JEFFREY M. LOITER, PARTNER

Optimal Energy|10600 Route 116, Suite 3|Hinesburg, VT 05401|802-482-5610|loiter@optenergy.com

PROFESSIONAL EXPERIENCE

Optimal Energy, Hinesburg, VT. *Partner*, 2015-present; *Managing Consultant*, 2006-2014.

As a Partner, Mr. Loiter is responsible for business development, administrative systems, and staff development in addition to project management. In addition, he provides quality control and editing for all of Optimal's client deliverables. His project work includes designing and developing statewide and utility-specific efficiency programs and supporting program implementation for both public and private-sector clients. He works primarily in the commercial sector on programs targeting electric, natural gas, and un-regulated fossil fuel consumption and specializes in developing solutions that fit the needs of specific customer segments and markets. Mr. Loiter is also an experienced analyst and uses these skills in a variety of contexts, such as reviewing and critiquing utility Integrated Resource Plans and efficiency potential studies.

Independent Consultant, Cambridge, MA, 2005-2006.

As an independent consultant for the Massachusetts Renewable Energy Trust SEED Initiative, Mr. Loiter evaluated renewable energy technology companies' applications for early-stage funding. Responsibilities included leading due diligence efforts on three applications and contributing to several others. Awards recommended for approval totaled $1.4 million. For a separate client, prepared two articles describing the potential impact of proposed federal legislation to increase domestic oil refining capacity, published in Petroleum Technology Quarterly (1Q 2006) and BCC Research/Energy Magazine (2006).

Industrial Economics, Inc., Cambridge, MA. *Associate*, 1997-2000; *Senior Associate*, 2001-2004.

Managed multi-disciplinary qualitative and quantitative assessments of natural resource damages and environmental policy for clients such as NOAA, USFWS, USEPA, USDOJ, the National Park Service, the State of Indiana, and the United Nations.

URS Consultants, Inc., New Orleans & Boston., 1991-1995.

Prepared water, air, and solid and hazardous waste permit applications for state and federal agencies on behalf of industry clients.

EDUCATION

Massachusetts Institute of Technology, Cambridge, MA
Master of Science in Technology & Policy, 1997

Cornell University, Ithaca, NY
Bachelor of Science with distinction, Civil and Environmental Engineering, 1991

REPRESENTATIVE PROJECT EXPERIENCE

Concord Municipal Light Plant, Strategic Planning Guidance and Modelling (2016-2017)
Optimal Energy and partner Industrial Economics, Inc, engaged the municipal electric utility in a strategic planning process with objective of charting a path towards accomplishing a range of town and utility goals, including greenhouse gas reductions, cost control, customer engagement, and beneficial electrification. The key deliverable from this project was an innovative strategic planning tool that allows the town to assess the overall effects of implementing multiple initiatives in a way that captures the interaction between sales, costs, revenues, rates, and greenhouse gas emissions.

Delaware Department of Natural Resources and Environmental Control, Energy Efficiency Advisory Council Program Development and Support (2015-present)
Optimal Energy provides broad program planning, analysis, and strategic guidance to the Delaware Energy Efficiency Advisory Council as it begins developing a new model for joint utility and public-sector delivery of energy efficiency services, with the objective of dramatically increasing energy savings and demand reductions in that state. In support of the Council, Mr. Loiter drafted Council organizing documents and regulations specifying evaluation, measurement, and verification (EM&V) procedures and standards. He also provided the Council with proposed electric and gas energy savings targets as supported by an earlier potential study.

Connecticut Municipal Electric Energy Cooperative, Conservation and Load Management Consulting (2006-present)
Optimal has provided energy efficiency consulting services to the Connecticut Municipal Electric Energy Cooperative (CMEEC) since the inception of their conservation and load management programs. Mr. Loiter contributes to the full range of these services, including program planning, program savings analysis and reporting, developing incentive and delivery strategies, and managing CMEEC's participation in the ISO-NE Forward Capacity Market. The latter has included drafting M&V plans specifying procedures for meeting all ISO-specified M&V rules and developing a web-based data tracking and reporting system. Mr. Loiter also helps CMEEC develop strategy for and manage participation in new FCM auctions and arranges for required annual certification reviews.

Orange and Rockland Utilities, Energy Efficiency Program Consulting (2006-present)
Optimal Energy supports program implementation and on-going program design and development for Orange and Rockland Utilities, a subsidiary of Consolidated Edison, Inc. Mr. Loiter managed the preparation of a DSM plan and Commission filings for this client during the initial phases of the New York State Energy Efficiency Resource Standard. He also led the commercial sector component of an electric and gas potential study for the utility, which included on-site customer audits and residential surveys.

New York State Department of Public Service, Generic Environmental Impact Statement and Supplement (2014-2016)
As part of proceedings on Reforming the Energy Vision (REV) and the Clean Energy Fund (CEF), Optimal contributed to a Generic Environmental Impact Statement (GEIS) by describing alternative energy supply resources, the potential scale of their use under two future scenarios, and the magnitude of possible negative environmental impacts that would result. Mr. Loiter led a team researching several technologies, including energy efficiency, customer-sited renewables, combined heat and power, alternative rate structures, and energy storage. The research led to estimates of the potential scale and impact of these solutions to New York's future energy challenges.

British Columbia Utility Commission, DSM Filing Technical Support (2012-2013)
In support of staff of the BCUC, Optimal Energy reviewed three utility filings related to DSM programs,

cost-recovery, and performance-based ratemaking. Mr. Loiter led a team that reviewed the filings, drafted interrogatories, and provided information regarding the appropriateness of program designs, measure-level costs and savings e, and cost-effectiveness inputs such as discount rates and avoided costs.

Maryland Energy Administration, EmPOWER Maryland Filing Reviews (2008-2009)
As part of efforts to reduce per-capita electric and natural gas under the 2008 EmPOWER Maryland Energy Efficiency Act, the Maryland Energy Administration was responsible for reviewing and commenting on utility-delivered energy efficiency programs and for designing and implementing its own state-wide efficiency portfolio. Mr. Loiter contributed to both of these efforts, appearing before the Public Service Commission on two occasions.

EPA State and Local Branch, EPA National Action Plan for Energy Efficiency (2008)
Prepared two documents for inclusion with EPA's National Action Plan for Energy Efficiency: a guidebook on conducting efficiency potential studies and a handbook describing the funding and administration of clean energy funds.

Various Clients (2008-present)
Studies of Energy Efficiency and Demand Response Potential
Led or contributed to several studies of efficiency and demand response potential, ranging from meta-analyses to detailed sector-specific assessments. Assessments have included both the residential sector and the commercial/industrial sectors, in locations including New York, Delaware, Vermont, New England, Texas, and a Canadian Atlantic province.

Tennessee Valley Authority, Energy Efficiency and Demand Response Plan (2012)
Managed Optimal's participation in a team developing a Five-Year Energy Efficiency and Demand Response Plan for the Tennessee Valley Authority. Optimal's role focused on programs for the commercial sector in TVA's service territory, encompassing efforts to reach a variety of markets and end-uses, including specific offerings for both very large and small commercial entities.

REPRESENTATIVE PUBLICATIONS

"Collaboration that Counts: The Role of State Energy Efficiency Stakeholder Councils," (with D. Sosland, M. Guerard, and J. Schlegel), *2012 ACEEE Summer Study on Energy Efficiency in Buildings,* Pacific Grove, CA, August 2012.

"Persistence and Cost of Behavioral Programs," presented at National Association of State Utility Consumer Advocates Mid-Year Meeting, Charleston, SC, June 2012.

"Impending EISA Lighting Standards: Impacts on Consumers and Energy Efficiency Lighting Programs," presented at National Association of Regulatory Utility Commissioners Annual Meeting (with M. DiMascio), Atlanta, GA, November 2010.

"From Resource Acquisition to Relationships: How Energy Efficiency Initiatives Can Work Effectively with Large Commercial & Industrial Customers," (with E. Belliveau, J. Kleinman, D. Gaherty, and G. Eaton), *2008 ACEEE Summer Study on Energy Efficiency in Buildings,* Pacific Grove, CA, August 2008.

National Action Plan for Energy Efficiency (2007). *Guide for Conducting Energy Efficiency Potential Studies.* Prepared by Philip Mosenthal and Jeff Loiter, Optimal Energy, Inc. December.

Loiter J.M and V. Norberg-Bohm (1999), "Technology policy and renewable energy: public roles in the development of new technologies," *Energy Policy* Vol.27 no.85-97

Request:
Reference New Hampshire Statewide Energy Efficiency Plan 2019 Update, at Bates 10-11, stating "The proposed SBC rate is 17 percent lower than the estimated 2019 SBC energy efficiency program rate…included in the [17-136] Settlement Agreement [and approved in]…the Commission's Order No. 25,932 in the EERS proceeding," and 374-F:3, VI stating "Legislative approval of the New Hampshire general court shall be required to increase the system benefits charge. This requirement of prior approval of the New Hampshire general court shall not apply to the full implementation of Order No. 25,932 issued by the commission, dated August 2, 2016," and Order No. 26,095 stating "The three-year level of funding for the electric programs is $154,142,000. Exhibit 2 at 31, Table 4.9. The 2018 funding level is $38,635,000; the 2019 funding level is $49,488,000; and the 2020 funding level is 66,019,000."

a. Please explain why the funding rate which was approved in either Order No. 25,932 or Order No. 26,095 is not the current rate used for the planned budget for 2019.
b. If it is the joint utilities' position that adjustment of the proposed SBC below the level established in Order No 25,932 complies with that Order and the directive provided to the Commission by the recent passage of HB 317, please explain why.
c. Is it the joint utilities' position that adjustment of the proposed SBC above the level established in Order No. 25,932 would comply with that Order and the directive provided to the Commission by the recent passage of HB 317. If not, please explain why.
d. Assuming the joint utilities can achieve the 2019 savings as a percent of retail sales approved in Order No. 25,932 with less funding than was assumed in the 2018-20 Plan, would the joint utilities object to leaving the SBC rate at the level approved in Order No 25.932 and utilizing any excess collections as a means of capitalizing a loan loss reserve or similar credit enhancement facility, therefore alleviating the current and future program costs associated with interest rate buy-downs? If so, please explain why.

Response:

a) As an initial matter, the question appears to be based upon the premise that the purpose of the EERS is to reach a specific spending target. Instead, the purpose of the EERS is to reach certain savings goals. In the DE 15-137 settlement it states, at page 7, that in developing the EERS plan "the Utilities **shall** incorporate the following statewide savings goals for the first three-year period" (emphasis added). The role of the utilities is to propose and use the funding amounts needed to cost-effectively reach the agreed upon, and required, savings goals, not simply to assure that a specific amount of money is spent or collected in any particular year.

- The SBC Rates presented in the DE 15-137 Settlement Agreement and Order were estimates to be further refined in the 2018-2020 Plan and the PUC did not issue approval for future rate changes with Order No. 25,932. Page 8 of the Settlement Agreement states: "The Settling Parties agree that the savings goals balance the goals of capturing more cost effective energy efficiency and benefits to ratepayers with the goal of gradually increasing funding for efficiency while minimizing the impacts on all ratepayers. The Utilities' **estimated** costs to achieve the identified savings goals are shown in Electric Attachment A, Page 10 and Gas Attachment B, Page 7. The Utilities will provide to the parties and the planning expert referred to in this Section II.C for review and comment updated estimated costs for achieving these savings levels as part of the comprehensive EERS Plan…" Additionally, " annual update filings shall be submitted for review by the Commission in an abbreviated process substantially similar to the mid-period submission presently used in the Core dockets. "

- The Commission specifically approved an SBC Rate for the 2018 programs, effective January 1, 2018. See the Secretarial Letter issued on December 29, 2017. http://www.puc.state.nh.us/Regulatory/Docketbk/2017/17-136/LETTERS-MEMOS-TARIFFS/17-136_2017-12-29_SEC_LTR_APP_SYSTEM_BENEFIT_CHARGE.PDF. Page 19 of Order No. 26,095 also specifically approves the SBC rates for the 2018 programs. "The System Benefits Charge rates presented by the Utilities in Exhibit 2 at 434 are hereby approved for effect January 1, 2018." The Commission did not issue similar approvals for SBC rates for 2019 or 2020 in Order No 26,095.

- The funding and budgets presented for 2019 and 2020 in the 2018-2020 Plan were based on a set of assumptions for SBC amounts (assumed sales forecasts and an assumed SBC Rate), RGGI funding amounts, FCM amounts and carryover amounts, as well as program costs and savings assumptions. However, the specific SBC rates for 2019 and 2020 were not proposed or approved in the 3-Year Plan because the process includes annual updates for these years. The annual update incorporates actual carryover amounts from 2017 as well as more current estimates of forecasted sales, RGGI funding, FCM revenues, savings assumptions, programs costs and also therefore, an updated SBC rate.

b) Order No. 25,932 did not approve an SBC rate for 2019 or any other year. The SBC rate for 2017 was approved in Order No. 25,976. The SBC rate for 2018 was approved in the Secretarial Letter dated 12-29-17 and Order No. 26,095. SBC rates for 2019 and 2020 will be approved during the annual update process for those program years. If the funding and budgets needed to achieve the approved savings target result in a proposed SBC rate lower than the estimates provided in the DE 15-137 Settlement, the proposal complies with Order No 25,932. Moreover, the SBC rates for 2017 and 2018 were both lower than their DE 15-137 Settlement estimates and received no objection from any party.

c) If the revised estimates for RGGI funding, FCM amounts, carryover amounts, program costs, and savings assumptions led to a need for an SBC amount above the estimates provided in Order No. 25,932 in order to reach the agreed upon savings targets then proposal of that higher SBC amount would comply with the Order.

d) If all parties agreed that the SBC rate should be set in order to achieve the budget amounts indicated for 2019 in the 2018-2020 Plan, the utilities would be open to discussing with parties the optimal use for those additional funds. We are not convinced at this time that a loan loss reserve would be the optimal use for theoretical additional funds. The program costs associated with interest rate buy-downs are currently minimal. The buy-downs provide residential customers with a 2% interest loan intended to remove barriers to implementing energy efficiency projects. A small percentage of completed projects utilize the offering. If the buy-down were removed and a loan loss reserve were put into place with lenders, we have no evidence that lenders would offer a 2% rate or lower without the buy-down. Assuming the rate would be higher, and thus potentially more of a barrier for customers, we have no evidence that a loan loss reserve would lead to greater uptake of loans or additional energy savings.

(Joint Utility Response)

Public Service of New Hampshire d/b/a Eversource Energy
Docket No. DE 17-136

Date Request Received: 10/05/2018 **Date of Response: 10/19/2018**
Request No. OCA 2-004 **Page 1 of 1**
Request from: Office of Consumer Advocate

Witness: Katherine W. Peters

Request:
Reference New Hampshire Statewide Energy Efficiency Plan 2019 Update, at Bates 36, and the AESC 2018 Study, which states "We have not reviewed any avoided T&D analyses from Eversource's Massachusetts and New Hampshire subsidiaries... We have reviewed some data for these utilities on the load growth and avoidable costs in some congested areas that may be suitable for targeted distributed resource solutions in pending New Hampshire pilot programs. But we have not found any computations of general avoided T&D costs for energy efficiency screening."

a. Did Eversource make efforts to provide Synapse with estimates of, or documents that might help them develop, avoided transmission and distribution costs? If so, please provide those documents. If not, please explain why not.
b. Did Liberty make efforts to provide Synapse with estimates of, or documents that might help them develop, avoided transmission and distribution costs? If so, please provide those documents. If not, please explain why not.
c. Did Unitil make efforts to provide Synapse with estimates of, or documents that might help them develop, avoided transmission and distribution costs? If so, please provide those documents. If not, please explain why not.

Response:

a) Eversource did not make efforts to provide Synapse with estimates of, or documents that might help them develop, avoided transmission and distribution costs. Eversource's internal T&D analyses are used by its internal engineering and planning staff to make initial determinations of potential investments, but they do not necessarily reflect the investments that will actually be made, or the costs that will actually be incurred, for work on the Eversource system. Eversource was concerned that if these internal documents had been provided, they could be shared with the members of the AESC Study Group per the terms and conditions of the contract with Synapse and would be used by Synapse or others to support conclusions about work that may or may not be needed or undertaken and costs that may or may not be incurred.

b) Liberty did not provide estimates or documents for avoided transmission and distribution costs due to contracting issues and concerns about confidentiality with the vendor at the time of the document request.

c) Unitil responded to the questions related to avoided transmission and distribution costs asked by Synapse in its memo dated November 15, 2017. As part of Unitil's response to those questions, the Company also provided copies of its Marginal Cost Studies for its gas and electric operations in New Hampshire. Those studies are publicly accessible in NH Docket DE 16-384 and DG 17-070.

Public Service of New Hampshire d/b/a Eversource Energy
Docket No. DE 17-136

Date Request Received: 10/05/2018 **Date of Response: 10/19/2018**
Request No. OCA 2-005 **Page 1 of 2**
Request from: Office of Consumer Advocate

Witness: Katherine W. Peters, Eric Stanley, Mary Downes

Request:
Reference New Hampshire Statewide Energy Efficiency Plan 2019 Update, at Bates 36-37, describing the value of reliability as estimated by the AESC 2018 Study.

a. Does the 2019 Update include the value of reliability identified in AESC 2018 as one of the benefits of the energy efficiency programs? If so, please show how or where that value is included. If not, please state why not.
b. For each Company with a Reliability Enhancement Program before the New Hampshire Public Utilities Commission, please provide the dollar per customer minute interruption values ($/dCMI) justifying the various investments in the Company's most recent Reliability Enhancement Program filing.

Response:
(a.) Joint Utility Response: The 2019 Update includes the value of reliability identified in AESC 2018. The reliability value is included in the Summer Generation benefit on the Present Value Benefits tables.

(b.) Eversource Response: Eversource has two capital projects in 2018 as part of the Reliability Enhancement Program. The first, titled "Circuit Tie – W185 to 4W1 along Safford Drive" has a projected cost per customer minute interrupted of $2.87. The second, titled "Circuit Tie – 3178X3 in Hinsdale", has a projected cost per customer minute interrupted of $4.80.

Liberty Response: Please see Attachment OCA 2-005b for the dollar per customer minute interruption values for Liberty's REP program.

Public Service of New Hampshire d/b/a Eversource Energy
Docket No. DE 17-136

Date Request Received: 10/05/2018 | **Date of Response: 10/19/2018**
Request No. OCA 2-006 | **Page 1 of 1**
Request from: Office of Consumer Advocate

Witness: Katherine W. Peters, Mary Downes

Request:
Reference New Hampshire Statewide Energy Efficiency Plan 2019 Update, at Bates 38, stating “[i]in order to treat electric and fossil fuel emissions consistently in benefit-cost screening, the NH 2019 Update incorporates comparable fossil fuel avoided emissions with a conservative calculation based on the AESC 2019 forecast of RGGI values and standard emissions output factors for those fuels.” Please provide the calculation that was used to determine fossil fuel avoided emissions, along with a narrative explaining the inputs and how they were incorporated into the calculation.

Response:
The dollar value of emissions associated with fossil fuels is calculated as the product of

a) the amount of carbon emissions associated with each fuel type, and
b) the value per ton of avoided carbon emissions based on the 2018 AESC estimates of RGGI market price trajectories

For part a, the amount of carbon emissions associated with each fuel type, the Companies used the following emissions factors per DOE’s Energy Information Administration (EIA):

Natural Gas – 116.6 pounds/MMBtu
Oil – 161.3 pounds/MMBtu
Propane – 136.9 pounds/MMBtu
Kerosene- 159.4 pounds/MMBtu

For part b, the dollar value of the avoided carbon emissions associated with avoided fossil fuels resulting from the energy efficiency measures, the Companies referenced the AESC forecast of RGGI price per ton of carbon emissions as depicted in Figure 20 and Appendix D of the 2019 AESC study..

For example, to calculate the avoided emissions value of 1 MMBtu of oil, the B/C model includes a formula multiplying the emissions value of 161.3 pounds of carbon/MMBtu of oil by the RGGI price ($2019) of $8.98/ton of carbon x 1 ton/2000 pounds = $0.724 per MMBtu of oil avoided. The emissions values for the other fossil fuels are calculated in a similar fashion , and the net present value of the emissions over the lifetime of the measures is included as a benefit.

(Joint Utility Response)

Public Service of New Hampshire d/b/a Eversource Energy
Docket No. DE 17-136

Date Request Received: 10/05/2018 **Date of Response: 10/19/2018**
Request No. OCA 2-007 **Page 1 of 1**
Request from: Office of Consumer Advocate

Witness: Katherine W. Peters

Request:
Reference New Hampshire Statewide Energy Efficiency Plan 2019 Update, at Bates 45-6, stating "[m]oving forward and in 2019, the existing DE 17-136 Quarterly Meeting should serve as a venue to discuss cross-cutting topics." Would the joint utilities object to a monthly meeting of the EESE Board EERS Committee as the appropriate venue to discuss such topics, in a manner modeled on the monthly meeting of the stakeholder advisory boards in Connecticut and Massachusetts? If so, please explain why.

Response:
There are two types of cross cutting topics that have been raised at working group meetings, those related to current implementation of the programs (such as HEA program performance) and those related to future program design (such as demand pilots). Topics related to current program implementation belong as agenda items for quarterly meetings. Topics related to future program goals or design belong in the planning process for the 2021-2023 Plan.

The legislative energy efficiency and climate mandates, goals and policies in MA and CT, which also give direction to the stakeholder boards, are different than those that currently exist in New Hampshire. The EESE Board or EERS Committee should not specifically model monthly meetings on these other boards, because the role and objectives are not the same.

The EESE Board has been effective as a facilitator for gathering and disseminating input and information on important topics related to energy and energy policy. The enhanced stakeholder process used for the 2018-2020 Plan, through the EESE Board and EERS Committee, provided the consultation and collaboration required under the Settlement Agreement and was a constructive process for gathering stakeholder feedback to inform the 2018-2020 Plan. We anticipate that cross-cutting topics that are part of the 2021-2023 Plan will receive stakeholder review and feedback through a similar stakeholder process.

(Joint Utility Response)

Public Service of New Hampshire d/b/a Eversource Energy
Docket No. DE 17-136

Date Request Received: 10/05/2018 **Date of Response: 10/19/2018**
Request No. OCA 2-008 **Page 1 of 1**
Request from: Office of Consumer Advocate

Witness: Katherine W. Peters

Request:
Reference New Hampshire Statewide Energy Efficiency Plan 2019 Update, at Bates 46, stating "[t]he utilities have developed a draft proposal for the consideration of the Working Group, which can serve as the basis for the remainder of the discussions." Is that draft proposal contained in the slides that were presented to the working group on May 23? If not, please provide a copy of this draft proposal.

Response:
The presentation to the working group on May 23, (contained in Attachment OCA 2-008 1.pdf) included a number of the objectives and options that the Utilities believe should be looked at for a revised PI calculation. At the June meeting the utilities distributed the two graphics contained in Attachment OCA 2-008 2, representing the current PI calculation and a potential new calculation that takes into account many of the topics discussed during the May meeting. There was not enough time at the June meeting for a discussion of the graphic and we did not return to the topic at the July meeting.

(Joint Utility Response)

Performance Incentive Work Group
Update from NH Utilities

May 23, 2018

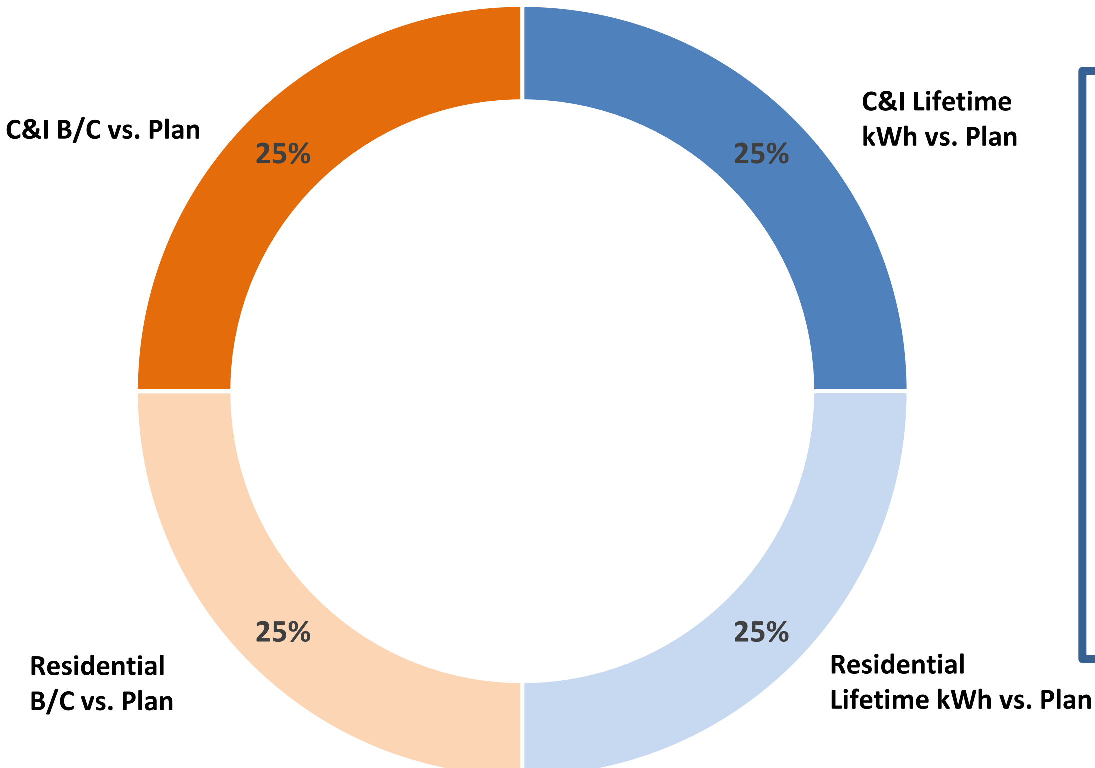
NH 2018 Performance Incentive

Electric Savings %: Percentage of electric lifetime savings to the total lifetime energy savings.
If > 55%, multiplier for each sector is 2.75%
If < 55%, multiplier for each sector is 2.2%

C&I Actual Expenditures: Sector PI is capped at 6.875% of actual Expenditures. Actual expenditures may exceed the sector budget by up to 5%

B/C Component:
is 50% of overall calculation and is capped at 3.4375% of actual expenditures for each Sector.

B/C Threshold:
Combined B/C for the sector must be greater than 1, or no incentive for B/C Component.



Savings Component:
is 50% of overall calculation and is capped at 3.4375% of actual expenditures for each Sector.

