Memorandum

TO: CONSERVATION LAW FOUNDATION

FROM: ASA S. HOPKINS, PHD, SHELLEY KWOK, JACKIE LITYNSKI, ALICE NAPOLEON, AND KENJI TAKAHASHI

DATE: MARCH 1, 2022

RE: EVALUATION OF DRAFT CONSULTANT REPORTS IN MASSACHUSETTS DPU DOCKET 20-80

At your request, Synapse Energy Economics (Synapse) has evaluated the draft consultant reports developed by Energy and Environmental Economics, Inc. (E3) and ScottMadden, Inc. (ScottMadden) (together, the consultants) on behalf of the Massachusetts local gas distribution utilities, in the process established by the Massachusetts Department of Public Utilities (DPU) Docket 20-80.[1] These reports present interesting and valuable information. Our primary focus is to identify areas where the reports can be improved in order to make the best information available to the utilities, the DPU, stakeholders, and the public as Docket 20-80 proceeds.

This memo addresses several distinct portions of the consultant reports and the analysis that underlies those reports. We begin by addressing the impact and implications of the consultant's assumption, adopted from the current methodology of the Massachusetts greenhouse gas (GHG) inventory, that biomethane has net-zero combustion GHG emissions. We also address how the E3 study's scenario definitions and modeling could better reflect cost-effective improvement in the efficiency of Massachusetts's building stock and the impact of the City of Boston's building decarbonization policies. We then address several aspects of the feasibility assessment presented by E3 in section 5 of Part I of the reports. Our first set of issues regarding the feasibility assessment pertain to multiple aspects of the evaluation of scenario costs as reflected in the energy system cost metric. For the second set of issues on the feasibility assessment, we address shortcomings of the "constructability" metric and point out what a consideration of optionality and flexibility could add to the scenario evaluation rubric. We conclude the memo with a discussion of what positive impact could be achieved through better integration between the pathways (Part I) and regulatory (Part II) portions of the consultant reports.

[1] E3 and ScottMadden. *The Role of Gas Distribution Companies in Achieving the Commonwealth's Climate Goals Independent Consultant Report – DRAFT Part I: Technical Analysis of Decarbonization Pathways* ("Part I") and *The Role of Gas Distribution Companies in Achieving the Commonwealth's Climate Goals Independent Consultant Report – DRAFT Part II: Considerations and Alternatives for Regulatory Design to Support Transition Plans* ("Part II"). Prepared for the Massachusetts local gas distribution utilities.

Biomethane

In its GHG inventories, the State of Massachusetts assumes that biomethane is a net zero-emission fuel at combustion, and the consultants have adopted this assumption.[2] This represents a perspective that emissions are accounted for in the agricultural or production sectors, and not attributed to end uses. (The inventory would account for biomethane leakage within the state.) However, if producers across the Northeast or further afield are making biomethane or other low-carbon gases for use in MA homes and businesses, it is reasonable to consider what climate impact those processes are having on MA's behalf. This is particularly important to consider in the context of a net-zero requirement that envisions using land use and actions in other sectors to offset combustion emissions.

We have estimated the additional GHG emissions caused by Massachusetts buildings' use of biomethane that should be included in the consultants' assessment of different scenarios. To develop an emissions rate for biomethane, we used the "high" resource potential scenario across the Mid-Atlantic and New England states from a report prepared by ICF for the American Gas Foundation.[3] The high-resource case is appropriate to use for this analysis because all of the consultants' scenarios are optimistic about the availability and production of biomethane. To assign emissions to each type of biomethane, we used the emission rates developed by the California Air Resources Board for use in the California Low Carbon Fuel Standard.[4] The resulting weighted average emissions rate is 1.8 kg CO_2e/therm. This is about one third of the 5.3 kg CO_2e/therm resulting from fossil methane combustion. We have not accounted for the increased methane emissions at production or pipeline leakage outside of Massachusetts,[5] which could substantially further increase the net emissions associated with biomethane use if they are not strictly controlled.

Using the rate of 1.8 kg CO_2e/therm and applying it to the "renewable gas" consumption assumed in each of the consultants' scenarios,[6] we derive the following additional emissions not counted in the consultants' reports, shown in Table 1.

---

[2] Ibid, Part I, page 48.

[3] ICF. 2019. *Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment*. Prepared for the American Gas Foundation. Available at https://gasfoundation.org/wp-content/uploads/2019/12/AGF-2019-RNG-Study-Full-Report-FINAL-12-18-19.pdf.

[4] California Air Resources Board. *LCFS Life Cycle Analysis Models and Documentation*. Available at https://ww2.arb.ca.gov/resources/documents/lcfs-life-cycle-analysis-models-and-documentation. The Low Carbon Fuel Standard values include emissions associated with compression for use in transportation vehicles; we reduced the emission values for different methane production pathways by this amount to produce pipeline values.

[5] Pipeline leakage within Massachusetts is accounted for in the consultants' reports, although behind-the-meter leakage (e.g., from appliances) does not appear to be included.

