Appendix A. Summary of Stakeholder Feedback and Additional Information

E3 received detailed feedback from four stakeholders on the draft technical report. This appendix provides additional clarifying assumptions and context on the findings and methods of the study to help address the thoughtful and constructive feedback received. The key points raised in stakeholder comments and E3's responses are included below.

Interpretation of the Counterfactual Load Forecast and the Implications for Near-Term Load Management Potential

As detailed in the Scenario Design section, E3 developed two load growth and management scenarios: **Incremental Growth**, aligned with ISO-NE CELT EV and heat pump adoption forecasts, and **CECP 2050 Growth**, aligned with the CECP 2050's Phased Scenario.

The Incremental Growth scenario reflects adoption forecasts developed by ISO-NE and calibrated to recent EV and heat pump adoption trends, while the CECP 2050 Growth scenario reflects a "backcast" of adoption required to comply with 2030 and 2050 economy-wide emission reduction targets. As shown in Table 3, 2030 EV adoption across Incremental and CECP 2050 scenarios is 7% and 18% of light-duty vehicles respectively. This leads to higher baseline load growth for the CECP 2050 Growth scenario, increasing the potential peak reduction (GW) that can be achieved by managed charging.

Both scenarios are compared to counterfactual cases that are not intended to represent business-as-usual forecasts such as those published by utilities or ISO-NE. Rather, the counterfactuals are designed to isolate and evaluate the impact of load management investments including those supported through existing programs. Specifically, the counterfactuals assume adoption of all-electric, non–cold-climate heat pumps and unmanaged EV charging. This framing enables the study to quantify the peak load impacts of <u>both</u> existing and potential future load management programs by comparing outcomes to a future without those investments.

This approach differs from how peak reductions are typically presented in ISO-NE materials (e.g., the CELT 2025 Report), where demand-side management impacts are generally reported as incremental to forecasts that already embed existing utility programs and anticipated adoption. In addition to assessing emerging peak reduction strategies, a core objective of this study was to highlight the peak reduction potential of mature technologies already supported through utility and state programs, including cold-climate heat pumps and building weatherization. Based on state guidance, E3 evaluated these measures against less efficient electrification baselines, which results in larger peak reduction estimates than analyses that compare electrification to non-electric baselines.

A second question/comment related to how the study evaluated measure performance. One stakeholder emphasized that expectations for near-term gains from this study could be overstated, and that measure potential should reflect historical, observed measure performance and current deployment constraints. This relates to the point above, as the study is not estimating incremental gains relative to the peak reduction embedded in existing utility and ISO forecasts, and instead assesses the combined potential of existing and new load management measures. To appropriately characterize per-measure potential, E3 leveraged the latest available data on observed measure performance and feasible deployment rates for each scenario, as detailed in Tables 1, 2, and 3.

Table 13 from the Technical and Feasible Potential Appendix provides additional context on the average peak reduction potential of passive and active measures in the Incremental Growth scenario across the top two hundred critical hours, rather than the single-hour maximum peak reduction achieved. In 2030, passive energy efficiency measures achieve an average of 1.1 GW of peak load reduction across the top 200 hours, while active measures achieve 637 MW of peak load reduction compared to a future without any existing or new programs in place.[1] These are not directly comparable to an existing load forecast that already embeds a significant share of the impacts of existing programs.

Additional Information on Cost, Adoption, and Measure Impact Assumptions

One stakeholder requested greater clarity regarding the assumptions underlying measure costs, adoption levels, and kW impacts across scenarios. To support this request, E3 summarized the measure adoption and performance assumptions in Table 2 and Table 3 of the report, with more detailed scenario assumptions included in Tables 8 and 9 of this Appendix. Detailed, annual adoption numbers are available in the publicly available Technical Potential Model. Representative hourly load shapes are included in the study appendix. E3 opted to share load shapes rather than single-hour peak kW reductions, to reflect that certain load management measures reduce load in certain hours while increasing load in others (e.g., pre-heating, pre-cooling, or load shifting), and that impacts vary across the day. Reporting only peak-hour reductions would not fully capture these temporal tradeoffs and the potential for rebound impacts. For measure costs, E3 added detail on the cost inputs used to Table 10 of the Cost Data Appendix, to supplement the list of sources included in the draft report.

