STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

In the matter of

Electric and Gas Utilities

Docket No. DE 20-092

2021-2023 Triennial Energy Efficiency Plan

DIRECT TESTIMONY OF
PHILIP H. MOSENTHAL

ON BEHALF OF THE
OFFICE OF THE CONSUMER ADVOCATE

October 29, 2020

(I.) Introduction

Q. Please state your name and business address.

A. Philip H. Mosenthal, Optimal Energy, Inc., 10600 Route 116, Hinesburg, Vermont 05461.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Office of the Consumer Advocate (OCA). All work developing my testimony has been completed by me or under my direction.

Q. How are you employed?

A. I am the founding partner of Optimal Energy, Inc., a consultancy specializing in energy efficiency and utility planning. Optimal Energy advises numerous parties including utilities, non-utility program administrators, governments, and environmental and other non-governmental groups.

Q. Tell me about your qualifications and experience.

A. I have 35 years of experience in all aspects of energy efficiency, including facility energy management, policy development and research, integrated resource planning, cost-benefit analysis, and efficiency and renewable planning, program design, implementation, evaluation and potential assessment. I have developed numerous utility efficiency plans, efficiency potential studies, and designed and evaluated utility and non-utility residential, commercial and industrial energy efficiency programs throughout North America, and in Europe and China.

I have served as a lead advisor in various roles in Connecticut, Massachusetts and Rhode Island on behalf of the Energy Efficiency Advisory Council, Energy Efficiency Board, and Energy Efficiency Resource Management Council, respectively, overseeing and advising on their nation-leading utility program administrators' plans, program designs, implementation and performance. I also was the lead developer of Vermont's "efficiency utility" (Efficiency Vermont), which is the nation's first and only regulated utility dedicated solely to capturing efficiency resources.

Recently, I have also been actively engaged in the Illinois Stakeholder Advisory Group (SAG) since its inception, representing the People of Illinois on behalf of the Illinois Office of the Attorney General. I have played a similar role in the Evergy (formerly KCPL&L) and Ameren stakeholder collaboratives in Missouri, on behalf of NRDC, the Sierra Club, and Renew Missouri in various Ameren and KCPL&L dockets. I have also performed extensive work in New York and New Jersey related to efficiency potential, policy and program planning.

Prior to co-founding Optimal Energy in 1996, I was the Chief Consultant for the Mid-Atlantic Region for XENERGY, INC. (now DNV-GL). I have a B.A. in Design of the Environment and an M.S. in Energy Management and Policy, both from the University of Pennsylvania.

My resume is attached as Exhibit PHM-1.

Q. Please summarize your testimony.

A. My testimony addresses the following issues related to the proposed Triennial Plan (Plan):

1. While I generally support the Plan and the goals it establishes, I have concerns regarding rules related to modification of goals; that many of the savings are

intended to represent gross savings rather than the net savings actually attributable to the programs; and the lack of any goals for delivered fuel MMBtu savings.

2. I have some concerns with evaluation, measurement and verification (EM&V) policies related to the timing of the application of results, as well as to the lack of adjustments to gross savings to represent net savings.
3. I have concerns with the midterm modification and stakeholder processes and triggers proposed for requiring Commission notification or approval.
4. I have a few programmatic or measure-specific recommendations related primarily to heating system conversions to heat pumps and the Energy Optimization pilot.

(II.) Savings and Net Benefits Goals

Q. Do you support the utility's savings and net benefits goals?

A. Broadly yes. I appreciate and support the utilities' willingness to pursue a substantial ramp up in savings goals, leading to cumulative annual Plan savings of 5 percent of load for electricity and 3 percent for gas. These will bring 2023 planned levels to 2 percent for electric and 1.2 percent gas, which reflect a substantial improvement and capture of a significant portion of the full cost-effective achievable potential, estimated at 2.5 percent and 1.7 percent in 2023, respectively.[1] It will also bring New Hampshire

[1] Dunsky Consulting. New Hampshire Potential Study: Statewide Assessment of Energy Efficiency and Active Demand Opportunities, 2021-2023. Volume 1. Figures 2 and 7.

closer in line with Massachusetts, where many of the New Hampshire utilities already deliver efficiency programs at deeper levels.

New Hampshire's pursuit of all cost-effective achievable efficiency savings would be appropriate, as cost-effective efficiency is, by definition, the least expensive energy resource. As such, maximizing capture of efficiency resources will lead to the lowest utility revenue requirements and ratepayer bills. This will maximize overall direct economic net benefits and indirect economic development in New Hampshire, as well as minimize environmental impacts. While the Plan falls significantly short of that goal, as estimated by the utilities' recent potential study,[2] I believe it represents a good faith effort at ramping up efficiency, while maintaining a reasonable balance around short term rate impacts.

Q. Do you support the Plan proposal to shift from an annual to a three-year plan?

A. Yes. I believe this approach is appropriate and desirable. It allows the utilities greater flexibility to respond to market opportunities and challenges, and it avoids the somewhat arbitrary concerns of exactly when an efficiency project completes and gets credited in the utility's tracking system. It also removes some theoretical perverse incentives that can occur based on the performance incentive design that could encourage utilities to modify the timing of program efforts in inappropriate ways. This multiyear approach is currently used in Massachusetts and Vermont, and in Illinois for the gas utilities, and has worked well.

[2] Dunsky Consulting. New Hampshire Potential Study: Statewide Assessment of Energy Efficiency and Active Demand Opportunities, 2021-2023. Volume 1: Narrative Report.

Q. Despite your broad support, do you have any concerns related to the savings and net benefit goals?

A. Yes. First, I have concerns around the utilities' request to be able to modify goals based on future changes related to evaluation, measurement & verification (EM&V) and/or the technical reference manual (TRM). Second, I have concerns about the use of gross savings for downstream programs. Finally, I have a concern around the lack of any goals and performance metrics for savings of delivered fuels (primarily oil and propane) attributable to the electric utility programs. I will discuss these in more detail later in my testimony.

Q. Please summarize your first concern related to savings adjustments.

A. While the utilities have proposed a significant and appropriate ramp up in savings levels, they have indicated an intention to modify their savings goals prior to January 2021 depending on the outcome of continuing discussions among the EM&V working group related to commercial lighting and custom savings.[3] Further, and even more concerning, they have established an expectation that future changes once the 2021-2023 Plan begins related to EM&V (including changes to the TRM) should result in changes to their savings goals if certain triggers are met. I believe this is inappropriate and the utilities should stand by the Plan savings goals despite any new information that may come to light in the future.

Q. Don't the utilities specifically state in the Plan that they do not intend to modify goals based on potential changes related to EM&V and avoided costs?

[3] Plan footnote 18 at 38 of the Triennial Plan (at page 36, Bates page 42) confirms that the TRM is still a work in progress, and the utilities stated this intention in the first technical session on September 14, 2020. A draft version of the TRM appears as Appendix A to the Triennial Plan.

A. They do state that for changes of less than 10 percent. Specifically, the Plan indicates that the utilities “will not change [the Plan goals] without the Commission’s approval regardless of the results of evaluations and the avoided cost study.”[4] However, they subsequently establish a midterm modification (MTM) trigger whereby they may ask the Commission for approval to modify goals if changes result in a 10 percent or greater change. Further, they state that the 10 percent trigger is a cumulative trigger level that applies to the total of all changes collectively: “If the collective impact of those evaluation findings is a change to the Granite State Test portfolio benefits or primary energy savings for the term of greater than 10 percent . . . a midterm modification Review will be triggered.”[5] While I address the midterm modification process and triggers in more detail later, I point out that given these statements it is virtually guaranteed that changes will indeed result in potential adjustments greater than 10 percent in a downward direction at least for net benefit goals. As a result, this “loophole” effectively eliminates any certainty that the stated goals will be reached or used for purposes of awarding performance incentives.

Q. Why do you believe that it is virtually guaranteed that the 10 percent trigger will be activated?

A. OCA 2-006 confirms it is a collective trigger, and specifically also states “[t]he trigger related to AESC Study and/or Evaluation Findings will be considered together,”[6] confirming that it is a single collective trigger for all changes with avoided costs and EM&V. While a full draft of the forthcoming AESC (Avoided Energy Supply Costs)

[4] 2021 – 2023 Triennal Plan at 29 (Bates page 42).
[5] Utility Response to Data Request OCA 2-006.
[6] OCA 2-006

study is not yet available, preliminary numbers have been developed that point to estimated reductions in the range of about 25 percent in both electric and gas energy avoided costs, and about 33 percent reduction in electric capacity costs. Therefore, it is hard to imagine that the collective 10 percent trigger would not be hit even with no EM&V changes.

Q. Given that the utilities have developed their goals with explicit assumptions in their benefit-cost (BC) models, isn't it reasonable that if those assumptions get modified, that the goals should also be modified accordingly?

A. Not for those related to savings. It is helpful to address the possible changes from EM&V and the TRM separately from changes to the avoided costs, and I propose different policies for each category. For avoided costs I do effectively support goal modification, although through a simpler and more straightforward method than in the Plan proposal, which I explain later. However, changes to the savings goals, absent some extreme and unforeseeable event outside of the utilities' control (such as additional COVID-19 impacts not already considered) are not appropriate.[7] What matters to ratepayers is that the savings the utilities have agreed to provide are actually captured and that they enjoy the intended benefits and bill savings from their significant investment in efficiency. The utilities' agreement to pursue the goals they have proposed should not be viewed as a deterministic result of their calculating a specific number based on a multitude of individual measure assumptions. Rather, it is the result of negotiations with stakeholders through the EERS Committee process. Quite simply, the BC models the

[7] Note the utilities have addressed expected COVID-19 impacts already in their Plan.

utilities put forth are simply an exercise in one illustrative example of how the goals might be achieved and to generate reasonable net benefits targets.