[6] The consultants' scenarios also include the use of synthetic natural gas and hydrogen as part of the "renewable gas" portfolio, also with an assumed emissions rate of zero. Given that the carbon for this production of synthetic gas would likely come from biological sources, and both hydrogen and synthetic natural gas are greenhouse gases that can leak in the production and transportation process, these gases would not have zero lifecycle emissions. We have assumed their lifecycle emissions are comparable to average biomethane.

Table 1. Estimated unaccounted-for lifecycle emissions from "renewable gas"

Scenario	Additional Renewable Gas Emissions (MMT of CO2e in 2050)	Percent increase in emissions over the 2050 requirement of 9.5 MMT
Efficient Gas	3.8	40%
Hybrid Elec.	1.3	13%
Low Elec.	1.7	18%
Networked Geo.	1.6	17%
Targeted Elec.	1.1	12%
High Elec.	0.3	3%
Interim 2030 CECP	0.3	3%
100% Gas Decomm.	0.1	1%

As this table shows, accounting for these additional emissions would result in substantial exceedances over the 90 percent emissions reduction requirement for 2050, unless they are countered by further emission reductions, at additional cost. Scenarios that utilize more low-carbon gas create more additional emissions, and therefore more additional cost. Additional emissions reductions will be relatively expensive to achieve, since lower-cost options have been adopted as part of the underlying scenarios. If we assume an incremental cost of $400 per metric ton, these costs could add an incremental $400 million per year or more to the cost of even moderate-renewable-gas scenarios relative to high-electrification scenarios.[7]

Scenario Definition and Modeling

Cost-effectiveness of residential deep retrofits

The scenarios developed in Part I of the consultant reports (prepared by E3) assume different levels of building shell improvement in different scenarios. In particular, the scenarios that depend on electric heating through the winter peak have deeper retrofits, while the Hybrid scenario, which depends on the

[7] For example, the annual unaccounted-for emissions are 1.3 MMT CO2e in 2050 in the Hybrid scenario and 0.3 MMT in the Interim 2030 CECP scenario. The incremental 1.0 MMT per year times $400 per ton equals $400 million per year.

gas system to meet a larger share of the winter peak, includes only MassSave-level retrofits. E3 presents a box with analysis showing that deep retrofits are not cost-effective in the Hybrid case.[8]

We analyzed whether the incremental cost of deep retrofits provides sufficient incremental value in the high-electrification cases for it to be worth it to switch exclusively to deep retrofits in these cases. Note that it would be possible for deep retrofits to be cost-effective when considered alone (that is, their benefits exceed their costs) while not being cost-effective when compared with MassSave-level retrofits (the incremental costs are not justified by incremental benefits). Because the costs presented when evaluating scenarios are their *net* costs, if deep retrofits do not provide net benefits relative to MassSave-level retrofits this scenario construction choice will make high-electrification scenarios appear more expensive than they would be if they were optimized.

E3 assumes an incremental cost of a deep retrofit, relative to a MassSave-level retrofit, of $4.38 per square foot. For a 1750 square foot home (close to the Massachusetts average), a MassSave-level retrofit is assumed to cost about $3,100, while a deep retrofit costs about $10,800. As a result of this additional spending, the building achieves additional savings: building shell performance improves by about 17 percent. (MassSave retrofits achieve 14 percent reductions in heating energy demand, weighted across single- and multi-family homes; deep retrofits achieve about 29 percent.) Those building shell improvements manifest as lower annual heating and cooling energy demand and lower winter peak heating energy consumption. Peak reductions save on electric generation capacity and transmission and distribution peak capacity. Our analysis asks whether the incremental cost of about $7,700 per retrofit housing unit (i.e., the cost of a deep retrofit, $10,800, minus the cost of a MassSave-level retrofit, $3,100) returns at least that much additional benefit.

Rather than conduct our analysis at the per-household level, we considered aggregate scenario costs for deep retrofits at the level assumed in the High Electrification, Interim 2030 CECP, and 100% Gas Decommissioning scenarios. In these cases, about 45 percent of homes (or 1.1 million homes) receive deep retrofits. The incremental cost is about $8.5 billion. Annualizing this cost using the parameters chosen by E3[9] yields an annual cost of about $400 million. Accounting for all the homes that are not retrofit, as well as new construction, E3 reports that the average building shell improvement in the Hybrid case is 6.5 percent, while it is 15 percent in the high-electrification cases.[10] This is a net improvement of about 9 percent.

When comparing Massachusetts scenario costs to regional electric system costs, we must scale to work at either the regional or state level. Although the Part I report does not lay out assumptions in detail, E3 appears to assume that all states in the region take a similar path to Massachusetts, whichever scenario is selected. Today, Massachusetts uses close to half the electricity in New England, so for the purposes

[8] E3 and ScottMadden. *The Role of Gas Distribution Companies.* Part I, Text Box 1 on page 51

[9] 3.6 percent discount rate and 40-year lifetime

[10] E3 and ScottMadden. *The Role of Gas Distribution Companies*. Page 7.

of simplicity we assume a simple factor of two between state and region. Therefore, if regional benefits from deep retrofits across the region exceed about $800 million per year, E3's choice to exclusively use deep retrofits in the high-electrification cases will be justified.

