Scoping a Future of Gas Study

In support of Massachusetts DPU Case No. 20-80

Prepared for Conservation Law Foundation

January 29, 2021

AUTHORS

Asa Hopkins, PhD
Shelley Kwok
Alice Napoleon
Cheryl Roberto
Kenji Takahashi

Synapse Energy Economics, Inc.

485 Massachusetts Avenue, Suite 3
Cambridge, Massachusetts 02139

617.661.3248 | www.synapse-energy.com

Contents

EXECUTIVE SUMMARY

The Massachusetts Department of Public Utilities (DPU) opened Investigation No. 20-80 to "examine the role of Massachusetts gas local distribution companies in helping the Commonwealth to achieve its 2050 climate goals."[1] The DPU's order requires the state's gas utilities to complete studies over the next year that will inform this examination and allow the DPU and other state agencies to develop the specific roadmap to required emission reductions. This white paper presents a set of criteria for the required "future of gas" studies. These criteria are designed to ensure that the studies will present sufficient, detailed, and justified data, analysis, and recommendations to inform the DPU and stakeholders.

The fundamental challenge facing gas utilities in the context of the pursuit of net zero emissions is that all pathways to net zero generally require dramatic reductions in the use of fossil pipeline gas. The determination of a net zero emissions limit for 2050 established a bright line for regulatory and utility decision-making regarding prudent management of the future of the state's utilities.

Gas utilities are infrastructure companies which recover the costs of their systems primarily through volumetric charges. This business model faces fundamental challenges in the face of substantial reductions in sales. The most cost-effective and robust pathways to net zero, based on analysis conducted to date, achieve emission reductions by shifting energy consumption away from the pipeline system entirely and toward electrification. For example, the benchmark case used in the Massachusetts 2050 Decarbonization Roadmap (2050 Roadmap), called the "All Options" case, reduces pipeline gas from 268 trillion BTU (TBTU) per year currently to 36 TBTU by 2050. This case is more than $1 billion less expensive than the "Pipeline Gas" case (which has only small declines in pipeline gas use). The Interim Clean Energy and Climate Plan for 2030 (2030 CECP) builds on the "All Options" case.

The analysis conducted for the 2050 Roadmap study provides a solid foundation for examination of the state's energy future but does not answer many critical questions regarding the gas system. The analysis and data provided by the gas utilities is therefore essential to developing a detailed roadmap, and that analysis must be completed in a comprehensive, transparent, and robust manner in order to be useful. Delays in developing the roadmap and embarking on the path laid out will only make the transition more difficult and more expensive, so it is critically important to get the analysis right the first time.

Essential criteria for success include:

- A study design and process that evaluate scenarios that are complete and consistent, build on the 2050 Roadmap and 2030 CECP, and avoid anchoring the analysis in

[1] Massachusetts Department of Public Utilities. October 29, 2020. Vote and Order Opening Investigation. Investigation No. 20-80. Available at: https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/12820821. Page 1.

unrealistic “straw” scenarios that would bias readers toward solutions preferred by utilities.

- Placing equity and justice at the front and center of policies and pathways to net zero, reversing the disproportionate burdens on frontline communities, and developing partnerships with these communities so they can lead the transition to clean heating at affordable prices.
- Accounting for the full costs and benefits of energy system infrastructure; this includes both electric and gas generation, transmission, and distribution systems (and systems developed for any other fuel or energy carriers) as well as end-use building systems.
- Transparent accounting for greenhouse gas emissions from the full lifecycle of energy production, transmission, distribution, and use, including leaks and losses.
- Respect for customer-facing economics presented in each scenario considered, and explicit identification of policies or programs to change those economics where necessary to achieve policy outcomes.
- A keen sense of the timescale of market transformation and stock turnover, as well as the timescale of utility infrastructure lifetimes and depreciation rates, in the context of the 29 years remaining until net zero.
- Careful consideration of the risk of failure along different pathways, as well as the path dependence which limits the ability to change course in the event of failure.
- Connecting utility business and financial models with utilities’ potential roles to enable and accelerate the pursuit of net zero.
- Clear understanding and planning for the interaction between gas and electric utilities, including those that share a corporate parent and those which do not.
- Avoiding unplanned catastrophic reduction in gas use and the associated stranded costs.

We hope that publishing these criteria assists the utilities and DPU in the development and review of these essential studies.

1. INTRODUCTION

The Massachusetts Department of Public Utilities (DPU) opened Investigation No. 20-80 in order to "examine the role of Massachusetts gas local distribution companies in helping the Commonwealth to achieve its 2050 climate goals."[2] This is a critical and timely docket for the examination of the future of the state's gas utilities. It follows Governor Baker's announcement of a net zero target for Massachusetts, then codified by the Secretary of Energy and Environmental Affairs as the legally binding emissions required for 2050 under the Global Warming Solutions Act.[3] This docket will be informed by the publication of the Massachusetts 2050 Decarbonization Roadmap[4] (2050 Roadmap) and the Interim Clean Energy and Climate Plan for 2030[5] (2030 CECP). The DPU seeks to develop a "regulatory and policy roadmap to guide the evolution of the gas distribution industry, while providing ratepayer protection and helping the Commonwealth achieve its goal of net-zero GHG [greenhouse gas] emissions energy."[6]