As the Commission has implicitly acknowledged through past support for awarding shareholder incentive payments based on actual performance, utilities should be held accountable for achieving actual performance outcomes, rather than simply going through the motions of documenting participation levels or other activities that may or may not lead to satisfactory performance. The utilities' portfolio of programs can and will accommodate lots of different efficiency measures, among lots of different customer types and sizes, and actual outcomes will inevitably differ from the BC model assumptions in terms of quantities of different measures, as well as the average savings of any given measure. Further, the utilities have extensive flexibility to modify approaches, how and who they target, and the measures they promote and rebate levels they pay. Essentially, one can think of the efficiency portfolios as comprising a very diversified set of measures and programs the utilities can manage and deploy to reach a desired performance outcome. This is analogous to how investors in the stock market pursue a diversified range of investments to minimize risk, and do not expect that each individual investment should provide a guaranteed return. The utilities similarly have a diversified portfolio they should be appropriately managing toward a performance goal.

Not only would it be unfair to shift this performance risk onto ratepayers (who are paying for the efficiency yet do not have control of the programs), but it would likely lead to worse outcomes. This is because it is important that the utilities have the appropriate incentive to respond to market changes and new information. For example, if it turns out a particular measure does not save as much as originally anticipated (and potentially is no longer even cost-effective), it may be appropriate for the utility to reduce promotion of that measure in lieu of a different measure that may be more beneficial. By holding the utilities harmless for EM&V findings, it eliminates any encouragement for utilities to modify their approaches, and inappropriately can encourage them to continue to pursue resources that may no longer be appropriate or even cost-effective. Ultimately, because the utilities have control over their programs and their spending of ratepayer funds, they should be held accountable for their performance.

Q. What are the utilities' expectations regarding responding to EM&V finding and market changes?

A. The utilities confirm that it is indeed appropriate for them, and that they intend, to respond with changes based on new information throughout the plan period.

> Approved term goals will not change without the Commission's approval regardless of the results of evaluations and the avoided cost study. However, in order to maximize savings and benefits for customers, the New Hampshire Utilities are likely to implement changes to program delivery and measure mix as a result of changing market conditions, evaluation findings, and other market intelligence gained during the term.[8]

In fact, the utilities state this is a key benefit of the three-year goals approach and confirm their ability to adjust to EM&V changes. "Under the three-year term construct, the New Hampshire Utilities will gain the flexibility to adapt to evaluation impacts and pursue cost effective energy efficiency opportunities in order to achieve the term goals within the approved budget."[9]

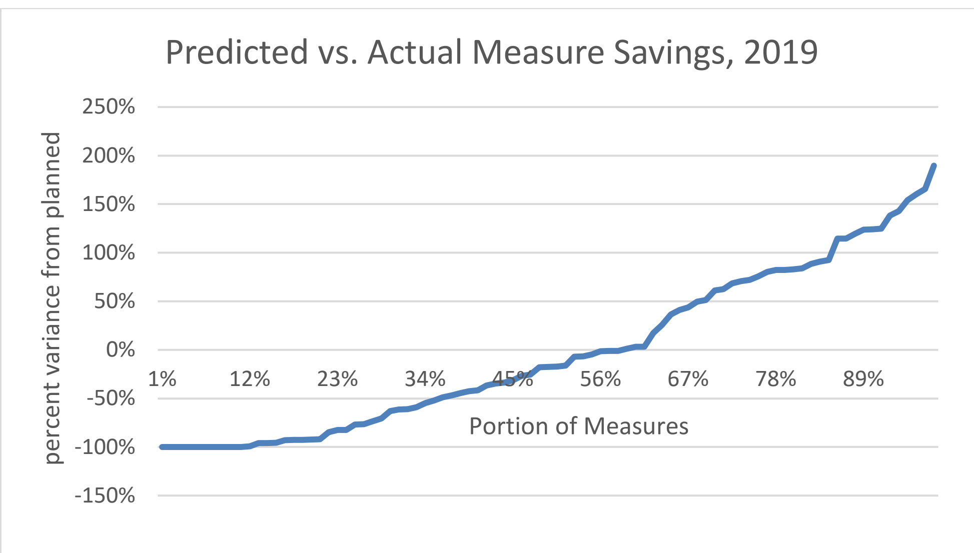
Q. You state that it is guaranteed that the actual measures adopted will differ from the assumptions in the BC Models. Please explain why?

[8] Triennial Plan at 29 (Bates page 35).

[9] Triennial Plan at 30 (Bates page 36).

A. As mentioned, the utilities enjoy a great deal of flexibility in exactly what they do, regardless of what any BC model assumes, which I support. Further, even if they did not, ultimately the mix of measures and customer participation is dependent on the individual decisions of numerous independent customers, contractors, and other market actors. This is evidenced by a comparison of the BC models for the last 2018-2020 utility plan, and the actual achievements in 2019.

In order to investigate this issue, I examined how Eversource New Hampshire's actual 2019 measure level savings compared to their projections in the 2019 plan BC model. The chart below shows the result of this analysis – the y-axis shows the variation of actual savings compared to planned savings, while the x-axis represents each measure, sorted from most negative variance to most positive variance, with the scale showing the percentage of the total number of measures.



If the measure level 2019 savings were close to the projections in the plan, you would see a relatively flat line along the x-axis (around 0 percent on the y-axis). Instead, you see a steep curve, with most measures having a greater than 50 percent variance from their projected savings. In fact, only 9 percent of measures fell within 10 percent of the planned estimates, and only 15 percent were within 25 percent. Note that to increase readability, this graph does not even include any measures with variance of over 200 percent from its planned savings. These omitted measures represent an additional 9 percent of measures which had variances so extreme it would render the graph essentially unreadable. The highest variance measure was a 24,013 percent increase.

Q. Is this a concern that actual program activity can bear little resemblance to the actual BC models?

A. No. This is simply the nature of delivering a diversified portfolio of programs and measures. The fact that the utilities are free to adjust to market conditions and customer preferences to manage toward their goals appropriately is a good thing. While the BC models are not deterministic, they generally represent a reasonable mix of pro forma measures for purposes of estimating overall cost-effectiveness and setting net benefits goals. The important point is that a change in the TRM does not necessarily have an extreme impact that cannot be accommodated and adjusted for. Fundamentally, if utilities are being held to performance standards (for which they can still be awarded shareholder earnings even with only a 65 percent achievement level), and are given approval to invest a certain amount to achieve those levels of performance, the ratepayers should have some assurance the benefits will actually accrue.

Q. You mention that you have a different position related to avoided cost changes. Can you explain why and what that position is?

A. Yes. While the savings captured from the utilities' diversified portfolios is largely within the utilities' control, changes to estimated avoided costs are not. They are primarily driven by regional, national and even international markets for energy, technology advancement, and the actions of numerous non-utility generators and gas commodity and pipeline operators. Therefore, I believe it is reasonable to adjust the net benefits goals for future avoided cost changes, as avoided costs are a key driver of the net benefits associated with any particular savings amount. However, I believe the utilities' approach could be unclear and is overly complicated, and could result in some indirect and inappropriate impacts or controversy.

Q. Please explain your proposal and why you believe it is an improvement over the utilities' proposal.

A. The utilities have proposed treating avoided cost changes the same as EM&V changes -- essentially to accept any modifications that result in less than a collective 10 percent impact on goals, but to adjust goals for changes greater than 10 percent. My proposal is simply to establish a policy that when any new estimates of avoided costs are adopted (expected to be in place for 2022), they replace the original estimates in the utilities' BC models, as they exist at the time of Plan approval and establishment of the net benefits goals. These new calculations would be used going forward from the date of adoption, with the prior period net benefits still estimated with the old avoided costs. This approach ensures that both the utilities and the ratepayers are held harmless from any exogenous changes to avoided costs, even if they are less than 10 percent, and simply holds all else constant.

Q. Besides potentially protecting the utilities and ratepayers for smaller difference less than 10 percent, why is your approach better?

A. First, the 10 percent protection limit is arbitrary. It is also virtually guaranteed to be far exceeded and is therefore moot, as I explained. And, as explained, the utilities are treating the 10 percent trigger as referring to a collective total impact. This means avoided cost changes could trigger a request for EM&V adjustments as well, even if the EM&V adjustments on their own were less than 10 percent. Perhaps more importantly, my proposal would require adjustment, whereas the current proposal is that, while a trigger may be activated, the utilities still may or may not request a modification. For example, if avoided costs where to go up, they could theoretically decline to request an adjustment, creating an unfair asymmetry. In addition, I believe the Plan could be construed in a way that created controversy over exactly what the goals should be and how to treat avoided cost modifications.

Q. Why does your proposal eliminate potential controversy?

A. By locking down the BC Models at the time the net benefits goals are established and approved, it holds all else constant, and isolates the impact to only changes to the avoided costs. It essentially calculates exactly what the net benefits goals would have been, had the new avoided costs already been known at the time of Plan approval. It is my understanding, based on discussion in the second docket technical session, that this is the utilities' intent with their proposal as well. However, that is unclear in the Plan and potentially could be a point of contention in the future. This can occur because changes to avoided costs will impact how cost-effective certain measures are, and thus they may cause utilities to modify their program approaches and measures promoted, as discussed previously. If that were the case, controversies over whether those additional program modifications by the utility to manage its portfolio might be attributable to avoided cost changes and should therefore be figured in to any BC model use for calculating the avoided cost goal adjustment, and even what all those potentially ambiguous changes might be. Similarly, if there were also EM&V findings that caused other changes in the BC models, those could also be at issue in terms of whether the net benefits adjustment for changing avoided costs should incorporate them also. Given the utilities have proposed a collective avoided cost and EM&V trigger, it is not clear how these two sets of impacts can be fully separated. I believe the Commission should make clear that the BC models, as filed and approved with the Plan, would remain constant but for any new avoided costs, and new net benefits goals will solely reflect the application of the appropriate avoided costs.

Q. What is your second goal concern related to gross savings?

A. The BC models include net-to-gross adjustments to estimate net savings for midstream/upstream measures, which are a small fraction of all the measures. However, all other savings estimates from the BC models represent gross savings. I believe all savings goals should represent net savings.