E3 has not presented the full data required to directly calculate the incremental benefits of deep retrofits. However, we can use the data available to estimate the benefits. First, we must derive the contribution of residential heat pumps to winter peaks. E3 states that using air source heat pumps (in both residential and commercial buildings) that are 30 percent more efficient at peak times would lower winter peaks by 10 GW.[11] This indicates that about 33.3 GW (10GW/30%) of winter peak is due to baseline-level heat pumps in the high-electrification scenarios. Regionally, the breakdown of heating load between sectors is about 40 percent residential and 60 percent commercial,[12] so about 13.3 GW (33.3 GW times 40 percent) of winter peak demand is from residential heat pumps, in high-electrification cases that have exclusively deep energy retrofits. With only MassSave-level retrofits, the load would instead be 14.6 GW. [13] Does 1.3 GW of regional peak savings and a 9 percent reduction in residential heating energy use justify spending $800 million per year on deeper retrofits?

E3 assumes a marginal distribution cost of $114 per kW-year. The report does not provide an estimate of marginal transmission costs because they are derived separately in E3's models. If we assume that marginal transmission and capacity costs together are about $200 per kW-year, then the 1.2 GW reduction in regional peak is worth about $260 million per year. (Note that we have concerns with E3's methods for developing marginal distribution costs for this analysis, so we believe that this number is more likely to be an overestimate.)

Looking at marginal generation capacity costs, E3 assumes battery capacity costs for a four-hour battery of $63 per kW-year and $82 per kW-year for a combustion turbine (presumably running on hydrogen or a low-carbon gas), both in 2040. If we assume an average capacity cost of $80 per kW-year, then electric generation capacity savings from deep retrofits amounts to $104 million per year.

Residential electric energy savings from deep retrofits would reduce heating energy by 9 percent to 15,121 GWh in 2050 in the High Electrification case,[14] so heating energy savings are about 15.1 GWh per year. At a very conservative average energy cost of $100/MWh (noting that this is more expensive than today's onshore wind, offshore wind, or solar PV prices, and the recent regional Avoided Energy Supply Components study estimates avoided energy costs of $62/MWh for winter peak times in Massachusetts,

[11] E3 and ScottMadden. *The Role of Gas Distribution Companies*. Part I, Figure 17 on page 49.

[12] E3. *Independent Consultant Report, Docket 20-80: The Role of Gas Distribution Companies in Achieving the Commonwealth's Climate Goals Appendix 4: Input Assumptions Workbook*, "Loads" sheet. Residential heating electric use in 2050 in the High Electrification case is 15,121 GWh, versus 22,958 for commercial.

[13] MassSave retrofits have 17 percent less savings in the 45 percent of homes that are retrofit, and therefore 9 percent less savings across the whole sector.

[14] Ibid.

including a 9 percent risk premium[15]), this would add another $150 million in benefits for the deep retrofits.

Combining three generous assumptions regarding the value of deep retrofits, we see that they provide an electric system value of about $500 million per year to the region as a whole, which is less than their cost of $800 million per year. E3's exclusive use of deep retrofits in the high-electrification cases is therefore not justified.

For buildings with greater-than-average savings potential, deep retrofits may make sense. However, for other buildings, a MassSave-level retrofit would provide more net energy system benefits. By assuming that all retrofit buildings require a deep retrofit, E3 has raised the relative cost of the high-electrification scenarios by several billion dollars over the 2020-2050 period while also making them appear more difficult to achieve because of the market transformation and additional barriers that must be overcome to scale deep retrofits to 45 percent of buildings.

Building energy use diversity

As we have just discussed, targeting deep energy efficiency toward high-energy-use buildings is more cost-effective than for average buildings. The consultants' scenarios appear to represent a limit on how many residential homes could be retrofit each year—no scenario assumes more than 45 percent of homes are retrofit by 2050. However, targeting those retrofits to higher energy-using buildings would produce greater savings than is represented by E3's average-based analysis. In response to a question in a stakeholder meeting, E3 claimed, "In the modeling, we assume that mostly older homes receive a building shell retrofit, resulting in higher overall energy demand reductions compared to an average building. This distribution is accounted for in the calculation of the weighted average of energy reduction from building shell improvements."[16]