Savings Threshold:
Applied to each Sector. Actual lifetime savings must be 65% or greater of predicted lifetime savings. Or no incentive for Savings Component

Residential Actual Expenditures: Sector PI is capped at 6.875% of actual Expenditures. Actual expenditures may exceed the sector budget by up to 5%

The MA Performance Incentive: Two Components

Performance incentives in MA have focused on achieving the two main goals:

1. Achieving **Savings ($)** while achieving all cost-effective energy efficiency
   - **Benefits** over the life of installed measures relating to electric energy, capacity, natural gas, oil, propane, water, NEIs expressed in Net Present Value monetary benefits
2. Achieving **Value ($)** through investment in energy efficiency
   - **Net benefits** (Benefits minus the customer + utility costs associated with the programs)

The MA Performance Incentive: Two Components

Savings Component	**Goal:** Maximize savings (total benefits in $NPV)
	Rewards PAs for acquiring additional lifetime primary energy and demand savings as well as other energy and non-energy benefits
	= 61.5% of total planned performance incentive pool based on the total dollar amount of benefits
Value Component	**Goal:** Maximize the value of the programs (total lifetime benefits minus total lifetime costs)
	Rewards PAs for achieving energy and non-energy benefits while minimizing unnecessary utility and customer expenditures
	= 38.5% of total planned performance incentive pool based on the total dollar amount of net benefits

Possible Areas for Adjustment

- Sector Approach vs. Portfolio Approach
- B/C as a threshold rather than calculation component
- Benefits as a calculation component
- Actual Spending vs. Budget
- 55% electric savings requirement

Objectives to consider

- **Further Promoting the achievement of EERS Goals**
  - Retain focus on the primary objective of kWh targets and energy savings, while providing additional focus on the benefits achieved by fossil fuel reductions and kW reductions
  - Simplify and streamline where possible for transparency

Objectives to Consider

- **Peak Load Reductions:**
  - Additional focus on Benefits can help measures that get good kW savings but lower kWh savings (cooling, thermostats)
  - Existing Planning process identifies planned kW reductions from measures in the Plan. Most kW savings in other states also come as a result of energy efficiency measures.
    - Utilities could do additional reporting to track progress vs. Plan for kW savings and which measures those savings come from
  - Pilots in surrounding states are identifying measures and program design elements for active kW reduction through efficiency programs, including understanding of cost effectiveness.
  - Evaluations in NH will provide information on peak reductions from EE portfolio measures

Objectives to consider

- **Low Income Participation:**
  - Additional focus on Benefits can help low-B/C, low-kWh, income eligible weatherization projects, which do get good benefits from fossil fuel reduction.
  - Shift from Sector to Portfolio approach in looking at spending/savings/benefits compared to Plan could help low-kWh projects like low-income weatherization
  - Shift from Sector to Portfolio threshold for B/C could help low-B/C projects like low-income weatherization

Measure Examples

	Total Resource Cost	Rebate	B/C Ratio	Lifetime kWh	Lifetime Fossil Fuel MMBtu	Summer Peak kW	Total Benefits
Low Income Weatherization	$ 8,136	$ 8,136	1.66	10,555	620	0.10	$ 13,487
(making rebate amt approximate C&I)	$ 16,272	$ 16,272	1.66	21,109	1239	0.20	$ 26,973.29
Large Business New Equipment Cooling	$ 24,830	$ 16,159	3.41	704,664		13.29	$ 84,587
Large Business New Equipment LED Lighting	$ 24,147	$ 16,159	8.71	2,159,403		19.28	$ 210,236
Large Business New Equipment Parking Lot Lights	$ 37,656	$ 16,159	3.04	1,700,778		-	$ 114,456

Discussion

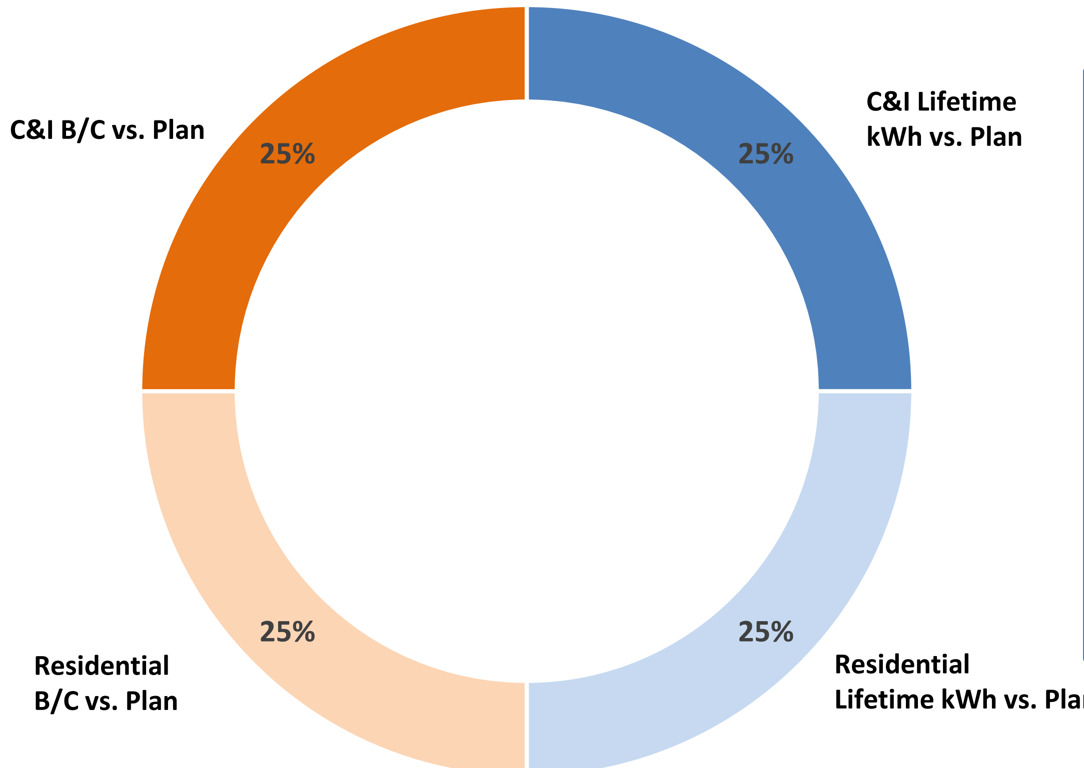
2018 Performance Incentive

Electric Savings %: Percentage of electric lifetime savings to the total lifetime energy savings.
If > 55%, multiplier for each sector is 2.75%
If < 55%, multiplier for each sector is 2.2%

C&I Actual Expenditures: Sector PI is capped at 6.875% of actual Expenditures. Actual expenditures may exceed the sector budget by up to 5%

B/C Component:
is 50% of overall calculation and is capped at 3.4375% of actual expenditures for each Sector.

B/C Threshold:
Combined B/C for the sector must be greater than 1, or no incentive for B/C Component.



Savings Component:
is 50% of overall calculation and is capped at 3.4375% of actual expenditures for each Sector.

Savings Threshold:
Applied to each Sector. Actual lifetime savings must be 65% or greater of predicted lifetime savings. Or no incentive for Savings Component

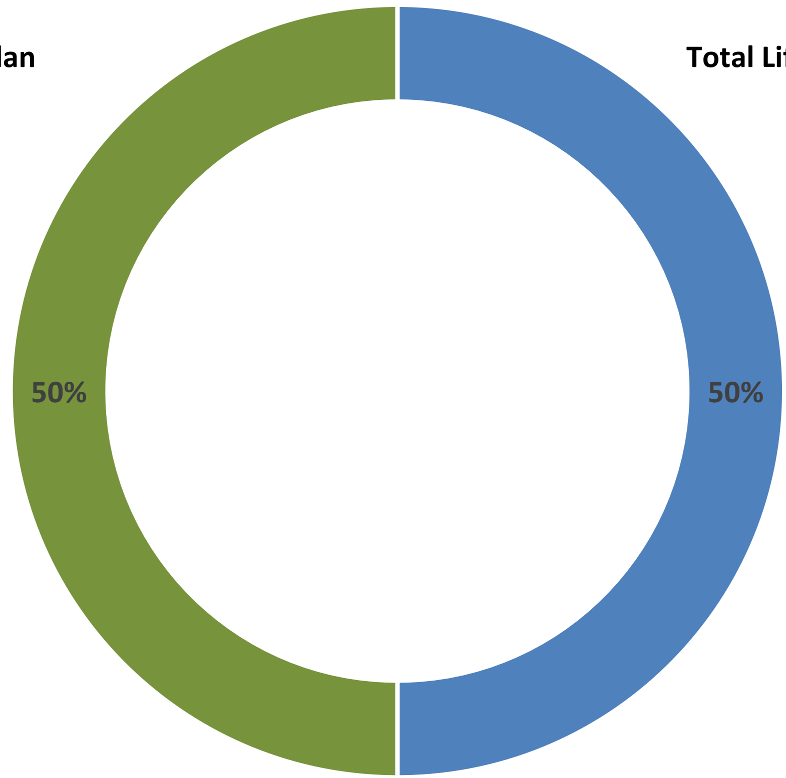
Residential Actual Expenditures: Sector PI is capped at 6.875% of actual Expenditures. Actual expenditures may exceed the sector budget by up to 5%

Potential PI Changes – Benefits and kWh Savings at Portfolio Level

Benefit Cost: Entire Portfolio must meet a threshold B/C of 1

Total $ Benefits / Plan

Total Lifetime kWh / Plan



Benefit Component:
is 50% of overall calculation and is capped at 3.4375% of Budget

Savings Component:
is 50% of overall calculation and is capped at 3.4375% of Budget

Savings Threshold:
Applied to Portfolio. Actual lifetime savings must be 65% or greater of predicted lifetime savings. Or no incentive for Savings Component

Portfolio Budget: Portfolio PI is capped at 6.875% of budget.

Public Service of New Hampshire d/b/a Eversource Energy
Docket No. DE 17-136

Date Request Received: 10/05/2018 | **Date of Response: 10/19/2018**
Request No. OCA 2-009 | **Page 1 of 1**
Request from: Office of Consumer Advocate

Witness: Katherine W. Peters

Request:
Reference New Hampshire Statewide Energy Efficiency Plan 2019 Update, at Bates 46, stating "[n]ow that this process has been finalized, the EM&V Working Group is well positioned to effectively manage any remaining items while also minimizing duplication of effort. A final meeting will be held September 2018." Please explain which venue (and why) the utilities then propose as a means of collecting input regarding:

a. The initial output of the cross-cutting NEI study Phase 1 on which NEIs should be adopted in New Hampshire;
b. Potential future application of the recently published National Standards Practice Manual in New Hampshire;
c. Recent trends towards the use of energy efficiency programs as a means of delivering strategic electrification.

Response:

a. The NH EM&V framework, as described in Sections 10.2 through 10.4 of the 2018 – 2020 Plan and in the 2018 Strategic Evaluation Plan published on the EM&V Working Group website outlines the EM&V process and the EM&V Working Group's role in that process. This framework provides for collecting and weighing input on all EM&V activity, including the cross-cutting NEI study Phase 1. As described, the members of the EM&V Working Group will provide input throughout the stages of evaluations, with the EESE Board member representing the Board's input, the Commission staff and independent experts representing the Commission's input, and the utility members representing utility input. The members of the working group are involved and have input into the details of the NEI study from start to finish. This includes having the opportunity to review and comment on all deliverables throughout the study. In addition to this opportunity for stakeholder input, regular updates are provided at the Quarterly Meetings and at the EESE Board. A draft report and presentation will provide an additional opportunity for feedback before the final report is issued.

b. The National Standards Practice Manual outlines a process for jurisdictions to develop their primary cost-effectiveness tests for energy efficiency and other energy resources, including consideration of applicable policy goals and objectives. Discussion of topics related to future policy will be incorporated into the planning process for the 2021-2023 program cycle.

c. Discussion of topics such as strategic electrification, related to future policy, will be incorporated into the planning process for the 2021-2023 program cycle.

Public Service of New Hampshire d/b/a Eversource Energy
Docket No. DE 17-136

Date Request Received: 10/05/2018 **Date of Response: 10/19/2018**
Request No. OCA 2-018 **Page 1 of 1**
Request from: Office of Consumer Advocate

Witness: Katherine W. Peters

Request:
Reference Tim Clougherty July 20, 2018 Presentation to the EESE Board regarding LED Street Lighting Conversion, describing significant energy cost savings, maintenance cost savings, improved quality of light, increased roadway safety, and reduced light pollution associated with conversion from High Intensity Discharge (HID) technologies to LED and advanced controls. Please describe, on a utility specific basis, each project completed (or planned to be completed) during 2018, including:

a. The program incentive offering;
b. Participant cost;
c. Number of fixtures incented;
d. kWh and kW savings; and
e. Whether any advanced (intelligent) controls were utilized as part of the project.

Response:
Eversource Response: See Attachment OCA 2-018, 2018 Eversource Streetlight Projects.xlsx for the requested information on 2018 projects.

Granite State Electric Response:
Granite State Electric has one LED Street Light project in process in 2018, with the following details:

a. Program incentive of $19,200 ($75 to $150 per fixture based on fixture cost and energy savings).

b. Participant cost was $123,590 (a portion of the cost is paid monthly at Tariff rates over life of agreement.)

c. 149 fixtures incented.

d. Annual Saving of 232,930 kWh and 53.9 kW

e. No advanced controls were utilized in this project.

Unitil Response: The Company offers two options for municipalities to participate in the LED street light offering: a) prescriptive and b) custom. Custom is applicable to complex projects such as whole town conversions. The Company does not anticipate that any conversions to LED street lighting will be completed in 2018.

2018 YEAR END PROJECTS - Inspection Dates

Eversource 2018 Streetlight Projects

Customer Name	Program	Quantity	Max kW	Annual kWh Savings	Incentive	Customer Cost	Advanced Controls Utilized?	Stage
Town of Pembroke-EOL	New Construction	240	14.60	63,238	$24,500.00	$24,689.00	N/A	*Potential
Town of Bedford-EOL	Municipal	168	14.80	64,495	$16,775.00	$7,580.00	N/A	Paid
Town of Epping-EOL	New Construction	125	7.40	32,097	$12,325.00	$6,461.63	N/A	Paid
Town of Farmington-EOL	Municipal	183	9.90	43,183	$18,725.00	$6,597.88	N/A	Paid
Town of Greenland-EOL	Municipal	120	5.40	23,561	$12,100.00	$3,646.82	N/A	Paid
Town of New Castle-EOL	Municipal	68	3.00	13,178	$6,800.00	$1,453.00	N/A	Paid
Town of Newington-EOL	Municipal	133	9.20	39,824	$13,225.00	$4,991.85	N/A	Paid
Town of Newmarket-EOL	Municipal	246	10.90	47,152	$24,325.00	$8,146.92	N/A	Paid
Town of North Hampton	Municipal	131	5.30	22,992	$13,100.00	$4,311.11	N/A	Paid
Town of Londonderry EOL-acct 01	Municipal	56	3.90	17,063	$5,600.00	$4,807.00	N/A	Paid
Town of Londonderry EOL-acct 02	Municipal	86	8.00	34,836	$8,600.00	$7,531.00	N/A	Paid
Town of Stoddard (EOL)	Municipal	27	3.30	14,356	$2,700.00	$1,281.63	N/A	Paid
Town of Swanzey, EOL	Municipal	110	2.75	11,973	$11,000.00	$2,125.20	N/A	Paid
Town of Marlborough, EOL	Municipal	112	6.20	27,003	$11,200.00	$4,384.39	N/A	Paid
Town of Bethlehem (EOL)	Municipal	236	15.21	66,224	$23,075.00	$9,647.96	N/A	Paid
Town of Conway (EOL)	Municipal	9	0.36	1,568	$900.00	$173.89	N/A	Paid
Town of Franconia (EOL)	Municipal	14	2.03	8,839	$700.00	$933.33	N/A	Paid
Town of Franconia (EOL)	Municipal	129	7.33	31,914	$12,875.00	$4,303.26	N/A	Paid
Town of Lisbon (EOL)	Municipal	142	8.67	37,749	$14,175.00	$4,443.88	N/A	Paid
Antrim LED Street Lights	Municipal	110	7.63	33,239	$10,900.00	$2,409.49	N/A	Paid
Bennington LED Street Lights	Municipal	38	1.80	7,841	$3,800.00	$1,797.05	N/A	Paid
Claremont LED Street Lights	Municipal	57	9.73	42,364	$4,950.00	$8,402.00	N/A	Paid
City of Berlin-LED Street Lights	Municipal	518	34.71	151,122	$50,000.00	$21,330.66	N/A	Paid
City of Berlin-LED Street Lights	SmallBusiness	423	28.46	123,646	$41,750.00	$16,611.00	N/A	Paid
Gorham Street Lights	Municipal	262	14.39	54,097	$26,200.00	$7,479.04	N/A	Paid
Henniker Town of	New Construction	79	10.90	47,524	$7,800.00	$1,706.59	N/A	Committed
Jaffrey Town Of	New Construction	157	11.35	49,418	$15,700.00	$2,106.34	N/A	Committed
Gorham Street Lights	Municipal	59	7.11	21,030	$5,900.00	$4,446.06	N/A	Paid
Town of Gilford (EOL)	Municipal	174	9.92	43,204	$17,200.00	$7,042.01	N/A	Paid

Public Service of New Hampshire d/b/a Eversource Energy
Docket No. DE 17-136

Date Request Received: 10/05/2018 **Date of Response: 10/19/2018**
Request No. OCA 2-019
Request from: Office of Consumer Advocate

Witness: Katherine W. Peters, Eric Stanley, Mary Downes

Request:
Reference Tim Clougherty July 20, 2018 Presentation to the EESE Board regarding LED Street Lighting Conversion, describing significant energy cost savings, maintenance cost savings, improved quality of light, increased roadway safety, and reduced light pollution associated with conversion from High Intensity Discharge (HID) technologies to LED and advanced controls.

a. Please provide on a company-specific basis for Eversource, Unitil, and Liberty, an inventory of street lighting by municipality, describing the number of luminaires by luminaire type and wattage. Please also include remaining undepreciated value of luminaires in their aggregate, by municipality.
b. Please describe each Company's policy for replacement of luminaires that have fully depreciated.
c. In the case of a municipality whose luminaires have fully depreciated, does that municipality continue to pay a luminaire charge for their luminaires?

Response:
<u>Eversource Response:</u>

(a) Please reference Attachment OCA 2-019 Eversource pages 1 and 2. Page 1 summarizes the number of fixtures under Rate OL, Rate EOL, and in total by fixture type and wattage. As shown, 75% of the municipal lighting fixtures are currently LEDs. The Company does not currently have this information readily available by municipality. As a result, the Company has also included on page 2 a list of municipalities that have converted or are in the process of converting their streetlights to LEDs. The estimated remaining undepreciated value of the fixtures served under Rate OL is $29,000, and under Rate EOL is $0.

(b) Under Rate OL the Company replaces fixtures as they fail with the same type and size of fixture if it is a standard fixture offered by the Company at no charge to the customer. Fixtures no longer offered by the Company (incandescent and mercury) are replaced with a high pressure sodium or metal halide fixture.

Under Rate EOL, the Company replaces high pressure sodium and metal halide fixtures as they fail with the same type and size of fixture. The Company provides the fixture and the customer reimburses the Company for the installed cost of the fixture. For LEDs, the customer provides the fixture and either reimburses the Company to install the fixture or hires a private line contractor to install the fixture.

The Company has successfully worked with its municipalities to ensure they are aware of the new lighting options available to them to save energy and reduce their electric bills, including LEDs. The energy efficiency incentives offered through NHSaves are a key component to this success. 41 of the communities served by Eversource have fully converted their street lighting to LEDs, and six communities and the NH Department of Transportation are in the process of converting to LEDs. Our policy is to continue to focus on the remaining communities who have not converted to LEDs, and provide support and assistance as needed.

(c) Yes.

Liberty Response:

a.) Please see Attachment OCA 2-019.

b.) Fully depreciated luminaires that continue to be in service are shown in plant account 373 as $0.00, or fully depreciated. If one of those luminaires needs replacement, the Company retires the old luminaire and installs a new luminaire, adding it to the plant account 373 at the installed value.

c.) Liberty's Rate M provides that regardless of whether a luminaire is fully depreciated, the municipality pays the monthly distribution charge for the luminaire. Rate M does not require any upfront payment from the customer for the luminaire. Thus if the luminaire is broken or fails, the customer is not charged to replace the luminaire. The monthly distribution charge includes any maintenance for the luminaire, such as replacement of photocells, and the energy used by the luminaire each month, and replacements as needed.

Unitil Response:

a.) Unitil is compiling this information.

b.) Unitil's tariff for Outdoor Lighting Service, Schedule OL, has a section regarding Change/Removal of a Fixture which states: "The Company will change the type of lighting fixture at the Customer's request, but may require the Customer to reimburse the Company for all or part of the depreciated cost of the retired equipment including installation and cost of removal, less any salvage value thereon." If the fixture is fully depreciated the cost associated with that portion would be $0.

c.) Yes, as long as the light remains active in service.

Eversource NH
Municipal Lighting*

Light Type	Lumens	Watts	Rate OL Number of Fixtures	Rate EOL Number of Fixtures	Total Number of Fixtures	Percent of Fixtures
High Pressure Sodium	4000	50	137	6,139	6,276	13%
	5800	70	102	243	345	1%
	9500	100	46	570	616	1%
	16000	150	16	634	650	1%
	30000	250	29	1,995	2,024	4%
	50000	400	12	140	152	0%
	130000	1000	-	57	57	0%
Metal Halide	5000	70	22	958	980	2%
	8000	100	11	102	113	0%
	13000	150	-	-	-	0%
	13500	175	3	85	88	0%
	20000	250	3	71	74	0%
	36000	400	5	53	58	0%
	100000	1000	-	103	103	0%
LEDs	Various		-	37,036	37,036	75%
Incandescent	600	105	79	-	79	0%
	1000	105	223	-	223	0%
	2500	205	4	-	4	0%
	6000	448	-	-	-	0%
Mercury	3500	100	515	-	515	1%
	7000	175	63	-	63	0%
	11000	250	21	-	21	0%
	15000	400	-	-	-	0%
	20000	400	7	-	7	0%
	56000	1000	1	-	1	0%
Fluorescent	20000	330	-	-	-	0%
High Pressure Sodium in Existing Mercury	12000	150	-	-	-	0%
	34200	360	-	-	-	0%
			1,299	48,186	49,485	

* Does not include private area lights associated with Rates R, G, GV or LG customers.

Eversource NH

Completed Conversion to LEDs	In the Process of Converting to LEDs
Allenstown	Berlin
Antrim	Gorham
Bedford	N Hampton
Bennington	NHDOT
Bethlehem	Farmington
Bradford	Gilford
Claremont	Lisbon
Conway	
Derry	
Dover	
Durham	
Epping	
Franconia	
Franklin	
Goffstown	
Grantham	
Greenland	
Hampstead	
Keene	
Laconia	
Lancaster	
Londonderry	
Manchester	
Merrimack	
Milford	
Nashua	
New London	
Newbury	
New Castle	
Newfields	
Newington	
Newmarket	
Portsmouth	
Rochester	
Rye-Jenness Beach	
Somersworth	
Stoddard	
Stratford	
Sunapee	
Swanzey	
Whitefield	

												Luminaire Type												
Town	HPS 50W	HPS 100W	HPS 250W	HPS 400W	HPS 50W	HPS Flood 250W	HPS Flood 400W	HPS Post Top 100W	Incandescent 105W	LED 130W	LED 190W	LED 30W	LED 50W	LED Flood 130W	LED Flood 90W	LED Post Top 50W	MV 1000W	MV 100W	MV 175W	MV 400W	MV Flood 1000W	MV Flood 400W	MW 400W	Total
ACWORTH		5	1		8	2			10										2					28
ALSTEAD		25			23	3	1											1	5					58
BATH					1																			1
CANAAN		24	4	1	69	16	3		15									1	3					136
CHARLESTOWN		117	14	3	116	7	1											1	20			1		280
CORNISH		1			1																			2
DERRY		1	1	1			1																	4
ENFIELD		52	5		206	17	13							1				8	7				1	310
HANOVER		147	81		265	13	2					15	19			4		8	6	18				578
LANGDON		10				2													3					15
LEBANON		204	198	11	530	69	75	6		27								34	57	13	1	9		1234
MARLOW					1																			1
MERIDEN		3																						3
MONROE		16	3		54	1												2	1			1		78
ORANGE		1				4	1																	6
PELHAM		154	28	15	30	21	51							1				2	5			6		313
PLAINFIELD		5	1	1	20	3												1	1					32
SALEM	5	992	175	115	977	93	253	394		63	3		54	6	3	10	1	18	10	14		3		3189
SURRY		2			1																			3
WALPOLE		65	17	3	122	26	8											1	29	1		2		274
WINDHAM		15	7	1	20	11	30													2				86
TOTAL	5	1839	535	151	2444	288	439	400	25	90	3	15	73	8	3	14	1	77	149	48	1	22	1	6631

Net Book Value		
Town	**Net Book Value**	
ACWORTH	$	6,412.12
ALSTEAD	$	14,100.00
CANAAN	$	48,889.34
CHARLESTOWN	$	37,703.73
DERRY	$	13,162.81
BLANK	$	3,576.06
ENFIELD	$	36,640.58
HANOVER	$	380,209.54
LANGDON	$	17,996.81
LEBANON	$	197,451.15
MONROE	$	15,205.24
ORANGE	$	447.81
PELHAM	$	84,148.79
PLAINFIELD	$	5,793.09
SALEM	$	334,083.31
SURRY	$	1,070.67
WALPOLE	$	30,900.75
WINDHAM	$	41,145.57
Grand Total	$	1,268,937.37

*BLANK refers to data that came over from National Grid without a town.

There is only 1 streetlight in the total.

Row Labels	Flood Light	Street Light	Yard Light	Total
ATKINSON	**26**	**222**	**17**	**265**
MERCURY VAPOR	**2**	**121**	**15**	**138**
100 WATTS		118	13	131
150 WATTS			2	2
250 WATTS	1	2		3
400 WATTS	1	1		2
METAL HALIDE	**2**			**2**
1000 WATTS	2			2
SODIUM VAPOR	**22**	**101**	**2**	**125**
1000 WATTS	6	1		7
150 WATTS	5	9		14
250 WATTS	3	9		12
400 WATTS	8	1		9
50 WATTS		81	2	83
BOSCAWEN	**28**	**118**	**43**	**189**
MERCURY VAPOR	**1**	**56**	**25**	**82**
100 WATTS		52	23	75
175 WATTS		1	2	3
250 WATTS	1	3		4
SODIUM VAPOR	**27**	**62**	**18**	**107**
100 WATTS		9	5	14
150 WATTS	11	5		16
250 WATTS	9	13		22
400 WATTS	7	2		9
50 WATTS		33	13	46
BOW	**70**	**218**	**28**	**316**
MERCURY VAPOR	**3**	**88**	**8**	**99**
100 WATTS		82	7	89
175 WATTS		4	1	5
250 WATTS	3	2		5
SODIUM VAPOR	**67**	**130**	**20**	**217**
100 WATTS		5	8	13
1000 WATTS	18	2		20
150 WATTS	14	6		20
250 WATTS	11	35		46
400 WATTS	24	5		29
50 WATTS		77	12	89
CANTERBURY	**6**	**39**	**6**	**51**
MERCURY VAPOR		**8**	**4**	**12**
100 WATTS		7	4	11
250 WATTS		1		1
SODIUM VAPOR	**6**	**31**	**2**	**39**
100 WATTS		4		4
150 WATTS	1	4		5
250 WATTS	1	20		21
400 WATTS	4	1		5
50 WATTS		2	2	4
CHICHESTER	**19**	**32**	**19**	**70**
MERCURY VAPOR		**5**	**9**	**14**
100 WATTS		5	8	13
175 WATTS			1	1

Row Labels	Flood Light	Street Light	Yard Light	Total
SODIUM VAPOR	**19**	**27**	**10**	**56**
100 WATTS		3	3	6
150 WATTS	2	4		6
250 WATTS	3	9		12
400 WATTS	14	2		16
50 WATTS		9	7	16
CONCORD	**432**	**2558**	**132**	**3122**
MERCURY VAPOR	**44**	**132**	**81**	**257**
100 WATTS		38	72	110
1000 WATTS	1			1
175 WATTS		48	9	57
250 WATTS	35	24		59
400 WATTS	8	22		30
SODIUM VAPOR	**388**	**2426**	**51**	**2865**
100 WATTS		54	21	75
1000 WATTS	66	7		73
150 WATTS	78	118		196
250 WATTS	115	526		641
400 WATTS	129	186		315
50 WATTS		1535	30	1565
DANVILLE	**11**	**59**	**13**	**83**
MERCURY VAPOR		**25**	**13**	**38**
100 WATTS		25	12	37
150 WATTS			1	1
SODIUM VAPOR	**11**	**34**		**45**
1000 WATTS	1	1		2
150 WATTS	2	1		3
250 WATTS	2			2
400 WATTS	6	1		7
50 WATTS		31		31
DUNBARTON			**3**	**3**
SODIUM VAPOR			**3**	**3**
50 WATTS			3	3
E. HAMPSTEAD		**1**		**1**
SODIUM VAPOR		**1**		**1**
150 WATTS		1		1
EAST KINGSTON	**14**	**22**	**18**	**54**
MERCURY VAPOR		**4**	**15**	**19**
100 WATTS		4	12	16
150 WATTS			3	3
SODIUM VAPOR	**14**	**18**	**3**	**35**
100 WATTS			3	3
150 WATTS	9	5		14
250 WATTS	4			4
400 WATTS	1			1
50 WATTS		13		13
EPSOM	**33**	**54**	**22**	**109**
MERCURY VAPOR	**2**	**9**	**7**	**18**
100 WATTS		8	6	14
175 WATTS			1	1
250 WATTS	1	1		2

Row Labels	Flood Light	Street Light	Yard Light	Total
400 WATTS	1			1
SODIUM VAPOR	**31**	**45**	**15**	**91**
100 WATTS		6	7	13
1000 WATTS	6			6
150 WATTS	9	8		17
250 WATTS	5	23		28
400 WATTS	11	4		15
50 WATTS		4	8	12
EXETER	**156**	**923**	**32**	**1111**
MERCURY VAPOR	**17**	**87**	**21**	**125**
100 WATTS		78	17	95
1000 WATTS	2			2
150 WATTS			4	4
175 WATTS		3		3
250 WATTS	5			5
400 WATTS	10	6		16
METAL HALIDE	**10**	**1**		**11**
1000 WATTS	10			10
175 WATTS		1		1
SODIUM VAPOR	**129**	**835**	**11**	**975**
100 WATTS		8	2	10
1000 WATTS	25	4		29
150 WATTS	25	52		77
250 WATTS	38	82		120
400 WATTS	41	14		55
50 WATTS		675	9	684
HAMPTON	**164**	**1164**	**51**	**1379**
MERCURY VAPOR	**32**	**541**	**39**	**612**
100 WATTS		453	31	484
150 WATTS			8	8
175 WATTS		7		7
250 WATTS	8	13		21
400 WATTS	24	68		92
METAL HALIDE	**7**			**7**
1000 WATTS	7			7
SODIUM VAPOR	**125**	**623**	**12**	**760**
100 WATTS			3	3
1000 WATTS	21	120		141
150 WATTS	24	36		60
250 WATTS	38	156		194
400 WATTS	42	12		54
50 WATTS		299	9	308
HAMPTON FALLS	**45**	**30**	**10**	**85**
MERCURY VAPOR	**8**	**10**	**8**	**26**
100 WATTS		8	7	15
1000 WATTS	7			7
150 WATTS			1	1
400 WATTS	1	2		3
METAL HALIDE	**2**			**2**
1000 WATTS	2			2
SODIUM VAPOR	**35**	**20**	**2**	**57**
1000 WATTS	11			11