Q. Please explain what gross and net savings are.

A. Gross savings are estimates of the savings that occur from an efficiency measure, regardless of whether it is attributable to the utility efficiency programs or not. In other words, it represents the engineering estimate of a measure savings compared to an assumed counterfactual baseline, regardless of whether that baseline is in fact what the customer otherwise would have installed. Many customers will naturally adopt some efficiency measures even in the absence of the program, even if unintentionally. For example, when an older air conditioner fails and needs replacement, the customer will, on average, purchase a new AC with a standard level of efficiency today, which is much higher than existed 20 years ago. While some customers may purchase the least efficient

AC unit legally allowable based on federal standards (the efficiency that gross savings are generally calculated from), many customers would purchase a somewhat higher efficiency even if the program did not exist. As a result, programs may pay rebates to customers who in some cases would have installed the high efficiency option anyway, or a moderately efficient option more efficient than the minimum. These are referred to as free riders—customers who participate in the program and collect a rebate but who would have adopted some or all of the efficiency anyway. Countering that, some programs can create market transformation benefits that encourage customers to adopt efficiency, but who may never bother to apply for a rebate. In this case, the program may create higher savings that does not show up in its tracking system at all. This is called spillover. Ultimately, utilities should be rewarded for the savings attributable to their programs, and common practice is to adopt "net-to-gross" (NTG) ratios to adjust gross savings to ensure accurate estimation of net savings.

Q. Why is it important to use accurate net to gross ratios?

A. NTG adjustments are important for numerous reasons. Using accurate NTG ratios encourages the utilities to adopt program designs and promote measure, rebates, and market interventions that result in actual new savings, as opposed to simply using ratepayer money to subsidize efficiency that would have happened anyway. One key reason accurate net savings are particularly important in New Hampshire is that many of the utilities receive direct payments of net lost revenues resulting from their programs. These payments are based on the same savings assumptions and calculations that are used to measure utility performance.[10] As a result, if gross savings are used, then not only are ratepayers paying incentives for measures that would have been installed anyway, but they are also paying the utility for lost revenue that is not actually lost. Therefore any overestimation of savings will directly cost ratepayers money and provide a double windfall to the utilities (both excess lost revenue and excess savings and performance earnings). This is clearly problematic, and results in greater rate impacts for all ratepayers.

In addition to creating a risk of double paying for phantom savings, crediting utilities for net savings is important to ensure utilities have appropriate incentives. This is because NTG ratios are largely a function of program designs and utility delivery approaches. Quite simply, the easiest savings for utilities to “capture” are those that are happening already (*e.g.*, the free riders). As a result, utilities should have appropriate incentives to guard against high freeridership, and to encourage high spillover. If only gross savings are counted, utilities have a strong incentive to target free riders. Not only does this make it much easier for them to capture savings on paper, it can provide the utility with credit for savings and shareholder earnings and lost revenue payments, while not actually eroding their sales, which ironically is a primary rationale for providing shareholder incentives and lost revenue payments in the first place. Only by holding utilities to account for net savings are the proper motivations created to strive to produce real new savings and net benefits that would not otherwise occur.

Q. What is the current New Hampshire policy regarding gross and net savings?

[10] Lost revenue calculations have some timing differences compared with performance calculations by recognizing the month of installation, while the performance calculations annualize all savings. However, they both use the same measure and program level inputs and assumptions.

A. This is not entirely clear. Historically New Hampshire has counted gross savings. However, in this Plan utilities have adopted some NTG ratios, and the TRM does include them. However, all downstream measures and programs still seem to use gross savings.[11] In response to OCA 2-002 the utilities still appear to consider gross savings the current practice, despite using some NTG ratios, citing a "1999 New Hampshire EE Working Group report, which stated that 'program designs should attempt to minimize free-riders' but 'the methodological challenges and associated costs of accurately assessing free-riders no longer justifies the effort required [to estimate NTG ratios]." They go on to say

> This approach is also in line with the 2019 New Hampshire Benefit-Cost Working Group recommendation to the Commission to continue the current use of adjusted gross savings to estimate impacts in the near term, and consider whether methodologies that account for free-ridership, spillover, and market transformation impacts may be prudent in the long term. As such, the EM&V Working Group has solicited an evaluation of C&I programs that will include an assessment of C&I measure categories for which the NTG ratio should be applied or changed.

Q. Given the lack of New Hampshire NTG studies, is it reasonable to adopt the 2019 working group's recommendation and allow time for studying whether a shift to net is appropriate -- and, if so, for what categories?

A. No. This is bad policy and, as stated, above, will result in overpayments to the utilities for non-existent lost revenue and poor incentives. Further, there is no need for New Hampshire specific NTG studies and New Hampshire incurring significant "associated costs of accurately assessing free riders." The TRM adopts numerous values and assumptions from outside New Hampshire, and there is a long history of extensive evaluation of NTG ratios in other New England states, and particularly in Massachusetts and Connecticut where many of the New Hampshire utilities are actually delivering

[11] Downstream programs refer to programs that are primarily engaging customers directly and providing rebates to them where applicable. Midstream and Upstream programs attempt to intervene in markets at a higher level, such as with retailers, contractors, distributors or manufacturers.

essentially the same or similar programs. Later I further discuss EM&V issues about how to adopt NTG ratios, and make recommendations on an initial approach.

Q. How does the current New Hampshire NTG practice compare with peer jurisdictions and the industry generally?

A. It is an outlier in New England where all states with savings goals count net savings.[12] In addition, while not universal, most jurisdictions in the U.S. rely primarily on net savings as well, and particularly the leading efficiency states. A recent report from the American Council for an Energy Efficient Economy (ACEEE) on a survey of statewide evaluation practices and policies indicates that only 19 percent of states solely use gross savings, while 38 percent use solely net and 43 percent use some combination of both.[13]

Q. Can you further discuss the NTG ratios used for the plan?

A. Yes. The utilities only use net-to-gross ratios that are different than 1.0 (essentially defaulting to gross) for midstream and upstream programs. In response to OCA 2-002 the utilities provide justification for this by stating midstream and upstream offerings "are known to have greater levels of freeridership than other programs as an inherent part of their program design." This is not necessarily true. While it is true that midstream and upstream programs will tend to capture more of the market as participants than downstream, therefore generally capturing those who will already adopt the measure, in some cases midstream and upstream programs can be designed to minimize freeridership and/or pursue measures with low natural market share, while many

[12] Maine tracks gross savings. However, Efficiency Maine is simply tasked with pursuing all cost-effective efficiency and has neither explicit savings goals, nor any performance incentives.

[13] York, Dan et al., National Survey of State Policies and Practices for Energy Efficiency Program Evaluation. October 2020. Figure 29, page 27.

downstream programs may result in very high freeridership and therefore low NTG ratios. Pursuing measures upstream that have low natural market share, such as New Hampshire is doing with heat pump water heaters, will tend to result in relatively high NTG ratios for example. Conversely, poorly marketed and delivered downstream programs, or those with very low rebate levels, can result in low NTG ratios simply because they capture only a fraction of the market and those most likely to participate will be those already planning the efficiency measure.

Regardless of which types of programs might have high or low free riders, it is still important that New Hampshire use best estimates of the actual savings resulting from the program interventions, which by definition requires applying NTG ratios. Using gross savings for non-upstream measures overstates savings attributable to the program. For example, the overall C&I net to gross ratio used for Eversource in its 2021 Massachusetts plan is 0.88, compared to 0.97 for their New Hampshire 2021 Plan. Effectively, this means that actual C&I savings in the Plan may be overstated by 10 percent.

Q. How do NTG ratios in New Hampshire compare to those of other states in the region?

A: New Hampshire has adopted net to gross ratios for upstream programs from Connecticut but uses gross savings for all other programs. However, every other jurisdiction in the region uses net to gross ratios for downstream programs in addition to their upstream ones. For example, see Exhibit PHM-2 for the net-to-gross ratios that Massachusetts will use for other programs in 2021. Further, these differences can add up to a significant impact, especially in the commercial sector. For example, this table shows the overall commercial sector net-to-gross ratios in 2021 for New Hampshire, Massachusetts, and Rhode Island.[14]

	2021 C&I NTG
RI	0.74
MA	0.88
New Hampshire	0.97

As seen, NTG ratios in New Hampshire lead to significantly higher stated savings compared to those in other nearby jurisdictions.

Q. What do you recommend New Hampshire adopt for NTG Ratios?

A: Given that New Hampshire is a small state with spending constraints, and given that many of the Southern New England states, some with many of the same utilities and similar programs, already dedicate significant resources to evaluating net-to-gross ratios, I recommend that New Hampshire adopt values found from these other states rather than spending significant funds for its own state specific studies. Vermont generally also relies on other state studies for its NTG ratios. This is in fact what the New Hampshire utilities already do for upstream measures – my recommendation is to expand this current practice logically to include all relevant measures and programs. Rhode Island currently has some of the most recent studies, and they tend to be much lower than New Hampshire is using for upstream C&I lighting, reflecting the rapid transformation to LED

[14] Connecticut is not included in the table below because I did not have the figures for its entire C&I sector savings. Also, the table focuses on only 2021 because Massachusetts has not yet established NTG ratios beyond 2021. I also focus on C&I because the New Hampshire utilities have specifically asked to change goals based on any new NTG values adopted prior to 2021 in the TRM for C&I lighting, but has not raised the issue for other end uses. C&I is also the most relevant because it accounts for 85 percent of the total portfolio savings, and the 2021 residential sector savings are heavily dominated by upstream lighting which has a NTG value adopted.

technology. Massachusetts tends to do studies less often and then locks in assumptions for the duration of its Plan. Given that New Hampshire's lighting market may be a few years behind the southern New England states, the somewhat dated Massachusetts numbers may be appropriate. Also, Massachusetts does the most EM&V studies, borders New Hampshire, and includes most of the New Hampshire utilities, and is therefore likely to be the most relevant source of appropriate NTG values.