The 2050 Roadmap and 2030 CECP illuminate in great detail the challenging future facing gas utilities in the decarbonizing world and explicitly raise a number of questions for regulators and policymakers to address. As the 2050 Roadmap states: "A comprehensive effort to study and develop policy strategies to carefully manage ongoing and future investments in the gas distribution system, facilitate sustainable deployment of limited zero-carbon gas resources for niche or hard-to-electrify buildings and end uses, and manage the orderly and equitable drawdown of fossil fuel use and infrastructure, is needed to ensure equitable outcomes. Higher costs cannot be borne by the consumers least able to pay, and steps must be taken to provide for an orderly and equitable transition."[7] The Executive Office of Energy and Environmental Affairs' 2020 determination of a net zero emissions limit for 2050 established a bright line for regulatory and utility decision-making regarding prudent management of the future of the state's utilities.

Anticipating the need for this "comprehensive effort," the DPU required the gas utilities to work together to produce a report or reports by the spring of 2022 that address the costs and GHG emissions

---

[2] Massachusetts Department of Public Utilities. October 29, 2020. *Vote and Order Opening Investigation*. Investigation No. 20-80. Page 1.

[3] Massachusetts Executive Office of Energy and Environmental Affairs. April 22, 2020. *Determination of Statewide Emissions Limit for 2050*. Available at: https://www.mass.gov/doc/final-signed-letter-of- determination-for-2050-emissions-limit/download.

[4] Massachusetts Executive Office of Energy and Environmental Affairs. 2020. *Massachusetts 2050 Decarbonization Roadmap*. Available at: https://www.mass.gov/doc/ma-2050-decarbonization-roadmap/download.

[5] Massachusetts Executive Office of Energy and Environmental Affairs. 2020. *Interim Clean Energy and Climate Plan for 2030*. Available at: https://www.mass.gov/doc/interim-clean-energy-and-climate-plan-for-2030-december-30-2020/download.

[6] Massachusetts DPU. October 29, 2020. *Vote and Order Opening Investigation*. Investigation No. 20-80. Page 4

[7] 2050 Roadmap, page 53.

associated with the transition of the gas system; cost recovery and responsibility, with particular focus on low-income customers; and analysis of electrification strategies. The studies must also discuss qualitative factors such as safety, reliability, economic development, and equity, and develop proposed recommendations.

In this paper, Synapse Energy Economics (on behalf of the Conservation Law Foundation) presents a set of criteria for the execution of the required "future of gas" studies. A utility report that meets these criteria will be sufficient to address the DPU's charge, rise to the challenge posed by the state's policy objectives, and meet policymakers', investors', and customers' needs for evaluation of pathways. We present these criteria now in order to inform the scope of work for the consultant(s) hired by the utilities to conduct these studies, and to provide transparency regarding the evaluation criteria by which the utilities should expect to be judged when the reports are filed.

We recognize that a roadmap does not prescribe a single path. In developing a roadmap, the DPU should recognize that flexibility will be required in order to adapt to future conditions. At the same time, however, rapid and aggressive near-term action is required in order to meet the state's 2030 and 2050 emission reduction requirements. Even a year of delay in action could make the 2030 emission level much more costly to meet, while simultaneously making it harder to transform markets at the pace required to meet the 2050 requirement. These criteria are intended to elicit all the necessary information required to make decisions, even in the face of uncertainty, that will enable action at the required pace and scale while considering equity, affordability, reliability, and quality of life.

Each of the sections that follow provides a set of criteria within a given topic area, explains why these are necessary criteria, and provides context for each criterion where necessary. We address the process and design of the studies themselves in Section 2. Section 3 addresses energy supply and the transmission of energy carriers. Sections 4 and 5 turn to the end use, with Section 4 addressing technical questions and Section 5 addressing customer perspectives and the importance of quantifying impacts on different types of customers. Section 6 addresses infrastructure planning for both gas and electric systems, and Section 7 concludes the paper with an examination of utility business models, the financial implications of the gas transition for the companies and their investors, and the resulting challenges ahead for utility managers.

2. Process and Study Design

The first set of criteria for a well-executed analysis relates to overall study design and process. These are cross-cutting concerns, which if not executed well will undermine trust in the analysis or render some or all of the analysis wasteful or useless.

Each case must be consistent with legal mandates (such as the 2030 CECP and 2050 net zero requirement) and document a clear relationship to the 2050 Roadmap

Pathways that are not consistent with the Commonwealth's overriding climate change mitigation objectives are not realistic and are counterproductive to the DPU making essential and timely decisions. Each scenario considered or modeled must also be consistent with the Commonwealth's other energy policies, such as the renewable portfolio standard, clean electricity standard, alternative portfolio standard, renewable energy procurements (offshore wind, etc.), and the statutory requirement to achieve all cost-effective energy efficiency. The 2050 Roadmap illustrates that multiple pathways are consistent with the established statutory and regulatory context. Where achieving a pathway modeled in a given case would require changes to statute or regulation, the report must be explicit about that assumption and the required change.

