and low flow showerheads were investigated in two recent residential program evaluations in Connecticut.

Nexant (2010)

The 2008 Home Energy Solutions (HES) program evaluation recommended applying water usage metrics from industry-accepted sources such as the 1999 American Water Works Association (AWWA) study which lists per capita water usage for faucets and showers based on water end use data collected from a sample of American households (Nexant, 2010). Onsite visits conducted at a sample of HES participant households provide examples of behavioral impacts on water savings estimates. Of the 41 homes visited, two participants reported rejecting installation of low flow showerheads or faucet aerators due to preference in maintaining current flow levels. Of the 22 participants within the sample who agreed to install low flow showerheads and faucet aerators, two quickly removed the low flow equipment, two reported taking longer showers, and one stated that more effort was required to hand-wash dishes.

KEMA (2010)

For the second recent evaluation, on-site visits were conducted for the 2007-2008 evaluation of the low-income Helps and Weatherization Assistance Partnership (WRAP) Programs at a sample of low-income participating Connecticut households (KEMA, 2010). Auditors collected data such as the flow rate of installed DHW measures, the average number of showers per day, and the duration per shower in minutes. The Connecticut WRAP report recommended assuming 1.6 minutes per faucet per day for estimating faucet aerator water savings, and 2.9 showers per day per household at 12.2 minutes per shower (or 35.4 minutes per day) for estimating showerhead water savings. Additionally, the report recommended assuming 2.5 gallons per minute (GPM) as the baseline for low flow showerhead savings. In order to adjust faucet aerator water savings for the number of faucet aerators installed, the algorithm recommended for estimating water savings per household involves multiplying estimated annual gallons of water saved per household by the square root of the number of faucet aerators installed at each household.[106] Similarly, the algorithm recommended for estimating shower head water savings per household multiplies the estimated gallons of water saved per household by the square root of the number of low flow showerheads installed at each household. The square root expression in the algorithms accounts for the fact that a second unit would not save as much as a first, a third unit would not save as much as a second unit, and so on.

5.13.1 Assessment of the Literature

The value to participants of reduced water usage can be calculated using a straightforward engineering calculation. NEI valuations in the literature for reduced water usage from low flow showerheads and faucet aerators have been estimated via this method. Behavioral impacts that may reduce water savings estimates have been documented, but are not well-studied and have not been incorporated into the NEI valuations. Because participant water and sewer rates are a component in the formula, the value of this NEI is sensitive to local rates and pricing structures.

[106] This adjustment assumes that the first faucet aerator is installed in the most commonly used faucet while subsequent aerators are installed on less commonly used faucets, resulting in fewer gallons saved per year because of lower usage.

5.13.2 Relevant PA Programs

The non-energy benefit of water bill savings from low flow showerheads and faucet aerators applies to PA programs which install low flow showerheads and faucet aerators, including the Multi-Family Retrofit, Low-Income Multi-Family Retrofit, Low-Income 1-4 Family Retrofit, and Mass Save programs.

5.13.3 Recommendations

Based on our review of the literature, NMR recommends quantifying the annual participant benefit of water and sewer bill savings from low flow showerheads and faucet aerators as follows:

a. Low Flow Showerheads

- (3696 gallons water saved per low flow showerhead per year (KEMA, 2010)) * square root of the average number of showerheads installed per site (PA data) * [$0.0036 (average cost of water per gallon in Massachusetts reported in Massachusetts Joint Statewide Three-Year Electric Energy Efficiency Plan) + $0.0050 (average cost of sewerage per gallon in Massachusetts reported in Massachusetts Joint Statewide Three-Year Electric Energy Efficiency Plan)]

b. Faucet Aerators

- (332 gallons water saved per faucet aerator per year (KEMA, 2010)) * square root of the average number of faucet aerator installed per site (PA data) * [$0.0036 (average cost of water per gallon in Massachusetts reported in Massachusetts Joint Statewide Three-Year Electric Energy Efficiency Plan) + $0.0050 (average cost of sewerage per gallon in Massachusetts reported in Massachusetts Joint Statewide Three-Year Electric Energy Efficiency Plan)]

If PA data on pre- and post-retrofit flow rates and the number of units installed at each site are available, then the recommendations for quantifying participant water and sewer bill savings are as follows:

c. Low Flow Showerheads

- ($GPM_{baseline}$(PA data) – $GPM_{retrofit}$(PA data)) * 35.4 minutes per day * 365 days per year * √number of showerheads installed at site (PA data) * [$0.0036 (average cost of water per gallon in Massachusetts reported in Massachusetts Joint Statewide Three-Year Electric Energy Efficiency Plan) + $0.0050 (average cost of sewerage per gallon in Massachusetts reported in Massachusetts Joint Statewide Three-Year Electric Energy Efficiency Plan)]

d. Faucet Aerators

($GPM_{baseline}$(PA data) – $GPM_{retrofit}$(PA data)) * 1.6 minutes per day * 365 days per year * √number of faucet aerators installed at site (PA data) * [$0.0036 (average cost of water per gallon in Massachusetts reported in Massachusetts Joint Statewide Three-Year Electric Energy Efficiency Plan) + $0.0050 (average cost of sewerage per gallon in Massachusetts reported in Massachusetts Joint Statewide Three-Year Electric Energy Efficiency Plan)]

Where:

- GPMbaseline = pre-retrofit flow rate in gallons per minute
- GPMretrofit = post-retrofit flow rate in gallons per minute

5.14 MORE DURABLE HOME AND EQUIPMENT AND APPLIANCE MAINTENANCE REQUIREMENTS

Home durability and maintenance requirements for heating and cooling equipment and appliances have generally been examined concurrently in the NEI literature. Homes built with better-quality heating, cooling, and structural materials are potentially more durable, therefore requiring less maintenance. To the extent that energy efficiency programs install better quality heating, cooling, and structural materials than what existed previously (in the case of retrofits) or what would have existed otherwise (in the case of new construction), they provide value to participants in the form of avoided maintenance costs and transaction costs. Similarly, energy efficiency programs that replace old equipment and appliances with new, energy efficiency equipment and appliances can provide value to participants in the form of avoided maintenance and transaction costs. New equipment and appliances generally require less maintenance than older ones. In addition, some energy-efficient technologies, such as CFLs, inherently require less maintenance than other technologies.

While it is possible that energy-efficient measures installed through retrofit programs may require less maintenance because they are new, it is not necessarily true that new energy-efficient measures require less maintenance than comparable, less efficient new measures.[107] In fact, instances of negative participant experiences with the maintenance of energy-efficient technologies have been documented in the NEI literature (Stoecklein and Skumatz, 2007). While decreased home maintenance requirements have been suggested multiple times in the literature as a potential participant NEI, few studies have actually estimated its value.

Barkett et al. (2006)

One study that did examine participant valuation of this NEI is the 2006 Non-Energy Impact Evaluation for the NY ENERGY STAR Labeled Homes program (Barkett et al., 2006). A survey of both participants and a comparison group found that 42% of program participants believed that their new ENERGY STAR-labeled home was more durable than their old home. Over 30% of all respondents reported that they did not know whether the new home was more durable than the old one. Those who reported either a positive or negative impact were asked to express the value of the NEI relative to the energy savings. On average, that subset of participants valued durability at around 15% of energy savings. Conjoint analysis questions asked at the end of the survey revealed that respondents placed a high value on home durability; they were willing to pay a premium of $5,648 in the upfront cost of the home to have a home that is “built following best practices in installation, so that the heating and cooling and structural materials are less prone to failure and may exceed their expected lifetimes.” The value of $5,648 was translated into an annual NEI value of $202 by dividing by an assumed measure lifetime of 28 years (Barkett et al., 2006). Sixty-four respondents completed the survey, but only 12 could be identified as program participants, due to a data recording error.

Fuchs et al. (2004)

In addition, several studies have attempted to value the NEI of decreased maintenance requirements associated with equipment and appliances installed through energy efficiency programs. For example, surveys conducted for the New York Energy $mart programs examined participant valuation of the equipment maintenance costs associated with ENERGY STAR appliances, including refrigerators, dishwashers, clothes washers, room air conditioners, CFLs, and lighting fixtures (Fuchs et al., 2004). A relative valuation method was employed, in which respondents were asked if the appliance had a positive impact, negative impact, or no impact with regard to each of 13 NEIs, one of which was “equipment

[107] It is also possible that high-efficiency heating and cooling equipment may have higher maintenance costs because high-efficiency furnaces needed more “work out time” to adjust safety controls and settings properly. In an evaluation of high-efficiency heating and cooling equipment in Vermont, one contractor described the safety and limit controls as ‘finicky.’ Other respondents reported that high-efficiency furnaces and boilers have higher maintenance costs because more parts and controls fail, and these parts are often more complex and expensive than standard-efficiency boilers and furnaces (NMR, 2009).

maintenance costs." When respondents indicated that there was an impact (positive or negative), they were then asked for the relative value of the impact. Survey results show that respondents valued the NEI of equipment maintenance costs at 9% of total NEIs for ENERGY STAR refrigerators, 5% of total NEIs for dishwashers, 6% of total NEIs for room air conditioners, 8% of total NEIs for CFLs, and 6% of total NEIs for lighting fixtures. Monetized NEI values were not presented in this report.

Skumatz and Gardner (2005)

Another study that investigated the NEI of equipment and appliance maintenance is the 2005 evaluation of Wisconsin's low-income weatherization assistance program (Skumatz and Gardner, 2005). The most commonly installed equipment/appliances through the program were CFLs, CO detectors, and smoke detectors. At least 50% of participants received these measures. In addition, 42% of participants received new refrigerators and 37% of participants received new heating systems. The participant survey for this study revealed that 28% of respondents reported a positive change in "reliability/amount have had to maintain new equipment," 71% reported no change, and 1% reported a negative change. Using a relative verbal scaling method comparing the NEI value to energy bill savings, an NEI value range of $19-$24 was estimated per participant per year for the Wisconsin low-income WAP[108].

5.14.1 Assessment of the Literature

Only one study in the literature attempted to quantify the value of durability to participants. The survey sample in this study contained people who had purchased a new home (both ENERGY STAR and non-ENERGY STAR) within the past year (Barkett et al., 2006). The energy efficiency measures employed through the program, however, had an estimated 28-year lifetime. Therefore, the respondents had relatively little experience with which to compare the maintenance requirements of their new homes with their old ones. Additionally, the study did not collect information regarding the durability of the homes in which respondents lived previously, which was the baseline comparison for durability.

Participant valuations of non-energy benefits associated with equipment and appliance maintenance have been investigated for low-income weatherization, ENERGY STAR appliance programs, and new homes, via the relative valuation survey method. Both positive and negative relative valuations have been produced by this method, but only one study translated these relative valuations into monetized values. In addition, it seems that respondent estimations of required maintenance should be interpreted with caution, due to the likely time lag between the installation of the equipment and need for maintenance and upkeep of the equipment. If a participant is surveyed too soon after installation, then he or she will likely not have had enough experience maintaining the new equipment or appliance to provide an accurate response. Further complication arises when a given participant has received multiple measures and each of those measures requires maintenance at different intervals. Participant surveys described in the NEI literature have generally been conducted within the first few years of program implementation.

Applying maintenance NEI values quantified in different studies to the PAs' programs is problematic for several reasons. First, not all participants surveyed experienced a change in equipment maintenance requirements; therefore, the relative values reported are based on relatively few participants. Additionally, in the evaluations reviewed, programs have installed different types of equipment and appliances in different proportions across participants. For programs that have employed multiple measures, participant valuation of reduced maintenance requirements has not always been obtained on a per measure basis, but for the total measures received by a given respondent. Therefore, it is unclear what portion of the participant's stated valuation was attributed to each measure. For at least one study, participants were asked to value the maintenance NEI associated with all program measures, and not just equipment and appliances. Therefore, the maintenance NEI values from this study potentially overlap with "durability of the home."

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[108] Equipment maintenance has also been examined in zero and low energy homes in New Zealand (see Appendix A for a summary of the study)

5.14.2 Relevant PA Programs

The NEI of a more durable home requiring less maintenance is applicable to the PAs' programs that install weatherization measures, shell measures, and heating and cooling equipment, including the PAs' low income-retrofit programs, low-income new construction programs, residential cooling and heating programs, residential heating and hot water programs, and non-low-income retrofit programs (i.e., Mass Save, multi-family retrofit programs).

Reduced equipment and appliance maintenance requirements is applicable to retrofit programs where new equipment and appliances replace old ones (and these replacements would not have taken place without the program), and to new construction programs employing energy-efficient technologies that inherently require less maintenance than less efficient technologies. These include the PAs' low income-retrofit programs, low-income new construction programs, residential cooling and heating programs, residential heating and hot water programs, and non-low-income retrofit programs (i.e., Mass Save, multi-family retrofit programs).

5.14.3 Recommendations

a. *More Durable Home*

Based on the surveys of program participants, NMR recommends an annual value of $49 for NLI participants and $35 for LI participants who installed shell and weatherization measures or heating and cooling equipment.

b. *Equipment and Appliance Maintenance*

Based on the surveys of program participants, NMR recommends an annual, per participant value of $124 for NLI participants and $54 for LI participants who installed heating and cooling equipment.

5.15 REDUCING ENERGY EXPENSES, MAKING MORE MONEY AVAILABLE FOR OTHER USES, SUCH AS HEALTH CARE

Low-income households spend a disproportionate amount of their income on energy costs, when compared to the population at large and to wealthier households. For example, low-income families spend approximately 17% of their income on energy costs, compared to higher income households, who spend 8% of their income on energy costs (Child Health Impact Working Group, 2007). Energy efficiency programs can reduce energy costs and therefore allow participating households to spend more money on food, healthcare, or other household needs. However, because the energy savings from these programs are already accounted for by the PAs in the AESC study and the TRC calculations, to count additional benefits from these energy savings would amount to double counting. This is not to say that low-income households do not benefit from reduced energy burdens, but rather that the benefits are already accounted for. For a more detailed discussion of the benefits from a reduced energy burden, see Appendix C.

5.15.1 Assessment of the NEI Literature

While reducing energy expenses has been linked to health benefits, energy savings from the programs are already counted as a benefit by the PAs in the AESC study and the TRC calculations. Counting additional benefits experienced by participants from these energy savings would amount to double counting.

5.15.2 Recommendations

Because energy savings from the programs are already accounted for by the PAs in the AESC study and the TRC calculations, NMR does not recommend counting participant benefits that derive from reduced energy costs. However, health improvements associated with improved home environments are considered below (section 5.16) and societal benefits such as reduced hospitalizations and health care costs should be considered and are discussed in section 6.4. Improved Health. [109]

5.16 HEALTH-RELATED NEIS – FEWER COLDS AND VIRUSES, IMPROVED INDOOR AIR QUALITY, EASE OF MAINTAINING HEALTHY RELATIVE HUMIDITY

Energy efficiency programs may have direct impacts on health through improved home environments, reduced exposure to hypothermia or hyperthermia—particularly during heat waves and cold spells—improved indoor air quality, and potential reductions in moisture and mold, leading to amelioration of asthma triggers and other respiratory ailments. The health-related non-energy impacts of energy efficiency programs have traditionally been difficult to estimate, in large part because of the lack of research directly examining these impacts, and because of the difficulty in isolating the impacts of the programs from other, potentially confounding, factors.[110]

Research has noted that, in cold climates, the number of deaths during winter months exceeds the number of deaths at other times of the year, known as "excess winter mortality." Cold weather deaths have been linked to cold indoor temperatures, often attributed to poorly insulated homes (Liddell, 2009). Cold-related deaths are most often associated with changes in blood pressure and blood chemistry, which increase the risk of strokes, heart attacks and other ailments. Cold temperatures are also linked to suppressed immune systems, increasing the risk of infections, and potentially linked to mental health.[111] In addition, other studies have suggested that exposure to cold, damp living conditions in infancy and childhood may affect longer-term health (Liddell, 2009).

Adverse health outcomes are also associated with excessive hot and cold weather, with increased prevalence of deaths and hospitalizations on excessively hot and cold days (Knowlton et al., 2009; O'Neil et al., 2005; Ostro et al., 2010; Snyder and Baker, 2010). Nationwide, studies have estimated that there are 1,700 to 1,800 heat-related deaths annually (Snyder and Baker, 2010). In addition, heat waves are associated with increased risks of hospitalizations for multiple diseases, including cardiovascular disease, respiratory disease, pneumonia and heat stroke (Ostro et al., 2010).

Asthma, a national public health concern, given the approximately 22 million cases of asthma in the United States, is also associated with housing-related factors (Mudarri and Fisk, 2007). Asthma attacks can be triggered by certain housing conditions, including presence of moisture and mold, pests (i.e., cockroaches and rodents), dust allergens, and particulate matter (Tohn, 2006; McCormack et al., 2009). Asthma is the most common chronic childhood disease and is one of the leading causes of missed school days, missed work days, emergency room visits, and hospitalizations (Tohn, 2006). In addition, asthma rates are higher among low-income populations than among other income groups (Stillman and Adams, 2010; Tohn, 2006). Of the 22 million cases of asthma, approximately 4.6 million are attributable to dampness and mold exposure in the home, at a cost of approximately $3.5 billion annually (Mudarri and Fisk, 2007). In general, building dampness and mold are associated with a 30% to 50% increase in a number of respiratory and asthma-related health problems, including upper respiratory tract ailments, coughing and wheezing, and asthma (Fisk et al., 2007; Institute of Medicine, 2004). A study of the Maine

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[109] If energy bill savings are not counted, we recommend that bill savings be counted rather than counting the benefits that derive from bill savings.

[110] In addition to the potential health impacts documented in the literature review, all of the health and safety experts interviewed (n=4) and all of the social service providers interviewed (n=3) believe that energy efficiency programs have positive health impacts on program participants.

[111] Two health experts and one social service provider identified amelioration of mental illness and reduced stress as possible health benefits.

State Housing Authority's weatherization program found high rates of asthma among participating households. It also found that a home with moisture and mold issues was more than three times as likely to include a resident with asthma, as a home without moisture and mold problems (Tohn, 2006).[112]

In addition to potential health benefits, two of the health experts interviewed for this project cautioned that energy efficiency programs may have negative health impacts, due to buildings become "too tight," leading to declining indoor air quality. This is particularly the case if a pollutant source, such as mold or pests, is not removed, so that exposure levels are in effect increased by reducing air infiltration, due to changes in the home made by the efficiency program. However, the studies examined in this literature review did not document any declines in health due to energy efficiency programs.

A number of recent studies in Europe and New Zealand have found associations of weatherization and other energy efficiency retrofits with improved health. A study in New Zealand examined the impacts of insulation and heating system retrofit program. The study included random assignment of families to experimental and control conditions. Study households were at particularly high risk, as study participants lived in uninsulated homes and included at least one household member diagnosed with respiratory illnesses. The study found that participants self-reported improved overall health, fewer incidents of wheezing over the past three months, fewer missed days of school and work, and fewer visits to their doctors after their homes had insulation and new heating systems installed (Howden-Chapmen et al., 2007, Liddell, 2009). The same study found improvements in the mental health of participants, though the authors emphasize that program participants were at clinical risk before intervention, so findings may not be broadly applicable to the population at large (Liddell, 2009).

Another study in New Zealand examined the impacts of installing energy-efficient and healthy heating systems into homes with basic insulation and poor heating systems (either un-flued natural gas or plug-in electric systems). Each household included a child diagnosed with asthma. Using a randomized design, the study found that the program significantly reduced symptoms of asthma, missed days from school, and visits to doctors and pharmacists, accompanied by fewer reports of poor health, sleep disturbed by wheezing, dry cough at night and lower respiratory tract symptoms. However, there were no differences in lung function between the participating and control households. Participating households were warmer than before the retrofit and recorded lower levels of nitrogen dioxide. The results provide evidence of a link between higher indoor air temperature on one hand, and reduced levels of nitrogen dioxide and reduced symptoms of asthma on the other (Howden-Chapmen et al., 2008; Preval et al., 2010). However, because of the very specialized nature of the study population (i.e., un-flued natural gas furnaces or plug-in electric heaters and presence of a child with asthma), it is not clear how applicable these findings are to the general population and more generalized weatherization and energy efficiency programs.[113] Further, it is difficult to differentiate the impact of the increase in housing temperature from the impact of reduced indoor air pollutants on health outcomes.

A study of heating and insulation retrofits in the United Kingdom (UK Fuel Poverty Strategy) included both longitudinal and cross-sectional research design elements. It examined the health impacts of the retrofits from 2001 to 2003. The study found that program participants who, after the retrofits, increased their indoor air temperature to temperatures recommended by the World Health Organization (WHO) (69.8°F for living rooms and 64.4°F for all other rooms) increased their life expectancy by ten days for men and seven days for women, compared to those who did not increase the temperature of their homes. In addition, the study found mental health improvements, with reductions in anxiety and depression among program participants. The research suggests that for every 10,000 retrofitted homes, 3,000 participants will show improvements in measures of anxiety or depression (Liddell, 2009).

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[112] Pre- and post-program participation data and data comparing participating to non-participating households were not available for asthma rates and incidences of moisture and mold issue.

[113] The authors note that they are examining potential health impacts on other household members (Howden-Chapmen et al., 2008).

The United Kingdom's National Center for Social Research (NATCEN) conducted a longitudinal study from 2001 to 2005, examining the association between housing conditions and the well being of English children. The study found long-term negative effects for children living in homes considered cold and damp. Children living in homes considered cold and damp for at least three years were more likely to have respiratory problems than children who had never lived in homes considered cold and damp (15% of children, compared to 6% of children) (Liddell, 2009). The same study found that homes that lacked affordable heat were associated with "multiple mental health risk" for adolescents and children living in those homes, but it is difficult to isolate the impact of unaffordable heating from other contributing factors (Liddell, 2009).

A study of the Scottish Central Heating Programme (CHP) compared 1,281 retrofitted households (two years after the retrofits) with 1,084 households on the CHP waiting list. The study found more limited impacts on health than the UK Fuel Poverty study, but still found that participants had significantly better self-reported health outcomes on four of 22 possible health outcomes (Liddell, 2009).

A study in Glasgow, Scotland, found that compared to a control population, homes upgraded from being cold, damp, and moldy to being warm, dry and mold-free resulted in improvements in blood pressure and general health, as well as reduced use of medications and hospitalizations and heating costs. However, it is not clear what portion of the health improvements were attributable to home temperatures or the reduction in mold (Lloyd, et al., 2008).

Studies of asthma in–home interventions suggest that weatherization programs may have some indirect benefits to asthmatics. Asthma in-home interventions generally include a number of elements, including education and outreach from nurses or public health workers, pest eradication, removal of carpets and visible mold, repairing water leaks and water intrusions, provision of bedding covers, provision of vacuums and cleaning supplies, providing social support, and improving ventilation. These interventions have been shown to reduce asthma symptoms, asthma triggers, and hospitalizations (Center for Managing Chronic Disease, 2007; Hoppin and Donahue, 2004; Takaro et al., 2004). Some research, in addition to traditional asthma interventions, has examined inclusion of heating and cooling repairs, finding that construction repairs that alleviated the root cause of moisture sources, combined with medical and behavioral interventions, reduced symptom days and health care use for asthmatic children living in homes with documented mold problems (Kercsmar et al., 2006).

While in-home interventions for asthma differ dramatically from energy efficiency programs, health and safety experts interviewed suggested that any programs, such as weatherization programs, that included repairs to water intrusions, would likely have health impacts related to asthma and other respiratory ailments. Further, Jacobs and Baeder (2009), in a review of the literature examining the effects of housing interventions on health, found that eliminating moisture intrusion and leaks, combined with the removal of mold and moldy items, reduced asthma triggers and exposure. Other research suggests that envelope sealing of homes may help to reduce particulate matter in the home, with potential benefits for respiratory ailments (Jacobs and Baeder, 2009).

Finally, recent research has begun to examine the association between the effects of air conditioning on hospitalizations and deaths related to excessive heat and heat waves. A study in California found that ownership and usage of air conditioning reduces the risks of hospitalizations during days of excessive heat. A 10% increase in air conditioning ownership resulted in reductions in excess risks of mortality for a number of diseases (Ostro et al., 2010). Similarly, a study of heat waves in Philadelphia, Chicago, and Cincinnati found people living in homes with central air conditioning were less likely to die than people living in homes without air conditioning (Snyder and Baker, 2010).

5.16.1 Evidence from the NEI evaluation literature

Health-related NEIs have rarely been included in the evaluation literature, and when they have been included, they have been measured by reductions in symptoms or lost days from work. They have not been linked to potential causal mechanisms such as increased temperature of the home during winter or reduced prevalence of mold spores or other indoor air pollutants.

TecMarket Works, SERA, and Megdal Associates (2001)

For example, the California LIPPT report estimated the value of health benefits of $3.78 by attributing reductions in self-reported sick days to weatherization programs (calculated as the number of reduced sick days multiplied by the minimum wage for a work day), but the LIPPT did not estimate values for reductions in lost days of school (TecMarket Works, SERA and Megdal Associates, 2001).

Skumatz and Dickerson (1997)

The evaluation of the VPP program estimated health benefits by assuming a reduction of four lost workdays due to reduced illnesses attributed to the weatherization program, plus the cost of one bottle of over-the-counter cold medicine (Skumatz and Dickerson, 1997).

Riggert et al. (1999)

The evaluation of the energy and non-energy impacts of Vermont's Weatherization Assistance Program derived a health benefit of $75 per participant per year, based on the estimates developed by the evaluation of the VPP program (Riggert et al., 1999).

Skumatz and Gardner (2005)

The evaluation of the Wisconsin WAP estimated health benefits through a relative valuation method, asking respondents to estimate the benefits of reductions in sick days, lost school days, visits to doctors, and frequency and intensity of various ailments, including asthma, headaches, and other ailments. Values for each ranged from $1 to $12 (Skumatz and Gardner, 2005). However, 90% of program participants reported no effect from the program on the health benefits.

NMR and Conant (2009)

The evaluation of the Massachusetts New Homes with ENERGY STAR program estimated the benefits of improved indoor air quality (IAQ) through a relative valuation method, using participant surveys. Participants estimated the value of improved IAQ at 32% of energy savings, or $126 per year (NMR and Conant, 2009).

Oppenheim and MacGregor (2002); Howat and Oppenheim (1999)

Other studies have estimated participant health benefits based on lost days of work (Oppenheim and MacGregor, 2002) or reduced public expenditures on health care (Howat and Oppenheim, 1999).

5.16.2 Assessment of the Literature

Health-related benefits to energy efficiency programs have been examined more extensively in Europe and New Zealand than in the United States. They have typically focused on programs targeting low-income households or households with particular health risks, such as asthma. These studies have found positive health impacts. Health effects appear to be linked to warmer indoor air temperatures in cold climates and reduced exposure to excessive heat in warmer climates, less indoor air moisture and other asthma triggers, and reductions in indoor air pollutants such as carbon monoxide. These improved housing conditions can be a result of energy efficiency measures and programs, such as insulating and weatherizing un-insulated or poorly insulated homes, repairing or replacing heating and air conditioning equipment. Health effects include fewer asthma attacks and symptoms, fewer sick days from work, fewer lost school days, fewer doctor and hospital visits, and fewer and less intense ailments more generally.

However, health benefits have not been monetized in the medical literature. Applying health impacts from these studies is problematic, for several reasons. Because of the targeted nature of some of the programs, the findings are not generalizable to the PAs' programs. Because of geographic and climatic differences, it is difficult to estimate program impacts from studies conducted in Europe and New Zealand.

Similarly, applying health impacts from the few studies in the evaluation literature is problematic, either because of climatic and geographic differences or because of the methods used to estimate the benefit.

5.16.3 Relevant PA Programs

The non-energy benefit of improved health applies to all PA programs that include shell measures or heating and cooling measures, especially low-income programs, including the PAs' low income-retrofit programs, low-income new construction programs, residential cooling and heating programs, residential heating and hot water programs, and non-low-income retrofit programs (i.e., Mass Save, multi-family retrofit programs).

5.16.4 Recommendations

Based on the surveys of program participants, NMR recommends an annual value of $4 for NLI participants and $19 for LI participants who installed shell and weatherization measures or heating and cooling equipment.

These findings are comparable to other estimates of health impacts reported in the NEI literature. For example, the California LIPPT estimated an annual health benefit of $3.98 based on survey data of reduced missed days from work (TecMarket Works, SERA and Megdal, 2001), while a $28 to $35 annual benefit was estimated in the 2005 WI low-income weatherization report, based on survey data using relative valuation of several, potentially overlapping, health benefits: missed days from work, fewer colds and viruses, fewer chronic conditions, less money spent on medicine, fewer headaches, fewer doctor's visits (Skumatz and Gardener, 2005).

We do not recommend deriving a value from the literature. The literature on the health impacts of energy efficiency programs is still limited. While there is literature suggesting potential impacts, in some cases it is extremely difficult to isolate the impacts of the programs from other, confounding factors, while in others it is difficult to generalize results based on a program that targets specialized populations.

Potential societal benefits such as reduced medical costs due to reductions in the incidence of symptoms or occurrences of specific health problems (such as asthma or other respiratory problems, heat stress and hypothermia) are discussed in section 6.4. Improved Health

In addition, health benefits are currently being examined by the evaluation of the national WAP, with some benefits being monetized (via reduced missed days from work), while others are not being monetized, such as reductions in incidence of symptoms such as asthma (Ternes et al., 2007). The report, which is expected to be released in 2011, could serve as a valuable addition to the literature on participant benefits.

We feel that further study examining the potential health impacts of the programs should be considered.

5.17 IMPROVED SAFETY (HEATING SYSTEM, VENTILATION, CARBON MONOXIDE, FIRES)

Reduced incidence of fire and carbon monoxide exposure are commonly identified as safety-related benefits resulting from weatherization programs in the NEI literature. Faulty heating equipment is among the common causes of residential fires (Insurance Information Institute, 1990 as cited in Brown et al., 1993). Additionally, low-income households that cannot afford to pay their heating bills, or have been terminated from service due to nonpayment, have been known to resort to alternative sources of home heating, which are more likely to cause fires and carbon monoxide poisoning. Similarly, households that have had electric service shut off and resort to candles for lighting are at an elevated risk of experiencing a fire. Weatherization programs often include measures that mitigate fire and CO exposure risks, such as heating system inspection, repair, and/or replacement, CO testing, and CO and fire detectors. The NEI value of reduced fires attributable to programs can be estimated, using data on the incidence and causes of residential fires and estimates of the avoided costs from fires, including loss of life, personal injury, and property loss. The value of reduced CO exposure has not been quantified as often as fire reduction in the NEI literature, but it could be quantified in a similar manner, for programs that provide CO testing and CO detectors, and to the extent that programs obviate the need for low-income households to resort to unconventional heat sources which emit CO in the home.

Brown et al. (1993)

The 1993 ORNL national WAP report identified fire prevention and carbon monoxide-related indoor air quality as safety-related benefits associated with the program (Brown et al., 1993). While a monetized NEI value was estimated in the report for program-induced avoided fire costs, the value of carbon monoxide mitigation was not estimated, due to insufficient data and incomplete understanding of the numerous interacting factors associated with weatherization and indoor air quality. During the 1989 program year for the national WAP, heating system repairs or safety improvements were made to 7% of weatherized homes, including fixing gas leaks and carbon monoxide problems, and repairing or replacing the following: thermocouples, thermostats, fan switches, furnace filters, gas valves, gas controls, lead detectors, and limit switches. Brown et al. (1993) noted that the measures installed through the national WAP reduce the costs of fires in several ways. First, safety measures, including fixing gas leaks, reduce the probability of fires. Additionally, cellulose insulation installed through the program tends to snuff out fires that occur in weatherized homes. Lastly, by making home heating bills more affordable, the program reduces the likelihood of participants resorting to the use of heat sources which have a greater fire risk, such as electric space heaters, wood burning stoves, kerosene heaters, extension cords from a neighbor's home, and illegal reconnections to power lines. Brown et al. (1993) estimated the value of avoided costs due to prevented deaths and property losses from fires to be $3.25 per weatherized dwelling. Although avoided fire-related injuries were identified as an NEI, in addition to fire-related deaths and property loss, the value of avoided fire-related injuries was excluded from the calculation, due to the difficulty in quantifying it and the anticipated low value of avoided injuries relative to the values of avoided deaths and property loss. The formula for estimating the value of avoided fire deaths used by Brown et al. (1993) included the following: the number of elderly and non-elderly occupants of weatherized dwellings, the expected rate of fire deaths each for elderly and non-elderly individuals (data has shown that the elderly are more likely to die in a residential fire than the non-elderly), the rate of 10% of fire deaths caused by residential heating equipment (Insurance Information Institute 1990; National Safety Council, 1989), and the average lifetime cost due to a fire death ($250,000 for the non-elderly and $24,000 for the elderly, taken from Statistical Abstract of the US, 1991). The avoided fire death component of the NEI value assumes that all potential fire deaths (attributable to residential heating equipment) are avoided by the program. The formula for estimating the value of avoided property loss due to fires includes an estimate of the rate at which low-income residential fires occur (assuming that low-income households are twice as likely to have a fire than the average US household), the rate of 21% of residential fires caused by heating systems (Insurance Information Institute, 1990), an estimate of the value of property loss due to a residential fire (assuming that the average property loss for low-income households is half that of the national average), and an assumed 25% reduction in fires due to the program. Carbon monoxide deaths and fires caused by alternative heating sources were not accounted for in the monetized NEI valuation.

Riggert et al, (1999)

The same estimation method employed by Brown et al. (1993) for the national WAP was used to estimate the NEI value of avoided fire deaths and property losses in the 1999 evaluation of Vermont's WAP (Riggert et al., 1999). However, the Vermont NEI value of $29.75 per weatherized home is much greater than the national WAP value of $3.25, due to the use of a different estimate of the value of a human life in the NEI valuation formula. Instead of the $250,000 per non-elderly person and $24,000 per elderly person assumed per avoided fire death in the national WAP estimation, a value of $4 million per avoided fire death taken from Ottinger (1990) was used in the Vermont estimation. Skumatz and Nordeen (2002) employed a similar estimation method as Brown et al. (1993) for the value of reduced fires associated with the Connecticut WRAP Program. Their value of $0.18 per participant was estimated based on the following: average property loss data from the Insurance Institute Fact Book (IIFB); an estimate of the percent of fires caused by equipment that might be fixed by the program (IIFB and program data); the percent of participants receiving health and safety equipment; an assumed percent of fires eliminated by the program based on the evaluator's judgment; and average loss of life and value of life estimates based on previous research by the author.

Blasnik (1997)

The value of the health and safety NEIs associated with the Ohio HWAP was based simply on the cost of health and safety measures employed by the program. The Ohio low-income HWAP included heating and water heating safety testing, repairing combustion equipment, and occasional safety-related replacements (Blasnik, 1997). The avoided use of alternative heating sources associated with service disconnection was also identified as a potential safety-related benefit from the program. Blasnik noted that the sample sizes and timeframes required to quantify the reduced frequency of fires and other rare, "high cost" events from the program were unavailable. Therefore, he proposed valuing the health and safety benefits of the program at the amount of money spent on health and safety measures. As cited in Riggert et al. (1999), the amount spent per home on measures associated with health and safety benefits for the 1994 Ohio HWAP was $317.

Barkett et al. (2006); NMR and Conant (2009); Skumatz and Gardner (2005)

Three recent studies have examined participant valuation of safety through the use of participant surveys. The first study is the 2006 Non-Energy Impact Evaluation for the NY ENERGY STAR Labeled Homes program. A survey comprising both participants and a comparison group found that 42% of program participants believed that their new ENERGY STAR labeled home was safer than their old home (Barkett et al., 2006).[114] Those respondents who reported either a positive or negative impact were asked to express the value of the NEI relative to the energy savings. On average, respondents valued the NEI of safety at about 35% of energy savings. Conjoint analysis questions asked at the end of the survey indicate that respondents were willing to pay a premium of $5,072 in the upfront cost of the home with a heating system that has backdraft protection (as opposed to one that has no backdraft protection), making it safer in terms of carbon monoxide levels. The value of $5,072 was translated into an annual NEI value of $181 by dividing by an assumed measure lifetime of 28 years (Barkett et al., 2006). Sixty-four respondents completed the survey, but only 12 could be identified as program participants, due to a data recording error. The second study in which safety was estimated via a participant survey is the 2008 Evaluation of Massachusetts New Homes with ENERGY STAR Program. Forty-six percent of respondents believed that their new ENERGY STAR homes provided more safety; out of all seven NEIs included in the survey, respondents were least likely to identify safety as an NEI associated with their new home (NMR and Conant, 2009). Via the relative valuation method, an annual NEI value of $105 (or 26% of bill savings) was reported for safety (n=63). Respondents valued the NEI of safety lower than the value of every other NEI included in the survey. The third study is the 2005 evaluation of Wisconsin's low-income weatherization assistance program. Using a relative verbal scaling method comparing the NEI value to energy bill savings, an NEI value range of $20-$26 was estimated per participant per year for the Wisconsin low-income WAP (Skumatz and Gardner, 2005).

Ternes et al. (2007)

Numerous safety-related impacts will be investigated in the upcoming evaluation of the national WAP. Some will be assigned monetized values, while others will not be monetized. A monetized value of reduction in fires will be calculated, based on the number of households weatherized, the average reduction in number of fires per weatherized household, and the average monetary loss in property, injury, and death per fire (Ternes et al., 2007). On a scale of low, medium, and high, Ternes et al. (2007) anticipate that the uncertainty involved in the average reduction in number of fires per household and the uncertainty in the average monetary loss per fire to be medium. CO levels will be measured before and after weatherization, but a monetized value to the change in CO levels resulting from the program will not be estimated. On the scale of low, medium, and high, the uncertainty regarding the change in CO levels in weatherized homes is expected to be high. In addition to fire and CO impacts, several other safety

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[114] Approximately 40% of all respondents reported no change with regard to safety, and 18% reported "don't know" (Barkett et al., 2006).

impacts will be included in the evaluation. For example, the evaluators at ORNL plan to estimate monetized values of the reduction in emergency medical care for tripping and falling in the home, the reduction in emergency medical care for burns from scalding domestic hot water, and for the reduction in theft from break-ins in weatherized homes. Moreover, non-monetized measurements of asbestos and radon will be collected pre- and post-weatherization for the WAP evaluation. .

5.17.1 Assessment of the Literature

Four estimation methods have been employed in quantifying the value of improved safety resulting from energy efficiency programs in the NEI literature. One of the most commonly employed methods is an algorithm including estimates of residential fires caused by faulty heating equipment, the program-induced decrease in incidence of residential fires, the number of deaths per fire, and property loss per fire. Data on the frequency, causes, and monetary losses associated with residential fires that have been used in these algorithms have been obtained from reliable sources, including the US Census Bureau and various insurance and safety organizations. Estimates of the value of a life lost in a fire are open to interpretation and can vary dramatically, based on the estimation method. The estimates of the program-induced decrease in incidence of residential fires have not been based on any program data, but seem to have been subjectively selected. All of the programs for which the NEI value of improved safety was estimated via this method were low-income weatherization programs. Although avoided deaths and injuries (including CO poisoning) attributable to the use of dangerous alternative heating and lighting sources have been discussed in the literature as safety-related non-energy impacts, none of the NEI values produced by this method incorporates estimates of CO poisonings or fires started by alternative heating or lighting sources.

The second commonly employed estimation method that has been used to value the safety impacts of energy efficiency programs is the relative valuation survey method, which has been applied to new homes with ENERGY STAR program, an ENERGY STAR Labeled Homes program, and a low-income weatherization program. For the two non-low-income programs, the proportions of respondents reporting safety as an impact (46% and 42%) are similar. The monetized NEI value of safety estimated for the retrofit program is double the NEI value for the new construction program. The baseline for comparison for each of these surveys is quite different: “a similar, newly constructed non-ENERGY STAR home” for the new construction program and “the home in which you last lived” for the retrofit program. The NEI values estimated via relative valuation for the non-low-income programs are much higher than the values estimated for the low-income program. This difference may be explained in part due to the difference in expected annual energy savings from the programs (which is the basis for estimating the benefit); but it is also likely due to the fact that the value for the low-income program was scaled relative to total NEIs and the non-low-income program NEI values were not.

Two other estimation methods have been used to value the NEI of improved safety. One of those methods is to value the NEI of improved safety as the amount of money spent on health and safety measures per weatherized home. This estimation method was applied for a low-income weatherization program, combining health and safety NEIs into one value. The other estimation method that has been used is the conjoint analysis method. This method was applied to an ENERGY STAR Labeled Homes program in which safety was described to respondents as “a heating system with backdraft protection.”

5.17.2 Relevant PA Programs

The NEI of improved safety applies to programs that implement measures reducing the risk of fires and CO exposure. However, since unsafe heating and ventilation systems are more likely to be prevalent in low-income households, and low-income households are least able to resolve unsafe conditions, NMR recommends quantifying this NEI for the PAs’ low-income programs.

5.17.3 Recommendation

Based on our review of the literature, NMR recommends the following annual values, per installed heating system, based on the accompanying algorithms:

- Avoided fire deaths:$37.40
    - [(0.004 (Rate of fire deaths caused by residential heating equipment per 1,000 households, US)[115] * $9,100,000 (Value of lost life, US EPA)[116] * (Number of heating systems replaced & repaired by PA programs / 1,000)]
- Avoided fire-related injuries: $0.03
    - [(0.014 (Rate of fire injuries caused by residential heating equipment per 1,000 households, US) [117] * $7,421 (Value of medical costs for treating fires, CDC) [118] * (Number of heating systems replaced & repaired by PA programs / 1,000) * 0.25 (percentage of heating system related fire injuries avoided, Brown et al., 1993)]
- Avoided fire-related property damage: $1.24
    - [(0.566 (Rate of fires caused by residential heating equipment per 1,000 households, US) [119] * $17,483 (Average value of residential property loss) * (Number of heating systems replaced & repaired by PA programs / 1,000) * 0.25 (percentage of fires avoided, Brown et al., 1993))/ 2 (Brown et al., 1993)]
- Avoided deaths attributable to CO poisonings: $6.38
    - [(0.0007 (Rate of deaths attributable to CO poisonings due to residential heating equipment per 1,000 households, US) [120] * $9,100,000 (Value of lost life, US EPA) * (Number of heating systems replaced & repaired by PA programs / 1,000)]

The algorithms outlined above are similar to the one used by Brown et al. (1993) to estimate the value of improved safety attributable to the national WAP.

For the value of a loss of life, NMR recommends using the EPA's Value of a Statistical Life (VSL) of $9.1 million. [121] Brown et al. assumed that 25% of fires would be prevented by the national WAP, that 100% of fire deaths from such fires would be prevented, and that the dollar value of property loss damages to low-income households would be half that of the national average. While these assumptions were not based on a program impact analysis, we believe that they are reasonable. For avoided CO poisonings, NMR recommends following the national WAP standard for avoided fire deaths and assuming that 100% of CO poisonings attributable to heating systems are avoided. If, however, further precision is sought, then the recommendation is to conduct a pre/post impact analysis on the incidence of fires and fire deaths in participant homes.

Alternatively, upon completion of the national WAP evaluation in 2011, an estimate of safety from avoided fires could be derived from the national evaluation and applied to the PAs' low-income programs.

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[115] Fire data provided by Hall (2010) and Karter (2010).

[116] Sinha, Depro and Braun (2010).

[117] Fire data provided by Hall (2010) and Karter (2010).

[118] Medical cost data provided by CDC 2011.

[119] Fire data provided by Hall (2010) and Karter (2010).

[120] CO data provided by Hall (2010) and Karter (2010).