Q. Would using NTG ratios for downstream measures impact the utilities' ability to meet the Plan goals?

A: The New Hampshire utilities will still be able to achieve the Plan goals, even using net to gross ratios for downstream C&I lighting, and therefore, should not adjust its goals downward for any new NTG value adopted in the TRM prior to January 2021. For example, if Eversource New Hampshire adopted the Massachusetts NTG ratios for 2021 for downstream lighting measures, total claimable C&I lighting savings would decrease by about 5 percent, or 2,500 MWh. This could easily be made up by increasing the savings coming from C&I non-lighting measures by 7 percent. After this increase, non-lighting savings would still only reach 45 percent of the 2021 potential found in the mid-scenario of the recently completed New Hampshire Potential study. In fact, if this were done the non-lighting savings would still even be lower than the potential found from the low, business as usual scenario.[15]

If you also add net-to-gross ratios to custom measures (the other C&I end use utilities have asked to adjust goals for based on any near term changes to the TRM) based on the values used in Massachusetts, total net savings would be reduced by another 1,900

[15] Dunsky Consulting, New Hampshire Potential Study: Statewide Assessment of Energy Efficiency and Active Demand Opportunities, 2021-2023, Volume 1, Figure 4.

MWh. This means that C&I non-lighting savings from the portfolio would have to increase by a total of 4,400 MWh or 12 percent to compensate both for C&I lighting and custom NTG adjustments. This is still lower than the potential found for C&I non-lighting measures in the low scenario of the potential study, and under half of the potential found in the mid scenario. As stated, the utilities have ample opportunity to manage their diversified portfolios to accommodate adjustments.

Q. Would adopting net-to-gross ratios while maintaining the savings goals require increased program budgets?

A. No. While it is true that, all else being equal, declining net-to-gross ratios would cause an increase in the cost per kWh of efficiency, I believe that the proposed budget has enough room to achieve the proposed savings targets even with more accurate net-to-gross ratios. For example, Massachusetts is on track to achieve roughly double the savings depth in 2021 than New Hampshire at comparable costs, despite using net-to-gross ratios for all downstream programs in addition to upstream. The table below shows the cost per kWh by sector for Eversource in Connecticut, Massachusetts, and New Hampshire for the 2021 plan. As seen, Connecticut and Massachusetts both have comparable costs to achieve savings as New Hampshire, even though they use net savings while New Hampshire largely uses gross.

State	Res $/kWh	C&I $/kWh
New Hampshire	$1.08	$0.43
Massachussetts	$0.86	$0.47
Connecticut	$0.71	$0.43

Q. Because New Hampshire electric programs pursue significant fuel neutral savings from delivered fuels, isn't this comparing apples to oranges?

A. No. I have netted out the fuel neutral MMBtu portion of the programs, to ensure a fair comparison reflecting only the electric portion of New Hampshire costs and savings. Using the current estimate of the ISO New England gas generation plant efficiency, I have converted all savings to a common unit to compare costs and savings.[16] I then assume costs are allocated proportional to the Btu value of savings coming from each fuel.

(III.) Evaluation, Measurement and Verification (EM&V) Policies

Q. If we adopt your recommendation to disallow savings goal adjustments based on EM&V findings, does that eliminate any concerns you might have with the initial specific assumptions made in the BC Models?

A. Partially, but not completely. With no goal adjustments, theoretically, in the long run, unreasonable BC model assumptions would not matter because they would be modified with more appropriate EM&V findings and TRM updates as they become available. However, even under this scenario, unreasonable assumptions would still be used in the near term, until new evaluation results were developed and adopted. New Hampshire currently uses an approach of only applying EM&V findings prospectively. This potentially means inaccurate accounting of savings achievements would exist for some time, and potentially the entire Plan term. If the Commission does not require fully retroactive savings based on EM&V, then it is critical that the technical reference manual (TRM) and net-to-gross (NTG) ratios adopted are reasonable assumptions.

[16] We convert MMBtu savings from delivered fuel into kWhs using the heat rate from NE ISO's 2018 ISO New England Electric Generator Air Emissions Report. https://www.iso-ne.com/static-assets/documents/2020/05/2018_air_emissions_report.pdf.

Q. You mentioned that your concerns about the initial BC model assumptions would not matter if the utilities were subject to fully retroactive EM&V results. Do you support only adopting EM&V changes related to calculating savings prospectively?

A. Partially. It is helpful to consider two separate categories of EM&V results: those affecting gross savings, and the NTG ratios used to adjust gross savings to reflect those savings attributable to the utilities' efforts. I do support adopting NTG ratios prospectively only, as well as any changes to the TRM which drive the gross savings estimates for most measures. However, I believe other aspects of gross savings should be retroactively adjusted for.

Q. Please explain how the TRM works and applies to gross savings?

A. The TRM, which is part of the utilities' filing as Part 2, documents agreed-upon deemed savings methodologies, assumptions, and values for standard ("prescriptive") efficiency measures. These prescriptive measures are generally relatively common measures that are broadly promoted, and that reflect typical and predictable savings that can be reasonably estimated in advance. In some cases, it may simply define a per measure savings value (*e.g.*, X kWh). In others, it may reflect a more nuanced calculation that may include basic algorithms with variables for some user defined values such as equipment operating hours or efficiency levels. By agreeing to count specific deemed savings for each measure in advance, the TRM serves both to reduce risk to the utilities dramatically, and to simplify and reduce the need for EM&V resources. The use of TRMs with deemed savings, and only applying new changes to TRMs prospectively is a fairly common practice in the industry, which I support.

Q. What are the "other aspects to gross savings" that you support fully retroactive adjustment for, as opposed to the deeming of savings in the TRM?

A. There are two other areas that commonly impact ex-post evaluation estimates of savings and that I believe should be retroactively applied: verification of data accuracy and the application of the TRM, and custom measure savings. Typically, EM&V will include assessment of the program data for accuracy. For example, it may find that measure counts are incorrectly entered into the database, or perhaps inadvertently never installed by the customer. In addition, verification should ensure the proper application and use of the TRM, which in some cases can be somewhat complex. For example, one might use the TRM values for an incorrect measure, or apply incorrect user defined TRM variables. These errors can be significant. For example, erroneously adding an extra zero to a measure count could dramatically overestimate savings. While they are unintentional, it is bad practice not to hold utilities accountable for these types of errors. Given that the utilities and their contractors have sole control of the data and how they apply the TRM, some verification process and retroactive correction is important and appropriate.

Q. Please explain what custom measures are and why you believe EM&V of custom measures should be retroactive?

A. Custom measures are all measures that are not specifically included in the TRM with deemed savings values that are agreed upon in advance, although there may be some guidelines for how to address custom measures in the TRM. They are measures that are unique to a particular customer application, or have savings that can vary widely and require some sort of site-specific calculation of savings. Custom measures generally apply to commercial and industrial customers, and are often some of the largest projects and reflect a large share of the savings. In fact, Eversource custom measures are estimated to account for 33 percent of the C&I savings, and 27 percent of the entire portfolio savings, in 2021.

Because the savings from each custom measure or project must be a site-specific calculation, the utility and its implementation contractors have sole discretion to estimate any amount of savings they want. In practice, this means deciding what the counterfactual baseline the customer otherwise would have done is (assuming the customer was planning some investment already), and then using some set of formulas and assumptions to estimate what is saved.[17] Because the utilities have unilateral control over these myriad decisions and assumptions, and they and their contractors have an incentive to maximize the savings from these projects, there should be an ex-post check on the appropriateness of these calculations.

Q. Is there any attempt to account for data errors and incorrect custom savings assumptions now?

A. Not retroactively. However, the utilities have adopted some "realization rates," that are intended to anticipate errors in advance. Essentially, realization rates are a measure of the variance between what a utility estimates it saved and what is ultimately confirmed through an evaluation. The theory is that if a prior evaluation found only 80 percent of the savings originally claimed, then applying an 80 percent realization rate to

[17] In some cases, custom savings may rely on some spot metering or other on-site data collection as well as engineering calculations.

new savings will effectively correct for these problems on average, resulting in a more accurate estimate of future savings. However, this is bad practice in that it is essentially deciding up front not to trust the data the utility is estimating, and assumes its savings calculations are erroneous. A program implementer is then encouraged to, at best, continue the bad practice because it is getting penalized for it anyway, and at worst, is incentivized to compensate for the fact that any estimate it makes will be discounted by erring on the high side when making the numerous assumptions necessary to estimate custom savings. Often this may simply be a subconscious bias.

Q. Doesn't the practice of retroactive gross savings adjustments increase EM&V costs?

A. No. Given that the utility goals would be three-year goals, it would still only necessitate performing these verification and custom impact analyses once for the entire plan. Further, custom measure evaluations often rely primarily on an engineering review of a sample of project documents, and may not require extensive metering, site visits, or other more expensive approaches.

Q. What is common practice in the DSM industry?

A. In my experience retroactive adjustments to gross savings from savings verification and custom measure impact evaluations are fairly routine. The ACEEE recently published a report on state EM&V policies and practices.[18] In it, they support a policy of using evaluations prospectively for NTG ratios and for TRM based savings, as I am recommending. However, they note that "on the other hand, there are certainly some purposes for which evaluation results are properly applied retrospectively, such as

[18] York, et. al., National Survey of State Policies and Practices for Energy Efficiency Program Evaluation, ACEEE, October 2020. https://www.aceee.org/research-report/u2009

determining the actual number and characteristics of measures installed and the characteristics of the measures replaced. Those types of factors should indeed be based on actual data observed in the evaluation."[19] In personal communication with Martin Kushler, one of the report authors, he confirmed that this was referring both to verification of data accuracy and to custom measure savings.

Q. You mentioned that the utilities propose adjusting goals for any change in the custom realization rate assumed in the TRM this year. What is your recommendation for that?

A. As stated, I believe custom gross savings should be subject to fully retroactive evaluation results, and therefore advance use of a realization rate is unnecessary and bad practice. However, if the Commission does not direct the utilities to use retroactive gross EM&V savings results for custom measures, then adopting a realization rate based on recent EM&V experience may be the best one can do. As I understand it, the EM&V Working Group has not reached any consensus on what an appropriate custom realization rate is. Given the ample past custom evaluations in the region which reflect some of the same utilities and their custom program approach, I recommend adopting a reasonable value from one of the most recent and credible studies in New England, or perhaps some average of the most relevant ones. While I defer to the EM&V Working Group to determine the most appropriate value, as stated, I oppose the utilities modifying their Plan goals regardless of the value adopted.