Cases which parallel the 2050 Roadmap would be particularly useful, because those cases are well documented and vetted by the Executive Office of Energy and Environmental Affairs. In particular, each utility should model and present a complete analysis of a case that corresponds to the All Options (baseline) case in the 2050 Roadmap. Cases which deviate from the 2050 Roadmap cases should do so only in ways that are clearly and carefully documented.

Each analysis should evaluate scenarios that are complete and internally consistent

When developing cases, the analysis should assume that the governmental, utility, and private sector actors reflected in a given scenario (including residents and businesses) would act reasonably to make cost-effective and prudent decisions. The analysis must avoid scenarios in which some entities make decisions that don't make sense (such as choosing manifestly non-cost-effective appliances or fuels, unless there is a compensating policy or program that changes their incentives). Each case presented and analyzed must be the best version of its scenario, attempting to solve all the problems raised within it. "Straw" scenarios that serve primarily as a foil to make a preferred scenario or scenarios look better are not useful.

Analyses must account for the broader energy system, not just the gas utility sector

A key question in developing scenarios will be the extent of remaining emissions from the natural gas utility sector, in the context of overall achievement of GHG reductions. It is therefore critical for analyses to be explicit about assumptions, emissions, and services delivered by the broader energy system. Electrification of building heating, for example, requires modeling of the electric sector in concert with pipeline gas; electrification of transportation offers potential controllable load that could reduce costs in the electric sector. The analyses should address the need for all sectors to contribute to meeting legal mandates, with the goal of finding an implementable all-sector path with both reasonable costs and sufficient certainty of success.

Analyses should be clear and reasonable regarding assumptions for policies and pathways implemented in other states and regions

While Massachusetts utilities and policymakers cannot be completely sure of the structure of policies and long-term goals of other states and provinces, the analyses must take the stated objectives and statutory or regulatory requirements of other jurisdictions into account. It is not reasonable to assume that Massachusetts will meet its goals while its neighbors pursue a "business as usual" path. The report must clearly document and justify the assumptions for the pathways pursued in other states/provinces. This is particularly important around shared resources (such as the regional transmission system) or limited resources (such as biofuel with credible lifecycle carbon accounting and agricultural waste).

Analyses should incorporate reasonable assumptions regarding the efficacy and impact of policies that comprise part of the scenario

Scenarios must not simply assume 100 percent success at achieving a policy target, or 100 percent participation in a program, without backing up those assumptions with clear sources and/or analysis. For instance, even regulatory tools such as building codes take some time to achieve their full effect due to development timelines and they are only as good as their enforcement.

If the analyses are conducted separately for each gas utility, the utilities should standardize approaches and assumptions to the maximum extent possible

If each gas utility conducts any of its own separate analyses, the utilities should coordinate on standardized approaches and assumptions to best of their abilities in order to allow for cross-comparisons between utilities. Utilities should also examine at least some of the same cases and produce explicitly comparable outputs in practical units such as rates, tons, capital investments, and therms. In particular, the assumptions and forecasting methodology used to project winter peaks and load shapes should be standardized where possible and clearly documented. This will require the utilities to make common assumptions for weather and associated energy system demands and to facilitate DPU and stakeholder review of the analyses.

While electric system utilities have established their reliability standard for resource adequacy based on the 1-day-in-10-years requirement, gas utilities typically plan for a more extreme design day (although there is not a consensus planning standard). Since managing winter peaks is likely to be a key issue in this analysis, the gas utilities need to develop and clearly state common assumptions surrounding which reliability standard they are planning for; and they should justify their choice. To the extent possible, this process should consider the rate at which winters have been trending warmer and account for climate change when assessing the risk of extreme winter weather events.

Analyses should utilize a well-defined and explained benefit-cost framework

The analysis should at minimum rely on the cost-effectiveness framework and practices that the state's energy efficiency program administrators have been using over many years, based on the DPU's Energy Efficiency Guidelines under D.P.U. 11-120-A and D.P.U. 20-150. This framework requires the use of the Total Resource Cost test and includes all benefits and costs associated with the energy system as well as all benefits and costs associated with program participants.[8] Following one of the key principles of the *National Standard Practice Manual*,[9] the analysis should further consider including other benefits and costs that support the state's policy goals and objectives which go beyond the TRC framework (such as the societal value of avoided GHG emissions and public health benefits).

Analyses should be transparent and accessible to stakeholders

Developing trust in the results of analysis requires the ability to understand and follow the details of quantitative analysis. The utilities must publish the models used or (if proprietary models must be used) publish all inputs and outputs and set up a process for stakeholders to request scenarios to be run. As just one illustrative example, when modeling heating service delivery during winter peaks, the utilities should be prepared to share models of and assumptions regarding the electric and gas sectors (such as the generation mix, electric and gas prices to different sectors and entities, and the planning reliability criteria used).