[121] Sinha, Depro and Braun, 2010. http://www.epa.gov/ttn/atw/rice/rice_neshap_ria2-17-10.pdf

5.18 IMPROVED SAFETY (LIGHTING)

CFLs have longer lifetimes than traditional incandescent light bulbs and therefore do not need to be replaced as frequently. Individuals potentially face the risk of injury from falling, while attempting to change ceiling light bulbs. The reduction in this risk has been suggested as an NEI associated with efficient lighting (TecMarket Works, SERA, and Megdal Associates, 2001). It has also been suggested that the value of this NEI might be significant for the elderly, who are likely to sustain greater injuries from a fall.

5.18.1 Assessment of the Literature

Improved safety from reduced falls has been suggested as an NEI associated with CFLs, but the value of this NEI has not been estimated in the literature. Moreover, the literature does not contain any evidence of decreased rates of injuries associated with replacing light bulbs.

5.18.2 Relevant PA Programs

The NEI value of improved safety associated with lighting potentially applies to all PA programs that include CFLs.

5.18.3 Recommendation

Due to the lack of research on injuries associated with changing light bulbs, NMR does not recommend quantifying the value of this NEI, at this time.

5.19 HEAT (OR LACK THEREOF) GENERATED

Incandescent light bulbs convert approximately 10% of electricity to light, with the remaining 90% converted to heat. Energy-efficient CFLs and LEDs do not generate as much heat as traditional light bulbs do. Replacing heat-generating incandescent light bulbs with energy-efficient bulbs can impact the heating and cooling requirements of a participant's home and should therefore be considered an energy impact, not a non-energy impact.

The 2006 Non-Energy Impacts Evaluation for New York Energy $mart programs sought to measure participant valuation of the lack of heat generated by CFLs (Barkett et al., 2006). A survey employing both relative valuation and conjoint analysis methods was completed by ten respondents who owned CFLs and 14 who did not. The relative value method in this survey did not produce a value for the NEI of "heat generated" while the conjoint analysis estimated an annual NEI value for "heat generated" of $0.92 per participant (n=21).

5.19.1 Recommendations

Because the lack of heat generated by CFLs compared to incandescent light bulbs is an energy-related impact, NMR does not recommend including this as an NEI.

5.20 WARM UP DELAY

CFLs can take a longer time to reach full light output than incandescent light bulbs. This warm-up delay can represent a negative non-energy impact to participants in energy-efficient lighting programs. Warm-up delay can be differentiated from turn-on delay (the amount of time it takes for a light to come on once the switch is turned), but it is unclear whether participants actually make this differentiation.

An estimated value of the non-energy impact arising from the warm up delay associated with CFLs is presented in the 2006 Non-Energy Impacts Evaluation for New York Energy $mart programs (Barkett et al., 2006). The annual value of $0.29 per participant was estimated via the conjoint analysis method. This value represents a negative impact, indicating how much respondents are willing to pay to go from a long warm up delay to a short delay. Therefore, this value should be subtracted from the sum of positive NEIs, in order to accurately reflect the total NEIs associated with energy-efficient lighting. Respondents who owned CFLs were asked if they had experienced a positive, zero, or negative impact with regards to warm up delay compared to incandescent light bulbs (n=10). About 36% of respondents reported no difference, 53% reported a negative impact, and the remainder answered "don't know." In this survey, warm-up delay was one of three attributes for which respondents reported negative NEIs; the other two attributes were turn-on delay and lighting quality. When asked to value the negative impact of warm-up delay relative to energy savings, those who indicated a negative impact reported a range of approximately 0%-15% of energy savings. The conjoint analysis question on which the monetized NEI value was based asked all respondents (n=21) to choose between two light bulb options with different prices. Participants were asked to choose between a light bulb that, when the switch is turned on, "the bulb provides full light output immediately," or a bulb that "takes about 90 seconds to reach full light output."

5.20.1 Assessment of the Literature

Only one study in the NEI literature examined participant valuation of the warm-up delay of CFLs compared to incandescent light bulbs. It is not clear that the respondents in this survey differentiated warm-up delay from turn-on delay. NMR does not believe that the NEI value produced by a small number of respondents to one study is reliable enough to extrapolate to all CFL users.

5.20.2 Relevant PA Programs

The NEI of warm-up delay potentially applies to all programs that implement CFLs.

5.20.3 Recommendations

Due to the lack of literature on participant valuation of the warm up delay associated with CFLs and its relatively small anticipated value, NMR does not recommend quantifying it at this time.

5.21 PRODUCT LIFETIME (HVAC EQUIPMENT, DOMESTIC HOT WATER EQUIPMENT, AND APPLIANCES)[122]

Products such as HVAC equipment, domestic hot water equipment, and appliances installed through energy efficiency retrofit programs are likely to have longer lifetimes than the remaining useful life of the products they replaced.[123] In addition to energy bill savings, participants may derive value from knowing that their new equipment will not need to be replaced for some time. In the case of new construction programs, where technological differences between energy-efficient and standard-efficiency HVAC equipment, domestic hot water equipment, and appliances result in a longer useful life of the energy-efficient versions, participants may derive value from knowing that they can put off the hassle and

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[122] This report does not include a review of the NEI of avoided refrigerator replacement. Outside of the value currently included in the TRM, we found no instance of this benefit in the literature and we do not know the basis for claiming this value. It appears that the basis is program experience and assumptions: "Efficiency programs typically replace inefficient refrigerators where it is cost-effective to do so. Based on program experience, assumed five-year deferral was discounted at 20-year (life of measure) Treasury bond rate, minus inflation. Http://online.wsj.com/mdc/public/page/2_3020-treasury.html?mod=2_0031." (Oppenheim and MacGregor, 2008). While we have not reviewed the study that this benefit was based on, the logic of the benefit is sound and the benefit seems reasonable.

[123] However, if the equipment replaced by a retrofit has reached its end-of-life, the more accurate comparison is between the lifetime of the new energy efficient equipment and new standard efficiency equipment.

expense of replacing their equipment longer than would have been possible had they chosen the standard-efficiency equipment.

Participant valuation of longer product lifetime has rarely been investigated in the NEI literature for residential programs. Where this NEI has been measured, a relative valuation survey method has been employed. For example, a survey conducted for the New York Energy $mart programs examined participant valuation of "appliance lifetime" associated with ENERGY STAR appliances, including refrigerators, dishwashers, clothes washers, and room air conditioners (Fuchs et al., 2004). The relative valuation method was employed in which respondents were asked if the appliance had a positive, negative, or no impact with regard to each of 13 NEIs. When respondents indicated that there was an impact (positive or negative), they were then asked for the relative value of the impact. Survey results show that respondents valued the NEI of appliance lifetime at 7% of total NEIs for ENERGY STAR refrigerators, 8% of total NEIs for dishwashers, 10% of total NEIs for ENERGY STAR clothes washers, and 8% of total NEIs for room air conditioners. Participant valuation of equipment lifetime was measured via the same method for a low-income multifamily retrofit program, and was found to be 3% of total NEIs (Myers and Skumatz, 2006). Monetized NEI values were not presented in either of the reports.

5.21.1 Assessment of the Literature

Participant valuation of longer lifetime has rarely been investigated in the NEI literature. Where this NEI has been assessed, it has been done so for ENERGY STAR appliances and a low-income multifamily retrofit program, via relative valuation participant surveys which reported appliance or equipment lifetime valuation relative to the total NEI value reported by participants. In order for the results from these surveys to produce reliable values, it is necessary for the participants to have some knowledge of the typical life of their equipment or appliance. However, past NEI studies on ENERGY STAR appliances, while showing that customers value the longer life of these appliances generally, have not provided participants with information on the actual expected lifetime (Violette et al., 2006). Therefore, for appliances and equipment with well-documented estimated useful lifetimes, an engineering estimate approach is a more appropriate estimation method for this NEI.

5.21.2 Relevant PA Programs

Product lifetime potentially applies to all PA programs that install HVAC equipment, domestic hot water equipment, and appliances that would not have been adopted in the absence of the program.

5.21.3 Recommendations

Due to the lack of literature on participant valuation of product lifetime, the relatively small value and potentially unreliable valuation found in the literature, NMR does not recommend applying values from the literature to the PAs' programs. And because of the expense and difficulty in providing an engineering estimate,[124] NMR does not recommend quantifying this NEI. Moreover, in cases of end-of-life equipment replacements, it is not clear that the efficient equipment has a longer lifetime or requires less maintenance than standard equipment. [125]

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[124] The NEI value of product lifetime can be positive, negative, or zero, depending on the whether the estimated useful life of energy efficient equipment installed through programs exceeds the estimated useful life of the equipment which would have been installed in the absence of the program. Financial savings are realized when expenses are pushed further into the future due to the time value of money. If a participant chooses equipment which has a longer useful lifetime than other equipment, the participant can delay the future expense of replacing the equipment at the end of its useful life. Therefore, the financial savings (or loss) derived from delaying (or advancing) the investment of replacing equipment represent the non-energy benefit of product lifetime.

[125] For example, high-efficiency heating and cooling equipment may have higher maintenance costs because high-efficiency furnaces needed more "work out time" to adjust safety controls and settings properly. In an evaluation of high-efficiency heating and cooling equipment in Vermont, one contractor described the safety and limit controls as 'finicky.' Other respondents reported that high-efficiency furnaces and boilers

5.22 AVAILABILITY OF HOT WATER

In addition to using less energy, tankless water heaters produce an endless supply of hot water. Never running out of hot water is a non-energy benefit to participants. Participant satisfaction with this feature of tankless water heaters was measured through a survey of 101 individuals who participated in a tankless water heater program in Massachusetts during 2005 and 2006. When asked to rate their level of satisfaction with the length of time they can use hot water without running out, nearly 90% of respondents reported being extremely satisfied with this aspect of their water heater (NMR, 2006). However, neither this report nor any other in the NEI literature attempted to quantify participant valuation of this NEI.

5.22.1 Assessment of the Literature

Availability of hot water is rarely discussed in the NEI literature. Participant valuation of this NEI does not appear to have ever been estimated before.

5.22.2 Relevant PA Programs

The non-energy benefit of endless hot water supply associated with tankless water heaters applies to PA programs which install tankless water heaters, including the residential new construction programs, residential water heating program, Mass Save, and the multifamily and one to four family programs.

5.22.3 Recommendation

Because there are no values in the literature for the NEI of availability of hot water, NMR does not recommend quantifying this NEI at this time.

5.23 PRODUCT PERFORMANCE

Appliances installed through energy efficiency programs may perform better than the appliances they replaced. For example, a participant may notice that his or her ENERGY STAR dishwasher cleans dishes better than the participant's old dishwasher, or that an ENERGY STAR room air conditioner circulates air more effectively through the room. It is not inherently true, however, that all new, energy-efficient appliances perform better in such ways than new, less efficient appliances. Furthermore, depending on the age of the appliance being replaced, it is likely that any new appliance, regardless of how energy efficient it is, will perform better than the old one.

Fuchs et al. (2004)

Participant valuation of appliance performance was examined for the New York Energy $mart programs (Fuchs et al., 2004). A relative valuation method was employed, in which respondents were asked if the appliance or lighting measure had a positive, negative, or no impact with regards to each of 13 NEIs, including "appliance performance." When respondents indicated that there was an impact (positive or negative), they were then asked for the relative value of the impact. Survey results show that, on average, respondents valued the NEI of appliance performance at 13% of total NEIs for ENERGY STAR refrigerators, 8% of total NEIs for dishwashers, 10% of total NEIs for room air conditioners, 10% of total NEIs for CFL bulbs, and 12% of total NEIs for lighting fixtures. Monetized NEI values were not presented in this report.

Skumatz and Gardner (2005)

have higher maintenance costs because more parts and controls fail, and these parts are often more complex and expensive than standard-efficiency boilers and furnaces (NMR, 2009).

Another study that investigated the NEI of product performance is the 2005 evaluation of Wisconsin's low-income weatherization assistance program (WAP) (Skumatz and Gardner, 2005). The most commonly installed measures through the program were CFLs, CO detectors, smoke detectors, attic insulation, and water pipe insulation; at least 50% of participants received these measures. In addition, 42% of participants received new refrigerators, 37% received new heating systems, and 45% received other heating system work. The participant survey for this study revealed that 21% of respondents reported a positive change in "equipment performance or features," 75% reported no change, and 4% reported a negative change. Using a relative verbal scaling method comparing the NEI value to energy bill savings, an NEI value range of $14-$18 was estimated per participant per year for the Wisconsin low-income WAP. This value reflects the cumulative value for equipment performance and features for all measures installed in the participant's home and is averaged across all participants.

5.23.1 Assessment of the Literature

Equipment and appliance performance has been investigated in the literature for several types of programs, via the relative valuation survey method. Often, the programs for which the NEI of performance has been estimated have included a mix of HVAC measures and appliances; therefore, it is unclear what portion of participant valuation of performance produced by these reports is due to which appliances or HVAC equipment. Additionally, surveys of participant valuation of performance have sometimes grouped performance and features together, which likely overlap for certain measures, but are arguably two distinct characteristics for other measures. Participant valuation of just "performance of appliances" has rarely been examined in the literature.

5.23.2 Relevant PA Programs

Product performance of appliances potentially applies to all PA programs that install appliances that would not have been adopted in the absence of the program.

5.23.3 Recommendation

NMR does not recommend quantifying the value of appliance performance due to the lack of research in the literature examining this NEI.

5.24 NEIS ASSOCIATED WITH LOW-INCOME ROOM AIR CONDITIONER REPLACEMENT

Quantec and SERA (2005)

According to the Massachusetts Statewide Technical Reference Manual, the PA's currently claim a $104 annual participant benefit including comfort, safety, and health effects for window AC replacement in Low-Income 1-4 Family Retrofit and Low-Income Multifamily Retrofit programs (Massachusetts Electric and Gas Energy Efficiency Program Administrators, 2010). The value of $104 per year was estimated in the evaluation of National Grid's 2003 Appliance Management Program (AMP), a pilot program that replaced inefficient air-conditioning units in low-income households (Quantec and SERA, 2005). In addition to an income eligibility requirement, the AMP program targeted participants who were typically home using their air-conditioning during peak hours (weekdays, 11 a.m. through 3 p.m.). Twenty-two homes in total received a new air conditioning unit through the program. NEI values were derived from two telephone surveys conducted for the evaluation: a pre-cooling season survey of 12 participants and 47 non-participants, and a post-cooling season survey of 12 participants and 60 non-participants. The survey found that participant homes had an average of 0.81 chronically ill or bedridden members per household, which the authors characterized as a "very high percentage." Respondents were asked to estimate the value of 11 individual NEIs derived from the efficient window air conditioning units via a relative valuation method, and were asked to specify the net impact from the efficient unit above and beyond the effect they would have realized from the installation of a standard efficiency unit. The 11 NEIs included in the survey were equipment maintenance, equipment performance, equipment lifetime, comfort, aesthetics, noise, safety, housing value, doing good for the environment, ability to pay energy and other bills, and health effects. The sum of each of these 11 NEIs is $104 – the NEI value that the PAs currently claim. The survey found that the most highly valued NEIs by participants were equipment performance ($14), comfort ($14), aesthetics ($13), and ability to pay energy and other bills ($13). Individual NEI valuations were scaled to respondents' estimation of total NEIs, which was estimated at $92-$122 via the willingness to pay method. An impact evaluation conducted for the AMP program estimated participant bill savings at about $8.50 per year. The average estimated annual savings reported by participants, however, was $120 per year – over ten times greater than the impact evaluation savings estimate. Valuation of the NEIs was calculated based on participants' perceived energy bill savings as opposed to the actual measured energy savings. The authors note that the NEI values derived from the participant survey would be approximately one-tenth as high if the actual, measured energy savings had been used instead.

5.24.1 Assessment of the Literature

The NEI values associated with low-income room air conditioner replacement reported in the evaluation of National Grid's 2003 Appliance Management Program were estimated via a relative valuation survey method, a commonly used technique for estimating the value of non-market goods and services. However, these values are likely inflated because they were calculated based on participants' perceptions of energy savings from the program (as opposed to actual energy savings), which were an order of magnitude greater than the actual energy savings. Additionally, it may not be appropriate to extrapolate the values derived from this report to all of the PAs' low-income customers, because the target population for the AMP program was restricted to low-income households in which members tended to be at home with the air conditioning on during peak usage hours. AMP participant households had an average of 0.81 chronically ill or bedridden members. Lastly, it is important to note that the value of $104 represents participant valuation of all 11 NEIs covered by the survey, and not just comfort, safety, and health effects – the three NEIs named in the TRM.

5.24.2 Relevant PA Programs

NEIs associated with low-income room air conditioner replacements apply to the PAs' Low-Income 1-4 Family Retrofit and Low-Income Multifamily Retrofit programs.

5.24.3 Recommendation

NMR recommends a value of $49.50 per low-income household that receives a room air conditioner replacement. We believe the NEI value of $104 is inflated for several reasons:

- NEIs were estimated based on perceived energy benefits which were over ten times greater than the impact evaluation savings estimate. The evaluators noted that the NEI values derived from the participant survey would be approximately one-tenth as high if the actual, measured energy savings had been used instead.
- The program targeted a specialized low-income population that may experience higher levels of NEIs than the general population of program participants who receive replacement window ACs.
- The total NEIs included NEIs that are accounted for elsewhere in this report (i.e., property value, doing good for the environment, and ability to pay).

To arrive at this estimate we first removed NEIs that are accounted for elsewhere in this report (i.e., aesthetics, property value, environmental benefits and ability to pay bills), leaving a value of $66 for the remaining NEIs. Next, we reduced the value of $66 by 25%, to adjust for the specialized population served by the program. The program targeted participants who were typically home using their air-conditioning during peak hours (weekdays, 11 a.m. through 3 p.m.). These participants may experience higher levels of NEIs than the general population of program participants who receive replacement window ACs.

5.25 ADDITIONAL PARTICIPANT NEIS FOUND IN THE LITERATURE

NMR's review of the literature found several participant-perspective NEIs in addition to the ones originally identified in the kick-off meeting. These additional NEIs have not often been quantified. They include the participant-perspective value of terminations and reconnections, bill-related calls, reduced transaction costs, and education. Although NMR does not recommend quantifying these additional NEIs, they are worth reviewing briefly.

5.25.1 Termination and Reconnection

Just as utilities incur costs associated with terminations and reconnections, participants incur costs when their service is terminated due to non-payment. Participant costs associated with service termination identified in the literature include the reconnection fee, the cost of borrowing money for the reconnection fee, participant time in arranging the reconnection, and the lost value of the dwelling, from it being uninhabitable for the duration of the service disconnection. Energy efficiency programs can reduce energy costs and therefore reduce the incidence of terminations and reconnections. However, because the energy savings from these programs are already counted by the PAs in the AESC study and the TRC calculations, to count additional benefits from these energy savings would amount to double counting. For a review of studies that have quantified participant benefits of reduced terminations and reconnections, see Appendix A.

a. Recommendation

Because energy savings from the programs are already counted as a benefit by the PAs, NMR does not recommend counting participant benefits that derive from reduced energy costs. .

5.25.2 Bill-related Calls

Just as the PAs incur costs associated with fielding or making bill-related calls to payment-troubled participants, participants incur the opportunity cost of time spent on the phone discussing bill-related issues with utilities. Since each party (participant and utility) spends time on a bill-related call, each incurs a cost. The value of time spent on bill-related calls by participants represents the value of the participant-perspective NEI of bill-related calls. This NEI has been assessed several times in the literature pertaining to low-income programs, based on the principle that, by making bills more affordable to participants and thereby reducing late or non-payment, participants will not need to call the utility as often regarding bill-related issues. However, as with terminations and reconnections, reductions in bill-related calls are realized because of energy savings from the programs. Because the energy savings from these programs are already counted by the PAs in the AESC study and the TRC calculations, to count additional benefits from these energy savings would amount to double counting. For a review of studies that have quantified participant benefits of reduced bill-related calls, see Appendix A.

a. Recommendations

Because energy savings from the programs are already counted as a benefit by the PAs, NMR does not recommend counting benefits that derive from reduced energy costs.[126]

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[126] If energy bill savings are not counted, we recommend that bill savings be counted rather than counting the benefits that derive from bill savings, as it would be much easier to count bill savings than the multiple benefits that derive from bill savings

5.25.3 Reduced Transaction Costs

Energy efficiency programs can help individuals avoid the transaction costs of weatherizing their homes on their own. These transaction costs include the time and effort spent learning about the energy efficiency opportunities in the home and locating the appropriate energy efficiency measures in the marketplace.

Skumatz and Dickerson (1999)

The participant NEI of reduced transaction costs was estimated to range from $0.00-$5.00 per participant for the VPP program and $0.00-$2.90 per participant for another low-income weatherization program in California (Skumatz and Dickerson, 1999). These estimates were based upon estimates by Feldman (1996) of participant transaction cost associated with programs, including CFLs. In order to derive the value ranges, the number of CFLs installed per household for each program was multiplied by Feldman's estimate of the transaction costs per bulb. The resulting product was then doubled, to account for the transaction costs associated with additional program measures beyond CFLs.

TecMarket Works, SERA, and Megdal Associates (2001)

Although a discussion of participant transaction costs was included in the 2001 LIPPT report, no monetized NEI value was computed there (TecMarket Works, SERA, and Megdal Associates, 2001). The estimation method outlined in the LIPPT report was the same method used to estimate the VPP and California weatherization program values, based on Feldman's 1996 work on CFLs. The RRM Working Group's Cost Effectiveness Subcommittee did not approve a monetized NEI value for transaction costs estimated in this manner for the LIPPT report.

Ternes et al. (2007)

In their upcoming evaluation of the national WAP, the evaluators at ORNL intend to include a monetized value of reduced participant transaction costs as a result of the program (Ternes et al., 2007). The proposed estimation method for this report is to multiply the average number of hours required to become familiar with energy-saving products per household by hourly minimum wage.

a. Assessment of the Literature

Participant valuation of reduced transaction costs has rarely been quantified. The few NEI values that have been quantified have been based on transaction cost estimates for CFLs only.

b. Relevant PA Programs

The participant NEI of avoided transaction costs potentially applies to any program that saves participants the time and effort of educating one's self about the energy efficiency opportunities in the home and locating the appropriate energy efficiency measures in the marketplace.

c. Recommendation

Due to the lack of research on participant valuation of avoided transaction costs, NMR does not recommend quantifying the value of this NEI at this time.

5.25.4 Education[127]

Education has sometimes been identified in the NEI literature as a participant benefit resulting from energy efficiency programs, although it has rarely been quantified. Two of the PA staff interviewed for this evaluation identified education as a non-energy impact associated with their programs. One interviewee pointed out that, regardless of whether they pursue any energy efficiency measures, homeowners benefit from the home energy audit because “they now have a much better understanding of how their house works.” Another interviewee stated that the program taught customers what questions to ask when dealing with HVAC contractors.

Participant valuation of education from energy efficiency programs has rarely been quantified in the literature. The value of education is inherently difficult to measure. While education is often identified as a non-energy benefit in the literature, the type and amount of education provided to program participants varies widely amongst programs.

For programs that do not include an educational component over and above a basic introduction to energy efficiency and measures, this NEI potentially overlaps with the participant NEI of reduced transaction costs. Unlike the reduced transaction costs NEI, education is not recognized as its own NEI and will not be investigated for the upcoming evaluation of the national WAP (Ternes et al., 2007). A review of studies that have examined educational benefits of energy efficiency programs is available in Appendix A.

a. Recommendation

Due to the lack of research on participant valuation of education from energy efficiency programs, NMR does not recommend quantifying the value of this NEI at this time.

[127] The educational benefits reviewed in this section pertain to improved understanding of energy and energy efficiency. The literature on reduced energy burdens reviewed in Appendix C sometimes discusses educational benefits.

6. SOCIETAL-PERSPECTIVE NEIs—LITERATURE REVIEW

Society may realize a number of non-energy impacts (NEIs) from energy efficiency programs. NEIs from the societal perspective are indirect program effects not realized by utilities, ratepayers, or program participants, but rather accrue to society at large. There is a growing NEI literature on the effects of reducing greenhouse gas emissions and other air pollutants through energy efficiency measures, which may mitigate the effects of climate change or may reduce respiratory and other ailments, benefitting the whole of society.[128] Much of the latest NEI literature focuses on these societal NEIs, given the interest in climate change and associated national "green" objectives. Economic development benefits have also been widely studied and the positive impacts on employment, tax revenues, earnings and economic output due to energy efficiency programs has been well established (Skumatz, Khawaja, and Krop, 2010). These economic and environmental NEIs are not included in this review because the environmental benefits and economic development benefits have been counted in the PAs' three-year plans (National Grid et al., 2009; NSTAR et al., 2009).

Many of the remaining societal NEIs of interest to the PAs, non-economic and non-environmental, are sparsely reported and quantified from the societal perspective. For example, improved equity benefits for the low-income population have rarely been quantified in the NEI literature. Where equity benefits associated with low-income programs have been addressed in the literature, improving the economic status of the low-income participants is often the primary program goal. Therefore, these programs tend to emphasize program elements that are not part of the PA programs, such as education, counseling, financial assistance, and job training. Additional societal NEIs that have been addressed in the NEI literature include health, safety, infrastructure (water), national security, and indoor air/environmental quality (IAQ/IEQ) impacts. As expected, a more developed literature exists for economic impacts (job creation and economic development) and environmental impacts (emissions).[129]

In this section we provide a review of the societal-perspective NEIs found in the literature.

6.1 EQUITY AND HARDSHIP

Low-income program studies have often focused on 'hardship' related benefits. These benefits are often measured not monetarily, but via other metrics such as family development models and the Home Energy Insecurity Scale developed for the federal LIHEAP office. These include NEIs on family stability, mobility, and reduced dependence on social assistance. A recent national study on the energy cost burden to low-income households found that the average energy burden of low-income households is about twice that of the national average: 13.5% for LIHEAP eligible households versus 7% for all US households (Snyder and Baker, 2010). One method of quantifying the reduced societal disparity for the low-income population is to value this NEI as equal to the energy cost savings benefit of the program. One study finds that if the energy savings benefit over time of a given program is at least 75% of the total program costs, it is appropriate to apply an avoided cost adder of 75% to this equity NEI (Howat and Oppenheim 1999).

With respect to further hardship benefits (family stability, mobility, and reduced dependence on state benefits), few studies of low-income programs have attempted to monetize hardship NEIs.

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[128] Two PA interviewees identified reduced GHG emissions as a societal NEI associated with their programs. Additionally, one of the health and safety experts interviewed identified reduced power plant emissions associated with the reduced energy use resulting from energy efficiency programs as a potential societal respiratory health benefit.

[129] Other societal benefits may exist, such as improved stability of neighborhoods, but to our knowledge the benefits have not been measured or quantified in the literature.

Khawaja (2001)

An evaluation of the Indiana REACH program, which provided energy assistance through LIHEAP and counseling, rather than implementing energy efficiency measures, found the program was successful in alleviating hardships and resulted in improvements in measures of social well-being. For example, program participants experienced the following improvements: an 18% reduction in school absences; 52% reduction in family moves; 9% increase in federal and state benefits per month; variable impacts on family debt; increase of 22% in total income; increase of 28% in total employment income; reduction of 12.5% in annual energy consumption expenditures; and a reduction of 28% in energy burden (Khawaja, 2001).

Drakos et al. (2008)

Another program that achieved reduced hardship and improved equity for low-income participants is the Oregon REACH program (Drakos et al., 2008). The Oregon REACH program employed a variety of program elements to achieve its goal of reducing the energy vulnerability of low-income families, including energy education, bill-payment assistance, family assessment, budget counseling, referral to other community services, solar hot water heating, and weatherization. Average income of program participants increased 4%, while employment scores, as measured by the family development tool, increased 6% over the course of the program. Many participants received do-it-yourself energy conservation kits, though only 10% of participants in the Oregon REACH program received weatherization. While quantifications of improvements in social indicators were provided in these reports, quantifications of the societal NEI of improved equity were not computed.

6.1.1 Assessment of the Literature

Results from the Indiana REACH, Oregon REACH, and numerous other low-income programs found in the literature demonstrate that programs that reduce the energy burden of the low-income population contribute to improved equity. However, none of the program reports in the literature quantified these equity benefits in the form of a monetized societal NEI. Moreover, these programs differ significantly from the PA programs in their goals and activities. Unlike the PA programs, the Indiana and Oregon REACH programs were designed specifically to improve the economic status of low-income participants. Additionally, relatively little emphasis was placed on the types of program measures employed in the PA programs, such as weatherization measures. Therefore, it is unclear how applicable the equity benefits demonstrated by these types of programs are to the PA programs. One proposed valuation method for the societal NEI of improved social equity is to compute an adder equal to the energy savings achieved by low-income energy efficiency program participants; however, this valuation method has not been employed in any of the energy efficiency program reports found in the literature. Skumatz, Khawaja, and Krop (2010), in assessing the current literature, rated the need for research on societal hardship benefits at a “High Priority,” due to the lack of existing research. NMR agrees with this assessment, as no monetized values can be derived from the literature.

6.1.2 Relevant PA Programs

The NEI of equity and hardship has generally been applied to low-income programs that result in substantial energy savings for participants. The energy savings result in improved equity and decreased social burdens for participants.

6.1.3 Recommendation

Because this NEI has not been quantified in the literature, NMR does not recommend quantifying equity and hardship for this evaluation.

In order to measure hardship or equity benefits, NMR recommends conducting primary research using the “Home Energy Security” scale in the participant surveys. This is a commonly used scale to measure the energy needs of program participants (Child Health Impact Working Group, 2007; Skumatz and Khawaja, 2010).

6.2 WEATHERIZATION BY UTILITY PROGRAMS SAVES COSTS OF INSPECTIONS AND UPGRADES BY OTHER AGENCIES

To the extent that weatherization programs obviate the need for other agencies to perform inspections and upgrades to low-income participant homes, financial savings can be realized. These savings accrue to society because the agencies that perform low-income housing inspections and upgrades are generally funded by tax dollars. Howat and Oppenheim (1999) identified reduced public expenditure on building inspections as a societal NEI, derived from weatherization programs that bring buildings up to code as a result of a weatherization. No quantified value of this NEI was provided in this report. In fact, NMR's review of the literature did not find any quantifications of this societal NEI.[130]

6.2.1 Assessment of the Literature

To our knowledge, the societal NEI of weatherization saving the costs of inspections and upgrades by other agencies has never been quantified.

6.2.2 Relevant PA Programs

This NEI potentially applies to any low-income program that implements structural or other safety measures which have the effect of bringing substandard buildings up to code.

6.2.3 Recommendation

Due to the absence of research in the literature on the impact of weatherization programs on reduced building inspections and upgrades by other agencies, NMR does not recommend quantifying the value of this NEI now.

6.3 ADDITIONAL SOCIETAL NEIs FOUND IN THE LITERATURE

NMR's review of the literature found several societal-perspective NEIs in addition to the ones originally identified during the kick-off meeting. These additional NEIs have not often been quantified and include the societal-perspective value of improved health, improved safety, reduced water consumption, and improved national security.

6.4 IMPROVED HEALTH – REDUCED MEDICAL COSTS

As noted in the participant NEI pertaining to health (see section 5.16. Health-Related NEIs – Fewer Colds and Viruses, Improved Indoor Air Quality, Ease of Maintaining Healthy Relative Humidity), energy efficiency programs may have direct impacts on health through improved home environments, such as reduced exposure to hypothermia or hyperthermia (particularly during heat waves and cold spells), and improved indoor air quality and potential reductions in moisture and mold, leading to amelioration of asthma triggers and other respiratory ailments. However, as noted by Skumatz, Khawaja, and Krop (2010), health impacts have rarely been studied, despite their potential impacts on the health care

[130] During interviews with social service program providers conducted for this evaluation, interviewees were asked if their programs coordinate with any low-income energy efficiency programs. One interviewee strongly believed that participation in "energy cost savings programs" by low-income individuals had the effect of decreasing the costs of the social service agency for which this interviewee worked and of freeing up resources to help additional low-income clients, but that no attempt had been made to quantify this benefit.

system. Society benefits from positive health impacts through, for example, reduced hospitalizations and visits to doctors due to reduced incidences of illnesses or reduced incidence rates of chronic conditions.

For example, Mudarri and Fisk (2007) estimate that approximately 4.6 million cases of asthma are attributable to dampness and mold exposure in the home, at a cost of approximately $3.5 billion annually (Mudarri and Fisk, 2007). Mason and Brown (2010) estimate that the annual medical costs of children with asthma are $1,044 more than medical costs for children without asthma and $2,157 more for adults with asthma, compared to adults without asthma. Further, building dampness and mold are associated with a 30%-50% increase in a number of respiratory and asthma related health problems, including upper respiratory tract ailments, coughing and wheezing, and asthma (Fisk et al., 2007; Institute of Medicine, 2004). A review of additional studies that have examined the health impacts of energy efficiency in office settings is presented in Appendix A.

To the extent that energy efficiency programs can improve health and reduce health care costs, they provide a benefit to society.

6.4.1 Assessment of the Literature

Savings from improved health from a societal perspective are not well documented in the literature. Health NEIs have rarely been studied, even though the impacts on the overall health care system are possibly very large. Possible measures of program impacts include reductions in visits to doctors, hospitals, or health clinics, due to health improvements in program participants that are attributable to the PAs' programs.

6.4.2 Relevant PA Programs

The NEI of improved health applies to all PA programs that include shell measures as well as heating and cooling measures, particularly low-income programs. The NEI applies to the PAs' low income-retrofit programs, low-income new construction programs, residential cooling and heating programs, residential heating and hot water programs, and non-low-income retrofit programs (i.e., Mass Save, multi-family retrofit programs).

6.4.3 Recommendation

Due to small sample sizes, NMR does not recommend a value for improved health (reduced medical costs) from the societal perspective at this time. NMR did not find convincing evidence of major health effects in terms of asthma, heat stress, and hypothermia. However, because of the potential health impacts of energy efficiency, NMR recommends reviewing the results of the current evaluation of the national WAP when the findings become available. Values for societal health benefits might be derived from these findings once the study is complete (Ternes et al., 2007).

If the national WAP evaluation does find societal health impacts, NMR recommends quantifying the societal benefit of improved health as follows:

- **Heat Stress:** [(Reductions in visits to hospital, emergency room, or urgent care facilities for heat stress (participant surveys) * $1,469.79 (Cost of general injury emergency room visit, adjusted for inflation)[131]) / Total number of participants]

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[131] Centers for Disease Control and Prevention, 2011. Treatment for heat stress is considered a "general injury by the CDC: "According to the Injury Surveillance Guidelines, an injury is the physical damage that results when a human body is suddenly or briefly subjected to intolerable levels of energy. Injury can … be an impairment of function resulting from a lack of one or more vital elements (i.e., air, water, or warmth), as in strangulation, drowning, or freezing…. The energy causing an injury may be one of the following: … thermal (e.g., air or water that is too hot or too cold."

- **Cold exposure:** [(Reductions in visits to hospital, emergency room, or urgent care facilities for cold exposure (participant surveys) * $1,469.79 (Cost of general injury emergency room visit, adjusted for inflation)[132]) / Total number of participants]
- **Asthma:** [(Reductions in visits to hospital, emergency room, or urgent care facilities for asthma (participant surveys) * $737.74 (Cost of treating asthma at emergency room, adjusted for inflation)[133]) / Total number of participants]
- In addition, we feel that further study examining the potential health impacts of the programs should be considered

6.5 IMPROVED SAFETY

The societal benefit of reduced emergency calls and hospital visits has been identified in the literature as an NEI resulting from improved safety attributable to energy efficiency programs. However, safety from a societal perspective is another NEI that has not been well researched. Of the reviewed literature, few studies have provided estimates for improved societal safety.

The most commonly included safety benefit is derived from providing a carbon monoxide (CO) monitor as part of a weatherization program. The LIPPT report (TecMarket Works, SERA, and Megdal Associates, 2001) notes that 4 to 5 carbon monoxide-related crises occur annually per 400,000 customers, according to a study conducted in Wisconsin. These are more likely to occur in a low-income household and to cost on average about $5,000 per incident. Because the California programs do not install CO monitors, the LIPPT did not recommend including a benefit for reductions in carbon monoxide-related crises.

However, the LIPPT did suggest two methods to estimate a safety benefit. One was to assume the benefit was equal to the value of the CO monitors. The second method was to estimate the likelihood of a crisis in program participants, an assumption of the percentage of carbon monoxide risks for these households would be eliminated (the LIPPT assumed a 100% reduction), and the estimated value of the crisis avoided. These two methods result in an estimated societal benefit of reducing these CO crises between $0.00 to 0.29 per household annually.

6.5.1 Assessment of the Literature

There are very few studies related to safety NEIs from a societal perspective, with the most common benefit deriving from the provision of CO monitors as part of weatherization programs. In the case of a specific type of safety equipment or measure, such as a CO monitor, a common method of calculating the NEI is to estimate the average number of crises avoided per household times the cost per avoided crisis or to use the value of the installed safety equipment. While the PAs' programs do not include CO monitors, furnace repairs and replacements may reduce carbon monoxide-related crises.

6.5.2 Relevant PA Programs

While the PAs' programs do not include CO monitors and few studies have examined safety from a societal perspective beyond CO monitors, this NEI may apply to PA programs that implement measures reducing the risk of fires and CO exposure. However, since unsafe heating and ventilation systems are

[132] Centers for Disease Control and Prevention, 2011. Treatment for cold exposure is considered a "general injury by the CDC: "According to the Injury Surveillance Guidelines, an injury is the physical damage that results when a human body is suddenly or briefly subjected to intolerable levels of energy. Injury can … be an impairment of function resulting from a lack of one or more vital elements (i.e., air, water, or warmth), as in strangulation, drowning, or freezing…. The energy causing an injury may be one of the following: … thermal (e.g., air or water that is too hot or too cold."

[133] Agency for Healthcare Research and Quality, 2008.

more likely to be prevalent in low-income households, and low-income households are least able to resolve unsafe conditions, NMR recommends limiting this NEI to the PAs' low-income programs.

Unfortunately, NMR could not find reliable data on either the reduction of CO poisonings attributable to furnace repairs or replacements or incidence of CO poisonings.[134]

6.5.3 Recommendation

Due to the lack of research in the literature on the valuation of improved safety from the societal perspective, NMR does not recommend estimating value of this NEI at this time.

6.6 OTHER – WATER, NATIONAL SECURITY

A further review of the literature found several other societal related NEIs of potential interest to the PAs' programs, though with very little quantifiable analysis. For instance, water is a scarce resource, managed heavily in many areas. Measures that save water benefit everyone in the area. The degree to which development of new water supply is avoided due to efficiency measures is the societal benefit of interest. The costs of developing new water capacity are often prohibitive. The societal benefit of water savings was investigated in the 2001 California LIPPT report. However, because the LIPPT assumed that low-flow water measures such as aerators and low-flow shower heads have relatively short lifetimes—an average of three years— the LIPPT determined that they only provided short-term water savings. This yields a NEI value of $0.00, due to the short duration of the measure, compared to the cost of development of new supply (TecMarket, SERA, and Megdal Associates, 2001).

Another societal NEI that has rarely been considered is that of improved national security. The most notable benefit comes from reducing the need for energy imports, thereby enhancing national security. In areas where fuel oil or kerosene are commonly used to heat homes, comprehensive weatherization programs have the greatest effect in reducing the amount of imported energy consumed. Riggert et al. (1999) derived a national security NEI benefit of $202 per household from avoided imported fuel sources by comprehensive weatherization measures in Vermont by assuming a ten percent adder effect for avoided imported oil. NMR updated Riggert et al.'s adder effect variable, which represents the cost of relying on imported oil, by calculating ten percent of the 2012-2016 levelized cost per MMBtu of crude oil from the AESC study (2011 dollars).

6.6.1 Assessment of the Literature

The societal-perspective NEIs of reduced water usage and improved national security have rarely been studied. Water savings are relatively straightforward to estimate and can provide relevant savings for programs that include water measures; however, the societal NEI value for water savings is negligible. NMR does not believe that a value for water savings can be derived from existing studies.

The NEI of national security is most valuable for programs in which participant homes are heated by fuel oil or kerosene. If the PAs' programs install weatherization and other heating related measures into homes that use fuel oil or kerosene as the primary heating fuel, an NEI value of improved national security can be derived from an algorithm developed from the literature (see Riggert et al., 1999).

[134] Hall (2010) reports emergency room visits caused by heating equipment, including anoxia (defined as "lack of oxygen, which may occur in a fire-affected atmosphere or when carbon monoxide from malfunctioning equipment crowds out oxygen"), but emergency room visits from CO specific causes are not reported.

6.6.2 Relevant PA Programs

The societal NEI of water savings potentially applies to PA programs that implement water-saving measures.

The NEI of national security potentially applies to all programs that reduce the consumption of imported fuels, such as the PAs' low-income programs and non-low-income retrofit programs that install weatherization and other heating related measures.

6.6.3 Recommendation

Based on the review of the literature for water, NMR does not recommend including estimates for water savings from the societal perspective (participant water savings are reviewed and estimated in section 5.13).

Based on the review of the literature, NMR recommends the following annual national security NEI for PA program participants' homes that use fuel oil or kerosene as the primary heating fuel, derived from the following algorithm, developed by Riggert et al. (1999):

- [(Estimated annual savings in fuel oil and kerosene, per measure, MMBtu (PA Data) * $1.83 (10% adder for cost of relying on imported oil or kerosene, per MMBtu)[135] * number of homes that use fuel oil or kerosene as the primary heating fuel)]

[135] The price per MMBtu represents a 10% adder of the forecasted 2012 to 2016 levelized cost of imported low-sulfur oil, as reported in the 2011 AESC report (Hornby et al., 2011)

7. PARTICIPANT-PERSPECTIVE NEIS, OWNERS OF LOW-INCOME RENTAL HOUSING—LITERATURE REVIEW

Our review of the literature found no mention of non-energy impacts pertaining to participating owners of low-income rental housing. However, interviews with PA staff identified several potential NEIs, including reduced maintenance pertaining to lighting (attributed to the longer life of a CFL, thus reducing labor costs), improved sense of environmental responsibility, improved marketing of rental property (i.e., a more energy-efficient rental unit is easier to market and rent), and reduced tenant turnover.

The following NEIs were estimated in the analysis of owners of low-income rental housing NEI surveys:

- Marketability and ease of finding renters
- Reduced maintenance of heating and cooling equipment
- Reduced maintenance for lighting (as with the occupant NEIs, NMR recommends that the PAs either use the value derived from the surveys or the O&M value from the TRM, but not both values)
- Reduced tenant turnover
- Reduced tenant complaints
- Expected increase in property value
- Improved durability of property
- NEI values are reported in section 10. Participant NEIs Estimated from Surveys—Owners of Low-income Rental Housing.
- NMR recommends applying the NEI values to the PAs' low-income multi-family programs.

8. NON-RESOURCE BENEFITS

Our evaluation also found what we believe to be a non-resource benefit of waste savings from the Massachusetts Appliance Turn-in Program.