Q. Why do you support a prospective-only application of NTG ratios?

[19] York, et. al., National Survey of State Policies and Practices for Energy Efficiency Program Evaluation, ACEEE, October 2020.footnore 32, p. 38

A. NTG ratio estimation is important, but also difficult to measure precisely. By definition, estimation of NTG ratios requires a determination of the counterfactual customer and trade ally behavior as if the efficiency programs did not exist. Because of this uncertainty and lack of estimation precision, use of retroactive NTG ratios can create a large risk to utilities, which may make it more difficult to track and manage their achievements toward goals reasonably, and which can cause them to be less willing to innovate. This is often particularly true for some of the most common measures that provide large overall savings, simply because the popularity of these measures also means a substantial portion of program participants might install them even without the program.

Ideally, I do believe NTG estimates should be applied retroactively, simply because that would result in the best estimates of what was actually saved (even if it might be somewhat uncertain). This would also ensure the most accurate lost revenue calculations. It is also important to hold utilities accountable for true net savings (as opposed to gross), because much of the impact on NTG values is a result of utility program designs and marketing approaches. Quite simply, the easiest way to “capture” savings on paper is to count savings from measures that participants were already planning to install anyway. In theory, one can design programs which primarily capture lots of freeridership, if not held accountable to adjust gross savings with NTG ratios.

That all said, because of the high risk perceived by the utility, and the inconsistency in NTG estimates among different evaluations, it has become fairly common practice in the industry to deem NTG values up front and only modify them prospectively. While this may remove some of the short-term incentive for utilities to strive to minimize freeridership and maximize NTG ratios, it still provides a reasonable long-term incentive. This is because if utilities were to target free riders in the short run, a future evaluation would likely find low NTG ratios that the utility would then need to adopt in its next plan, making it more difficult for it to achieve success. As noted above, ACEEE supports use of NTG ratios prospectively,[20] and noted that 43 percent of its survey respondents apply NTG ratios fully prospectively, while 27 percent use results fully retroactively, and 16 percent do some of each.[21] While in theory retroactive adjustment would most accurately support lost revenue calculations, given the uncertainty in studying NTG from one year to the next, it is hard to say whether updating NTG values more frequently will lead to substantially better lost revenue estimates. For certain key measures that are transforming rapidly such as C&I lighting, it would be appropriate, however, to adopt new values annually based on the best available studies and market share data in the region.

(IV.) Savings Goals for Delivered Fuel MMBtu Savings

Q. Please summarize your last savings goal concern related to the delivered fuel savings.

A. The Plan calls for capturing significant savings from houses using oil and propane for space and water heating. Eversource’s plan, for example, calls for 260,000 MMBtu of delivered fuel savings as part of its electric programs. This reflects savings in fossil-fuel heated buildings from measures generally offered in the programs. When customers use

[20] York, et. al., National Survey of State Policies and Practices for Energy Efficiency Program Evaluation, ACEEE, October 2020, p. 38
[21] York, et. al., National Survey of State Policies and Practices for Energy Efficiency Program Evaluation, ACEEE, October 2020, Figure 31, p. 28

natural gas for heating, the gas utilities contribute a share of the cost of rebates, since many measures save both heating and cooling end uses. Because gas utility funding is not available to serve the delivered fuel customers, the electric utility fully funds measures such as insulation and air sealing, which save some electricity but primarily generate fuel savings.

I support this practice. The Plan anticipates substantial costs going to these measures, and large savings and benefits from these fossil fuel end uses. However, a comparison of costs for the electric programs shows the cost per kWh saved to be very high. Overall, Eversource's portfolio costs for the residential sector are $2.30 per annual kWh saved for the Plan term, when not adjusting for any of the MMBtu savings. However, when adjusting by removing the MMBtu portion using the same method described above to convert between MMBtu and kWh, it comes down to $1.34 per kWh. This is the result of substantial funds supporting residential measures that save very little electricity and primarily are fossil-fuel-saving measures. When accounting for the fossil fuel savings, the residential costs per unit saved are more in line with other New England efficiency portfolios, as shown above.

While I am supportive of investing in cost-effective savings of fossil fuels, I recommend that the utilities have a goal for these savings, and a performance incentive metric based on that goal. For Eversource these estimated MMBtu savings reflect over $150 million in benefits, fully 21 percent of the entire electric program benefits and over 60 percent of the residential sector benefits. Without any goals, the utilities have no actual obligation to capture these significant MMBtu savings.

Establishing goals and shareholder incentives for the MMBtu savings is important because without them, the utilities can simply divert some or most of the funds budgeted for those MMBtu savings to less expensive electric savings measures. While those electric savings may also be welcome, it essentially would allow the utility exorbitant budgets to spend and enable them to exceed their electric savings goals easily and thereby capture the maximum shareholder incentives associated with the electric savings. Note that not only are the Plan budgeted costs/kWh much higher because of large costs going to capture MMBtu savings, the measures that offer the fossil savings, such as building shell measures, tend to be most expensive measures in general. Given the large expenditures targeted to the MMBtu savings that drive up the planned cost/kWh dramatically, the Commission should ensure those additional costs (and subsequent rate impacts) are truly necessary and get allocated for their intended purpose.

Q. Given the utilities have a performance incentive goal associated with net benefits, doesn't that address your concern?

A. Partially, but not sufficiently. Clearly the MMBtu savings will contribute to the overall net benefits. The utilities have suggested this in OCA 2-022 as a reason they have not proposed any MMBtu goal. However, this is insufficient for a few reasons. First, shifting funds allocated for MMBtu savings to electric savings will likely provide as much or more net benefits than if they were spent on fossil-fuel savings. This is because building shell and other heating system improvements tend to be more costly than a lot of the electric saving measures such as lighting, which the utilities already rely heavily on. In other words, they tend to have lower overall net benefits than the less expensive electric-only savings. Second, the utilities have fully 65 percent of the weighting of the entire performance incentive pool allocated to electric annual and lifetime energy and demand savings, in addition to the net benefits metric. If such a heavy weighting on electric savings (which contribute analogously to net benefits as fossil savings do) is deemed appropriate, then surely some weighting related to actually achieving the intended MMBtu savings is also appropriate.

Q. What do you recommend for a performance incentive metric for MMBtu savings?

A. I recommend a goal for lifetime MMBtus analogous to the lifetime electric energy savings goal. This would be structured the same as all the other performance incentive metrics, with a target goal, and then earnings scaling up or down within a bandwidth from 65 percent to 125 percent of goal achievement. I believe a relatively small weighting of total incentive funds is sufficient to ensure the utilities are appropriately incentivized to capture these savings. I recommend a 10 percent weight for this metric. Given MMBtu savings goal reflects 21 percent of the total program benefits, this is still a relatively small weight. Given that 65 percent of the weight is tied to electric savings not including net benefits, I believe there is ample room to shift 10 percent to MMBtu savings from the annual or lifetime electric savings metrics.

(V.) Midterm Modification and Stakeholder Processes and Triggers

Q. You previously discussed some concerns with some of the midterm modification (MTM) triggers related to goal adjustments. Do you have further concerns related to the midterm modification process?

A. Yes. I have some concerns related to the midterm modification process and triggers. They relate to the overall process and level of stakeholder engagement, as well as some of the specific triggers proposed.

Q. What are your broader issues with the midterm modification process and stakeholder engagement?

A. As mentioned above, I support the concept of a true three-year Plan, with goals and budgets treated as cumulative three-year targets. I also support an annual update filing documenting significant changes from the original Plan, which should be the intent and the vehicle for a Commission "notification" trigger as described in Section 2.1.6 of the Plan. This Section also states an intent to continue "the current practice of alerting the Commission and stakeholders regarding relatively modest changes in program budgets, program design or delivery, or measure offerings."[22] However, the Plan then lists "circumstances requiring notification to the Commission."[23] These few circumstances are limited to changes to program budgets, transitioning a pilot to a full-scale program, and the annual filing of the TRM. This seems much more limited than "modest changes in program design or delivery, or measure offerings."[24] The utilities confirmed in the second technical session on October 23, 2020 that the "alerting" does indeed only refer to the very minimal triggers "requiring notification." This leaves the stakeholders in the dark regarding most Plan changes.

[22] Triennial Plan at 37 (Bates page 43).

[23] *Id.*

[24] *Id.*

I encourage the Commission to formalize the stakeholder process to ensure regular communication between stakeholders and the utilities on a full range of program changes and progress, as well as to work out appropriate implementation and interpretation of the innumerable policy and EM&V related issues that may come up. I note that the EESE Board recently voted unanimously to adopt recommendations to the Commission including that "the EERS Committee should remain active and engaged in program review, energy efficiency working groups, and any mid-term modifications," provided as Exhibit PHM-3.[25] The current approach is for the Commission Staff to convene quarterly meetings, which are primarily a forum for the utilities to present on program achievements. While these meetings do offer a forum to raise and discuss other issues, there is generally not sufficient time to ensure full engagement of stakeholders in understanding the utility practices and developing suggestions, making and responding to proposals, or working out ad hoc issues that may arise. In my experience, the most successful stakeholder collaborative processes meet monthly, and often have standing and ad hoc committees that meet and engage on specific topics more frequently. This is the case in all three southern New England states. I suggest the Commission adopt the EESE Board recommendations and ensure that a more robust and frequent engagement is possible.

Q. Can you expand on how this more engaged stakeholder process might work?

[25] "Energy Efficiency and Sustainable Energy Board Comments on stakeholder engagement and 2024-2026 planning process" submitted to the Public Utilities Commission in Docket 20-092 on October 27, 2020.

A. Yes. Typically, effective stakeholder processes work to reach consensus on issues, and therefore can avoid the need to bring things to the Commission for resolution. This often can lead to better outcomes, quicker decisions, broader stakeholder support, and avoid potentially contentious litigation before the Commission. It also provides for more opportunity for input from those stakeholders lacking the resources to intervene in the event the utilities notify the Commission of a change that they strongly oppose.