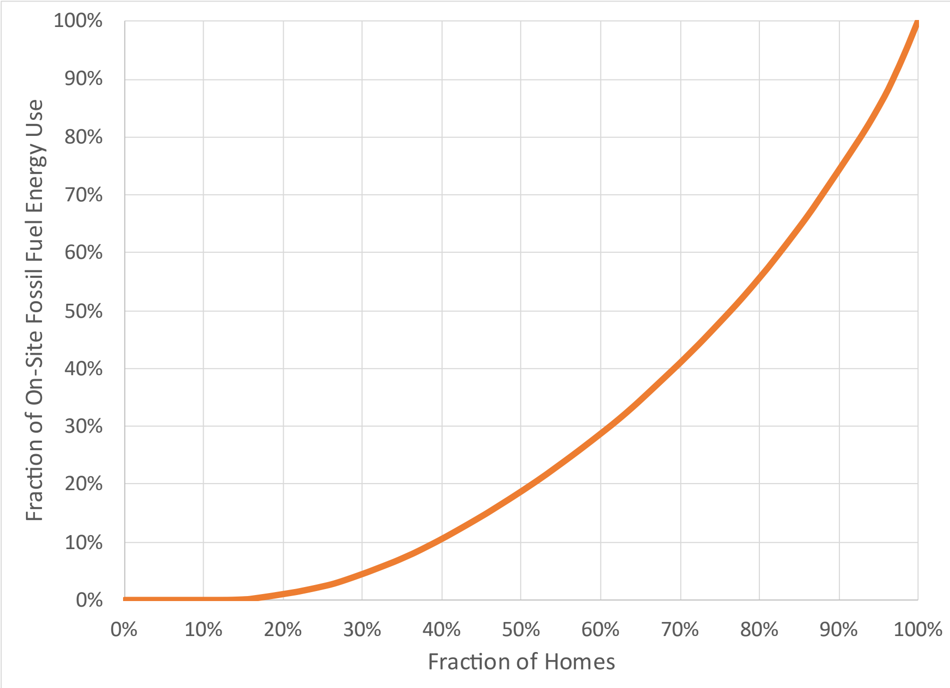
However, E3's presented analysis does not show that the true diversity of residential heating energy use has been accounted for. Figure 1 shows how skewed the distribution of fossil fuel energy use is in Massachusetts homes, based on the *2015 Residential Energy Consumption Survey* by the U.S. Energy Information Administration. The highest-consuming twenty percent of homes in the state use almost 45 percent of the fossil fuels used for home heating, and 50 percent of homes use more than 80 percent of the fossil fuels.

---

[15] Synapse Energy Economics et al. May, 2021. *Avoided Energy Supply Components in New England: 2021 Report*. Prepared for the AESC 2021 Study Group. Available at https://www.synapse-energy.com/sites/default/files/AESC%202021_20-068.pdf. Table 48, page 139.

[16] ERM and E3. *Technical Session Comments/Questions for E3.* Available at https://thefutureofgas.com/content/downloads/1.19.22%20-%20Technical%20session%20questions%20and%20comments_E3%20answers.pdf

Figure 1. Distribution of residential fossil fuel heating energy use in Massachusetts, 2015



Source: Synapse analysis of U.S. Energy Information Administration, Residential Energy Consumption Survey 2015.

Retrofitting 45 percent of homes by 2050, if those homes were the homes with the greatest fossil fuel use, would mean addressing homes that consume about three-quarters of residential fossil fuels for space heating. Deep retrofits of 30 percent in these homes would imply reductions in heating demand by about 22 percent,[17] before accounting for new construction efficiency. E3's analysis is limited to 15 percent heating energy savings, including new construction. The additional 8 percent heating use reduction that comes from targeting high-consumption homes would reduce the winter electric peak in high-electrification scenarios by between 1.5 and 2 GW in 2050. Using E3's winter peak and energy cost estimates, we estimate that these additional savings from energy efficiency would deliver value on the order of $600 million per year beyond what is reflected in the existing E3 report in 2050. Notably, the benefits of targeted efficiency are understated more for high-electrification cases (High Electrification, Interim 2030 CECP, or 100% Gas Decommissioning) than for the Hybrid or Targeted Electrification scenarios that meet some or all of winter peak with the gas system. That is, while the Hybrid case would also see increased savings by targeting retrofits to high-consumption homes, it would not see the benefits of electric peak savings. We estimate that the aggregate net cost impact of accounting for the value of targeted efficiency on the relative costs of the high-electrification scenarios compared to the Hybrid scenario would be several billion dollars across the 2020 to 2050 period, along with additional savings continuing past 2050.

[17] 30 percent savings on 75 percent of the state's residential heating load would reduce aggregate heating load by 22.5 percent.

It may seem odd to say on the one hand, that there is more cost-effective efficiency than E3 has accounted for, and on the other hand, that the efficiency measures E3 assumed (in some cases) are not cost-effective relative to other options and therefore skew the results of the evaluation. However, these analyses have consistent implications: E3 should have properly accounted for the diversity of building energy use and conducted an evaluation of the optimal depth of building shell improvements—and on which buildings—to include in each case to maximize net benefits. Because this analysis has not been conducted or included in the consultant reports, the reports present an incomplete and less useful picture with respect to the relative costs and benefits of each scenario. The results as presented systematically make the high-retrofit, high-electrification scenarios look more expensive, relative to the Hybrid case, than they would if these effects were included in the analysis.