8.1 WASTE SAVINGS: REFRIGERATOR/FREEZER TURN-IN PROGRAMS

The Massachusetts Appliance Turn-in Program is a regional refrigerator and freezer collection initiative administered through the Northeast Energy Efficiency Partnerships by National Grid, NSTAR Electric, Western Massachusetts Electric Company, and the Cape Light Compact in Massachusetts. JACO, a third party implementation contractor, handles all aspects of program implementation, including recycling the refrigerators and freezers that it collects. Hazardous materials such as chlorofluorocarbon (CFC) or hydro chlorofluorocarbon (HCFC) gases, polychlorinated biphenyls (PCBs), mercury, and oils contaminated with CFCs and HCFCs are removed from the collected units and disposed of in accordance with US EPA Responsible Appliance Disposal (RAD) program guidelines.[136]

By removing from customers' homes refrigerators and freezers that are inefficient or unnecessary, the program creates energy savings and reduces demand on the electrical grid. The program also creates non-energy impacts (NEIs), which are the effects of the program other than those energy savings. In general, programs may create both positive and negative NEIs, but this analysis investigates the beneficial NEIs of the appliance recycling program, such as the environmental benefits derived from properly collecting, destroying, or recycling the materials contained within these units. According to an analysis of program records from June 2009 through November 2010, on average, each unit collected in Massachusetts contained approximately 100 pounds of metal, 20.0 pounds of plastic, 1.5 pounds of glass, 8.5 pounds of foam insulation, and 0.6 pounds of Freon. The metal is sold to scrap metal dealers, plastic and glass are stripped from the units and recycled, and the foam insulation (which potentially contains ozone-depleting CFCs) is taken to a waste to energy plant and incinerated at a high temperature. By following the stringent RAD guidelines, JACO recycles the refrigerators and freezers it collects to a level that exceeds EPA regulations, which do not require foam incineration or recycling of the glass and plastic in the units.[137]

To the extent that appliance turn-in programs ensure that hazardous materials are disposed of properly and that the materials comprising old appliances are recycled, beneficial societal non-energy impacts can be derived in the form of 1) avoided landfill space, 2) avoided use of raw or virgin materials in the production of new goods through the use of recycled components, and 3) avoided release of ozone-depleting substances and greenhouse gases into the atmosphere. Federal law and regulations do, however, require the proper disposal or storage of refrigerant, mercury, PCBs, and used oil, such that the sponsors cannot claim the environmental and health benefit associated with avoiding the release of these materials, because they would have already been properly managed, barring illegal activity.

Non-energy impacts associated with appliance turn-in programs have not been estimated in NEI literature. However, the three impacts previously mentioned can be estimated via the following engineering algorithms.

[136] U.S. Environmental Protection Agency, Stratospheric Protection Division. "Responsible Appliance Disposal (RAD) Program." Accessed May 10, 2011. http://www.epa.gov/ozone/partnerships/rad/.

[137] 40 C.F.R. § 82 Subpart F, http://ecfr.gpoaccess.gov/cgi/t/text/text-idx?c=ecfr&sid=f40bf28473d6464a12bfbe9adb547cd2&rgn=div6&view=text&node=40:17.0.1.1.2.6&idno=40.

8.1.1 Avoided Landfill Space

According to program data, between June 2009 and November 2010,[138] JACO collected approximately 30 pounds of plastic, glass, and insulating foam from each unit. These materials were either recycled or incinerated, and were thus diverted from eventual disposal in landfills as a result of the program.[139] The NEI value of this avoided landfill space can be estimated by multiplying the quantity of recycled materials per appliance by average landfill tip fees. The average landfill tip fee in the Northeast in 2004, the most recent year that data was made publicly available by the National Solid Wastes Management Association (NSWMA), is $70.53 per ton.[140] Estimated in this manner, the NEI value of avoided landfill space per unit is approximately $1.06.

8.1.2 Recycling of Plastics and Glass

The program recycles plastic and glass that would typically be landfilled in the absence of the program, thereby returning these materials to the manufacturing stream. Producing goods from such recycled materials is generally less energy-intensive than producing goods from virgin inputs; therefore, recycling this plastic and glass results in decreased GHG emissions.

The societal benefit of avoided emissions attributable to the program can be estimated using the EPA's Waste Reduction Model (WARM) which employs a materials life-cycle approach allowing users to estimate energy impacts and GHG emissions of alternative waste management practices. WARM assumes that recycled materials displace virgin materials in manufacturing. JACO program records indicate that 20.0 pounds of plastic and 1.5 pounds of glass per unit were recycled through the program. The emissions reduction associated with recycling 20.0 pounds of plastic and 1.5 pounds of glass and returning them to the manufacturing stream (as opposed to disposing of these quantities in landfills and producing virgin materials to take their place in the manufacturing stream) is 0.01564 metric tons of carbon dioxide equivalent (CO_2e).[141] The 2009 Avoided Energy Supply Costs (AESC) in New England reports an estimated value for carbon dioxide emissions of $80 per ton. Multiplying the avoided 0.01564 CO_2e per unit by $80 per ton of CO_2 yields an NEI value of approximately $1.25 per unit for the reduced use of virgin materials in the manufacturing process.

8.1.3 Incineration of Insulating Foam

Chemical blowing-agents, typically CFCs or HCFCs, are used to spray foam into refrigerators and freezers when they are being manufactured. These gases are trapped in the air pockets of the foam for the life of the appliance, and in the absence of the program, they are released into the atmosphere when

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[138] This data was reported by NMR Group in its evaluation of the 2009-2010 Massachusetts Appliance Turn-in Program, submitted to National Grid, NSTAR Electric, Cape Light Compact, and Western Massachusetts Electric Company in May 2011.

[139] Although the metal that is sold to scrap dealers is ultimately recycled into new products, NMR does not include metal in the estimation of NEI values. Instead, NMR assumes that the metal from old units would have likely been sold to a scrap yard (and ultimately recycled) in the absence of the program by another channel due to its relatively high scrap value. Alternate channels by which used appliances end up in scrap yards include haulers, municipal disposal channels, and scavengers. These findings, derived from secondary research and interviews with market actors, are reported in NMR's *Massachusetts Appliance Turn-in Program – Secondary Market and Appliance Disposal Report*, submitted to National Grid, NSTAR Electric, Cape Light Compact, and Western Massachusetts Electric Company in May 2011. The EPA also confirms that metals are generally salvaged while foams, plastics, and glass are typically landfilled: "Appliance Disposal Practices in the United States." Accessed May 10, 2011. http://www.epa.gov/ozone/partnerships/rad/raddisposal_factsheet.html.

[140] The following states were included in the Northeast region for the NSWMA analysis: CT, ME, MA, NH, NY, RI, VT.

[141] Carbon dioxide equivalent is a measurement used to compare the emissions of various greenhouses gases to carbon dioxide, based on their global warming potential (GWP). Global Warming Potential is the "ratio of the [global] warming caused by a substance to the warming caused by a similar mass of carbon dioxide." The GWP of CO_2, for example, is 1. CFC-11 thus causes 4,750 times more global warming than would an equivalent quantity of CO_2.
Source: U.S. Environmental Protection Agency. "Ozone Layer Protection Glossary." Accessed March 20, 2011, http://www.epa.gov/ozone/defns.html.

the unit is shredded at a metal shredding facility. After the unit is shredded at such a facility, the foam is typically landfilled, where any remaining blowing-agent escapes into the atmosphere. These blowing-agents are potent greenhouse gases, and through high temperature incineration, the program prevents their release into the atmosphere.

The EPA estimates that an average refrigerator or freezer contains 1.0 pounds of blowing-agent in its foam.[142] These blowing-agents could be a number of different chemicals depending on the date of manufacture, as certain chemicals were phased out due to environmental regulations. According to the EPA, prior to 1995, the blowing-agent is likely to have been CFC-11, with a global warming potential (GWP) of 4,750, and from 1995 onward, HCFC-141b is the assumed blowing-agent, with a GWP of 725.[143] According to program data, 87.7% of units collected were manufactured prior to 1995, and are thus assumed to have contained CFC-11, with a significantly higher GWP than newer units.

The per unit NEI value of the avoided release of blowing-agent into the atmosphere can be estimated by multiplying the CO_2e of the blowing-agent by the 2009 Avoided Energy Supply Costs in New England's externality value of CO_2, which is $80/ton. To estimate the CO_2e of each unit collected by the program, the evaluation team used the EPA's RAD data to assume that each unit contained 1.0 pounds of blowing-agent,[144] and then multiplied that quantity by the GWP of the likely blowing-agent based on the unit's age, which results in the CO_2e, in pounds, of each unit's blowing-agent. The average CO_2e value per unit of a pre-1995 unit is 4,750 pounds, and 725 pounds for a unit manufactured in 1995 or later. Each of these values can then be multiplied by $0.04 per pound (AESC value of $80/ton of CO_2). Thus, the average per unit value of preventing the environmental release of one pound of blowing agent from a pre-1995 unit is $190, and $29 from a unit manufactured in or after 1995. Over time, as the prevalence of pre-1995 units declines, the average per unit value preventing the environmental release of one pound of blowing agent will decline.

For the Massachusetts program, the average CO_2e of all collected units from June 2009 to November 2010 was 4,256 lbs, and the average per unit value of preventing the environmental release that material was $170.22.[145]

8.1.4 Relevant PA Programs

The NEIs derived from appliance turn-in programs apply to the Massachusetts Appliance Turn-in Program.

[142] U.S. Environmental Protection Agency, Stratospheric Protection Division. *RAD 2009 Annual Report*. August 2010. http://www.epa.gov/Ozone/partnerships/rad/downloads/RAD_2009_Annual_Report.pdf.

[143] Evelyn Swain. U.S. Environmental Protection Agency. EPA Responsible Appliance Disposal Program Webinar for National Association of State Energy Officials. March 2010. Accessed May 10, 2011. http://www.naseo.org/events/webinars/RAD/NASEO_RAD_Presentation_March2010.pdf.

Ms. Swain indicated in telephone conversations with evaluators that in the 2000's, manufacturers shifted away from HCFC-141b to blowing-agents with lower GWPs, but this transition did not happen uniformly across all manufacturers. In addition, less than 2% of units collected by the Massachusetts program were manufactured more recently than 2000. Therefore, we are only taking into account the 1995 blowing-agent transition in our estimates of the blowing-agent types present in the collected units.

[144] The data JACO was able to provide the evaluation team did not identify the specific types or quantities of blowing-agents that were recovered from each individual model, therefore the team relied on EPA estimates from its 2009 RAD Annual Report.

[145] Note that these values do not account for any potential CO_2 emissions released during the incineration process. We are assuming that the emissions released from the incineration process is equivalent to the CO_2 emissions that would have been generated by the metal shredding facilities when shredding the appliances and foam in preparation for the landfill.

8.1.5 Recommendations

NMR recommends a one-time NEI value of avoided landfill space of $1.06 per unit, a one-time NEI value of reduced use of virgin materials in the manufacturing process of $1.25 per unit, and a one-time NEI value of preventing the environmental release of CFCs or HCFCs from insulating foam of $170.22 per unit. These values are derived from the following algorithms:

Avoided landfill space:

- (30 lb plastic, foam, and glass material/unit) / (2,000 lb/ton) * [$70.53 /ton (2004 Northeast regional average landfill tipping fee)]

Avoided use of raw/virgin materials in the manufacturing process:

- 0.01564 $MTCO_2e$/unit (WARM) * $80/ton (Avoided Energy Supply Costs in New England: 2011 Report)

Avoided GHG emissions:

- For pre-1995 units:
- Average CO_2e/pre-1995 unit (4,750 CO_2e/unit (EPA and JACO)) * $80/ton (Avoided Energy Supply Costs in New England: 2011 Report)
- For units manufactured 1995 and after:
- Average CO_2e/1995 and later unit (725 CO_2e/unit (EPA and JACO)) * $80/ton (Avoided Energy Supply Costs in New England: 2011 Report)

9. PARTICIPANT NEIs ESTIMATED FROM SURVEYS—OCCUPANTS

Large majorities of low-income (LI) and non-low-income (NLI) respondents believed that the energy efficiency retrofits provide NEIs and that the NEIs provide hundreds of dollars of benefit to them.

For example, among NLI respondents four out of five (80%) believed the retrofits have increased the value of their property, three out of four (76%) said that thermal comfort had increased, 73% reported increased reliability or reduced maintenance of their new heating or cooling equipment, and seven out of ten (70%) NLI respondents thought that the quality and lifetime of the lighting, when taken together, was a positive impact. Among LI respondents, about two-thirds of respondents (65%) said that the improvements had increased the comfort level of their home, and a similar percentage (68%) said that the quality and lifetime of the lighting, when taken together, constituted a positive impact. Slightly fewer than six out of ten respondents (57%) reported an expected increase in property value.[146]

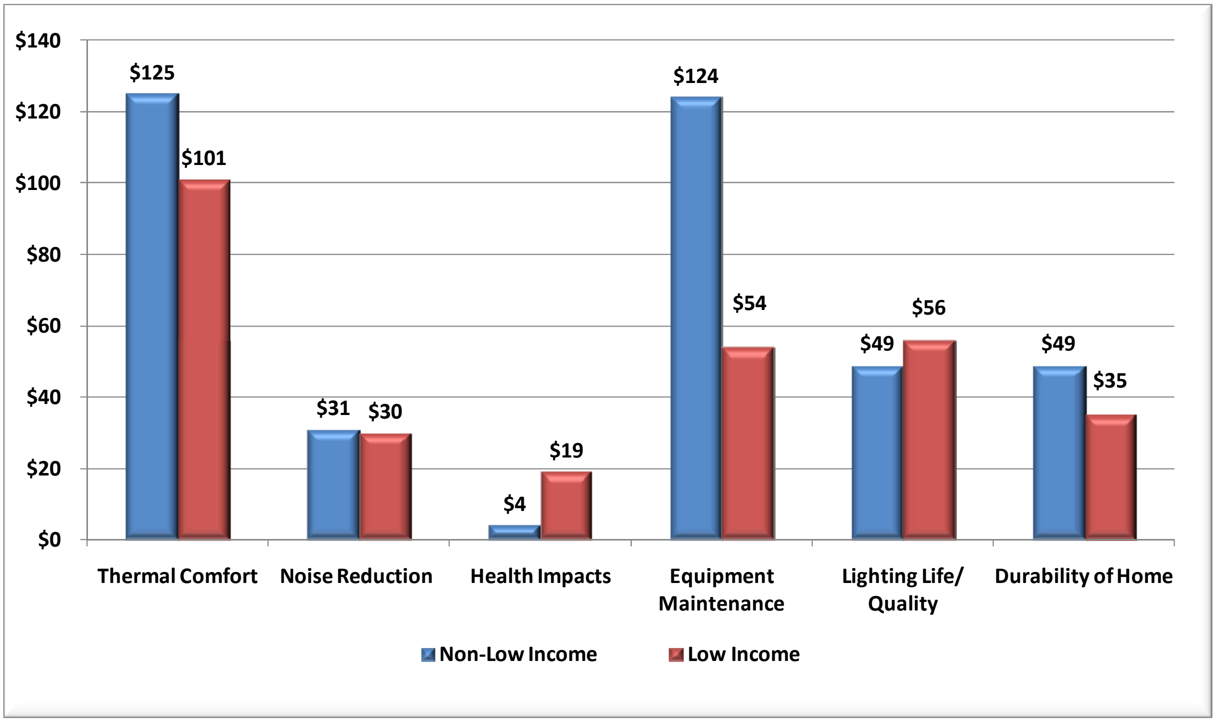
Overall, on average, non-low-income participants believed that NEIs were worth $261 and low-income participants believed that their NEIs were worth $242. In terms of energy bill savings, NLI participants believed that their NEIs were worth 77% of their energy savings, while low-income participants believed that NEIs were worth 52% of their own energy savings. Values for individual NEIs are scaled to these total NEI values.[147]

In general, NLI respondents placed a higher value per participant than did the LI respondents on the NEIs that provide annual benefits, except health impacts and lighting life and quality (Figure 9-1). NLI respondents valued thermal comfort and equipment maintenance the most ($125 and $124 per year, respectively), while LI respondents valued thermal comfort, lighting life and quality, and equipment maintenance the most ($101, $56, and $54, respectively).

[146] Only homeowners were asked about impacts on property values.

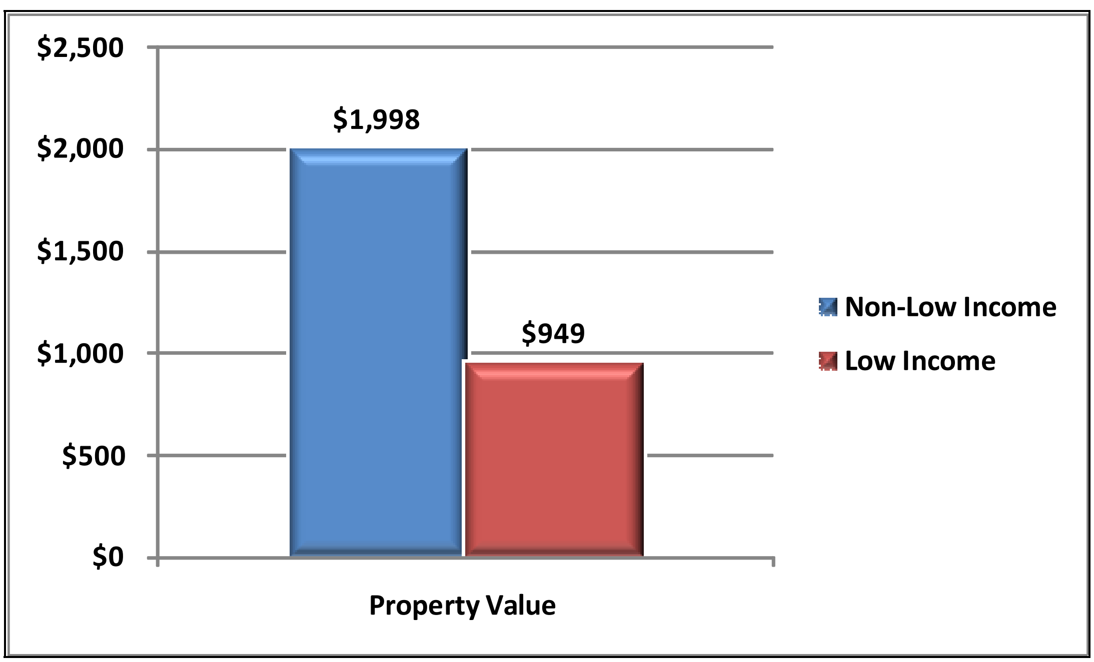
[147] Scaling was done at the individual respondent level, for those NEIs applicable to the particular respondents. This leads to individual NEI values that are not directly additive, since only some respondents experienced each NEI.

Figure 9-1. Low-income and Non-low-income Respondent Valuation of Annual NEIs



Non-low-income respondents estimated a substantially higher one-time property value increase attributable to the energy efficiency retrofits than did low-income respondents (Figure 9-2).

Figure 9-2. Low-income and Non-low-income Valuation of One-time Property Value NEI



In addition, this portion of the study attempted an alternative method of estimating participant perspective health benefits—via reductions in sick days attributed to the energy efficiency retrofits, as well as societal

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benefits via reduced medical costs flowing from reduced incidence of heat stress, hypothermia, and asthma. Because of the extremely small number of respondents reporting program induced changes in health, NMR does not recommend using results from this method. Findings are reported in Appendix A.6 and A.7. However, health benefits are also being examined in the current evaluation of the national WAP; values might be able to be derived from these findings once the study is complete (Ternes et al., 2007).

9.1 PERCEPTION OF EFFICIENCY IMPROVEMENT AND NEIS

Respondents were asked about their perception of the energy-efficiency of their homes after the improvements as compared to before. As a whole, respondents perceived that the improvements made their homes more efficient, but the extent to which respondents perceived their homes' efficiency to have improved appears to differ between the two income groups (Table 9-1). Non-low-income (NLI) respondents were somewhat more likely than low-income (LI) respondents to report greater efficiency (90% versus 74%) and less likely to report that the efficiency had not changed (7% versus 18%).

Table 9-1. Perception of Energy-Efficiency after Improvements

	Low-income	Non-low-income
Sample size	213	209
More efficient	74%	90%
Less efficient	2%	0%
Same efficiency	18%	7%
DK/Refused	5%	3%

Before respondents were asked about specific non-energy impacts (NEIs), they were asked if there were any positive or negative impacts they might have noticed as a result of the improvements, other than energy savings. The most frequently mentioned positive impact for both groups was thermal comfort, with over one-third (36%) of the NLI respondents and over one-quarter (27%) of the LI respondents reporting this benefit. About one out of four respondents (26% and 23% for the LI and NLI groups, respectively) cited more affordable energy bills (Table 9-2). In addition, noise reduction (both equipment noise and noise from outside the home) was reported by about one out of ten (11%) NLI respondents and a small percent of the LI respondents (3%). Other benefits respondents mentioned include equipment reliability, less use of fuel, and the life and or/quality of the energy-efficient light bulbs. Respondents also volunteered several non-energy benefits not directly asked about in the survey, including safety, ease of use of the new equipment, reduction in ice dams on the roof, increased hot water availability, and fewer rodents and insects entering the home.

Table 9-2. Positive Impacts of Installations Noticed by Occupants

NEI	Low-income	Non-low-income
Sample size	213	209
Increased thermal comfort	27%	36%
More affordable energy bills	26%	23%
Reduced noise	3%	11%
Equipment reliability/reduced maintenance	3%	6%
Less use of energy/fuel	3%	4%
Improvement in lighting life/quality	2%	1%
Increased safety	1%	1%
Equipment easier to use	1%	0%
Home heats up faster	1%	1%
Cooler in summer	1%	1%
Fewer ice dams on roof	1%	1%
Fewer rodents or insects	1%	1%
More hot water available	1%	1%
Less odor (e.g., when switching from oil to gas heat)	1%	1%
Household health benefits	0%	1%
Improved temperature control	--	1%
Improved humidity control	--	1%
Other benefits	6%	6%
No benefits mentioned	36%	28%

Very few negative impacts were identified by the respondents. Eight out of ten LI respondents and nearly nine out of ten NLI respondents (88%) said they had not noticed any negative impacts from the efficiency improvements (Table 9-3). Further, no single negative impact was mentioned by more than four percent of respondents, suggesting that negative impacts are few in number and not consistent across the handful of households that have experienced them. The negative impacts reported include continued draftiness, dissatisfaction with the new lighting, remaining ice dams or snow accumulation on the roof, and increased time for the hot water to heat.

Table 9-3. Negative Impacts of Installations Noticed by Occupants

NEI	Low-income	Non-low-income
Sample size	213	209
Lack of thermal comfort (draftiness)	4%	1%
Dissatisfaction with lighting	4%	2%
Ice dams or snow accumulation on roof	2%	1%
Leaks in attic	2%	--
Weather stripping is ineffective	2%	--
Increased equipment noise	1%	1%
Reduced equipment reliability	1%	--
Less affordable energy bills	1%	--
Hot water takes too long to heat	1%	3%
Increased insect activity	1%	1%
Other negative impacts	4%	2%
No negative impacts mentioned	80%	88%

9.2 PERCEPTION OF NEIS

After respondents were asked about impacts they might have noticed, they were asked about specific NEIs. First, they were asked whether they had noticed the impact since the efficiency improvements, as well as whether the impact was positive or negative. For example, for thermal comfort, we inquired whether their homes were more comfortable, less comfortable or the same comfort level as before the improvements (Table 9-4).

Among the LI respondents, about two-thirds (65%) said that the improvements had increased the comfort level of their home, and a similar percentage (68%) said that the quality and lifetime of the lighting, when taken together, constituted a positive impact. Slightly fewer than six out of ten respondents (57%) reported an expected increase in property value.[148] Less than one-half of respondents said that the other NEIs were positive, with just over four out of ten (43%) reporting increased reliability of equipment, about one out of three (34%) reporting increased durability of the home, one out of four (25%) reporting decreased noise from outside the home, and one out of five (20%) reporting a reduction in colds, flus, and asthma-related conditions. No NEI was regarded as negative by more than one out of ten respondents. When asked about the total impact of all the NEIs that had been discussed in the survey (except property value), eight out of ten LI respondents (80%) said that the impact was positive, while about one out of six

[148] Only homeowners were asked about impacts on property values.

(14%) said that it was neither positive nor negative. Only two percent of LI respondents judged the overall impact to be negative.

In general, the NLI respondents appear to have been more likely than the LI respondents to report positive impacts of the improvements. The NEI most frequently regarded as positive by the NLI group was property value, with four out of five (80%) saying that they expected the value of their property to increase. Approximately three out of four (76%) said that thermal comfort had increased, and a similar percentage (73%) reported increased reliability or reduced maintenance of the new equipment. In addition, seven out of ten (70%) NLI respondents thought that the quality and lifetime of the lighting, when taken together, was a positive impact. Each of the remaining NEIs received positive ratings from less than one-half of this group: durability of the home (44%), noise (30%), and health impacts (20%). No NEI received negative ratings from more than 6% of the NLI respondents. A large majority (92%) of the NLI group said that the total impact of all the NEIs (except property value) was positive, and fewer than one out of ten (7%) said the overall impact was neither positive nor negative.

Table 9-4. Respondents who Say Home Provides NEIs

NEI	Low-income (n=213)				Non-low-income (n=209)			
	Sample size	Positive	Negative	No difference	*Sample size*	Positive	Negative	No difference
Thermal comfort	*213*	65%	1%	31%	*209*	76%	1%	20%
Noise (from equipment or outside home)	*213*	25%	1%	72%	*209*	30%	2%	65%
Health (colds/flus/asthma)	*213*	20%	4%	73%	*209*	20%	1%	72%
Property value (homeowners only)	*176*	57%	1%	38%	*207*	80%	0%	15%
Equipment reliability/maintenance	*141*	43%	6%	47%	*139*	73%	3%	21%
Lighting quality and lifetime	*148*	68%	10%	20%	*107*	70%	6%	21%
Durability of home	*213*	34%	2%	60%	*209*	44%	1%	52%
Overall impact of NEIs*	*213*	80%	2%	14%	*209*	92%	1%	7%

*Does not include property value.

Comparisons to other studies provide additional understanding into NEIs. In particular, we compared the results of this study with one of participants in Mass Save and another with participants in the ENERGY STAR Homes program. The LI and NLI respondents report similar levels of positive impacts of energy efficiency improvements in a recent survey of Mass Save program participants.[149] The Mass Save survey

[149] In the fall of 2010 Cadmus and Opinion Dynamics Corporation (ODC) conducted surveys with 1,202 customers who participated in the 2010 Mass Save® Residential Single Family Retrofit (Mass Save) Program

included a brief set of questions asking respondents if they experienced non-energy impacts as a result of their energy efficiency retrofits. Overall, 63% of Mass Save participants experienced a positive change in thermal comfort, 33% experienced a positive change in noise, 22% experienced a positive change in asthma and other chronic health conditions and 34% experienced a positive change in the durability of their home. More details of the Mass Save survey results are provided in Appendix B: Mass Save NEIs .

However, LI and NLI respondents appear to report lower positive levels for some NEIs than homeowners of new ENEGY STAR (ES) homes in Massachusetts (NMR and Conant, 2009). For example, 86% of ES homeowners who responded to the ES Homes survey believed their new home provided an NEI of thermal comfort compared to 76% of NLI retrofit participants and 65% of LI retrofit participants. Further, 67% of ES homeowners stated that their home provided a benefit of reduced noise compared to 30% of NLI retrofit participants and 25% of LI retrofit participants. However, lighting life and quality appeared to be slightly less likely to be perceived as a positive NEI by ES homeowners, with 61% reporting this as a positive NEI compared to 70% of NLI retrofit participants and 68% of LI retrofit participants. An important difference between the two surveys is that the ES homeowners were comparing their homes to what they imagined other new, non-ES homes, were like, whereas the respondents in the current study were comparing their current experience with their actual previous experience in the same home.

9.3 NEI VALUE CALCULATION

Survey respondents were asked to estimate an annual value for the NEIs they experience in their homes.[150] The survey used a *relative valuation* method, asking respondents to value each NEI in relation to their annual energy bill savings, either as a dollar amount or as a percentage of energy savings.[151] Each respondent was told an estimate of their annual energy bill savings based on the measures the participant had installed with the PAs' programs.

The survey first asked homeowners if they believed their home had a particular NEI, and whether it was positive or negative. Taking the thermal comfort NEI as an example, respondents were asked if they believed their home, because of the energy efficiency improvements, was more comfortable than before, less comfortable, or no different in its comfort level (in terms of temperature and draftiness). Those who believed it was more comfortable were asked to place a value per year on this increased comfort, with a choice of dollars or a percentage of energy savings. Those who believed it was less comfortable were asked how much the decreased comfort took away from the value of living in the home, either in dollars or as a percentage of energy savings. NEI values for those who believed their home was no different in comfort level from before the improvements were set to zero.

Assigning monetary values to intangibles such as comfort is not an easy task. Respondents who responded that they did not know were further prompted with the following questions:

> "Compared to energy bill savings, would you say increased comfort is worth nothing, about a one fourth of energy bill savings, about a half of energy bill savings, about three-fourths of energy bill savings, about equal to energy bill savings, or more than energy bill savings? If the latter, how much more?"

The NEIs for respondents who still could not provide an answer are treated as missing in the calculation of average NEI values.

After providing values for the individual NEIs, respondents were asked to assign an annual value to the total impact of all the NEIs together (except for any changes in property value). Each respondent's

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[150] The NEI of property value as asked in terms of a one-time change in value

[151] A discussion of the various methods used to estimate NEIs in the literature is found in the section 5.1: Methods Used to Measure Participant NEIs

individual NEI values were scaled in proportion to the respondent's valuation of the total impact of all the NEIs in order to account for any overlap in NEIs or over-estimation of the individual NEIs. Potential overlap and overestimation can be conceptualized in two ways. First, when asking respondents to valuate non-market goods with multiple parts or components, the stated value of the whole is often less than the value of the sum of the parts. This is often referred to as 'part-whole bias' when the values of the individual parts are not adjusted for the value of the whole (Bateman et al., 1996; Brown and Duffield, 1995). Second, when valuating several related things, the stated value of the total is often less than that of the sum of the individual items, often referred to as an "embedding effect" (Baron and Greene, 1996; Brown et al, 1995). There could be any number of explanations for this, but in the case of NEIs it is likely that there is "overlap" among the various NEIs asked about, such that respondents do not conceptualize the individual NEIs as being completely distinct and therefore their values are not additive.

Overlap could be occurring among NEIs in a few different possible ways. One way is if there is an implied causal relationship in the respondent's mind between two NEIs, so that it would be redundant to "pay for" each separately. For example, if a respondent thinks that fewer drafts lead to fewer colds and viruses, the respondent might think that both NEIs are valuable, but when combined, the NEIs are less valuable in total because when the respondent 'pays' for fewer drafts the respondent also benefits from fewer colds/viruses. Alternatively, two or more NEIs could be conceptually or experientially similar, so that they share at least some of their perceived meaning. For example, a respondent might perceive comfort, fewer illnesses, and reduced noise as all being different but somewhat overlapping aspects of an overall sense of "well-being," such that the various aspects, when taken separately, add up to more than the overall sense. Finally, one NEI can be considered a subset of another NEI, such that the value of one "contains" the value of another. For example, longer lighting life and even durable home could be perceived as part of "reduced equipment maintenance," such that the value of equipment maintenance includes the value of the other two.

The individual NEI values were scaled in the following way: each NEI value was represented as a proportion of the sum of that respondent's individual NEI values. This proportion was then applied to the respondent's reported valuation of the total impact of all the NEIs, yielding the scaled value for each NEI[152]. The scaling factor is specific to each respondent and varies widely throughout the sample. For example, if a respondent said their total NEI value was $300, while reporting their health NEI as $300 and their thermal comfort NEI as $100, the scaled NEI values for this respondent would be a health NEI of $225 and a thermal comfort NEI of $75. The specific NEI values for this same respondent would be much different if the respondent reported their total NEI value to be $1000 or $100. In addition to scaling, respondent values were weighted according to their strata. For example, NLI respondents in the heating and cooling strata received a weight of 1.53 while NLI respondents in the shell plus heating and cooling strata received a weight of 0.10. Thus, the scaling and the weights affect the calculation of average values.

As an example, assume respondent A is from the heating and cooling strata and reports total NEIs as $300, health NEI as $300 and their thermal comfort NEI as $100, the scaled NEI values for this respondent would be a health NEI of $225 and a thermal comfort NEI of $75. Respondent B, from the shell plus heating and cooling strata, reports total NEIs as $650, health NEI as $500 and their thermal comfort NEI as $200, the scaled NEI values for this respondent would be a health NEI of $464 and a thermal comfort NEI of $186. Because the respondents are weighted differently, the weighted average value for health would equal $240 and the weighted average value for comfort would equal $82. A more detailed discussion of the scaling of the NEI values is presented in Appendix A.2 (Scaling of NEI Values)

Table 9-5 and Table 9-6 present the mean NEI values of non-low-income and low-income respondents. Two mean values are presented for each NEI—the first reflects reported NEI values (shown in dollars as well as in terms of mean percent of bill savings), while the second reflects respondents' reported values

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[152] When the respondent failed to give a value when asked for Total NEI value the scaling was based on the sum of the respondents individual measure values.

scaled in proportion to the total NEI value provided by respondents. Upper and lower bounds of values are calculated at a 90% confidence level; the central estimate may be considered for planning purposes. The mean of the sum of the individual NEIs as well as the mean total NEI values, are also presented. Sum of NEIs is the sum of the unscaled values of the individual annual NEIs (i.e., excluding property value) while total NEI value is the value provided by respondents when asked for the total value of all NEIs, excluding property value. The values reported in Table 9-5 and Table 9-6 and the overall population values reported in Table 9-7 and Table 9-8 are weighted to strata and income group. The following weights were applied to the non-low-income sample: a weight of 1.53 for the heating and cooling strata, a weight of 1.40 for the shell strata a weight of 0.10 for the shell plus heating and cooling strata. For the low-income sample, the following weights were applied: a weight of 1.22 for the heating and cooling strata, a weight of 0.98 for the shell strata a weight of 0.79 for the shell plus heating and cooling strata. In addition, cases that are at least three times the standard deviation of percent bill savings of the total scaled NEI value are excluded

It should be noted that the individual NEI values do not sum to equal the mean "Sum of NEIs" and "Total NEI" values presented in the table, because the individual NEIs were based on respondents who expressed a value for a given NEI, whereas the Sum of NEIs and Total NEIs apply to all respondents. For example, lighting quality and lifetime was only estimated for respondents who had installed energy efficient lighting through the PAs' programs and estimated a value for lighting quality and lifetime (40 NLI respondents and 88 LI respondents). As a result, for 168 NLI respondents, the Sum of NEIs does not include a dollar value for lighting quality and lifetime (because they did not install lighting through the programs). Similarly, equipment maintenance was only estimated for respondents who had installed energy efficient heating and cooling equipment through the PAs' programs and estimated a value for reduced equipment maintenance (117 NLI respondents and 122 LI respondents).Therefore, the number of NEIs that contribute to the Sum of NEIs varies from respondent to respondent. This variation in sample size also has an impact on the consistency of scaling across measures, the scaled value for lighting measure is based on 40 NLI respondents and 88 LI respondents while the scaled value for equipment maintenance was only based on those respondents who had installed energy efficient heating a cooling equipment. This variation in sample size translates into a different base for the scaling, so it should not be expected that lighting and equipment maintenance be subject to the same scaling factor. For a detailed explanation as to how these factors interplay in the scaling, see Table A-4 in Appendix A.

As shown in Table 9-5, the most highly valued annual-value NEI by the NLI respondents is thermal comfort, with a mean annual value of $125 (nearly $300 before scaling to total impact values) and reduced equipment maintenance, with a mean annual value of $124 (nearly $200 before scaling). Reduced noise, improved health, and increased durability of the home were valued the least, each with a mean value of less than $50 annually. Respondents assigned a far higher value to expected increase in property value, a one-time impact, than those for the annual-value NEIs, with a mean of nearly $2,000,[153]

The LI respondents show a similar pattern to that of the NLI respondents (Table 9-6).Among the annual-value NEIs, increased thermal comfort was given the highest value, with a mean annual value of $101 (over $200 before scaling), and reduced equipment maintenance, with a mean annual value of $54 (over $100 before scaling). Similar to the LI group, for the NLI group reduced noise, improved health, and increased durability were given the lowest values, all means of less than $60 annually. Again, the expected increase in property value (a one-time impact) was valued more highly than the annual NEIs, with a mean of nearly $1000,

Table 9-7 reports the mean NEI values by strata for the NLI population. The shell plus heating and cooling strata consistently valued their NEIs higher than did the other strata. The heating and cooling strata valued thermal, comfort health impacts, property value, and durability of home more highly than did the shell strata.

[153] As noted earlier, property value represents a one-time benefit while the remaining NEIs are annual benefits.

Within the LI population (Table 9-8), the shell strata gave a larger value to thermal comfort and noise reduction than did the other strata. Property value and equipment maintenance were valued more highly by the heating and cooling strata than by the other two strata.

Table 9-5. Mean NEI Values from Survey[1]: Non-low-income Population

	Value per year	Thermal comfort		Noise reduction		Health impacts		Property Value [2]	Equipment maintenance [3]		Lighting life/quality [4]		Durability of home		Sum of NEIs	Total NEI Value
		Value	Scaled value	Value	Scaled value	Value	Scaled value	Value	Value	Scaled value	Value	Scaled value	Value	Scaled value	Value	Scaled value
Sample size		**165**		**183**		**176**		**157**	**117**		**40**		**173**		**208**	
Overall	Dollars	$272	$125	$53	$31	$40	$4	$1,998	$175	$124	$104	$49	$57	$49	$472	$261
	% Bill Savings	48%	37%	12%	11%	0%	3%	NA[5]	33%	36%	5%	7%	10%	12%	136%	77%
Lower Bound NEI Value	Dollars	$196	$95	$32	$18	$12	$-3	$1,493	$134	$92	$33	$20	$34	$30	$354	$211
	% Bill Savings	41%	29%	7%	6%	-9%	1%	NA	27%	25%	-3%	3%	7%	8%	111%	65%
Upper Bound NEI Value	Dollars	$348	$154	$73	$44	$67	$12	$2,502	$216	$157	$174	$78	$80	$67	$589	$310
	% Bill Savings	55%	45%	17%	15%	9%	4%	NA	40%	46%	13%	11%	12%	16%	161%	89%

[1]The values reported in this table are weighted to strata and income group. In addition, cases that are at least three times the standard deviation of percent bill savings of the total scaled NEI value are excluded. The following weights were applied to the non-low-income population: a weight of 1.53 for the heating and cooling strata, a weight of 1.40 for the shell strata a weight of 0.10 for the shell plus heating and cooling strata. For the low-income sample, the following weights were applied: a weight of 1.22 for the heating and cooling strata, a weight of 0.98 for the shell strata a weight of 0.79 for the shell plus heating and cooling strata.

[2]Property Value was not scaled because, as a one-time NEI value, it was excluded from the survey question about total annual value of NEIs. Property value was limited to respondents who own their home.

[3]Equipment maintenance was only asked of respondents who installed heating or cooling equipment.

[4]Lighting was only asked of respondents who installed energy efficient lighting through the PAs' programs.

[5]Percent of annual bill savings is not shown for Property Value because it is a one-time NEI.

Table 9-6. Mean NEI Values from Survey[1]: Low-income Population

	Value per year	Thermal comfort		Noise reduction		Health impacts		Property Value[2]	Equipment maintenance[3]		Lighting life/quality[4]		Durability of home		Sum of NEIs[5]	Total NEI Value[6]
		Value	Scaled value	Value	Scaled value	Value	Scaled value	Value	Value	Scaled value	Value	Scaled value	Value	Scaled value	Value	Scaled value
Sample size		172		193		195		143	122		88		185		208	
Overall	Dollars	$205	$101	$63	$30	$29	$19	$949	$116	$54	$103	$56	$78	$35	$431	$242
	% Bill Savings	34%	20%	7%	4%	5%	4%	NA[5]	16%	12%	32%	15%	16%	8%	132%	52%
Lower Bound NEI Value	Dollars	$158	$67	$41	$16	$15	$5	$495	$75	$34	$72	$38	$43	$21	$341	$192
	% Bill Savings	29%	13%	5%	3%	2%	1%	NA	12%	8%	24%	9%	12%	5%	69%	44%
Upper Bound NEI Value	Dollars	$251	$134	$84	$45	$42	$33	$1,404	$156	$74	$133	$74	$113	$48	$521	$293
	% Bill Savings	38%	27%	9%	6%	8%	5%	NA	21%	16%	40%	20%	19%	11%	195%	60%

1The values reported in this table are weighted to strata and income group. In addition, cases that are at least three times the standard deviation of percent bill savings of the total scaled NEI value are excluded. The following weights were applied to the non-low-income population: a weight of 1.53 for the heating and cooling strata, a weight of 1.40 for the shell strata a weight of 0.10 for the shell plus heating and cooling strata. For the low-income sample, the following weights were applied: a weight of 1.22 for the heating and cooling strata, a weight of 0.98 for the shell strata a weight of 0.79 for the shell plus heating and cooling strata.

2Property Value was not scaled because, as a one-time NEI value, it was excluded from the survey question about total annual value of NEIs. Property value was limited to respondents who own their home.

3Equipment maintenance was only asked of respondents who installed heating or cooling equipment.

4Lighting was only asked of respondents who installed energy efficient lighting through the PAs' programs.

5Percent of annual bill savings is not shown for Property Value because it is a one-time NEI.

Table 9-7. Mean NEI Values from Survey[1]: Non-low-income Population, by Strata

	Thermal comfort		Noise reduction		Health impacts		Property Value [2]	Equipment maintenance[3]		Lighting life/quality[4]		Durability of home		Sum of NEIs[5]	Total NEI Value[6]
	Value	Scaled value	Value	Scaled value	Value	Scaled value	Value	Value	Scaled value	Value	Scaled value	Value	Scaled value	Value	Scaled value
Shell measures	$204	$130	$51	$22	$19	$9	$973	-	-	$94	$47	$21	$18	$260	$170
Heating and Cooling measures	$284	$103	$44	$35	$49	$-2	$2,534	$157	$120	$62	$34	$70	$64	$562	$300
Shell Plus Heating and Cooling	$872	$384	$197	$86	$186	$38	$4,929	$423	$183	$494	$186	$312	$192	$1,886	$864
Overall Population	$272	$125	$53	$31	$40	$4	$1,998	$175	$124	$104	$49	$57	$49	$472	$261

[1] Cases that are three times the standard deviation of percent bill savings of the total scaled NEI value are excluded. The following weights were applied to the overall population values: a weight of 1.53 for the heating and cooling strata, a weight of 1.40 for the shell strata a weight of 0.10 for the shell plus heating and cooling strata. Because of the removal out outliers, applying the strata weights to the respective strata level NEI values in order to estimate the overall population mean will not yield the overall population mean values reported in this table.

[2] Property Value was not scaled because, as a one-time NEI value, it was excluded from the survey question about total annual value of NEIs. Property value was limited to respondents who own their home.

[3] Equipment maintenance was only asked of respondents how installed heating or cooling equipment.

[4] Lighting was only asked of respondents who installed energy efficient lighting through the PAs' programs.

Table 9-8. Mean NEI Values from Survey[1]: Low-income Population, by Strata

	Thermal comfort		Noise reduction		Health impacts		Property Value [2]	Equipment maintenance[3]		Lighting life/quality[4]		Durability of home		Sum of NEIs[5]	Total NEI Value[6]
	Value	Scaled value	Value	Scaled value	Value	Scaled value	Value	Value	Scaled value	Value	Scaled value	Value	Scaled value	Value	Scaled value
Shell	$225	$190	$99	$65	$19	$31	$568	-	-	$117	$64	$71	$55	$374	$341
Heating and Cooling	$185	$69	$28	$11	$19	$11	$1,740	$167	$79	$67	$80	$82	$18	$415	$213
Shell Plus Heating and Cooling	$211	$40	$68	$13	$56	$17	$343	$69	$17	$122	$39	$80	$32	$531	$159
Overall Population	$205	$101	$63	$30	$29	$19	$949	$116	$54	$103	$56	$78	$35	$431	$242

[1] Cases that are at least three times the standard deviation of percent bill savings of the total scaled NEI value are excluded. The following weights were applied to the overall population values: a weight of 1.22 for the heating and cooling strata, a weight of 0.98 for the shell strata a weight of 0.79 for the shell plus heating and cooling strata.

[2] Property Value was not scaled because, as a one-time NEI value, it was excluded from the survey question about total annual value of NEIs. Property value was limited to respondents who own their home.

[3] Equipment maintenance questions were only asked of respondents who installed heating or cooling equipment.

[4] Lighting was only asked of respondents who installed energy efficient lighting through the PAs' programs.