Row Labels	Flood Light	Street Light	Yard Light	Total
150 WATTS	8			8
250 WATTS	3	4		7
400 WATTS	13			13
50 WATTS		16	2	18
HOPKINTON			**1**	**1**
SODIUM VAPOR			**1**	**1**
50 WATTS			1	1
KENSINGTON	**61**	**20**	**22**	**103**
MERCURY VAPOR	**12**	**6**	**21**	**39**
100 WATTS		4	19	23
150 WATTS			2	2
250 WATTS	2			2
400 WATTS	10	2		12
SODIUM VAPOR	**49**	**14**	**1**	**64**
100 WATTS			1	1
1000 WATTS	3			3
150 WATTS	8	3		11
250 WATTS	9	2		11
400 WATTS	29			29
50 WATTS		9		9
KINGSTON	**61**	**161**	**59**	**281**
MERCURY VAPOR	**4**	**45**	**51**	**100**
100 WATTS		41	43	84
150 WATTS			8	8
175 WATTS		1		1
250 WATTS	1			1
400 WATTS	3	3		6
SODIUM VAPOR	**57**	**116**	**8**	**181**
100 WATTS		2	1	3
1000 WATTS	10	2		12
150 WATTS	7	7		14
250 WATTS	11	45		56
400 WATTS	29	6		35
50 WATTS		54	7	61
LOUDON			**1**	**1**
SODIUM VAPOR			**1**	**1**
50 WATTS			1	1
NEWTON	**24**	**101**	**17**	**142**
MERCURY VAPOR	**5**	**52**	**15**	**72**
100 WATTS		52	11	63
1000 WATTS	1			1
150 WATTS			4	4
250 WATTS	1			1
400 WATTS	3			3
METAL HALIDE	**1**			**1**
1000 WATTS	1			1
SODIUM VAPOR	**18**	**49**	**2**	**69**
100 WATTS		4	2	6
1000 WATTS	4			4
150 WATTS	2	3		5
250 WATTS	6	5		11

Row Labels	Flood Light	Street Light	Yard Light	Total
400 WATTS	6	1		7
50 WATTS		36		36
PEMBROKE		**12**		**12**
SODIUM VAPOR		**12**		**12**
100 WATTS		1		1
150 WATTS		3		3
250 WATTS		8		8
PENACOOK	**24**	**108**	**27**	**159**
MERCURY VAPOR		**4**	**11**	**15**
100 WATTS			11	11
250 WATTS		4		4
SODIUM VAPOR	**24**	**104**	**16**	**144**
100 WATTS		8	14	22
150 WATTS	3	2		5
250 WATTS	16	5		21
400 WATTS	5	3		8
50 WATTS		86	2	88
PLAISTOW	**161**	**550**	**20**	**731**
MERCURY VAPOR	**33**	**308**	**17**	**358**
100 WATTS		280	16	296
1000 WATTS	3			3
150 WATTS			1	1
175 WATTS		4		4
250 WATTS	9	12		21
400 WATTS	21	12		33
METAL HALIDE	**3**			**3**
1000 WATTS	3			3
SODIUM VAPOR	**125**	**242**	**3**	**370**
100 WATTS		2		2
1000 WATTS	42	1		43
150 WATTS	16	14		30
250 WATTS	24	63		87
400 WATTS	43	2		45
50 WATTS		160	3	163
SALISBURY	**7**	**15**	**8**	**30**
MERCURY VAPOR		**4**	**5**	**9**
100 WATTS		4	5	9
SODIUM VAPOR	**7**	**11**	**3**	**21**
100 WATTS		1	3	4
150 WATTS	3	2		5
250 WATTS	3			3
400 WATTS	1			1
50 WATTS		8		8
SEABROOK	**92**	**674**	**21**	**787**
MERCURY VAPOR	**22**	**111**	**19**	**152**
100 WATTS		79	19	98
1000 WATTS	1	1		2
175 WATTS		1		1
250 WATTS	2	10		12
400 WATTS	19	20		39
METAL HALIDE	**2**			**2**

Row Labels	Flood Light	Street Light	Yard Light	Total
1000 WATTS	2			2
SODIUM VAPOR	**68**	**563**	**2**	**633**
100 WATTS		1	1	2
1000 WATTS	8			8
150 WATTS	14	71		85
250 WATTS	25	106		131
400 WATTS	21	5		26
50 WATTS		380	1	381
SOUTH HAMPTON	**2**	**6**	**14**	**22**
MERCURY VAPOR		**1**	**12**	**13**
100 WATTS		1	11	12
150 WATTS			1	1
SODIUM VAPOR	**2**	**5**	**2**	**9**
100 WATTS			1	1
250 WATTS	1			1
400 WATTS	1			1
50 WATTS		5	1	6
STRATHAM	**45**	**118**	**18**	**181**
MERCURY VAPOR	**4**	**5**	**12**	**21**
100 WATTS		3	11	14
150 WATTS			1	1
250 WATTS	2			2
400 WATTS	2	2		4
METAL HALIDE	**10**			**10**
1000 WATTS	10			10
SODIUM VAPOR	**31**	**113**	**6**	**150**
100 WATTS			3	3
1000 WATTS	9			9
150 WATTS	10	12		22
250 WATTS	5	39		44
400 WATTS	7	2		9
50 WATTS		60	3	63
WEBSTER	**3**	**2**	**12**	**17**
MERCURY VAPOR			**7**	**7**
100 WATTS			7	7
SODIUM VAPOR	**3**	**2**	**5**	**10**
100 WATTS			1	1
150 WATTS	1	1		2
250 WATTS	2			2
50 WATTS		1	4	5
Grand Total	**1484**	**7207**	**614**	**9305**

Public Service of New Hampshire d/b/a Eversource Energy
Docket No. DE 17-136

Date Request Received: 10/05/2018 **Date of Response: 10/19/2018**
Request No. OCA 2-020 **Page 1 of 2**
Request from: Office of Consumer Advocate

Witness: Katherine W. Peters, Eric Stanley, Mary Downes

Request:
Reference Tim Clougherty July 20, 2018 Presentation to the EESE Board regarding LED Street Lighting Conversion, describing the benefits of intelligent street lighting controls as including safety and security, response time, maintenance savings, intelligent traffic control, meter reading, and feature/event lighting.

a. Please explain whether Eversource, Unitil, or Liberty's Street Lighting Tariff provides an opportunity for usage of advanced controls, including the ability to utilize the advanced controls as a meter for the street lights themselves. If not, please explain why not.
b. Has Eversource NH (PSNH) communicated with Eversource MA (NSTAR) about their ongoing work with the City of Cambridge to develop standardized tariff language which would allow Cambridge to benefit from bill savings associated with their advanced controls? (See outcomes of those discussion embodied in Testimony and Tariff revision, dated 10/02/18)
c. Please provide the opinion of each company as to whether a similar tariff language and procedures for utilizing advanced controls would be warranted in New Hampshire.

Response:
(a.)

<u>Eversource Response:</u> Eversource's current street lighting tariff is predicated on standard lighting schedules (e.g., dusk to dawn). Advanced controls may be employed under these schedules, with settings that control lighting operation in a manner consistent with the those tariff schedules. Eversource does not recognize these controls as meters, per se, but understands that the software for such systems provides the ability to calculate usage and other operational characteristics of lights being controlled. Further review would be required to ascertain whether such controls meet the definition and requirements of Puc 300 rules for designation as a meter.

<u>Liberty Response:</u> Liberty's tariff does not allow for advanced controls to be used as a meter for street lights. Liberty is working with the City of Lebanon on a street lighting pilot that may allow for advanced controls in the field.

<u>Unitil Response:</u> Unitil's Street Lighting Tariff does not reference advanced controls. Unitil has not investigated this option.

(b.)

<u>Eversource Response:</u> Yes. The tariff submitted by Eversource was developed as the result of a collaborative stakeholder process, and is supported by participants, including the municipalities such as the City of Cambridge who have or are considering applying advanced controls for

operation of street lighting, as a reasonable and practical methodology for implementing such controls, determining appropriate billing determinants and achieving corresponding bill savings.

(c.)

Eversource Response: It is Eversource's opinion that the provisions for advanced controls reflected in its MA street lighting tariff provide a basis upon which comparable tariff language and procedures can be developed and would be warranted for similarly-situated street lighting customers (i..e, those who have or are interested in utilizing advanced controls) in its NH service area.

Liberty Response: Liberty is unaware of the Eversource tariffs in Massachusetts. The utilization of advanced controls on street lighting may be warranted for future tariffs. With regards to advanced controls operating as a meter, the metering would need to meet the requirements of the Puc 300 rules in order for the Company to consider the technology.

Unitil Response: See response to part a.

Received: 10/05/18 Date of Response: 10/26/18

Request No.: OCA 2-22 Witness: Karen Asbury

Request:

Reference Unitil Electric Delivery Service Tariff, at Page 59-63J, describing an 3,000 lumen LED Cobra Head Fixture monthly luminaire charge as $12.80 and a 4,000 lumen Sodium Vapor Fixture monthly luminaire charge as $13.20. Please provide the useful life of each of the above-named these fixtures, their initial purchase cost, their depreciation schedules, and describe in detail any other costs that may be included in the luminaire price per month. If any embedded system costs beyond the cost of the fixture itself are included in the luminaire price per month rather than the distribution charge, please explain why this is the case and how those costs were determined.

Response:

The current luminaire charges are as follows:
3,000 lumen LED cobra head fixture: $13.03/mo.
4,000 lumen sodium vapor street light: $13.44/mo.

See Unitil Energy Systems, Inc., Electricity Delivery Service Tariff, Tenth Revised Page 59 and Second Revised Page 63-E (Effective May 1, 2018).

As indicated in OCA 2-21, the luminaire charge for sodium vapor light fixtures includes the cost of the fixture, cost of installation, cost of maintenance and cost of the distribution system (demand costs and customer costs) to provide electric delivery service to the fixture. The luminaire charge for LED light fixtures only include the cost of the distribution system to provide electric delivery service (demand costs and customer costs) since the customer pays the initial cost of the light, the cost of installation, and the cost of ongoing maintenance.

Note that sodium vapor street light charges are based on historical rate design. The Company's outdoor lighting luminaire charges have been increased in rate cases in order to move towards the class' revenue requirement allocation. The luminaire charges for the LED lights were initially established in the Company's last rate case and, similiarly, do not reflect the full cost of service.

The current purchase costs are as follows:
3,000 lumen LED cobra head fixture: $294.73
4,000 lumen sodium vapor street light: $217.61

Received: 10/05/18 Date of Response: 10/26/18

Request No.: OCA 2-22 Witness: Karen Asbury

The Company does not have information on useful life for the sodium vapor street light. For the LED cobra head fixture, they have a design life of 100,000 hours. We estimate a useful life of greater than 20 years.

The depreciation schedule for street lights is 17 years. Street lights are depreciated based on a depreciation rate established for the entire account, not by light.

Public Service of New Hampshire d/b/a Eversource Energy
Docket No. DE 17-136

Date Request Received: 10/05/2018 **Date of Response: 10/19/2018**
Request No. OCA 2-024 **Page 1 of 2**
Request from: Office of Consumer Advocate

Witness: Katherine W. Peters

Request:
Reference the Regulatory Assistance Project's September 22, 2018 Presentation to the Benefit Cost Working Group, Slides 8-10, suggesting the consumer economics of heat pump water heaters have a 40% advantage over oil water heaters, plus benefits associated with controllability during key hours of the year.

a. Please describe the number of oil water heaters expected to be incented during the 2019 Plan.
b. Please describe the number of propane water heaters expected to be incented during the 2019 Plan.
c. Please describe the number of heat pump water heaters expected to be incented during the 2019 Plan.
d. Please describe the number of controllable (dispatchable) water heaters, by fuel type, expected to be incented during each year of the 2018-20 Plan.
e. Please describe the source of baseline unit efficiency for heat pump water heaters and whether there is a specific standard that the joint utilities require as a means of determining which units provide enough incremental savings above the baseline unit to warrant program savings.
f. Would the joint utilities object to a requirement that, aside from those customers whose water heater is currently gas-fired and connected to a distribution system, the only water heater incentives moving forward shall be for heat pump water heaters? If so, please explain why.
g. Would the joint utilities object to provision of an additional up-front incentive for those water heaters which are controllable by, for example, requiring that in order to receive such additional incentive waters heaters must comply with Tier 3 or better of NEEA's Advanced Water Heater Specification? If so, please explain why.

Response:

a. Zero

b. Zero

c. 317

d. The NH Utilities did not plan or direct rebates based on whether or not the unit is controllable.

e. The utilities use the ENERGY STAR Heat Pump Water Heater in the Vermont Technical Resource Manual (page 396) as the minimum standard efficiency for program eligibility and as the baseline unit efficiency for heat pump water heaters.

f. The NH Utilities currently focus water heating incentives in the Products program exclusively on heat pump water heaters and are agreeable to continuing this practice. However, heat pump water heaters are not a universal solution for all non-gas customers. There are restrictions on where heat pump water heaters can be installed (e.g. ventilation, space and temperature requirements) that may make them an impractical option in some situations. For that reason, other types of water heaters are offered through the HEA program, and the utilities would not rule out completely a potential future expansion of water heating rebates in the Products program to include other viable technologies.

g. The utilities would not object, pending an examination of the cost effectiveness of providing such an incentive and what the resulting net benefits may be.

(Joint Utility Response)

Public Service of New Hampshire d/b/a Eversource Energy
Docket No. DE 17-136

Date Request Received: 10/17/2018 **Date of Response: 10/26/2018**
Request No. OCA 3-003 **Page 1 of 1**
Request from: Office of Consumer Advocate

Witness: Katherine W. Peters

Request:
Reference New Hampshire Statewide Energy Efficiency Plan 2019 Update, at Bates Pages 96-97, describing the customer engagement platform. Does the customer engagement platform provide the customer "Green Button Connect My Data" functionality?

Response:
Eversource promotes the Green Button data functionality on its website (www.eversource.com) under the Energy Efficiency area. This allows customers to download their usage data, formatted specifically for use with Green Button. Additionally, the customer engagement platform includes an "Energy Saving Plan" functionality, which allows residential and C&I customers to access and download their energy usage and cost data (including data disaggregated by end use), identify measures to save energy and costs, create an energy savings plan, and track how they are doing against their plan.

(Eversource Response)

Public Service of New Hampshire d/b/a Eversource Energy
Docket No. DE 17-136

Date Request Received: 10/17/2018 **Date of Response: 10/26/2018**
Request No. TWH 2-010
Request from: The Way Home

Witness: Katherine W. Peters

Request:
Please provide the internal policies and procedures for prioritizing the selection of housing units to treat through the HEA Program.

a. Please provide separate policies and procedures for each utility, and/or for each CAA, if those policies and procedures differ.
b. Please explain the differences, if any, between the current internal policies and procedures and those policies and procedures that were used to prioritize the selection of HEA jobs prior to the implementation of the Energy Efficiency Resource Standard pursuant to NH PUC Order No. 25,932, dated August 8, 2016.
c. How do households that are eligible for the HEA Program know their status and position on an HEA waiting list?
d. Must eligible households renew their eligibility each year by submitting a new application?
e. Do households move up on a waiting list so that they are closer to receiving services? If so, how do they move up a waiting list?

Response:
The Utilities have coordinated with the CAAs on this response, as many of the items refer to activity or policy that originates at the CAA's.

a.) The CAAs prioritize each job using the statewide Priority Scorecard developed by the State Office of Strategic Initiatives, which includes demographics such as elderly, disabled, children, etc. The CAAs follow the same prioritization rules in HEA as those used with the DOE Weatherization Assistance Program (WAP), as often times they are trying to leverage both DOE and HEA funds. Emergency situations become first priority. For jobs with HEA funds only, the utility could request additional prioritization based on high electric use or other customer need.

b.) There are no differences.

c.) The CAAs indicate that households do not receive notification of their position on the list, as this list is updated as applications are processed through fuel and electric assistance and emergencies arise.

d.) HEA follows the income qualifications for the Electric Assistance Program (EAP), the Fuel Assistance Program (FAP) and subsidized housing. EAP, FAP and most subsidized housing does require recertification annually except for elderly which are qualified for two years. Neither the CAAs or the utilities require customers complete a separate application for WAP or HEA.

e.) CAAs schedule projects and manage their wait list internally and move customers up as jobs are completed. It is possible for a customer to be bumped up on the list. Customers may apply and fit a new demographic (i.e. customer applies this year and now has a child or a disability). The primary reason for a customer to be bumped up on the list is an emergency situation.

(Joint Utility response)

Public Service of New Hampshire d/b/a Eversource Energy
Docket No. DE 17-136

Date Request Received: 10/17/2018 **Date of Response: 10/26/2018**
Request No. TWH 2-011 **Page 1 of 1**
Request from: The Way Home

Witness: Katherine W. Peters

Request:
Please provide, for each utility and for each CAA, a copy of all procedures by which a utility (and/or a CAA) projects the expected benefit-cost ratio of a potential measure that could be funded through the HEA Program.

a. Do the utilities and/or the CAAs project the expected benefit-cost ratio for all homes on an HEA waiting list prior to the time that the home is audited? Please explain.
b. Do the utilities and/or the CAAs project the expected benefit-cost ratio for all homes on an HEA waiting list after a home is audited and prior to a home being treated using HEA funds? Please explain.
c. Do the utilities and/or the CAAs record HEA jobs that fall below a 1.0 benefit-cost ratio in the database that the utilities and CAAs use to track and evaluate HEA jobs? Please explain.
d. How do the utilities and/or the CAAs determine whether to pursue a potential HEA job that falls below a 1.0 benefit-cost ratio?
e. During a program year, do the utilities ever instruct the CAAs that they cannot pursue HEA jobs that fall below a specific benefit-cost ratio? Please explain.

Response:

a.) There is no projected benefit-cost ratio for any home on the waiting list prior to the time the home is audited. Information gathered and energy modeling performed during the audit is necessary to project a benefit cost ratio.

b.) The projected B/C ratio is calculated in OTTER, the utility tracking system once the CAA has uploaded the proposed package of measures. The CAA will upload the proposed package of measures after the audit and prior to implementing the work.

c.) OTTER computes a B/C for each job, but the utilities to do not typically track jobs based on their B/C.

d.) Projects with B/C ratios of <1 are treated on a case by case basis. The decision to pursue the job is made by the utility implementation staff after discussing the individual issues and needs of the home with the CAA auditor.

e.) If the average project has been coming in with a B/C ratio lower than the planning number used to set the filing goal, the implementation staff may inform CAAs that they need to aim for a higher B/C on remaining jobs.

(Joint Utility Response)

Public Service of New Hampshire d/b/a Eversource Energy
Docket No. DE 17-136

Date Request Received: 10/09/2018 | **Date of Response: 10/23/2018**
Request No. CLF 2-011 | **Page 1 of 1**
Request from: Conservation Law Foundation

Witness: Katherine W. Peters

Request:
Please state whether the NH utilities could effectively accomplish additional efficiency measures if they did not lower their spending for 2019 from previously planned spending levels for 2019.

Response:
If the Utilities had additional funding for 2019, that additional funding could be utilized to achieve additional energy savings. However, the specific goals of the EERS are to achieve an energy savings goal of 1% of 2014 sales for electric and 0.75% of 2014 sales for natural gas. The EERS goals were set with the agreement of all parties in DE 15-137. Page 8 of the Settlement Agreement states: “The Settling Parties agree that the savings goals balance the goals of capturing more cost effective energy efficiency and benefits to ratepayers with the goal of gradually increasing funding for efficiency while minimizing the impacts on all ratepayers." It is the role of the utilities to develop budgets and propose the funding levels that are required in order to cost-effectively meet the agreed-upon goals. See OCA 2-001 for additional detail regarding the requirements of the EERS and the utility funding proposal.

(Joint Utility response)

Public Service of New Hampshire d/b/a Eversource Energy
Docket No. DE 17-136

Date Request Received: 10/10/2018 **Date of Response: 10/24/2018**
Request No. STAFF 2-034 **Page 1 of 1**
Request from: New Hampshire Public Utilities Commission Staff

Witness: Katherine W. Peters

Request:
Reference Bates 46 stating “The Working Group [PI] should complete its review by the end of the first quarter of 2019, providing enough time for any recommendations to be considered for the 2020 Plan.”

a. Upon what timeline is the proposed termination date based?
b. Given that future PI Working Group sessions have been postponed until January 2019, please provide a meeting schedule envisioned by the utilities, with topics to be discussed and agreed upon, that would accomplish all aspects of the PI Working Group’s scope of work by March 31, 2019.
c. Please indicate whether and /or where the Settlement Agreement and Commission Order in Docket No. DE 17-136 involving the PI Working Group contained a specific sunset provision or termination date.

Response:

a. The utilities proposed completion of the PI Working Group by the end of the first quarter of 2019 in order to create a focused time frame for completion of the work. Given that the PI Working Group has now suspended meetings for the duration of 2018, due to the discussions happening in this docket and other activities, the utilities would be amenable to adjusting the completion date to the end of the second quarter of 2019. This time line would provide 6 monthly meetings for discussion and decision-making. Completion of the work by June 2019 would allow time for incorporating changes into the 2020 Update filing.
b. The utilities suggest a schedule of 6 meetings covering the following topics:
Meeting 1: Discussion of the utility proposal, how it would work and how it meets many of the objectives that the group discussed during 2018.
Meeting 2: Discussion of whether a specific metric, in addition to the utility proposal, would further promote achievement of the existing low-income program goals and if so, what that metric might be.
Meeting 3: Discussion of whether a specific metric, in addition to the utility proposal, would further promote achievement of the planned peak load reductions and if so, what that metric might be.
Meeting 4: Follow-up discussion regarding the utility proposal and metrics discussions. Discussion of whether the potential 2020 mechanism will be relevant in 2021 if there is a chance the EERS goals might change for the second 3-year Plan.
Meeting 5: Revised proposal(s) for a 2020 PI Mechanism, based on Meetings 1-4.
Meeting 6: Agreement on final 2020 PI Mechanism.
c. "The PI Working Group shall make recommendations for the 2020 Plan update." Settlement Agreement, page 6. If the recommendations are going to be included in the 2020 Plan update, the ǿϮ⅏ʅ Ϯ₮ ǘKŜ ∃⅏ϮdzLJ Ydzǎǘ ōŜ ǒϮYLJɬŜǘŜŘ ʎƴǘʎYŜ ǘϮ ʎƴǑɬdzŘŜ ŀƴŘ ŀǑǑϮdzƴǘ ₮Ϯ⅏ ǘKŜ ⅏ŜǑϮYYŜƴŘŀǘʎϮƴǎ ʎƴǘKŜ Ř⅏ŀ₮ǘʎƴƎ Ϯ₮ ǘKŜ нлнл ¦ LJŘŀǘŜ .

DE 17-136 EERS
Benefit/Cost Working Group
Staff Comments on Proposed Assumptions for 2019 Plan
July 27, 2018

1. **2018 AESC Study [1] Updates to Current Assumptions** (i.e., energy, capacity, zone-on-zone DRIPE, gas, and other fuels) – Staff agrees to include updates as discussed, with further clarifications noted below regarding other assumptions.

2. **Oil DRIPE** (new)–Staff agrees to include zone-on-zone oil DRIPE.

3. **Pooled Transmission Facilities (PTF)** (new to AESC) – Staff suggests using only the $94/kW-year (not the $20/kW-year) for the avoided cost for Transmission as estimated as a new AESC assumption for the 2019 plan year update only because we typically use the estimate from the AESC Study. However, Staff still needs more info and justification on the estimation of the $94/kW-year and the increase from $20/kW-year to $94/kW-year.

4. **Reliability (generation)** (new to AESC)–Staff does not agree to include anything for reliability at this point, especially given the limitations of the studies used as the basis for the estimate and the infancy of this assumption in the AESC, but Staff encourages further research regarding reliability.

5. **Environmental for fossil fuel** – Staff agrees to include an adder for environmental for the fossil fuels, because no justification can be found for why it was excluded for fossil fuels; however, Staff suggests a recalculation possibly using RGGI as the basis for the percentage of embedded environmental. For example, according to page 372 of the revised 2018 AESC study, the embedded cost of RGGI is $0.006/kWh and the total CO_2 cost is $0.048/kWh; therefore, the embedded environmental cost is 12.5% of the total CO_2 cost. Staff suggests RGGI as the basis for the embedded cost instead of RPS (renewable portfolio standard) because RPS is mainly a renewable-focused policy (that also includes environmental benefits), whereas the revised AESC study shows the embedded (RGGI) and non-embedded CO_2 costs. Staff also suggests that the methodology for calculating the $/MMBtu assumption be explained in detail, because it is not clear how it is derived.

6. **Low Income Adder** – Staff does not agree to include a low income adder for only one year since we have included a 10% adder for all programs through 2019, and a low income-specific, non-energy impact study will be completed with NH-specific data for the update for the 2020 plan.

[1] *Avoided Energy Supply Components in New England: 2018 Report*, Initial Release - March 30, 2018; Amended- June 1, 2018. http://www.synapse-energy.com/project/aesc-2018-materials

HISTORY OF THE NEW HAMPSHIRE TOTAL RESOURCE COST TEST (TRC)'S ENVIRONMENTAL ADDER

The adder is suggested for electric utilities by working group report in July 1999 and adopted by the Commission in November 2000:

DR 96-150- 1999 Energy Efficiency Working Group Report Revising TRC
"The Group, agrees that even with the inclusion of non-electric resource benefits and costs in the proposed New Hampshire Cost-Effectiveness analysis, energy efficiency programs produce environmental and other benefits that are not otherwise captured in the direct avoided costs. The Group, with the exception of Northern, agrees that 15% should be added to avoided energy costs at this time as a proxy for the net benefits from energy efficiency related savings, and believes that including this adder is consistent with New Hampshire law. (See State Law in Appendix 3) While some Group members strongly believe that adequate market-based price proxies currently exist for some of these benefits (e.g., using the price of credits for valuing avoided NOx and SO2 emissions), uncertainty about the fuel source of marginal production in a restructured industry renders the application of these proxies difficult until some history has been established in this regard. These members further believe that use of these proxies should be considered once experience is gained with bid-based generation dispatch in the New England Power Pool, and that similar proxies for other benefits (e.g., avoided CO2 and Mercury emissions) should also be considered as they become available. However, these members agree that, all else being equal, the 15% adder could be adjusted by an appropriate amount, if and when any pollutant-specific proxies are incorporated in the cost-effectiveness test. The Group agrees that as these proxies are developed, care should be taken to recognize that the value of the avoided emissions used to achieve existing regulatory thresholds may already be included in the avoided cost of generation." (EE Working Group Report, p. 16-17)

DR 96-150- Order No. 23, 574 Approving the EE Working Group Report's Revised TRC
"We will accept the cost-effectiveness test as proposed in the Working Group's Report. We do so recognizing that the thresholds of a benefit-cost ratio have changed, and that the test itself now includes spillover benefits and costs not previously included in the cost-effectiveness test, as well as a 15 percent adder to represent environmental and other benefits of energy efficiency/conservation programs. Although the Commission has not previously authorized the use of adders, we will do so here and permit such a mechanism until some material change occurs that would warrant our reconsideration of the adder or its magnitude." (Order No. 23,574- p. 14)
"We defer the decision whether to impose the guidelines issued in this order on New Hampshire's gas utilities….Comments on the applicability of this order to gas utilities should be submitted within 60 days from the issuance date of this order." (p. 23)

DE 01-057- Order No. 23,850 Approving Plans and Modifying Previous Commission Determination
"Finally, we will approve the Joint Request for Modification of Commission Order No. 23,574 filed by PSNH. RSA 365:28 authorizes us to take such action after notice and hearing. We agree with the Electric Utilities that adoption of a single avoided cost methodology to apply to the cost-effectiveness test used to evaluate each program offering for each utility will promote the goal of having uniform offerings of Core Programs in all utility service territories." Order No. 23,850- p. 18)

The adder is adopted for gas utilities via settlement agreement in November 2002 and approved by Commission Order in December 2002:

DG 02-106- Settlement Agreement
"The Settling Parties and Staff agree that there are certain non-quantified environmental/other benefits associated with the delivery of energy efficiency programs. The Settling Parties and Staff further agree that certain environmental/other adders may be required to capture these non-quantified benefits for evaluating the cost-effectiveness of proposed energy efficiency plans. The Settling Parties and Staff have agreed to use the 15% adder developed by the Energy Efficiency Working Group and approved by the Commission in Order 23,574 in determining the cost effectiveness of the proposed gas efficiency programs. The Settling Parties and Staff agree that it may be appropriate for the environmental/other adder to be reviewed by the Commission as it is applied to gas efficiency programs in the future." (DG 02-106 Settlement Agreement, FN 1) (Links to OCA shared drive, available upon request)

DG 02-106- Gas Energy Efficiency Guidelines Exhibit to Settlement Agreement

- "Program cost-effectiveness will be based on a cost-effectiveness test that includes the following components to the extent that credible supporting data is readily available:
  Benefits
  - Avoided production, transportation, and distribution costs
  - Customer benefits
  - Quantifiable avoided resource costs (e.g., water)
  - Adder for other non-quantified benefits of 15%

  Costs
  - Program costs
  - Customer Costs
  - Quantifiable additional resource costs (e.g., water)
  - Utility performance incentives, applied at the portfolio level
- Programs with benefit/cost ratios equal to or greater than 1.0 may be approved by the Commission for implementation. Exceptions include low-income programs and educational programs. The Commission may approve a program with a benefit/cost ratio less than 1.0 if the program's benefits are difficult to estimate but the program is well-designed.
- Multi-year analyses may be conducted as appropriate
- Projected costs and benefits will be stated in present value terms using the Prime Rate.
- Cost-effectiveness analyses for a joint or coordinated program may be joint, individual to the utility, or some combination of these options based on the structure and operation of the initiative." (Guidelines Exhibit)(Links to OCA shared drive, available upon request)

DG 02-106- Northern Utilities Benefit-Cost Ratio Results 3.10.04
Applies the 15 percent adder via a row labeled "External Environmental Benefits" [Link](Links to OCA shared drive, available upon request)

DG 02-106- Order No. 24,109 Approving Energy Efficiency Programs for Gas Utilities
Order approved settlement agreement in its entirety; no explicit reference to the adder. [Link]

The adder continues in the Core filings until the 2008 Core program plan filing, with the removal never explicitly discussed in settlement agreement or before the Commission.