I recommend that, prior to any formal notification or request for approval filings to the Commission, the utilities engage with stakeholders with the intent of reaching consensus, and with sufficient time to do so. This would allow the parties an opportunity to provide input prior to the utilities' instituting changes and ideally to work out any differences and reach consensus, resulting in improved decisions, broader support, and fewer litigated issues. It appears that the utilities intend to make Plan changes unilaterally and simply let the Commission and stakeholders know after the fact (and in many cases not at all), at which point it may be difficult to consider possible alternatives. If this advance stakeholder engagement happens, there may be no need to notify the Commission unless issues rise to the level of the midterm modification notification or approval triggers.

For items that do rise to the level of midterm modification triggers, this engagement process should occur with sufficient time to consider alternatives, and to attempt to reach consensus. Regardless of whether an issue rises to the level of a trigger, if no consensus can be reached, the utilities would still have discretion to move forward with changes not requiring Commission approval, or any filings for Commission approval. However, the timing would enable stakeholders to bring the issue to the

Commission and file a "non-consensus" document stating its position, to allow for any Commission consideration, if the party so desired. In practice this would be rare, but the process of engagement and striving for consensus will generally lead to better outcomes.

Q. Would this process prevent the utilities from acting in a timely manner?

A. No. This would generally be for more substantial Plan changes or shifts in emphasis, or policy and EM&V practices that might establish important precedent and that utilities are likely to be considering with sufficient time for discussion. Ultimately, utilities would still be free to execute decisions as necessary to effectively manage their programs. In my experience, these collaborative processes function well and utilities tend to develop an understanding of what issues might be contentious and when it is important to gain the support of stakeholders. The intent is to reach better ultimate outcomes, ensure the utilities have considered reasonable alternatives or modifications to their plans, and get broad support while avoiding more formal regulatory processes.

Q. In addition to ensuring the midterm modification process allows for sufficient, timely and on-going stakeholder participation, do you have any concerns with the specific midterm modification triggers the utilities have proposed?

A. Yes. First, as discussed previously, I do not believe the utilities should modify goals as an expected practice based on EM&V changes regardless of whether they collectively exceed a 10 percent level. In addition, I believe some of the triggers proposed that are related to spending and sector and program level shifts should be modified.

Q. Can you expound on the triggers related to goal changes?

A. Yes. The utilities have proposed triggers that would require Commission approval for reductions in benefits or savings goals exceeding 10 percent. In response to OCA 2-

007(a) the utilities seem to confirm that they are not simply reserving the right to petition the Commission for a change in goals, but that it would be an automatic and expected filing:

> The Mid-Term Modification process is designed to set out the conditions under which a filing by the Utility or Utilities and review by the Commission is **required** during the 36-month term covered by the 2021-2023 Plan. An MTM trigger therefore is the threshold for a filing to initiate review of the impacts of that trigger. The reasonableness of any change to the original plan will be for the Commission to determine. [Emphasis added]

The utilities did acknowledge during the second technical session on October 22, 2020 that they could choose to decline to request a modification but that the trigger would still require a filing. As mentioned, I do not support modifying goals based on new EM&V results. However, I am advised by counsel that the utilities always retain the right to petition the Commission for goal reductions or other relief, for any reason. As a result, I believe the 10 percent goal triggers are both unnecessary, and likely to establish an inappropriate presumption of reasonableness and expectation of approval whenever the 10 percent target is reached. An expectation of automatic, or routine, adjustments is inappropriate. Rather, I believe there should be a high burden of proof for approval of goal reductions, and the utilities would need to make an argument that factors largely out of their control necessitate such an action, such as unforeseen and unmanageable COVID-19 impacts not previously anticipated. In fact, the utilities already seem to be preserving and acknowledging this right in Section 2.1.7 where they state that "in exigent circumstances, a New Hampshire Utility may petition the Commission for an exception to the specific mid-term modification triggers and procedures set forth above. The New Hampshire Utility shall have the burden to demonstrate the compelling nature of such request." In the second Docket technical session on October 22, 2020, the utilities confirmed that this higher burden of proof would not apply to requests to modify goals if a trigger had been met.

Q. Do the utilities enjoy any other flexibility or relief related to benefits and savings goals if they cannot meet them?

A. Yes. This is exactly the reason for the use of a performance incentive mechanism enabling utilities to earn shareholder incentives within a large band of achievement, including falling significantly short of goals. The utilities have proposed reducing many of the performance incentive metrics from the Performance Incentive Working Group's 75 percent recommendation to 65 percent, explicitly to allow more flexibility and risk mitigation. In many aspects of life 65 percent achievement is barely above a failing grade, and 75 percent simply mediocre. I believe that this lower threshold, along with the large amount of flexibility the utilities enjoy which enables them to modify their programs and delivery, is more than a sufficient buffer. Quite simply, if the utilities spend all of the budgeted ratepayer funds, the ratepayers deserve some assurance that reasonable levels of performance and benefits are achieved for their investment. Adding even more risk of substandard performance onto the ratepayers is inappropriate.

Q. Explain your position regarding the proposed Plan triggers.

A. My concerns relate to budgets. First, I have no disagreement with the triggers requiring notification, so long as the utilities first engage with stakeholders to consider any alternatives or modifications that may be appropriate, and that they also participate in an effective stakeholder process that ensures they disclose more modest intended Plan changes in a timely fashion.

I offer the following comments on the proposed Plan triggers requiring Commission approval (excluding the 10 percent reduction in goal trigger already discussed).

- **Inclusion of a new program.** I do not oppose this trigger. However, I believe addition of a new program should not require formal approval, so long as it does not otherwise also cause a spending trigger to be enacted. I support utility flexibility to explore new opportunities they identify if they believe they will be effective and cost-effective, so long as stakeholders have had the opportunity to discuss the issues.
- **The suspension or closure of an approved energy savings program.** I support this trigger.
- **An increase in a sector's approved term budget exceeding 110 percent of the original budget dollar amount.** This trigger should be modified to ensure that any sector level increase in budget does not create a very large adverse impact to the residential funds available. As written, this trigger could refer to two possible scenarios, or any combination of the two. First, one could simply increase the total portfolio budget to accommodate the sector level increase (recognizing all the funding for the increase would have to come only from that sector). Alternatively, this could refer to still maintaining the overall portfolio budget, and simply shifting among sectors. The latter is more typical in my experience, and the situation where I have a concern. Regarding the first instance, I do support the current utility flexibility to overspend budgets in total by up to 10 percent. I also am not opposed to a trigger for increasing total portfolio spending by more than 110 percent, which could be applied to any mix of sectors. However, the latter instance where funds must come from a different sector (while maintaining the same overall portfolio budget) is problematic because of the extreme imbalance between C&I and residential spending and savings. C&I sector spending is much larger than residential. Because income eligible spending cannot be reduced, all funds

would have to come from the non-income-eligible residential sector in the event C&I spending was increased without increasing the entire portfolio budget. A C&I spending increase of 10 percent for Eversource, for example, would require a reduction in residential spending of 32 percent.[26] I believe this is problematic given the importance of a reasonable equity balance and the already heavily weighted C&I sector. I therefore propose a trigger for any shift in sector level budgets *up or down* by more than 10 percent. This will protect the residential from very large reductions in funding without approval.

- **A projected decrease to the planned and approved benefits or primary annual energy savings (kWh or kW for Electric Utilities; MMBtu for Natural Gas Utilities) in a particular sector of greater than 25 percent over the term.** I interpret this to mean a shifting of net benefit or savings goals *between* sectors, given that any request to modify overall portfolio goals or performance incentives would certainly require Commission approval, and should only be contemplated under an extreme situation and require a high burden of proof that it is necessary and reasonable, as discussed. I do not support this trigger. As with the 10 percent sector budget increase, my concern is that the Plan is heavily weighted toward C&I savings already. For example, the electric C&I/Municipal sector NHSaves Statewide program accounts for 85 percent of the three-year cumulative annual electric savings goal. Further low income represents an additional 2 percent, leaving only 13 percent of savings coming from residential. Therefore, a 25 percent reduction in the residential goal would leave this sector with just under 10 percent of the entire portfolio savings.[27] I believe it is important to ensure a reasonable amount of residential investment and savings for equity reasons. I suggest reducing this trigger to greater than a 10 percent reduction. Note this

[26] Eversource Electric BC Model. Calculation based on $160 million C&I and $50 million Residential.

[27] Triennial Plan, Table 1-4.

would apply to an intentional plan shift, as opposed to a situation where a utility simply failed to achieve the full sector savings or benefits planned for because of lower than expected customer uptake.

Q. Do you recommend any additional triggers?

A. Yes. I recommend the utilities should notify stakeholders and attempt to achieve consensus for any planned shift in program budgets of more than 20 percent up or down, and if no consensus is reached, obtain Commission approval. My concern is that some programs provide important, comprehensive and long-lived savings that are relatively costly, while other programs are much lower cost per unit of savings but lack any comprehensiveness or durability. Similarly, some programs target hard to reach segments, while others pursue easier and less costly savings. Pursuit of comprehensive, long lived savings and effectively serving hard to reach customers should be a policy priority. This rule would ensure against extreme and undesirable shifts such as dramatically reducing funding for major home retrofit measures and allocating them to home energy reports that provide very short-term behavioral savings. If such a shift were implemented, it would also allow utilities to meet goals much more easily because the Plan budgets were designed to support the much more costly, but important, home retrofit savings. The utilities already have a significant incentive to plan for large expenditures in comprehensive programs and then shift effort to less expensive programs such as residential lighting and behavior. Therefore, significant shifts should require approval.

I do note that under Section 2.1.8--Program Continuity, the Plan proposes that "transferring available program funds from underperforming programs into programs with higher demand within the same sector" be allowed with no notification. I am not completely opposed to this. To be clear, the above trigger would apply only to intentional, advance planning decisions to formally shift budget allocations. This would be distinct from situations where one program simply ended up spending less because of lack of participation while another program ended up more popular and exceeded its budget somewhat because of greater participation. By preserving intended budgets, the utility should have the incentive to try to remedy any lack of participation through greater marketing, program design changes, or other efforts, while not being penalized for ultimate shortfalls beyond any indirect impact on performance metric earnings that might occur.