We recommend that the utilities establish an explicit stakeholder process with the Attorney General's Office, the Department of Energy Resources, or a contractor convening stakeholder input and broader public comment at regular intervals. This should include regular check-ins with agendas covering presentations of draft or interim results (rather than simply updates on the process). The Energy Efficiency Advisory Council's Equity Working Group and GWSA Implementation Advisory Council working groups recently consulted as part of the 2050 Roadmap and 2030 CECP processes. These provide existing structures that the DPU should utilize to avoid reinventing the wheel. It is important to also engage and inform beyond those already engaged stakeholders. For example, explicit and targeted engagement with energy justice and customer protection advocates should inform how scenarios' results are evaluated and presented.

Analyses and recommendations should account for the risk of failure along different pathways, as well as the path dependence which limits the ability to change course in the event of failure, and identify the state of technological maturity (and associated amount of risk) for each technology

Some pathways may depend on technologies not yet in wide use or production (such as hydrogen boilers or gas heat pumps) and most will assume that technologies improve in their performance over

---

[8] The costs include measure costs and all program administrative costs including shareholder incentives. Benefits include all of utility system benefits such as avoided costs of energy, generation capacity, transmission and distribution capacity, environmental compliance costs, reduced risk, and increased reliability. Environmental compliance costs include the cost associated with meeting the GWSA's GHG emissions reduction targets. Benefits also include various participant benefits including, but not limited to, fuel and water savings as well as improvements in health, safety, comfort, and productivity.

[9] Woolf, T., et al. 2020. *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources*. National Energy Screening Project. Available at: https://www.nationalenergyscreeningproject.org/national-standard-practice-manual/.

time. However, product availability and performance are not assured. Similarly, new policy or programmatic approaches may have greater risk of failure or may need more time to be effective than assumed. For example, when developing scenarios one technology may appear to enable a cheaper path under baseline assumptions, but if it were to fail to be available or were not adopted, the resulting pathways could result in very high costs. Meanwhile, another technology or policy approach might be more proven but slightly more expensive, or allow optionality and flexibility in the case of failure. Analyses should make clear where this tradeoff exists, and how it informs the recommendations.

Recommendations should be sufficient to achieve a pathway consistent with state policy, and identify clear responsibilities for action

Where recommendations differ from, or elaborate upon, the objectives and policies presented in the 2030 CECP, the utilities must present sufficient detail and analysis to show that the recommended policies or actions achieve the same GHG objectives with reasonable cost, both before 2030 and in their effects between 2030 and 2050.

Recommendations should be actionable, with both a clearly identified entity that would act and a clear timeline for action. In the case where it is not clear that a recommendation can be executed (e.g., it depends on federal action or action by another entity outside of Massachusetts), the report(s) should identify the fallbacks that would be needed to achieve the proposed pathway.

Where possible, recommendations should be measurable and paired with the appropriate metrics. The report should also present the potential limits or obstacles to meeting the recommendations (and what the source of that barrier is, such as legislative, shareholder, regulator, etc.).

3. ENERGY CARRIER SUPPLY AND TRANSMISSION ANALYSIS

The second set of criteria relates to the supply of energy carriers[10] and the transmission infrastructure for those carriers to bring them to the distribution system in Massachusetts. Existing fossil fuel and electric infrastructure may require changes or additions (e.g., to carry more energy or a different fuel), new intermediaries such as hydrogen require careful and complete assessment of production and transportation, and non-fossil chemical fuels have specific concerns related to their supply and production.

[10] By "energy carriers" we mean the physical processes or chemicals used to transport energy from where it is gathered in the environment (such as from sunlight on a solar PV generator or a well drilled in the earth) to end use customers.

3.1. Fossil Gas, Oil, and Propane

The analysis should identify the natural gas transmission, distribution, and storage assets utilized (currently built or unbuilt), and show operation consistent with the physical and operational limits of those assets

Pathways that do not reflect the gas distribution system's current or projected assets or do not comply with current operating limits are unrealistic and will not be useful in this context. Limits such as safe operating lifetimes of assets should be inputs to the model such that scenarios are not allowed to deviate from these bounds.

The analysis should be transparent about the prices of fossil fuels assumed in the analysis, the breakdown of those prices between commodity and transportation costs, and how those prices reflect scenario assumptions regarding existing and potential future regulations (national, state, or local) on its production as well as demand for fossil fuels in other regions

While there is still uncertainty surrounding future policies and long term-goals of Massachusetts and its neighbors, those performing these analyses must do their best to consider the impacts of potential legislation on fossil fuel prices and demand such that the final results of the study are reasonable and defensible. Assumptions made about electrification and fossil fuel consumption within a given scenario have the potential to impact price forecasts and need to be accounted for. All assumptions used to develop these price forecasts must be clearly stated so that stakeholders may assess whether or not they are realistic for each scenario.