DE 06-135- 2007 Core Plans
"The present value of the avoided costs was increased by 15% to represent environmental and other benefits as recommended by the Energy Efficiency Working Group and authorized by the NHPUC in DR 96-150, Order No. 23,574, dated November 1, 2000." (2007 Core Plans, Attachment C- p.54)(Links to OCA shared drive, available upon request)

DE 07-106- 2008 Core Plans
"The use of the 15% adder to represent environmental and other benefits as recommended by the Energy Efficiency Working Group, originally authorized by the NHPUC in DR 96-150, Order No. 23,574, dated November 1, 2000, ***was discontinued*** because the 2007 AESC avoided costs include market-based price proxies for power plant emissions of NOx, SO2, Mercury and CO2." (2008 Core Plans, Attachment C- p. 60)

Note: This change is not discussed any further in the Settlement Agreement, the Commission's Order, or the hearing transcript. It was given only brief treatment in a single data request from Staff.

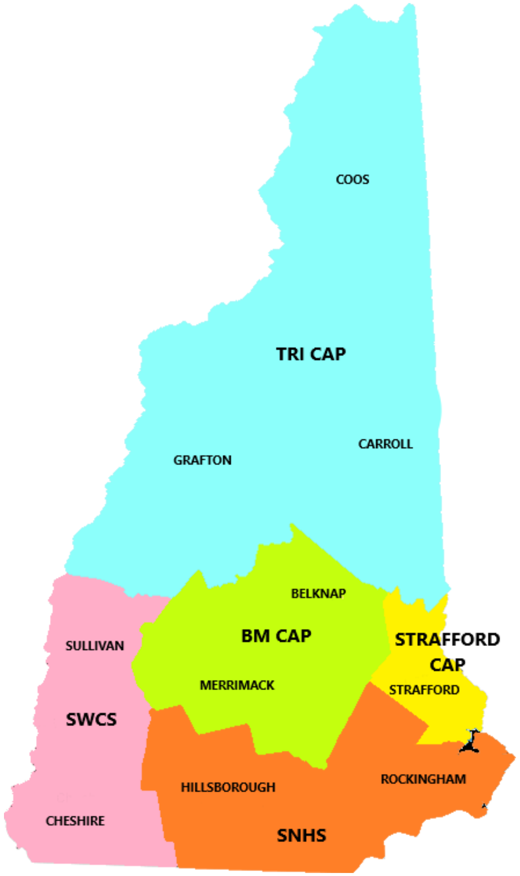
Joint Utilities' Response to Staff Data Request in 2008 Core Plan Docket
"**Question:**
How do those proxies compare with the 15% generic adder originally authorized in NHPUC DR96-105? (p56)
Response:
The proxy values may not be comparable to the generic adder. As noted in the Response to Staff Request 1-15, the allowances are internalized into the 2008 avoided electric energy supply costs. This is in contrast to the adder, which was intended to capture values not included in the avoided costs. To determine the percentage of the avoided costs that is comprised by the allowance costs of the pollutants, we can convert the proxy values from the AESC report in Exhibit 5-11 into $/kWh, using AESC study provided values of average avoided emissions per kWh in Exhibit 7-3 of the AESC report. This conversion depends on the unit on the margin, its heat rate and the carbon content of its fuel. Summing the allowance costs, gives total ***internalized*** allowance costs of about $0.0026/kWh in 2008 for the four pollutants. This increases to $0.0196/kWh in 2022, also in 2008 dollars. These prices compare to electric energy avoided costs of about $0.082 in 2008 dollars in both years. Thus the allowances are about 3% of the avoided costs in 2008 and 24% in 2022."
(PSNH Response to Staff Set 1, Q NSTF-016 -p. 19)(Links to OCA shared drive, available upon request)

Stakeholder Meeting
Home Energy Assistance Program

July 24, 2018

Low-Income Eligibility List

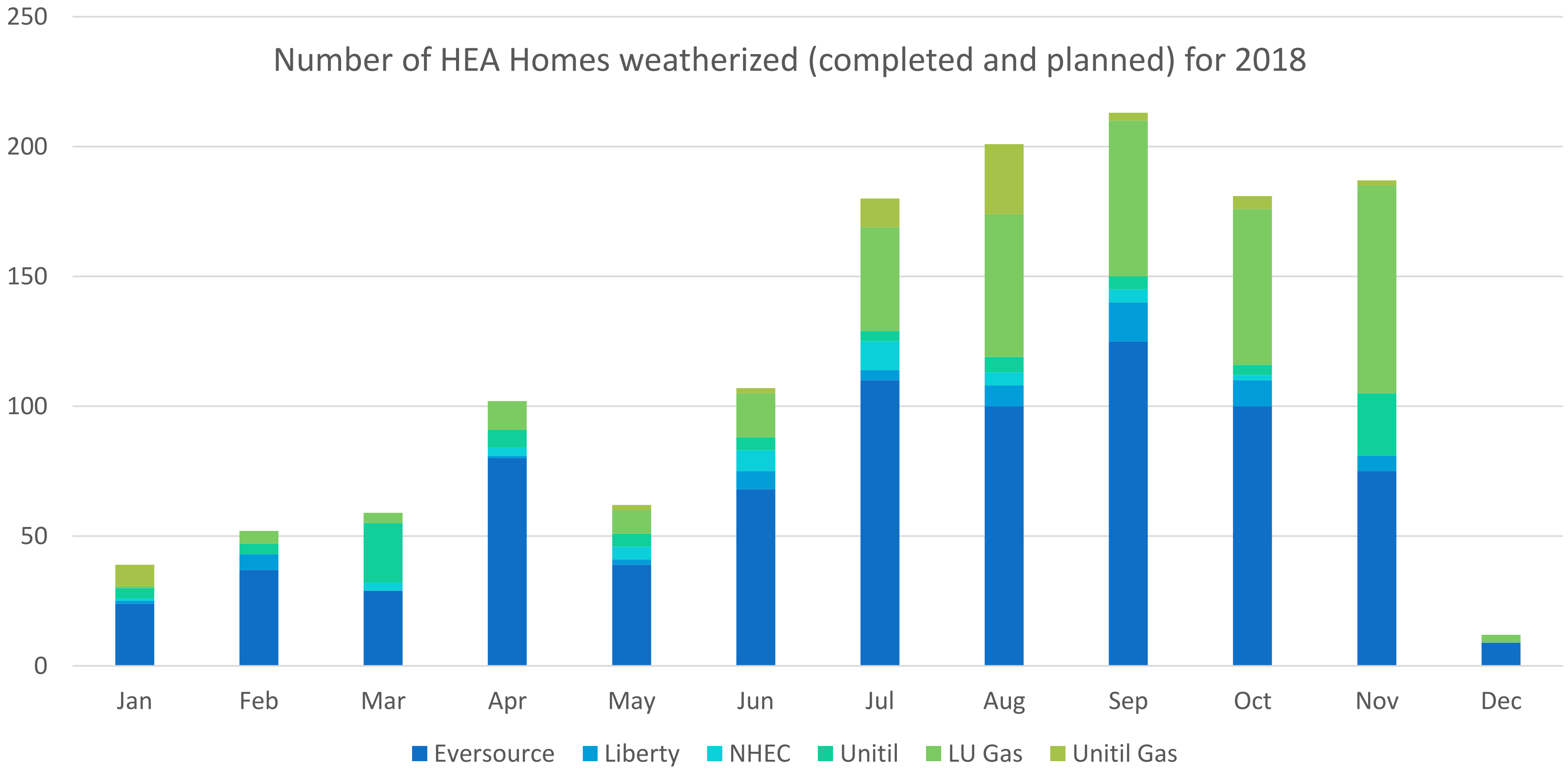
- Number of households qualified for FAP in 2018 is 29,791
  - BMCA – 4,604
  - SNHS – 13,010
  - SWCS – 4,019
  - SCCA – 2,570
  - TCCA – 5,588
- Number of FAP households that asked for weatherization services during their application in 2018 is 8,268
- Census data for number of households at or below 200% of the federal poverty level in NH is approximately 112,700



High level benchmarking with other states

	Electric Program Budget	Low-Income Electric Budget	Gas Program Budget	Low-Income Gas Budget	Low Income Budget as % Total Spend	% of state population under 200% of Poverty in 2016 *
Massachusetts 2016-18 Avg	$1,857,576,341	$203,237,116	$665,553,278	$135,176,393	13.41%	22%
Connecticut 2018	$203,879,462	$24,211,175	$58,957,639	$14,417,695	14.70%	22%
Vermont 2017	$61,648,932	$11,310,183			18.35%	25%
Rhode Island 2017	$90,011,700	$11,069,300	$27,513,400	$5,841,400	14.39%	26%
Maine 2017	$31,096,921	$3,632,885	$10,537,366	$1,103,480	11.38%	31%
New Hampshire 2018	$36,623,566	$6,225,885	$9,157,813	$1,556,830	17.00%	19%

Completed and Projected 2018 HEA Weatherization Projects



HEA in 2018

Number of homes served

Utility	Goal	Completed	In-process	Prospective	Potential % to Goal
Eversource	596	298	198	300	134%
Liberty Electric	48	18	6	36	125%
NHEC	42	23	11	9	102%
Unitil	83	48	18	24	110%
Liberty Gas	262	52	35	258	132%
Unitil Gas	60	12	38	10	100%

Summary of CORE Program Policies and Precedents Relevant to Beneficial Electrification

A. Core Program Fuel Neutral Pilots-

1. Prior to October 2008, only HEA Programs have fuel blind aspect
2. October 2008- Utilities first propose Home Energy Solutions fuel blind component in Draft 2008 Plan
3. December 2008- Settlement leaves fuel blind proposal unresolved, allowing parties to file further details in comments prior to Order
4. December 2008- PSNH Memo supporting use of the SBC for fuel blind pilot, Staff brief in opposition, OCA comments in opposition, NHLA Comments in favor, OEP Comments generally supportive
5. January 2009- Order 24,930 approves plans without fuel blind program, and directs utilities to file further details on those programs
6. April 2009- Utilities file further details on fuel blind program
7. April 2009- Staff files a letter outlining its opposition to the pilots, and recommendations to ease their concerns if the pilots are adopted
8. June 2009- Order No 24,974 adopts the pilots
9. June 2009- August 2012- parties repeatedly file to expand pilots to full HES/HPwES program, but Staff opposes expansion

B. Fuel Neutral Programs Graduate from Pilot Status

1. August 2012- Order No. 25,402- After three years, for the first time HPwES's fuel-neutral programs became non-pilots; Commission establishes a performance incentive working group in light of Staffs concerns regarding spending SBC dollars on unregulated fuel savings; *working group also* ***directed to focus on peak demand reduction.***
2. September 2013- Order No. 25,569- In light of the earlier adoption of the fuel neutral programs, but parties' preference that electric savings have the priority over unregulated fuels, Commission adopted PI working group recommended 55% electric threshold for higher performance incentive. *Side Note: Working group suggests value of peak demand reduction already included in avoided costs and separate metric would overemphasize value of peak demand reduction while providing no factual basis for why emphasizing peak demand reduction is detrimental to ratepayers.*

C. Utilities Cease Claiming Unregulated Fuel Savings for Heat Pumps

a. September 2013- 2014 Core Plan Update (Bates 0006)- Utilities propose modification of the heat pump incentive and rebate, namely: "the base case assumption has changed from a fossil fuel appliance to a standard efficiency mini-split heat pump," in order to bring our assumptions "in line with standard practice in other northeast states." This means the program administrators no longer claim the MMBtu savings they previously did for heat pump technologies, and will offer a lower participant incentive.

b. November 2013- Staff Testimony supports rebate reduction, but does not mention MMBtu savings elimination.

c. December 2013- Order No. 25,615- Commission approves revised savings and incentives for heat pumps with utilities no longer claiming fossil savings.

September 21, 2018

NH Presentation

Efficiency & Electrification:
Strategic Partners

Emily Levin
VEIC

VEIC

Savings Assumptions

State	Program/Utility	Incentive Level	Incremental Electric Savings	Retrofit Fuel Savings
CT	Energize CT	$300	Yes	No
MA	Mass Save	$100-300	Yes	No
ME	Efficiency Maine	$500	Yes	No
NH	NH Saves	$375-750	Yes	No
NY	NYSERDA	$500	Yes	No
	Utility Programs	$100-300		
RI	National Grid	$100-300	Yes	Yes
VT	Efficiency Vermont	$600-800	Yes	Yes

VEIC

2019-2021 Conservation & Load Management Plan

Connecticut's Energy Efficiency & Demand Management Plan

Connecticut General Statutes—16-245m(d)

Submitted by: Eversource Energy, United Illuminating, Connecticut Natural Gas Corporation, and Southern Connecticut Gas

Date: November 1, 2018 (10-5-2018 VERSION)

- Benefits used within each of the B/C tests and their source;
- Financial parameters (e.g., discount rate and inflation factors used in B/C testing);
- Use of avoided costs from the 2018 AESC; and
- Avoided Costs (Appendix).

5.2 AVOIDED ENERGY SUPPLY COST STUDY

Most of the avoided costs used in the Companies' B/C testing will be updated for the 2019-2021 Plan based on the recently completed 2018 AESC.[87] The 2018 AESC was sponsored by New England energy efficiency program administrators. In addition, other non-utility parties (e.g. regulators and consultants) formed the Avoided Cost Study Group to oversee the development of the 2018 AESC. Previous iterations of an avoided cost study were conducted on a biennial basis. However, beginning in 2015, the AESC moved to a three-year cycle which coincides with the current three-year planning cycle in Connecticut.

5.3 BENEFIT-COST TESTS

Benefit-Cost Tests

The following three B/C tests were utilized in the 2019-2021 Plan. The B/C tests compare the net present value of program induced avoided costs with the cost to achieve the benefits. These three B/C tests have been used since the 2015 Plan and include: (1) the Utility Cost Test, (2) the Modified Utility Cost Test, and (3) the Total Resource Cost Test. These tests are summarized below, and additional details are provided in Table 5-1 below.

- **The Utility Cost Test** ("UCT") includes the value of utility-specific benefits and program costs associated with those benefits. For example, the UCT includes energy avoided costs from electric and natural gas conservation measures/programs and all program costs associated with acquiring those benefits. The UCT does not include customer out-of-pocket costs, or costs or benefits associated with oil or propane savings. Nor does the UCT include non-energy impacts or the non-embedded value of GHG emissions reductions.
- **The Modified Utility Cost Test ("MUCT")** includes all benefits and costs as the UCT. In addition, the MUCT includes oil and propane-avoided costs, and the program costs associated with acquiring oil and propane savings. Note that the MUCT currently applies only to electric residential programs that have oil or propane savings.

[87] Synapse Energy Economics, Inc. *Avoided Energy Supply Component in New England: 2018 Report*, Mar. 30, 2018.

- The Total Resource Cost Test ("TRC") includes all energy and non-energy benefits, such as water savings, non-embedded emissions, environmental attributes, and non-energy impacts. In addition, the TRC includes all costs associated with acquiring these savings. This includes program costs and customer out-of-pocket costs.

Table 5-1 provides the benefits (numerator) and costs (denominator) that are used within the three B/C tests, as well as their value and source.

Table 5-1: Benefit/Cost Testing Summary (including the source of the avoided costs/benefits)

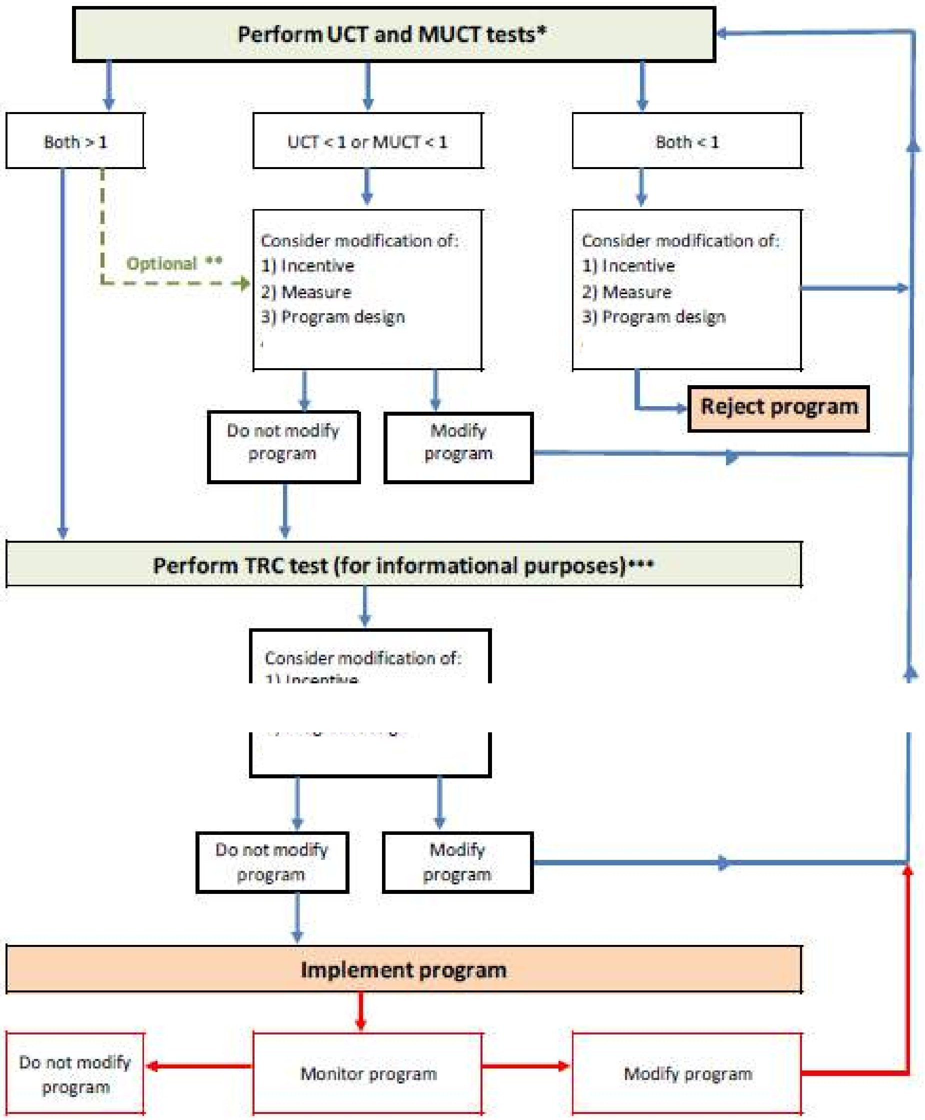
Benefit Type (numerator)	Units	Value 15 Year Levelized Cost ($2018)	Utility Cost Test (Natural Gas/Electric)	Modified Utility Cost Test	Total Resource Cost Test	Source
Electric Program Benefits						
Energy	$/kWh	$0.058	X	X	X	2018 AESC
Capacity	$/kW	$71.09	X	X	X	2018 AESC
Transmission	$/kW	$0.86	X	X	X	EDCs (Note 1)
Distribution	$/kW	$30.89	X	X	X	EDCs (Note 1)
Pooled Transmission Facilities (Note 2)	$/kW	$92.16	X	X	X	2018 AESC
Reliability (Note 2)	$/kW	$4.15	X	X	X	2018 AESC
Energy DRIPE (Note 3)	$/kWh	$0.028	X	X	X	2018 AESC
Capacity DRIPE (Note 4)	$/kW	$258.42	X	X	X	2018 AESC
Natural Gas Program Benefits						
Natural Gas	$/MMBtu	$7.76	X	X	X	2018 AESC
DRIPE (Note 5)	$/MMBtu	$3.02	X	X	X	2018 AESC
Other Benefits						
Oil	$/MMBtu	$22.51		X	X	2018 AESC
Oil DRIPE	$/MMBtu	$0.112		X	X	2018 AESC
Propane	$/MMBtu	$31.39		X	X	2018 AESC
Water	$/Gallons	$0.014			X	CT rates (Note 6)
Non-Energy Impacts	$ (varies)	N/A			X	Various
Non-Embedded Emissions	$/kWh	$0.042			X	2018 AESC
Fossil Emissions	$/ton	$100/ton CO_2 $11,955/ton NOx			X	2018 AESC
Cost (denominator)			Electric Cost (no oil/propane)	Program Cost (including oil, propane)	Total Cost (program + customer)	

Note 1: Transmission and Distribution benefits ae based on Electric Distribution Companies' ("EDC") studies conducted in 2017. The Companies use weighted average values for T ($0.84/kW) and D ($30.29/kW) from those studies.
Note 2: Pooled Transmission Facilities and Reliability are new benefits. They were not included in previous versions of the AESC Study and therefore, were not included in B/C screening prior to 2019.
Note 3: Includes all DRIPE identified in 2018 AESC, including own-fuel DRIPE and cross-fuel DRIPE (Connecticut DRIPE and rest-of-pool).
Note 4: Capacity DRIPE includes Connecticut and rest-of-pool components.
Note 5: Includes all DRIPE identified in 2018 AESC including own-fuel DRIPE and cross-fuel DRIPE (Connecticut DRIPE and rest-of-pool).
Note 6: Water-avoided costs based on 2016 Tighe and Bond water and sewer data for Connecticut. http://rates.tighebond.com/index.aspx.

In Connecticut, the UCT (or MUCT for electric programs that save fossil fuels) is considered to be the primary test. The TRC is used as a secondary test to provide a broader perspective of program performance. The flow chart below (Figure 5-1) illustrates the use of three B/C tests and the iterations that may be used to refine program performance and optimize the energy efficiency portfolio.

Figure 5-1: Connecticut B/C Testing Process[88]

In



* Multiple rounds of UCT and MUCT testing may be employed to refine a program.
** Modifications to improve savings and benefits might be considered.
*** TRC is not used as pass/fail test. Judgment about whether a program passes muster is based on the UCT and MUCT. The TRC test merely provides an indication of whether participant contribution and program incentive are appropriate without further modification.

[88] The Connecticut B/C flowchart was developed through a collaborative effort between DEEP staff and the Companies.

addition to the continuation of the three B/C tests, the Companies will maintain the basic framework of the B/C tests to remain consistent with prior DEEP feedback.[89] This includes the following: (1) the use of nominal avoided costs, and (2) a nominal discount rate of 5.5 percent for all B/C testing. The discount rate is used to calculate the net present value of the avoided costs over the life energy efficiency measures. The nominal avoided costs are calculated using a 2.0 percent inflation factor based on the 2018 AESC.

5.4 FUTURE CONSIDERATIONS

In May 2017, the National Efficiency Screening Project ("NESP") released the National Standards Practice Manual for Cost-Effectiveness ("NSPM").[90] The NSPM builds upon the existing California Standards Practice Manual that has been used throughout the United States for decades. The NSPM expands B/C testing beyond traditional tests and allows jurisdictions more flexibility to adjust current tests to better align with local policies.

Recently, DEEP has initiated discussions with the Companies on the development of a Resource Value Test ("RVT") consistent with the NSPM to reflect State policy goals outlined in the 2018 CES. The RVT could provide more appropriate methodologies to screen measures (e.g., high-efficiency heat pumps) that offer customers energy savings and have environmental attributes (e.g., GHG emissions, water savings, etc.) consistent with the strategies outlined in the 2018 CES. The Companies will continue to work collaboratively with DEEP during this process and implement any changes to B/C testing in plan updates.

In August 2018, Synapse Energy Economics, on behalf of the Massachusetts Department of Energy Resources, issued a study[91] on the associated incremental avoided compliance costs of the Massachusetts Global Warming Solutions Act. This study titled *Analysis of the Avoided Costs of Compliance of the Massachusetts Global Warming Solutions Act* concluded that the incremental avoided cost of compliance with the Massachusetts Global Warming Solutions Act was $17/MWh or $35/tons of carbon dioxide. For the 2019-2021 Plan, the Companies and the Energy Efficiency Board will review the Massachusetts study to determine and evaluate if similar incremental avoided compliance costs should be incorporated into the Companies' benefit-cost methodologies.

[89] September 26, 2014 DEEP Resolution of Conditions.

[90] National Efficiency Screening Project. *National Standards Practice Manual*, May 2017. Available at: https://nationalefficiencyscreening.org/national-standard-practice-manual/.

[91] Synapse Energy Economics. *Analysis of the Avoided Costs of Compliance of the Massachusetts Global Warming Solutions Act*, Aug. 2018. Available at: http://www.synapse-energy.com/sites/default/files/AESC-2018-17-080-June-Release.pdf.

Energy Efficiency Board Monthly Meeting

Wednesday, September 12, 2018, 1:00 – 3:30 PM
10 Franklin Square, New Britain, CT (Hearing Room 2)

Meeting Materials in Box.com: https://app.box.com/s/01sqsrz8ccxd81f6t8iepfjwea24h4tw
Call-in number: (571) 317-3122 / Call-in passcode: 135-725-253
Web conference: https://global.gotomeeting.com/join/135725253

Agenda

1. Process (15 min)

A. Minutes - approve minutes from August 8, 2018 Board meeting
B. Public Comments - 3 minutes per organization
C. Update on Fireye product eligibility issue

2. Programs and Planning (130 min)

A. 2019-2021 C&LM Plan (105 min)
- Key Plan Elements – Companies and Consultants
- Budget – Companies and Consultants
- Avoided costs and cost-effectiveness inputs for 2019-2021 Plan – Jeff Schlegel
- Preliminary Plan goals - Companies
- Board discussion
- VOTE on 2019-2021 Plan Budget and Initial Plan Text

B. SBEA recapitalization update (10 min)
C. DEEP summary of schedule and process for cost-effectiveness testing public meetings on September 13 and in mid-November (15 min)

3. Other (5 min)

4. Closing Public Comments – 3 minutes per organization

Adjourn

Updating the Energy Efficiency Cost-Effectiveness Framework in Minnesota

Application of the National Standard Practice Manual to Minnesota
August 8, 2018
Contract 137458

Conservation Applied Research and Development (CARD) Report

Prepared for: Minnesota Department of Commerce, Division of Energy Resources
Prepared by: Synapse Energy Economics, Inc.

Prepared by:
Erin Malone
Tim Woolf
Danielle Goldberg

Synapse Energy Economics, Inc.
485 Massachusetts Avenue, Suite 2
Cambridge, MA 02139
Phone: (617) 661-3248
website: www.synapse-energy.com
Project Contact: Erin Malone

Contract Number: 137458

Prepared for Minnesota Department of Commerce, Division of Energy Resources:
Jessica Looman, Commissioner, Department of Commerce
Bill Grant, Deputy Commissioner, Department of Commerce, Division of Energy Resources

Adam Zoet, Project Manager
651-539-1798
adam.zoet@state.mn.us

ACKNOWLEGEMENTS

This project was supported by a grant from the Minnesota Department of Commerce, Division of Energy Resources, through the Conservation Applied Research and Development (CARD) program, which is funded by Minnesota ratepayers.