Boston's building decarbonization policies

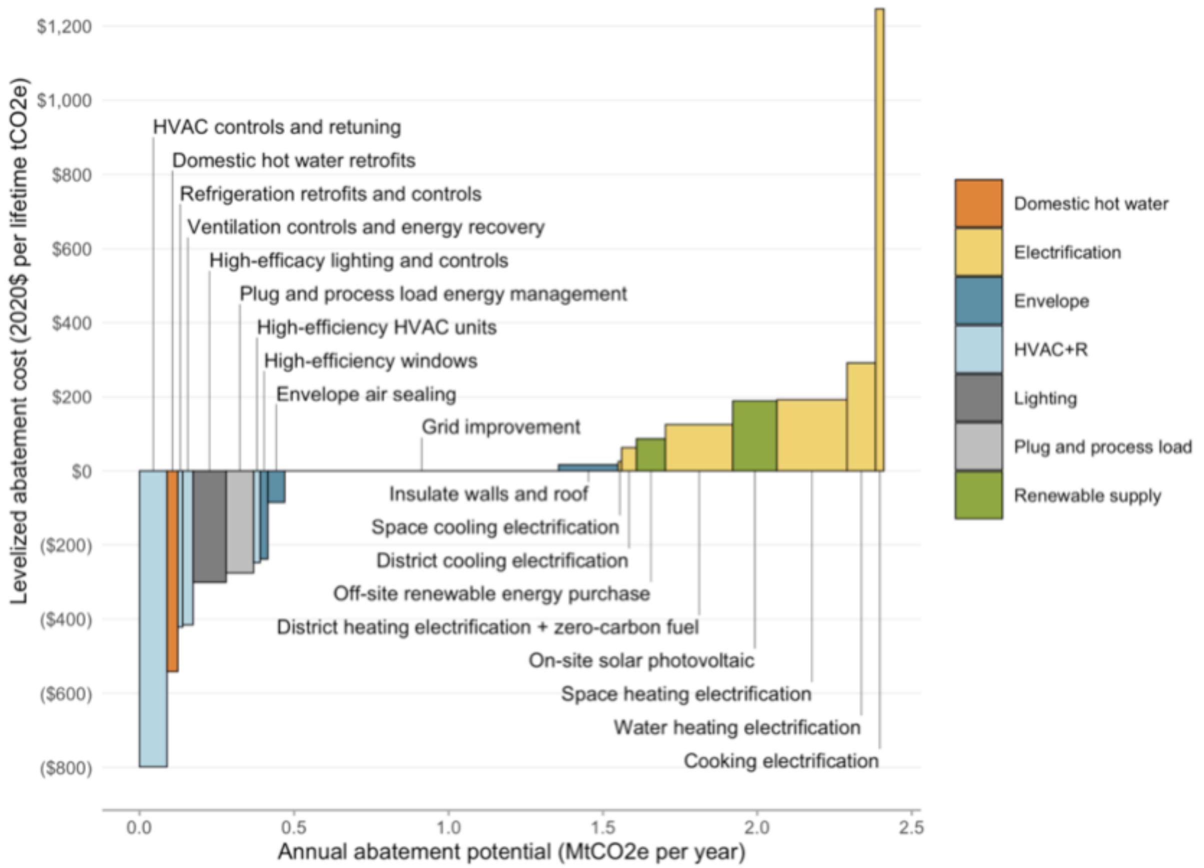
The state's commercial building sector has a similarly skewed distribution of fossil fuel energy use. E3 assumed little (in some scenarios) to no (in other scenarios) improvements in commercial building shells. However, some improvement in shell performance is likely warranted and cost-effective in high-consumption buildings in all cases. Boston's recently Building Emissions Reduction and Disclosure Ordinance (BERDO) will drive an improvement in building shells as well as changes in district heating and heating equipment choices, regardless of the pathway pursued by the state and gas utilities. The BERDO lays out a path to zero emissions, by building type, by establishing required emission levels every five years. The consultants did not account for this performance standard in their modeling and analysis.

Over 800 million square feet of commercial buildings (not counting multi-family residential buildings) report their energy consumption under the Boston BERDO. E3 assumes that there are about 1.3 billion square feet of commercial buildings in the state, so the BERDO applies to more than 60 percent of the commercial floor area in the state.

A technical analysis for the BERDO update process, prepared by Synapse,[18] showed that building shell improvements are likely to be a lower-cost component of a decarbonization pathway for commercial buildings than electrification (although electrification would also be a key contributor). Figure 2 shows that windows, air sealing, and wall and roof insulation are each negative-cost or low-cost methods to reduce emissions in Boston's commercial building stock. E3's pathways analysis for Part I, and the regulatory analysis for Part II, should have incorporated Boston's policy as important context for the commercial and multi-family residential sectors.