The analyses should account for the GHG emissions resulting from methane leakage throughout the supply chain, including at production, compression, transportation, and end use

It would be a flaw of the analysis if the utilities were to exclude emissions associated with methane leakage from the total GHG impacts of the gas distribution system and at end uses. While the gas operators are required by Massachusetts to report the estimated methane emissions from their mains and service pipelines, [11] the actual impact may be higher due to leakage at end uses and actual leaks that exceed the estimated values used in emissions reporting. A recent study focusing on methane leakage of residential end uses in Boston calculated emissions rates for multiple gas appliances.[12] The emissions caused by methane leakage at production, transition into pipelines, transition from pipelines, and at end use are not negligible and should not be treated as such in this analysis. The utilities should

[11] 310 CMR 7.73. 2020. *Reducing Methane Emissions from Natural Gas Distribution Mains and Services.* MassDEP. Available at: https://www.mass.gov/doc/310-cmr-773-emergency-regulation-showing-changes-december-2020/download

[12] Merrin, Z., P. Francisco. 2019. "Unburned Methane Emissions from Residential Natural Gas Appliances." *Environmental Science and Technology* 53, 9, 5473-5482. Available at: https://doi.org/10.1021/acs.est.8b05323

be explicit regarding the assumed relationship between leakage rates and the volume of lost and unaccounted-for gas.

Additionally, the 20-year Global Warming Potential (GWP) for methane should be used in this analysis as opposed to the 100-year GWP to properly align with the timeframe defined by the state's net zero goal. The findings of this analysis will be far more useful if the emissions impact of methane is commensurate with the relevant policies.

3.2. Electricity

The analyses should identify the electric generation, transmission, and utility-scale storage assets utilized (currently built or unbuilt), and show operation consistent with the physical and operational limits of those assets

Pathway models must be set up such that they are representative of the current electric grid and any planned generation, storage, and transmission investments in order to ensure the results reasonably represent the system. Given that the modeling will be done at the transmission level, the gas utilities should also represent the flexible interconnections in place with Canada. The analysis must also assume reasonable and safe operating limits and lifetimes for each asset. The 2050 Roadmap provides reasonable cases for the development of renewable and zero-carbon supply resources for the electric sector which the utilities can use. Analyses which rely on substantially different cases than the range presented in the 2050 Roadmap must meet a high burden to show they are reasonable.

The analyses should identify the fuels consumed by combustion power plants, and their sources (storage, transmission, and production)

The gas utilities will need to transparently state their assumptions about the fuels being used by combustion power plants, especially as GHG limits grow more stringent. Namely, the utilities should discuss the role of hydrogen as a fuel as well as for non-electric purposes such as a scalable flow battery used for storage. If any analysis proposes to use methane in power plants, the model must account for upstream emissions caused by leakage throughout the supply chain.

The analyses should transparently develop internally consistent forecasts for gross and net load (as well as flexible load) that are consistent with meeting GHG requirements, including the impact of transportation electrification

A key component to these modeling analyses will be the development of load forecasts that properly account for the impact of electrification and energy efficiency. One thing the gas utilities should consider is the potential for demand response and load-shifting to provide a more flexible load, especially in the context of transportation electrification. The 2050 Roadmap provides reasonable estimates of the load flexibility resulting from the inherent storage in electric vehicles as well as building-based demand response. Substantial differences from the 2050 Roadmap must be justified.

3.3. Bio-Derived Methane

For scenarios which utilize methane derived from biological sources such as waste or agriculture…

The analyses should provide (and justify) explicit assumptions regarding the cost and availability of bio-methane for consumption in Massachusetts

For scenarios that propose to rely on bio-methane as a replacement for fossil fuels, the gas utilities must provide information that demonstrates how this fuel will be supplied. The critical aspects here are the amounts of different kinds of feedstock (which may change over time), the development of facilities to turn that feedstock into pipeline-quality gas, how that fuel will be transported for end use, and the competing demands for the resulting fuel in different sectors (including transportation and electric generation) and regions of the country. Given that many other jurisdictions are looking to move away from fossil fuels, it would be unreasonable to assume that the current supply chain of bio-methane is sufficient to support the projected demand. For this reason, the utilities need to consider how long it will take for the industry to increase production enough to meet the assumed portion of regional demand. They must also quantify any transportation barriers for end use. In addition, the utilities must present reasonable cost projections for this fuel that are consistent with the production situation analyzed and the prices offered in other markets.

The analyses should account for the GHG emissions resulting from methane leakage throughout the supply chain, including at production, scrubbing and compression, transportation, and end use

The process of converting organic waste into usable pipeline gas requires many steps, each of which have the potential to release methane into the environment. For example, IEA Bioenergy has identified areas of the production process where fugitive emissions have been especially problematic, such as digestate storage and biogas upgrading.[13] The gas utilities should ensure they use the most accurate leakage rate estimates as well as the 20-year GWP in order to properly estimate GHG emissions associated with bio-methane.

The analyses should provide (and justify) explicit assumptions regarding the net GHG emissions resulting from the use of bio-methane in the manner incorporated into the scenario, including a clear case supporting any claim of zero or negative net emissions

The gas utilities should be required to show how they derived the net GHG benefit of replacing natural gas with biogas and provide a clear statement of their assumptions. This methodology must include the impacts of leakage throughout the supply chain and set a reasonable baseline for avoided methane emissions. For example, it would be unrealistic to assume that methane produced from agricultural waste would otherwise be released into the atmosphere and that all of those emissions would be

---

[13] IEA Bioenergy. 2017. *Methane emissions from Biogas Plants.* Available at: https://www.ieabioenergy.com/wp-content/uploads/2018/01/Methane-Emission_web_end_small.pdf.

avoided with the conversion to renewable natural gas in these studies. Assuming that other jurisdictions will take comparable action to reduce GHG emissions, as we suggest, requires assuming mitigation of methane emissions from agricultural or waste sources in the baseline case.