Table 9-9 reports the results of further analysis of the property value NEI. It reveals relatively modest differences in the estimated impact of the efficiency improvements on property values of detached single family homes and all other housing types (i.e., townhouses or duplexes, homes in buildings with two to four units and homes in buildings with five or more units).

Table 9-9. Mean Property Value NEI, by Type of Housing and Population

	Detached Single Family Home	Multi-family Home
Sample Size	*184 (NLI); 164 (LI)*	*25 (NLI); 26 (LI)*
Non-low-income	$2,024	$1,863
Low-income	$924	$1,116

9.4 ASSOCIATION BETWEEN NEI VALUES AND INSTALLED MEASURES

Most NEI evaluations estimate NEI values at the participant level, rather than at the measure level, due to the diversity of measures installed by programs evaluated for NEIs and because of the interaction among measures to produce an individual NEI. For example, heating systems, insulation, air sealing, windows, and doors are among the measures that likely contribute to increased thermal comfort of a home. To estimate NEIs at the measure level, NMR assigned a portion of a given NEI value to an individual measure, based on the average energy bill savings for which the measure is responsible. In addition, NMR examined a second method, using OLS regression models to determine the monetary relationship between the energy efficient measure and the NEIs. However, NMR does not recommend using the results to estimate NEI values at the measure level, but instead reports the results in Appendix A: Additional Analysis of NEI Surveys

9.4.1 Association between NEI Values and Installed Measures: Percentage of Bill Savings

To estimate NEIs at the measure level, NMR assigned a portion of a given NEI value to an individual measure based on the average energy bill savings for which the measure is responsible. This method has also been used for the *2001 California Low Income Public Purpose Test (LIPPT) report for the Reporting Requirements Manual (RRM) Working Group Cost Effectiveness Committee* (TecMarket Works, SERA and Megdal Associates, 2001).

Computation of dollar values for a specific NEI begins with calculating the average portion of bill savings attributed to each measure for an individual NEI. As a first step, the NMR team made a determination whether a measure reasonably contributes to an individual NEI. For example, air sealing, cooling equipment, door, insulation, window, and weatherization measures contribute to changes in outside noise heard inside the home.[154] Next, the team calculated the average percentage of bill savings for each measure that contributes to an NEI. For example, air sealing represents, on average, 8% of the bill savings of measures that contribute to Thermal Comfort, while heating systems represent 39% of those bill savings; combined, all of the measures sum to 100% of the bill savings associated with each NEI.

[154] For the NLI sample, the following measures were not included in this analysis: doors, heating controls, pipe wrap, hot water tank wrap, pool timer and faucet aerators. For the LI sample, the following measures were not included in the analysis: cooling systems, heating and cooling systems, heating and hot water systems, heating controls, AC system sizing, pool timer, and hot water tank wrap. While these measures reasonably contribute to several NEIs, such as comfort or property value, the measures were either not installed in any homes included in this study or savings data at the measure level were not available.

Last, the team multiplied the average percentage of bill savings by the average NEI value to estimate an NEI value for each measure.

As illustrated in Table 9-10 and Table 9-11, the attribution of NEI values to measures by non- and low-income participants reveals that several measures typically account for the bulk of dollar benefits for a particular NEI: heating systems, insulation, weatherization measures,[155] and air sealing. In both the non-low-income and low-income sample, the largest absolute dollar value benefit from installed measures is found in the property value NEI. The non-low-income sample estimated an NEI value of $1,998 and low-income respondents an NEI value of $949. The installed heating systems, insulation and additional air sealing accounts for $1,193 of the property value NEI for non-low-income participants and $618 in value to low-income participants, or 60% and 65% of the total annual property value NEI respectively. Thermal comfort and equipment maintenance also derive a large NEI dollar value from participation in various PA programs. Heating systems, air sealing, insulation, and various weatherization programs have the greatest impact, a benefit to the thermal comfort NEI in both samples. Heating system measures provide the greatest benefit in the equipment maintenance NEI.

Looking more closely at the non-low-income sample (Table 9-10), it is evident that heating systems across the various NEIs provide the largest percentage and annual dollar benefit. Insulation measures provide the second largest additional benefit or roughly 20% of the total NEI value for each NEI contribution. Finally, the weatherization measure, which represents program level rather than measure level savings for National Grid and Berkshire gas program participants, contributes similarly to the NEIs as did insulation. Weatherization contributions range from 19% to 36% of the annual bill savings for the NEIs or $1 to $25 in annual benefit.

The low-income sample exhibits a similar distribution of NEI benefits with some notable exceptions (Table 9-10). For example, air sealing measures generally represent the highest percentage of bill savings, followed by insulation measures. Air sealing represents the largest percentage of bill savings for noise reduction at 55% of the NEI or valued at $16 annually. Another marked difference from non-low-income participants is the contribution of the lighting measure to the property value NEI. Lighting accounts for 24% of the total property value NEI and a $226 one-time benefit for the low-income sample while the non-low-income sample only derives 5% of total benefit from lighting (or $97 in dollar terms).

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[155] The 'Weatherization' measure represents the program level savings for National Grid and Berkshire Gas customers; savings data for the individual measures installed were not available for these programs

Table 9-10. Attribution of NEI Values to Energy Efficiency Measures, Non-low-income Participants, Dollars per Measure[156] (Weighted mean value of all respondents)

	Thermal Comfort		Noise Reduction		Health Impacts		Property Value		Equipment Maintenance		Lighting Quality		Durability of Home	
	% bill savings	$[157]	% bill savings	$	% bill savings	$	% bill savings	$	% bill savings	$	% bill savings	$	% bill savings	$
Sample size, by NEI[158]	*209*	*180*	*147*	*187*	*209*	*190*	*209*	*171*	*139*	*125*	*47*	*41*	*209*	*188*
Air sealing	8%	$10.13	16%	$4.88	8%	$0.32	7%	$135.83	-	-	-	-	8%	$3.95
Appliance (refrigerators and freezers)	-	-	-	-	-	-	<1%	$1.44	-	-	-	-	-	-
Cooling systems	3%	$3.92	9%	$2.83	3%	$0.13	3%	$62.65	6%	$7.54	-	-	3%	$1.54
Duct sealing	<1%	$0.16	-	-	<1%	$0.01	<1%	$2.51	-	-	-	-	<1%	$0.06
Heating & cooling syst.	4%	$5.05	-	-	4%	$0.16	4%	$80.69	8%	$9.42	-	-	4%	$1.98
Heating & hot water sys.	1%	$1.83	-	-	1%	$0.06	1%	$29.17	3%	$3.41	-	-	1%	$0.72
Heating system	39%	$48.63	-	-	39%	$1.56	34%	$678.52	83%	$102.40	-	-	36%	$17.42
Hot water system	-	-	-	-	-	-	4%	$82.56	-	-	-	-	4%	$2.13
Insulation	20%	$25.15	37%	$11.54	20%	$0.80	19%	$378.05	-	-	-	-	20%	$9.82
Lighting	-	-	-	-	-	-	5%	$96.61	-	-	100%	$49.00	-	-
Service to heating or cooling system	<1%	$0.47	-	-	<1%	$0.01	<1%	$7.44	1%	$0.87	-	-	<1%	$0.18
Low flow showerhead	-	-	-	-	-	-	<1%	$0.03	-	-	-	-	-	-
AC system sizing	<1%	$0.19	-	-	<1%	$0.01	<1%	$3.01	<1%	$0.37	-	-	<1%	$0.07
Programmable thermo.	3%	$3.99	-	-	3%	$0.13	3%	$51.49	-	-	-	-	3%	$1.33
Window	1%	$0.68	2%	$0.54	1%	$0.02	<1%	$6.72	-	-	-	-	<1%	$0.21
Weatherization[159]	20%	$25.00	36%	$11.22	20%	$0.79	19%	$381.28	-	-	-	-	19%	$9.57
Total Value	100%	$125	100%	$31	100%	$4	100%	$1,998	100%	$124	100%	$49	100%	$49

[156] For the purpose of attributing NEI values to individual measure, the evaluation team only included measures that reasonably have an impact on an individual NEI. For example, heating, cooling and shell measures are included in the NEI for thermal comfort. A cell with a '-' indicates that the measure does not reasonably impact the individual NEI. The following measures were not included in this analysis: doors, heating controls, pipe wrap, hot water tank wrap, pool timer and faucet aerators. While these measures reasonably contribute to several NEIs, such as comfort or property value, the measures were either not installed in any homes included in this study or savings data at the measure level were not available.

[157] The values in the table are reported as dollars per measure.

[158] The sample size for each individual NEI varies because analysis is limited to those respondents who had specific measures installed.

[159] The 'Weatherization' measure represents the program level savings for National Grid and Berkshire Gas customers; savings data for the individual measures installed were not available for these programs.

Table 9-11. Attribution of NEI Values to Energy Efficiency Measures, Low-income Participants, Dollars per Measure[160]

(Weighted mean value of all respondents)

	Thermal Comfort		Noise Reduction		Health Impacts		Property Value		Equipment Maintenance		Lighting Quality		Durability of Home	
	% bill savings	$[161]	% bill savings	$	% bill savings	$	% bill savings	$	% bill savings	$	% bill savings	$	% bill savings	$
Sample size, by NEI[162]	*211*	*177*	*141*	*191*	*211*	*199*	*213*	*147*	*140*	*122*	*108*	*89*	*212*	*189*
Aerator	-	-	-	-	-	-	3%	$26.61	-	-	-	-	-	-
Air sealing	30%	$30.23	55%	$16.39	30%	$5.69	15%	$144.93	-	-	-	-	30%	$10.61
Appliance (refrigerators and freezers)	-	-	-	-	-	-	3%	$26.61	-	-	-	-	-	-
Door	<1%	$0.01	<1%	$0.01	<1%	$0.01	<1%	$0.04	-	-	-	-	<1%	$0.01
Duct sealing	1%	$0.68	-	-	1%	$0.13	1%	$5.11	-	-	-	-	1%	$0.23
Heating system	28%	$28.01	-	-	28%	$5.27	26%	$249.20	51%	$27.43	-	-	28%	$9.72
Hot water system	-	-	-	-	-	-	<1%	$1.65	-	-	-	-	1%	$0.20
Insulation	25%	$25.38	45%	$13.56	25%	$4.77	24%	$223.63	-	-	-	-	25%	$8.76
Lighting	-	-	-	-	-	-	24%	$226.31	-	-	100%	$56.00	-	-
Pipe wrap	6%	$5.56	-	-	6%	$1.05	1%	$5.00	-	-	-	-	-	-
Service to heating or cooling system	6%	$6.18	-	-	6%	$1.16	<1%	$3.52	49%	$26.57	-	-	11%	$3.77
Low flow showerhead	-	-	-	-	-	-	<1%	$1.72	-	-	-	-	-	-
Programmable thermostat	5%	$4.87	-	-	5%	$0.92	4%	$34.47	-	-	-	-	5%	$1.68
Window	<1%	$0.08	<1%	$0.04	<1%	$0.01	<1%	$0.19	-	-	-	-	<1%	$0.03
Total Value	100%	$101	100%	$30	100%	$19	100%	$949	100%	$54	100%	$56	100%	$35

160 For the purpose of attributing NEI values to individual measure, the evaluation team only included measures that reasonably have an impact on an individual NEI. For example, heating, cooling and shell measures are included in the NEI for thermal comfort. A cell with a '-' indicates that the measure does not reasonably impact the individual NEI. The following measures were not included in the analysis: cooling systems, heating and cooling systems, heating and hot water systems, heating controls, AC system sizing, pool timer, and hot water tank wrap. While these measures reasonably contribute to several NEIs, such as comfort or property value, the measures were either not installed in any homes included in this study or savings data at the measure level were not available.

161 The values in the table are reported as dollars per measure.

162 The sample size for each individual NEI varies because analysis is limited to those respondents having specific measures installed.

9.5 OTHER HEALTH IMPACTS

This evaluation attempted an alternative method of estimating participant perspective health benefits—via reductions in sick days attributed to the energy efficiency retrofits, as well as societal benefits via reduced medical costs flowing from reduced incidence of heat stress, hypothermia, and asthma. Because of the extremely small number of respondents reporting program induced changes in health, NMR does not recommend using results from this method. Findings are reported in Appendix A.6 and A.7. NMR did not find convincing evidence of major health effects in terms of asthma, heat stress, and hypothermia. However, because of the potential health impacts of energy efficiency, NMR recommends reviewing the results of the current evaluation of the national WAP when the findings become available. Values for participant and societal health benefits might be derived from these findings once the study is complete (Ternes et al., 2007).

9.6 DEMOGRAPHICS

Respondents were asked to provide the number of household members in three different age groups. Overall, the LI respondents' households are more likely to be elderly, with nearly half of respondents (49%) reporting having a member of the household that is 65 years or older compared to 29% of NLI households. Also, the average NLI household is slightly larger than the LI household, with an average of 2.8 total household members compared to 2.3 for LI households. The majority of both the LI and the NLI respondents (69% and 63% respectively) had no household members of 18 years old or younger, but, among those households with children, most had one to three children living in the home (26% LI and 35% NLI), but only low-income households had more than three children living in the home (3%). More than one-third (37%) of the LI respondents, but only one-fifth of the NLI respondents, had no household members between the ages of 19 and 64, while over one-half (54%) of the LI respondents and three-quarters of the NLI respondents reported between one and three household members in this age group.

Table 9-12. Ages of Household Members

	18 years or younger		19 to 64 years		65 or older		Total number of household members	
	Non-LI	LI	Non-LI	LI	Non-LI	LI	Non-LI	LI
Sample size	*209*	*210*	*209*	210	*209*	*210*	*209*	*210*
Zero	63%	69%	20%	37%	70%	49%	0%	0%
One to three	35%	26%	75%	54%	29%	49%	68%	77%
Four to six	0%	3%	4%	3%	0%	0%	30%	20%
DK/Refused	1%	2%	1%	2%	1%	2%	2%	3%
Mean	0.6	0 .6	1.7	1.1	0.5	0.6	2.8	2.3

Although most respondents in both samples own their homes, a sizeable proportion of LI respondents rent their home (17%).

Table 9-13. Home Ownership

	Non-low-income	Low-income
Sample size	*209*	*213*
Own home	99%	83%
Rent home	1%	17%

Over three-quarters (77%) of the LI respondents and nearly nine out of ten NLI respondents (88%) live in detached, single-family homes. Less than 5% of each group lives in larger buildings with five or more units.

Table 9-14. Type of Building

	Non-low-income	Low-income
Sample size	*209*	*213*
Detached single-family home	88%	77%
Townhouse/duplex	5%	8%
Two-to-four family building	5%	9%
Part of a building with five or more units	1%	4%
Mobile home	0%	1%
DK/Refused	0%	1%

NLI respondents are more likely to live in larger homes, with close to one-half (47%) of the NLI respondents living in homes 2,000 square feet or larger, whereas just over one-quarter (27%) of LI respondents live in homes this size. The most common home size for both groups was between 1,500 and 1,999 square feet, with close to two out of five in the LI group, and about three out of ten in the NLI group, reporting that their home was in this range. About one-quarter of respondents (26% of the LI respondents and 23% of the NLI respondents) lived in homes of fewer than 1,500 square feet.

Table 9-15. Size of Home*

Square Feet	Non-low-income	Low-income
Sample size	*209*	*210*
Less than 1,500	23%	26%
1,500 – 1,999	29%	37%
2,000 – 2,499	25%	17%
2,500 – 2,999	11%	6%
3,000 – 4,000	6%	3%
4,000 – 4,999	2%	0%
5,000 or more	1%	1%
Don't know/refused	2%	10%

*Respondents who said "don't know" or "refused" to this question were asked the number of rooms in their home. Number of rooms was then converted to square feet for these respondents using the assumption that the average room is 300 square feet.

The NLI respondents reported higher levels of education than did the LI respondents. Whereas 41% of LI respondents had no more than a high school education, only 12% NLI respondents attained no more than a high school diploma. Also, only 34% of the LI respondents had completed college or graduate/professional school, while nearly three-quarters (73%) of the NLI respondents who had done so.

The right-most column shows the educational attainment levels for the overall MA population ages 25 years and older, as collected through the American Community Survey and reported by the US Census Bureau.[163] In terms of educational attainment, the LI respondents appear to be more similar to the MA population as a whole than might be expected, given their low-income status. Compared to the MA population, the LI group is slightly *less* likely to have a less-than-high-school education (10% for the LI group and 12% for MA), somewhat *more* likely to have graduated from high school (31% and 27% for the LI group and MA respectively), and slightly *more* likely to have some college but no degree (18% and 16%). However, they were also slightly *less* likely to be a college graduate (19% versus 22%) or to have a graduate or professional degree (13% versus 16%).

[163] United States Bureau of the Census. 2009. *2005-2009 American Community Survey 5-Year Estimates.* http://factfinder.census.gov/servlet/ADPTable?_bm=y&-geo_id=04000US25&-qr_name=ACS_2009_5YR_G00_DP5YR2&-ds_name=ACS_2009_5YR_G00_&-_lang=en&-_sse=on

Table 9-16. Level of Education

Degree attained	Non-low-income	Low-income	MA (US Census)*
Sample size	*210*	*209*	*4,416,135*
Less than high school	1%	10%	12%
High school graduate (includes GED)	11%	31%	27%
Technical or trade school graduate; Associates Degree	3%	6%	16%**
Some college, no degree	13%	18%	16%
College graduate	32%	19%	22%
Some graduate school	5%	2%	***
Graduate or professional degree	35%	13%	16%
Don't know/refused	1%	1%	_

*Education levels for the state of Massachusetts as estimated by the United States Bureau of the Census's 2005 to 2009 American Community Survey. http://factfinder.census.gov/servlet/ADPTable?_bm=y&-geo_id=04000US25&-qr_name=ACS_2009_5YR_G00_DP5YR2&-ds_name=ACS_2009_5YR_G00_&-_lang=en&-_sse=on
** Reported as Percent with Associate's Degree in The American Community Survey
**The ACS did not include "some gradual school" as an educational category.
***Percents for the educational categories above are based only on those who gave a valid response, and therefore sum to 100%. The percent who said "don't know" or "refuse" are shown in this row.

Overall, LI respondents appear to be older than NLI respondents. For LI respondents, the most frequently reported age range was sixty-five years and older (45%); for the NLI respondents, the most frequently reported range was fifty-five to sixty-five years. In addition, NLI respondents were more likely to be younger, with over one-quarter (28%) of NLI respondents between 25 and 44 years old while only 15% of the LI respondents who were of this age range.

Both the NLI and LI groups are also older than the MA population as a whole, particularly for the LI population. The LI population has much smaller proportions of people under 35 and larger proportions of people over 65. The NLI has a smaller proportion of people under the age of 35 and much higher proportion of people age 55 to 64.

Table 9-17. Age of Respondent

Age range	Non-low-income	Low-income	MA (US Census)*
Sample size	*209*	*210*	*4,857,420***
18 to 24	0%	0%	9%***
25 to 34	8%	4%	17%
35 to 44	20%	11%	20%
45 to 54	19%	20%	21%
55 to 64	30%	18%	15%
65 or over	23%	45%	18%
Don't know/refused ****	1%	1%	__

* Age for the population of the state Massachusetts as estimated by the United States Bureau of the Census's 2005 to 2009 American Community Survey. http://factfinder.census.gov/servlet/ADPTable?_bm=y&-geo_id=04000US25&-qr_name=ACS_2009_5YR_G00_DP5YR5&-ds_name=&-_lang=en&-redoLog=false
**Population of the state of Massachusetts limited to those 20 years or older for purposes of comparison to survey respondents
***Reflects the percent of population that is 20-24.
****Percents for the age categories above are based only on those who gave a valid response, and therefore sum to 100%. The percent who said "don't know" or "refuse" are shown in this row.

The results of a question asking about household income confirm that the NLI respondents have higher income levels, overall, than the LI respondents. Whereas nearly one-half (47%) of the LI respondents reported incomes of $25,000 or less, only four percent of the NLI respondents did so. In addition, less than ten percent (8%) of the LI respondents, versus nearly one-half (47%) of the LI respondents, reported incomes of $75,000 or higher.

The LI group also has lower income levels than the population of Massachusetts as a whole: More than one-half (55%) of the LI respondents who gave valid responses reported household incomes of $25,000 or less, versus only 20% who reported incomes this low in the MA population. Also, while only one in ten LI respondents reported household incomes of $75,000 or more, more than four times that many (43%) reported such incomes in the MA population

Table 9-18. Household Income

Household income	Non-low-income	Low-income	MA (US Census)*
Sample size	*209*	*210*	*2,465,654*
$14,999 or less	1%	29%	12%
$15,000 to $25,000	4%	26%	8%
$25,000 to $34,999	7%	13%	8%
$35,000 to $49,999	10%	14%	11%
$50,000 to $74,999	22%	7%	17%
$75,000 to $99,999	24%	5%	14%
$100,000 to $149,999	20%	4%	16%
$150,000 or more	13%	1%	13%
Don't know/refused**	18%	15%	--

* Income levels for the state of Massachusetts as estimated by the United States Bureau of the Census's 2005 to 2009 American Community Survey. http://factfinder.census.gov/servlet/ADPTable?_bm=y&-geo_id=04000US25&-qr_name=ACS_2009_5YR_G00_DP5YR3&-ds_name=ACS_2009_5YR_G00_&-_lang=en&-redoLog=false&-_sse=on

**Percents for the income categories above are based only on those who gave a valid response, and therefore sum to 100%. The percent who said "don't know" or "refuse" are shown in this row.

Two-thirds of the LI respondents (67%) were women, whereas the majority of the NLI respondents (59%) were men. This is consistent with broader demographic patterns of households headed by women being more likely to be considered low-income than households headed by males.

Table 9-19. Gender

	Non-low-income	Low-income
Sample size	*209*	*210*
Female	41%	67%
Male	59%	33%

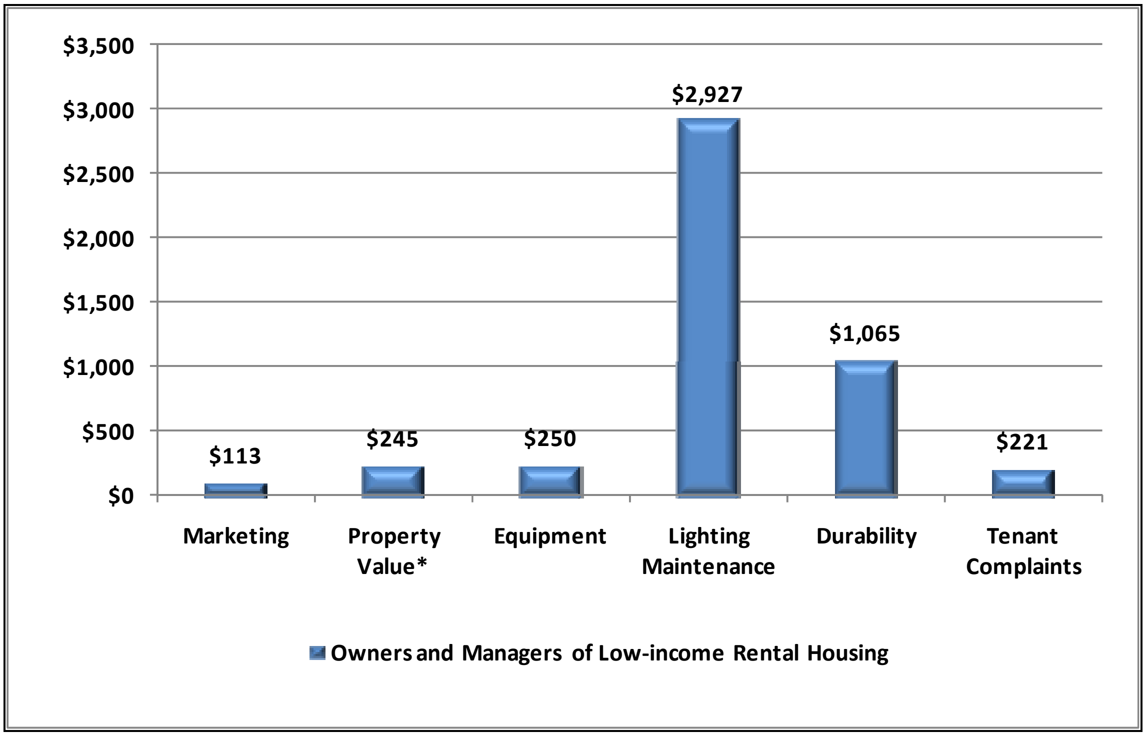
10. PARTICIPANT NEIs ESTIMATED FROM SURVEYS—OWNERS OF LOW-INCOME RENTAL HOUSING

In addition to surveying occupants of homes retrofitted through the PAs' programs, we surveyed 21 owners and managers of low-income rental housing concerning 27 low-income rental facilities (containing more than 7,000 housing units), via computer-assisted telephone interviewing. Compared to the occupant survey, smaller percentages of owners and managers of low-income rental housing believe the retrofits provide NEIs. However, some of the NEIs, particularly reduced maintenance costs associated with lighting and increased durability of the property, provide substantial benefits.

The NEI most frequently regarded as positive was *lighting maintenance*, with 80% of respondents reporting reduced maintenance for the new lighting that was installed. In addition, over two out of five respondents (42%) said that the improvements had resulted in increased durability of their buildings. Less than one-third of respondents considered the other NEIs to be positive; approximately one-third (31%) reported fewer tenant complaints, approximately one-quarter (23%) reported an expected increase in property value, one-sixth (15%) reported increased marketability, but none reported a positive impact on tenant turnover.

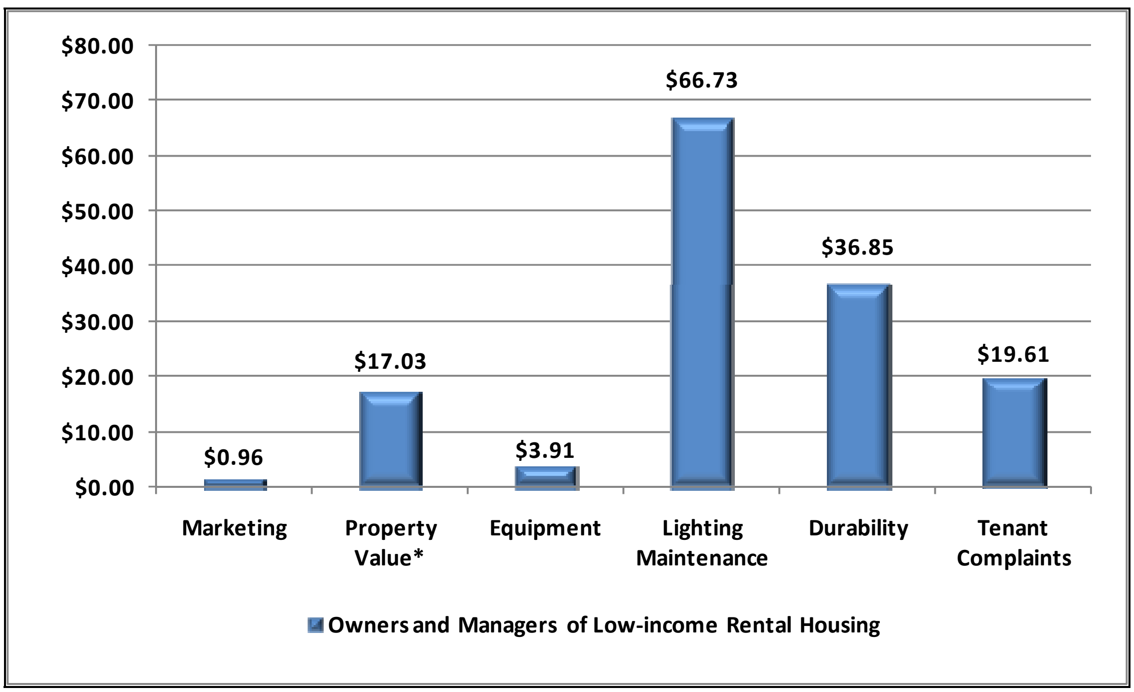
NEI values are reported on a per building basis in Figure 10-1 and on a per housing unit basis in Figure 10-2. The most highly valued NEI by the owners and managers of low-income rental housing was reduced costs associated with lighting maintenance with a mean annual value of $2,927 per building and $66.73 per housing unit, followed by increased durability of their building or property, with a mean annual value of $1,065 per building and $36.85 per housing unit. Improved marketing, equipment maintenance, property value (one-time benefit) and tenant complaints were all valued at $250 a year or less per building and under $20 per unit. One NEI, reduced tenant turnover, was valued at $0 for all respondents.

Figure 10-1. Owners and Managers of Low-income Rental Housing Valuation of NEIs. Per Building



*Property Value is a one-time benefit while the remaining NEIs are annual benefits.

Figure 10-2. Owners and Managers of Low-income Rental Housing Valuation of NEIs. Per Unit



*Property Value is a one-time benefit while the remaining NEIs are annual benefits

10.1 PERCEPTION OF EFFICIENCY IMPROVEMENTS AND NEIS

We asked owners and managers of multifamily low-income housing whether they thought the energy efficiency of their property had changed since the measures were installed. More than eight out of ten (82%) said it was more efficient than before, while one out of six (15%) said the efficiency had not changed (Table 10-1). No owners and managers thought the building was less efficient.

Table 10-1. Owners' Perception of Building's Energy Efficiency after Improvements

	Owners & Managers, LI Rental Housing
Sample size	*27*
More efficient	82%
Less efficient	0%
Same efficiency	15%
DK/Refused	4%

In response to a question asking whether they had noticed any changes in their energy bills since the measures were installed, nearly four out of ten building owners (37%) reported that the bills had decreased, while approximately one-quarter (26%) said the bills had not changed (Table 10-2). Nearly four out of ten (37%) did not know whether the bills had changed; presumably, many of these owners do not see the bills because the tenants pay them directly.

Table 10-2. Energy Bill Changes Noticed by Owners

	Owners & Managers, LI Rental Housing
Sample size	*27*
Lower bills	37%
Higher bills	0%
No change in bills	26%
Don't know	37%

Respondents whose tenants paid their energy bills directly (nine owners or 33% of all owners) were also asked whether their tenants had told them about any changes in their bills (Table 10-3). Of the five respondents whose tenants had mentioned the bills, four said that the bills were lower since the measures were installed.

Table 10-3. Energy Bill Changes Mentioned by Tenants to Owners

(Base: Owners whose tenants pay their own energy bills)

	Number of Owners & Managers, LI Rental Housing
Sample size	*9*
Lower bills	4
Higher bills	0
No change in bills	1
Tenants have not mentioned bills	4

Respondents were then asked about any comments their tenants might have made to them about the impacts of the measures that were installed. Over one-half (52%) said that their tenants mentioned that their bills had decreased (Table 10-4). About one out of ten respondents (11%) reported that their tenants were pleased with the new refrigerators that were installed. According to the landlords and managers, other positive impacts mentioned by tenants include thermal comfort, longer-lasting bulbs, improved equipment, and less equipment noise. Negative impacts mentioned by tenants include decreased reliability of equipment (11%), too much time for the lights to come on (4%), and that the lights were either too bright or too dim (4%).

Table 10-4. Tenants' Comments to Owners about Impacts of Improvements

NEI	
Sample size	*27*
Lower energy bills	52%
Increased reliability of equipment	11%
Pleased with new refrigerators	11%
More comfortable temperature	7%
Bulbs last longer	7%
Improved lighting	4%
Less equipment noise	4%
Takes too long for lights to come on	4%
Noisier equipment	4%
Lighting too bright or too dim	4%
Other comments	4%
No comments	0%

The owners were asked whether they had personally noticed any positive or negative impacts of the installments, other than changes in energy bills. Nineteen percent of owners mentioned that the lights were brighter and 11% said that that the lights required less maintenance (Table 10-5).[164] Other positive impacts mentioned by respondents include that their tenants were made more aware of energy efficiency (7%), that their tenants appreciate the new refrigerators (7%), that the new equipment or appliances were more reliable than the previous ones (4%), and that the temperature of the building was more comfortable than before (4%).

Table 10-5. Positive Impacts Noticed by Respondents

NEI	
Sample size	*27*
Brighter lights	19%
Less lighting maintenance	11%
Tenants more aware of energy efficiency	7%
Tenants appreciate new refrigerators	7%
Improved reliability of equipment/appliances	4%
Thermal comfort	4%
Other benefits	4%
Don't know	22%
No benefits noticed	52%

When asked about any negative impacts of the measures that were installed, about three out of four respondents (74%) said that they had not noticed any negative impacts (Table 10-6). Approximately two out of ten (19%) mentioned increased lighting maintenance, and less than one out of ten (7%) mentioned that there was mercury in the light bulbs.

Table 10-6. Negative Impacts Noticed by Respondents

NEI	
Sample size	*27*
Increased maintenance for lighting*	19%
Mercury in bulbs	7%
Other negative impacts	7%
Don't know	4%
No negative impacts	74%

*Increased maintenance includes cost of replacement bulbs and difficulty finding them.

[164] The lighting maintenance benefit likely applies to lights in common areas and to units in which the landlord is responsible for replacing light bulbs.

10.2 PERCEPTION OF NEIS

Before we asked owners and managers of multi-family buildings to estimate a monetary value for the NEIs they experienced in their buildings, we inquired whether they had noticed the impact since the efficiency improvements, as well as whether the impact was positive or negative. For example, for *marketability*, we asked respondents whether their rental units were more marketable, less marketable, or the same level of marketability as before the improvements. The NEI most frequently regarded as positive was *lighting maintenance*, with 80% of respondents reporting reduced maintenance for the new lighting that was installed (Table 10-7). In addition, over two out of five respondents (42%) said that the improvements had resulted in increased durability of their buildings. Less than one-third of respondents considered the other NEIs to be positive; approximately one-third (31%) reported fewer tenant complaints, approximately one-quarter (23%) reported an expected increase in property value, and one-sixth (15%) reported increased marketability. No respondents said that tenant turnover had changed since the improvements. Regarding negative impacts, slightly more than one out of ten respondents (12%) said that tenant complaints had increased, and a small percent (4%) said that the building had become less durable. Six respondents reported an additional impact not discussed previously in the survey. Of these, five reported a positive impact and one reported a negative impact. Specifically, these additional NEIs included helping the “bottom line” due to lower energy bills, increasing tenants’ awareness of energy efficiency, increased safety, respect from the community, and the bulbs not lasting long enough.

When asked whether the total impact of the NEIs discussed in the survey (not including any change in property value) was positive, negative, or had no effect, about four out of five respondents (81%) said that the total impact was positive, and the remaining respondents (19%) said that the total impact was neither positive nor negative.

Table 10-7. Respondents who Say Building Provides NEI

NEI	*Sample size*	Positive	Negative	No difference
Marketability of rental units	*26*	15%	0%	81%
Tenant turnover	*26*	0%	0%	96%
Property value	*26*	23%	0%	77%
Equipment maintenance	*22*	20%	0%	60%
Lighting maintenance	*15*	80%	0%	13%
Durability of home	*26*	42%	4%	54%
Tenant complaints	*26*	31%	12%	58%
Other NEI	*6*	83%	17%	--
Overall impact of NEIs*	*26*	81%	0%	19%

*Does not include property value.

10.2.1 NEI Value Calculation

Survey respondents were asked to estimate an annual monetary value for the NEIs they experience in their buildings.[165] The survey used a *relative valuation* method, asking respondents to value NEIs as a percentage of energy savings.[166] Each respondent was told an estimate of the annual energy bill savings for the retrofitted building based on the measures installed in the building.

The survey first asked the owners and managers of low-income rental housing if they believed their building had a particular NEI, then whether it was positive or negative. Taking the marketability NEI as an example, respondents were asked if they believed that the energy efficiency improvements had made their building more marketable than before, less marketable, or no different in the marketability. Those who believed their property or units in their building were more marketable were asked to place a value per year for the ease in marketing and renting either in dollars or as a percentage of energy savings. Those who believed their property or units in their building were less marketable were asked to place a value per year for the difficulty in marketing and renting either in dollars or as a percentage of energy savings. NEI values for those who believed there was no difference in the marketability of their property or units in their building from before the improvements were set to zero.

Finally, those respondents who were unable to place a value on the NEIs were further prompted with the following questions:

> "In terms of energy bill savings, which of the following would you say is closest to the value of having your property easier to market and rent, about a one fourth of energy bill savings, about a half of energy bill savings, about three-fourths of energy bill savings, about equal to energy bill savings, or more than energy bill savings? If the latter, how much more?"

The NEIs for respondents who still could not provide an answer are treated as missing in the calculation of average NEI values.

After providing values for the individual NEIs, respondents were asked to assign an annual value to the total impact of all the NEIs together (except for any changes in property value). We scaled each respondent's individual NEI values in proportion to the respondent's valuation of the total impact of all the NEIs in order to account for any overlap in NEIs or over-estimation of the individual NEIs. This scaling of individual NEI values occurred in the following way: Each NEI value was represented as a proportion of the sum of that respondent's individual NEI values. This proportion was then applied to the respondent's reported valuation of the total impact of all the NEIs, yielding the scaled value for each NEI. As with the occupant NEIs, the scaling factor is specific to each respondent and varies widely throughout the sample. For example, if a respondent said their total NEI value was $1,000 while reporting that reduced costs associated with lighting maintenance was worth $1,000 and the value of increased durability of their building was worth $500, the scaled NEI values for the respondent would be $667 for reduced costs for lighting maintenance and $333 for increased durability. A more detailed discussion of the scaling of NEI values can be found in section 9.3. NEI Value Calculation and in Appendix A.2 (Scaling of NEI Values).

It should be noted that the individual NEI values do not sum to equal the mean "Sum of NEIs" value presented in the table because the individual NEIs were based on respondents who expressed a value for a given NEI whereas the Sum of NEIs was estimated for all respondents. For example, lighting maintenance was only estimated for respondents who had installed energy efficient lighting through the

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[165] The NEI of property value as asked in terms of a one-time change in value

[166] A discussion of the various methods used to estimate NEIs in the literature is found in the section 5.1: Methods Used to Measure Participant NEIs.

PAs' programs and estimated a value for reduced maintenance costs (12 buildings).Therefore, the number of NEIs that contribute to the Sum of NEIs varies from respondent to respondent.

NEI values of owners and managers of low-income rental housing are reported on a per building basis in Table 10-8 and on a per housing unit basis in Table 10-9. It should be noted that when the NEI values are converted from a per building to a per housing unit basis, the number of housing units used to calculate the average varies from NEI to NEI and is based on the number of housing units reported by the respondents who experienced the individual NEI. For example, the NEI of marketing is based on housing units for 21 respondents while the NEI of lighting maintenance is based on housing units for 12 respondents.

Two mean values are presented for each NEI—the first reflects reported NEI values (shown in dollars as well as in terms of mean percent of bill savings), while the second reflects respondents' reported values scaled in proportion to the total NEI value provided by respondents. Table 10-8 reports upper and lower bounds of values, calculated at a 90% confidence interval; the central estimate may be considered for planning purposes.

The most highly valued NEI by the owners and managers of low-income rental housing was reduced costs associated with lighting maintenance with a mean annual value of $2,927 per building and $66.73 per housing unit, followed by increased durability of their building or property, with a mean annual value of $1,065 per building and $36.85 per housing unit. Improved marketing, equipment maintenance, property value (one-time benefit), and tenant complaints were all valued at $250 a year or less per building and under $20 per unit. One NEI, reduced tenant turnover, was valued at $0 for all respondents. In addition, five respondents provided values for an additional impact not discussed previously in the survey. These other NEIs included helping the "bottom line" because of lower energy bills, increasing tenants' awareness of energy efficiency, increased safety, and respect from the community; these other NEIs had a mean annual value $3,439.

Table 10-8. Mean NEI Values from Survey[1]: Owners and Managers of Low-income Rental Housing, Per Building

Value per year		Marketing Value	Marketing Scaled value	Equipment maintenance[3] Value	Equipment maintenance[3] Scaled value	Lighting Maintenance[4] Value	Lighting Maintenance[4] Scaled value	Property Value[2] Value	Durability Value	Durability Scaled Value	Tenant Complaints Value	Tenant Complaints Scaled value	Other Value	Other Scaled value	Sum of NEIs[5] Total**	Total Scaled[6] NEI Value Total***
Sample size		23		4		12		24	24		22		5		23	
Overall	Dollars	$104	$113	$500	$250	$2,997	$2,927	$245	$913	$1,065	$344	$221	$3,464	$3,439	$3,741	$3,280
	% Bill Savings	8%	8%	3%	2%	36%	28%	NA[7]	11%	10%	6%	4%	29%	18%	31%	36%
Lower Bound NEI Value	Dollars	$-16	$-19	$-342	$-171	$1,618	$1,144	$32	$225	$257	$-145	$-27	$-1,976	$-2,002	$1,792	$1,533
	% Bill Savings	-1%	-1%	-2%	-1%	18%	12%	NA	4%	3%	-1%	1%	-12%	8%	20%	24%
Upper Bound NEI Value	Dollars	$224	$244	$1,342	$671	$4,376	$4,710	$459	$1,601	$1,873	$833	$470	$8,904	$8,882	$5,689	$5,027
	% Bill Savings	16%	17%	9%	5%	54%	44%	NA	19%	17%	14%	7%	71%	29%	43%	49%

[1]The table does not report values for "reduced tenant turnover." All respondents valued reduced tenant turnover at $0.

[2]Property Value was not scaled because, as a one-time NEI value, it was excluded from the survey question about total annual value of NEIs.

[3]Equipment maintenance was only asked of respondents who installed heating or cooling equipment (programmable thermostats).

[4]Lighting was only asked of respondents who installed energy efficient lighting.

[5] Sum of NEIs is equal to the sum of the unscaled values of the individual annual NEIs (i.e., excluding property value).

[6] Total Scaled NEI Value is the value provided by respondents when asked for the total value of all NEIs, excluding property value.

[7]Percent of annual bill savings is not shown for Property Value because it is a one-time impact.

Table 10-9. Mean NEI Values from Survey[1]: Owners and Managers of Low-income Rental Housing, Per Housing Unit

	Value per year	Marketing		Equipment maintenance[3]		Lighting Maintenance[4]		Property Value [2]	Durability		Tenant Complaints		Other		Sum of NEIs[5]	Total Scaled[6] NEI Value
		Value	Scaled value	Value	Scaled value	Value	Scaled value	Value	Total	Total	Value	Scaled value	Value	Scaled value	Total	Total
Sample size*		21		4		12		22	22		20		3		23	
Overall	Dollars	$0.90	$0.96	$7.81	$3.91	$97.56	$66.73	$17.03	$25.38	$36.85	$31.20	$19.61	$84.30	$86.61	$95.51	$94.28
	% Bill Savings	0.70%	0.08%	0.05%	0.03%	1.71%	1.21%	0.36%	0.42%	0.58%	0.20%	0.19%	0.10%	0.16%	1.04%	1.36%

[1]The table does not report values for "reduced tenant turnover." All respondents valued reduced tenant turnover at $0.

[2]Property Value was not scaled because, as a one-time NEI value, it was excluded from the survey question about total annual value of NEIs.

[3]Equipment maintenance was only asked of respondents who installed heating or cooling equipment (programmable thermostats).

[4]Lighting was only asked of respondents who installed energy efficient lighting.

[5] Sum of NEIs is equal to the sum of the unscaled values of the individual annual NEIs (i.e., excluding property value).

[6] Total Scaled NEI Value is the value provided by respondents when asked for the total value of all NEIs, excluding property value.

[7]Percent of annual bill savings is not shown for Property Value because it is a one-time impact.