[18] Synapse Energy Economics. 2021. *Boston Building Emissions Performance Standard: Technical Methods Overview*. Prepared for City of Boston. Available at https://www.synapse-energy.com/sites/default/files/Boston_Performance_Standard_Technical_Methods_2021-02-18_20-013.pdf

Figure 2. Levelized abatement cost of building decarbonization strategies, 2035 grid emission factor. Reproduction of Figure 14 from *Boston Building Emissions Performance Standard: Technical Methods Overview*.



Source: Synapse model.

Feasibility

Part I of the consultant report draws on a wide range of analyses to present a feasibility analysis, which is summarized in Figure 31 (page 71) and is the subject of Section 5 of the report. This analysis directly informs the consultants' recommendations, and the resulting approaches presented by the local distribution companies. The section evaluates nine measures of feasibility and rates each scenario on a three-level scale on each metric. Our comments address the cumulative energy system cost and constructability metrics, and then identify that the consultants have overlooked the value of optionality and flexibility. We also address the customer equity metric in our later discussion of integration between Parts I and II of the consultant reports.

Cumulative Costs

As a measure of the affordability of different scenarios, the E3 report uses a metric of the simple sum of net costs over the period from 2020 to 2050. The costs and benefits used for this calculation are the aggregate "annual cost of energy supply and delivery infrastructure, end-use equipment, and fuel costs, net of fuel savings, relative to the Reference scenario."[19] We have two areas of particular concern regarding this metric and how it is calculated. First, we believe that the electric distribution cost is likely to be overestimated. Second, by ending the analysis period for this metric in 2050, the metric fails to show the substantial difference in ongoing costs after 2050 in different cases; these costs are an important aspect of long-term affordability and intergenerational equity.

Distribution costs

The electric distribution costs used by E3 in developing the overall scenario costs are derived from marginal cost of service (MCOS) studies filed by the state's electric utilities in recent rate cases. The purpose of such studies is to estimate the additional revenue requirement created by a typical additional kW of peak load. These studies are conducted by using regression analysis to derive a relationship between historical changes in peak load and historical investments in peak-demand-related distribution assets. This analysis does not fully fit the purpose of the study of electrification impacts, for two primary reasons:

- MCOS studies include investments related to new customer additions as part of load growth-related costs.[20] In the context of this analysis, new customer addition costs should be the same between cases, aside from the portion of those costs that changes with the level of peak demand expected from the new customers. Therefore, some or all of the costs associated with new customers should be removed from the incremental distribution cost when comparing between scenarios, like those in the Part I report, that have the same customer growth.
- The MCOS studies are conducted based on today's peak loads on the Massachusetts electric system, which are summer loads, whereas the peaks analyzed in the consultants' decarbonization study are winter peaks. Distribution asset performance is directly impacted by the weather. In particular, on the coldest days when peaks would be highest, lines and transformers would also have their greatest capacity. This effect would both tend to delay the need to upgrade existing assets as winter peaks begin to exceed summer ones and allow for lower-cost assets to be installed to meet the new peaks. If distribution asset capacity increases by at least 20 percent during winter peak, relative to summer peak, which we believe is a reasonable assumption based on distribution planning analyses we have seen in the Mid-Atlantic region, then the cost of distribution upgrades is overstated by at least 20 percent.

The consultant reports fail to capture these effects on distribution expenditure driven by building electrification loads. The net result of this shortfall in methodology is to make scenarios with higher winter peak loads (that is, those scenarios that do not use a hybrid approach using the gas system) appear needlessly more expensive, relative to those with lower peak loads. For example, the

---

[19] E3 and ScottMadden. *The Role of Gas Distribution Companies*. Part I, page 71.

[20] For example, more than one third of the growth-related costs in National Grid's MCOS used by E3 are caused by new business. *Testimony, Exhibits and Workpapers of: Howard S. Gorman (Marginal Cost of Service Study) Monthly Minimum Reliability Contribution Panel*. D.P.U. 18-150, Exhibit NG-MCS-4.

incremental cost of the Interim CECP scenario compared with the Hybrid scenario (which differ in winter peak by 16 GW) is likely overstated by about $650 million in 2050,[21] and several billion dollars over the 2020-2050 period.

E3 also appears to use the value of $114/kW-year as an annual distribution system cost without adjusting the financial parameters to reflect the approach and perspective used for the annualization of other costs. For example, in the evaluation of efficiency cost-effectiveness, E3 proposes to use a 3.6 percent discount rate and a forty-year lifetime. This results in an annual carrying cost for efficiency investments that is 4.75 percent of the upfront capital cost. In contrast, the carrying cost for utility distribution assets is much higher. In National Grid's MCOS, for example, the results of which were used by E3, the carrying cost for demand-related distribution infrastructure is 8.18 percent.[22] While the finances of the state's investor-owned distribution utilities have required this higher carrying cost, it is not appropriate to treat all of these annualized costs as societal costs and add them one-for-one to annualized costs calculated with different discount rates and different perspectives. If the state were to use securitization or another alternative financing approach to paying for distribution system upgrades that can lower the cost of capital, the incremental distribution cost from electrification would fall.