3.4. Hydrogen

For scenarios which utilize hydrogen either as an end-use fuel or intermediary…

The analysis should account for the inputs required to produce hydrogen (including electricity and/or natural gas) and the outputs of the hydrogen production process (including GHG emissions)

Pathways that require the use of hydrogen as an intermediary or end-use fuel must clearly state how the fuel will be produced and what the impact on GHG emissions will be. If electricity will be used for hydrogen production, the gas utilities should include a cost comparison between hydrogen use and electrification as well as an analysis of the additional electricity needed for this process. This should consider any contribution to peak load caused by increased electricity use for hydrogen production.

If a fossil fuel such as methane is proposed as a source for hydrogen, the utility should clearly state its plan for the resulting carbon dioxide emissions from this process, as well as accounting for methane leakage. This should include a discussion of carbon capture and sequestration (CCS) requirements such as infrastructure and costs. Because CCS is a newer technology, price estimates should account for startup and learning costs.

The analysis should identify and account for the required infrastructure for the production, processing, and storage of hydrogen on the timescales relevant to each scenario

Given that hydrogen is not currently a grid-scale technology, the gas utilities must consider the costs and technological risks associated with building out the required infrastructure. Scenarios that rely on hydrogen should clearly discuss the required investment and expected performance of assets such as electrolyzers and steam reformers. Cost, performance, and technological feasibility should be addressed for hydrogen storage (as pure hydrogen or in the form of hydrogen-rich chemicals like ammonia) for scenarios in which hydrogen is used. This includes storage for use in the near term (for instance, to balance offshore wind variability) or for seasonal storage.

The analyses should identify and account for the required pipeline infrastructure for hydrogen, including which—if any—natural gas infrastructure is repurposed for carrying hydrogen, as well as associated investments required for that infrastructure

For any scenarios dependent on hydrogen being transported around the region or between regions, the utilities should include a discussion on the limitations and potential capability of the current gas pipeline infrastructure to accommodate hydrogen as well as any associated necessary incremental investments. If a comprehensive retrofit or overhaul of the existing system to fully expand hydrogen transport capability is used in a scenario, the full costs and benefits of that investment must be accounted for over its full lifetime.

3.5. Methane Synthesized from Hydrogen

For scenarios which utilize hydrogen as a feedstock to produce methane (sometimes called synthetic natural gas)…

The analysis should identify the source for carbon to be used in producing the methane, and the mechanism used to transport the carbon to the point where it is used to produce methane

Methane can be produced from hydrogen by adding a carbon atom to four hydrogen atoms. The gas utilities should transparently state where they plan to get the carbon from for any scenarios that intend to synthesize methane from hydrogen. This should include a discussion of the carbon source in terms of geography and process as well as any required infrastructure investments for its transportation, gasification, catchment, etc., and any assumed market development or activities in other regions that would support or compete with the Massachusetts utilities' needs. The analysis must account for the cost of all of the feedstocks (carbon, hydrogen, and energy) and all associated infrastructure.

The analyses should account for the GHG emissions resulting from methane leakage throughout the supply chain, including at production, compression, transportation, and end use

The ability of synthetic methane to act as a low- or zero-GHG replacement for fossil gas depends on how much methane is released in the process between its production and intended combustion. Purposely producing a higher-GWP gas such as methane comes with responsibility to minimize leakage, and account for any that is lost. Emission accounting should include incidental methane release during production and leakage throughout the supply chain, as well as emissions resulting from energy used in the production and transport of the fuel.

4. END-USE EQUIPMENT

The third set of criteria relate to assessment of end-use equipment. Some of these concerns apply to all end-use equipment, while others relate to specific types of equipment. They address stock-turnover timelines, efficiency gains, and technology performance.

The analyses should account for the natural timescales of equipment replacement and stock turnover, as well as the time required to develop supply chains, educate consumers, and train the necessary workforce

Stock turnover in end-use gas equipment, especially for large equipment such as space and water heaters, takes place over many years (with the timescale varying based on the equipment type and its useful life). Further, increases in market share for new end-use technologies such as heat pumps occurs gradually based on the expected changes in relevant supply chains and training of workforce, as well as consumer education. The gas utilities need to account for these changes in the market (which themselves may be driven by policy) when assessing the expected energy impacts from such changes.

On the other hand, the gas utilities also need to examine the level of transition and market transformation that is required in the near and long terms in order to be on track for the GWSA 2050 targets and consistent with the 2030 CECP targets. The utilities then need to adopt necessary programmatic initiatives to help transform the market (e.g., new rebates for heat pumps, training of HVAC contractors) and encourage necessary changes in end-use equipment adoption by consumers (i.e., fuel switches from gas equipment to heat pumps).