Table of Contents

Appendix A

Efficiency Vermont 2018-2020 QPIs

(November 2017)

Table A-1: 100% Targets and Base Performance Award

QPI#	Title	Performance Indicator	100% Target	Award Weight	Base Performance Award
1	Total Resource Benefits	Present worth of lifetime electric, fossil fuel, and water benefits	$318,107,900	30%	$1,213,050
2	Annual Electricity Savings	Annual incremental net MWh savings	357,400	30%	$1,213,050
3	Summer Peak Demand Savings	Cumulative net summer peak kW demand savings	45,900	17%	$687,395
4	Winter Peak Demand Savings	Cumulative net winter peak kW demand savings	62,400	14%	$566,090
5	Lifetime Electricity Savings	Lifetime incremental net MWH savings	3,582,200	9%	$363,915
TOTAL				**100%**	**$4,043,500**

All results are verified by the Vermont Department of Public Service and approved by the Vermont Public Utility Commission annually.

Efficiency Vermont 2018-2020 QPIs

(November 2017)

Table A-2: Threshold and Scaling Up to 100% Target Level

QPI #1: TOTAL RESOURCE BENEFITS (TRB)

	Minimum	100% Target Level	Increase Rate
Achievement	$234,395,300	$318,107,900	$0.0058
% of model	70%	95%	Per TRB dollar between $234,395,300 and $318,107,900
% of award	60%	100%	
Award amount	$727,830	$1,213,050	

QPI #2: ANNUAL ELECTRICITY SAVINGS (MWh)

	Minimum	100% Target Level	Increase Rate
Achievement	263,400	357,400	$5.1619
% of model	70%	95%	Per MWh between 263,400 and 357,400
% of award	60%	100%	
Award amount	$727,830	$1,213,050	

QPI #3: SUMMER PEAK DEMAND SAVINGS (kW)

	Minimum	100% Target Level	Increase Rate
Achievement	33,800	45,900	$22.7238
% of model	70%	95%	Per kW between 33,800 and 45,900
% of award	60%	100%	
Award amount	$412,437	$687,395	

QPI #4: WINTER PEAK DEMAND SAVINGS (kW)

	Minimum	100% Target Level	Increase Rate
Achievement	46,000	62,400	$13.8071
% of model	70%	95%	Per kW between 46,000 and 62,400
% of award	60%	100%	
Award amount	$339,654	$566,090	

QPI #5: LIFETIME ELECTRICITY SAVINGS (MWh)

	Minimum	100% Target Level	Increase Rate
Achievement	2,639,500	3,582,200	$0.1544
% of model	70%	95%	Per MWh between 2,639,500 and 3,582,200
% of award	60%	100%	
Award amount	$218,349	$363,915	

Efficiency Vermont 2018-2020 QPIs

(November 2017)

Table A-3: Scaling Above 100% Target Level

QPI	Performance Indicator	100% Target Level	Increase Rate	Units
1	Total Resource Benefits (TRB)	$318,107,900	$0.0090	per $ above 100% Target Level
2	Annual Electricity Savings (MWh)	357,400	$7.9787	per MWh above 100% Target Level
3	Summer Peak Demand Savings (kW)	45,900	$35.4167	per kW above 100% Target Level
4	Winter Peak Demand Savings (kW)	62,400	$21.2121	per kW above 100% Target Level
5	Lifetime Electricity Savings (MWh)	3,582,200	$0.2387	per MWh above 100% Target Level

Table A-4: Minimum Performance Requirements

QPI#	Title	Minimum Requirement	Policy Goal Advanced	Form of Verification	Performance Incentive Award Reduction %	Financial Impact
6	Minimum Electric Benefits	Total electric benefits divided by total costs is greater than 1.2	Equity for all Vermont electric customers as a group by ensuring that the overall electric benefits are greater than the costs incurred to implement and evaluate the *EEU* and the *EEC*	Tracking System	Eliminates 100% of performance incentive award	$4,043,500
7	Threshold (or minimum acceptable) Level of Participation by Residential Customers	Total residential sector spending is greater than $39,956,000	Equity for residential customers by ensuring that a minimum level of overall efficiency efforts, as reflected in spending, will be dedicated to residential customers	Accounting System	Reduces total performance incentive award at *100% Target Level* by 18%	$727,830
8	Threshold (or minimum acceptable) Level of Participation by Low-Income Households	Total low-income services spending is greater than $11,050,000	Equity for low-income customers by ensuring that a minimum level of overall efficiency efforts, as reflected in spending, will be dedicated to low-income households	Accounting System	Reduces total performance incentive award at *100% Target Level* by 18%	$727,830
9	Threshold (or minimum acceptable) Level of Participation by Small Business Customers	Total non-residential premises with annual electric use of 40,000 kWh/yr or less that acquire kWh savings is greater than 2,000	Equity for small business customers by ensuring that a minimum level of overall efficiency efforts, as reflected in participation, will be dedicated to small business accounts	Tracking System	Reduces total performance incentive award at *100% Target Level* by 18%	$727,830
10	Geographic Equity	TRB for each geographic area is greater than values shown on Table A-5	Geographic equity for all Vermont electric customers by ensuring that energy efficiency benefits are geographically distributed on an equitable basis	Tracking System	Reduces total performance incentive award at *100% Target Level* by 6%	$242,610
11	Administrative Efficiency	Meet all pre-determined milestones on schedule	To clearly define and track all administrative costs, including incentive, and non-incentive costs, associated with Efficiency Vermont's delivery of services under the Order of Appointment	Tracking Report	Reduces total performance incentive award at 100% Target Level by 2%	$80,870
12	Service Quality	Achieve 92 or more metric points in the Service Quality and Reliability Plan over the course of the Performance Period	To establish Quality Performance Standards and associated reporting requirements for energy efficiency services provided by Efficiency Vermont	Quarterly, Annual and Performance Period Reports	Reduces total performance incentive award by $1,630 per point lost (beyond 16) with a potential total reduction at 100% Target Level by 4.4%	$150,000
13	Resource Acquisition Performance Period Spending	Total spending for a three-year performance period (including applicable operations fees) is less than $135,906,528.	To minimize total spending variances above Commission approved 2018-2020 budgets	2020 Savings Claim Summary	Reduces total performance incentive award at 100% Target Level by 2.0% and increases at 0.5%	Penalty begins at $20,000 and increases per Table A-13
14	Development and Support Services Performance Period Spending	Total spending for a three-year performance period (including applicable operations fees) is less than $14,138,248.	To minimize total spending variances above Commission approved 2018-2020 budgets	2020 Savings Claim Summary	Reduces total performance incentive award at 100% Target Level by 2.0% and increases at 0.5%	Penalty begins at $2,000 and increases per Table A-15

2.13 ACTIVE DEMAND REDUCTION STRATEGIES (RESIDENTIAL)

Eversource Demand Reduction Strategies

Eversource has dedicated resources throughout 2017 and 2018 toward testing and evaluating active demand reduction technologies and demand response initiatives for the Residential marketplace. During the 2019-2021 Plan, Eversource will use the knowledge gained from its 2018 Demand Response pilots to construct permanent offerings that incentivize active demand reduction strategies and measures that enable them. These offerings could include but are not limited to: traditional demand response direct-load management, software, and controls. Eversource would expand its efforts through new customers and emerging controllable equipment and manage these demand reduction assets through the use of innovative control structures that will allow Eversource to coordinate dispatches.

United Illuminating Demand Reduction Strategies

During the 2019-2021 Plan, United Illuminating will transition its active demand response pilots into full-fledged solutions, while adding new customers and additional controllable demand reduction technologies. The continuation of the existing pilots as programs during the 2019-2021 Plan is a critical step in understanding local demand response markets and in starting the logical process of integrating demand response and energy efficiency tactics into one comprehensive offering to increase the value to customers and decrease costs to United Illuminating. These demand response programs will allow United Illuminating to gather additional event data to better assess and to quantify the potential active demand reductions associated with each demand response technology and/or strategy and any associated energy savings.

Common to Eversource and United Illuminating

Not limited solely to summer peak demand reductions, the Companies' Active Demand Response ("ADR") solutions can be useful for ramping (ISO-NE dispatch only), load curtailment, operational needs and shortage events, as well as winter demand reduction needs. Automation and advances in technology make it possible to manage customer loads in new ways with strategies that bring additional values to the Companies and the customer.

Where possible, all Demand Response solutions will be integrated and co-delivered with the Companies' existing Residential Energy Efficiency Portfolio offerings to increase the value to customers and decrease costs to Eversource and United Illuminating. During the implementation of these solutions, the Companies understand that customer education regarding Demand Reduction solutions is imperative. Throughout the 2019-2021 Plan, Eversource and United Illuminating will look to educate customers regarding the benefits of Demand Response solutions, the demand reduction technologies used, and the financial incentives and rebates that will be offered.

2019-2021 Residential Demand Response Solutions

For the 2019-2021 Plan, the Electric Companies will use their Demand Response solutions to assess active demand reduction (kW) of each program, customer participation rates vs. opt-outs, and customer satisfaction and engagement with the solution(s). For the 2019-2021 Plan, the Companies will implement the following Residential Demand Response solutions:

- **Connected Wi-Fi Thermostats & HVAC Systems**

  This "Bring Your Own Thermostat" initiative will incorporate the next generation of connected Wi-Fi thermostats in order to empower and engage customers with demand response programs. The Companies will have remote controllability of customers' HVAC system temperature set points and schedules, and customers will have a better understanding and control of their energy usage.

  The target market is all residential electric customers who have central HVAC systems that provide air conditioning in their homes. The Companies will offer their program to: (1) any existing customers with a qualifying connected Wi-Fi thermostat, and (2) HES and HES-Income Eligible participants as an add-on measure. To encourage participation, the Companies will host educational sessions for HES and HES-Income Eligible contractors regarding the benefits of the technology, who qualifies, and how a customer can take advantage of the incentive offering.

  Qualifying customers will receive a one-time enrollment incentive and an annual demand response participation incentive (per qualified thermostat). This is in addition to an Energize Connecticut $100 rebate that will continue to be offered through the HES solution for qualified thermostats. The demand response enrollment incentive will be tied to confirmation of successful enrollment in Eversource's or United Illuminating's program; rather than tied to the purchase of a connected Wi-Fi thermostat itself. This validates that the customer has properly installed the device and enrolled in the program, thereby minimizing the risk of leakage to other utility service territories.

- Wi-Fi-Enabled Room Air Conditioners

  This is an additional demand response initiative for the Companies to pursue during the 2019-2021 Plan. The Companies will follow manufacturers' advances in Wi-Fi-enabled window air conditioners units. As the costs for these units go down, the Companies could cost-effectively provide free window air conditioner units at little or no cost to qualifying limited-income customers.

During the 2016-2018 Plan, United Illuminating collected data and analyzed the results and cost-effectiveness of its Room A/C Smart Plug pilot. This pilot tested the effectiveness of a smart plug utilized between a customer's window Room A/C unit and the wall plug. In the fall of 2018 (after third summer of calling events), United Illuminating's benefit-cost analysis determined that the pilot was not cost-effective. The key factor was the low installation and reinstallation rates of the smart plug with the window Room A/C unit and the cost of continual customer engagement to reinstall the smart plug with the Room A/C in subsequent cooling seasons. Wi-Fi-enabled window Room A/Cs would resolve the issue where the current smart plug and window Room A/C units are separated at the end of each season, thus increasing the chances that they will not be re-installed together at the start of the next cooling season.

- Wi-Fi-Enabled Heat Pump Water Heaters

Similar to connected Wi-Fi thermostats, new models of HPWHs come Wi-Fi-enabled for easy pairing with the Companies' residential Demand Response portals and can offer the Companies the ability to pursue additional demand reduction opportunities.

For the 2019-2021 Plan, United Illuminating will look to expand upon its current pilot marketed through the HES-Income Eligible solution by adding additional customers to its population of controlled HPWHs. Qualifying customers will receive a free installed Wi-Fi-enabled HPWH and be enrolled in the initiative. In 2019-2021, United Illuminating will also explore the potential of a market-rate Wi-Fi-enabled HPWH offering with point-of-purchase rebates and automatic enrollment (customer and HPWH unit) into the Demand Response initiative. For the 2019-2021 Plan, Eversource will explore introducing a similar promotion through the home energy performance solutions—HES and HES-Income Eligible.

During the 2019-2021 Plan, the Companies will also explore other market entry points, such as instant rebates for specific Wi-Fi HPWHs at big-box retail stores. The integration of these additional market-rate Wi-Fi HPWHs into the Demand Response portals is the next logical step in supporting the continued growth of new smart appliances. The Wi-Fi HPWH is the first smart appliance that was added to the Companies' existing Demand Response portals other than Wi-Fi thermostats. The Companies hope this portal and network of smart and connected devices will continue to enable quick and successful launches of future demand response efforts for smart appliances and connected equipment.

- Peak Time Rebate Pilot (United Illuminating)

United Illuminating's Peak Time Rebate ("PTR") two-year pilot will end in the spring of 2020. The PTR pilot rewards customers based on the amount of energy that they reduce in their homes during peak events, which are typically during the summer and winter seasons when the local electric distribution systems may be under stress due to high electrical usage.

The pilot will provide 10,000 United Illuminating customers with messaging and a PTR to encourage customer participation and additional reductions beyond that of a standard behavioral demand response ("BDR") program. Incentives per event are based on event reductions and rebates will be paid to customers at the end of each summer and/or winter season. Customers can choose their level of participation, including: simply turning off lights, increasing their air conditioner temperature settings by several degrees, shifting load to a later time of the day to turn off all loads, and/or going outside with the family for a hike.

Event days will be called at United Illuminating's discretion based on ISO-NE Seasonal Peak Hours and/or predicted high loads on United Illuminating's electrical distribution systems. It is anticipated that approximately six (two summer events and four winter events) will be called on average. Baseline usage is simply calculated using 15-minute interval data and is the mean ten-of-ten or the average of the past 10 days (non-weekend and holidays). For each hour that they achieve their goal, the customer's incentive earned will increase.

Additional Demand Reduction Opportunities

During the 2019-2021 Plan, the Companies will also explore the demand reduction opportunities and potential associated with EV chargers, as well as the integrated operation and value of all controllable demand response loads to their distribution systems.

For the 2019-2021 Residential Energy Efficiency Portfolio, United Illuminating will also evaluate additional demand reduction strategies, including but not limited to: online energy marketplaces and online platforms for competitive demand response program participation. Online energy marketplaces are becoming increasingly commonplace in the utility industry and offer personalized retail centers for customers to buy rebate-eligible and discounted efficiency products from a utility-branded site. Additionally, these marketplaces provide the functionality for customers to enroll in demand response programs simultaneously while purchasing connected Wi-Fi thermostats or other demand response products. Products such as connected Wi-Fi thermostats are typically discounted, can decrease free ridership, and can increase demand response program participation with auto enrollment at the time of check out.

During the 2019-2021 Plan, United Illuminating will explore online platforms that encourage competitive demand response participation. These social media feedback systems for behavioral demand reduction strategies, such as PTR programs, allow customers to compete with their friends online to reduce their energy use during peak demand days, while sharing their results daily on a social gaming application. Online platforms that promote competitive demand response program participation (i.e., games or competitions) hold the potential for increased demand reductions; compared to those programs where customers install a demand response device but did not participate in a social media or competitive game aspect.

Energy Efficiency Solutions, and in addition to the services and incentives provided to them through the EUA initiative.

The Companies will work to claim savings from operational behavioral savings through the Customized Solutions Partnership's SEM Demonstration (detailed later in Section 3.14).

Process Reengineering for Increased Manufacturing Efficiency

The Process Reengineering for Increased Manufacturing Efficiency ("PRIME") initiative specifically targets Connecticut's manufacturing sector. PRIME engages manufacturers in a systematic approach to identifying inefficiencies and waste in their business operations. Through the PRIME initiative, manufacturers receive training in lean manufacturing techniques to eliminate or reduce waste, improve product efficiency, reduce operating inefficiencies, minimize environmental impacts (reduced GHG emissions), reduce electrical energy consumption, and to streamline manufacturing processes.

Through the PRIME initiative, the Companies conduct a competitive solicitation process for highly-qualified lean manufacturing vendors. These vendors conduct a site-survey to determine what site-specific and market segment-oriented lean manufacturing techniques should be implemented. The Companies offer incentives for energy-efficient equipment through their ECB and EO solutions and provide funding for lean manufacturing training that is based on the energy savings associated with the training.

CUSTOMIZED SOLUTIONS PARTNERSHIP SEM DEMONSTRATION

The primary objective of the Companies' Customized Solutions Partnership ("CSP") SEM Demonstration ("CSP/SEM Demonstration") is to provide the largest C&I customers, primarily large manufacturers, with the opportunity for strategic, customized energy management solutions that offer electric and natural gas incentives, analytical services to assist with achieving high levels of energy, and operational efficiencies within their facilities.

For the 2019-2021 Plan, the CSP/SEM Demonstration's other objectives follow:

- Test an enhanced approach for the Companies' current offering based on the ISO 50001 framework for SEM;
- Establish a SEM savings verification protocol for use in Connecticut;
- Test baseline development for whole plant and process boundaries;
- Evaluate impacts on program costs, savings, cost-effectiveness, and cost-ratios; and
- Develop custom, negotiated savings baselines based on whole plant, process line, or major system boundaries.

Target Market

The target market for the CSP/SEM Demonstration is any C&I customer within the Companies' service territories that have approximately 3 MW of aggregate demand or larger and demonstrates a willingness to sign and commit to a CSP that establishes a multi-year (generally three years in duration) energy efficiency target mutually established upon between the customer and the appropriate utility. A direct sales market strategy will be used for large C&I customers that satisfy the large customer requirement. Throughout the 2019-2021 Plan, the Companies will work with Connecticut Industrial Energy Consumers to ensure their membership is aware of the CSP/SEM Demonstration.

Background

Key Customized Solutions Partnership Elements

Through the CSP, the CSP/SEM Demonstration will facilitate multi-year SEM plans, annual savings targets, and provide streamlined access to the C&I Energy Efficiency Portfolio's incentives and offerings (i.e., technical services and financing on an-as-needed basis). Additionally, the CSP may include other allied services as an integrated and strategic efficiency package, including but not limited to the Connecticut Green Bank's financial offerings.

A typical CSP will include the following attributes and features:

- A non-binding Strategic Partnership Agreement between the customer and the Companies (signed at the officer level);
- A three-year term (typically);
- Established annual electric and natural gas energy savings targets, with at least two percent of historical annual consumption or equivalent process improvements;
- Customer-specific with the necessary flexibility to accommodate issues such as the capital planning process, financial hurdle rates, focus on manufacturing processes (if applicable), and the inclusion of outside engineering and technical services;
- The CSP should be the result of multiple strategic engagements between the customer, the Companies, and any other relevant party requested by the customer to address all relevant areas of the customer's organization; and
- A mutually agreed upon model (e.g., engineering, linear regression, spreadsheet based, DOE 2) developed by the Companies and/or the customer that will be used to estimate savings.

ISO 50001 & the DOE ISO 50001 Ready Navigator

ISO 50001[42] is an international standard focusing on energy management and is based on the same management principles of continual improvement as ISO 9001 (focusing on quality) and ISO 140001 (focusing on sustainability). The current 2018 ISO 50001 model provides a framework for organizations to:

- Develop a policy for more efficient use of energy;
- Establish targets and objectives to meet the policy;
- Use data to better understand and make decisions regarding energy procurement and use;
- Measure the results;
- Review how well the policy works; and
- Continually improve energy management.

The DOE ISO 50001 Ready Navigator[43] ("Ready Navigator Tool") is an energy management tool designed to walk C&I customers through a step-by-step process of establishing an ISO 50001 compliant energy management system ("EMS"). The Ready Navigator Tool identifies 25 tasks that fall within four sections: (1) Planning, (2) Energy Use Review, (3) Continual Improvement, and (4) System Management and aligns with the Business Sustainability Challenge approach.

The intent of the CSP/SEM Demonstration is to ensure more effective program and solution customization for larger C&I customers. All incentives offered through the CSP/SEM Demonstration will be subject to benefit-to-cost screening to ensure continued cost-effectiveness of the Business and Energy Sustainability solution's initiatives and will be subject to the Companies' current incentive structures and caps. The CSP should be designed to align and integrate with any established sustainability program or goals of the customer. Like the Business Sustainability Challenge, the CSP/SEM Demonstration will track non-energy benefits, such as carbon reductions, increase in productivity, or quality improvements.

CSP/SEM Demonstration Model

The CSP/SEM Demonstration will utilize the Business and Energy Sustainability solution's designs, primarily the Business Sustainability Challenge, to help C&I customers design and implement capital retrofit projects, control strategies, and operational and behavioral changes that save

[42] DOE. ISO 50001. Available at: https://www.iso.org/iso-50001-energy-management.html.
[43] DOE. ISO 50001 Ready Navigator Tool. Available at: https://navigator.industrialenergytools.com/.

energy and reduce energy intensity. A key requirement of the CSP/SEM Demonstration is that the customer must put an EMS into practice. The structure of the EMS must be based on the Ready Navigator Tool; however, the Companies will not require ISO 50001 certification. A customer's existing EMS and practices may be sufficient to meet some or all of the requirements established by the Ready Navigator Tool.

The key difference for the CSP/SEM Demonstration is that retrofit capital projects, end-of-equipment life projects, and operational changes can be incentivized through SEM measurement and verification practices, instead of the traditional ways, such as engineering estimates or deemed savings. Savings will be determined as follows:

- New construction and retrofit project savings and incentives shall continue to be claimed and budgeted through the ECB or the EO solutions (unless claimed through the Business Sustainability Challenge/SEM method); and
- Operational and behavioral SEM savings and incentives shall be determined by means of a mutually agreeable mathematical or software model, after subtracting new construction savings; and
- Savings from equipment purchase through the upstream programs will be subtracted from the SEM savings.

In order to encourage C&I customers (i.e., Connecticut Industrial Energy Consumers) to replace large equipment in advance of end-of-life reasons, the Companies have developed an early retirement program (through the EO solution) to structure incentives to hasten equipment replacement in 21st century manufacturing facilities and state buildings, and large industrials. The Companies will establish incentive budgets based on savings methodologies where the Companies will count the savings from the first five years based on existing conditions; whereas the remaining years of the new equipment's useful life will be compared to code (similar to current practice). As part of the C&I Energy Efficiency Portfolio budget, the Companies will allocate a designated budget (approximately $1 million per year) that will be targeted toward hastening equipment replacement in certain market sectors.

As an initial step, the CSP will be a partnership between the customer and the Companies establishing a commitment to work together to achieve mutually-stated goals tailored to the customer's specific facilities over a multi-year period. The CSP will include customer-specific savings and sustainability goals, the senior management commitment to provide the resources needed to achieve those goals, the technical assistance to be provided, and the potential achievable incentive funding to assist the customer in achieving such energy goals. This multi-year commitment will set the stage for achieving deeper and more comprehensive energy efficiency savings than a "single measure" or "single year" approach.

Incentive Strategy

The CSP/SEM Demonstration's incentive structure is designed to promote a large degree of customer flexibility while focusing on achieving large-scale implementation at modest program cost rates. The basic annual incentive will be calculated in accordance with the Companies' current caps, and the existing C&I Energy Efficiency Portfolio's incentive structures and cost rates in exchange for a stated value of savings to support the customer's internal processes.

CSP/SEM Demonstration energy savings will be based on a predetermined $/kWh (electric) and/or $/ccf (natural gas) incentive, as well as process efficiency improvements that result in reduced energy use per unit of production or process. The boundaries and baselines will be negotiated as part of the multi-year CSP development. The CSP will establish the specific savings goals, incentive structures, and commitments of each respective customer. For new construction, facility additions, or end-of-life/retrofit equipment replacement, the incentives will reflect the existing ECB or EO solutions' published incentive structures.

The Companies have allocated approximately $250 million toward large C&I Energy Efficiency Portfolio budgets for the 2019-2021 Plan. Within these budgets, the Companies have allocated approximately $4.5 million over the three-year plan to cover CSP/SEM Demonstrations.

Technical Assistance & Strategies

The CSP will incorporate, where appropriate, additional technical services available to customers, including: operational training, operator certification and energy management support services, employee engagement, and other continuous improvements elements into the CSP through the Business and Energy Sustainability solution. The Companies will work with customers to provide account management (e.g., training on program offerings, explanation of incentives, etc.) to maximize opportunities to receive energy efficiency incentives. Technical assistance and strategies will include:

- SEM Ready Navigator Tool assistance and training, including: benchmarking, monitoring and tracking, employee engagement, and other continuous improvement elements; and
- High-performance system operations and optimization through:
    - Application of best practices for system operations and optimization for refrigeration, HVAC, compressed air, pumping, motor drive, HVAC, and other process-related systems;
    - Targeted technical training and relevant operator certification for efficient systems operations, such as: Compressed Air Challenge, Pump Systems Matter, Green Motor Management, Certified Refrigeration Energy Specialists, and Building Operator Certification;

- System commissioning and operator training;
- Kaizen events and "sleeping plant" audits to identify opportunities; and
- Support and cost sharing for the establishment of Energy Management Information Systems ("EMIS") to provide key performance indicators and feedback loops to system operators and management.

Financing

The CSP provides customers with a flexible framework to explore financing service options, and where appropriate, to leverage Energy Efficiency Fund financing and funds with customer resources. The CSP/SEM Demonstration's financing options will include, but not be limited to:

- Companies' C&I Energy Efficiency Portfolio financing offerings;
- Connecticut Green Bank financing offerings;
- Third-party offerings, such as energy service performance contracts, leasing, energy service agreements, etc.;
- Innovative use of customers' internal funding; and
- Project development support and brokering services.

Retro-commissioning and Monitoring-Based Commissioning

As buildings age and the occupancy and building use changes, it is important to maintain a building's energy management systems to reduce operational inefficiencies and energy use. The Retro-commissioning initiative ("RCx") is designed to identify energy-saving opportunities in existing C&I buildings by improving the operation of a building's management system. The RCx initiative helps C&I customers identify low-cost and no-cost non-capital energy-efficient measures that can result in energy savings for the building or facility owner. According to a study by Lawrence Berkeley Laboratory, RCx projects often have simple payback periods of one to two years;[44] therefore, investments in RCx usually have attractive financial returns.

The Companies have conducted a competitive solicitation process for RCx engineering firms. These vendors conduct initial site assessments of a building which is funded partially or in whole by the Companies. If warranted and approved by the customer, the RCx engineering firm will utilize a structured process to create a detailed RCx implementation plan that documents how the facility should be operated to maximize energy efficiency opportunities and improve the facility's

[44] Evan Mills. Lawrence Berkley National Laboratory. *Building Commissioning: A Golden Opportunity for Reducing Energy Costs and Greenhouse-gas Emissions,* 2009. Available at: http://cx.lbl.gov/documents/2009-assessment/lbnl-cx-cost-benefit.pdf.

overall performance. The Companies provide co-funding for the development of the RCx implementation plan.

The Companies also support monitoring-based commissioning (“MBCx”), which is a continuous optimization process that utilizes sensors and software to keep existing building performing at optimal levels. Additional incentives for additional EEMs are available through the ECB and EO solutions. The Companies also provide custom incentives for measures implemented on a custom basis and that are not addressed by other C&I Energy Efficiency Solutions.

Operations and Maintenance Services

The Operations and Maintenance Services (“O&M Services”) initiative enables C&I customers to “tune-up” or improve the electrical and thermal efficiencies of their operations by making changes and repairs to equipment, and by fixing compressed air leaks and existing infrastructure. Either the Companies’ staff or an O&M Services contracted vendor will partner with a participating customer to identify energy efficiency opportunities and support their implementation.

O&M Services provides a number of improvements that maximize operational efficiency and optimize performance, including: compressed-air system leak studies and repairs, modifications and/or repairs to building management system control components and software programming, and stream trap repairs and upgrades. The Companies have designed custom incentives that are based on the associated costs and energy savings resulting from the energy efficiency improvements.

3.15 C&I DEMAND REDUCTION STRATEGIES

Throughout 2017 and 2018, the Companies have dedicated resources toward testing active demand reduction technologies and initiatives for the C&I marketplace.

Eversource Demand Reduction Strategies

Throughout 2017 and 2018, Eversource has dedicated resources toward testing active demand reduction technologies and demand response initiatives for the C&I marketplace. During the 2019-2021 Plan, Eversource will use the knowledge gained from the 2018 Demand Response pilots to construct offerings that incentivize active demand reduction strategies and measures that enable them. These offerings could include but are not limited to: traditional demand response direct-load controls and software and controls, and storage. Eversource would manage these demand reduction assets through the use of innovative control structures that will allow Eversource to coordinate dispatches.

United Illuminating Demand Reduction Strategies

During the 2019-2021 Plan, United Illuminating will transition its active demand response pilots into full-fledged solutions, while adding new customers and additional controllable demand reduction technologies. The continuation of the existing pilots as programs during the 2019-2021 Plan is a critical step in understanding the local demand response markets and in starting the logical process of integrating demand response and energy efficiency tactics into one comprehensive offering to increase the value to customers and decrease costs to United Illuminating. These demand response programs will allow United Illuminating to gather additional event data to better assess and quantify the potential active demand reductions associated with each demand response technology and/or strategy and any associated energy savings.