Costs after 2050

Costs and benefits after 2050 are not included in the affordability metric presented in the E3 report. This means that pathways with higher near-term costs, but which save money in the longer term, are shown as being more costly than cases with lower near-term costs and higher long-term ones. For example, the hybrid case requires ratepayers to pay an ongoing delivery revenue requirement for gas utilities in the range of $3 billion per year, indefinitely. In contrast, the 100% Decommissioning scenario has no ongoing gas system costs after 2050. While the 100% Decommissioning scenario has higher ongoing electric system costs to meet winter peak loads, these costs (using E3's assumptions regarding the costs of generation and distribution assets[23]) are in the range of $1.5 billion per year. And as cold climate heat pump technologies improve, the cost will decrease. (The high-efficiency heat pump sensitivity analyzed by E3 shows an ongoing relative winter peak cost of about one-third this size.) In total, the high-electrification scenarios that do not rely on a hybrid approach (including the Interim 2030 CECP, High Electrification, and 100% Decommissioning cases) appear to present ongoing savings of $1 billion per year, or more, after 2050. As discussed below, regulatory actions before 2050 can create additional savings both before and after 2050, which are also not included in the presentation of this metric.

---

[21] 16GW times $114 per kW is 1.8 billion per year. 20 percent of this for the winter weather adjustment is $360 million, and new business impacts likely add at least another 20 percent from this lower baseline, for a total correction of more than $650 million.

[22] Testimony, Exhibits and Workpapers of: *Howard S. Gorman (Marginal Cost of Service Study) Monthly Minimum Reliability Contribution Panel*. D.P.U. 18-150, Exhibit NG-MCS-1, page 16.

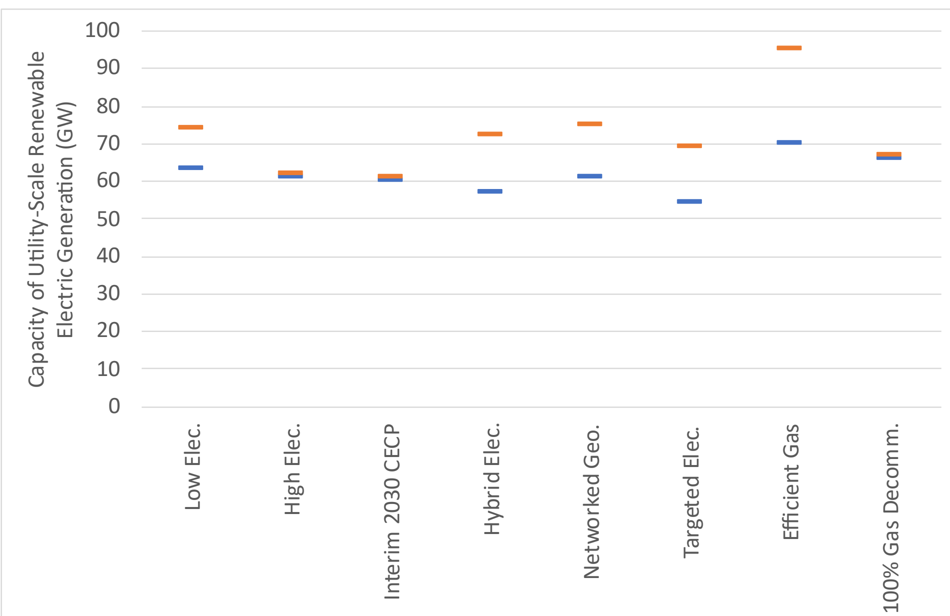
[23] E3 has not made sufficient information available to include transmission system costs in our analysis. However, they are unlikely to bridge the gap presented here.

Constructability

We agree with the consultants that it is important to consider the constructability of the substantial increases in electric sector infrastructure required in the different cases. Figure 31 on page 71 of the Part I report shows the Low Electrification and Hybrid Electrification scenarios as being more feasible in the constructability dimension. Constructability is defined as "[t]he pace and scale of electric and gas sector infrastructure additions. Scenarios with higher overall infrastructure requirements of gas and/or electric equipment face a higher level of challenge." However, the results of the constructability metric as shown in Figure 31 do not reflect the underlying data presented on the following pages of that report. Particularly, the results appear to discount the challenge of constructing electric infrastructure outside of Massachusetts to produce the power required to produce hydrogen and synthetic fuels for Massachusetts use, along with the potential need for incremental infrastructure (or retrofits of existing infrastructure) required to bring those fuels to the state. Recent experience with electric transmission has shown that building infrastructure in other states to meet Massachusetts's needs can be more challenging or expensive than expected.

While the Part I report does not include the specific values for out-of-state generation capacity required, we used the values presented in Figure 33 on page 79 of the Part I report, combined with the New England regional values shown in Table 13 on page 78, to produce Figure 3, below. This figure shows the combined capacity of renewable electric generation required in the different cases. The low and high limits represent the consultants' optimistic and conservative views of renewable fuels.