With respect to cost-effectiveness, the benefit-cost analysis presented in the report uses the Technical Potential scenario to evaluate the technical cost-effectiveness of the measures themselves, to capture the societal cost-effectiveness that measures could provide prior to layering in assumptions about program design, incentive levels, and subsequent customer measure uptake.

[1] Note that Tables 12 and 13 only provide the load shifted outside of critical hours, without accounting for load shifted to new critical hours, while Figure 13 captures the impacts of these shifts across the aggregated dispatch of measures.

EV Load Shape Assumptions and Scenario Definitions

One stakeholder requested information on the EV charging load shapes used in this study and noted that the EV charging load shapes used reflected optimistic load management potential relative to observed program impacts.

For this study, E3 relied on EV charging load shapes developed by Synapse Energy Economics in support of the Electric Vehicle Infrastructure Coordinating Council (EVICC). The EV scenarios in this report reflect different assumed shares of unmanaged and managed charging, which do not map one-to-one to EVICC scenarios. Where differences in load shapes occur across spreadsheets and figures, these are due to different blends of unmanaged and managed charging, as outlined in Table 3.

With respect to the unmanaged charging baseline, E3 agrees that field-observed unmanaged charging today may show less afternoon peak coincidence than the unmanaged shapes used in this study. This is by design, as the study aims to communicate the value of managed charging relative to a counterfactual baseline of unmanaged charging, rather than attempting to estimate the incremental gains of new managed charging programs relative to existing load management efforts today. Existing Massachusetts program data reflect the success of ongoing managed charging strategies and customer awareness efforts; the findings of this study emphasize the importance of continuing these efforts. The unmanaged baseline used also ensures that the reference case used for comparison avoids the likely bias in early adopter customer behavior today as the adoption scenarios used in this study include widespread EV adoption. Finally, using these load shapes provides consistency between this study and the parallel EVICC EV charger needs analysis.

Thus, as discussed above, the purpose of this study is not to forecast near-term program peak reduction relative to existing programs, but rather to explore the societal benefits and costs of load management at different levels of load growth and management. For future research examining specific EV charging management program design, as broader populations adopt EVs, using empirical data on observed charging behavior will be valuable to assess the incremental value of program design changes.

Variability in EV Charging Patterns

One stakeholder noted that average load shapes mask significant variability across vehicles, with some EVs offering high load management value and others offering minimal impact.

E3 agrees that charging behavior is heterogeneous and that targeting high-value vehicles could improve program impacts and cost-effectiveness. However, modeling a full distribution of vehicle-level charging behavior was beyond the scope of this study. The technical potential analysis uses average aggregate load shapes to estimate system-level impacts. At high adoption levels, aggregation effects tend to smooth individual variability, and average shapes provide a reasonable approximation of coincident peak impacts at the system scale.

Future research could examine the distribution of charging behaviors to better understand the potential for segmentation of high-value vehicles and fleets. As EV adoption grows and more high-resolution charging data become available, this represents a promising area for deeper analysis.

Modeling of Stretch and Specialized Energy Codes

One stakeholder requested additional clarity related to how code-driven heating load reductions were modeled, and whether the Specialized Code could be separately represented from the Stretch Code.

The heating load reduction inputs used in this study were informed by Table 9 of the Decarbonization Roadmap Study Buildings Sector Report,[2] and were verified by the State's building energy codes team. These reflect estimated reductions in heating energy intensity relative to baseline new construction codes, with the distribution of building types from NREL ResStock and ComStock datasets used to develop weighted average residential and commercial Stretch and Specialized code reductions, respectively.