10.2.2 Association between NEI Values and Installed Measures

As with the occupant NEIs, to estimate NEIs at the measure level, NMR assigned a portion of a given NEI value to an individual measure based on the average energy bill savings for which the measure is responsible. This method has also been used for the *2001 California Low Income Public Purpose Test (LIPPT) report for the Reporting Requirements Manual (RRM) Working Group Cost Effectiveness Committee* (TecMarket Works, SERA, and Megdal Associates, 2001). The team also ran a number of regression models in an attempt to quantify the relationship between each NEI category and specific measures installed by the owners and managers of low-income rental housing, but we were unable to find any significant relationships between measures and NEIs.

Table 10-10 reports the attribution of NEIs to individual measures for owners and managers of low-income rental housing on a per building basis and Table 10-11 reports the NEI values on a per housing unit basis. Compared to the occupant sample, the sample of owners and managers of multi-family rental housing had fewer types of measures installed: refrigerators and freezers, hot water systems and other water saving measures, lighting, programmable thermostats, and air sealing. Not surprisingly, with fewer types of measures installed, the total value of NEIs to owners and managers was a much smaller percentage of bill savings (36%) than for occupants—62% for low-income and 57% for others. As illustrated in the tables, energy efficient lighting has the greatest percentage contribution to the NEIs for owners and managers, at 46% of estimated energy savings and in turn 46% of each individual NEI (except for reduced lighting maintenance). Refrigerators and freezers provide the second largest percentage contribution to multi-family owner NEIs, at 35% of estimated bill savings.

Table 10-10. Attribution of NEI Values to Energy Efficiency Measures, Multi Family Owners, Per Building

	Marketing		Reduced Tenant Turnover		Increased Property Value		Equipment Maintenance and Reliability		Reduced Lighting Maintenance		Durability		Tenant Complaints	
	% bill savings	$	% bill savings	$	% bill savings	$	% bill savings	$	% bill savings	$	% bill savings	$	% bill savings	$
Sample size	*27*	*23*	*27*	*25*	*27*	*24*	*0*	*4*	*19*	*5*	*27*	*23*	*27*	*22*
Refrigerators or Freezers	35%	$40	35%	$0	35%	$86	-	-	-	-	35%	$373	35%	$78
Hot Water System or Water Saving Measures	1%	$1	1%	$0	1%	$2	-	-	-	-	1%	$11	1%	$2
Energy Efficient Lighting	46%	$52	46%	$0	46%	$113	-	-	100%	$2,927	46%	$490	46%	$102
Thermostats	11%	$12	11%	$0	11%	$27	100%	$250	-	-	11%	$117	11%	$13
Air Sealing	7%	$8	7%	$0	7%	$17	-	-	-	-	7%	$75	7%	$16
Total Value	100%	$113	100%	$0	100%	$245	100%	$250	100%	$2,927	100%	$1,065	100%	$221

Table 10-11. Attribution of NEI Values to Energy Efficiency Measures, Multi Family Owners, Per Housing Unit

	Marketing		Reduced Tenant Turnover		Increased Property Value		Equipment Maintenance and Reliability		Reduced Lighting Maintenance		Durability		Tenant Complaints	
	% bill savings	$	% bill savings	$	% bill savings	$	% bill savings	$	% bill savings	$	% bill savings	$	% bill savings	$
Sample size	*27*	*21*	*27*	*25*	*27*	*22*	*0*	*4*	*19*	*12*	*27*	*22*	*27*	*20*
Refrigerators or Freezers	35%	$0.34	35%	$0	35%	$5.96	-	-	-	-	35%	$12.90	35%	$6.86
Hot Water System or Water Saving Measures	1%	$0.01	1%	$0	1%	$0.17	-	-	-	-	1%	$0.37	1%	$0.20
Energy Efficient Lighting	46%	$0.44	46%	$0	46%	$7.83	-	-	100%	$66.73	46%	$16.95	46%	$9.02
Thermostats	11%	$0.11	11%	$0	11%	$1.87	100%	$3.91	-	-	11%	$4.05	11%	$2.16
Air Sealing	7%	$0.07	7%	$0	7%	$1.19	-	-	-	-	7%	$2.58	7%	$1.37
Total Value	100%	$0.96	100%	$0	100%	$17.03	100%	$3.91	100%	$66.73	100%	$36.85	100%	$19.61

10.2.3 Multi-family Firmographics

Respondents were asked how many units were in the building for which they estimated the NEIs. Out of the twenty-five buildings for which the number of units were known, more than one-half (14 buildings) had fifty units or fewer, while five were large buildings with 100 or more units.

Table 10-12. Number of Units in Building for which Respondent Estimated NEIs

Number of units	Number of Buildings	Percentage of Buildings
20 or less	7	26%
21 to 50	7	26%
51 to 99	6	22%
100 or more	5	19%
Don't know	2	7%
Total	27	100%
Mean # of units	57	
Median # of units	40	

Respondents were also asked how many buildings they own and manage, how many they manage but do not own, and how many they own but do not manage. Of the respondents who were able to report on the number of buildings owned or managed, all respondents own or manage multiple buildings, ranging from two to 130 buildings. The right-most column shows that the majority of respondents (53%) own and/or manage between one and ten buildings.

Table 10-13. Number of Buildings Respondents Own and/or Manage

Number of Buildings	Own and Manage	Manage, but do not own	Own, but do not manage	Total (Own and/or Manage)
0	14%	38%	62%	0%
1 to 5	19%	24%	9%	24%
6 to 10	29%	0%	0%	29%
11 to 20	10%	0%	0%	14%
More than 20	10%	10%	0%	14%
Don't know	19%	29%	29%	19%
Total	100%	100%	100%	100%
Mean # of buildings	9	10	.3	19

Table 10-14 shows the number of units respondents own and/or manage. Overall, respondents own or manage large numbers of low-income rental units; the median number of units owned or managed is 670 (two respondents own or manage tens of thousands of units, so the median is a more meaningful measure of central tendency for the sample).

Table 10-14. Number of Units Respondents Own and/or Manage

Number of Units	Own and Manage	Manage, but do not own	Own, but do not manage	Total Units (Own and/or manage)
0	14%	38%	62%	0%
1 to 99	10%	19%	5%	14%
100 to 499	14%	5%	0%	19%
500 to 999	19%	10%	5%	14%
1,000 to 9,999	19%	5%	0%	33%
10,000 or more	10%	0%	0%	10%
Don't know	14%	24%	29%	10%
Total	100%	100%	100%	100%
Mean # of units	7,438	443	35	7,447
Median # units	508	11	0	670

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APPENDIX A: ADDITIONAL ANALYSIS OF NEI SURVEYS

This appendix provides additional analysis of the surveys of low-income and non-low-income program participants, providing supplemental analysis on the strata within each population.

A.1 PERCEPTION OF EFFICIENCY IMPROVEMENTS AND NEIS

Respondents were asked whether they thought their home, after the improvements, was more energy-efficient, less energy-efficient, or the same level of efficiency as before the improvements. Within the LI respondents, respondents who had only shell measures installed (i.e., the shell group) were slightly more likely than those who had heating and cooling measures installed (i.e., the heating & cooling group) to say that the home's energy efficiency improved (78% versus 74%). Surprisingly, respondents in the shell plus heating & cooling group were the least likely to regard their home as more efficient than before, with approximately seven out of ten (71%) of respondents in this group saying their home was more efficient; this group was also the most likely to say that the efficiency had not changed, with one out of four respondents with both types of measure giving this response (versus 14% and 17% in the shell group and the heating & cooling groups, respectively).

The NLI respondents' responses were less surprising. While slightly fewer than nine out of ten respondents in the shell group and the heating & cooling group indicated that their home's efficiency had improved (89% and 87%, respectively), slightly more than nine out of ten (93%) among those who had both types of installments gave this indication. This latter group was also somewhat less likely than the others to say that the efficiency of their home had not changed (4%, versus 11% and 6% for the shell group and heating & cooling groups, respectively.

Table A-1. Perception of Energy-Efficiency after Improvements

	Low-Income				Non Low-Income			
Efficiency	Shell	Heating & Cooling	Shell Plus Heating & Cooling	Total	Shell	Heating & Cooling	Shell Plus Heating & Cooling	Total
Sample size	*72*	*72*	*69*	*213*	*70*	*68*	*71*	*209*
More efficient	78%	74%	71%	74%	89%	87%	93%	90%
Less efficient	1%	3%	3%	2%	0%	0%	0%	0%
Same efficiency	14%	17%	25%	18%	11%	6%	4%	7%
DK/Refused	7%	7%	1%	5%	0%	7%	3%	3%

For each NEI, respondents reported whether it was a positive impact, a negative impact, or had no effect. The results are shown in Table A-2 (for LI respondents) and Table A-3 (for NLI respondents) by the type of measures they had installed.

Among the LI respondents, those who had shell measures installed (i.e., the shell group) were somewhat more likely than the heating & cooling group to give positive ratings to several of the NEIs, including thermal comfort (shell group: 68%; heating & cooling group: 58%), noise (shell: 29%; heating & cooling: 15%), health impacts (shell: 21%; heating & cooling: 13%), and property value (shell: 71%; heating & cooling: 44%). However, while about two out of three respondents (66%) in the heating & cooling group regarded the lighting quality and lifetime as a positive impact, fewer than three out of five (57%) in the shell group did so. Approximately four out of five in both groups (shell: 82%; heating & cooling: 78%) said that the overall impact of the NEIs (not including property value) was positive. Respondents who had both shell measures and heating & cooling measures installed were somewhat more likely than the other groups to report that thermal comfort, noise, health, and lighting were positive impacts. The proportion of the shell plus heating & cooling group who said that the overall impact of the NEIs was positive (81%) was similar to that in the other two groups.

Among the NLI respondents, the shell group was again somewhat more likely than the heating & cooling group to say that several of the NEIs were positive, including thermal comfort (shell: 83%; heating & cooling: 65%), noise (shell: 34%; heating & cooling: 19%), and lighting quality and lifetime (shell: 55%; heating & cooling: 46%). However the shell group was somewhat less likely than the heating & cooling group to say that property value and durability of the home were positive impacts. Slightly less than nine out of ten (87%) in the shell group, and slightly more than nine out of ten in the heating & cooling group (93%) considered the total impact of the NEIs (not including property value) to be positive.

The shell plus heating & cooling group was somewhat more likely than both of the other groups to report property value, lighting, and durability of the home as positive impacts, and this group was the most likely of all the groups to say that the total impact of the NEIs was positive (96%).

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Table A-2. Low-Income Respondents who Say Home Provides NEIs, by Measure Type

NEI	Shell				Heating & Cooling				Shell Plus Heating & Cooling			
	n	Pos	Neg	No diff	*n*	Pos	Neg	No diff	*n*	Pos	Neg	No diff
Thermal comfort	*72*	68%	3%	25%	*72*	58%	0%	39%	*69*	70%	1%	28%
Noise (from equipment or outside home)	*72*	29%	0%	69%	*72*	15%	1%	82%	*69*	32%	1%	64%
Health (colds/flus/asthma)	*72*	21%	4%	71%	*72*	13%	3%	82%	*69*	26%	4%	67%
Property value (homeowners only)	*69*	71%	0%	26%	*59*	44%	3%	42%	*48*	52%	0%	48%
Equipment reliability/maintenance	*0*	NA	NA	NA	*72*	54%	1%	39%	*69*	32%	10%	55%
Lighting quality and lifetime	*14*	57%	14%	21%	*32*	66%	9%	22%	*62*	71%	10%	19%
Durability of home	*72*	35%	0%	63%	*72*	39%	3%	51%	*69*	28%	3%	67%
Overall impact of NEIs*	*72*	82%	1%	13%	*72*	78%	3%	15%	*69*	81%	1%	13%

*Does not include property value.

Table A-3. Non-low-Income Respondents who Say Home Provides NEIs, by Measure Type

NEI	Shell				Heating & Cooling				Shell Plus Heating & Cooling			
	n	Pos	Neg	No diff	*n*	Pos	Neg	No diff	*n*	Pos	Neg	No diff
Thermal comfort	*70*	83%	0%	14%	*68*	65%	2%	28%	*71*	80%	0%	17%
Noise (from equipment or outside home)	*70*	34%	0%	63%	*68*	19%	4%	72%	*71*	35%	1%	59%
Health (colds/flus/asthma)	*70*	17%	1%	76%	*68*	18%	2%	74%	*71*	24%	1%	68%
Property value (homeowners only)	*68*	66%	0%	24%	*68*	79%	0%	18%	*71*	93%	0%	4%
Equipment reliability/maintenance	*0*	NA	NA	NA	*68*	72%	2%	25%	*71*	75%	4%	17%
Lighting quality and lifetime	*11*	55%	18%	27%	*13*	46%	0%	46%	*23*	91%	4%	4%
Durability of home	*70*	29%	1%	64%	*68*	41%	0%	57%	*71*	61%	0%	34%
Overall impact of NEIs*	*70*	87%	0%	11%	*68*	93%	2%	6%	*71*	96%	0%	4%

*Does not include property value.

A.2 SCALING OF NEI VALUES

This section is meant to provide a more detailed explanation of how a respondent's individual NEI values were scaled to their total NEI value, as presented in section 9.3: NEI Value Calculation. Table A-4 represents an abbreviated data set and demonstrates the scaling and summing method employed in this report.

In order to not overestimate the value of individual NEIs, the individual NEI values provided by the respondent were scaled to the total NEI value provided by the respondent. In cases when the respondent did not provide a total NEI value, the sum of the respondent's reported NEIs was used for scaling (see Table A-4 row D for an example).

Table A-4 illustrates that the number of NEIs that contribute to the total NEIs and the sum of the individual NEIs varies from respondent to respondent. In some cases, the respondent was not able to provide a value for an NEI (for example, "comfort" in row D). In other cases, respondents were not asked about individual NEIs. Respondents were only asked to provide NEI values for NEIs they could logically experience based on the measures installed by the PAs' programs. For example, if a respondent did not install lighting through the program, they were not asked about lighting quality and lifetime. Similarly, if the respondent did not install heating and cooling equipment through the program, they were not asked about equipment maintenance.

Rows B through G provide examples of respondents who could not provide NEI values or were not asked about several individual NEIs. Row H shows the sample size for the mean values, the mean values are based on all relevant cases reported in the table (i.e. the number of respondents for a given NEI). The number of relevant cases varies by NEI and the only mean value that encompasses the entire sample is the sum NEI. Because the scaled value is based on the relationship between the individual NEI values and the total NEI value provided by each respondent, there is a high level of variation in the scaling. For example, row A shows a respondent who valued their health NEI at $2,166 while assigning their overall value of total NEI $1,083 meaning that their scaled health NEI is $1,833 less than the value they assigned.

.

Table A-4. Example of NEI Scaling, Unweighted

	Respondent reported NEI Values						Sum of Reported NEIs	Reported Total value of NEIs						
Row label	Comfort	Noise	Health	Equipment	Light	Durability	SUM NEI	Total NEI	Comfort Scaled	Noise Scaled	Health Scaled	Equipment Scaled	Light Scaled	Durability Scaled
A	1,083	1,083	2,166	1,083	1,083	542	7,040	1,083	167	167	333	167	167	83
B	1,200	500	1,200	-	-	0	2,900	2,500	1,034	431	1,034	-	-	0
C	143	285	143	-	-	-	570	285	71	143	71	-	-	-
D	-	28	141	-	-	-	169	-	-	28	141	-	-	-
E	0	0	132	-	-	-	132	132	0	0	132	-	-	-
F	425	0	106	213	-	106	851	425	213	0	53	106	-	53
G	102	0	102	-	-	142	345	102	30	0	30	-	-	42
	Mean Values based on the number of valid observations in the preceding rows.													
H	n=6	n=7	n=7	n=2	n=1	n=4	n=7	n=7	n=6	n=7	n=7	n=2	n=1	n=4
I	492	271	570	648	1,083	198	1,715	755	253	110	256	137	167	45

A.3 NEI VALUES FOR INDIVIDUAL SAMPLE STRATA

The following set of tables (Table A-5, Table A-6, Table A-7) break out the mean NEI value by strata and income group. Among the shell sample (Table A-5) the LI and NLI groups attribute similar values to their NEIs except for property value where the NLI group mean is just over $400 higher than the LI group. Within the heating and cooling shell (Table A-6) the NLI group's mean valuation of thermal comfort is $100 higher than the LI group and their mean valuation of property value in nearly $800 higher than the LI group. There is much less uniformity of NEI means between income groups in the shell; plus heating and cooling combination strata (Table A-7) than there is in the other strata. The NLI NEI means for thermal comfort, property value, lighting life/quality, and equipment maintenance are hundreds of dollars more than their LI counterparts in the combination strata.

It should be noted that the individual NEI values do not sum to equal the mean "Sum of NEIs" and "Total NEI" values presented in the tables, because the individual NEIs were based on respondents who expressed a value for a given NEI, whereas the Sum of NEIs and Total NEI values were estimated for all respondents.

Table A-5. Mean NEI Values from Survey: Shell Sample[1]

		Thermal comfort		Noise reduction		Health impacts		Property Value[2]	Equipment maintenance[3]		Lighting life/quality[4]		Durability of home		Sum of NEIs[5]	Total NEI Value[6]
	Value per year	Value	Scaled value	Value	Scaled value	Value	Scaled value	Value	Value	Scaled value	Value	Scaled value	Value	Scaled value	Value	Scaled value
Sample size		50		61		58		44	-		9		54		63	
Non-LI Shell Sample	Dollars	$204	$130	$51	$22	$19	$9	$973	-	-	$94	$47	$21	$18	$260	$170
	% Bill Savings	63%	40%	18%	7%	-7%	3%	452%	-	-	<1%	7%	8%	6%	98%	52%
Sample size		58		67		63		59	-		9		65		71	
LI Shell Sample	Dollars	$225	$190	$99	$65	$19	$31	$568	-	-	$117	$64	$71	$55	$374	$341
	% Bill Savings	43%	32%	10%	7%	8%	4%	84%	-	-	11%	5%	13%	10%	59%	58%

[1]Cases that are three times the standard deviation of percent bill savings of the total scaled NEI value are excluded.

[2]Property Value was not scaled because, as a one-time NEI value, it was excluded from the survey question about total annual value of NEIs. Property value was limited to respondents who own their home.

[3]Equipment maintenance was only asked of respondents who installed heating or cooling equipment.

[4]Lighting was only asked of respondents who installed energy efficient lighting through the PAs' programs.

[5] Sum of NEIs is equal to the sum of the unscaled values of the individual annual NEIs (i.e., excluding property value)

[6] Total NEI Value is the value provided by respondents when asked for the total value of all NEIs, excluding property value.

Table A-6. Mean NEI Values from Survey: Heating and Cooling Sample[1]

	Value per year	Thermal comfort: Value	Thermal comfort: Scaled value	Noise reduction: Value	Noise reduction: Scaled value	Health impacts: Value	Health impacts: Scaled value	Property Value[2]: Value	Equipment maintenance[3]: Value	Equipment maintenance[3]: Scaled value	Lighting life/quality[4]: Value	Lighting life/quality[4]: Scaled value	Durability of home: Value	Durability of home: Scaled value	Sum of NEIs[5]: Value	Total NEI Value[6]: Scaled value
Sample size		57		59		58		56	57		11		59		63	
Non-LI Heating & Cooling Sample	Dollars	$204	$284	$103	$44	$35	$49	$-2	$2,534	$157	$120	$62	$34	$70	$64	$562
	% Bill Savings	63%	37%	35%	6%	13%	5%	2%	1,885%	34%	37%	7%	7%	10%	16%	167%
Sample size		59		64		68		43	60		23		57		70	
LI Heating & Cooling Sample	Dollars	$185	$69	$28	$11	$19	$11	$1,740	$167	$79	$67	$80	$82	$18	$415	$213
	% Bill Savings	31%	17%	4%	3%	1%	3%	479%	21%	17%	42%	23%	17%	4%	205%	54%

[1]Cases that are three times the standard deviation of percent bill savings of the total scaled NEI value are excluded.

[2]Property Value was not scaled because, as a one-time NEI value, it was excluded from the survey question about total annual value of NEIs. Property value was limited to respondents who own their home.

[3]Equipment maintenance was only asked of respondents who installed heating or cooling equipment.

[4]Lighting was only asked of respondents who installed energy efficient lighting through the PAs' programs.

[5] Sum of NEIs is equal to the sum of the unscaled values of the individual annual NEIs (i.e., excluding property value)

[6] Total Scaled NEI Value is the value provided by respondents when asked for the total value of all NEIs, excluding property value.

Table A-7. Mean NEI Values from Survey: Shell plus Heating and Cooling Combination Sample[1]

		Thermal comfort		Noise reduction		Health impacts		Property Value[2]	Equipment maintenance[3]		Lighting life/quality[4]		Durability of home		Sum of NEIs[5]	Total NEI Value[6]
	Value per year	Value	Scaled value	Value	Scaled value	Value	Scaled value	Value	Value	Scaled value	Value	Scaled value	Value	Scaled value	Value	Scaled value
Sample size		58		63		60		57	60		20		60		68	
Non-LI Shell Plus Heating & Cooling Sample	Dollars	$872	$384	$197	$86	$186	$38	$4,929	$423	$183	$494	$186	$312	$192	$1,886	$864
	% Bill Savings	39%	44%	13%	19%	7%	2%	825%	17%	9%	15%	10%	18%	19%	185%	89%
Sample size		55		62		64		41	62		56		63		67	
LI Shell Plus Heating & Cooling Sample	Dollars	$211	$40	$68	$13	$56	$17	$343	$69	$17	$122	$39	$80	$32	$531	$159
	% Bill Savings	25%	10%	7%	3%	8%	4%	132%	8%	4%	29%	11%	16%	11%	110%	42%

[1]Cases that are three times the standard deviation of percent bill savings of the total scaled NEI value are excluded.

[2]Property Value was not scaled because, as a one-time NEI value, it was excluded from the survey question about total annual value of NEIs. Property value was limited to respondents who own their home.

[3]Equipment maintenance was only asked of respondents who installed heating or cooling equipment.

[4]Lighting was only asked of respondents who installed energy efficient lighting through the PAs' programs.

[5] Sum of NEIs is equal to the sum of the unscaled values of the individual annual NEIs (i.e., excluding property value)

[6] Total Scaled NEI Value is the value provided by respondents when asked for the total value of all NEIs, excluding property value.

A.4 ASSOCIATION BETWEEN NEI VALUES AND BILL SAVINGS

Table A-8 displays the estimated average annual energy bill savings for the survey respondents, by population and strata. Overall, low-income respondents are expected to save $473 annually and non-low-income respondents are expected to save $673 annually. For the low-income respondents, the shell stratum has the highest average annual energy savings ($583) while for the non-low-income respondents the shell plus heating and cooling stratum has the highest average annual energy savings ($1,275).[167]

Table A-8. Mean NEI Values from Survey: Shell plus Heating and Cooling Combination Sample[1]

Strata	Low-income	Non-low-income
Sample size	213	209
Shell	$583	$380
Heating and Cooling	$392	$347
Shell plus Heating and Cooling	$445	$1,275
Overall Population	$473	$673

Table A-9 displays the results of a series of bivariate Ordinary Least Squares (OLS) regressions for which the value of a specific NEI is the dependent variable and total bill savings is the independent variable. We report results for the LI and NLI populations separately. These regression analyses are useful in gauging the magnitude of effect of bill savings on the value of individual NEIs. For example, every dollar increase in bill savings results in a $2.08 in the value of Thermal Comfort among the LI population. Total bill savings had the largest impact on Lighting among the LI and NLI groups and had the smallest impact on the Health NEI for the LI population and Noise Reduction for the NLI population. The value attributed to the relationship between bill savings and NEIs is fairly consistent between the LI and NLI groups, except for Noise Reduction and Property Value. The discrepancy between the income groups could be due to the difference in housing characteristics, as 23% of the low-income respondents live in multifamily homes (*i.e.* not a single-family, detached home) in which noise reduction would be a more noticeable NEI, while only 12% of the NLI sample lives in multifamily structures. Moreover, more NLI respondents than LI respondents own their homes, increasing the importance of property value to the NLI sample.

It is important to note that, by breaking out the individual NEIs in these bivariate regression models[168], we are showing a real relationship, but the context of the relationship (that a single NEI is not the only one experiencing an impact) is missing and therefore the relationship between bill savings and specific NEI should be interpreted with caution. Even though the analysis is a series of bivariate regressions they are not additive for a total effect. The bivariate regression for specific NEIs are based on respondents who experienced and provided a value for a specific NEI, whereas the bivariate regression for total NEIs is for the entire relevant sample. For a more accurate picture of how bill savings impacts overall NEI values, it would be best to consider the relationship between bill savings

[167] Estimated annual bill savings ranged from a low of $13.93 to a high of $4,910.74 for non-low-income respondents and from a low of $3.15 to a high of $2,150.81 for low-income respondents.

[168] Bivariate means that only the single dependent and independent variables entered the model; it is often called “simple” regression.

and the Total NEI Value. For example, a dollar increase in bill savings increases the reported value of NEIs by $0.48 among the LI group and $0.46 among the NLI group.

Table A-9. Mean NEI Values from Survey: Shell plus Heating and Cooling Combination Sample[1]

	Thermal Comfort	Noise Reduction	Health Impacts	Property Value	Equipment Maintenance	Lighting	Durability of Home	Total NEI Value
Low-income	2.08	1.23	0.83	1.00	5.74	7.60	1.48	0.48
Non-low-income	1.92	0.62	0.95	2.67	5.93	8.69	1.11	0.46

*These regressions were weighted by strata and income group. All values are significant at the .05 level. The constant was set to zero.

A.5 ASSOCIATION BETWEEN NEI VALUES AND INSTALLED MEASURES: ORDINARY LEAST SQUARES (OLS) REGRESSION

Table A-10 and Table A-11 show the results of the OLS regression models computed with the NEI value as the dependent variable and related energy efficiency measures (all transformed to dummy variables) as the dependent variables. Table A-10 shows the results for the LI sample, while Table A-11 shows the results for the NLI sample. We ran a separate model for each individual NEI. The models were weighted by strata and income group.[169] Performing a regression on these data allows us to determine the monetary relationship between the energy efficient measure and the NEI. For example, the results indicate that installing Air Sealing in low-income households increased the value of the Noise NEI by $784 compared to those without Air Sealing. A dash in the table indicates that the measure did not have a significant relationship with the individual NEI; for example, Air Sealing appears to be significantly related to Noise and Health, but not to Comfort, Property Value, Equipment Maintenance and Durability for the low-income respondents.

Among the LI sample, Air Sealing and Service to Heating and Cooling systems have the most consistent effect among the NEIs. Air Sealing serves to increase the value of Noise, Health, and Total NEIs while Service Heating and Equipment does the same for Comfort, Equipment, and Durability of the Home. In contrast, programmable thermostats and new windows appear to negatively affect a number of NEIs.

[169] We also forced the constant to be equal to zero, which mean the regression crosses the y axis at zero. This eases interpretation so we can easily identify the amount of savings rather than having to calculate the change in savings.

Table A-10. Dollar Relationship between Measures and NEIs*—Low-income

	Comfort	Noise	Health	Property Value	Equipment	Lighting	Durability	Total NEIs
Air Sealing**	-	784	438	-	-	-	-	143
Heating	-	-	-	2,088	2,972	-	1,908	205
Hot Water	-	-	-	-	-	-	-	-201
Insulation	1,826	-	879	-	-	-	-	-
Lighting	-	-	-	-	-	1,829	-	134
Service Heating and Cooling	1,792	-	-	-	1,073	-	771	-
Thermostat	-	-	-780	-1,926	-	-	-	-
Window	-2,941	-754	-982	-	-	-	-777	-

*All coefficients in this model are significant at the .1 level and most are significant at the .05 level.
**The significant measures reported in Table 1 and 2 do not represent every measure that was tried in the model. All measures from the following list, Aerator, Air Sealing, Appliance (Refrigerators and Freezers), Cooling, Door, Duct Sealing, Heating and Cooling, Heating and Hot Water, Heating, Heating Controls, Hot Water, Insulation, Lighting, Pipe Wrap, Rebate, Service Heating Cooling, Showerhead, System Sizing, thermostat, Pool Timer, Tank Wrap, Window, that were logically linked to each specific NEI was attempted in the model though we made the choice to adopt a parsimonious method and only left significant measures in the model.

Among the NLI sample, Heating systems and Insulation have the most consistent positive impact across NEIs. Heating systems positively impacts the values of the Comfort, Health, Property Value, Equipment, Durability and Total NEIs while Insulation positively impacts the Comfort, Noise, Health, Property Value, and Total NEIs. In contrast, pipe wrap, programmable thermostats, and new windows appear to negatively affect a number of NEIs.

Table A-11. Dollar Relationship between Measures and NEIs*—Non-low-income

	Comfort	Noise	Health	Property Value	Equipment	Lighting	Durability	Total NEIs
Aerator**	-	-	-	-3,698	-	-	-	3,522
Air Sealing	-	-	-	-	-	-	1,444	-
Appliance	-	-	-	-	-	-	-	-466
Duct Sealing	-1,599	-	-	18,872	-	-	-	-68
Heating	1,100	-	656	2,654	1,093	-	597	372
Heating and Hot Water	-	-	-	-	-	-	-	344
Insulation	2,467	416	927	1,350	-	-	-	211
Lighting	-	-	-	-	-	1,307	-	-
Pipe Wrap	-2,452	-	-903	-1,313	-	-	-	-115
Thermostat	-1,163	-	-669		-	-	-	-
Window	-	-	-	-1,526	-	-	-	-168

*All coefficients in this model are significant at the .1 level and most are significant at the .05 level.
**The significant measures reported in Table 1 and 2 do not represent every measure that was tried in the model. All of the following measures—Aerator, Air Sealing, Appliance (Refrigerators and Freezers), Cooling, Door, Duct Sealing, Heating and Cooling, Heating and Hot Water, Heating, Heating Controls, Hot Water, Insulation, Lighting, Pipe Wrap, Rebate, Service Heating Cooling, Showerhead, System Sizing, thermostat, Pool Timer, Tank Wrap, Window—that were logically linked to each specific NEI were attempted in the model, although we chose to adopt the parsimonious method of leaving only significant measures in the model.

Comparing Table A-10 for the LI sample and Table A-11 for the NLI sample demonstrates that there is little consistency between the measures that increase NEI values among the two groups. The only significant relationships found in both samples include the following:

- Positive impact of insulation on comfort
- Positive impact of insulation on health
- Negative impact of programmable thermostat on health
- Positive impact of heating systems on property values
- Positive impact of heating systems on equipment maintenance
- Positive impact of lighting measures on lighting quality
- Positive impact of heating systems on the durability of the system

Interpreting the results of all of these OLS regression is difficult in part because this method seeks to isolate the impact of individual measures, but, in reality, their combination when installed in homes contributes greatly to the production of a given NEI. While the results may help identify some of the key measures for an individual NEI, NMR does not recommend using these values for individual measures.

A.6 OTHER PARTICIPANT PERSPECTIVE HEALTH IMPACTS

This section reports on an alternative method to estimating participant perspective health benefits via reductions in sick days attributed to energy efficiency measures installed by the programs. Because of the extremely small number of respondents reporting program induced changes in health, NMR does not recommend using the NEI values reported in this section but we do present them in the interest of providing information to inform further discussion and future exploration into this issue.

Energy efficiency programs may have direct impacts on health through improved home environments, reduced exposure to hypothermia or hyperthermia—particularly during heat waves and cold spells—improved indoor air quality, and potential reductions in moisture and mold, leading to amelioration of asthma triggers and other respiratory ailments. Therefore, participants in energy efficiency programs may realize a number of health related improvements due to installed measures, resulting in fewer days off work due to illness.

Respondents were asked to report the number of sick days they or a household member had taken after the energy-efficient improvements and during a period of a year before the improvements. Those whose number of sick days had changed since the improvements were further asked whether they thought the change in sick days was related to the improvements. The evaluation team estimated the value of the participant health benefits based on changes in self reported sick days that respondents attributed to the installations and associated changes in lost wages.

It should be noted that the recommended (NEI) values for all of the health-related impacts represent conservative estimates. Importantly, any reported changes in sick days or the number of times a participant sought medical care for heat stress and other conditions that were not attributed to the improvements were not included in the value estimates. Rather, value estimates were solely based on those participants who attributed changes in number of sick days or medical visits to the efficiency improvements; the value for all other respondents (including those who had no changes or who considered their changes to be unrelated to the improvements) was set to zero. In addition, conclusions are interpreted cautiously because some of the sub-samples are extremely small, in some cases only one respondent.

The number of reported sick days before and after the improvements is illustrated in Table A-11 (for NLI respondents) and Table A-13 (for LI respondents). Each table also shows sick days before and after the improvements for the subset of respondents who 1) had a change in sick days from before to after the improvements, and 2) said the change in sick days was related to the improvements. Again, this subset was used for estimating the total reduction in lost wages.

Table A-11 shows the change in sick days for all respondents who gave a valid response to the question (i.e., did not say “don’t know” or “refuse”), as well as for the sub-sample of NLI participants who attributed their change in sick days to the improvements. The two right-most columns show that, among the eleven respondents who attributed their change in sick days to the improvements, only 10% had no sick days before the improvements, while close to one-half (45%) had no sick days after. Also, whereas about one out of three respondents who attributed changes in sick days to the improvements (34%) missed at least six days before the improvements, only 10% missed that many after.

For the LI respondents, the mean number of sick days after the improvements decreased from a mean of 2.0 to 1.7 (Table A-13). Among the six LI respondents who attributed their change in sick days to the improvements, the number of sick days was reduced from 4.1 to 0. All of these respondents had one to five sick days before the improvements, whereas none had any sick days after.

Table A-12. Sick Days Before and After Improvements, Non-low- income

Non-low Income	Reported sick days, all respondents		Reported sick days, respondents who attributed change in sick days to improvements	
	Sick days before	Sick days after	Sick days before	Sick days after
Sample size	*173*	*202*	*11*	*11*
0 sick days	66%	77%	10%	45%
1 to 5 sick days	21%	17%	56%	45%
6 to 10 sick days	9%	3%	23%	10%
11 to 20 sick days	2%	2%	11%	0%
More than 20 sick days	2%	2%	0%	0%
Mean sick days	2.4	1.3	4.4	2.4

Table A-13. Sick Days Before and After Improvements, Low-income

Low-income	Reported sick days, all respondents		Reported sick days, respondents who attributed change in sick days to improvements	
	Sick days before	Sick days after	Sick days before	Sick days after
Sample size	*185*	*206*	*6*	*6*
0 sick days	76%	83%	0%	100%
1 to 5 sick days	15%	8%	100%	0%
6 to 10 sick days	6%	6%	0%	0%
11 to 20 sick days	2%	1%	0%	0%
More than 20 sick days	1%	1%	0%	0%
Mean sick days	2.0	1.7	4.1	0.0

Table A-14 (NLI) and Table A-15(LI) illustrate how we estimated the NEI value per participant for reduction in sick days. First, we estimated lost wages by multiplying the number of sick days before and after the improvements by the respondent's daily wage rate, for the subset of respondents who attributed their changes in sick days to the improvements (i.e., the attribution group), and then applying the strata weights.[170] We calculated total lost wages before and after the improvements for the attribution group by summing the lost wages for the respondents in the attribution group reporting missed days before and after the improvements (again, applying the strata weights). Total reduction in lost wages was derived by subtracting lost wages after from lost wages before. Finally, this number, representing the reduction in lost wages for the attribution group, was divided by the total number of respondents in each income group, as we did not consider there to be a reduction in lost wages for the participants who did not attribute their change in sick days to the improvements. The resulting

[170] Daily wage rates were estimated as follows. An annual salary was estimated as the median of the salary range reported by the participant. If the participant did not report a salary range, the average of each population (i.e. low-income and non-low-income) was used. The annual wage rate was divided by 245 work days, assumed to be the annual number of work days.

reduction in lost wages was calculated to be $58 per participant for NLI respondents and $12 per participant for the LI respondents.

Table A-14. Reduction in Lost Wages Due to Sick Days, Non Low- Income

	Before improvements	After improvements
Sample size (Number of respondents in attribution group with any sick days before/after improvements)	*10*	*6*
Mean sick days	4.4	2.4
Total lost wages	$21,952	$9,788
Total reduction in lost wages	$12,164	
Average reduction in lost wages (total reduction in lost wages divided by all 209 NLI respondents)	58	

Table A-15. Reduction in Lost Wages Due to Sick Days, Low-income

	Before improvements	After improvements
Sample size (Number of respondents in attribution group with any sick days before/after improvements)	*6*	*0*
Mean sick days	4.1	0.0
Total lost wages	$2,648	$0
Total reduction in lost wages	$2,648	
Average reduction in lost wages (total reduction in lost wages divided by all 209 NLI respondents)	$12	

A.7 SOCIETAL PERSPECTIVE HEALTH IMPACTS

This section reports on potential societal health-related benefits estimated via reduced medical costs due to reductions in incidences of heat stress, hypothermia, and asthma. Because of the extremely small number of respondents reporting program induced changes in health, NMR does not recommend using the NEI values reported in this section but we do present them in the interest of providing information to inform further discussion and future exploration into this issue.

Energy efficiency programs may have direct impacts on health through improved home environments, reduced exposure to hypothermia or hyperthermia—particularly during heat waves and cold spells—improved indoor air quality, and potential reductions in moisture and mold, leading to amelioration of asthma triggers and other respiratory ailments. Therefore, participants in energy efficiency programs may realize a number of health related improvements due to installed measures, resulting in fewer days off work due to illness. In addition, society at large benefits because of reduced medical costs due to reductions in the incidence of symptoms or occurrences of specific health problems (such as asthma or other respiratory problems, heat stress and hypothermia).

Energy efficiency programs may have direct impacts on health through improved home environments, such as reduced risks of heat stress and hypothermia as well as improved indoor air quality and potential reductions in moisture and mold, leading to amelioration of asthma triggers and other respiratory ailments. Society at large benefits because of lower medical costs due to reductions in the incidence of symptoms or occurrences of specific health problems (such as asthma or other respiratory problems, heat stress and hypothermia).

Respondents were asked to report the number of visits made to a hospital, emergency room, or urgent care facility for heat stress, overexposure to cold, and asthma after the energy-efficient improvements and during a period of a year before the improvements. They were further asked whether they thought any changes in the number of times they sought care for these conditions was related to the improvements. The evaluation team estimated the value of the societal health benefits based on changes in the number of times care was sought—specifically, changes that respondents attributed to the installations—and associated changes in costs for medical care. Based on a review of the medical literature, the average cost for a visit to a medical center for heat stress and overexposure to cold adjusted for inflation is approximately $1,470 per visit.[171] The average cost of treating asthma at an emergency room, adjusted for inflation, is approximately $738.[172] These values multiplied by the reduction in number of care visits sought as reported by the respondents yield the recommended respective NEI value.

A.7.1 Heat Stress

None of the NLI respondents reported seeking care for heat stress either before or after the improvements (Table A-16). Among the LI respondents, there was a slight reduction in heat stress incidents—while 4% sought care before the improvements, 2% sought care after. However, only one of these respondents reported that the change in the number of times seeking medical care for heat stress was related to the energy efficiency improvements. This participant reported that medical care was sought for heat stress twice prior to improvements and five times since, exhibiting an increase in the number of times care was sought for heat stress (Table A-17).

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[171] Centers for Disease Control and Prevention, 2011. Treatment for heat stress and overexposure to cold is considered a "general injury" by the CDC: "According to the Injury Surveillance Guidelines, an injury is the physical damage that results when a human body is suddenly or briefly subjected to intolerable levels of energy. Injury can … be an impairment of function resulting from a lack of one or more vital elements (i.e., air, water, or warmth), as in strangulation, drowning, or freezing…. The energy causing an injury may be … thermal (e.g., air or water that is too hot or too cold)."

[172] Agency for Healthcare Research and Quality, 2008.

Table A-16. Medical Care Visits for Heat Stress Before and After Improvements, Non-low Income

Non-low Income	Reported number of times sought care, all respondents		Reported number of times sought care, respondents who attributed change to improvements	
	Before	After	Before	After
Sample size	*198*	*209*	*0*	*0*
0 times sought	100%	100%	0%	0%
1 to 5 times sought	0%	0%	0%	0%
6 to 10 times sought	0%	0%	0%	0%
11 to 20 times sought	0%	0%	0%	0%
More than 20 sought	0%	0%	0%	0%
Mean times care sought	0.0	0. 0	0.0	0.0

Table A-17. Medical Care Visits for Heat Stress before and After Improvements, Low-income

Low-income	Reported number of times sought care, all respondents		Reported number of times sought care, respondents who attributed change to improvements	
	Before	After	Before	After
Sample size	*188*	*210*	*1*	*1*
0 times sought	96%	98%	0%	0%
1 to 5 times sought	3%	2%	100%	100%
6 to 10 times sought	1%	0%	0%	0%
11 to 20 times sought	0%	0%	0%	0%
More than 20 sought	0%	0%	0%	0%
Mean times care sought	0.1	0.1	2.0	5.0

None of the NLI respondents attributed changes in incidents of heat stress to the energy efficiency improvements, so the value for NLI respondents is $0. Table A-18(LI) illustrates how we estimated the annual NEI value per participant for changes in heat stress incidents. First, health care cost for heat stress was estimated by multiplying the number of times care was sought for heat stress before and after the improvements, for the subset of respondents who attributed their changes in sick days to the improvements (i.e., the attribution group), by the average cost for a visit to a medical center for heat stress ($1,470 per visit) and applying the strata weights.[173][174] Total health care costs before and after the improvements for the attribution group were then calculated by summing the health care costs for the respondents in the attribution group reporting medical visits for heat stress before and after the improvements (again, applying the strata weights). The total change in health care costs for heat stress was derived by subtracting health care costs after from health care costs before. Finally, this number, representing the change in health care costs for the attribution group, was divided by the total number of respondents in each income group, as there was considered to be no change in health care costs for the participants who had not attributed their change in number of medical visits for heat stress to the improvements. The resulting change in health care costs for heat stress was calculated to be $0 per participant for NLI respondents and a negative benefit of $26 per participant for the LI respondents.

Measuring changes in heat stress depends upon the occurrence of a severe heat wave that triggers heat stress among members of the population. It may be that our sample size was too small to measure incidences of heat stress during a heat wave, or the time period of the study may not have included a severe heat wave in Massachusetts. Changes in incidence rates of heat stress are also being examined in the upcoming evaluation of the national WAP; values might be able to be derived from these findings (Ternes et al., 2007).

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[173] Centers for Disease Control and Prevention, 2011. Treatment for heat stress and overexposure to cold is considered a "general injury by the CDC: "According to the Injury Surveillance Guidelines, an injury is the physical damage that results when a human body is suddenly or briefly subjected to intolerable levels of energy. Injury can … be an impairment of function resulting from a lack of one or more vital elements (i.e., air, water, or warmth), as in strangulation, drowning, or freezing…. The energy causing an injury may be … thermal (e.g., air or water that is too hot or too cold…"

[174] Total reductions in lost wages were weighted to strata and income group.

Table A-18. Change in Medical Care Cost for Heat Stress before and After Improvements, Low-income

Low-Income	Reported number of times sought care, respondents who attributed change to improvements: Before	After
Sample size (Number of respondents in attribution group who sought care before/after improvements)	*1*	*1*
Mean number of medical care visits	2	5
Total health care costs	$3,597	$8,992
Total reduction in health care costs	$-5,395	
Average reduction in health care costs, heat stress (total change in health care costs divided by all 213 respondents)	$-26	

A.7.2 Hypothermia

Among the NLI respondents (Table A-19), one respondent (fewer than one out of one hundred) reported seeking care for hypothermia twice before the improvements, and none sought care for hypothermia after. This respondent attributed the change to the energy-efficiency improvements that were installed. Among the LI respondents (Table A-20), there was a slight reduction in hypothermia incidents—while 4% sought care before the improvements (with a mean of 3.1 visits for these respondents), 3% sought care after (with a mean of 2.7 visits). However, only one of these respondents reported that the change in the number of times seeking medical care for hypothermia was related to the energy efficiency improvements. This participant reported that medical care was sought for hypothermia three times prior to improvements and one time since, exhibiting a decrease in the number of times care was sought for hypothermia.