Common to Eversource and United Illuminating

Not limited solely to summer peak demand reductions, the Companies' Active Demand Response ("ADR") programs can also be useful for ramping (ISO-NE dispatch only), load curtailment, distribution system operational needs and shortage events, as well as winter demand reduction needs. Automation and advances in technology make it possible to manage customer loads in new ways with strategies that bring additional values to Eversource, United Illuminating, and the customer.

After the three-year 2019–2021 Plan period, Eversource, United Illuminating, and their respective active Demand Response program vendor(s) will assess the:

- Demand reduction (kW) associated with the active demand response component of each program;
- Customer participation rates vs. opt-outs; and
- Customer satisfaction and engagement with the programs.

Where possible, all of the Demand Response programs will be integrated and co-delivered with the Companies' existing C&I Energy Efficiency Portfolio offerings to increase the value to customers and decrease costs to Eversource and United Illuminating. Eversource and United Illuminating will look to integrate Demand Response program offerings with other C&I Energy Efficiency Solutions. During program implementation, the Companies understand that customer education regarding Demand Reduction initiatives is imperative. During the 2019-2021 Plan, Eversource and United Illuminating will look to educate customers regarding the benefits of Demand Response programs, the technologies used in the Companies' pilots, and the financial incentives and rebates that will be offered.

Eversource: 2019-2021 C&I Demand Response Solutions

Eversource envisions developing a C&I curtailment active demand reduction offering that is *technology agnostic* and provides an incentive for verifiable shedding of load in response to a signal or communication. Typical technologies or strategies used to curtail load include energy management systems, building management systems, software and controls, HVAC controls, lighting with controls (manual, networked system or integrated), process offsets, any open ADR compliant technology, startup sequencing, among other customer facility specific approaches. Since the offering is technology agnostic, Eversource will be able to incent the performance of customers adopting innovative and emerging demand reduction technologies, including storage technologies. Customers can use any technology or strategy at their disposal and be incentivized based on the performance of their curtailment.

This approach would use Curtailment Service Providers ("CSPs") to assess curtailment opportunities at a facility and deliver curtailment services to enrolled customers. CSPs would identify curtailment opportunities, as well as demand charge and Installed Capacity ("ICAP") tag management opportunities and present a complete curtailment proposal to the customer. The demand charge and ICAP tag management aspects provide opportunities for direct bill savings to customers.

Customers and CSPs respond to dispatch signals or any number of criteria specified by Eversource, generally using a system peak trigger. Events will be called the day before curtailment is needed. The core model remains focused on reducing demand during summer and winter peak events typically targeting fewer than 20 hours per summer. The goal of the offering is to call events at times of peak energy use. For customers participating in ISO-NE demand response markets, ISO-NE event days will be excluded from baseline calculations. This approach would be structured to avoid interfering with the ISO-NE programs or penalizing customers for participating in both programs.

This approach would constitute a new service offering to the C&I Energy Efficiency Portfolio and would provide value to large C&I customers and generate claimable benefits, primarily avoided capacity, transmission and distribution ("T&D"), and capacity DRIPE.

United Illuminating: 2019-2021 C&I Demand Response Solutions

Commercial & Industrial - Targeted Auto Demand Response

Targeted demand response used to defer investments in distribution systems can be a valuable tool to solve localized load growth issues. Targeted demand response programs, such as United Illuminating's C&I Auto Demand Response pilot can often defer distribution system investments for multiple years.

For the 2019-2021 Plan, United Illuminating will look to grow its C&I Auto Demand Response pilot by adding additional customers. Initial customers targeted are those that are served by the Woodmont and Ash Creek substations in southwest Connecticut and who are able to commit a minimum of 50 kW in demand reductions. These two substations have been identified by United Illuminating and ISO-NE as critical peak demand reduction areas, particularly for the FCM. Geo-targeting could potentially increase the cost-effectiveness of this C&I demand response pilot, and increase the benefits attributed to demand response programs.

C&I demand response programs tend to require a high degree of customization around specific customer capabilities and will often only target non-process or critical loads. Besides the typical HVAC loads associated with typical C&I demand response programs, the C&I Auto Demand Response pilot is also looking to identify new and advanced demand response technologies and practices, including connected equipment, and energy management and analytic systems. These new demand response technologies include advanced thermostat controls for HVAC systems, and advanced/smart energy management systems that through sensing, feedback, and the use of algorithms, can control a building's performance holistically for minimized energy use and cost

Customers within this pilot will receive a base $/kW for committed load reductions plus a $/kWh performance incentive based on actual energy reduced during an event.

Small Business: Direct Load Control –Smart Wi-Fi Thermostat (HVAC)

Very similar to the residential Room A/C Smart Plug program, United Illuminating's Small Business "Bring Your Own Thermostat ("BYOT")" program will continue to target small C&I customers with installed connected Wi-Fi thermostats. The thermostats used for these small businesses are the exact same connected Wi-Fi thermostats utilized in residential households. Therefore, the participating small businesses are treated as a subset of customers controlled through the utility portal for the United Illuminating's Residential Direct Load Control Wi-Fi Thermostat program.

For the 2019–2021 Plan, United Illuminating will look to expand its existing program customer base with additional customers beyond the original pilot's targeted 50 customers. United Illuminating will experiment with different marketing approaches to reach more customers and try to better understand the incentives required to motivate and sign up customers.

Case No. EEU-2016-03
Appendix D

VGS 2018-2020 Performance Indicators

QPI#	Title	Performance Indicator	Target	Description	Weight	Form of Verification	Entity Responsible for Verification
Quantifiable Performance Indicators							
1	Annual Incremental Mcf Savings	Annual incremental net Mcf expected savings	192,599 Mcf	Encourage EEU to design and implement efficiency iniatives that will maximize natural gas savings	25%	Annual Verification Process	Department of Public Service
2	Lifetime Natural Gas Savings	a. Present worth of lifetime natural gas avoided costs	$33,897,797	Encourage EEU to design and implement efficiency iniatives that will maximize lifetime natural gas benefits	15%	Annual Verification Process	Department of Public Service
		b. Lifetime Mcf savings	3,195,212 Mcf		15%		
3	Peak Day Natural Gas Savings	Peak day incremental expected savings	898 Mcf	Encourage EEU to design and implement efficiency iniatives that will maximize the capacity reduction coincident with peak day demand	15%	Annual Verification Process	Department of Public Service
4	Residential Single Family Comprehensiveness	(a) Percent of home energy audits converted to a measure installation within 12 months	30%	Ensure that energy efficiency iniatives are designed and implemented to achieve comprehensiveness of savings	10%	Tracking System	Department of Public Service
		(b) Percent of all cost-effective measures as well as those measures recommended by the audit and installed by the customer within 12 months.	70%		10%		
5	Long-term Market Transformation	Offer energy efficiency training for contractors	one per year	Encourage EEU to design and implement efficiency iniatives that maximize market transformation	5%	Tracking System	Department of Public Service
6	Business Comprehensiveness of Savings	Diversity of measures implemented in commercial retrofit projects	minimum of measures installed during the prior 12 months shall be: 10% control-related; 20% heating systems, heat recovery, or domestic hot water systems; 10% process-related; and 30% shell-related	Ensure that energy efficiency iniatives are designed and implemented to achieve comprehensiveness of savings	5%	Tracking System	Department of Public Service
Minimum Performance Requirements							
7	Equity for all Natural Gas Ratepayers	Total natural gas energy efficiency benefits divided by total costs	Equal or greater than 1.2 cost/benefit ratio	Ensure that the overall naturall gas benefits are greater than the costs incurred to implement and evaluate the VGS efficiency programs	Minimum Requirement	Tracking System	Department of Public Service
8	Equity for Residential Ratepayers	A minimum of 70% of the residential-sector share of total resource-acquisition spending in the residential sector	$4,291,087	Ensure that a minimum level of overall efficiency effort, as reflected in spending, will be dedicated to residential customers	Minimum Requirement	Tracking System	Department of Public Service
9	Equity for Low-Income Customers	A minimum of 70% of the low-income-sector share of total resource-acquisition spending on low-income services	$116,474	Ensure that a minimum level of overall efficiency efforts, as reflected in spending, will be dedicated to low-income customers	Minimum Requirement	Tracking System	Department of Public Service
10	Equity for Small Business Customers	Percent of commercial (non-residential) installed end uses that are classified as Rate G1 or G2 (use 600 Mcf/yr. or less)	30%	Ensure that a minimum level of overall efficiency efforts, as reflected in participation, will be dedicated to small commercial accounts	Minimum Requirement	Tracking System	Department of Public Service
11	Administrative Efficiency	Meet determined milestones on schedule, including: (a) Defining all administrative costs, incentive and other costs; and (b) By July 31, 2018, submit a proposal on how these costs will be tracked and reported, including a metric on the ratio of incentive costs to non-incentive costs and total adminstrative costs as a percent of total budget for the current performance period.	Track the ratio of incentive to non-incentive costs and report as a percent of total budget by July 31, 2018	Encourage VGS to continually assess its operations to continue to deliver services that maximize ratepayer value	Minimum Requirement	Tracking System	Department of Public Service
12	Total Resource Benefits	In consultation with the Department, file a status update on the feasibility and cost-benefit analysis of tracking water and delivered fuel resource benefits	Status update by July 31, 2018	Encourage VGS to design and implement efficiency initiatives that will maximize the lifetime benefits	Minimum Requirement	Tracking System	Department of Public Service
13	Addison County Participation	Meet minium energy efficiency program participation rate for customers in Addison County	Achieve 30% energy efficiency participation in Addison County by 2020	Maximize the percent of Addison County customers that benefit from VGS energy efficiency programs	Minimum Requirement	Tracking System	Department of Public Service

STATE OF NEW HAMPSHIRE

CONSUMER ADVOCATE
D. Maurice Kreis

ASSISTANT CONSUMER ADVOCATE
Pradip K. Chattopadhyay

OFFICE OF CONSUMER ADVOCATE
21 S. Fruit St., Suite 18
Concord, N.H. 03301-2429

TDD Access: Relay NH
1-800-735-2964

Tel. (603) 271-1172

Website:
www.oca.nh.gov

June 17, 2018
Mr. Jim Cunningham
Chair, Lost Base Revenue Working Group
New Hampshire Public Utilities Commission
21 South Fruit Street, Suite 10
Concord, New Hampshire 03301

Re: Docket No. DE 17-136, Electric and Gas Distribution Utilities
2018-20 New Hampshire Statewide Energy Efficiency Plan
Comments in Response to Lost Base Revenues Working Group Report

Dear Mr. Cunningham:

Pursuant to the direction provided by Staff in the June 13, 2018 "Key Takeaways" memo requesting comments on the Draft Final Lost Base Revenue (LBR) Report,[1] please treat this letter and the attached memorandum as the comments of the Office of the Consumer Advocate (OCA) on the Draft Final LBR Report.

As you know, the LBR Working Group was established by the Commission to determine "the impact of customer peak load and demand charge ratchets" on utility lost base revenues associated with commercial and industrial kW demand reductions attributable to the statewide electric efficiency programs. Order No. 26,095 (January 2, 2018). With that aim in mind, the Commission Staff, the Office of the Consumer Advocate, utility representatives, and other interested stakeholders met six times throughout 2018, striving to reach a consensus methodology for calculating the appropriate lost base revenues.

At the direction of Staff and the other interested stakeholders, the utilities provided a Draft Final LBR Report detailing the various inputs of the LBR calculation on June 19, 2018. Particularly helpful in understanding the methodology are the LBR templates provided by each utility, and embedded within the report in spreadsheet form. That templates attempt to project actual kW reductions based on end use load shape data from a 2015 New Hampshire DNV-GL evaluation, end use load shape data from the Electric Power Research Institute (EPRI) load shape catalogue, and the average Eversource Rate GV customer load profile.

[1] Lost Base Revenue Working Group June 13, 2018 Key Takeaways Memo, June 13, 2018. The deadline for comment submissions described in the key takeaways document was later extended by a Staff. Available at: https://www.puc.nh.gov/EESE%20Board/EERS_WG/061318_lbr_key_takeaways.pdf

The methodology suggested in the Draft Final LBR Report represents a significant improvement in accuracy over the previous methodology which simply combined revenues attributable to kWs and kWhs into a single kWh average distribution rate, which is then multiplied by kWh savings to arrive at an LBR value. While we commend the working group members for their willingness to collaborate and believe the draft final report represents a significant improvement over previous drafts, we take this opportunity to provide the attached memo suggesting improvements to the methodology which would affect the lost base revenues proposed in the 2019 update of the 2018-20 energy efficiency program plan.[1]

Please feel free to contact me with any questions you may have relating to these comments.

Sincerely,

Brian D. Buckley

Brian D. Buckley
Staff Attorney
Office of the Consumer Advocate

---

[1] The OCA's comments in this instance focus on the methodological approach chosen in the Draft Final LBR Report, rather than the specific language of the report itself because we do not see the language of this working group report as binding upon the Commission in future proceedings. If we were to place a greater emphasis on the language of the report, we would take issue with footnote 13 which suggests any revision of the residential rate structure to include a kW charge would not trigger a re-examination of the residential sector LBR. We disagree with this assertion, and suggest that such a revision should trigger just such a re-examination.

Resource Insight Inc.

MEMORANDUM

To: Brian Buckley

From: Paul Chernick, Stacia Harper

Date: July 12, 2018

Subject: Comments on Utility LBR Report

Effect of Ratchets

Eversource

Eversource applies ratchets only to the LG customers, and found in its Appendix D that the ratchet applies to few customers and has little effect on its demand revenues. Eversource computes that the 11,356 kVA effect of ratchets is only about 0.4% of the 2,703,760 kVA of LG billing demand for the twelve months ending February 2018. This comparison is irrelevant. If the billing demand for each of the LG customers had been determined by the ratchet in 11 months of the year, and the ratchet effects had been about 5% of metered demand, Eversource's method would suggest that the ratchet's effect on demand revenues would be about 4.6%, even though the vast majority of energy-efficiency measures would be implemented in months controlled by ratchets and would have no effect on demand revenues in that month. Indeed, most energy-efficiency measures in that situation would have no effect on the billed demand for several months; the ratchet would reduce the demand-revenue loss by about half over the first year.

Eversource offers an even more irrelevant comparison of the effect of ratchets on the billing demands of two LG customers who participated in energy-efficiency programs to the billing demand of *all* LG customers, most of whom had no energy-efficiency load reduction. Eversource should have compared the LG energy-efficiency participants affected by ratchets to the LG energy-efficiency participants in the 2017/18 period.

Nonetheless, only about 8.5% of the LG customers were affected by the ratchet in this period, and most of them for only few months. We estimate that only about 1% of potential demand LBR for these customers would be avoided due to the ratchets, and thus agree that the effect on ratchets for Eversource lost revenues will be *de minimus*. The Eversource LG ratchets would tend to bind less often than those of ratchet-exposed customers of the other utilities, who face 15-minute demand billing (rather than Eversource's more stable 30-minute demand measure), an 80% ratchet (rather than Liberty's 90%), and (since they are only the largest Eversource customers) perhaps greater internal diversity and inherently flatter load shapes from month to month.

Unitil

Unitil applies ratchets only to the G1 customers (its largest customers) and provided a table of the months that each of the 17 G1 customers who participated in the 2017 program was subject to the ratchet. Unitil concludes that the effect of the ratchet on its LBR is small, but we do not follow Unitil's reasoning. In order to do a full analysis, we would need more than a year of monthly billing demands, as well as the billing demand reduction that Unitil is claiming for each participant. The following analysis uses the limited data that Unitil provided.

Table 1 shows, for each installation month and each G1 energy-efficiency participant, the number of months for which the ratchet would prevent the load reduction from affecting revenues. We assumed that the monthly load patterns provided in Appendix D for 2017 were typical, so if the ratchet applied in January 2017, we assumed it would apply in January 2018, as well.

Table 1: Number of Months in First Year Affected by Ratchet, by Month

Install	Customer Number																
Month	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Jan		4		*2*	3	12	4	1	4	2	8	7	*3*			5	
Feb		3		*2*	2	12	3	1	3	1	7	6	*3*			4	
Mar		2		*2*	1	12	2	1	2		6	5	*3*			3	
Apr		1		*2*		12	1	1	1		5	4	3			2	
May				*1*		12		1			4	3	2			1	
Jun				*1*		12					3	2	1				
Jul				1		12					2	1					
Aug						12					1						
Sep		*5*		*2*	*3*	12	*5*	*2*	*7*	*2*		*11*	*4*	*1*		*7*	*2*
Oct		*5*		*2*	*3*	12	*5*	*2*	7	*2*	*10*	*10*	*4*	*1*		*7*	*2*
Nov		*5*		*2*	*3*	12	*5*	2	6	*2*	10	9	4	1		7	2
Dec		5		*2*	*3*	12	5	1	5	*2*	9	8	*4*	1		6	1

For example, for Customer 2, the ratchet applied in January through April, and in December. Thus, a load reduction in December would have no effect on billing demand for the first five months (December to April). Assuming that the peak load occurred in June, July or August (as do more than half the 1,200 customers in the Eversource GV peak data), a metered-demand reduction for Customer 2 in September, October or November would reduce billing in those months, but not in the five months controlled by the ratchets.[1] We applied the same approach to the other customers with ratchet effects, with modifications for Customer 6 (which Unitil says was affected by the ratchet in all 12 months) and Customers 11 and 12 (which had ratchet effects in July and August, as well as the winter months).

Table 1 applies only for metered demand reductions small enough that the months not affected by the ratchet before energy efficiency also will not be affected by the ratchet after energy-efficiency installations. Larger load reduction will move additional months into the category of months affected by the ratchets.

The total customer-months affected by ratchets in Table 1 sum to 514, out of a potential total of 17 customers × 12 installation months × 12 billing months in the first year after installation = 2,448, or 21%. Thus, the Unitil ratchets appear to reduce the first-year demand LBR by about 21%.

Unitil estimates a somewhat larger ratchet effect of about four months per year, or 33% of the billing demands. (Report Draft, June 13, 2017, at 15) Unitil makes the same error as Eversource, focusing on the percentage difference between metered demand and the ratcheted billing demand, rather than the percentage of customer-months subject to ratchets. If a ratchet applies due to load in an earlier month, the effect of a new load reduction in the current month is zero.

Liberty

Liberty provides data only for the G-1 class, even though its G-2 tariff also has a ratchet. While we have not analyzed the Liberty data in the same detail as the Eversource and Unitil data, Liberty's data indicates that its ratchets will reduce the demand LBR in 40% of customer-months, more than Unitil's 35% of customer-months. Since Liberty uses a 90% ratchet, rather than the 80% ratchet of Eversource and Unitil, it makes sense that its ratchet will protect it from demand LBR more effectively than for the other utilities.

Extrapolating that density of ratchet events suggests that Liberty's first-year demand LBR would be reduced about 24% by its ratchet.

[1] The values in Table 1 that are in italics identify months in which the ratchet did not apply, but in which load reductions would not affect billing demand in one or more later month.

Timing of Billing Demands

The utilities propose to compute the contribution of energy-efficiency measures to demand LBR in each month for each of seven end uses by:

1. Estimating the time of monthly diversified peak for the Eversource GV customer class (as a proxy for all demand-metered load), such as 11 AM for January. [2]
2. Taking the maximum estimated percentage of installed load (as a percent of installed use) operating in that hour on any day of that month (such as any of the 31 occurrences of 11 AM in January), from load shapes developed by DNV-GL or EPRI (for end uses not reported by DNV-GL).

We believe that these estimates are overstated for several reasons.

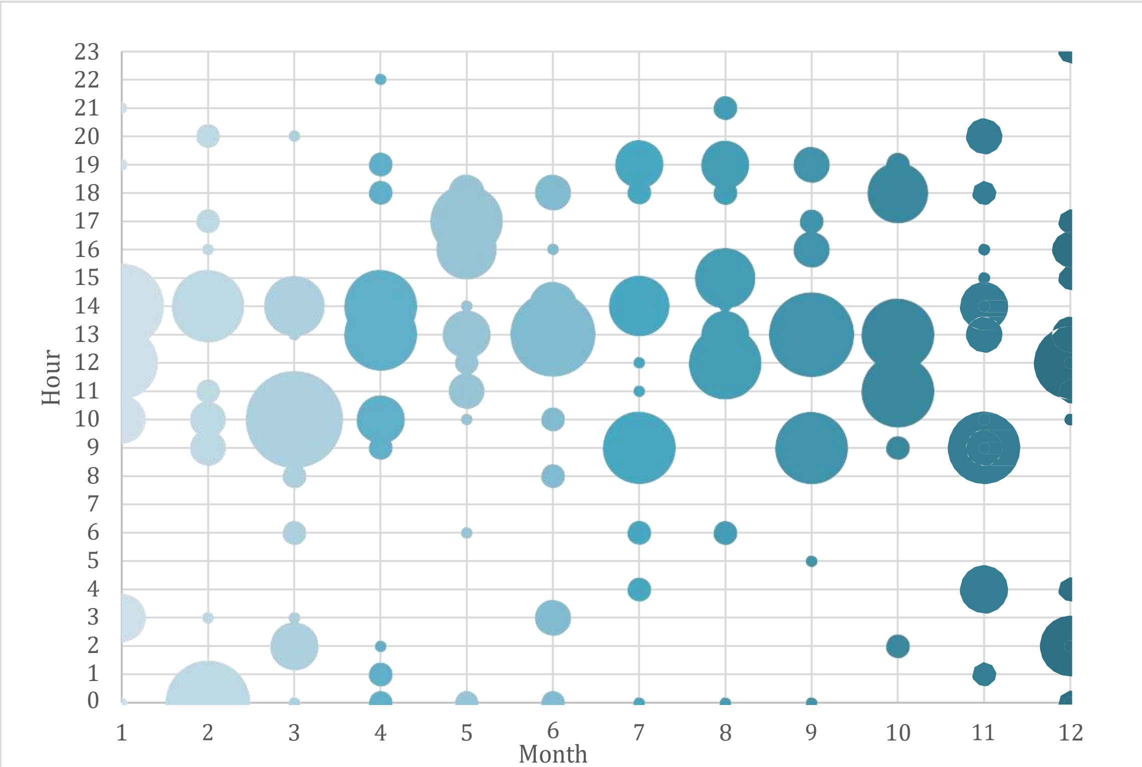
First, only fifteen or thirty minutes of high load are required to set a billing demand.[3] Hence, any measure that reduces minutes of equipment usage, rather than the electric consumption per minute, should be assumed to have no effect on billing demand and hence no demand LBR. The utilities have indicated that they do not attribute any demand LBR to occupancy sensors or set-back thermostats, but the same reasoning applies to building-shell measures (insulation, window treatments), the effect of reduced internal load on cooling, and any other measures that reduce equipment running time.

Second, the utilities estimate reductions in demand charges as if all the customers were the average customer. In reality, within any given month, customers experience maximum loads at a variety of times. Figure 1 shows the number of customers peaking in each hour, for each month, from the data that Eversource provided in Docket No. 16-576, DR EFCA-TASC 1-2. The smallest dots are one customer; the largest (March at 10 AM) is 8 customers.

[2] The utilities chose the Eversource rate GV class based on its diversity and availability of recent data. According to the tariff, the maximum demand for GV customers should be between 100 kW and 1,000 kW, but some GV customers actually have peak loads below or above these limits. Eversource provided the group with the load and time of annual maximum demand for 1,200 GV customers, which is useful for some purposes, but not for monthly billing demand. We have supplemented those data with hourly loads for each of the 34 customers in Eversource's GV load-research sample for 2015, which Eversource provided in Docket No. 16-576.

[3] Billing demands are set by the highest fifteen minutes of load in Unitil and Liberty; and, thirty minutes in Eversource.

Figure 1: Variation in Timing of Monthly Peaks



We do not have enough data to guess at the reasons for the pattern of maximum load hours. Clearly, some end use is operating at a high level to trigger the billing demands at midnight or 3 AM, but it is likely to be something different from the end use driving the peaks in the early afternoon.

Even among the customers who peak at a particular hour, the days on which they peak vary. The eight customers with March peaks at 10 AM, for example, peaked on 8 different days.

Third, since individual customers peak on different days, the particular end-use equipment affected by the energy-efficiency program may be operating much less on the customer's maximum-demand hour than in the same hour of some other day. Table 2 reproduces the DNV-GL end-use coincidence factors that the utilities proposed to use, based on the monthly maximum in the listed hour, while Table 3 shows the average coincidence factor in the listed hour of weekdays.[4] We do not report the parking-lot light factor, which the utilities set at zero for all month. We do include the occupancy sensors, even though the utilities say they will assume no effect on demand charges.

[4] The EPRI coincident factors are provided by season—peak (apparently summer) and off-peak—rather than monthly.

Table 2: Maximum DNV-GL load in hour, by month

Month	GV Class Peak Hour	Cooling	Heating	Lighting	LED	Occ Sens	Process
1	11	0.03	0.69	0.75	0.87	0.67	0.63
2	11	0.01	0.69	0.75	0.83	0.67	0.64
3	11	0.11	0.7	0.75	0.83	0.67	0.64
4	12	0.19	0.69	0.75	0.92	0.67	0.76
5	14	0.3	0.71	0.75	0.87	0.66	0.80
6	14	0.63		0.75	0.86	0.66	0.81
7	14	0.8		0.76	0.87	0.54	0.80
8	14	0.64		0.75	0.88	0.65	0.80
9	14	0.56		0.74	0.88	0.69	0.81
10	14	0.17	0.73	0.75	0.88	0.67	0.73
11	12	0.16	0.71	0.75	0.92	0.67	0.66
12	11	0.09	0.7	0.73	0.83	0.67	0.63
Average		0.31	0.47	0.75	0.87	0.66	.73

Table 3: Average DNV-GL load in hour, by month

Month	GV Class Peak Hour	Cooling	Heating	Lighting	LED	Occ Sens	Process
1	11	0.002	0.57	0.70	0.80	0.59	0.58
2	11	0.000	0.56	0.71	0.81	0.59	0.59
3	11	0.003	0.57	0.70	0.77	0.60	0.58
4	12	0.096	0.53	0.30	0.80	0.26	0.55
5	14	0.18	0.54	0.32	0.84	0.23	0.54
6	14	0.48		0.30	0.83	0.24	0.63
7	14	0.47		0.28	0.84	0.25	0.63
8	14	0.48		0.29	0.84	0.25	0.65
9	14	0.42		0.31	0.85	0.24	0.62
10	14	0.11	0.52	0.28	0.85	0.23	0.55
11	12	0.048	0.57	0.30	0.86	0.25	0.52
12	11	0.004	0.58	0.68	0.78	0.58	0.57
Annual Average		0.19	0.37	0.43	0.82	0.36	.58

While the computation presented in Table 3 omits weekends, dozens of the monthly peaks of the GV customer sample occurred on Saturday or Sunday.

The cooling load at the peak hour (averaged across the months) is 62% of the maximum load used by the utilities, the heating average is 79% of maximum, lighting is 58%, and process 81%.

Fourth, the utilities make inconsistent assumptions about the timing of the customer peaks. For example, they assume that every commercial customer peaks at noon in April and they then assume that the peak occurs on the 20th for cooling, the 8th for heating, some Wednesday for lighting, some Sunday for LEDs, and the 29th for process loads. Those maximum end-use loads cannot all occur on the same day. Indeed, it is illogical to assume that the heating and cooling peak loads for the month would occur in the same hour of the same day.

Fifth, customers do not generally have one peak hour in a month, with other loads being much lower. Many customers have multiple hours in which demand is within a few percent of the monthly hourly maximum.[5] Those hours may vary widely by time of day (say, 8 AM to 2 PM) and date. If a particular project significantly depresses load in what would have been the customer's maximum-demand hour, the peak may shift to a slightly lower hour in which the efficiency project has less effect.

Recommendations

Below we provide our specific recommendations relative to both the effect of the ratchet on kW revenues and the timing of billing demand.

Effect of the Ratchet

The data provided by the utilities within the working group process relative to the demand ratchets was not of sufficient granularity to determine the actual effect of the demand ratchet on lost revenues. While we agree with Eversource's assertion that the effect of the demand ratchet on LBR is likely *de minimus* in the context of their overall lost revenues, the preliminary data submitted by Unitil and Liberty indicates first year lost based revenues may be impacted significantly by the ratchet and that further discovery on this issue is warranted. In particular, more than a year of monthly billing demands, as well as the billing demand reduction being claimed for each participant would help inform actual lost base revenues. While we recognize that it is not feasible to calculate lost revenues at the individual customer level, we firmly believe that analysis of actual impacts on a statistically significant sample of individual customer bills would best inform each Company's kW lost revenues and the associated average distribution rate.