The analyses must provide (and justify) explicit assumptions for the cost and performance of each end-use technology utilized in each scenario, including how cost and performance change over time

Technology cost and performance will influence how and how much consumers use energy and what type of equipment and fuels they use (and more specifically how equipment types and fuel demands change over time). For end uses currently served by natural gas, as well as for any other end uses where the assumptions influence the evaluation of scenarios (such as air conditioners, but also electric vehicles if their load flexibility varies between scenarios, etc.) it is important for the gas utilities to explicitly incorporate the cost and performance of each relevant end-use technology in each scenario. The utilities also need to incorporate the expected changes in the cost and performance of the end uses over time, especially for emerging technologies or technologies with smaller market penetration rates, such as electric heat pumps. When conducting this analysis, the utilities need to identify and take into account the level of risk and maturity of each technology—that is, how certain should we be about the cost and performance of a given piece of technology in a given year.

The analyses must account for the difference between manufacturer specifications and real-world equipment performance

Analyses of end-use equipment and energy consumption need to use equipment performance data based on real-world equipment performance because real-world performance often differs from manufacturer specifications. This concern applies to heat pumps, but also to natural gas water heaters and furnaces and boilers. Where manufacture specifications are key assumptions in gas utilities' energy planning, such assumptions need to be adjusted for the difference between manufacture specifications and real-world equipment performance.

The analyses must be explicit about any projected changes in the state's industrial sector, and how manufacturers' energy and process fuel demands will be met

The analyses should use the best available information at the time of planning to take into account the projected changes in the state's industrial sector (including electric power generators and combined heat and power systems) and how the changes will affect energy use for the sector. If the pipeline gas system is used differently to serve these customers than for other classes (e.g., residential service is transitioned to electric but industrial uses retain pipeline gas) this impacts the allocation of costs and could have an impact on the state's economic vitality.

The analyses must be clear regarding assumed regulations for end-use demand, including building codes, appliance standards, permitting requirements, and other federal, state, and local regulations

Federal, state, and local regulations all influence the way consumers use natural gas and other fuels. Such regulations include federal appliance standards, state building codes, local stretch codes/net-zero/all-electric codes, and clean heat standards. It is imperative for the analysis to account for the regulations currently in place and expected to be implemented in the future, including in particular those described in the 2030 CECP.

4.1. Electric

The analyses must account for the performance of air-source and ground-source heat pump systems at different outdoor temperatures

The performance of heat pump technologies for space heating is significantly affected by the outdoor temperatures or the heat sources heat pumps rely on as a heat source. The level of such impacts is especially large for air-source heat pumps when compared to other types of heat pumps. Therefore, the analyses must incorporate heat pump performance at different temperature levels down to the coldest expected temperatures.

The analyses should account for the impact of heat pump water heater location on energy consumption and peak demand

The most widely used heat pump water heaters are an all-in-one packaged type that can be installed in various locations in or around buildings, such as a basement, closet, utility room, garage, or outdoors. Because ambient temperatures in these locations differ, the performance of heat pump water heaters also differs markedly by these locations. Thus, it is critical to develop reasonable assumptions about where most heat pump water heaters will be installed and account for the expected performance of the heat pump water heaters. Where possible, the analysis should also incorporate the cooling and dehumidifying benefits that this equipment provides during summer months.

The analyses should account for the replacement of existing electric-resistance-based heating systems (for both space and water heating) with heat-pump-based systems

When electric heat pumps replace existing electric resistance heaters, the heat pumps can provide substantial energy savings benefits to consumers as well as for the electric grid system; they can be as much as four times as efficient as electric resistance heaters. They can save space and water heating bills for consumers and reduce winter peak loads on the electric grid substantially, mitigating the increase in load from electrification of fossil fuel end uses.

The analyses should reflect the potential for load flexibility in newly electric loads

Water heaters, and to a lesser degree space heating in tight and efficient building shells, can offer load flexibility because of inherent thermal storage. Further, a district heating system, while not widespread in the state currently, can receive heat produced by electric heat pumps and provides a large heat storage that can work as a large load flexible resource. Scenarios must reflect the value and utilization of this flexibility where it is cost-effective, and include recommendations about how to capture this potential.

4.2. Hybrid Heat Pump and Combustion Systems

For scenarios which utilize hybrid heat pump/combustion systems (such as integrated furnace and ducted heat pump systems, or ductless heat pump systems installed alongside boilers)…

The analyses must identify and justify the assumed controls used to dispatch the combustion or heat pump components, such as the changeover temperature

Hybrid heating systems offer the potential to mitigate peak impacts on the electric system in exchange for maintaining peak draws on combustion fuel systems and the associated emissions. It is therefore essential to document and include explicit assumptions and analysis of the form and action of the controls that govern which system(s) are operating during which conditions. For example, is there an outdoor temperature at which the heat source would change over? A signal from the utility? The analysis should also compare the customer economics and system impacts of maintaining pipeline gas connections for the combustion fuel versus the use of on-site storage (e.g., propane tanks).

4.3. Hydrogen and Blends

For scenarios which utilize hydrogen, either as the sole fuel for an end use or blended with methane…

The analyses should account for any need to replace customer end-use equipment to burn the supplied fuel, including any need to simultaneously replace all equipment within a building or served by a distribution line

Most combustion equipment cannot burn hydrogen blended into its supply fuel above a certain percentage. For example, safety features of natural gas equipment depend on a colored flame, while hydrogen burns with a nearly invisible flame.[14] If a scenario depends on burning hydrogen above the blend limits established by existing equipment, it must account for the cost of equipment replacement, competition with delivered gas (e.g., propane or liquified natural gas), and the need to coordinate equipment replacement across all systems connected to the pipeline that uses the new fuel.