Table A-19. Medical Care Visits for Hypothermia before and After Improvements, Non-low-income

Non-low-income	Reported number of times sought care, all respondents		Reported number of times sought care, respondents who attributed change to improvements	
	Before	After	Before	After
Sample size	*197*	*209*	*1*	*1*
0 times sought	100%	100%	0%	100%
1 to 5 times sought	<1%	0%	100%	0%
6 to 10 times sought	0%	0%	0%	0%
11 to 20 times sought	0%	0%	0%	0%
More than 20 sought	0%	0%	0%	0%
Mean times care sought	2.0	0.0	2.0	0.0

Table A-20. Medical Care Visits for Hypothermia before and After Improvements, Low-income

Low-income	Reported number of times sought care, all respondents		Reported number of times sought care, respondents who attributed change to improvements	
	Before	After	Before	After
Sample size	*190*	*212*	*1*	*1*
0 times sought	96%	98%	0%	0%
1 to 5 times sought	3%	2%	100%	100%
6 to 10 times sought	1%	1%	0%	0%
11 to 20 times sought	0%	0%	0%	0%
More than 20 sought	0%	0%	0%	0%
Mean times care sought	3.1	2.7	3.0	1.0

Table A-21 (NLI) and Table A-22 (LI) illustrate how the annual NEI value per participant for changes in hypothermia incidents was estimated. First, the health care cost for hypothermia was estimated by multiplying the number of times care was sought for hypothermia before and after the improvements, for the subset of respondents who attributed their changes in hypothermia to the improvements (i.e., the attribution group), by the average cost for a visit to a medical center for hypothermia ($1,470 per visit) and applying the strata weights. Total health care costs before and after the improvements for the attribution group were then calculated by summing the health care costs for the respondents in the attribution group reporting medical visits for hypothermia before and after the improvements (again, applying the strata weights). The total change in health care costs for hypothermia was derived by subtracting health care costs after from health care costs before. Finally, this number, representing the change in health care costs for the attribution group, was divided by the total number of respondents in each income group, as there was considered to be no change in health care costs for the participants who had not attributed their change in number of medical visits for hypothermia to the improvements. The resulting change in health care costs for hypothermia was calculated to be $1.41 per participant for NLI respondents and $14 per participant for the LI respondents.

Table A-21. Change in Medical Care Cost for Hypothermia Before and After Improvements, Non-low-income

Non-low-income	Reported number of times sought care, respondents who attributed change to improvements	
	Before	After
Sample size (Number of respondents in attribution group who sought care before/after improvements)	*1*	*0*
Mean number of medical care visits	2	0
Total health care costs	$294	$0
Total reduction in health care costs	$294	
Average reduction in health care costs, heat stress (total change in health care costs divided by all 209 respondents)	$1.41	

Table A-22. Change in Medical Care Cost for Hypothermia Before and After Improvements, Low-income

Low-income	Reported number of times sought care, respondents who attributed change to improvements	
	Before	After
Sample size (Number of respondents in attribution group who sought care before/after improvements)	*1*	*1*
Mean number of medical care visits	3	1
Total health care costs	$4,409	$1,470
Total reduction in health care costs	$2,939	
Average reduction in health care costs, heat stress (total change in health care costs divided by all 213 respondents)	$14	

A.7.3 Asthma

Among the NLI respondents (Table A-23), about one-third (31%) reported seeking care for asthma between one and five times before the improvements, and fewer than one out of five (17%) sought care for asthma between one and five times after. In addition, a few respondents (3%) sought care between six and ten times after the improvements. There was an overall increase in asthma incidents, from a mean of 2.1 to a mean of 3.3, for respondents who had any asthma incidents. For the two respondents who attributed the change in asthma incidents to the energy-efficiency improvements that were installed, the mean number of incidents increased from 2.5 to 3.0. Among the LI respondents (Table A-23), there was a reduction in asthma incidents—while 38% sought care before the improvements (with a mean of 5 visits for these respondents), 25% sought care after (with a mean of

3.5 visits). However, among the three LI respondents who said that the change in the number of times seeking medical care for asthma was related to the energy efficiency improvements, there was an overall increase in asthma incidents, from a mean of 4.5 to 6.9 visits to a medical facility for asthma.

Table A-23. Medical Care Visits for Asthma before and After Improvements, Non-low-income

	Reported number of times sought care, all respondents		Reported number of times sought care, respondents who attributed change to improvements	
Non-low-income	**Before**	**After**	**Before**	**After**
Sample size	*45*	*48*	*2*	*2*
0 times sought	69%	80%	0%	52%
1 to 5 times sought	31%	17%	100%	48%
6 to 10 times sought	0%	3%	0%	0%
11 to 20 times sought	0%	0%	0%	0%
More than 20 sought	0%	0%	0%	0%
Mean times care sought	2.1	3.3	2.5	3.0

Table A-24. Medical Care Visits for Asthma before and After Improvements, Low-income

	Reported number of times sought care, all respondents		Reported number of times sought care, respondents who attributed change to improvements	
Low-income	**Before**	**After**	**Before**	**After**
Sample size	*61*	*70*	*3*	*3*
0 times sought	62%	75%	0%	33%
1 to 5 times sought	26%	21%	59%	26%
6 to 10 times sought	7%	4%	41%	41%
11 to 20 times sought	5%	0%	0%	0%
More than 20 sought	0%	0%	0%	0%
Mean times care sought	5.0	3.5	4.5	6.9

Table A-25 (NLI) and Table A-26 (LI) illustrate how the annual NEI value per participant for changes in asthma incidents was estimated. First, the health care cost for asthma was estimated by multiplying the number of times care was sought for asthma before and after the improvements, for the subset of respondents who attributed their changes in asthma to the improvements (i.e., the attribution group), by the average cost for a visit to a medical center for asthma ($737.74 per visit), applying the strata weights. Total health care costs before and after the improvements for the attribution group were then calculated by summing the health care costs for the respondents in the attribution group reporting medical visits for asthma before and after the improvements (again, applying the strata weights). The total change in health care costs for asthma was derived by subtracting health care costs after from health care costs before. Finally, this number, representing the change in health care costs for the attribution group, was divided by the total number of respondents in each income group, as there was considered to be no change in health care costs for the participants who had not attributed their change in number of medical visits for asthma to the improvements. The resulting reduction in health care costs for asthma was calculated to be $11 per participant for NLI respondents and $14 per participant for the LI respondents.

Table A-25. Change in Medical Care Cost for Asthma Before and After Improvements, Non-low-income

Non-low-income	Reported number of times sought care, respondents who said change is related to improvements	
	Before	After
Sample size (Number of respondents in attribution group who sought care before/after improvements)	*2*	*2*
Mean number of medical care visits	2.5	3
Total health care costs	$5,347	$3,097
Total reduction in health care costs	$2,250	
Average reduction in health care costs, heat stress (total change in health care costs divided by all 209 respondents)	$11	

Table A-26. Change in Medical Care Cost for Asthma Before and After Improvements, Low-income

Low-income	Reported number of times sought care, respondents who said change is related to improvements	
	Before	After
Sample size (Number of respondents in attribution group who sought care before/after improvements)	*3*	*2*
Mean number of medical care visits	3	1
Total health care costs	$4,409	$1,470
Total reduction in health care costs	$2,939	
Average reduction in health care costs, heat stress (total change in health care costs divided by all 213 respondents)	$14	

APPENDIX B: MASS SAVE NEIS

In the fall of 2010 Cadmus and Opinion Dynamics Corporation (ODC) conducted surveys with 1,202 customers who participated in the 2010 Mass Save® Residential Single Family Retrofit (Mass Save) Program.[175] Mass Save is a program that provides energy efficiency audits at no cost to customers, as well as free installation of measures such as CFLs, programmable thermostats, and low-flow showerheads, as needed. The audit also provides recommendations for improving the overall energy efficiency of the home and provides incentives to install measures such as insulation/weatherization, heating equipment, and energy efficient appliances.

The survey included questions about potential non-energy impacts that participants may have experienced as a result of their participation in the Mass Save program. The NEI questions focused on the perceived changes in thermal comfort, outside noise, sick days, chronic health conditions (asthma), colds and flu, and the ability to sell or rent the home after measures were installed. Respondents were only asked individual NEI questions if they had installed measures that were determined to reasonably contribute to the individual NEB of interest. For example, respondents who installed windows, insulation, air conditioner or a heating system, programmable thermostats, air sealing or sealing of heating and cooling ducts were asked about changes in the thermal comfort of their home.

Table B–1 summarizes the Mass Save participants' perceived changes in several NEIs commonly reported to result from energy efficiency improvements. Participants were asked if they noticed potential positive or negative changes in their household associated with the specific NEI. Almost two out of three respondents reported a positive change in thermal comfort (63%) after measures were installed, while one out of three (33%) reported no change.[176] One out of three (33%) participants noticed a positive change in the reduction of outside noise associated with installed measures while more than two out of three experienced no change (65%).[177]

Respondents were also asked about changes in sick days or health.[178] A change in sick days attributed to installed measures elicited a modest noticeable change. Only 4% of respondents noticed a positive change, less than 1% a negative change and the vast majority reported no noticeable changes (93%). Respondents asked whether they noticed any changes in the frequency or intensity of chronic health conditions such as asthma reported similar results as changes in sick days, 4% a positive change, 1% a negative change, and 95% reporting no changes. Those asked if they noticed any changes in the frequency or intensity of other illnesses such as colds or flu, again reported results similar to sick days and asthma, mentioning that 7% noticed a positive change, whereas 90% reported no changes.

Lastly, respondents were asked if they believed it would be easier to sell or rent their home because of the installed improvements or conversely more difficult to sell or rent their home.[179] Almost one out of three (31%) eligible respondents affirmed that the installed measures would positively impact the ability to sell or rent the home. Less than one percent reported the measures would negatively impact the ability, while 64% reported the installed measures made no difference in the ability to sell or rent the home.

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[175] Surveyed participants were customers for one of four Program Administrators (PAs): National Grid, NSTAR, Cape Light Compact and WMECO.

[176] Respondents who installed windows, insulation, air conditioner or a heating system, programmable thermostat, air sealing or sealing of heating and cooling ducts were asked about changes in the thermal comfort of their home.

[177] Respondents who installed windows or insulation were asked about changes in the level of outside noise heard in the home.

[178] Respondents who installed windows, insulation, air conditioner or a heating system, programmable thermostat, air sealing or sealing of heating and cooling ducts were asked about changes in sick days or health.

[179] Respondents who installed either a new air conditioner, heating system, water heater, windows, or insulation or had purchased a new refrigerator were asked about changes in their ability to sell or rent their home.

Table B-1Summary of Non Energy Impacts, Mass Save Participants

NEI	*Sample size*	Positive	Negative	No difference
Thermal comfort	554	63%	2%	33%
Noise (from equipment or outside home)	239	33%	<1%	65%
Number of sick days	551	4%	<1%	93%
Chronic health/asthma	551	22%	5%	95%
Health (colds and flus)	551	7%	1%	90%
Ability to sell or rent home	359	31%	<1%	64%
Durability of home	213	34%	2%	60%
Overall impact of NEIs*	213	80%	2%	14%

APPENDIX C: ADDITIONAL LITERATURE REVIEWED FOR SELECT NEIs

This appendix provides a summary of additional literature reviewed for this study.

C.1 UTILITY-PERSPECTIVE NEIS

C.1.1 Transmission and Distribution Savings

Avoided transmission and distribution losses are already accounted for in the TRC benefit-cost test for the PAs' electric energy efficiency plan (National Grid et al. (2009); NSTAR et al. (2009). A brief review of other studies that have estimated the value of transmission and distribution losses may be useful.

Skumatz and Dickerson (1997, 1999)

Skumatz and Dickerson (1997, 1999) estimated the value of transmission and distribution savings for a variety of programs, including low-income weatherization, the VPP program, and refrigerator and air conditioner rebate programs. The NEI values were estimated by applying a combined T&D line loss and deferral estimate of 10% to each program's savings in avoided cost terms. The resulting annual utility savings per participant ranged from $0.92 for the refrigerator rebate program to $4.33 for the VPP program. The authors noted, however, that whether the non-energy benefit applied to a specific utility depended on whether the utility was in a competitive environment.

Skumatz and Gardner (2005)

An annual NEI value of $2.59 per household was estimated for the distribution-only portion of the non-energy benefits associated with Wisconsin's low-income WAP in a 2005 report (Skumatz and Gardner, 2005). This value assumed a line loss reduction of 6.5% and an estimated avoided cost per kWh of $0.05.

Ternes et al. (2007)

In the upcoming national WAP evaluation, the evaluators at Oak Ridge National Laboratory (ORNL) plan to calculate a monetized value of savings to utilities from reduced transmission and distribution losses, by multiplying the electricity savings in weatherized households in kWh by the average amount of electricity lost in transmission and distribution per kWh sold (Ternes et al., 2007). Relative to all other NEIs that the national WAP evaluators plan to measure in the upcoming WAP evaluation, the evaluators anticipate both the magnitude and uncertainty surrounding the monetized value to be low.

C.2 PARTICIPANT-PERSPECTIVE NEIS

C.2.1 Improved Sense of Environmental Responsibility

While the environmental benefits of the PAs' programs have been estimated in the *Avoided Energy Supply Costs in New England: 2011 Report* (Hornby et al, 2011) and included in the PAs' three year energy efficiency plans (National Grid et al., 2009; NSTAR et al., 2009), a brief review of other studies that have estimated how program participants value environmental benefits may be useful.

As participants are generally aware that reducing their own energy consumption has a positive effect on the environment, programs that increase the energy efficiency of their homes can result in a sense of satisfaction from being environmentally responsible. Although sense of environmental responsibility (or, as expressed in some surveys, participants' perceptions of the value of the "environmental impact" of their participation in the program) is not included in NEI studies as frequently as is thermal comfort, when it is included, it tends to be one of the most highly valued participant NEIs for both all-income and low-income whole-house programs, possibly second only to comfort.

a. NON-LOW-INCOME PROGRAMS

Myers and Skumatz (2006)

Myers and Skumatz' analysis of NEI studies from several multi-family retrofit programs (2006) yielded an estimated average value for sense of environmental responsibility of 16% of the value of all Participant NEIs combined, only slightly lower than the value for thermal comfort (19%).

NMR and Conant (2009)

The NEI evaluations of new construction programs we reviewed did not include environmental responsibility in their surveys; however, in response to an open-ended item in the survey used in NMR's evaluation of the Massachusetts New Homes with ENERGY STAR program, participants were asked to identify any additional NEIs that had not been mentioned in the survey, and five participants identified having a positive impact on the environment (NMR and Conant, 2009). The average value for this NEI given by these respondents was 60% of bill savings, or $220. Again, although this value was not scaled relative to overall NEI values, the fact that participants valued environmental responsibility nearly as much as they did thermal comfort (70% of bill savings) is notable.

b. LOW-INCOME PROGRAMS

Myers and Skumatz (2006)

For the low-income multifamily retrofit programs included in the analysis noted above (Myers and Skumatz, 2006), the estimated value for environmental responsibility across studies was even higher than that for the all-income programs, at 27% of the total value for the Participant NEIs combined.

Skumatz and Dickerson (1999)

In Skumatz and Dickerson's analysis of NEI results from various low-income weatherization programs (1999), environmental impact was rated as the second most important NEI for programs with insulation.

Skumatz and Nordeen (2001)

The NEI evaluation of the CT Weatherization Residential Assistance Programs (Skumatz and Nordeen, 2001) found that 17% of those who experienced an increased sense of environmental responsibility from the program said that environmental responsibility was of greater value than their bill savings, and that this NEI had the second highest value out of those included in the survey, but specific NEI values were not reported.

Sense of environmental responsibility tends to be one of the most highly valued participant NEIs for both all-income low-income whole-house programs, possibly second only to comfort. Participants in a variety of programs are aware that that reducing their own energy consumption has a positive effect on the environment and can result in a sense of satisfaction from being environmentally responsible.

C.3 BUFFERS ENERGY PRICE INCREASES

Only one study in the literature quantified the NEI value of buffering energy price increases. The value of this participant NEI was measured in the 2008 Evaluation of the Massachusetts New Homes with ENERGY STAR Program through participant surveys (NMR and Conant, 2009). A relative valuation method was employed in which respondents were asked if they believed their new home, because it was an ENERGY STAR home, buffered against future energy price increases. Ninety-four percent of surveyed respondents believed that their ENERGY STAR home buffered against energy bill increases (n=70). Respondents were then asked to value this NEI as a percentage of their estimated annual energy savings of $400. The mean NEI value estimated in this report was 97% of bill savings, or $386 per participant per year. Upper and lower bounds calculated at the 90% confidence level for this survey were 40% and 153% of bill savings. This was the highest value for the seven NEIs examined in this study.

C.4 REDUCED NEED TO MOVE AND COSTS OF MOVING, INCLUDING HOMELESSNESS

A number of studies have examined the benefits associated with reducing energy costs and reducing mobility and homelessness. For example, in the 1993 evaluation of the national WAP, Brown et al. cited a study concluding that 2.5% of the 1974-1975 mortgage failures were attributable to energy price increases (Metrostudy Corporation, 1976). Also cited in Brown et al. (1993) is a survey of homeless persons and emergency shelter providers by Robinson (1991), which found that among the housing-related reasons for homelessness in Pennsylvania, utility terminations were identified as the cause 7.9% of the time. Robinson also reported that 32% of homes were abandoned within one year of electric service termination and 22% of homes were abandoned within one year of gas service termination. The 1999 Evaluation of the Energy and Non-energy Impacts of Vermont's Weatherization Assistance (Riggert et al.) cited additional findings linking energy costs with mobility, including a report that 42% of homes in Maine were vacated from one to eleven months after service termination between 1986 and 1987 (Colton, 1994), and that 42% of the "most recent five year frequent movers" in a Missouri telephone survey stated that energy bills were "very important" in their move (Colton, 1995). A recent survey of national Low Income Home Energy Assistance Program (LIHEAP) participants reported that due at least in part to their energy bills, in the previous five years 5% of respondents had been evicted from their home or apartment, 4% had had a foreclosure on their mortgage, 12% had moved in with friends or family, and 3% had moved into a shelter or became homeless (Berger and Yan, 2010). In addition, 12% of respondents had had their electric or gas service terminated in the past year due to nonpayment, and 53% those who did not have either service terminated said that they would have if they had not received LIHEAP support. This body of research suggests that the ability to pay energy bills is one of the factors associated with mobility.

Brown et al (1993)

An estimate of the impact of the national WAP on low-income mobility is provided in the 1993 evaluation (Brown et al., 1993). A pre/post treatment/control analysis conducted of approximately 5,000 weatherized and 5,000 controlled dwellings revealed that dwellings experienced significantly less mobility after weatherization: 11 occupancy changes per 100 dwellings before weatherization versus nine occupancy changes per 100 dwellings after weatherization. Over the same time period, occupancy changes for the control group actually increased from 12 occupancy changes per 100 dwellings to 18. Brown et al. (1993) performed a rough calculation of the per participant NEI associated with the 4,000 avoided moves from the program based on the mobility impact analysis, reporting the benefit to be less than $1.00 per weatherized dwelling. Due to the uncertainty about the underlying assumptions and the relatively small magnitude of this monetized figure, the monetized value was not included in the benefit/cost calculations and the estimation formula was not reported in the evaluation.

Skumatz and Dickerson (1997)

One of the first monetized values of reduced forced moves attributable to weatherization programs is provided in Skumatz and Dickerson (1997), based on the Venture Pilot Program, a low-income weatherization and education program in California. An NEI range of $0.00-$100.00 per participant annually was reported, based on the estimated program impact on mobility taken from Brown et al. (1993), estimates of change in expected high school dropout rates, and the difference in lifetime earnings between graduates and dropouts. This NEI valuation did not include any direct moving expenses; only the indirect impact of reduced lifetime earnings, based on the premise that increased mobility is linked to increased dropout rates, was included.

Skumatz and Dickerson (1999)

An NEI value range of $0.00-$52.00 per participant per year was estimated in a similar manner for another California low-income weatherization program (Skumatz and Dickerson, 1999).

Skumatz (2002)

Although participant-reported survey results were not used in the computation of the NEI value associated with this program, a survey of the California low-income weatherization program participants indicates that 16% of respondents reported that the program definitely helped them avoid a move (Skumatz, 2002).

Riggert et al. (1999) & Dalhoff (2007)

The midpoint of $50.00 from the range estimated by Skumatz and Dickerson for the VPP program was applied as the NEI value of reduced mobility rates for the 1999 Vermont WAP analysis (Riggert et al., 1999). For the 2007 update to the Vermont WAP analysis, the same estimation method (i.e. the midpoint of the Skumatz and Dickerson VPP range) was employed, but was adjusted for inflation, resulting in an NEI value of $62.00 (Dalhoff, 2007).

Oppenheim & MacGregor (2002)

The annual NEI estimate for reduced forced moves of $10.10 per participant presented in Oppenheim and MacGregor (2002) includes both direct and indirect costs of moving. The direct cost component of the NEI was computed by multiplying an estimated 6% of avoided service terminations by 32% of terminations resulting in forced mobility (taken from Robinson, 1991) by an estimated $500 in moving costs. Additionally, an estimated $26.06 was added to account for the decreased earning power of children who lose education due to homelessness. The 6% figure for avoided service terminations assumes that all low-income service terminations are avoided.

TecMarket Works, SERA, and Megdal Associates (2001)

Unlike the VPP, California weatherization program, Oppenheim and MacGregor, and Vermont WAP estimates, the NEI calculation for the California LIPPT report was based only on the direct costs of moving; it excluded any indirect costs. An annual NEI value of $1.30 per participant was estimated for the LIPPT report, based on an estimated rate of 0.6% avoided moves per participant, taken from Blasnik (1997), an estimated number of hours spent per move, minimum wage, and an estimate of one month's rent (TecMarket Works, SERA and Megdal Associates, 2001). The LIPPT report authors noted that Blasnik's 0.6% estimate of avoided moves was based on a pre/post analysis of turnover in new party meters, with a control group, and that the program on which it was based had a low percentage of renters (only 16%).

Skumatz & Nordeen (2002)

The annual NEI value of $0.65 per participant for the Connecticut WRAP program was estimated via the same method as for the California LIPPT report, except that one month's rental costs were excluded from the calculation (Skumatz and Nordeen, 2002). A survey of Connecticut WRAP participants revealed that 16% of respondents indicated that the program helped them avoid a move; however, the more conservative rate of 0.6% avoided moves from Blasnik (1997) was considered more reliable than the self-reported figure, and therefore was used in the NEI estimation formula instead of the self-reported 16%.

Skumatz & Gardner (2005)

The NEI value for reduced mobility was estimated for the 2005 report on Wisconsin's low-income weatherization program (Skumatz and Gardner, 2005) via the relative valuation survey method. First, respondents were asked to report whether they experienced positive, negative, or no effects as a result of their participation in the program. Ninety-five percent of respondents reported no effect on the likelihood of moving because of energy costs, while 3% of respondents reported a positive change and 2% reported a negative change. An annual NEI value of $1.00 per participant was presented in this report. In addition to the NEI relative valuation questions, respondents were asked which of the NEI categories was most important to them. Two percent of respondents reported "likelihood of moving because of energy costs" to be the most important NEI to them out of the 21 NEIs included in the survey.

Ternes et al. (2007)

The national WAP evaluators at ORNL plan to calculate a monetized value of the NEI of reduced mobility in the upcoming national WAP evaluation (Ternes et al., 2007). The proposed estimation method involves calculating the average reduction in number of moves per weatherized household and the average cost per move. The decision to collect new data for quantifying NEIs for this evaluation is based on several factors, including the uncertainty surrounding performance metrics (i.e. impact values), the uncertainty surrounding monetized metrics, and the potential magnitude of the monetized NEI value. The decision process involves rating the aforementioned factors as either "low," "medium," or "high." Ternes et al. find the uncertainty regarding the average reduction in number of moves per weatherized household to be "high," the uncertainty regarding the average cost per move to be "medium," and the potential magnitude of the monetized value to be "medium." In order to determine the average number of moves, billing data will be examined for both a treatment and a control group for the year following weatherization. If, however, billing data does not indicate when the occupants of a dwelling move, then a telephone survey will be employed in order to determine the number of moves during the year following weatherization. While the NEI of reduced mobility will be measured in the upcoming national WAP evaluation, there is no plan to estimate the program impact on homelessness or the value of avoided homelessness.

The participant-perspective NEI of reduced mobility has been measured via numerous methods and formulas in the literature for low-income households. Some of the monetized NEI valuations address the issue of homelessness, although, the majority do not. Most NEI value estimations consist of an algorithm, including an assumed percentage reduction in moves and the avoided direct and/or indirect costs associated with moving. For most NEI values estimated in this way, the percentage reduction in mobility was taken either from Brown et al. (1993) or from Blasnik (1997). The direct and indirect costs of forced moves and homelessness vary considerably with regard to which costs are included in the NEI valuation. The earlier NEI valuations in the literature tended to be high, accounting for lost lifetime earning potential, based on an assumed rate of high school dropouts resulting from increased mobility and/or homelessness during childhood. More recent NEI valuations are more conservative and exclude the indirect costs of decreased educational attainment. The formulas for estimating the avoided moving costs are not provided in the literature; therefore, it is not possible to assess the reliability of these avoided cost assumptions. One NEI value found in the literature was estimated by a different method than all of the other estimates. This value was estimated via the relative valuation survey method; it was extremely low, because only 5% of respondents indicated that the program had any effect on their "likelihood of moving because of energy costs," and 40% of those 5% of respondents actually indicated a negative effect.

C.5 MORE DURABLE HOME AND EQUIPMENT AND APPLIANCE MAINTENANCE REQUIREMENTS

Equipment maintenance has been examined in zero and low energy homes in New Zealand using the relative valuation survey method (Stoecklein and Skumatz, 2007). Sixty participants completed the online survey, in which each participant was required to complete the relative valuation questions for two of the following four measures: double glazing, super insulation, solar water heat, and solar design features (such as trombe walls). Respondents indicated that, on average, they had positive experiences with the maintenance requirements of the double glazing and super insulation, and negative experiences with the maintenance requirements of the solar water heat systems and the solar design features of their homes. The relative share of maintenance as compared to the other NEIs included in the survey was 1% for double glazing, 3% for super insulation, -30% for solar water heat, and -3% for solar design. Participants found the maintenance requirements of the solar water heat systems to be particularly burdensome, and, on average, valued the maintenance hassles associated with solar water heat systems at 30% of energy bill savings. Monetized NEI values were not presented in this report.

C.6 REDUCING ENERGY EXPENSES, MAKING MORE MONEY AVAILABLE FOR OTHER USES, SUCH AS HEALTH CARE

Energy efficiency programs can reduce energy costs and therefore allow participating households to spend more money on food, healthcare, or other household needs. However, because the energy savings from these programs are already counted as a benefit by the PAs, to count additional benefits from these energy savings would amount to double counting.

Clearly, low-income populations face a number of burdens related to energy costs and household budget tradeoffs. In order to pay energy costs, families often spend less on food, medications, and other necessities. Lower spending on food may lead to nutritional risk, which in turn can lead to poor growth, malnutrition, and cognitive and developmental deficits that affect school performance, while reduced spending on medications may exacerbate medical conditions. In addition, households may be limited in their ability to make repairs to existing homes or move out of risky homes, increasing the risks of pest infestations, water leaks that lead to mold, and exposure to lead paint. These risks in turn can lead to increased incidence and severity of asthma and other respiratory diseases, lead poisoning and other health risks (Child Health Impact Working Group, 2007).

Low-income families and recipients of Federal Low Income Home Energy Assistance Program (LIHEAP) often skip meals and reduce caloric intake during the winter, due to high energy bills. For example, low-income households have been found to reduce food expenditures by roughly the same amount as their increase in winter fuel expenditures, resulting in reduced caloric intake during the winter months (Bhattacharay et al., 2003).[180] Other studies have found similar relationships between reduced food expenditures and reduced caloric intake during winter heating months, with resulting higher risks of anemia, other vitamin deficiencies and at-risk for hunger (Child Health Impact Working Group, 2007). Children in families facing food insecurity in turn face a number of long-term risks, such as poor growth, poor health or chronic illness, increased risks of hospitalizations, lower measures of physical and psychosocial functioning, and deficits in cognitive and behavioral development that affects school performance (Child Health Impact Working Group, 2007).

Studies of LIHEAP participants have documented the risks faced by program participants. For example, in a survey of LIHEAP participants in 2005, participating households in the Northeast made the following home budget tradeoffs:[181]

- 73% of participating households reduced household expenses due to energy bills
- 20% of participating households went without food due to energy bills
- 28% of participating households went without medical or dental care due to energy bills
- 23% of participating households didn't pay rent/mortgage in full at least once

Similar budget trade-offs were found in the most recent study of national LIHEAP recipients, including (Berger and Yang, 2009):

- 26% of participating households kept their home at a temperature perceived to be unsafe or unhealthy
- 33% of participating households did not fill a prescription or took less than the prescribed dose
- 25% of participating households had someone in the house become sick due to a cold

[180] In one study, increased[180] Increased rates of vitamin deficiencies and anemia were observed among poor families in winter, but these increases were not statistically significant (Bhattacharya et al., 2003)

[181] Similar measures of risk have been found in studies of LIHEAP participants in other parts of the country. For example, a study of 2004 LIHEAP participants in Missouri found that 46% of participants paid energy bills instead of buying food, 45% skipped taking medications or took less than the prescribed amount of medication, 60% of respondents closed off a room to avoid heating it, and 54% of respondents used their ovens to heat their homes (Colton, 2004). See also Berger and Yang, 2009, for more details on 2009 LIHEAP participants.

In addition, the constraints of energy costs and substandard housing increase the likelihood that poor families will experience unhealthy housing conditions, such as pest infestations, mold, and lead paint. There is substantial evidence linking asthma to conditions such as excessive moisture and mold, infestations of roaches and rodents, and poor ventilation. Children exposed to these conditions experience more asthma symptoms, miss more days of school, and have more frequent emergency room visits and hospitalizations (Child Health Impact Working Group, 2007).

Programs that help reduce energy burdens for low-income families may help alleviate risks and provide health benefits. For example, a study examining potential impacts of LIHEAP on the nutritional and health risks among children less than three years old found that, among low-income families, children in families not receiving LIHEAP were 20% more likely to be at nutritional risk for growth problems than children in families that did receive LIHEAP. However, the study was not able to examine the potential long-term impacts of these differences in nutritional risks. In addition, children in families not receiving LIHEAP were 30% more likely to be admitted to the hospital for acute reasons, on the day of the study, than children in families that did receive LIHEAP. However, there were no differences in lifetime hospitalizations (Frank et al., 2006).

C.7 TERMINATION AND RECONNECTION

Participant valuation of avoided terminations and reconnections has been measured for several low-income programs. NEI estimates have been developed, based on surveys and/or computations of the value of participant time spent getting service restored, as well as the costs incurred by the participant to have service restored. Various assumptions have been made when data such as termination and reconnection rates, program-induced change in termination rates, and participant value of time were unavailable or difficult to measure

Skumatz & Dickerson (1997)

The NEI of reduced terminations and reconnections from the participant perspective was investigated for the California Venture Partners Pilot low-income program via several methods including a survey asking participants what they would be willing to pay to avoid service termination (Skumatz and Dickerson, 1997). The survey revealed that customers were willing to pay up to $50 per year to avoid a service termination. Additionally Moreover, participant cost to restart service (divide among all participants, not just those with terminations) was estimated to be up to $1.00 and lost rental value was estimated to be up to $0.15 per year for VPP program. The estimate to restart service was based on termination rates for qualified customers, an assumed percentage reduction in the rate of terminations based on the arrearage reduction from Magouirk (1995), the average balance to be paid in order to restore service, the reconnection fee, an assumption of credit card interest rates to represent the cost to borrow money for reconnection, and the value of an assumed four hours of participant time spent at minimum wage coordinating the reconnection. The estimate of lost rental value was based on the loss of value of one day of rent for a property and the assumed percentage reduction in the rate of terminations based on Magouirk (1995). This estimate was discounted by 25% to account for the fact that few properties would be turned off during the heating season and that a full day may not be lost for some participants.

Skumatz (2002); Skumatz and Dickerson (1999)

NEI value ranges for a California low-income weatherization program were estimated in a similar manner as for the VPP program. A survey of these program participants revealed that 14% of participants a noticed change in “shutoffs,” and of those reporting a change, 81% indicated that the change was for the better, while 19% indicated that the change was for the worse (Skumatz, 2002). Quantified NEI value ranges for the California weatherization program include $0.00-26.06 to avoid termination, $0.00-0.52 to restart service, and $0.00-0.08 in lost rental value (Skumatz and Dickerson, 1999).

TecMarket Works, SERA, and Megdal Associates (2001)

Another report estimating participant valuation of avoided terminations and reconnections is the 2001 California LIPPT report (TecMarket Works, SERA, and Megdal Associates, 2001). An annualized NEI value of $0.17 was estimated for avoided shutoffs, and a value of $0.08 was estimated for avoided reconnects. The shutoff NEI was computed based on average shutoffs per year per customer for the relevant California utilities, an estimated reduction in shutoffs of 23%, and an assumed eight hours spent at minimum wage getting power restored. The reconnection NEI was computed in a similar manner; it was based on average reconnections per year per customer for the relevant California utilities, an estimated percentage reduction in reconnections of 23%, the reconnection fee, and an interest rate component for borrowing the money to pay the reconnection fee. The benefit period for reduced terminations, used to compute the annualized value in this study, was assumed to be three years, while the benefit period for reduced reconnections was assumed to be ten years.

Ternes et al. (2007)

In their upcoming evaluation of the national WAP, the evaluators at ORNL intend to include a monetized value of avoided shut-offs and reconnections as a result of the program (Ternes et al., 2007). The proposed estimation method for this report is to multiply the average number of shut-offs and reconnections per weatherized household by the average cost to customers per shut-off, including "lost rent" and the reconnection fee. On a scale of "low," "medium," and "high," Ternes et al. (2007) anticipate the uncertainty regarding both the average reduction in shut-offs and reconnections and the average cost to customers per shut-off to be "low."

C.8 BILL-RELATED CALLS

Participant valuation of time spent on bill-related calls to the utility has been measured by relative valuation survey results, or by an algorithm including time spent on the phone and minimum wage as variables. The monetized NEI value produced from the survey method is more than an order of magnitude greater than the values produced by the algorithms. Of the algorithm-derived NEI values of participant-perspective bill-related calls, all are based on assumed impact values for payment-related behavior from the literature, rather than on data about program-induced changes in customer calls. No impact evaluations could be found in the literature supporting the assumption that energy efficiency programs do in fact lead to a reduction the number of customer calls to utilities.

TecMarket Works, SERA, and Megdal Associates (2001)

The NEI value of reduced bill-related calls from the participant perspective was estimated to be $0.18 annually per participant in the 2001 California LIPPT report (TecMarket Works, SERA, and Megdal Associates, 2001). This value was calculated based on the average number of customer calls per year, the average length per customer call, an assumed percentage reduction in bill-related calls, and minimum wage. Data on bill-related calls from low-income customers and program-induced reduction in customer calls was unavailable; therefore, proxy values were substituted in the formula for calculating this NEI value. For example, data on all customer calls (regardless of income) was used to calculate the average number of calls and average length per call. Additionally, the proxy value used in place of percent reduction in customer calls was a point estimate, based on an assortment of bill payment behavior and collection activity impact studies.

Skumatz and Nordeen (2002)

An annual participant NEI value of $0.29 was estimated for the Connecticut Weatherization Residential Assistance Partnership (WRAP) program via a similar method as the CA LIPPT (Skumatz and Nordeen, 2002).

Skumatz and Gardner (2005)

Participant valuation of reduced time spent on bill-related calls was measured via a participant survey for the Wisconsin low-income WAP (Skumatz and Gardner, 2005). Respondents were asked if they noticed any impact with regards to each NEI in the survey, and if so, whether the impact was negative or positive. Seven percent of respondents reported a positive impact for "change in number of calls to utility related to bills," while 1% reported a negative impact, and 91% reported no impact. Respondents who reported an impact were then asked whether the impact was much less valuable, somewhat less valuable, same value, somewhat more valuable, or much more valuable than the potential energy savings. These results were translated into average participant value relative to energy savings, which was then multiplied by annual estimated energy savings, in order to yield an NEI value range of $6.00-$8.00 per year.

C.9 EDUCATION

Energy education can be as basic as energy conservation tips and familiarization with energy efficiency measures, but some low-income programs reviewed in the literature have sizable education components, covering areas such as financial literacy and household budgeting.

Skumatz et al. (2009)

One such attempt to quantify the value of program-induced education is reported in Skumatz et al. (2000), although the results were based on a small sample. In this report, a survey for several residential programs—including central AC and lighting rebate programs, a financing program, the VPP and California low-income weatherization program—indicated that participants valued the education associated with measure programs at 10% of energy savings.

Skumatz (2002)

Another participant survey for the California low-income weatherization program indicated that 55% of participants reported receiving educational benefits and feeling more in control over bills as a result of the program (Skumatz, 2002). The average willingness to pay for the combined value of the educational benefits and feeling of control over bills was $93.88. Some programs, such as the VPP program, specifically include an educational component, while others do not.

For programs that do not include an educational component over and above a basic introduction to energy efficiency and measures, this NEI potentially overlaps with the participant NEI of reduced transaction costs. Unlike the reduced transaction costs NEI, education is not recognized as its own NEI and will not be investigated for the upcoming evaluation of the national WAP (Ternes et al., 2007).

C.10 SOCIETAL-PERSPECTIVE NEIs

C.10.1 Improved Health

Other studies on improved health indicators from energy efficiency measures have attempted to quantify the benefits resulting from improved environmental quality (IEQ) in office settings. While not directly comparable to studies of residential and low-income programs, these studies provide a context for the scale of the potential impacts. Improving ventilation and relative humidity in buildings can result in a reduction of colds, viruses, and allergy and asthma events. Fisk (2002) has demonstrated that there are significant societal benefits to IEQ on the order of several billion dollars in savings annually. Estimates of potential health and productivity gains from improved IEQ are $6-14 billion for reduced respiratory illness, $1-4 billion for reduced allergies and asthma, $10-30 billion for reduced sick building syndrome, and $20-60 billion for improved worker performance from changes in thermal environment and lighting.

APPENDIX D: UTILITY-PERSPECTIVE NEI VALUES DERIVED FROM THE LITERATURE

The utility-perspective NEIs for which NMR recommends deriving values from the literature include reductions in arrearage carrying costs, bad debt write-offs, terminations and reconnections, customer calls, notices, and safety-related emergency calls. NMR's review of the literature found eight reports containing utility-perspective NEI values based on programs comparable to the PAs' programs with respect to program components[182], energy efficient measures[183], and target populations[184]. These eight studies, published between 1997 and 2005, are displayed in Table D–1 along with the reported NEI values[185]. The table does not include NEI values from evaluations of programs that were not comparable to the PAs' programs. For example, the 2008 evaluations of the Oregon HEAT and REACH Programs (Drakos et al., 2008) and the 2005 evaluation of the Utah HELP program (Khawaja and Wiley, 2005) were excluded because these programs relied heavily or entirely on payment assistance, counseling, and educational components, program elements not included in the PAs' low-income programs.

[182] The low-income energy efficiency programs in the literature incorporated different program elements, including different combinations of energy efficiency measures, educational and counseling components, and in some cases payment assistance. NMR considered programs comparable to the PAs' programs to be those relying primarily on energy efficiency measures. Programs relying primarily or entirely on education, counseling, or payment assistance components were not considered comparable to the PAs' programs.

[183] In determining whether an NEI value from the literature was applicable to the PAs' programs, NMR reviewed the measures implemented by the programs in each study. Next, NMR compared the measures in the literature to measures implemented through the PAs' programs (the PAs provided lists of measures implemented through their programs). With the exception of low-income programs relying primarily on education, counseling, or payment assistance components, the majority of low-income weatherization and retrofit programs in the NEI literature offer similar measures as the PAs' low-income programs, such as insulation, air sealing, heating system repairs/replacements, lighting, and DHW measures.

[184] NMR considers low-income programs that are open to all low-income customers to be comparable to the PAs' low-income programs. Studies of programs that targeted only a subset of low-income customers, such as high-arrearage low-income customers, were not considered comparable to the PAs' programs.

[185] An empty cell in Table D-1 signifies one of two things: either an NEI value was not estimated for a particular study, or the NEI value reported was based on an NEI from another report included in the table. An example of the latter scenario is the NEI of reduced carrying cost on arrearages reported for the national low-income WAP (Schweitzer and Tonn, 2002), in which the NEI value was estimated by taking the midpoint of the values reported for the Venture Partners Pilot and CA low-income weatherization programs (Skumatz and Dickerson, 1997 and 1999).

Table D-1. Reported NEI Values (Dollars per Participant per Year)

Study	Reported NEI Value, $/year/participant					
	Carrying Cost on Arrearages	Bad Debt Write-Offs	Terminations and Reconnections	Customer Calls	Notices	Safety-Related Emergency Calls
WI Low-income Weatherization (Skumatz and Gardner, 2005)	1.37	--	0.13	0.43	0.30	--
National Low-income Weatherization NEBs Study (Schweitzer and Tonn, 2002)	--	6.09	0.55	--	--	6.91
MA Low-income Weatherization (Skumatz Economic Research) Associates, 2002)	1.71	3.62	--	0.59	--	0.40
CT Low-income Weatherization (Skumatz and Nordeen, 2002)	2.03	2.24	0.10	0.55	1.16	0.21
CA Low-income Public Purpose Test (TecMarket Works, Skumatz Economic Research Inc, and Megdal Associates, 2001)	3.76	0.48	0.07	1.58	1.49	0.07
VT Low-income Weatherization (Riggert et al., 1999)	--	--	7.00	--	--	15.58
CA Low-income Weatherization (Skumatz and Dickerson, 1999)	2.09	2.34	0.33	0.07	0.04	7.91
Venture Partners Pilot Program (Skumatz and Dickerson, 1997)	4.00	4.50	0.63	0.13	0.08	15.00

Recommended values for the utility-perspective NEIs of reductions in arrearage carrying costs, bad debt write-offs, terminations and reconnections, customer calls, notices, and safety-related emergency calls were calculated via a two-step process. First, NMR adjusted the reported values from the literature into 2010 dollars using an inflation rate of 2.5 percent per year, the same inflation rate used in the PAs' three-year plans (see National Grid et al., 2009; NSTAR et al., 2009). Next, we calculated the average (mean), median and midpoint of the inflation-adjusted NEI values. NMR recommends using the median value.[186] Each NEI value from the literature was given equal weight in the calculation of the average value. Table D–2 displays the reports from which NEI values of reduced arrearage carrying costs for programs comparable to the PAs' programs were obtained, the reported NEI values (the same as in Table D–1), and the inflation-adjusted values in 2010 dollars. The same information for the NEI values associated with bad debt write-offs, terminations and reconnections, customer calls, notices, and safety-related emergency calls, are presented in Tables D-3 through D-7.

[186] NMR recommends using the median value as the median helps moderate the impact of potential outlier values.