Timing of Billing Demands

We recommend that the LBR demand-charge component be set to zero for any measure that reduces run time, including occupancy sensors, setback thermostats, building shell measures, among others. For other measures, based on the multiple

[5] The 15-minute and 30-minute maximum demand reading may have even more occurrences near the monthly billing peak, but we do not have any data on less-than-hourly loads.

reasons that the coincidence factors would tend to be overstated, the utility estimates of demand-charge LBR should be reduced by 50%.

Memorandum

August 10, 2018

From: Eversource, Liberty, and Unitil—Utility members of the New Hampshire Lost Base Revenue (LBR) Working Group

To: NH LBR Working Group

Re: Docket No. DE 17-136, Electric and Gas Distribution Utilities 2018-20 New Hampshire Statewide Energy Efficiency Plan, NH PUC Staff and OCA comments on June 19, 2018 draft report, *New Hampshire Energy Efficiency Calculation of Lost Base Revenue* ("Draft LBR Report")

At the direction of Staff and the other interested stakeholders, the utilities provided a Draft LBR Report detailing the various inputs of the LBR calculation on June 19, 2018. OCA and their consultant, Resource Insight, provided comments on the Draft LBR Report on July 17, 2018 and Staff provided comments on July 20, 2018. The utility members of the LBR Working Group offer the following responses.

Utility Response to Staff Comments

The utilities appreciate Staff's thorough review of the Draft LBR Report, and the many hours of discussion and research that guided the development of the report. The utilities support many of Staff's revisions to the draft. In the hopes of achieving a consensus document, the utilities request the following technical items be adjusted, in order for the utilities to consider endorsing the report.

1. In several places in the draft, Staff's revisions describe the "half year convention" as follows: "for planning purposes, the annualized target kWh energy and kW demand savings for program year 2019 are assumed to be installed 50 percent in the first year (2019) and 50 percent in the second year (2020)." The description should be modified to: "for planning purposes, 50 percent of the annualized target kWh energy and kW demand savings for program year 2019 are assumed to be achieved in the first year (2019) and 100 percent are assumed to be achieved in subsequent years."
2. Page 8 and 9 includes the following revised language: "the calculation claims savings beginning in the month of the paid date—which *can be up to* two months (approximately) after measures are installed and generating savings." The language should remain as written, which more accurately reflects the underlying data: "the calculation claims savings beginning in the month of the paid date—which *is on average* two months after measures are installed and generating savings."
3. The tables in appendix B include note (b), from which Staff removed the following language: "Annualized kW savings are derived by multiplying by 12." This language should remain.
4. The following language on p.6 should be modified: "Line 10, % In-Service Rate: The percentage of measures, incented by an energy efficiency program, that EM&V studies estimate to be operating. The in-service rate is calculated by dividing the evaluation's quantity of kW savings installed and operating by the same values that are present in the utilities' project files." This should be revised for accuracy to: "The percentage of measures, incented by an energy efficiency program, that EM&V studies estimate to be installed and *capable of* operating. The in-service rate is calculated by dividing the evaluation's quantity of measures installed by the quantity of measures that are

present in the utilities' project files." In-service rate only accounts for whether equipment is in place and functional. Actual operation of the equipment is accounted for in other impact factors.

5. The following language on p.6 should be modified: "Claimed savings are generally initial savings, prior to the EM&V Studies (e.g., initial project tracking system savings)." This should read: "Claimed savings generally reflect project-specific calculations or deemed savings values, which are based on prior EM&V studies, engineering analyses, and equipment specifications."
6. On p.7, the definition for "Line 20, Average Distribution Rate" should be revised for accuracy. The utilities have excluded certain charges, such as the customer, meter, and luminaire charges, prior to performing this calculation to reach the ADR for LBR purposes. The utilities still believe the appropriate term is the "LBR ADR", as this modified rate is used solely for the purpose of calculating LBR. Other references within the Table of Contents and on p.3 should also be revised to "LBR ADR" for the same reason.
7. On p.7, the definition for "Line 14, Billing Adjustments to Reflect Ratchets" should be revised and expanded. A ratchet is not a rate level, but rather a rate structure meant to increase revenue certainty from a particular set of customers that are more likely to have volatile consumption, with the intended outcome of lessening the potential burden on all other customers. One other minor change is within the paraphrasing of Eversource's tariff, which should be revised to (please see footnote revisions as well): "Paraphrasing this tariff, the ratchet demand is the third option and it is eighty percent (80%) of the amount by which the greatest amount defined in the ~~three~~ two options during the eleven (11) preceding months exceeds 1,000 kilovolt-amperes is used for billing purposes.[1]" In addition, the footnote for Unitil should be restated to read: "Unitil concluded that the impact of the ratchet was small in percentage terms and, as agreed to in the settlement establishing this working group, it is not feasible to identify the impacts with precision and not feasible to track demand charge impacts on a customer by customer basis."
8. Within the Executive Summary of Staff's document, there is a reference to the documents on the Commission website for this working group. We request that the report, as well as the website where the documents are posted, include a statement that the documents relate to the issues reviewed by the LBR Working Group, but that the members of the LBR Working Group do not necessarily agree on the value, reliability, or relevance of the posted documents.
9. The Executive Summary should clarify that the purpose of the Working Group was not only to establish a forecast of LBR for planning purposes, but more broadly to determine the kW values to be used for calculating actual LBR and to consider the general impact of customer peak load and the general impact of demand charge ratchets on those kW values.
10. Footnotes 19 and 20 on p.14 include Staff comments that (1) LBR calculations going forward should reflect updated measure life for measures installed in prior years, and (2) the utilities should use

[1] According to Eversource analysis, the ratchet option was immaterial. In the sensitivity analysis, the percentage of total demand billing that represented ratchet demand billing was 0.4%. For customers with a ratchet that potentially could have implemented EE or other non-EE changes at facility or temperature sensitive load changes, the maximum possible impact from EE on Eversource's billing demand from ratchets for this time frame would be 0.002%. http://www.puc.state.nh.us/EESE%20Board/EERS_WG/061318_wg_eversource_ratchet_analysis.pdf

discrete average distribution rates by rate class beginning no later than the next triennium. These are both previously settled matters, and if the LBR Draft Report is to reflect a consensus on how to calculate LBR for 2019 and 2020, these comments on the next triennium should be removed.

Finally, Staff's revisions to the Draft Report include a statement that Staff will review comments and recommendations from the OCA consultant, Resource Insight, as part of its review of the 2019 annual update filing. For the multiple reasons outlined below, the utilities strongly object to Resource Insight's conclusions and recommendation, and would not agree with future revisions to the Draft Report incorporating those recommendations.

Utility Response to OCA Comments

The utilities appreciate OCA's participation and input during the course of the Working Group, including recommendations that were adopted in the Final Draft Report to (1) utilize load shapes from the 2015 New Hampshire DNV-GL evaluation, (2) where load shapes from the DNV-GL evaluation were not available, use end use load shape data from the Electric Power Research Institute (EPRI) load shape catalogue. The utility members of the Working Group dedicated numerous hours to reviewing and incorporating these suggestions, in the spirit of collaboration and increased accuracy of LBR calculations.

However, the utilities strongly object to the conclusions and recommendation from the OCA consultant, Resource Insight, to reduce the LBR kW savings amount by 50 percent. First, there are numerous significant methodological problems underlying their recommendation, which are detailed below. Second, proposing such a significant adjustment only after the final scheduled meeting of the Working Group—without previously raising the underlying issues for group discussion prior to submitting comments—is at odds with a collaborative process meant to achieve some level of agreement. Had these issues been aired during the six months of meetings and discussions, the utilities could have provided information to address the questions and worked to develop consensus through the process. Instead, the utilities offer the following responses to comments in Resource Insight's July 12, 2018 memorandum.

1. **Use of averages.** Per the Settlement Agreement, the LBR Working Group was established to determine the kW values to be used in the LBR calculation and to consider the general impact of customer peak load and the general impact of demand charge ratchets on those kW values. The Settling Parties agreed "that LBR calculations are based upon averages and that it is not feasible to identify the impacts stated above with precision, and further agree that it is not feasible to track demand charge impacts on a customer-by-customer basis." Nevertheless, Resource Insight raises several points related to the fact that "the utilities estimate reductions in demand charges as if all the customers were the average customer." In objecting to our calculations, Resource Insight selected only examples of theoretical cases that fall on one side of the average—the side in which the utilities would be overstating LBR. They noticeably neglect to note any examples that fall on the other side of that average. For example, Figure 1 shows the variation in timing of monthly peaks, including customers peaking during evening or night-time hours, and the text states that "some end use is operating at a high level to trigger the billing demands at midnight or 3 AM, but it is likely to be something different from the end use driving the peaks in the early afternoon." What Resource Insight fails to mention is that for such a theoretical customer, if the utilities were overstating LBR

kW for the typical measures that drive daytime peaks, we would also be *understating* LBR kW for whatever that end use is that is driving the night-time peaks. The Resource Insight comments include several similar examples of theoretical outliers that are at odds with the settled issue of using averages to calculate LBR (see the secondary customer peak issue below).

2. **Measures that reduce run time without reducing connected load.** A primary aspect of Resource Insight's recommendation is that the LBR demand-charge component be set to zero for any measure that reduces run time, including occupancy sensors, setback thermostats, building shell measures, among others. The utilities' calculations already account for this, as detailed in the Draft Final Report, which states on p.11 that "the connected load savings for measures such as occupancy sensors or wi-fi thermostats reflect that their savings are driven by reduced run-time/hours of use, rather than reductions in connected load. As a result, the connected load savings for such measures are typically very small." For example, of the 4,367 kW in Eversource forecasted demand charge reductions in 2019, about 33 kW (0.75%) are due to occupancy sensor measures. For these and other measures such as wi-fi thermostats and shell measures that primarily reduce run time, the *maximum load reduction kW* savings is generally 0 kW or close to 0 kW, based on project-specific engineering calculations. However, it should be noted that these measures in many cases *do* result in small demand reductions. For example, installing occupancy sensors in a building that had previously lit unused space during peak hours would result in reduced load during those peak hours. In such cases, reported kW reductions are based on project-specific engineering analyses—analyses that must meet numerous ISO-NE requirements for rigor to support bidding into the Forward Capacity Market. Resource Insight's comments focused on the values for *% kW demand reduction at customer peak* for such measures—values that it should be noted were taken directly from the results of the DNV-GL study that OCA directed the utilities to use. However, the relevant value in the calculation is *maximum load reduction kW,* which accounts for kW savings achieved, or not achieved, by measures that primarily reduce run time rather than connected load.

3. **Secondary customer peaks**. Resource Insight states that "customers do not generally have one peak hour in a month, with other loads being much lower. Many customers have multiple hours in which demand is within a few percent of the monthly hourly maximum... If a particular project significantly depresses load in what would have been the customer's maximum-demand hour, the peak may shift to a slightly lower hour in which the efficiency project has less effect." Resource Insight raised this theoretical example without providing any evidence of a measure and customer load shape where demand in the primary peak hour would be reduced while demand in secondary peak hours would not be reduced to similar levels. Peaks in a given month will almost always be driven by the same set of end uses—so measures reducing the highest peak would also reduce secondary peaks. For example, temperature and humidity are common drivers of peaks, and efficient HVAC equipment will address both primary and secondary peaks. For industrial customers with manufacturing-driven peaks, efficient production equipment will reduce both primary and secondary peaks. Although it is theoretically possible that there are exceptions to this rule, again, this Working Group was established to consider the general impact of customer peak load and the general impact of demand charge ratchets on those kW values, and the Settling Parties agreed that LBR calculations are based upon averages. Moreover, it is the utilities' understanding that this concern was never raised during the six months of working group meetings, and originally surfaced

within the OCA's final comments and suggestions. If OCA had brought this issue to light during a Working Group meeting, the utilities could have addressed it in a more collaborative fashion.

The utilities went to great lengths to respond to comments and suggestions from other Working Group members since the start of 2018, making numerous adjustments to the LBR calculation in an attempt to make it as accurate and precise as feasible, and in some cases to reach a consensus calculation that could be amenable to all parties. In contrast, the Resource Insight recommendation to reduce savings by 50 percent is arbitrary, imprecise, and irreconcilable with the support Resource Insight provides in their memo.

DOE/EE-1274

SEE Action
STATE & LOCAL ENERGY EFFICIENCY ACTION NETWORK

Energy Efficiency Collaboratives

Driving Ratepayer-Funded Efficiency through Regulatory Policies Working Group

September 2015

The State and Local Energy Efficiency Action Network is a state and local effort facilitated by the federal government that helps states, utilities, and other local stakeholders take energy efficiency to scale and achieve all cost-effective energy efficiency by 2020.

Learn more at www.seeaction.energy.gov

Table of Contents

Enhanced Permanent Statewide Collaboratives

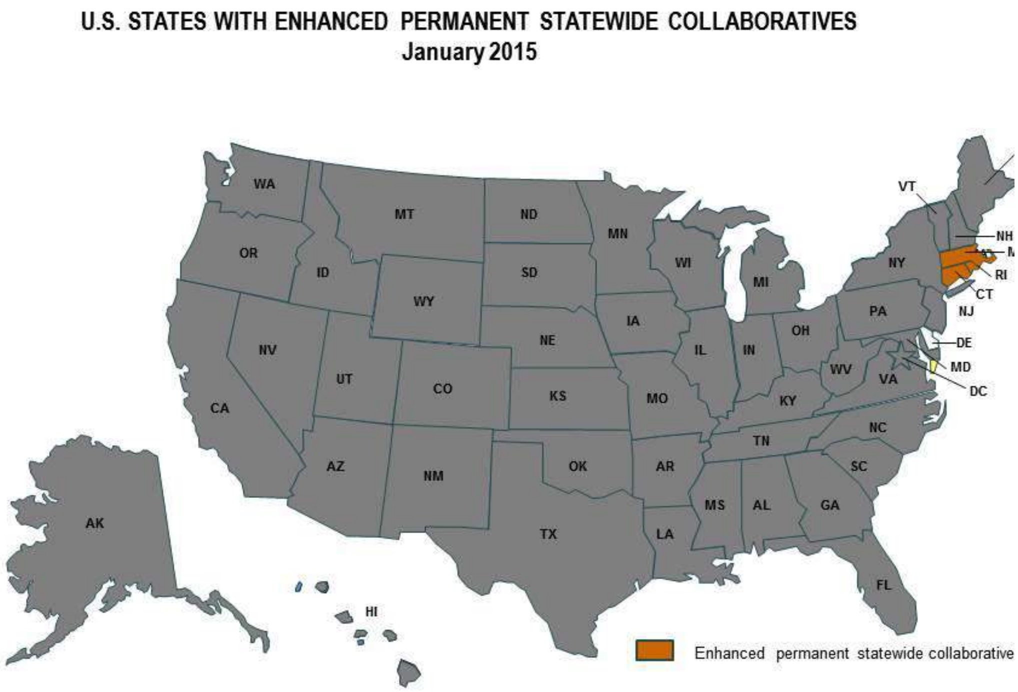


Figure 2. U.S. states with enhanced permanent statewide collaboratives

An enhanced permanent statewide collaborative (from herein referred to as an "enhanced collaborative"), as defined by this guide, is characterized by a significant operating budget, statutory permanence, and a broad array of specific tasks and responsibilities. Three states were found to have this type of collaborative: Connecticut, Massachusetts, and Rhode Island.

Scope and Structure

Enhanced collaboratives generally have a statewide scope[7] and operate at a high level, maintaining staff, engaging consultants, and preparing recommendations. Their significant operating budgets[8] are used for regular meetings, subcommittee activities, and extensive reporting. Generally, they are exempt from *ex parte* communication rules, as the commissioners have the final say, which allows the deliberations of the collaborative process to be more robust and transparent.

[7] Some have differing responsibilities and duties regarding municipal and cooperative electric companies. With all types of collaboratives, where municipal and cooperative utilities are not regulated, they are invited to participate, and often do, as their interests allow.

[8] The Connecticut collaborative has a budget of roughly $700,000 out of a total energy efficiency budget for the state of $220 million. The Massachusetts consultant team work plan has a budget of about $1.5 million. See: http://ma-eeac.org/wordpress/wp-content/uploads/Consultant-Team-Year-2014-Approved-Workplan1.pdf. The Rhode Island Council receives approximately 1.2% of the system benefits charge, or $1.2 million, to support its activities.

Most enhanced collaboratives are called “board” or “council” because they have formal requirements for their membership structure established in the state statute.[9] Typically, voting members include heads of appropriate state agencies (or their designate), as well as representatives from consumer, industrial, trade, and environmental groups. The board members and chairs can be selected in different ways—in Connecticut, the commission appoints members, and those members elect a chair and vice chair. In Massachusetts, the Department of Public Utilities appoints the members based on a sector representation included in the statute and the Department of Energy Resources representative always chairs the council. And in Rhode Island, the members are appointed by the governor with the advice and consent of the Senate, specifying which of these members are to serve as chair and vice chair.

The facilitation of enhanced collaboratives varies by state, but each has a high-level staff person heading the collaborative. In Connecticut, an executive secretary employed by the board to support its appointed chair facilitates the board’s proceedings. In Massachusetts, there is a team of consultants who act as agents of and advisors to the council. These consultants regularly report to the council at large about efforts related to their specific area of expertise, such as industrial programs, residential programs, evaluation, avoided costs, and other policy issues. The council annually publishes a listing of its priorities for the coming year to shape the consultants’ work plans and to inform the program administrators[10] of their priorities. The stakeholder engagement process in these collaboratives can be regulated by statute to varying degrees. Both the Rhode Island and Connecticut legislation obligates the board to implement a stakeholder participation process to allow individuals to have a voice in the process of energy efficiency program design. The Massachusetts charter does not specifically call for stakeholder engagement, but agenda time is set aside to allow stakeholders to present their point of view.

These enhanced collaboratives are generally created or modified as part of a shift in the state’s energy efficiency approach. The original Connecticut board[11] was created in response to the shift to retail competition in 1998; when the board was updated in 2007 and renamed the Connecticut Energy Efficiency Board, it was part of a revamp of the utility energy efficiency structure undertaken by the legislature.[12] In Massachusetts, the Energy Efficiency Advisory Council was created as part of the Green Communities Act,[13] which substantially increased the focus and pace of energy efficiency and renewable energy activities in Massachusetts. In these cases, the legislature desired to create a mechanism to oversee the development and administration of energy efficiency programs and assure transparency in the execution of the mandated energy efficiency goals. In Rhode Island, the Energy Efficiency and Resource Management Council was established in 2006 to guide implementation of that state’s comprehensive energy reform law that tripled efficiency budgets.[14] In each state, legislation required the acquisition of all cost-effective energy efficiency.

> Each of these enhanced statewide permanent collaborative boards was legislatively created as a component of a shift in structure or emphasis in the state’s energy efficiency approach. As major changes were proposed, these states felt it necessary to engage a more rigorous and inclusive process to inform their program efforts.

[9] For Massachusetts, see: https://malegislature.gov/Laws/SessionLaws/Acts/2008/Chapter169, paragraph 22. The Connecticut Legislature created the Energy Conservation Management Board pursuant to Section 33 of PA 98-28 (CGS § 16-245m), An Act Concerning Electric Restructuring. In Rhode Island, the Energy Efficiency and Resources Management Council was created by the Comprehensive Energy Conservation, Efficiency and Affordability Act in 2006.

[10] The program administrators include the investor-owned electric and natural gas utilities in the state as well as a municipal aggregator.

[11] “Energy Conservation Management Board” is the name of this earlier body.

[12] Energize Connecticut. (2014). *Connecticut Energy Efficiency Board.* Retrieved from: http://www.energizect.com/about/eeboard.

[13] An Act Relative to Green Communities. (2008). Massachusetts Session Laws, Chapter 169, Section 22. Available at: https://malegislature.gov/Laws/SessionLaws/Acts/2008/Chapter169https://malegislature.gov/Laws/SessionLaws/Acts/2008/Chapter169.

[14] Rhode Island Energy Efficiency and Resource Management Council. (2014). Retrieved from: http://www.rieermc.ri.gov/.

As the issues and challenges of energy efficiency programs evolve, the role and function of the councils change as well. For example, in Connecticut in 2005, the board expanded its efforts[15] to cover gas utility programs and was given new responsibilities in evaluating the state's energy efficiency programs.

Decision Making and Influence

Enhanced collaboratives are equipped with the necessary tools as well as a statutory mandate to conduct a thorough examination of the utility programs and filings. They become the acknowledged venue where energy efficiency issues are worked through and stakeholder input is incorporated into program plans. Although the commission remains the final arbiter of issues addressed by the enhanced collaborative, it tends to rely on the findings and recommendations of the collaborative.

Enhanced collaboratives generally have a formal process in which voting members decide an issue. Program administrators often participate as non-voting members of the board and provide their perspective on key issues. In Rhode Island, state law requires the Energy Efficiency and Resource Management Council (EERMC) to propose energy savings targets for utility programs, the final proposal of which is agreed upon by majority vote. Once this planning exercise has been completed, the Rhode Island Public Utilities Commission (PUC) is charged with regulatory review and approval of the proposed budgets and savings targets.[16]

In Massachusetts, the Energy Efficiency Advisory Council (EEAC) operates primarily through a consensus process, though this is a custom rather than a mandate. The statute only requires a vote of approval, so in those rare cases in which consensus cannot be reached, the EEAC operates by majority vote.[17] Where there is significant disagreement, items are reconsidered to address the major concerns. After being vetted through the collaborative process, energy efficiency plans must be reviewed and approved by the Department of Public Utilities (DPU). The DPU approval process considers program designs, budgets, cost effectiveness, and other compliance issues related to the Green Communities Act. If the program administrators do not agree with an EEAC decision, they can bring the issue before the DPU.

Accomplishments and Challenges

All of the enhanced collaboratives produce an annual report[18,19,20] summarizing the energy efficiency accomplishments in the state, as well as the activities of the collaborative. Additionally, because of their budget and expertise, enhanced collaboratives are able to take on other various studies and projects. For example, the Massachusetts EEAC funded a study to assess expected economic conditions in the state that could have an effect on energy efficiency efforts. In Rhode Island, the EERMC, with other groups, developed Standards for Energy Efficiency and Conservation Procurement and System Reliability ("Standards") for the PUC's review and approval. The Standards serve as an administrative roadmap, defining the roles and responsibilities for the different programs involved and laying out a clear process for achieving the goals of least-cost procurement.

These studies and projects can be done to improve deemed savings estimates, develop avoided costs, or evaluate new technologies, sometimes in conjunction with other states. In New England, all six states, with representation from utilities, public advocates, stakeholders, and collaborative consultants, participate in a joint effort to develop

[15] The Connecticut Energy Efficiency Board's oversight was expanded with the passage of 2005 legislation to include the energy efficiency programs of the Connecticut Municipal Electric Energy Cooperative and the state's natural gas utilities.

[16] Comprehensive Energy Efficiency, Conservation, and Affordability Act. (2006). § 39-1.27.7.1 (f).

[17] EEAC Bylaws as Adopted. (2013, May). Article 8. Available at: http://www.ma-eeac.org/Docs/2_General%20Info/EEAC%20Bylaws%20As%20Adopted%20-%20Final%20Revisions%205-16-13.pdf.

[18] Rhode Island Energy Efficiency and Resources Management Council. (2014). *Annual Report to the General Assembly*. Retrieved from: http://www.rieermc.ri.gov/documents/annual/4_EERMC_April%202014.pdf.

[19] Energize Connecticut. (2013). *Energy Efficiency Board Annual Legislative Reports.* Retrieved from: http://www.energizect.com/about/eeboard/annualreports.

[20] Massachusetts EEAC. (2013). *Annual Reports.* Retrieved from: http://ma-eeac.org/results-reporting/annual-reports/.

avoided costs to be used in measure and program screening. The utilities are ultimately responsible for the results of the study, but collaborative consultants advise the process.

Although the budget and time required for this type of collaborative is large, much of the work is necessary for some entity to undertake to properly support energy efficiency programs. Additionally, the inclusive planning and evaluation efforts undertaken by the collaboratives can greatly enhance the delivery and design of programs, making better use of the program funds.

Appendix. Collaborative Profiles

Enhanced Permanent Statewide Collaboratives

Connecticut

Name: Connecticut Energy Efficiency Board

Origin: Statute—CT Public Act 11-80 Section 33

Geography: Statewide

Membership: Members appointed by the Commissioner of Energy and Environmental Protection

Duration: Ongoing

Coverage: Electric and Gas

Website: http://www.energizect.com/about/eeboard

Origin: The Energy Efficiency Board (EEB), first known as the Energy Conservation Management Board, was created by the legislature in 1998 pursuant to Section 33 of PA 98-28 (CGS § 16-245m), An Act Concerning Electric Restructuring, to advise and assist the two large investor-owned utility electric companies in development and implementation of comprehensive energy efficiency programs. In 2005, the board's name was changed to the Connecticut Energy Efficiency Board, and its oversight was expanded to include the energy programs of the Connecticut Municipal Electric Energy Cooperative and the natural gas utilities—Connecticut Natural Gas Corporation, Southern Connecticut Gas Company, and Yankee Gas Services (Conn. Gen. Stat. §§ 16-245m, 7-233y and 16-32f).

Scope/Functions/Topics: The EEB's role is to advise and assist the electric distribution companies and gas companies in the development of combined energy efficiency, conservation, and load management plans; assist the electric distribution and gas companies in implementing such plans; collaborate with the Connecticut Green Bank to further the goals of such plan; coordinate the programs and activities funded by the Clean Energy Fund and the Energy Efficiency Fund; and report to the General Assembly. Utility program administrators are non-voting members of the board.

The EEB guides the expenditures and planning for the Connecticut Energy Efficiency Fund (CEEF). The CEEF is funded by various sources, including customer contributions, money from the Regional Greenhouse Gas Initiative, and the ISO New England forward capacity market payments, among others. These funds are used to support energy efficiency and renewable energy programs in Connecticut. In addition, the EEB assists the Department of Energy and Environment (DEEP) with evaluating CEEF-funded programs.

Group Decision Making: The board makes findings and recommendations regarding any program over which it has jurisdiction. Its review of the program plans, budgets, and savings goals proposed by the program administrators is a key piece of the review process undertaken by the commission. Decisions are made through motions from the floor, followed by votes (the board has 10 voting members and 5 non-voting utility members). A majority vote is necessary for a motion to pass. The EEB approves the utility conservation and load management plans before sending them to the commissioner of DEEP for final approval.

Membership: The board members are appointed to their positions by the Commissioner of Energy and Environmental Protection and serve for 5 years, after which they may be reappointed. By statute, voting members include representatives of (1) DEEP, (2) the Office of the Attorney General, (3) the Office of Consumer Counsel, and (4) an environmental group knowledgeable in energy conservation program collaboratives; (5) the electric distribution companies in whose territories the activities take place for such programs; (6) a statewide manufacturing association; (7) a chamber of commerce; (8) a statewide business association; (9) a statewide retail organization; (10) a statewide farm association; (11) a municipal electric energy cooperative created pursuant to Chapter 101a of the Connecticut General Statutes; and (12) residential customers. Representatives of gas companies, electric distribution companies, and the municipal electric energy cooperative shall be non-voting members of the board. The members of the board elect a chairperson from the voting members. Utility representatives are non-voting members.

Duration: The board was created in statute and will be functional until such time as the statute is modified.

Influence: DEEP approves program plans, budgets, and savings targets. The board undertakes detailed analysis of the energy efficiency programs and plans proposed by the program administrators and submits a recommendation to DEEP. It prepares and submits detailed comments and a recommendation regarding the program proposals, budgets, and targets proposed by the program administrators.

Role of the Commission: The Public Utilities Regulatory Authority is not represented on the board and does not participate in the process on a regular basis. DEEP serves on the board and participates on a regular basis.

Massachusetts

Name: Massachusetts Energy Efficiency Advisory Council

Geographical Coverage: Statewide

Origin: Statute

Membership: 15 voting members appointed by the Department of Public Utilities, based on a sector representation included in statute. Non-voting members are from the electric and gas distribution companies, municipal aggregators, heating oil business, and energy efficiency business.

Duration: Ongoing

Coverage: Electric and Gas

Website: http://ma-eeac.org/

Origin: The Massachusetts Energy Efficiency Advisory Council originated in the Green Communities Act of 2008,[56] which contained a number of new and expanded policies regarding energy use and energy efficiency.

Scope/Functions/Topics: The council reviews and approves energy efficiency program plans and budgets; works with program administrators in preparing efficiency resource assessments; and determines the economic, system reliability, climate, and air quality benefits of efficiency and load management resources. In addition, the council recommends long-term efficiency and load management goals.

Group Decision Making: Approval of efficiency and demand resource plans and budgets requires a two-thirds majority vote.

Membership: The Department of Public Utilities appoints the 15 voting members representing a variety of energy efficiency stakeholders, as well as 15 non-voting members, including the program administrators and other stakeholders. Meetings are open to the public, and stakeholders are given the opportunity to examine the analysis developed for the group and provide their perspective on program and policy issues.