E3 also appreciates the comment on passive house requirements for large multifamily buildings in jurisdictions with the Specialized Code, which would yield an estimated 6% to 8% greater reduction in heating energy use intensity reduction relative to similar multifamily buildings in jurisdictions with the Stretch Code, as per the input table cited above. Given the wide range of measures modeled in this study, E3 did not have the scope to build differentiated impacts for Stretch and Specialized codes but recognizes the increased efficiency and peak reduction performance of the latter.

Definition of Avoided "Energy" Costs

One stakeholder requested clarification of the "Energy" line item within the Avoided Utility Marginal Costs.

In the report, the "Energy" component reflects avoided electric supply and avoided gas commodity costs as defined in the 2024 Avoided Energy Supply Cost (AESC) study. For electricity, this includes wholesale energy market costs and associated losses. For gas, this includes avoided commodity supply costs. These values are time-varying (hourly for electric and annual for gas) and reflect forecasted marginal supply costs consistent with other key research efforts in the Commonwealth such as the Three-Year Energy Efficiency and Decarbonization Plans.

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[2] https://www.mass.gov/doc/buildings-sector-technical-report/download

Table 1: Measure Cost Data and Sources

Measure	Cost ($2025)	Source
Residential Thermostat Control	$70-$120/site	*Lawrence Berkeley National Laboratory, The California Demand Response Potential Study, Phase 4: Appendices to Report on Shed and Shift Resources Through 2050, May 2024 ("LBNL DR Potential Study 2024")*
Residential Cold-Climate Heat Pumps	$1,600/household incremental cost relative to standard heat pump	*Cost estimates shared by MassCEC ahead of upcoming building electrification cost study ("MassCEC 2025")*
Residential Ground Source Heat Pumps	$34,000/household incremental cost relative to standard heat pump	*MassCEC 2025*
Residential Hybrid Heat Pump Control	$70-$120/site	*LBNL DR Potential Study* 2024
Residential Water Heater Control	$180/site for electric resistance water heater $0 for heat pump water heater	*LBNL DR Potential Study* 2024
Residential Shell Upgrade, Light	$4,800/household for single family $8,100/household unit for multifamily	*MassCEC 2025*
Residential Shell Upgrade, Deep	$34,000/household for single family $32,000/household unit for multifamily	*MassCEC 2025*
Residential Stretch Code	$6,600/household	*New Buildings Institute Analysis for DOER*
Residential Appliance Control	$1,400/household	*LBNL DR Potential Study* 2024

Commercial Thermostat Control	$60-$80/kW, $11/kW annual operating costs	*LBNL DR Potential Study* 2024
Commercial Cold-Climate Heat Pumps	$18/sqft, incremental to standard air source heat pump	*MassCEC 2025*
Commercial Hybrid Heat Pump Control	$60-$80/kW, $11/kW annual operating costs	*LBNL DR Potential Study* 2024
Commercial Water Heater Control	$4/kW, $5/kW annual operating costs	*LBNL DR Potential Study* 2024
Commercial Shell Upgrade, Light	$38/sqft	*MassCEC 2025*
Commercial Shell Upgrade, Deep	$45/sqft	*MassCEC 2025*
Commercial Stretch Code	$5.50/sqft	*New Buildings Institute Analysis for DOER*
Commercial Refrigeration Load Shift	$280/kW annual operating costs	*LBNL DR Potential Study* 2024
Managed Light Duty Vehicle Charging	-	*No incremental cost*
Managed Medium- and Heavy-Duty Vehicle Charging	-	*No incremental cost*
Vehicle to Grid Charging	$10,000/charger for light duty vehicles $15,000/charger for medium- and heavy-duty vehicles	*Literature review, primarily informed by National Grid V2G estimate and Joint Office of Energy and Transportation bus electrification resource.*

Behind-the-meter Storage	\$3,300/kW in 2030 \$2,600/kW in 2050	*National Renewable Energy Laboratory, Annual Technology Baseline 2024*
Industrial Demand Response	\$204/kW \$51/kW annual operating costs	*LBNL DR Potential Study* 2024