Table D-2. Inputs to Recommended Value for Carrying Cost on Arrearages

Carrying Cost on Arrearages ($/year/participant)		
Study	**Reported Value**	**Adjusted for Inflation (2010 dollars)**
WI Low-income Weatherization (Skumatz and Gardner, 2005)	$1.37	$1.55
MA Low-income Weatherization (Skumatz Economic Research Associates, 2002)	$1.71	$2.08
CT Low-income Weatherization (Skumatz and Nordeen, 2002)	$2.03	$2.47
CA Low-income Public Purpose Test (TecMarket Works, Skumatz Economic Research Inc, and Megdal Associates, 2001)	$3.76	$4.70
CA Low-income Weatherization (Skumatz and Dickerson, 1999)	$2.09	$2.74
Venture Partners Pilot Program (Skumatz and Dickerson, 1997)	$4.00	$5.51
Average of adjusted values	--	$3.18
Median of adjusted values	--	$2.61
Midpoint of adjusted values	--	$3.53

Table D-3. Inputs to Recommended Value for Bad Debt Write-offs

Bad Debt Write-Offs ($/year/participant)		
Study	**Reported Value**	**Adjusted for Inflation (2010 dollars)**
National Low-income Weatherization NEBs Study (Schweitzer and Tonn, 2002)	$6.09	$7.42
MA Low-income Weatherization (Skumatz Economic Research Associates, 2002)	$3.62	$4.41
CT Low-income Weatherization (Skumatz and Nordeen, 2002)	$2.24	$2.73
CA Low-income Public Purpose Test (TecMarket Works, Skumatz Economic Research Inc, and Megdal Associates, 2001)	$0.48	$0.60
CA Low-income Weatherization (Skumatz and Dickerson, 1999)	$2.34	$3.07
Venture Partners Pilot Program (Skumatz and Dickerson, 1997)	$4.50	$6.20
Average of adjusted values	--	$4.07
Median of adjusted values	--	$3.74
Midpoint of adjusted values	--	$4.01

Table D-4. Inputs to Recommended Value for Terminations and Reconnections

Terminations and Reconnections ($/year/participant)		
Study	**Reported Value**	**Adjusted for Inflation (2010 dollars)**
WI Low-income Weatherization (Skumatz and Gardner, 2005)	$0.13	$0.15
National Low-income Weatherization NEBs Study (Schweitzer and Tonn, 2002)	$0.55	$0.67
CT Low-income Weatherization (Skumatz and Nordeen, 2002)	$0.10	$0.12
CA Low-income Public Purpose Test (TecMarket Works, Skumatz Economic Research Inc, and Megdal Associates, 2001)	$0.07	$0.09
VT Low-income Weatherization (Riggert et al., 1999)	$7.00	$9.18
CA Low-income Weatherization (Skumatz and Dickerson, 1999)	$0.33	$0.43
Venture Partners Pilot Program (Skumatz and Dickerson, 1997)	$0.63	$0.86
Average of adjusted values	--	$1.64
Median of adjusted values	--	$0.43
Midpoint of adjusted values	--	$4.64

Table D-5. Inputs to Recommended Value for Customer Calls

Customer Calls ($/year/participant)		
Study	**Reported Value**	**Adjusted for Inflation (2010 dollars)**
WI Low-income Weatherization (Skumatz and Gardner, 2005)	$0.43	$0.49
MA Low-income Weatherization (Skumatz Economic Research Associates, 2002)	$0.59	$0.72
CT Low-income Weatherization (Skumatz and Nordeen, 2002)	$0.55	$0.67
CA Low-income Public Purpose Test (TecMarket Works, Skumatz Economic Research Inc, and Megdal Associates, 2001)	$1.58	$1.97
CA Low-income Weatherization (Skumatz and Dickerson, 1999)	$0.07	$0.09
Venture Partners Pilot Program (Skumatz and Dickerson, 1997)	$0.13	$0.17
Average of adjusted values	--	$0.68
Median of adjusted values	--	$0.58
Midpoint of adjusted values	--	$1.03

Table D-6. Inputs to Recommended Value for Notices

Notices ($/year/participant)		
Study	Reported Value	Adjusted for Inflation (2010 dollars)
WI Low-income Weatherization (Skumatz and Gardner, 2005)	$0.30	$0.34
CT Low-income Weatherization (Skumatz and Nordeen, 2002)	$1.16	$1.41
CA Low-income Public Purpose Test (TecMarket Works, Skumatz Economic Research Inc, and Megdal Associates, 2001)	$1.49	$1.86
CA Low-income Weatherization (Skumatz and Dickerson, 1999)	$0.04	$0.05
Venture Partners Pilot Program (Skumatz and Dickerson, 1997)	$0.08	$0.10
Average of adjusted values	--	$0.75
Median of adjusted values	--	$0.34
Midpoint of adjusted values	--	$0.96

Table D-7. Inputs to Recommended Value for Safety-related Emergency Calls

Safety-Related Emergency Calls ($/year/participant)		
Study	**Reported Value**	**Adjusted for Inflation (2010 dollars)**
National Low-income Weatherization NEBs Study (Schweitzer and Tonn, 2002)	$6.91	$8.43
MA Low-income Weatherization (Skumatz Economic Research Associates, 2002)	$0.40	$0.49
CT Low-income Weatherization (Skumatz and Nordeen, 2002)	$0.21	$0.26
CA Low-income Public Purpose Test (TecMarket Works, Skumatz Economic Research Inc, and Megdal Associates, 2001)	$0.07	$0.09
VT Low-income Weatherization (Riggert et al., 1999)	$15.58	$22.56
CA Low-income Weatherization (Skumatz and Dickerson, 1999)	$7.91	$10.37
Venture Partners Pilot Program (Skumatz and Dickerson, 1997)	$15.00	$20.68
Average of adjusted values	--	$8.98
Median of adjusted values	--	$8.43
Midpoint of adjusted values	--	$11.43

APPENDIX E: NEI SURVEY, OWNERS AND MANAGERS OF LOW-INCOME RENTALS

Owners of Low-income Housing — NEI Survey

CaseID

Respondent Data

- Name
- Phone

Utility Name

- Ex
- Ex
- Ex

Utility Program Name

- Ex
- Ex
- Ex

Measures received

- Ex
- Ex
- Ex
- Ex

Estimated Annual Savings

INTRODUCTION AND SCREENING

Hello, my name is ______, and I'm calling from Tetra Tech on behalf of Massachusetts utilities and energy efficiency organizations about some of the programs and services they offer, including the energy efficiency improvements you had done recently to your property through <PA NAME>'s energy efficiency programs.

I1 May I speak with [CONTACT NAME]?

1 Yes [GO TO I1a]
2 No [SKIP TO I3]

I1A The survey should take around 20 minutes and the information you provide will help the sponsors improve their programs and services. Your responses will be kept strictly confidential. For quality and training purposes, this call will be recorded.

I2 According to our records, energy efficiency improvements were made at your property at [ADDRESS] with the help of [PA NAME]'s [NAME OF PA'S PROGRAM] program sometime within the past 2 years. Are you the person who is most familiar with these energy efficiency improvements?

1 Yes [SKIP TO I4]
2 No [GO TO I3]
D DON'T KNOW [GO TO I3]
R REFUSED [THANK & TERMINATE]

I3 Is there someone else I could speak to now who has been involved with the energy efficiency improvements recently made to the property at [ADDRESS]

1 Yes [RE-READ INTRO AND START WITH I1a]
2 No [ASK TO SCHEDULE A TIME TO CALL BACK]
D Don't know [THANK & TERMINATE]
R Refused [THANK & TERMINATE]

I4 I would like to confirm that the following energy efficiency improvements were installed at your property at [ADDRESS] [LIST EFFICIENCY MEASURES FROM PROGRAM DATA]. Is this correct?

1 Yes [GO TO I5]
2 Yes, participated, but installed different efficiency measures
[RECORD EFFICIENCY MEASURES AND RE-SCHEDULE INTERVIEW]
3 No, did not participate in the program [THANK & TERMINATE]
D Don't know [THANK & TERMINATE]
R Refused [THANK & TERMINATE]

I5 Comparing your property now to before you had the energy efficiency improvements installed, would you say your property is more energy-efficient, less energy-efficient or about the same level of energy efficiency?

1 More energy-efficient
2 Less energy-efficient
3 Same level of efficiency
D Don't know
R Refused

I6 Since installing the energy efficiency measures, have you noticed any changes in your energy bills for the property at [ADDRESS]?

1 Yes, lower energy bills
2 No, higher energy bills
3 No change in bills
D Don't know
R Refused

I7 Are the tenants at [ADDRESS] responsible for paying their own energy bills, or are utilities included in the rent?

1 Tenants pay their bills [GO TO I8]
2 Energy bills included in rent [SKIP TO I9]
3 Tenants pay some bills, some included in rent [GO TO I8]
D Don't know [SKIP TO I9]
R Refused [SKIP TO I9]

I8 Since installing the energy efficiency measures for the property at [ADDRESS], have any tenants told you that they have seen changes in their energy bills? If so, what changes?

1 Yes, lower energy bills
2 Yes, higher energy bills
3 No change in bills
4 Have not heard anything from tenants about energy bills
D Don't know
R Refused

I9 Since installing the energy efficiency measures for the property at [ADDRESS], have any tenants commented on what they like or do not like about the energy efficiency improvements?
[IF YES: What are they?]
[PROBE: Is there anything else? RECORD UP TO THREE RESPONSES]

1 Lower energy bills
2 More comfortable
3 Improved reliability of heating and cooling equipment or appliances
4 Less noise from outside
5 Higher energy bills
6 Less comfortable
7 Decreased reliability of heating/cooling equipment or appliances
8 More noise from outside
9 Nothing
10 Other (SPECIFY)
11 Don't know
12 Refused

I10_int Properties such as yours, which have had energy efficiency improvements, typically are more energy efficient than comparable properties that have not had similar efficiency improvements made. As a result, properties such as yours use less energy for heating, cooling, and water heating and have lower energy bills.

I10 In addition to your energy savings, have you noticed any other positive impacts resulting from the energy efficiency improvements made to your property?
[IF YES: What are they?]
[PROBE: Is there anything else? RECORD UP TO THREE RESPONSES]

1 No benefits
2 Easier to lease or rent units; improved marketing of rental property
3 Improved reliability of heating and cooling equipment or appliances
4 Less maintenance of heating and cooling equipment or appliances
5 Less maintenance for lighting
6 Reduced tenant turnover
7 Other (SPECIFY)
D Don't know/don't remember
R Refused

I11 Have you noticed any negative impacts resulting from the energy efficiency improvements made to your property?
[IF YES: What are they?]
[PROBE: Is there anything else? RECORD UP TO THREE RESPONSES]

1 No negative impacts
2 More difficult to lease or rent units
3 Less reliable heating and cooling equipment or appliances
4 More maintenance of heating and cooling equipment or appliances
5 More maintenance for lighting
6 Increased tenant turnover
7 Higher energy bills
8 Other (SPECIFY)
D Don't know
R Refused

MARKETABILITY AND EASE OF FINDING RENTERS

M1 In terms of your ability to market your property and lease your rental units, would you say that, because of the energy efficiency improvements, your property is EASIER to market and rent, HARDER to market and rent, or would you say there is no difference in your ability to market your property and lease your rental units?

1 Easier to market and rent [GO TO M2]
2 More difficult to market and rent [GO TO M3]
3 No difference [GO TO T1]
D Don't know [GO TO M2]

M1A [IF I10=2 (Easier to rent) AND M1=2 (More difficult)] Earlier you said that it's been easier to lease or market units. Can you please confirm for me whether the energy efficiency improvements have had an overall POSITIVE or NEGATIVE impact on marketing and renting units, or has there been no difference in ease of marketing your property?

1 Positive [SKIP TO M2]
2 Negative [SKIP TO M3]
3 No difference [SKIP TO T1]

M1B [IF I11=2 (Harder to market) AND M1=1 (Easier)] Earlier you said that it's been harder to lease or market units. Can you please confirm for me whether the energy efficiency improvements have had an overall POSITIVE or NEGATIVE impact on marketing and renting units, or has there been no difference in ease of marketing your property?

1 Positive [SKIP TO M2]
2 Negative [SKIP TO M3]

3 No difference [SKIP TO T1]M2 [IF M1=1 (EASIER TO MARKET AND RENT)] A property with the type of energy efficiency improvements you installed typically saves $XX annually on energy bills. Assuming you [IF I7=1 or 3: and your tenants] are saving $XX per year on energy, what is the value to you per year of having your property easier to market and rent, either in dollars or as a percentage of energy savings?

1 $____/year [SKIP TO T1]
2 _____% of annual energy savings [SKIP TO T1]
D Don't know [SKIP TO M2A]
[SAVINGS HAVE BEEN ESTIMATED FOR THE ENTIRE PROPERTY, NOT AT THE UNIT LEVEL]

M2A [IF M1=1 & M2=DON'T KNOW] In terms of energy bill savings, which of the following would you say is closest to the value of having your property easier to market and rent?

[READ RESPONSES]
1 Nothing
2 About one-fourth of typical annual energy bill savings
3 About one-half of typical annual energy bill savings
4 About three-fourths of typical annual energy bill savings
5 About equal to the typical annual energy bill savings
6 More than energy bill savings [GO TO M2AX]
7 Other
8 DO NOT READ: Have not noticed any change in being able to market and rent property
D Don't know

M2AX [IF M2A=6 OR 7] How much in total?

[IF M2A=6, $/year must be higher than $XX, or % must be greater than 100]
1 $___ / year
2 ____% of annual energy savings

M3 [IF M1=2 (HARDER TO MARKET AND RENT)] A property with the type of energy efficiency improvements you installed typically saves $XX annually on energy bills. Assuming you [IF I7=1 or 3: and your tenants] are saving $XX per year on energy, what is the cost to you per year of the increased difficulty in marketing and renting your property, either in dollars or as a percentage of energy savings?

1 $____/year [SKIP TO T1]
2 _____% of annual energy savings [SKIP TO T1]
D Don't know [GO TO M3A]
[SAVINGS HAVE BEEN ESTIMATED FOR THE ENTIRE PROPERTY, NOT AT THE UNIT LEVEL]

M3A [IF M1=2 & M3=DON'T KNOW] In terms of energy bill savings, which of the following is closest to the cost of the increased difficulty in marketing and renting your property?

[READ RESPONSES]
1 Nothing
2 About one-fourth of typical annual energy bill savings
3 About one-half of typical annual energy bill savings
4 About three-fourths of typical annual energy bill savings
5 About equal to the typical annual energy bill savings
6 More than energy bill savings
7 Other
8 DO NOT READ: Have not noticed any change in being able to market and rent property
D Don't know

M3AX [IF M3A=6 OR 7] How much in total?

[IF M3A=6, $/year must be higher than $XX, or % must be greater than 100]
1 $___ / year
2 ____% of annual energy savings

REDUCED TENANT TURNOVER

T1 In terms of the amount of tenant turnover in your property's rental units, would you say that, because of the energy efficiency improvements, your property has LESS tenant turnover than before the improvements were made, MORE tenant turnover, or would you say there is no difference in the amount of tenant turnover?

1 Less tenant turnover [GO TO T2]
2 More tenant turnover [GO TO T3]
3 No difference [GO TO PV1]
D Don't know [GO TO PV1]

T1A [IF I10=6 (Decreased turnover) AND T1=2 (More turnover)] Earlier you said that you've noticed a decrease in tenant turnover. Can you please confirm for me whether the energy efficiency improvements have caused MORE or LESS tenant turnover, or have they made no difference in the amount of tenant turnover?

1 Less [SKIP TO T2]
2 More [SKIP TO T3]
3 No difference [SKIP TO PV1]

T1B [IF I11=6 (Increased turnover) AND T1=1 (Less turnover)] Earlier you said that you've noticed an increase in tenant turnover. Can you please confirm for me whether the energy efficiency improvements have overall caused MORE or LESS tenant turnover, or have they made no difference in the amount of tenant turnover?

1 Positive [SKIP TO T2]
2 Negative [SKIP TO T3]
3 No difference [SKIP TO PV1]

T2 [IF T1=1 (LESS TENANT TURNOVER)] A property with the type of energy efficiency improvements you installed typically saves $XX annually on energy bills. Assuming you [IF I7=1 or 3: and your tenants] are saving $XX per year on energy, what is the value to you per year of having less tenant turnover, either in dollars or as a percentage of energy savings?

1 $____/year [SKIP TO PV1]
2 _____% of annual energy savings [SKIP TO PV1]
D Don't know [SKIP TO T2A]

T2A [IF T1=1 & T2=DON'T KNOW] In terms of energy bill savings, which of the following would you say is closest to the value of the decreased tenant turnover?

[READ RESPONSES]
1 Nothing
2 About one-fourth of typical annual energy bill savings
3 About one-half of typical annual energy bill savings
4 About three-fourths of typical annual energy bill savings
5 About equal to the typical annual energy bill savings
6 More than energy bill savings [GO TO T2AX]
7 Other [GO TO T2AX]
8 DO NOT READ: Have not noticed any decrease in tenant turnover
D Don't know

T2AX [IF T2A=6 OR 7] How much in total?

[IF T2A=6, $/year must be higher than $XX, or % must be greater than 100]
1 $___ / year
2 ____% of annual energy savings

T3 [IF T1=2 (MORE TENANT TURNOVER)] A property with the type of energy efficiency improvements you installed typically saves $XX annually on energy bills. Assuming you [IF I7=1 or 3: and your tenants] are saving $XX per year on energy, what is the cost to you per year of the increased tenant turnover, either in dollars or as a percentage of energy savings?

1 $____/year [SKIP TO PV1]
2 _____% of annual energy savings [SKIP TO PV1]
D Don't know [GO TO T3A]

T3A [IF T1=1 & T3=DON'T KNOW] In terms of energy bill savings, which of the following is closest to the cost to you of the increased tenant turnover?

[READ RESPONSES]
1 Nothing
2 About one-fourth of typical annual energy bill savings
3 About one-half of typical annual energy bill savings
4 About three-fourths of typical annual energy bill savings
5 About equal to the typical annual energy bill savings
6 More than energy bill savings [GO TO T3AX]
7 Other [GO TO T3AX]
8 DO NOT READ: Have not noticed any increased in tenant turnover
D Don't know

T3AX [IF T3A=6 OR 7] How much in total?

[IF T3A=6, $/year must be higher than $XX, or % must be greater than 100]
1 $___ / year
2 ____% of annual energy savings

EXPECTED INCREASE IN PROPERTY VALUE

PV1 Not counting any investments you may have made in the energy efficiency improvements, would you say that, because of the energy efficiency improvements, your property has a HIGHER value than it would have without the improvements, a LOWER value than it would have without the improvements, or would you say about the same value?

1 Higher value [GO TO PV2]
2 Lower value [GO TO PV3]
3 No difference [GO TO EQ1]
D Don't know [GO TO EQ1]

PV2 [IF PV1=1 (HIGHER VALUE)] A property with the type of energy efficiency improvements you installed typically saves $XX annually on energy bills. Assuming you [IF I7=1 or 3: and your tenants] are saving $XX per year on energy, how much do you think the improvements add to the value of your property, either in dollars or as a percentage of energy savings?

1 $____ [SKIP TO EQ1]
2 _____% of annual energy savings [SKIP TO EQ1]
D Don't know [SKIP TO PV2A]

PV2A [IF PV1=1 & PV2=DON'T KNOW] In terms of energy bill savings, which of the following is closest to the increase in property value?

[READ RESPONSES]
1 Nothing
2 About one-fourth of typical annual energy bill savings
3 About one-half of typical annual energy bill savings
4 About three-fourths of typical annual energy bill savings
5 About equal to the typical annual energy bill savings
6 More than energy bill savings [GO TO PV2AX]
7 Other [GO TO PV2AX]
8 DO NOT READ: Have not noticed any increased property value
D Don't know

PV2AX [IF PV2A=6 OR 7] How much in total?

[IF PV2A=6, $/ must be higher than $XX, or % must be greater than 100]
1 $___
2 ____% of annual energy savings

PV3 [IF PV1=2 (LOWER VALUE)] A property with the type of energy efficiency improvements you installed typically saves $XX annually on energy bills. Assuming you [IF I7=1 or 3: and your tenants] are saving $XX per year on energy, how much do the improvements take away from the value of your property, either in dollars or as a percentage of energy savings?

1 $____/ [SKIP TO EQ1]
2 _____% of annual energy savings [SKIP TO EQ1]
D Don't know [GO TO PV3A]

PV3A [IF PV1=2 & PV3=DON'T KNOW] In terms of energy bill savings, which of the following is closest to the amount that the improvements take away from the value of your property?

[READ RESPONSES]
1 Nothing
2 About one-fourth of typical annual energy bill savings
3 About one-half of typical annual energy bill savings
4 About three-fourths of typical annual energy bill savings
5 About equal to the typical annual energy bill savings
6 More than energy bill savings [GO TO PV3AX]
7 Other [GO TO PV3AX]
8 DO NOT READ: Have not noticed any decreased property value
D Don't know

PV3AX [IF PV3A=6 OR 7] How much in total?

[IF PV3A=6, $ must be higher than $XX, or % must be greater than 100]
1 $___
2 ____% of annual energy savings

EQUIPMENT MAINTENANCE/RELIABILITY
[ONLY ASK IF INSTALLED HEATING AND COOLING EQUIPMENT]

EQ1 [ASK IF INSTALLED HEATING AND COOLING EQUIPMENT; OTHERWISE, SKIP TO LT1] In terms of the maintenance requirements or reliability of your heating and cooling equipment, would you say that, because of the energy efficiency improvements, your heating and cooling equipment 1) requires LESS maintenance and has IMPROVED reliability than before the improvements were made, 2) requires MORE maintenance and is LESS reliable, or would you say that 3) there is no difference in the maintenance requirements or reliability of your heating and cooling equipment?

1 Less maintenance/more reliable [GO TO EQ2]
2 More maintenance/less reliable [GO TO EQ3]
3 No difference [GO TO LT1]
D Don't know [GO TO LT1]

EQ1A [IF I10=3 or 4 (Improved HVAC) AND EQ1=2 (More maintenance)] Earlier you said that your heating and cooling equipment has been more reliable, or requires less maintenance. Can you please confirm for me whether the energy efficiency improvements have had an overall POSITIVE or NEGATIVE impact on maintenance of your heating and cooling equipment, or has there been no difference in maintenance requirements?

1 Positive [SKIP TO EQ2]

2 Negative [SKIP TO EQ3]
3 No difference [SKIP TO LT1]

EQ1B [IF I11=3 or 4 (Negative HVAC) AND EQ1=1 (Less maintenance)] Earlier you said that your heating and cooling equipment has been less reliable, or requires more maintenance. Can you please confirm for me whether the energy efficiency improvements have had an overall POSITIVE or NEGATIVE impact on maintenance of your heating and cooling equipment, or has there been no difference in maintenance requirements?

1 Positive [SKIP TO EQ2]
2 Negative [SKIP TO EQ3]
3 No difference [SKIP TO LT1]

EQ2 [IF EQ1=1 (LESS MAINTENANCE)] A property with the type of energy efficiency improvements you installed typically saves $XX annually on energy bills. Assuming you [IF I7=1 or 3: and your tenants] are saving $XX per year on energy, what is the value to you per year of the reduction in maintenance to heating and cooling equipment, either in dollars or as a percentage of energy savings?

1 $____/year [SKIP TO LT1]
2 _____% of annual energy savings [SKIP TO LT1]
D Don't know [SKIP TO EQ2A]

EQ2A [IF EQ1=1 & EQ2=DON'T KNOW] In terms of energy bill savings, which of the following would you say is closest to the value of the reduction in maintenance to heating and cooling equipment?

[READ RESPONSES]
1 Nothing
2 About one-fourth of typical annual energy bill savings
3 About one-half of typical annual energy bill savings
4 About three-fourths of typical annual energy bill savings
5 About equal to the typical annual energy bill savings
6 More than energy bill savings [GO TO EQ2AX]
7 Other [GO TO EQ2AX]
8 DO NOT READ: Have not noticed any reduction in maintenance to heating/cooling equipment
D Don't know

EQ2AX [IF EQ2A=6 OR 7] How much in total?

[IF EQ2A=6, $/year must be higher than $XX, or % must be greater than 100]
1 $___ / year
2 ____% of annual energy savings

EQ3 [IF EQ1=2 (MORE MAINTENANCE)] A property with the type of energy efficiency improvements you installed typically saves $XX annually on energy bills. Assuming you [IF I7=1 or 3: and your tenants] are saving $XX per year on energy, what is the cost per year of the increase in maintenance to heating and cooling equipment, either in dollars or as a percentage of energy savings?

1 $____/year [SKIP TO LT1]
2 _____% of annual energy savings [SKIP TO LT1]
D Don't know [GO TO EQ3A]

EQ3A [IF EQ1=1 & EQ3=DON'T KNOW] In terms of energy bill savings, which of the following is closest to the cost of the increase in maintenance to heating and cooling equipment?

[READ RESPONSES]
1 Nothing
2 About one-fourth of typical annual energy bill savings
3 About one-half of typical annual energy bill savings
4 About three-fourths of typical annual energy bill savings
5 About equal to the typical annual energy bill savings
6 More than energy bill savings [GO TO EQ3AX]
7 Other [GO TO EQ3AX]
8 DO NOT READ: Have not noticed any increase in maintenance to heating/cooling equipment
D Don't know

EQ2AX [IF EQ2A=6 OR 7] How much in total?

[IF EQ2A=6, $/year must be higher than $XX, or % must be greater than 100]
1 $___ / year
2 ____% of annual energy savings

REDUCED MAINTENANCE FOR LIGHTING [ONLY ASK IF INSTALLED LIGHTING]

LT1 [ASK IF INSTALLED LIGHTING, OTHERWISE SKIP TO D1] The energy efficient lighting you installed, in addition to saving energy, generally has a longer lifetime and may require less maintenance than incandescent lighting. After installing the energy efficient lighting, would you say that your lighting requires LESS maintenance than before the improvements were made, requires MORE maintenance or would you say there is no difference in the maintenance requirements of your lighting?

1 Less maintenance [GO TO LT2]
2 More maintenance [GO TO LT3]
3 No difference [GO TO D1]
D Don't know [GO TO D1]

LT1A [IF I10=5 (Improved lighting) AND LT1=2 (More maintenance)] Earlier you said that your lighting requires less maintenance. Can you please confirm for me whether the energy efficiency improvements have had an overall POSITIVE or NEGATIVE impact on your lighting maintenance requirements, or has there been no difference in maintenance requirements?

1 Positive [SKIP TO LT2]
2 Negative [SKIP TO LT3]
3 No difference [SKIP TO D1]

LT1B [IF I11=5 (Negative lighting) AND LT1=1 (Less maintenance)] Earlier you said that your lighting requires more maintenance. Can you please confirm for me whether the energy efficiency improvements have had an overall POSITIVE or NEGATIVE impact on your lighting maintenance requirements, or has there been no difference in maintenance requirements?

1 Positive [SKIP TO LT2]
2 Negative [SKIP TO LT3]
3 No difference [SKIP TO D1]

LT2 [IF LT1=1 (LESS MAINTENANCE)] A property with the type of energy efficiency improvements you installed typically saves $XX annually on energy bills. Assuming you [IF I7=1 or 3: and your tenants] are saving $XX per year on energy, what is the value to you per year of the reduction in maintenance requirements of your lighting, either in dollars or as a percentage of energy savings?

1 $____/year [SKIP TO D1]
2 _____% of annual energy savings [SKIP TO D1]
D Don't know [SKIP TO LT2A]

LT2A [IF LT1=1 & LT2=DON'T KNOW] In terms of energy bill savings, which of the following would you say is closest to the reduction in maintenance requirements of your lighting?

[READ RESPONSES]
1 Nothing
2 About one-fourth of typical annual energy bill savings
3 About one-half of typical annual energy bill savings
4 About three-fourths of typical annual energy bill savings
5 About equal to the typical annual energy bill savings
6 More than energy bill savings [GO TO LT2AX]
7 Other [GO TO LT2AX]
8 DO NOT READ: Have not noticed reduction in maintenance requirements of lighting
D Don't know

LT2AX [IF LT2A=6 OR 7] How much in total?

[IF LT2A=6, $/year must be higher than $XX, or % must be greater than 100]
1 $___ / year
2 ____% of annual energy savings

LT3 [IF LT1=2 (MORE MAINTENANCE)] A property with the type of energy efficiency improvements you installed typically saves $XX annually on energy bills. Assuming you [IF I7=1 or 3: and your tenants] are saving $XX per year on energy, what is the cost per year of the increase in maintenance requirements of your lighting, either in dollars or as a percentage of energy savings?

1 $____/year [SKIP TO Q#0] OR
2 _____% of annual energy savings [SKIP TO Q#0]
D Don't know [GO TO Q#0]

LT3A [IF LT1=2 & LT3=DON'T KNOW] In terms of energy bill savings, which of the following is closest to the cost of the increase in maintenance requirements of your lighting?

[READ RESPONSES]
1 Nothing
2 About one-fourth of typical annual energy bill savings
3 About one-half of typical annual energy bill savings
4 About three-fourths of typical annual energy bill savings
5 About equal to the typical annual energy bill savings
6 More than energy bill savings [GO TO LT3AX]
7 Other [GO TO LT3AX]
8 DO NOT READ: Have not noticed an increase in the maintenance requirements of lighting
D Don't know

LT2AX [IF LT2A=6 OR 7] How much in total?

[IF LT2A=6, $/year must be higher than $XX, or % must be greater than 100]
1 $___ / year
2 ____% of annual energy savings

DURABILITY

D1 In terms of the durability of your property, would you say that, because of the energy efficiency improvements, your property is 1) MORE durable and LESS prone to needing repairs than before the improvements were made, 2) LESS durable and MORE prone to needing repairs, or would you say that 3) there is no difference in the durability of your property?

1 More durable / fewer repairs [GO TO D2]
2 Less durable / more repairs [SKIP TO D3]
3 No difference [SKIP TO TC1]
4 Don't know [SKIP TO TC1]

D2 [IF D1=1 (MORE DURABLE)] A property with the type of energy efficiency improvements you installed typically saves $XX annually on energy bills. Assuming you [IF I7=1 or 3: and your tenants] are saving $XX per year on energy, what is the value to you per year of the increased durability of your property, either in dollars or as a percentage of energy savings?

1 $____/year [SKIP TO TC1]
2 _____% of annual energy savings [SKIP TO TC1]
D Don't Know [GO TO D2A]

D2A [IF D1=1 & D2=DON'T KNOW] In terms of energy bill savings, which of the following is closest to the value of the increased durability of your property?…

[READ RESPONSES]
1 Nothing
2 About one-fourth of typical annual energy bill savings
3 About one-half of typical annual energy bill savings
4 About three-fourths of typical annual energy bill savings
5 About equal to the typical annual energy bill savings
6 More than energy bill savings [GO TO D2AX]
7 Other [GO TO D2AX]
8 DO NOT READ: Have not noticed any increase in the durability of the property
D Don't know

D2AX [IF D2A=6 OR 7] How much in total?

[IF D2A=6, $/year must be higher than $XX, or % must be greater than 100]
1 $___ / year
2 ____% of annual energy savings

D3 [IF D1=2 (LESS DURABLE)] A property with the type of energy efficiency improvements you installed typically saves $XX annually on energy bills. Assuming you [IF I7=1 or 3: and your tenants] are saving $XX per year on energy, what is the cost per year of the decreased durability of your property, either in dollars or as a percentage of energy savings?

1 $____/year [SKIP TO TC1]
2 _____% of annual energy savings [SKIP TO TC1]
D Don't know [GO TO D3A]

D3A [IF D1=1 & D3=DON'T KNOW] In terms of energy bill savings, which of the following is closest to the cost of the decreased durability of your property?

[READ RESPONSES]
1 Nothing
2 About one-fourth of typical annual energy bill savings
3 About one-half of typical annual energy bill savings
4 About three-fourths of typical annual energy bill savings
5 About equal to the typical annual energy bill savings
6 More than energy bill savings [GO TO D3AX]
7 Other [GO TO D3AX]
8 DO NOT READ: Have not noticed any decrease in the durability of the property
D Don't know

D3AX [IF D3A=6 OR 7] How much in total?

[IF D3A=6, $/year must be higher than $XX, or % must be greater than 100]
1 $___ / year
2 ____% of annual energy savings

TENANT COMPLAINTS

TC1 In terms of the number of complaints made by your tenants, would you say that, because of the energy efficiency improvements, your tenants make FEWER complaints than before the improvements were made, make MORE complaints, or would you say there is no difference in the number of complaints made by your tenants?

1 Fewer complaints [GO TO TC2]
2 More complaints [SKIP TO TC3]
3 No difference [SKIP TO OTH1]
4 Don't know [SKIP TO OTH1]

TC2 [IF TC1=1 (FEWER COMPLAINTS)] A property with the type of energy efficiency improvements you installed typically saves $XX annually on energy bills. Assuming you [IF I7=1 or 3: and your tenants] are saving $XX per year on energy, what is the value to you per year of the decrease in tenant complaints, either in dollars or as a percentage of energy savings?

1 $____/year [SKIP TO OTH1]
2 _____% of annual energy savings [SKIP TO OTH1]
D Don't know [GO TO TC2A]

TC2A [IF TC1=1 & TC2=DON'T KNOW] In terms of energy bill savings, would you say the decrease in tenant complaints is worth…

[READ RESPONSES]
1 Nothing
2 About one-fourth of typical annual energy bill savings
3 About one-half of typical annual energy bill savings
4 About three-fourths of typical annual energy bill savings
5 About equal to the typical annual energy bill savings
6 More than energy bill savings [GO TO TC2AX]
7 Other [GO TO TC2AX]
8 DO NOT READ: Have not noticed a decrease in tenant complaints
9 Don't know

TC2AX [IF TC2A=6 OR 7] How much in total?

[IF TC2A=6, $/year must be higher than $XX, or % must be greater than 100]
1 $___ / year
2 ____% of annual energy savings

TC3 [IF TC1=2 (MORE COMPLAINTS)] A property with the type of energy efficiency improvements you installed typically saves $XX annually on energy bills. Assuming you [IF I7=1 or 3: and your tenants] are saving $XX per year on energy, what is the cost to you per year of the increase in tenant complaints, either in dollars or as a percentage of energy savings?

1 $____/year [SKIP TO OTH1]
2 _____% of annual energy savings [SKIP TO OTH1]
D Don't know [GO TO TC3A]

TC3A [IF TC1=1 & TC3=DON'T KNOW] In terms of energy bill savings, which of the following is closest to the cost of the increase in tenant complaints?

[READ RESPONSES]
1 Nothing
2 About one-fourth of typical annual energy bill savings
3 About one-half of typical annual energy bill savings
4 About three-fourths of typical annual energy bill savings
5 About equal to the typical annual energy bill savings
6 More than energy bill savings [GO TO TC3AX]
7 Other [GO TO TC3AX]
8 DO NOT READ: Have not noticed an increase in tenant complaints
D Don't know

TC3AX [IF TC3A=6 OR 7] How much in total?

[IF TC3A=6, $/year must be higher than $XX, or % must be greater than 100]
1 $___ / year
2 ____% of annual energy savings

OTHER NEI

OTH1 Is there another impact resulting from the energy efficiency improvements that we have not discussed?

1 Yes [GO TO OTH2]
2 No [SKIP TO T1]
D Don't know [SKIP TO T1]
R Refused [SKIP TO T1]

OTH2 What is the impact?

[RECORD VERBATIM]

OTH3 Would you say that [INSERT VERBATIM FROM OTH2] has had a positive impact or a negative impact on your property?

1 Positive impact [GO TO OTH4]
2 Negative impact [SKIP TO OTH5]
3 No impact [SKIP TO T1]
D Don't know [SKIP TO T1]

OTH4 [IF OTH3=1 (POSITIVE IMPACT)] A property with the type of energy efficiency improvements you installed typically saves $XX annually on energy bills. Assuming you [IF I7=1 or 3: and your tenants] are saving $XX per year on energy, what is the value to you per year of [INSERT VERBATIM FROM OTH2] either in dollars or as a percentage of energy savings?

1 $____/year [SKIP TO T1]
2 _____% of annual energy savings [SKIP TO T1]
D Don't know [GO TO OTH4A]

OTH4A [IF OTH3=1 & OTH4=DON'T KNOW] In terms of energy bill savings, would you say [INSERT VERBATIM FROM OTH2] is worth…

[READ RESPONSES]
1 Nothing
2 About one-fourth of typical annual energy bill savings
3 About one-half of typical annual energy bill savings
4 About three-fourths of typical annual energy bill savings
5 About equal to the typical annual energy bill savings
6 More than energy bill savings [GO TO OTH4AX]
7 Other [GO TO OTH4AX]
D Don't know

OTH4AX [IF OTH4A=6 OR 7] How much in total?

[IF OTH4A=6, $/year must be higher than $XX, or % must be greater than 100]
1 $___ / year
2 ____% of annual energy savings

OTH5 [IF OTH3=2 (NEGATIVE IMPACT)] A property with the type of energy efficiency improvements you installed typically saves $XX annually on energy bills. Assuming you [IF I7=1 or 3: and your tenants] are saving $XX per year on energy, what is the cost to you of [INSERT VERBATIM FROM OTH2] either in dollars or as a percentage of energy savings?

1 $____/year [SKIP TO T1]
2 _____% of annual energy savings [SKIP TO T1]
D Don't know [GO TO OTH5A]

OTH5A [IF OTH3=2 & OTH5=DON'T KNOW] In terms of energy bill savings, which of the following is closest to the cost to you of [INSERT VERBATIM FROM OTH2]?

[READ RESPONSES]
1 Nothing
2 About one-fourth of typical annual energy bill savings
3 About one-half of typical annual energy bill savings
4 About three-fourths of typical annual energy bill savings
5 About equal to the typical annual energy bill savings
6 More than energy bill savings [GO TO OTH5AX]
7 Other [GO TO OTH5AX]D Don't know

OTH5AX [IF OTH5A=6 OR 7] How much in total?

[IF OTH5A=6, $/year must be higher than $XX, or % must be greater than 100]
1 $___ / year
2 ____% of annual energy savings

TOTAL VALUE OF NEIS

TOT1 Next, please think about the total of all of the positive and negative effects caused by the energy efficient improvements made to your property EXCEPT for any changes in your property value. To summarize, you reported that [LIST POSITIVE EFFECTS] were positive effects and that [LIST NEGATIVE EFFECTS] were negative effects caused by the energy efficient improvements made to your property. Would you say that the combination of all of these effects is positive, negative or no effect?

1 Positive [GO TO TOT2]
2 Negative [GO TO TOT3]
3 No Effect [SKIP TO F1]
D Don't know [SKIP TO F1]
R Refused [SKIP TO F1]

TOT2 [IF TOT1=1 (POSITIVE)] Assuming you [IF I7=1 or 3: and your tenants] are saving $XX per year on energy, what is the value of all of the effects combined, either in dollars or as a percentage of energy savings?

1 $____/year [SKIP TO F1]
2 _____% of annual energy savings [SKIP TO F1]
D Don't know [SKIP TO TOT2A]

TOT2A [IF TOT1=1 & TOT2=DON'T KNOW] In terms of energy bill savings, would you say the value of all of the effects combined is closest to…

[READ RESPONSES]
1 Nothing
2 About one-fourth of typical annual energy bill savings
3 About one-half of typical annual energy bill savings
4 About three-fourths of typical annual energy bill savings
5 About equal to the typical annual energy bill savings
6 More than energy bill savings [GO TO TOT2AX]
7 Other
D Don't know

TOT2AX [IF TOT2A=6 OR 7] How much in total?

[IF TOT2A=6, $/year must be higher than $XX, or % must be greater than 100]
1 $___ / year
2 ____% of annual energy savings

TOT3 [IF TOT1=2 (NEGATIVE)] Assuming you [IF I7=1 or 3: and your tenants] are saving $XX per year on energy, what is the cost to you per year of all of the effects combined, either in dollars or as a percentage of energy savings?

1 $____/year [SKIP TO F1]
2 _____% of annual energy savings [SKIP TO F1]
D Don't know [GO TO TOT3A]

TOT3A [IF TOT1=2 & TOT3=DON'T KNOW] In terms of energy bill savings, which of the following is closest to the value that all of the effects combined takes away from your property?

[READ RESPONSES]
1 Nothing
2 About one-fourth of typical annual energy bill savings
3 About one-half of typical annual energy bill savings
4 About three-fourths of typical annual energy bill savings
5 About equal to the typical annual energy bill savings
6 More than energy bill savings [GO TO TOT3AX]
7 Other [GO TO TOT3AX]
D Don't know

TOT3AX [IF TOT3A=6 OR 7] How much in total?

[IF TOT3A=6, $/year must be higher than $XX, or % must be greater than 100]
1 $___ / year
2 ____% of annual energy savings

FIRMOGRAPHCS / DETAILS ABOUT APARTMENTS AND COMPANY

F_INT Now I have a few last questions for statistical purposes only.

F1 How many apartment units are located in the building at the address we have been talking about? [PROMPT: That is at (INSERT SAMPLE ADDRESS)?]

___ [RECORD # UNITS]
888 Don't know

F2 Do you or your firm own and manage this property, manage this property only, or own this property but not manage it?

1 Own and manage property
2 Manage property only
3 Own but not manage
4 Other
D Don't know
R Refused

F3A In total, how many multifamily residential properties do you or your firm own and manage?

___ [RECORD NUMBER]
888 Don't know

F3A_1 In total, how many apartment units are located in these properties?
[PROMPT: That is, the properties you own *and* manage.]

____ [RECORD NUMBER]
8888 Don't know

F3B In total, how many multifamily residential properties do you or your firm manage, but not own?

___ [RECORD NUMBER]
888 Don't know

F3B_1 In total, how many apartment units are located in these properties?
[PROMPT: That is, the properties you manage, but do not own.]

____ [RECORD NUMBER]
8888 Don't know

F3C In total, how many multifamily residential properties do you or your firm own, but not manage?

___ [RECORD NUMBER]
888 Don't know

F3C_1 In total, how many apartment units are located in these properties?
[PROMPT: That is, the properties you own, but do not manage.]

____ [RECORD NUMBER]
8888 Don't know

APPENDIX F: NEI SURVEY: LOW-INCOME AND NON-LOW-INCOME RETROFITS

Massachusetts Statewide: Low-income and Non-low-income Retrofits — NEI Survey

CaseID

Respondent Data

- Name
- Phone
- Address

Utility Name

- Ex
- Ex
- Ex

Utility Program Name

- Ex
- Ex
- Ex

Measures received

- Ex
- Ex
- Ex
- Ex

Estimated Annual Energy Savings

INTRODUCTION AND SCREENING

Hello, my name is ______, and I'm calling from Tetra Tech on behalf of Massachusetts utilities and energy efficiency organizations about some of the programs and services they offer to residential customers, including the home energy efficiency improvements you had done recently through [PA NAME's] energy efficiency programs. The survey should take around 20 minutes and the information you provide will help the sponsors improve their programs and services. Your responses will be kept strictly confidential.

I1 May I speak with [CONTACT NAME]?

1 Yes [GO TO I2]

2 No [SKIP TO I3]

I2 Are you the person in your household who is most familiar with the energy efficiency improvements made to your home recently at the following address: [ADDRESS]?

1 Yes [SKIP TO I4]
2 No, someone else in the household is more familiar [SKIP TO I3]
3 Landlord for participating address [GO TO I2A]
D DON'T KNOW [SKIP TO I3]
R REFUSED [THANK & TERMINATE]

I2A Do you live in one of the units at [INSERT ADDRESS] that had the energy efficiency improvements made?

1 Yes [SKIP TO I3A]
2 No, live at different address [THANK & TERMINATE]
R Refused [THANK & TERMINATE]

I3 Is there someone else in your home I could speak to now who has been involved with the energy efficiency improvements made to your home recently?

1 Yes [RE-READ INTRO AND START WITH I2]
2 No [ASK TO SCHEDULE A TIME TO CALL BACK]
D Don't know [THANK & TERMINATE]
R Refused [THANK & TERMINATE]

I3A First, I would like to confirm that the energy efficiency improvements were made to a home that was built before 2009.

1 Yes, this is a home built before 2009 [GO TO I4]
2 No, this is a home built since 2009 [THANK & TERMINATE]
D Don't know [THANK & TERMINATE]
R Refused [THANK & TERMINATE]

I4 Next, I would like to confirm that you installed the following energy efficiency improvements with the help of [PA NAME]'s [NAME OF PA'S PROGRAM] program in the past 2 years: [LIST EFFICIENCY MEASURES FROM PROGRAM DATA]. Is that correct?