(VI.) Heating System Conversions and the Energy Optimization Pilot

Q. What programmatic concerns do you have related to heat pumps and the Energy Optimization pilot?

A. The Plan calls for delivery of an Energy Optimization (EO) pilot program. EO refers to electrifying heating loads that are currently using oil or propane, where cost-effective and beneficial to the customer. There is a broad consensus in the energy industry that moving building fossil-fuel loads to heat pumps using electricity will be needed to meet climate goals. Thus, the utilities have proposed a minimal effort in this area by offering the pilot program to residential customers, with a goal of completing 100 installations each year.[28] The utilities are proposing this as a pilot for three years rather than as offerings in their main programs apparently because they view it as an untested

[28] Triennial Plan at 170 (Bates page 176).

experiment that requires three years of learning before heat pump conversions can become more standard measures. The Plan states that,

> The pilot will provide the NH Utilities with a more comprehensive understanding and experience of the benefits of heat pumps to the electric system, as well as the impact on emissions from GHGs and nitrogen and sulfur oxides. The NH Utilities will also investigate customer experience and optimal program delivery standards related to this offering.[29]

Q. What are your thoughts regarding the pilot?

A. I am supportive of Energy Optimization to facilitate beneficial electrification. Further, I recognize that cold climate heat pumps are a relatively new technology, and that efforts to help transform the heat pump market through greater adoption is important to bring costs down and further technology advancement. However, I find it odd that the utilities believe they need to conduct a three-year long pilot experiment to determine how to do this. This is because Eversource and Unitil have been doing this very thing in Massachusetts beginning in 2018, and have completed approximately 2,000 heat pump conversion projects already, with another 2,000 planned for 2021.[30]

The Massachusetts experience should be sufficient to enable the utilities to offer these measures in their regular programs and build the savings into Plan goals and more aggressively promote them. Further, the EERS Committee encouraged the utilities to aggressively target conversions of electric resistance heating to cold climate heat pumps in this Plan. While the utilities have in fact included this as an eligible measure, they are planning a relatively small effort of only a little more than 100 conversions per year. This

[29] Triennial Plan at 169 (Bates page 175).
[30] OCA 2-030.

compares to roughly 50,000 New Hampshire households with electric resistance heating, according to the U.S. Census.[31]

Q. Why are electric resistance heating conversions to heat pumps important, and how are they related to the EO Pilot?

A. First, it is one of the most important residential electric efficiency measures available to the utilities. This is because heating is the biggest energy load for New Hampshire residents and heat pumps are far more efficient, offering very large customer bill savings. Electric resistance heating is generally the most expensive heating option, with significantly higher operating costs than oil, propane, or natural gas. Compounding this is that electric resistance heating tends to exist in disproportionately high numbers in low income households (both single and multifamily). Therefore, these approximately 50,000 households offer large, cost-effective savings, while also providing significant benefits in terms of reducing low income energy burdens.

Secondly, installing cold climate heat pumps to replace electric resistance heating is fundamentally the same measure as for fossil fuel replacements. All the issues around shifting systems, addressing comfort and customer satisfaction issues, and ensuring that an adequate back up heating system remains in the home and is properly controlled to optimize usage depending on outdoor conditions, are essentially the same. Therefore the electric utilities have a unique opportunity to focus first on their primary role of capturing

[31] The American Community Survey, Table S2504 indicates that 53,861 households have electric space heating. While that figure can include heat pumps, I expect that the vast majority of them are electric resistance. https://data.census.gov/cedsci/table?q=S25&g=0400000US33&d=ACS%201-Year%20Estimates%20Subject%20Tables&tid=ACSST1Y2019.S2504.

cost-effective electric efficiency savings, while building any expertise they need for a larger scale effort in the future (in addition to all their work in Massachusetts).

Q. Do you have other concerns related to the EO pilot?

A. Yes. The utilities plan to offer rebates to municipalities for installation of high efficiency oil and propane boilers and furnaces. While this is not a major portion of their municipal program, encouraging replacement of these heating systems that are close to the end of their life with yet another oil or propane unit will lock the municipality into continued fossil fuel use for 20 years or more. Given the recognized need to begin shifting away from oil and propane, and the fact that these customers already need to make a major investment in a heating system replacement, means they offer a perfect, time-sensitive opportunity to encourage them aggressively to convert to heat pumps. Because they are already expecting to invest in a new heating system, the economics of shifting to heat pumps is much improved because they only need to cover the incremental additional cost of the heat pumps as compared to a new furnace or boiler.

In OCA 2-027 the utilities have provided their 2018 Municipal Heating Equipment Incentive. While it does offer a heat pump water heating option, out of eleven different heating system rebates listed, there is not even a single mention of heat pumps for space heating—neither ducted, ductless, boilers, or variable refrigerant flow systems, all of which can be applicable to commercial buildings. While the utilities may offer heat pump rebates on a separate form, they do not appear to have any rebates intended to promote system conversions which require more aggressive rebates, as opposed to just an incremental improvement in efficiency when a customer is already buying a heat pump. These municipal customers offer another unique opportunity to gain experience in heating system conversions to heat pumps, especially since commercial buildings offer some unique challenges different than residential buildings, and can take advantage of a much broader set of heat pump technologies.

The utilities do note that if a municipality is already going to buy an oil or propane unit, it is still worthwhile to ensure it is efficient. I agree. However, this apparent lack of any aggressive effort to encourage them first to install heat pumps is problematic. Further, the utilities state that the municipal customers are not even eligible to participate in the utilities EO pilot, which they are limiting to only residential customers.[32] If there is any need at all for a pilot, it should be in commercial buildings where the utilities and industry as a whole have less experience with heat pump conversions. Although I note that the Massachusetts utilities are already doing commercial projects as well as residential.

Q. Do you have any recommendations?

A. Yes. The Commission should order the utilities to develop a residential program initiative to target electric resistance customers aggressively, with low income households as a priority, and to offer appropriate rebates and other program services to facilitate significant adoption of heat pumps. The Commission should also direct the utilities to offer and aggressively promote, rebates and services for municipalities with oil and propane equipment at or near the end of life, or who are otherwise planning a new equipment purchase, to convert to heat pump systems. Finally, I encourage the utilities to

[32] OCA 2-28

consider opening their EO pilot up to commercial buildings, and/or shifting it to standard residential and C&I program offerings rather than a limited pilot.

(VII.) Conclusion

Q. Please summarize your testimony and recommendations to the Commission.

A. I recommend the Commission approve the Triennial Plan, with the following recommended modifications.

1. Savings and net benefits goals should not be adjusted based on EM&V findings or TRM updates.
2. Net benefit goals should be automatically adjusted for changes in avoided costs, holding all other variables constant as they exist in the BC models at the time of Plan approval.
3. All goals should reflect net savings, with appropriate adoption of net-to-gross ratios, and any lost revenue calculations should only use net savings. NTG ratios should be adopted from studies in other regional jurisdictions as appropriate and determined by the EM&V Working Group.
4. Gross savings estimates should be subject to retroactive adjustment based on impact evaluations and verifications, with the exception that values and procedures in the TRM should be deemed and any changes should only be applied prospectively. The TRM should undergo review and update annually.

5. Net-to-gross ratios should be deemed and any modifications should only be applied prospectively. The NTG ratios should be reviewed annually, and updated if appropriate.
6. A more robust stakeholder process should be mandated, with utilities engaging on a regular basis with the EERS Committee at least monthly.
7. Changes to programs, policies or other plans or practices should be discussed with the Stakeholder group. This should occur prior to implementation of changes whenever practicable, including, but not limited to, all actions that will create a midterm modification trigger.
8. Midterm modification triggers should be modified as discussed, including, but not limited to, removal of triggers related to modifying goals based on EM&V findings.
9. The utilities should more aggressively pursue electric resistance heating system conversions to heat pumps, should aggressively promote heat pump options for any municipal customers contemplating replacements of delivered-fuel-fired heating systems, and should consider expanding the EO pilot to include commercial services and/or be incorporated into the full-scale programs as standard offerings.

Q. Does this conclude your testimony?

A. Yes.

PHILIP H. MOSENTHAL, PARTNER

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PROFESSIONAL EXPERIENCE

Optimal Energy, Hinesburg, Vermont. *Founding Partner*, 1996-present

As the Founding Partner Mr. Mosenthal is responsible for business development as well as direct consulting and analysis for numerous electric and gas utilities, government entities and other non-utility parties on energy efficiency, resource planning, regulatory issues, program design, and evaluation and market assessments. Mr. Mosenthal has over 30 years' experience in energy efficiency consulting, including facility energy management, utility and state planning, regulatory policy, program design, implementation, evaluation, and research. He has particular expertise in efficiency regulatory policy, assessment and integrated analysis of demand-side energy resources, valuation of energy resources and cost-benefit analysis, and program planning, design and evaluation. Mr. Mosenthal has developed numerous utility, state, and regional integrated resource and DSM plans, and has designed and evaluated energy efficiency programs throughout North America, Europe, and China. He has also led numerous efficiency and renewables potential studies and is a nationally recognized expert on efficiency resource assessment and valuation. Mr. Mosenthal has played key roles in many utility-stakeholder processes and successfully worked to build consensus among diverse parties in various assignments. This work has included leading policy and planning initiatives related to goal setting, EM&V frameworks, cost recovery, and performance incentives. Mr. Mosenthal has testified before numerous regulatory commissions, state legislatures, and the U.S. Nuclear Regulatory Commission. Mr. Mosenthal also has designed program implementation procedures, managed implementation contracts, trained efficiency program and planning staff, and performed numerous commercial and industrial facility energy efficiency analyses for end users.

Resource Insight, Middlebury, Vermont. *Senior Research Associate*, 1995-1996

Xenergy, Incorporated (now DNV-GL), Allendale, New Jersey. *Chief Consultant*, 1990-1995

EDUCATION

University of Pennsylvania, Philadelphia, Pennsylvania
Master of Science, Energy Management and Policy, 1990

University of Pennsylvania, Philadelphia, Pennsylvania
Bachelor of Arts, Design of the Environment, 1982

REPRESENTATIVE PROJECT EXPERIENCE

New Hampshire Office of Consumer Advocate, Technical Consulting Services Related to Policy, Program Planning, and Stakeholder Engagement (2015 - present)
Since 2015 Optimal Energy has engaged with the NH OCA to support all of its engagement as part of the Energy Efficiency $ Sustainable Energy Board, which was created by the NH legislature "to promote and coordinate energy efficiency, demand response, and sustainable energy programs in the state." Mr.