Figure 3. Total required capacity of renewable electricity generation by scenario



As illustrated in the figure, the required capacity is similar for all cases except for the Efficient Gas scenario. The Interim CECP and High Electrification scenarios have the lowest high-end estimate, while Targeted Electrification has the lowest low-end estimate. However, based on this analysis, we believe it is misleading to characterize the Hybrid and Low Electrification scenarios as having less of a "constructability" challenge than the other cases.

Optionality and Flexibility

Retaining flexibility and optionality has value. Once irreversible infrastructure investments have been made, that value is destroyed. Optionality has value because the future is uncertain, and if circumstances change and an investment turns out to have been the wrong choice, it cannot be undone. It is therefore important to consider that value when making infrastructure decisions. The magnitude of the optionality value depends on the scale of the at-risk investment and on the likelihood that it will turn out to have been a mistake. In the context of building sector decarbonization, the loss of optionality value that comes with continuing to irreversibly invest in a gas system that is at risk of abandonment is a substantial cost that is not outweighed by countervailing optionality costs in electrification-driven approaches.

The comparison rubric presented in Part I of the consultant reports does not account for optionality value and is therefore incomplete. There are two primary infrastructure choices considered in the consultants' analysis that could be considered irreversible. The first is the choice to continue to invest in the gas pipeline system through the Gas System Enhancement Plan (GSEP) program (and, to a smaller degree, to expand the system to serve new customers). Scenarios that continue to utilize the full gas system (such as the Hybrid and Efficient Gas cases) incur this cost from lost optionality because, in the event that electrification turns out to be more cost-effective than projected by the consultants,[24] the gas system investment costs have been incurred and cannot be undone. The second is the choice to fully electrify buildings rather than maintain flexibility to use pipeline gas. This creates a cost in the scenarios that do not utilize hybrid approaches because if the gas options turn out to be less expensive these building owners will not be able to take immediate advantage.

Including the optionality cost in the evaluation of these scenarios could seem to balance out, because they favor exactly disjoint sets of scenarios. However, the optionality cost is not the same in the two cases, and the greater cost is borne by the cases which invest in the gas system. This is true for two primary reasons:

- GSEP investments are front-loaded in the analysis period, so there is less time to make decisions to continue or cease these investments, and the uncertainty of outcomes at the time of the decision is greater. Building electrification is a gradual process spread over the period between now and 2050, so building owners and policymakers can make adjustments in approach as circumstances change. Building owners could also choose to rejoin the gas system later if a gas-based approach turns out to be preferable.

[24] For example, if higher-performance heat pumps can be widely adopted or renewable gas turns out to be more expensive or less available than projected.

- Full electrification is a low-regrets strategy for building owners today, especially when compared to a hybrid approach. Many buildings which fully electrify do not face substantially higher costs than buildings that remain on the gas system, especially if the benefits of improved comfort and indoor air quality are included in the analysis.

Integration

Part II of the consultant reports presents options that could change the results of Part I, yet the results of the analyses are not integrated. In particular, many of the costs accounted for in the total energy system cost in Part I are shaped by regulatory and policy treatment. To take one example, using the results and approaches detailed in Part II, accelerating depreciation of gas utility assets would change the total energy system cost between 2020 and 2050 presented as a metric in Part I.

Part II of the consultant reports analyzes the case of using "units of production" or UOP depreciation rather than straight line depreciation. Faster depreciation lowers overall system cost because the utilities' investors earn a return on their capital over fewer years. While the results presented in Figure 9 of Part II do not include the total gas system delivery cost, Synapse analysis of changing depreciation approaches for Eversource/NSTAR indicates a roughly 10 to 12 percent decrease in aggregate ratepayer costs between 2020 and 2050 with UOP or other accelerated depreciation approaches that return all or nearly all of gas utility investors' funds by 2050. We expect similar results for other Massachusetts gas utilities. Neither our analysis nor, to our knowledge, the consultants' analysis includes the impact of accelerated depreciation on gas utility capital structure and return on equity. A utility with faster depreciation would score better on creditworthiness metrics,[25] allowing for lower cost of debt and equity, and potentially for changes in the capital structure that would further lower costs.

Faster depreciation would impact not just the total system cost between 2020 and 2050, but also the equity challenges that must be addressed throughout the coming decades. By reducing system costs more rapidly as sales fall, rates are lower and the affordability gap for low-income customers could be more effectively mitigated. This could affect the scoring of high-electrification scenarios on the consultant's "customer equity" metric.

As previously discussed, the consultant reports fail to address ongoing costs after 2050. Using UOP or other accelerated depreciation would not only lower costs during the period before 2050—they would also reduce or eliminate costs and risks after 2050. The reports should be amended or extended to quantify and account for these changes.

[25] For example, higher depreciation rates, once reflected in rates, create greater cash flow and improve a company's "free funds from operations" and "free operating cash flow" metrics. See S&P Global Ratings. 2013. *Corporate Methodology*. Available at: https://www.spratings.com/scenario-builder-portlet/pdfs/CorporateMethodology.pdf.