1 Yes [GO TO I5]
2 Yes, but installed different efficiency measures
[RECORD EFFICIENCY MEASURES AND RE-SCHEDULE INTERVIEW]
3 No, did not participate in the program [THANK & TERMINATE]
D Don't know [THANK & TERMINATE]
R Refused [THANK & TERMINATE]

I5 Do you own or rent your home?

1 Own
2 Rent
R Refused

I6 What type of building is your home? [READ RESPONSES]

1 Detached single-family home
2 Townhouse or duplex, with a wall separating the units from basement to roof, and with separate utilities for each unit
3 Two, three, or four family building–one or more units stacked on top of another OR with one water and sewer bill for the whole building
4 Part of a building with five or more units
5 Other (SPECIFY)
D Don't know
R Refused

I7 Comparing your home now to before you had the energy efficiency improvements installed, would you say your home is more energy-efficient, less energy-efficient or about the same level of energy efficiency?

1 More energy-efficient
2 Less energy-efficient
3 Same level of efficiency
D Don't know
R Refused

I8_int Homes such as yours that have had energy efficiency improvements typically are more energy efficient than comparable homes that have not had similar efficiency improvements made. As a result, homes such as yours use less energy for heating, cooling, and water heating and have lower energy bills.

I8 In addition to your energy savings, have you noticed any other positive impacts resulting from the energy efficiency improvements made to your home?

[IF YES: What are they?]
[PROBE: Is there anything else? RECORD UP TO THREE RESPONSES]

1 No benefits
2 Fewer drafts; home feels more comfortable
3 Quieter, less noise from outside
4 Quieter, less noise from appliances or heating and cooling equipment
5 Increased property value
6 Improved health, general
7 Improved health, asthma or other chronic health conditions
8 Improved health, fewer colds and flu
9 Improved safety of the home
10 Improved reliability of heating and cooling equipment or appliances
11 More affordable energy bills
12 Other (SPECIFY)
13 Don't know/don't remember
14 Refused

I9 Have you noticed any negative impacts resulting from the energy efficiency improvements made to your home?

[IF YES: What are they?]
[PROBE: Is there anything else? RECORD UP TO THREE RESPONSES]

1 No negative impacts
2 More drafts; home feels LESS comfortable
3 Noisier, MORE noise from outside
4 Noisier, MORE noise from appliances or heating and cooling equipment
5 Declining health, general
6 Declining health, asthma or other chronic health conditions
7 Declining health, MORE colds and flu
8 Decreased safety of the home
9 Decreased reliability of heating and cooling equipment or appliances
10 Less affordable energy bills
11 Other (SPECIFY)
12 Don't know/don't remember
13 Refused

NEI_Int Next I would like to ask you about several impacts you may have experienced as a result of the energy efficiency improvements made to your home.

COMFORT

C1 In terms of the temperature and draftiness of your home, would you say that, because of the energy efficiency improvements, your home is MORE comfortable than it was before the improvements were made, LESS comfortable, or would you say there is no difference in the comfort level?

1 More comfortable [GO TO C2]
2 Less comfortable [SKIP TO C3]

3 No difference [SKIP TO N1]
D Don't know [SKIP TO N1]

C1A [IF I8=2 (Less drafts) AND C1=2 (Less comfortable) Earlier you said that you noticed fewer drafts or your home felt more comfortable. Can you please confirm for me whether the energy efficiency improvements have had an overall POSITIVE or NEGATIVE impact on your comfort level, or have they made no difference to your comfort level?

1 Positive [SKIP TO C2]
2 Negative [SKIP TO C3]
3 No difference [SKP TO N1]
D Don't know [SKIP TO N1]

C1B [IF I9=2 (More drafts) AND C1=1 (More comfortable)] Earlier you said that you noticed more drafts or your home felt less comfortable. Can you please confirm for me whether the energy efficiency improvements have had an overall POSITIVE or NEGATIVE impact on your comfort level, or have they made no difference to your comfort level?

1 Positive [SKIP TO C2]
2 Negative [SKIP TO C3]

C2 [IF C1=1 (MORE COMFORTABLE)] A home with the type of energy efficiency improvements you installed typically saves $XX annually on energy bills. Compared to the typical energy savings of $XX per year, how much would you say this increased comfort adds to the value of living in your home each year, either in dollars or as a percentage of energy savings?

1 $____ / year [SKIP TO N1]
2 _____% of annual energy savings [SKIP TO N1]
D Don't know [GO TO C2A]

[IF REPONDENT SAYS THEY HAVE NOT REALIZED ENERGY SAVINGS: The annual energy bill savings are an estimate based on the type of energy efficiency improvements made to your home. Please try to estimate the value of the increased comfort in terms of this estimate of bill savings.]

C2A [IF C1=1 & C2=DON'T KNOW] Compared to the typical energy bill savings of $x, would you say the increased comfort is worth…

[READ RESPONSES]
1 Nothing
2 About one-fourth of typical annual energy bill savings
3 About one-half of typical annual energy bill savings
4 About three-fourths of typical annual energy bill savings
5 About equal to the typical annual energy bill savings
6 More than energy bill savings [GO TO C2AX]
7 Other [GO TO C2AX]
8 DO NOT READ: Have not noticed any increased comfort
D Don't know

C2AX [IF C2A=6 OR 7] How much in total?

[IF C2A=6, $/year must be higher than $XX, or % must be greater than 100]
1 $___ / year
2 ____% of annual energy savings

C3 [IF C1=2 (LESS COMFORTABLE)] A home with the type of energy efficiency improvements you installed typically saves $XX annually on energy bills. Assuming you're saving $XX per year on energy, how much would you say the decreased comfort takes away from the value of living in your home each year, either in dollars or as a percentage of energy savings?

1 $____ / year [SKIP TO N1]
2 _____% of annual energy savings [SKIP TO N1]
D Don't know [GO TO C3A]

[IF REPONDENT SAYS THEY HAVE NOT REALIZED ENERGY SAVINGS: The annual energy bill savings are an estimate based on the type of energy efficiency improvements made to your home. Please try to estimate the value of the decreased comfort in terms of this estimate of bill savings.]

C3A [IF C1=1 & C3=DON'T KNOW] In terms of energy bill savings, which of the following is closest to the value that the decreased comfort takes away from living in your home?

[READ RESPONSES]
1 Nothing
2 About one-fourth of typical annual energy bill savings
3 About one-half of typical annual energy bill savings
4 About three-fourths of typical annual energy bill savings
5 About equal to the typical annual energy bill savings
6 More than energy bill savings [GO TO C3AX]
7 Other [GO TO C3AX]
8 DO NOT READ: Have not noticed any decreased comfort
D Don't know

C3AX [IF C3A=6 OR 7] How much in total?

[IF C3A=6, $/year must be higher than $XX, or % must be greater than 100]
1 $___ / year
2 ____% of annual energy savings

OUTDOOR NOISE / QUIETER INTERIOR ENVIRONMENT

N1 In terms of the amount of noise you hear from outside your home, would you say that, because of the energy efficiency improvements, your home is QUIETER than it was before the improvements were made with less noise from outside, LESS QUIET with more noise from outside, or would you say there is no difference in the noise level?

1 Quieter, with less noise from the outside [GO TO N2]
2 Less quiet, with more noise from the outside [SKIP TO N3]
3 No difference [SKIP TO CF1]
D Don't know [SKIP TO CF1]

N1A [IF I8=3 (Less outside noise) AND N1=2 (More noise)] Earlier you said that you noticed less noise from outside your house. Can you please confirm for me whether the energy efficiency improvements have made your home more quiet, less quiet, or have they made no difference to the noise level of your home?

1 More quiet [SKIP TO C2]
2 Less quiet [SKIP TO C3]
3 No difference [SKIP TO CF1]
D Don't know [SKIP TO CF1]

N1B [IF I9=3 (More noise) AND N1=1 (Quieter)] Earlier you said that you noticed more noise from outside your house. Can you please confirm for me whether the energy efficiency improvements have made your home more quiet or less quiet, or have they made no difference to the noise level in your home?

1 More quiet [SKIP TO C2]
2 Less quiet [SKIP TO C3]
3 No difference [SKIP TO CF1]
D Don't know [SKIP TO CF1]

N2 [IF N1=1 (QUIETER)] A home with the type of energy efficiency improvements you installed typically saves $XX annually on energy bills. Assuming you're saving $XX per year on energy, how much would you say this reduced noise level adds to the value of living in your home each year, either in dollars or as a percentage of energy savings?

1 $____ / year [SKIP TO CF1]
2 _____% of annual energy savings [SKIP TO CF1]
D Don't know [GO TO N2A]

[IF REPONDENT SAYS THEY HAVE NOT REALIZED ENERGY SAVINGS: The annual energy bill savings are an estimate based on the type of energy efficiency improvements made to your home. Please try to estimate the value of the decreased noise level in terms of this estimate of bill savings.]

N2A [IF N1=1 & N2=DON'T KNOW] In terms of energy bill savings, would you say the decreased noise is worth…

[READ RESPONSES]

1	Nothing	
2	About one-fourth of typical annual energy bill savings	
3	About one-half of typical annual energy bill savings	
4	About three-fourths of typical annual energy bill savings	
5	About equal to the typical annual energy bill savings	
6	More than energy bill savings	[GO TO N2AX]
7	Other	[GO TO N2AX]
8	DO NOT READ: Have not noticed any decreased noise	
D	Don't know	

N2AX [IF N2A=6 OR 7] How much in total?

[IF N2A=6, $/year must be higher than $XX, or % must be greater than 100]

1	$___ / year
2	____% of annual energy savings

N3 [IF N1=2 (NOISIER)] A home with the type of energy efficiency improvements you installed typically saves $XX annually on energy bills. Assuming you're saving $XX per year on energy, how much would you say the increased noise level takes away from the value of living in your home each year, either in dollars or as a percentage of energy savings?

1	$____ / year	[SKIP TO CF1]
2	_____% of annual energy savings	[SKIP TO CF1]
D	Don't know	[GO TO N3A]

[IF REPONDENT SAYS THEY HAVE NOT REALIZED ENERGY SAVINGS: The annual energy bill savings are an estimate based on the type of energy efficiency improvements made to your home. Please try to estimate the value of the increased noise level in terms of this estimate of bill savings.]

N3A [IF N1=2 & N3=DON'T KNOW] In terms of energy bill savings, which of the following is closest to the value that the increased noise takes away from living in your home?

[READ RESPONSES]
1 Nothing
2 About one-fourth of typical annual energy bill savings
3 About one-half of typical annual energy bill savings
4 About three-fourths of typical annual energy bill savings
5 About equal to the typical annual energy bill savings
6 More than energy bill savings [GO TO N3AX]
7 Other [GO TO N3AX]
8 DO NOT READ: Have not noticed any increased noise
D Don't know

N3AX [IF N3A=6 OR 7] How much in total?

[IF N3A=6, $/year must be higher than $XX, or % must be greater than 100]
1 $___/year
2 ____% of annual energy savings

HEALTH, COLDS, FLUS, ASTHMA AND OTHER CHRONIC CONDITIONS

CF1 In terms of the frequency or intensity of colds, flus, and other illnesses, such as asthma or other chronic health conditions, would you say that you and your household, because of the energy efficiency improvements, have had FEWER cases or symptoms of the cold, flu or other illnesses such as asthma, MORE cases or symptoms of the cold, flu or other illnesses such as asthma, or would you say there is no difference in the frequency or intensity of colds, flus, and other illnesses such as asthma?
[IF RESPONDENT INDICATES THERE HAVE BEEN CHANGES IN HEALTH, BUT NOT DUE TO EFFICIENCY IMPROVEMENTS, CHOOSE "NO DIFFERENCE".]

1 Fewer colds, flus, and improved chronic conditions [SKIP TO CF2]
2 More colds, flus, and worsened chronic conditions [SKIP TO CF3]
3 No difference [SKIP TO PV1]
4 Other (SPECIFY) [GO TO CF1A]
D Don't Know [SKIP TO PV1]

CF1A [IF CF1=2 and any of I8_6, I8_7 or I8_8: Earlier you said that your household had noticed improved health.]
[IF CF1=1 and any of I9_5, I9_6 or I9_7: Earlier you said that your household had noticed declining health.]
Can you please confirm for me whether the energy efficiency improvements have had an overall positive or negative impact on your household's health, or have they made no difference to your household's health?

[INDICATE ALL THAT APPLY]
1 Positive [SKIP TO CF2]
2 Negative [SKIP TO CF3]
3 No difference [SKIP TO PV1]
D Don't Know [SKIP TO PV1]

CF2 [IF CF1=1 OR (4 WITH ANY IMPROVEMENTS)] A home with the type of energy efficiency improvements you installed typically saves $XX annually on energy bills. Assuming you're saving $XX per year on energy, how much would you say the decrease in the number of cases or severity of symptoms of colds, flus and other illnesses adds to the value of living in your home each year, either in dollars or as a percentage of energy savings?

1 $____ / year [SKIP TO PV1]
2 _____% of annual energy savings [SKIP TO PV1]
D Don't know [GO TO CF2A]

[IF REPONDENT SAYS THEY HAVE NOT REALIZED ENERGY SAVINGS: The annual energy bill savings are an estimate based on the type of energy efficiency improvements made to your home. Please try to estimate the value of the decrease in the number of cases or severity of symptoms of colds, flus, and other illnesses in terms of this estimate of bill savings.]

CF2A [IF CF1=1 OR (4 WITH ANY IMPROVEMENTS)] & CF2=DON'T KNOW] In terms of energy bill savings, would you say the decrease in the number of cases or severity of symptoms of colds, flus and other illnesses, is worth…

[READ RESPONSES]
1 Nothing
2 About one-fourth of typical annual energy bill savings
3 About one-half of typical annual energy bill savings
4 About three-fourths of typical annual energy bill savings
5 About equal to the typical annual energy bill savings
6 More than energy bill savings [GO TO A2AX]
7 Other [GO TO A2AX]
8 DO NOT READ: Have not noticed any decrease colds, flu, or other illnesses or in asthma or other chronic conditions.
9 Don't know

CF2AX [IF CF2A=6 OR 7] How much in total?

[IF CF2A=6, $/year must be higher than $XX, or % must be greater than 100]
1 $___/year
2 ____% of annual energy savings

CF3 [IF CF1=2 OR (4 WITH ANY WORSENING)] A home with the type of energy efficiency improvements you installed typically saves $XX annually on energy bills. Assuming you're saving $XX per year on energy, how much would you say the increase in the number of cases or severity of symptoms colds, flus and other illnesses takes away from the value of living in your home each year, either in dollars or as a percentage of energy savings?

1 $____ / year [SKIP TO PV1]
2 _____% of annual energy savings [SKIP TO PV1]
D Don't know [GO TO CF3A]

[IF REPONDENT SAYS THEY HAVE NOT REALIZED ENERGY SAVINGS: The annual energy bill savings are an estimate based on the type of energy efficiency improvements made to your home. Please try to estimate the value of the increase in the number of cases or severity of symptoms of colds, flus, and other illnesses in terms of this estimate of bill savings.]

CF3A [IF CF1=2 OR (4 WITH ANY WORSENING)] & CF3=DON'T KNOW] In terms of energy bill savings, which of the following is closest to the value the increase in the number of cases or severity of symptoms colds, flus and other illnesses takes away from living in your home?

[READ RESPONSES]
1 Nothing
2 About one-fourth of typical annual energy bill savings
3 About one-half of typical annual energy bill savings
4 About three-fourths of typical annual energy bill savings
5 About equal to the typical annual energy bill savings
6 More than energy bill savings [GO TO CF3AX]
7 Other [GO TO CF3AX]
8 DO NOT READ: Have not noticed any increase in colds, flu or other illnesses or worsening of asthma or other chronic conditions
9 Don't know

CF3AX [IF CF3A=6 OR 7] How much in total?

[IF CF3A=6, $/year must be higher than $XX, or % must be greater than 100]
1 $___ / year
2 ____% of annual energy savings

EXPECTED INCREASE IN PROPERTY VALUE [ONLY ASK IF OWN HOME]

PV1 [IF I5 NE 1 SKIP TO EQ1] Not counting any investments you made in the energy efficiency improvements, would you say that, because of the energy efficiency improvements, your home has a HIGHER value than it would have without the improvements, a LOWER value than it would have without the improvements, or would you say about the same value?

1 Higher value [GO TO PV2]
2 Lower value [SKIP TO PV3]
3 No difference [SKIP TO EQ1]
D Don't know [SKIP TO EQ1]

PV2 [IF PV1=1 (HIGHER VALUE)] A home with the type of energy efficiency improvements you installed typically saves $XX annually on energy bills. Assuming you're saving $XX per year on energy, how much would you say the improvements add to the overall value of your property, either in dollars or as a percentage of energy savings?

1 $____ [SKIP TO EQ1]
2 _____% of annual energy savings [SKIP TO EQ1]
D Don't know [GO TO PV2A]

[IF REPONDENT SAYS THEY HAVE NOT REALIZED ENERGY SAVINGS: The annual energy bill savings are an estimate based on the type of energy efficiency improvements made to your home. Please try to estimate the value of the higher property values in terms of this estimate of bill savings.]

PV2A [IF PV1=1 & PV2=DON'T KNOW] In terms of energy bill savings, would you say the improvements add to the value of your home:

[READ RESPONSES]
1 Nothing
2 About one-fourth of typical annual energy bill savings
3 About one-half of typical annual energy bill savings
4 About three-fourths of typical annual energy bill savings
5 About equal to the typical annual energy bill savings
6 More than energy bill savings [GO TO PV2AX]
7 Other [GO TO PV2AX]
8 DO NOT READ: Have not noticed any increased property value
9 Don't know

PV2AX [IF PV2A=6 OR 7] How much in total?

[IF PV2A=6, $/year must be higher than $XX, or % must be greater than 100]
1 $___ / year
2 ____% of annual energy savings

PV3 [IF PV1=2 (LOWER VALUE)] A home with the type of energy efficiency improvements you installed typically saves $XX annually on energy bills. Assuming you're saving $XX per year on energy, how much would you say the improvements take away from the value of your home, either in dollars or as a percentage of energy savings?

1 $____ [SKIP TO EQ1]
2 _____% of annual energy savings [SKIP TO EQ1]
D Don't know [GO TO PV3A]

[IF REPONDENT SAYS THEY HAVE NOT REALIZED ENERGY SAVINGS: The annual energy bill savings are an estimate based on the type of energy efficiency improvements made to your home. Please try to estimate the value of the decreased property values in terms of this estimate of bill savings.]

PV3A [IF PV1=2 & PV3=DON'T KNOW] In terms of energy bill savings, which of the following is closest to the amount that the improvements take away from the value of your home?

[READ RESPONSES]
1 Nothing
2 About one-fourth of typical annual energy bill savings
3 About one-half of typical annual energy bill savings
4 About three-fourths of typical annual energy bill savings
5 About equal to the typical annual energy bill savings
6 More than energy bill savings [GO TO PV3AX]
7 Other [GO TO PV3AX]
8 DO NOT READ: Have not noticed any decreased property value
D Don't know

PV3AX [IF PV3A=6 OR 7] How much in total?

[IF PV3A=6, $/year must be higher than $XX, or % must be greater than 100]
1 $___
2 ____% of annual energy savings

EQUIPMENT MAINTENANCE / RELIABILITY [ONLY ASK IF INSTALLED HEATING AND COOLING EQUIPMENT]

EQ1 [ASK IF RESPONDENT INSTALLED HEATING AND COOLING EQUIPMENT; OTHERWISE, SKIP TO LT1] In terms of the maintenance requirements or reliability of your heating and cooling equipment, would you say that, because of the energy efficiency improvements, your heating and cooling equipment 1) requires LESS maintenance and is MORE reliable than before the improvements were made, 2) requires MORE maintenance and is LESS reliable, or would you say that 3) there is no difference in the maintenance requirements or reliability of your heating and cooling equipment?

1 Less maintenance/more reliable [GO TO EQ2]
2 More maintenance/less reliable [SKIP TO EQ3]
3 No difference [SKIP TO LT1]
D Don't know [SKIP TO LT1]

EQ1A [IF I8=10 (Increased reliability) AND EQ1=2 (More maintenance)] Earlier you said that your appliances or heating and cooling equipment seemed more reliable. Can you please confirm for me whether the energy efficiency improvements have had an overall POSITIVE or NEGATIVE impact on your appliance or equipment's reliability, or have the improvements made no difference to its reliability?

1 Positive [SKIP TO EQ2]
2 Negative [SKIP TO EQ3]
3 No difference [SKIP TO LT1]
D Don't know [SKIP TO LT1]

EQ1B [IF I8=9 (Decreased reliability) AND EQ1=2 (Less maintenance)] Earlier you said that your appliances or heating and cooling equipment seemed less reliable. Can you please confirm for me whether the energy efficiency improvements have had a POSITIVE or NEGATIVE impact on your appliance or equipment's reliability, or have the improvements made no difference to its reliability? 1 Positive [SKIP TO EQ2] 2 Negative [SKIP TO EQ3]

3 No difference [SKIP TO LT1]
D Don't know [SKIP TO LT1]

EQ2 [IF EQ1=1 (LESS MAINTENANCE)] A home with the type of energy efficiency improvements you installed typically saves $XX annually on energy bills. Assuming you're saving $XX per year on energy, how much would you say the reduction in maintenance of heating and cooling equipment adds to the value of living in your home each year, either in dollars or as a percentage of energy savings?

1 $____ / year [SKIP TO LT1]
2 _____% of annual energy savings [SKIP TO LT1]
D Don't know [GO TO EQ2A]

[IF REPONDENT SAYS THEY HAVE NOT REALIZED ENERGY SAVINGS: The annual energy bill savings are an estimate based on the type of energy efficiency improvements made to your home. Please try to estimate the value of the reduction in maintenance of heating and cooling equipment in terms of this estimate of bill savings.]

EQ2A [IF EQ1=1 & EQ2=DON'T KNOW] In terms of energy bill savings, would you say the reduction in maintenance of heating and cooling equipment is worth…

[READ RESPONSES]
1 Nothing
2 About one-fourth of typical annual energy bill savings
3 About one-half of typical annual energy bill savings
4 About three-fourths of typical annual energy bill savings
5 About equal to the typical annual energy bill savings
6 More than energy bill savings [GO TO EQ2AX]
7 Other [GO TO EQ2AX]
8 DO NOT READ: Have not noticed any reduction in maintenance to heating and cooling equipment
D Don't know

EQ2AX [IF EQ2A=6 OR 7] How much in total?

[IF EQ2A=6, $/year must be higher than $XX, or % must be greater than 100]
1 $___ / year
2 ____% of annual energy savings

EQ3 [IF EQ1=2 (MORE MAINTENANCE)] A home with the type of energy efficiency improvements you installed typically saves $XX annually on energy bills. Assuming you're saving $XX per year on energy, how much would you say the increase in maintenance of heating and cooling equipment takes away from the value of living in your home each year, either in dollars or as a percentage of energy savings?

1 $____ / year [SKIP TO LT1]
2 _____% of annual energy savings [SKIP TO LT1]
D Don't know [GO TO EQ3A]

[IF REPONDENT SAYS THEY HAVE NOT REALIZED ENERGY SAVINGS: The annual energy bill savings are an estimate based on the type of energy efficiency improvements made to your home. Please try to estimate the value of the increase in maintenance of heating and cooling equipment in terms of this estimate of bill savings.]

EQ3A [IF EQ1=2 & EQ3=DON'T KNOW] In terms of energy bill savings, which of the following is closest to the value that the increase in maintenance to heating and cooling equipment takes away from living in your home?

[READ RESPONSES]
1 Nothing
2 About one-fourth of typical annual energy bill savings
3 About one-half of typical annual energy bill savings
4 About three-fourths of typical annual energy bill savings
5 About equal to the typical annual energy bill savings
6 More than energy bill savings [GO TO EQ3AX]
7 Other [GO TO EQ3AX]
8 DO NOT READ: Have not noticed any increase in maintenance to heating and cooling equipment
D Don't know

EQ3AX [IF EQ3A=6 OR 7] How much in total?

[IF EQ3A=6, $/year must be higher than $XX, or % must be greater than 100]
1 $___/year
2 ____% of annual energy savings

LIGHTING QUALITY AND LIFETIME [ONLY ASK IF INSTALLED LIGHTING]

LT1 [ASK IF RESPONDENT INSTALLED LIGHTING; OTHERWISE, SKIP TO D1] The energy efficient lighting you installed, in addition to saving energy, generally has a longer lifetime and may also have a different lighting quality than incandescent lighting. After installing the energy efficient lighting, would you say that the longer lifetime and lighting quality of the new lighting, taken together, is a POSITIVE feature of the lighting, a NEGATIVE feature of the lighting, or makes no difference to you?

1 Positive feature [GO TO LT2]
2 Negative feature [SKIP TO LT3]
3 No difference [SKIP TO D1]
D Don't know [SKIP TO D1]

LT2 [IF LT1=1 (POSITIVE FEATURE)] A home with the type of energy efficiency improvements you installed typically saves $XX annually on energy bills. Assuming you're saving $XX per year on energy, how much would you say the longer life and lighting quality of your energy efficient lighting add to the value of living in your home each year, either in dollars or as a percentage of energy savings?

1 $____ / year [SKIP TO D1]
2 _____% of annual energy savings [SKIP TO D1]
D Don't know [GO TO LT2A]

[IF REPONDENT SAYS THEY HAVE NOT REALIZED ENERGY SAVINGS: The annual energy bill savings are an estimate based on the type of energy efficiency improvements made to your home. Please try to estimate the value of the longer life and lighting quality of your energy efficient lighting in terms of this estimate of bill savings.]

LT2A [IF LT1=1 & LT2= DON'T KNOW] In terms of energy bill savings, would you say the longer life and lighting quality is worth…

[READ RESPONSES]
1 Nothing
2 About one-fourth of typical annual energy bill savings
3 About one-half of typical annual energy bill savings
4 About three-fourths of typical annual energy bill savings
5 About equal to the typical annual energy bill savings
6 More than energy bill savings [GO TO LT2AX]
7 Other [GO TO LT2AX]
8 DO NOT READ: Have not noticed longer life and lighting quality
D Don't know

LT2AX [IF LT2A=6 OR 7] How much in total?

[IF LT2A=6, $/year must be higher than $XX, or % must be greater than 100]
1 $___/year
2 ____% of annual energy savings

LT3 [IF LT1=2 (NEGATIVE FEATURE)] A home with the type of energy efficiency improvements you installed typically saves $XX annually on energy bills. Assuming you're saving $XX per year on energy, how much would you say the longer life and lighting quality of your energy efficient lighting takes away from the value of living in your home each year, either in dollars or as a percentage of energy savings?

1 $____ / year [SKIP TO D1]
2 _____% of annual energy savings [SKIP TO D1]
D Don't know [GO TO LT3A]

[IF REPONDENT SAYS THEY HAVE NOT REALIZED ENERGY SAVINGS: The annual energy bill savings are an estimate based on the type of energy efficiency improvements made to your home. Please try to estimate the value of the longer life and lighting quality of your energy efficient lighting in terms of this estimate of bill savings.]

LT3A [IF LT1=2 & LT3=DON'T KNOW] In terms of energy bill savings, which of the following is closest to the value that the longer life and lighting quality takes away from living in your home?

[READ RESPONSES]
1 Nothing
2 About one-fourth of typical annual energy bill savings
3 About one-half of typical annual energy bill savings
4 About three-fourths of typical annual energy bill savings
5 About equal to the typical annual energy bill savings
6 More than energy bill savings [GO TO LT3AX]
7 Other [GO TO LT3AX]
8 DO NOT READ: Have not noticed longer life and lighting quality
D Don't know

LT3AX [IF LT3A=6 OR 7] How much in total?

[IF LT3A=6, $/year must be higher than $XX, or % must be greater than 100]
1 $___ / year
2 ____% of annual energy savings

DURABILITY OF HOME

D1 In terms of the durability of your home, would you say that, because of the energy efficiency improvements, your home is 1) MORE durable and LESS prone to needing repairs than before the improvements were made, 2) LESS durable and MORE prone to needing repairs, or would you say that 3) there is no difference in the durability of your home?

1 More durable/fewer repairs [GO TO D2]
2 Less durable/ more repairs [SKIP TO D3]
3 No difference [SKIP TO T1]
D Don't know [SKIP TO T1]

D2 [IF D1=1 (MORE DURABLE)] A home with the type of energy efficiency improvements you installed typically saves $XX annually on energy bills. Assuming you're saving $XX per year on energy, how much would you say the increased durability adds to the value of living in your home each year, either in dollars or as a percentage of energy savings?

1 $____ / year [SKIP TO T1]
2 _____% of annual energy savings [SKIP TO T1]
D Don't know [GO TO D2A]

[IF REPONDENT SAYS THEY HAVE NOT REALIZED ENERGY SAVINGS: The annual energy bill savings are an estimate based on the type of energy efficiency improvements made to your home. Please try to estimate the value of the increased durability in terms of this estimate of bill savings.]

D2A [IF D1=1 & D2=DON'T KNOW] In terms of energy bill savings, would you say the increased durability of your home is worth…

[READ RESPONSES]
1 Nothing
2 About one-fourth of typical annual energy bill savings
3 About one-half of typical annual energy bill savings
4 About three-fourths of typical annual energy bill savings
5 About equal to the typical annual energy bill savings
6 More than energy bill savings [GO TO D2AX]
7 Other [GO TO D2AX]
8 DO NOT READ: Have not noticed any increase in the durability of the home
D Don't know

D2AX [IF D2A=6 OR 7] How much in total?

[IF D2A=6, $/year must be higher than $XX, or % must be greater than 100]
1 $___/year
2 ____% of annual energy savings

D3 [IF D1=2 (LESS DURABLE)] A home with the type of energy efficiency improvements you installed typically saves $XX annually on energy bills. Assuming you're saving $XX per year on energy, how much would you say the decreased durability of your home takes away from the value of living in your home each year, either in dollars or as a percentage of energy savings?

1 $____ / year [SKIP TO T1]
2 _____% of annual energy savings [SKIP TO T1]
D Don't know [GO TO D3A]

[IF REPONDENT SAYS THEY HAVE NOT REALIZED ENERGY SAVINGS: The annual energy bill savings are an estimate based on the type of energy efficiency improvements made to your home. Please try to estimate the value of the decreased durability in terms of this estimate of bill savings.]

D3A [IF D1=2 & D3=DON'T KNOW] In terms of energy bill savings, which of the following is closest to the value that the decreased durability of your home takes away from living in your home?

[READ RESPONSES]
1 Nothing
2 About one-fourth of typical annual energy bill savings
3 About one-half of typical annual energy bill savings
4 About three-fourths of typical annual energy bill savings
5 About equal to the typical annual energy bill savings
6 More than energy bill savings [GO TO D3AX]
7 Other [GO TO D3AX]
8 DO NOT READ: Have not noticed any decrease in the durability of the home
D Don't know

D3AX [IF D3A=6 OR 7] How much in total?

[IF D3A=6, $/year must be higher than $XX, or % must be greater than 100]
1 $___ / year
2 ____% of annual energy savings

TOTAL VALUE OF NEIS

T1 [ASK IF I5=1 (OWN); OTHERWISE, SKIP TO T2] Next, please think about the total of all of the positive and negative effects caused by the energy efficient improvements made to your home EXCEPT for any changes in your property value. To summarize, you reported that [LIST POSITIVE EFFECTS] were positive effects and that [LIST NEGATIVE EFFECTS] were negative effects caused by the energy efficient improvements made to your home. Would you say that the combination of all of these effects is positive, negative or no effect?

1 Positive [SKIP TO T3]
2 Negative [SKIP TO T5]
3 No Effect [SKIP TO H1]
D Don't know [SKIP TO H1]
R Refused [SKIP TO H1]

T2 [ASK IF I5=2 (RENT)] Next, please think about the total of all of the positive and negative effects caused by the energy efficient improvements made to your home. To summarize, you reported that [LIST POSITIVE EFFECTS] were positive effects and that [LIST NEGATIVE EFFECTS] were negative effects caused by the energy efficient improvements made to your home. Would you say that the combination of all of these effects is positive, negative or no effect?

1 Positive [GO TO T3]
2 Negative [SKIP TO T5]
3 No Effect [SKIP TO H1]
D Don't know [SKIP TO H1]
R Refused [SKIP TO H1]

T3 [IF T1=1 OR T2=1 (POSITIVE)] Assuming you're saving $XX per year on energy, what is the value of all of the effects combined each year, either in dollars or as a percentage of energy savings?

1 $____ / year [SKIP TO H1]
2 _____% of annual energy savings [SKIP TO H1]
D Don't know [GO TO T3A]

[IF REPONDENT SAYS THEY HAVE NOT REALIZED ENERGY SAVINGS: The annual energy bill savings are an estimate based on the type of energy efficiency improvements made to your home. Please try to estimate the combined value of all of the effects in terms of this estimate of bill savings.]

T3A [IF (T1=1 OR T2=1) & T3=DON'T KNOW] In terms of energy bill savings, would you say the value of all of the effects combined is worth…

[READ RESPONSES]
1 Nothing
2 About one-fourth of typical annual energy bill savings
3 About one-half of typical annual energy bill savings
4 About three-fourths of typical annual energy bill savings
5 About equal to the typical annual energy bill savings
6 More than energy bill savings [GO TO T3AX]
7 Other [GO TO T3AX]
D Don't know

T3AX [IF T3A=6 OR 7] How much in total?

[IF T3A=6, $/year must be higher than $XX, or % must be greater than 100]
1 $___ / year
2 ____% of annual energy savings

T4 [IF T1=2 OR T2=2 (NEGATIVE)] Assuming you're saving $XX per year on energy, how much value would you say all of the effects combined takes away from the value of living in your home each year, either in dollars or as a percentage of energy savings?

1 $____ / year [SKIP TO H1]
2 _____% of annual energy savings [SKIP TO H1]
D Don't know [GO TO T4A]

[IF REPONDENT SAYS THEY HAVE NOT REALIZED ENERGY SAVINGS: The annual energy bill savings are an estimate based on the type of energy efficiency improvements made to your home. Please try to estimate the combined value of all of the effects in terms of this estimate of bill savings.]

T4A [IF T1=2 OR T2=2 & T4=DON'T KNOW] In terms of energy bill savings, which of the following is closest to the value that all of the effects combined take away from living in your home?

[READ RESPONSES]
1 Nothing
2 About one-fourth of typical annual energy bill savings
3 About one-half of typical annual energy bill savings
4 About three-fourths of typical annual energy bill savings
5 About equal to the typical annual energy bill savings
6 More than energy bill savings [GO TO T4AX]
7 Other [GO TO T4AX]
D Don't know

T4AX [IF T4A=6 OR 7] How much in total?

[IF T4A=6, $/year must be higher than $XX, or % must be greater than 100]
1 $___ / year
2 ____% of annual energy savings

HOUSEHOLD HEALTH

H1 Next I have just a few more questions about your household's health since you installed the energy efficiency improvements. Since installing the energy efficiency improvements, have you or anyone else in your household missed work because of illness to you or a member of your household?

1	Yes	[GO TO H2]
2	No	[SKIP TO H3B]
D	Don't know	[SKIP TO H4]
R	Refused	[SKIP TO H4]

H2 How many days of work have you or anyone else in your household missed work because of illness to you or a member of your household?

___ [RECORD NUMBER]

H3 How does this compare to the 12 months before the efficiency improvements were installed? Would you say it is more, less, or about the same?

1 More [Go to H3A]
2 Less [Go to H3A]
3 About the same [Skip to H4]
D Don't know [Skip to H4]
R Refused [Skip to H4]

H3A [IF H3=1 or 2] How many [more/less]?

___ [RECORD NUMBER] [Skip to H3D]

H3B In the 12 months before the efficiency improvements were installed, did you or anyone else in your household miss work because of illness to you or a member of your household?

1	Yes	[GO TO H3C]
2	No	[SKIP TO H4]
D	Don't know	[SKIP TO H4]
R	Refused	[SKIP TO H4]

H3C How many days of work did you or anyone else in your household miss because of illness to you or a member of your household in the 12 months before the efficiency improvements were installed?

___ [RECORD NUMBER]

H3D Please think of the reasons for the change in the number of sick days off work in your household, from the year before the energy efficiency improvements were installed to the period since they were installed. Do you think the change is related to the energy efficiency improvements or do you think the change is unrelated to the improvements?

1 Related
2 Unrelated
3 Don't know
R Refused

H4 Since installing the energy efficiency improvements, have you or anyone else in your household sought medical care at a hospital, emergency room, or urgent care facility for heat stress that occurred while inside your home?

1 Yes [GO TO H5]
2 No [SKIP TO H6B]
D Don't know [SKIP TO H8]
R Refused [SKIP TO H8]

H5 How many times have you or anyone else in your household sought medical care at a hospital, emergency room, or urgent care facility for heat stress?

___ [RECORD NUMBER]

How does this compare to the twelve months before you installed the efficiency improvements? Would you say it is more, less, or about the same?

1 More [GO TO H6A]
2 Less [GO TO H6A]
3 About the same [SKIP TO H7]
D Don't know [SKIP TO H7]
R Refused [SKIP TO H7]

H6A [IF H6=1 or 2] How many [more/less]?

___ [RECORD NUMBER] [Skip to H7]

H6B In the twelve months before the efficiency improvements were installed, did you or anyone else in your household seek medical care because of heat stress that occurred while inside your home?

1 Yes [GO TO H6C]
2 No [SKIP TO H8]
D Don't know [SKIP TO H8]
R Refused [SKIP TO H8]

H6C How many times did you or anyone else in your household seek care because of heat stress in the twelve months before the efficiency improvements were installed?

___ [RECORD NUMBER] [SKIP TO H8]

H7 Since installing the energy efficiency improvements, how many days were you or anyone else in your household hospitalized due to heat stress?

___ [RECORD NUMBER]

H8 Since installing the energy efficiency improvements, have you or anyone else in your household sought medical care at a hospital, emergency room, or urgent care facility for overexposure to cold conditions inside your home?

1 Yes [GO TO H9]
2 No [SKIP TO H10B]
D Don't know [SKIP TO H12]
R Refused [SKIP TO H12]

H9 How many times have you or anyone else in your household sought medical care at a hospital, emergency room, or urgent care facility for overexposure to cold conditions inside your home?

___ [RECORD NUMBER]

H10 How does this compare to the 12 months before you installed the efficiency improvements? Would you say it is more, less, or about the same?

1 More [GO TO H10A]
2 Less [GO TO H10A]
3 About the same [SKIP TO H11]
D Don't know [SKIP TO H11]
R Refused [SKIP TO H11]

H10A [IF H10=1 OR 2] How many [more/less]?

___ [RECORD NUMBER] [SKIP TO H11]

H10B In the twelve months before the efficiency improvements were installed, did you or anyone else in your household seek medical care for overexposure to cold conditions inside your home?

1 Yes [GO TO H10C]
2 No [SKIP TO H12]
D Don't know [SKIP TO H12]
R Refused [SKIP TO H12]

H10C How many times did you or anyone else in your household seek care for overexposure to cold conditions inside your home in the 12 months before the efficiency improvements were installed?

___ [RECORD NUMBER] [SKIP TO H12]

H11 Since installing the energy efficiency improvements, how many days were you or anyone else in your household hospitalized due to overexposure to cold conditions?

___ [RECORD NUMBER]

H12 Has anyone in your household been diagnosed with asthma or a related chronic health condition?

1 Yes [GO TO H13]
2 No [SKIP TO DG1]
D Don't know [SKIP TO DG1]

H13 [ASK IF H12=1] Since installing the energy efficiency improvements, have you or anyone else in your household sought medical care at a hospital, emergency room, or urgent care facility due to their asthma or other chronic health condition?

1 Yes [GO TO H14]
2 No [SKIP TO H15B]
D Don't know [SKIP TO DG1]
R Refused [SKIP TO DG1]

H14 How many times have you or anyone else in your household sought medical care at a hospital, emergency room, or urgent care facility due to their asthma or other chronic health condition?

___ [RECORD NUMBER]

H15 How does this compare to the 12 months before you installed the efficiency improvements? Would you say it is more, less, or about the same?

1 More [GO TO H15A]
2 Less [GO TO H15A]
3 About the same [SKIP TO H16]
D Don't know [SKIP TO H16]
R Refused [SKIP TO H16]

H15A [IF H15=1 OR 2] How many [more/less]?

___ [RECORD NUMBER] [SKIP TO H16]

H15B In the twelve months before the efficiency improvements were installed, did you or anyone else in your household seek medical care for their asthma or related chronic health condition?

1 Yes [GO TO H15C]
2 No [SKIP TO DG1]
D Don't know [SKIP TO DG1]
R Refused [SKIP TO DG1]

H15C How many times did you or anyone else in your household seek care for their asthma or related chronic health condition in the twelve months before the efficiency improvements were installed?

___ [RECORD NUMBER] [SKIP TO DG1]

H16 Since installing the energy efficiency improvements, how many days were you or anyone else in your household hospitalized due to their asthma or other chronic health condition?

___ [RECORD NUMBER]

DEMOGRAPHICS

DG1 Now I have a few last questions for statistical purposes only. Including yourself, how many people live in your home in the following age ranges most of the year?

_A Less than 18 years old
_B 18 to 64
_C 65 or older

FOR DG1_A TO DG1_C

__ [RECORD NUMBER]
99 REFUSED

DG2 Approximately how many square feet is your home?

1 Less than 1,500
2 1,500 to less than 2,000
3 2,000 to less than 2,500
4 2,500 to less than 3,000
5 3,000 to less than 4,000
6 4,000 to less than 5,000
7 5,000 or more
D Don't know
R Refused

DG3 [IF DG2=D/R] How many rooms are in your home, not counting bathrooms or unfinished basements?

1 1
2 2
3 3
4 4
5 5
6 6
7 7
8 8
9 9
10 10 or more
11 Refused

DG4 What is the highest level of education that you have completed?

[READ CATEGORIES]
1 Less than high school
2 High school graduate
3 Technical or trade school graduate
4 Some college
5 College graduate
6 Some graduate school
7 Graduate degree
R Refused

DG5 What is your age? Are you…

[READ CATEGORIES]
1 18 to 24
2 25 to 34
3 35 to 44
4 45 to 54
5 55 to 64
6 65 or over
R Refused

DG6 What category best describes your total household income in 2010, before taxes?

[READ CATEGORIES]
1 Less than $15,000
2 $15,000 to less than $25,000
3 $25,000 to less than $35,000
4 $35,000 to less than $50,000
5 $50,000 to less than $75,000
6 $75,000 to less than $100,000
7 $100,000 to less than $150,000
8 $150,000 or more
R Refused

DG7 [DO NOT READ] Gender

1 Female
2 Male

COMMONWEALTH OF MASSACHUSETTS

DEPARTMENT OF PUBLIC UTILITIES

Cape Light Compact to the Department of Public Utilities for Approval of Mid-Term Modifications to Its Three-Year Energy Efficiency Plan for Plan Year 2012	)	D.P.U. 11-116

AFFIDAVIT OF KEVIN F. GALLIGAN

Kevin F. Galligan does hereby depose and say as follows:

I, Kevin F. Galligan, certify that the Petition and attached Exhibits filed on this date, on behalf of the Cape Light Compact, were prepared by me or under my supervision and are true and accurate to the best of my knowledge and belief.

Signed under the pains and penalties of perjury.

Kevin F. Galligan

Kevin F. Galligan

Dated: October 28, 2011

T:\Clients\BCY\EEP\EEP Implementation\2010 - 2012 EEP Filing\2012 MTM Filing (DPU 11-116)\KFG Affidavit 10-28-11 (bcy).doc