Mosenthal serves as the project manager. Through this engagement, Optimal has played a leadership role in the development of all gas and electric DSM efforts in New Hampshire, and has participated in numerous working groups including ones related to cost recovery and lost revenue policy and estimation, performance incentive design, DSM plan development and program design, and EM&V. Key areas of focus have included: designing NH's first Energy Efficiency Resource Standard (EERS) and negotiated its initial targets; analyzing and critiquing the methods for calculating lost revenue and its subsequent reform; negotiating policy issues around cost recovery practices related to lost revenue and amortization of program costs; design and implementation of performance incentive mechanisms; critical review, negotiations, and testimony on the utility gas and electric plans; development and updates of the TRM and other EM&V issues; critical review and negotiations on efficiency potential and baseline studies; and analyzed and made recommendations on electric grid modernization (the latter through Optimal's subcontractor).

Illinois Office of the Attorney General, Advisor on Energy Efficiency Policy, Planning, Design, Implementation and Evaluation (2007 – present)
Mr. Mosenthal has served as the project manager and lead advisor to the Illinois Office of the Attorney General on all aspects relating to development and on-going participation in a statewide utility collaborative process, establishment of statewide energy efficiency policies and frameworks, development of statewide legislation, program planning, design, implementation, evaluation, and general oversight of utility electric and gas efficiency programs throughout Illinois. In this role, Mr. Mosenthal played a leadership role in the development of a statewide collaborative stakeholder process with the utilities and other parties, on behalf of the IL AG, and continues to be a lead technical consultant in this collaborative. Mr. Mosenthal has also assisted with development of legislative and regulatory laws and policies (including the most recent statute establishing a cost recovery and shareholder performance incentive model), provided expert testimony in numerous dockets before the Illinois Commerce Commission, assisted in development of grid modernization rules and policies, and worked on electric procurement issues related to the Illinois Power Agencies resource procurement process and mechanisms.

Massachusetts Energy Efficiency Advisory Council, Technical Consulting Services (2006 – present)
Optimal Energy has led the Technical Consultant team for the Massachusetts Energy Efficiency Advisory Council (EEAC) since its inception in 2006. Mr. Mosenthal has served in various roles on this team, including overall Team Manager, Team lead for the commercial and industrial sector, and senior advisor on efficiency policy, planning, programs, and EM&V. Optimal's role includes representing the EEAC on all aspects of negotiating efficiency policies, programs, plans, goals and budgets with the program administrators, and oversight of all program implementation and evaluation, monitoring and verification activities. Prior to the EEAC's inception, Mr. Mosenthal served in a similar role as a manager and lead for the C&I sector on numerous Massachusetts' Utility Collaboratives working directly with the utilities on behalf of the non-utility parties, from 1998-2006.

New Jersey Board of Public Utilities, Potential Study and Consulting Services (2019-present)
New Jersey's 2018 Clean Energy Act mandates delivery of aggressive efficiency efforts, the development of all policies and administrative and EM&V frameworks to guide efficiency, and the completion of an energy efficiency potential study to inform the Board as it establishes savings goals and other metrics. Mr. Mosenthal is an integral part of the team, working on the assessment of potential, and leading work on the establishment of targets and performance incentives / penalties, EM&V framework, and cost-effectiveness policies.

Rhode Island Energy Resource Management Council, Technical Consulting for the Energy Resource Management Council (2006 – present)

Optimal Energy has led the Technical Consultant team for the Rhode Island Energy Resource Management Council (ERMC) since its inception in 2006. Mr. Mosenthal has served in various roles on this team, including as the team lead for the commercial and industrial sector, and senior advisor on policy, planning, programs, and EM&V. Optimal's role includes representing the ERMC on all aspects of negotiating efficiency policies, plans, programs, goals and budgets with National Grid, the program administrator. We also provide oversight of all program implementation and evaluation, monitoring and verification activities.

Natural Resources Defense Council, Efficiency Assessment and Development of a New Policy Framework and Targets for a New Gas and Electric Efficiency Resource Standard for New York State (2018)

Mr. Mosenthal was the project manager and lead investigator in development of a proposal in support of New York State Governor Cuomo's plans to announce new efficiency resource policy and goals. This project included proposing an aggressive new EERS for achieving electric efficiency savings of 3% per year and gas efficiency savings of 1.5% per year. In addition, it developed a new all fuels EERS framework and shareholder incentive recommendations that would encourage not only efficiency but also beneficial electrification of existing fossil fuel fired thermal loads. This project also included engagement with senior State Government. This proposal was largely adopted by New York State and announced by Governor Cuomo on Earth Day 2018. It has led to New York having the most aggressive electric efficiency goals in the U.S., as well as an innovative new beneficial electrification policy and goals from heat pump deployment in lieu of gas and oil energy systems.

Net-To-Gross Ratios for Eversource MA in 2021

Program	End Use	NTG
A1a - Residential New Homes & Renovations	HVAC	0.98
A1a - Residential New Homes & Renovations	Hot Water	0.99
A1a - Residential New Homes & Renovations	Lighting	0.25
A2a - Residential Coordinated Delivery	HVAC	0.87
A2a - Residential Coordinated Delivery	Hot Water	1.01
A2a - Residential Coordinated Delivery	Lighting	0.70
A2a - Residential Coordinated Delivery	Process	1.00
A2a - Residential Coordinated Delivery	Envelope	1.19
A2a - Residential Coordinated Delivery	Refrigeration	1.09
A2c - Residential Retail	HVAC	0.91
A2c - Residential Retail	Hot Water	0.84
A2c - Residential Retail	Lighting	0.32
A2c - Residential Retail	Process	0.52
A2d - Residential Behavior	Behavior	1.00
B1a - Income Eligible Coordinated Delivery	HVAC	1.00
B1a - Income Eligible Coordinated Delivery	Hot Water	1.00
B1a - Income Eligible Coordinated Delivery	Lighting	1.00
B1a - Income Eligible Coordinated Delivery	Process	1.00
B1a - Income Eligible Coordinated Delivery	Envelope	1.00
B1a - Income Eligible Coordinated Delivery	Refrigeration	1.00
B1a - Income Eligible Coordinated Delivery	Behavior	1.00
C1a - C&I New Buildings & Major Renovations	HVAC	0.95
C1a - C&I New Buildings & Major Renovations	Lighting	0.79
C1a - C&I New Buildings & Major Renovations	Process	1.02
C1a - C&I New Buildings & Major Renovations	Envelope	1.02
C1a - C&I New Buildings & Major Renovations	Refrigeration	1.02
C1a - C&I New Buildings & Major Renovations	Motors/Drives	1.02
C1a - C&I New Buildings & Major Renovations	Custom Measures	1.00
C1a - C&I New Buildings & Major Renovations	Compressed Air	1.01
C2a - C&I Existing Building Retrofit	HVAC	0.92
C2a - C&I Existing Building Retrofit	Hot Water	0.92
C2a - C&I Existing Building Retrofit	Lighting	0.94
C2a - C&I Existing Building Retrofit	Process	0.92
C2a - C&I Existing Building Retrofit	Refrigeration	0.92
C2a - C&I Existing Building Retrofit	Motors/Drives	0.93
C2a - C&I Existing Building Retrofit	Custom Measures	0.92
C2a - C&I Existing Building Retrofit	Compressed Air	0.94
C2b - C&I New & Replacement Equipment	HVAC	0.64
C2b - C&I New & Replacement Equipment	Lighting	0.66

C2b - C&I New & Replacement Equipment	Process	0.91
C2b - C&I New & Replacement Equipment	Refrigeration	0.91
C2b - C&I New & Replacement Equipment	Motors/Drives	0.88
C2b - C&I New & Replacement Equipment	Compressed Air	0.89
C2b - C&I New & Replacement Equipment	Food Service	0.86

At its September 18th meeting the EESE Board discussed the role of its EERS Committee between planning periods and the structure and timeline for developing the next EERS plan. At its October 16th meeting, the EESE Board voted unanimously (with PUC staff abstaining from the vote) in support of the following recommendations and to communicate them directly to the Commission in docket DE 20-092. The EESE Board makes the following recommendations:

The EERS Committee should remain active and engaged in program review, energy efficiency working groups, and any mid-term modifications.

In order to facilitate this participation, the EERS Committee should continue to have access to consultant services on an on-going basis between planning periods.

The planning timeline for the 2024 and beyond plan should consider that current New Hampshire law would requires legislative approval of future increases in the System Benefits Charge to fund energy efficiency. Therefore, the EESE Board proposes the following process:

> **December 2020** – EESE Board revises charter of EERS Committee as necessary and appoints members of the Committee, to serve during the next triennium.
>
> **January 2021-February 2021** – EERS Committee develops request for proposals (RFP) for issuance to potential consultants.
>
> **March 2021** – RFP issued by one of the stage agencies represented on the EERS Committee
>
> **May 2021** – Winning bidder selected, contract signed, submission to Governor & Executive Council for Approval
>
> **July 2021** – Consultant on board and begins work with EERS Committee.
>
> **September 2022-November 2022** – EERS Committee works with program administrators to determine and propose EERS savings goals, associated budgets, and SBC rates for 2024-2026 triennium.
>
> **December 2022** – The EESE Board and EERS Committee work with program administrators to initiate General Court approval of the proposed SBC rate.
>
> **January 2023 – June 2023** – EERS Committee meets to develop EERS plan including priorities, programs, and measures.

July 2023 – EERS plan is submitted to the Commission and adjudicative docket begins.

December 2023 – Order issued by the Commission on EERS plan.

Additional considerations for 2024 and beyond planning process:

- PUC Staff's role and engagement in the collaborative planning process must be clarified.
- The facilitator and consultant contract for the planning process should be with a state agency other than PUC staff such as OCA, DES, OSI, &c.
- The Commission should clarify that no violation of RSA 91-A occurs when EERS Committee members caucus outside of formal EERS Committee meetings since no decisions are made during such caucuses.