Duration: The council was created in statute and will be functional until such time as the statute is modified.

Resources: The council is chaired by the Massachusetts Department of Energy Resources Commissioner. The council is authorized in statute to propose a budget not to exceed 1% of utility program expenditures.

[56] See: https://malegislature.gov/Laws/SessionLaws/Acts/2008/Chapter169, Section 22.

Influence: The council prepares an analysis of the energy efficiency plans proposed by the utility and reviews and approves programs. The council also offers advice and guidance to the program administrators as they develop program plans. The DPU ultimately approves program plans, budgets, and savings targets as submitted by the program administrators. The council monitors the progress of the programs in achieving their goals, conducts formal program evaluations, and submits an annual report to the commission.

Role of the Commission: The commission does not participate in the process on a regular basis. The Department of Energy Resources supports the council in its daily activities.

Rhode Island

Name: Rhode Island Energy Efficiency and Resource Management Council

Geographical Coverage: Statewide

Origin: Statute—RI Gen. Laws § 42-140.1 et seq

Membership: 13 members (9 voting) appointed by the governor

Duration: Ongoing

Coverage: Electric and Gas

Website: http://www.rieermc.ri.gov/

Origin: The EERMC originated in the Comprehensive Energy Conservation, Efficiency, and Affordability Act of 2006, which revamped much of the existing energy efficiency legislation in Rhode Island. The EERMC's responsibilities were expanded in 2010 to include the evaluation of the cost effectiveness of utility energy efficiency procurement plans. The council reports its findings to the PUC.

Scope/Functions/Topics: The council advises the PUC on matters relating to energy efficiency programs, renewable energy procurement, low-income consumers, and distributed energy resources.

Group Decision Making: The council may make findings and recommendations regarding changes to any program over which it has jurisdiction. It participates in commission processes relating to energy efficiency and also provides advice to utilities regarding their programs. Decisions are made through motions from the floor, followed by votes. The council has nine voting members and four non-voting members, including utility representation.

Membership: The governor appoints the 13 council members, including representatives from energy-using sectors and utility representatives. Meetings are open to the public, so stakeholders can critically examine the analysis developed through the group and provide their perspective on program and policy issues. One of the purposes of the council, stated in the legislation, is to "provide consistent, comprehensive, informed and publicly accountable stakeholder involvement in energy efficiency, conservation and resource development."

Duration: The council was created in statute and will be functional until such time as the statute is modified.

Resources: Council activities are facilitated by the Rhode Island Office of Energy Resources (OER). The OER's director also serves as the council's executive director. The council has a budget of roughly $1.2 million, the majority of which is spent on consultants to assist in the program review and evaluation process. The council receives approximately 1.2% of the electric and gas system benefits charge to support its activities.

Influence: The PUC approves program plans, budgets, and savings targets. The council prepares an analysis of the energy efficiency plans proposed by the utilities and submits this to the PUC. The council also monitors the progress of the programs in achieving their goals and submits an annual report to the commission.

Role of the Commission: Other than the duties outlined previously, the commission does not participate in the process on a regular basis. The OER supports the council in its daily activities.

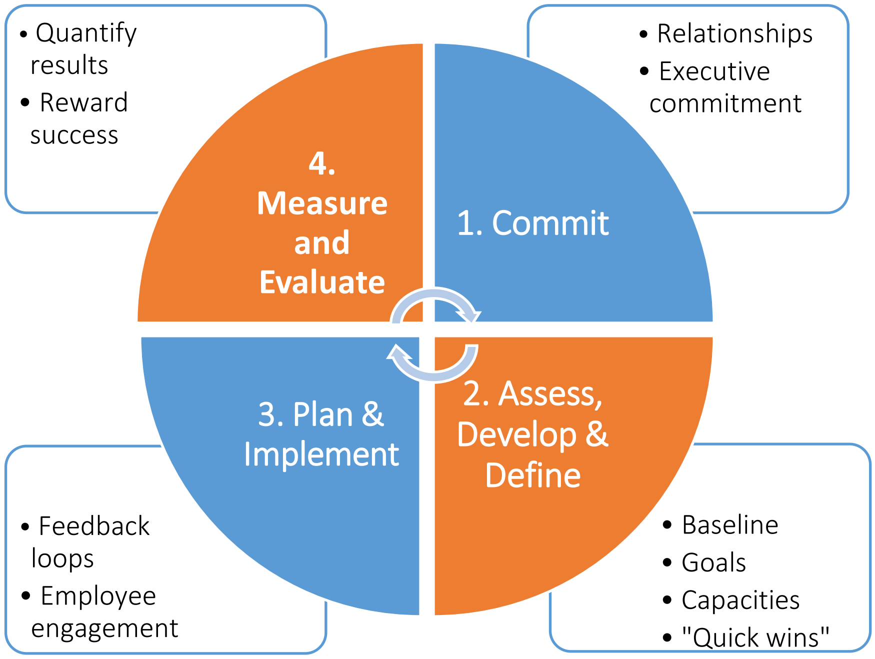
behavior change at a management level and transforms the heart of decision-making; moving from reactive incentives to ongoing flexible engagement. The Business Sustainability Challenge creates win-win solutions where C&I customers can be proactive about addressing environmental issues (e.g., climate change and water pollution) and engage their employees, customers, and stakeholders in original and innovative channels.

The Business Sustainability Challenge is an umbrella approach that weaves together each of the Industrial Solutions offerings into a coherent package that make it easy for customers to navigate and capitalize on the wide variety of C&I incentives. The initiative provides third-party technical sustainability strategy consultants to work with management teams regarding long-term strategy and planning for all business operations, while the Energy Utilization Assessments initiative focuses more on sustainability and efficiency efforts at a facility level, and the Process Reengineering for Increased Manufacturing Efficiency initiative addresses operational efficiencies. Business Sustainability Challenge engagements result in the development and execution of long-term plans that bring together the action steps needed for C&I customers to realize deep energy savings and make substantial improvements in other key aspects of sustainability.

Strategic Energy Management

Strategic Energy Management ("SEM") is a long-term approach to pursue energy efficiency that focuses on setting goals, tracking progress, and reporting results. The Business Sustainability Challenge serves as the Companies' main SEM approach to establish long-term relationships with energy users and to target persistent energy savings. Though the Business Sustainability Challenge contains all of the value of a traditional SEM program that other states' energy efficiency portfolios present to customers, the offering provides many additional aspects of sustainability that help define it as a cutting-edge program. Figure 3-4 describes the Companies' SEM approach and how the Business Sustainability Challenge functions as a structured process to implement SEM.

Figure 3-4: Strategic Energy Management as Facilitated by the Business Sustainability Challenge



- Step One: Commit. The Business Sustainability Challenge's SEM approach begins by establishing relationships between the customer and the Companies. The Business Sustainability Challenge is built around a multi-year, executive-level management commitment by the customer to target persistent energy savings.
- Step Two: Assess, Develop and Define. Once an executive commitment has been made, the Companies can move to the second step of the SEM approach. First, an assessment of the baseline energy and sustainability conditions of the subject facility is performed, and then energy-saving and sustainable goals are established. Then, the internal capacities of the customer are developed and to maintain momentum some "quick win" actions are identified and implemented.
- Step Three: Plan and Implement. Over the long-term, as internal capacities are utilized to establish energy and sustainability goals, the customer builds in feedback loops and actively engages its workforce with the Business Sustainability Challenge. This engagement makes the established goals "everyone's."
- Step Four: Measure and Evaluate. Finally, results are quantified by measurement and evaluation against both the customer's metrics and the Companies' evaluation, measurement, and verification ("EM&V") protocols, and successes are rewarded.

The Business Sustainability Challenge is the only initiative that the Companies provide that pulls together all the pieces of the SEM approach; however, all the Companies' offerings and services are always available (as appropriate) to customers on an a la carte basis.

Benefits of the Business Sustainability Challenge

The Business Sustainability Challenge addresses the energy needs of a customer by making continuous improvements in business and facility operations that lead to sustainability and competitive business advantage. The Companies have long recognized the importance of educating customers about the value (energy and non-energy) of participating in the C&I Energy Efficiency Portfolio. The Business Sustainability Challenge's innovative solutions help businesses see where energy efficiency provides a foundation for their key business goals such as improving their bottom line, management, sales, or innovation, and eventually move into sustainable industry leadership through net-zero and net-positive operations. Initially customers develop and implement strategic carbon and energy management plans and choose if they want to also tackle other common sustainability aspects, such as water and wastewater, materials, and employee engagement and product innovation.

At each of the four steps, the Business Sustainability Challenge connects businesses with the resources they need to blaze a path of continuous improvement and to achieve both energy savings and comprehensive non-energy benefits. The Business Sustainability Challenge is successful because it addresses energy efficiency needs in tandem with the other most pressing issues in the Connecticut business community such as productivity, overall competitiveness, regulatory pressures, workforce development, and sales growth. Improvements in each of these areas are often multiple times more valuable than just energy efficiency savings, so combining them all is a compelling package to many customers.

Initiative Offerings

The Business Sustainability Challenge moves beyond fundamental energy efficiency programming. The BSC provides participating large and medium-sized customers with individual assistance via technical and strategy consultants. Smaller-sized customers receive access to online tools and calculators to help them obtain their energy and sustainability goals via the Companies' Customer Engagement Platforms.

The Business Sustainability Challenge facilitates peer roundtables, organized by market segments, which provide customers with the ability to share best practices and opportunities for collaboration. At the roundtables, C&I customers can share ideas, discuss how to best engage their workforce around energy and sustainability, and begin to develop collaborations that help them tackle harder issues that may have slower paybacks than energy efficiency, but have similarly important social and environmental benefits to Connecticut residents (e.g., renewable energy, cost-effective recycling, material recovery, purchasing, etc.).

For the 2019-2021 Plan, the Companies plan to offer a pilot demonstration of industrial cohorts. Cohorts are where a group of customers work together to adopt a more strategic approach in energy management in their facilities. Through the Business Sustainability Challenge, the Companies will explore the benefits of working with industrial cohorts of six to twelve C&I customers whose business operations and/or industries are similar but non-competing (so there are no concerns regarding customer confidentiality). The cohort approach improves the cost-effectiveness and scalability of the CSP/SEM Demonstration so that Business Sustainability Challenge practitioners can work with larger groups of customers to deliver trainings, provide roundtables of positive reinforcement, and facilitate peer feedback loops where best practices are shared and to help maintain forward momentum. The SEM cohort process will be consistent with that laid out by the Consortium for Energy Efficiency's Strategic Energy Management Minimum Elements."[41]

Energy Utilization Assessments

The Energy Utilization Assessment ("EUA") initiative is a tool in the Business and Energy Sustainability portfolio that focuses on delivering a standardized approach to facility audits. This approach is action-oriented and geared toward finding holistic energy efficiency solutions for C&I customers focusing on low and no-cost upgrades that can generate substantial energy and financial savings as well as quick paybacks. Through a competitive solicitation process, the Companies have a select group of vendors that provide audit services that are cost-shared with the participating C&I customer. This cost-sharing model filters customer participation to those who are truly serious about investing in greater competitiveness and sustainability solutions than other Business and Energy Sustainability initiatives provide.

The EUA identifies measures and business operations that will generate additional energy efficiency opportunities through the Companies' C&I Energy Efficiency Portfolio. At a minimum, it results in a report that contains a project register that focuses on low to no-cost Energy Conservation Measures ("ECMs") that typically save 10+ percent of a customer's total energy consumption and have under three-year combined payback when conducted under a comprehensive incentive. This project register serves as the initial technical detail used to initiate a SEM with the customer's management team. To emphasize the action-oriented nature of the EUA, the Companies provide reimbursement (incentives) up to the full customer contribution. The Companies calculate this incentive based on energy savings from participation in other C&I

[41] Consortium for Energy Efficiency. *Strategic Energy Management Minimum Elements,* 2014.

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

D.P.U. 17-05

JOINT TESTIMONY OF

RICHARD D. CHIN

AND

KEVIN J. MORLEY

EXHIBIT NSTAR-STL

IN SUPPORT OF
NSTAR ELECTRIC COMPANY
d/b/a EVERSOURCE ENERGY

October 2, 2018

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Richard D. Chin. My business address is 247 Station Drive, Westwood, MA 02090.

Q. By whom are you employed and in what capacity?

A. I am Manager of Rates for the Eversource Energy operating companies of NSTAR Electric Company ("NSTAR Electric" or "the Company") and NSTAR Gas Company ("NSTAR Gas"). As Manager of Rates, I am responsible for the design of rates and the preparation of rate schedules for NSTAR Electric and NSTAR Gas. I am also responsible for preparing and submitting various regulatory filings to the Department on behalf of NSTAR Electric and NSTAR Gas.

Q. Please describe your education and professional background.

A. I graduated from Yale University in 1994 with a Bachelor of Arts degree in History. Upon graduation, I worked for two years as a corporate legal assistant at the law firm of Fried, Frank, Harris, Shriver, & Jacobson. I subsequently enrolled in Columbia University's School of International and Public Affairs, completing a Master of Public Administration in May 1999. In July 1999, I took a position as a consultant with London Economics, LLC, an economic consulting firm specializing in energy and utilities. My primary responsibilities were to model energy markets across the U.S. and Canada for both regulatory commissions and independent power producers. In January 2005, I joined NSTAR Electric & Gas as a Senior Regulatory Policy and Rate Analyst. In September 2012, I was named to my current position.

Q. Have you previously testified in any formal hearings before regulatory commissions?

A. Yes, I have presented testimony before the Department numerous times. Most recently, I testified in NSTAR Electric Company/Western Massachusetts Electric Company, D.P.U. 17-05 regarding the decoupling and the design of base distribution rates for the consolidated NSTAR Electric.

Q. Please state your name and business address.

A. My name is Kevin J. Morley. My business address is 247 Station Drive, Westwood, MA 02090.

Q. By whom are you employed and in what capacity?

A. I am an Energy Efficiency Project Engineer for the Company. As Project Engineer, I am responsible for site-specific energy engineering analyses for commercial & industrial projects. Within this role, I investigate new technologies for implementation programs and I also serve as a technical liaison for Eversource on commercial and industrial energy efficiency issues.

Q. Please describe your education and professional background.

A. I graduated from Wentworth Institute of Technology in 1994 with a Bachelor of Science in Mechanical Engineering Technology. Upon graduation, I worked in several engineering positions as an independent contractor until I accepted a permanent position at Stone & Webster Engineering Corporation ("Stone &

Webster") in November 1997 as a titled Engineer. I worked for over four years with Stone & Webster and advanced to my final position of Senior Project Controls Engineer. In August 2002, I joined NSTAR Electric & Gas as a Project Engineer in Energy Efficiency which is my current position. I am a registered Professional Engineer (P.E.) with the State of Massachusetts: License #49869. I currently hold three active certifications with the Association of Energy Engineers including: Certified Energy Manager (CEM), Distributed Generation Certified Professional (DGCP), and Certified Lighting Efficiency Professional (CLEP).

Q. Have you previously testified in any formal hearings before regulatory commissions?

A. No.

Q. Why is the Company making this filing?

A. On November 30, 2017, the Department of Public Utilities (the "Department") approved a performance-based ratemaking mechanism for the Company in D.P.U. 17-05. The City of Cambridge (the "City") intervened in D.P.U. 17-05, in part, to address a billing issue pertaining to the City's street lights. Specifically, the City installed street lighting controls to operate almost all of its fixtures at 70 percent of maximum output in order to reduce usage for some street lights through scheduling the time of operation (Cambridge Brief, at 5, citing Exh. CAMB-SL-1, at 2; Cambridge Reply Brief, at 1).

Eversource's current customer-owned street and security lighting tariff (Rate S-2) assumes a fixed dusk- to- dawn schedule. The dusk- to- dawn schedule enables the

Company to bill customers on an unmetered basis, which reduces costs for street lighting customers by allowing them to bypass the cost of meter installations. However, this tariff structure does not allow municipalities to recover the cost savings from any reduction in energy usage through street light controls.

In D.P.U. 17-05, the City requested that the Department direct the Company to work with the City to develop a modified Rate S-2 tariff that reflects reduced usage caused by street lighting controls (Cambridge Brief, at 6; Cambridge Reply Brief, at 1-2). In its D.P.U. 17-05-B Order, the Department directed the Company to provide the Department with a report detailing its efforts to establish a working group with interested parties ("Working Group"), and the Working Group's progress on reaching a solution to measuring street light usage data. D.P.U. 17-05-B, at 317.

On May 11, 2018, the Company filed a letter with the Department that reported the Company's efforts to establish the Working Group with interested parties and progress on reaching a solution to measuring street light usage data. The Company indicated in the letter that it planned to submit a second progress report on the Working Group's efforts to identify a solution that resolves the issues related to communities employing street lighting controls on or before October 1, 2018 followed by a third progress report on or before January 1, 2019, to identify the Working Group's progress and a proposed solution if the Working Group has reached consensus on a solution.

Following, the May 11, 2018 filing, the Working Group continued to meet monthly, examined existing data, and engaged with industry experts to evaluate multiple solutions. The Company provided both in-person and remote access to these monthly meetings to accommodate schedules and promote greater participation. All participants had an opportunity to comment on the content at each meeting. In addition, members were also offered opportunities to present to the group as meeting topics were discussed as part of each meeting. In total, there were four formal Working Group meetings and a separate, recommended industry webinar from Cimcon Lighting on streetlight infrastructure and smart city applications.

Q. Please describe the purpose of your testimony.

A. The Company has developed a proposed solution based on input from and the approval of the Working Group. The proposed solution is being presented in this testimony which will preclude the need for a third progress report on or before January 1, 2019 as set forth in the May 11, 2018 letter filed with the Department. Our testimony 1) describes the Working Group's identified approaches; 2) provides a report on the Working Group's activities and progress; and 3) presents the Company's proposed solution. Our testimony is organized into sections that correspond to these three general areas of discussion.

II. IDENTIFIED APPROACHES OF THE WORKING GROUP

Q. What potential solutions to address customer-controlled street lighting were identified and considered by the Working Group?

A. The Company's May 11, 2018 letter outlined four potential approaches to address customer-controlled street lighting:

1. Customer-Owned Wireless Control Infrastructure;
2. Company-Owned Wireless Control Infrastructure;
3. Alternative Burn Hour Schedules; and
4. Individually Metered and/or Group Metered with Control Boxes.

Q. Please describe how the Company could utilize an existing Customer Owned Wireless Control Infrastructure to bill customer-controlled lighting.

A. Certain municipalities, such as the City, have installed their own wireless control infrastructure. One potential solution considered by the Company and the Working Group was to accept billing data from the customer-owned control infrastructure. The challenge with this approach was the need to develop a solution that accepts various data formats from multiple manufacturers on behalf of the Company's many customers. In addition, after receiving the data, the Company would need to develop a method to verify the accuracy of the information to the level of its internal standards for data processing. The Company would also have to anticipate advancements in this evolving technology to address the potential needs of its customers in the future.

For the Company to accept metering data from customers, it would have to develop a detailed specification and data template that could be issued to any city or town regardless of the control manufacturer that they may be considering. A standard protocol for the electronic transfer of such data may also be needed to facilitate billing. The Company would require its specification and format to be met as a condition for the acceptance of any data files. The time, complexity, and cost associated with this possible solution make it less than ideal.

Q. Please describe how a Company-Owned Wireless Control Infrastructure could be used to bill customer-controlled lighting.

A. In a Company-Owned Wireless Control Infrastructure construct, the Company would own and install metering nodes and would exercise control over customer lighting. Customers would have to supply lighting schedules to the Company for implementation. This would allow for one consistent platform across all customers that corresponds to the Company's existing systems (billing, operations, etc.). However, such a system would add additional costs and require the Company and the municipalities to work in concert to develop lighting schedules. There would also be liability concerns for the Company as responsibility for the safe and proper lighting of public areas would partly fall on the Company.

Q. Please describe the Alternative Burn Hour Schedule option.

A. Under this option, the Company would modify the customer-owned street lighting tariff to introduce reduced burn hour schedules to communities that install control technologies on their street lights. The schedules could be based on the performance data of the customer's lighting control systems, but communities would be subject to verification that the street lighting controls are operational and performing as designed. This is the solution that was ultimately identified by the Company and the Working Group as the most practicable, straight forward, and cost-effective solution.

Q. Please describe how customer-controlled lighting can be Individually Metered and/or Group Metered with Control Boxes.

A. This option is currently available to customers but has traditionally been deemed an unattractive alternative. Under this approach, all customer-owned lights would require meter installations at the customer's expense. Although this direct "measuring" approach would be effective from a technical standpoint, these methods are the least desirable from the financial standpoint of street lighting customers due to the associated cost of the necessary metering equipment.

III. WORKING GROUP PROGRESS REPORT AND CONCLUSION

Q. Who were the participants in the Working Group that evaluated the identified potential solutions?

A. The Working Group included representatives from the City of Cambridge, Town of Westwood, and City of Newton—communities that either have controlled lighting systems installed or are exploring them. Other technical experts within the lighting control industry also participated including representatives from Cimcon Lighting, Light Smart Energy Consulting, Fred Davis Corporation, and FP Outdoor Lighting Controls. Governmental participants included staff from both the Massachusetts Department of Energy Resources (DOER) and Governor Baker's office and representatives from the Metropolitan Area Planning Council (MAPC), which coordinates street lighting initiatives with cities and towns, as well as several other municipalities and their vendors in the Company's service territory. Finally, colleagues from National Grid and Unitil were also key participants in the Working Group meetings.

Q. What considerations were taken into account in the Working Group's evaluation of a customer wireless control infrastructure solution and what was the Working Group's conclusion?

A. The Working Group had concerns regarding the costs and feasibility of automated data integration. The Working Group relied on the experience of National Grid's pilot program in Rhode Island which evaluated metering data provided by customer-controlled lighting systems. Although the integration of streetlight metering data into National Grid's billing system was part of their initial scope within the Rhode Island pilot, their analysis showed that the complexity was much more than anticipated which resulted in higher pilot costs. As a result, the Rhode Island Public Utilities Commission (RIPUC) directed National Grid to suspend this phase of the pilot.

While an automated process to integrate streetlight metering data into the Company's billing systems may be theoretically useful (regardless of whether the controls were company-owned or customer-owned), the cost, complexity, and time required to implement such a solution are unfavorable and would not meet the goals set forth by the Company and Working Group which prioritized a cost-effective solution that could be expeditiously implemented.

It is anticipated that further consolidation and standardization within market and technology will make it possible for utilities to structure automated channels for accepting data in the future. However, in the interest of immediate improvements and advancement of current systems and processes, the Working Group supported the Company's recommendation for an unmetered approach that would bridge the gap between evolving lighting technology and the Company's billing methodologies.

Q. What is the Working Group's recommendation?

A. The Working Group recommends that the Company utilize a variation of the Alternate Burn Hour Schedule methodology described above. This method relies on an unmetered calculation rather than establishing protocols for the acceptance of meter data from customer-owned devices. Unlike the metered solutions considered by the Working Group, the proposed approach could be implemented, subject to approval by the Department, by Fall 2018 as requested by members of the Working Group. The implementation of this solution would allow communities with existing, unmetered controls like the City of Cambridge, Town of Westwood, and others to realize the cost savings from the reduction in energy usage through their streetlight control systems. In addition, the expeditious implementation of this cost-saving mechanism within the existing tariff would help promote the adoption of controls on new conversion projects resulting in additional energy and cost savings for municipalities in the Commonwealth which further supports the Baker Administration's Municipal LED Streetlight Conversion Program.

IV. PROPOSED TARIFF CHANGE AND IMPLEMENTATION

Q. What tariff changes are being proposed by the Company?

A. The Company is filing clean and redlined copies of proposed M.D.P.U. No. 45B (Exh. NSTAR-STL-1) which modifies the Company's customer-owned street and security lighting provision. Specifically, the Company is introducing a "Customer Controlled Lighting" clause that requires customers, who wish to depart from the Company's dusk to dawn lighting schedule, to submit revised, or reduced, wattage ratings required to produce the customer's operating schedule. In addition, the customer must provide verification to the Company that it has installed controls that meet the Company's standard for metering accuracy.

Q. Please describe how the Company will produce customer specific lighting usage for billing.

A. The Company currently utilizes a dusk to dawn burn hour schedule to produce lighting usage for billing. This is accomplished by multiplying the rated wattage of the fixture (including ballast) by the Company's burn hour schedule which assumes that lights turn on for a pre-determined number of evening hours. Under the Company's proposal, customers who control their lighting and who wish to be billed according to their own schedule will have to submit to the Company revised wattage ratings for each light such that application of the Company's burn hour schedule to the revised wattages will produce the scheduled kWh to be delivered.

Q. How will the Company verify that the customer is operating under the intended lighting schedule?

A. The Company has included a requirement in the proposed tariff that customers who elect to control their lights must also provide the Company access, either directly or indirectly, to the data from the Customer's control system in order for the Company to verify the measured energy use of the lighting systems and modify the charges if necessary as part of the Company's measurement and verification protocols. The schedule of wattage ratings may be revised once per year at the request of the Customer.

Q. Will the proposed solution require programming changes to Company's billing systems?

A. No. The Company can leverage existing work processes to incorporate customer revisions to the rated wattages of their lighting fixtures. While no technical changes are required, the customer will need to verify to the Company that it has installed a controlled-lighting system and provide a data set of de-rated wattages by fixture in support of its proposed lighting schedule.

Q. When does the Company expect to implement the proposed provision?

A. Subject to approval by the Department, the Company can implement its proposal for billing effective November 1, 2018.

Q. Does this conclude your testimony?

A. Yes, it does.

AVAILABILITY

Street and security lighting service under this rate schedule is available for street and security lighting installations owned by any city, town, or other public authority, herein referred to as the Customer. Service under this rate is subject to the Company's printed requirements and the Company's Terms and Conditions – Distribution Service, each as in effect from time to time.

RATE PER MONTH

Delivery Services:		Eastern Massachusetts	Western Massachusetts
Customer Charge:	As per	M.D.P.U. No. 1	M.D.P.U. No. 2
Distribution:	As per	M.D.P.U. No. 1	M.D.P.U. No. 2
Transition:	As per	M.D.P.U. No. 1	M.D.P.U. No. 2
Transmission:	As per	M.D.P.U. No. 1	M.D.P.U. No. 2

Supplier Services: (Optional)

Basic Service: As in effect per Tariff

Minimum Charge:

The minimum charge per month shall be the Customer Charge.

RATE ADJUSTMENTS

The charges for delivery service shall be subject to the following provisions:

Revenue Decoupling Adjustment Mechanism
Residential Assistance Adjustment Clause
Attorney General Consultant Expense
Storm Reserve Adjustment Mechanism
Basic Service Cost Adjustment
Transmission Service Cost Adjustment
Renewable Energy Charge
Performance Based Revenue Adjustment
Vegetation Management
Pension Adjustment Mechanism
Net Metering Recovery Surcharge
Long Term Renewable Contract Adjustment
Storm Cost Recovery Adjustment
Solar Program Cost Adjustment
Transition Cost Adjustment
Energy Efficiency Charge
Miscellaneous Charges

Customer Controlled Lighting

Where lighting controls that meet the current ANSI C12.20 standard have been installed that allow for variation from the Company's annual burn hour schedule, the Customer must provide verification of such installation to the Company and a schedule indicating the wattage ratings expected to serve lights subject to the Customer's control and operation. Upon installation and at any time thereafter, the Customer must also provide the Company access, either directly or indirectly, to the data from the Customer's control system in order for the Company to verify the measured energy use of the lighting systems and modify the billed usage as appropriate on a prospective basis. The schedule of wattage ratings may be revised once per year at the request of the Customer. However, it is the Customer's responsibility to immediately notify the Company of any planned or unplanned changes to its scheduled usage to allow for billing adjustments as may be needed.

The charge for the monthly kilowatt-hours shall be determined on the basis of the wattage ratings of the light sources and installed control adjustments established at the beginning of the billing period multiplied by the average monthly hours of the annual burn hour schedule. The wattage ratings shall allow for the billing of kilowatt-hours according to the schedule submitted by the Customer to the Company and reflect any adjustments from the lighting control system including, but not limited to, fixture tuning, dimming, variable dimming, and multiple hourly schedules.

GENERAL CONDITIONS

1. The Customer shall be responsible for specifying the type and size (wattage and lumen ratings) of lighting fixtures.

2. Customer shall plainly mark Customer-owned street and security lighting lamppost for the purpose of ownership identification. All street and security lighting facilities provided by the Customer for installation on the Company's system shall be free from all defects and shall in no way jeopardize the Company's electric distribution system. The Company may refuse to allow the placement of any street and security lighting facilities which, in the Company's sole reasonable opinion, are not so free from defects or that might so jeopardize said system.

3. A meter will be required on all installations for traffic signals if more than one lamppost is connected.

4. If an installation of Customer-owned street and security lights requires the removal of Company-owned street and security lighting units, the provisions in Rate S-1, as it exists from time to time,

This page intentionally left blank.