The analyses should account for any need to replace transmission or distribution pipelines, services, or other utility assets in order to transport the modeled fuel, and be explicit about the blend limits of any equipment not replaced

Some metals can become brittle when exposed to hydrogen, and different ignition characteristics can change safety limits on equipment.[15] As a result, both pipelines and equipment (like compressors) may have limits on the amount of hydrogen that can be safely blended. Typical limits for hydrogen blending with existing equipment are in the range of 20 percent by volume; due to the lower energy density of hydrogen, this is about 7 percent on an energy basis. Scenarios that utilize higher levels of blending (or pure hydrogen) should account for these effects and the associated investments. If the gas system would be operated with multiple fuels or blend levels, the utilities must describe how the systems would be segregated and account for associated costs.

The analyses should account for changes in pipeline energy-carrying capacity and leakage rates

Hydrogen has a different energy density than methane (the small molecules carry less energy per molecule but can be packed more closely together), so a pipeline carrying hydrogen has a different capacity than the same pipe carrying methane. For scenarios utilizing hydrogen, the analysis should include the cost of upgrading any lines which do not have the necessary capacity to meet customer needs, and/or include explicit actions to lower customer demand. In addition, hydrogen has higher leakage rates by approximately a factor of three (including through plastic pipes), so changes in losses must also be accounted for.[16]

---

[14] U.S. Department of Energy. "Safe Use of Hydrogen." Accessed January 2021 at https://www.energy.gov/eere/fuelcells/safe-use-hydrogen.

[15] Melaina, M.W., O. Antonia, and M. Penev. 2013. *Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues*. National Renewable Energy Laboratory. NREL/TP-5600-51995. Available at: https://www.energy.gov/sites/prod/files/2014/03/f11/blending_h2_nat_gas_pipeline.pdf

[16] *Ibid*.

4.4. Demand-Side Management Programs

The analyses should describe how the outcomes of energy efficiency programs would need to change to achieve the goals or levels of deployment described in each scenario

Current natural gas energy efficiency programs focus on gas appliance energy efficiency measures and weatherization measures. Gas efficiency equipment programs prolong reliance on gas systems and make it harder for the state to meet the state's long-term GHG emission reduction targets. Energy efficiency programs need to shift away from funding high efficiency gas consuming equipment and focus mainly on building shell improvements and heat pump technologies. In fact, the 2030 CECP reflects this need by stating that the state will move Mass Save programs away from support for fossil fuel heating systems by the end of 2024 (and 2022 in new construction).[17] Thus, it is crucial for the analysis to explicitly account for and model these changing efficiency programs. This includes how costs would be allocated between electric and gas ratepayers (and the resulting impact on rates) and how the programs will scale up to meet the deployment targets established in the 2030 CECP and required to meet 2050 targets. If scenarios include financing-based approaches or amortization of efficiency program costs, the analysis should account for the spread of customer and program costs over time.

The analyses must reflect state policy to achieve all cost-effective energy efficiency, and describe how cost-effectiveness evaluation would reflect changes in fuel costs and equipment lifetimes

The state has a mandate for energy efficiency program administrators to acquire all available, cost-effective energy efficiency resources, and the analysis must follow this mandate. The analysis should account for the avoided costs from beneficial electrification. This entails avoided costs related to the following: gas commodity (including the cost of any lower-GHG fuels blended into or used instead of fossil methane); gas transmission and distribution pipeline systems; gas pipes and meter equipment to buildings; GHG emissions; and methane leaks. In addition, the cost-effectiveness analysis must recognize and analyze changes in natural gas equipment lifetimes consistent with the timeline of the state's emissions mandates. (If fossil fueled equipment will be replaced before the end of its typical useful life, then only savings associated with the shorter lifetime should be counted.)

The analyses should reflect the potential to acquire increased load flexibility and demand response in both electric and pipeline gas systems

Emerging load flexibility and demand response measures are increasingly available. Examples include gas demand response measures such as thermostat and heating system controls, electric water heater-based demand response, and controlled electric vehicle charging. These measures can effectively store excess electricity from the grid when prices are low and help support the integration of renewable energy on the grid. Further, district heating systems could also store heat when fuel prices are low

[17] 2030 CECP, p. 30-32.

and/or excess electricity from renewable energy is available. By incorporating this potential, the analyzed cases can reflect the obligation to pursue least-cost service.

The analyses should reflect customer benefits from improved building shells, including addressing pre-weatherization issues such as the presence of asbestos, knob and tube wiring, or other health and safety issues, and the improved health benefits resulting from better control of the indoor environment such as associated improvements in indoor air quality

Non-energy benefits are included in cost-effectiveness screening for demand-side programs. Building improvements to reduce or eliminate GHG emissions also provide an opportunity to improve the health and safety of those buildings for their occupants. This includes the removal of toxic substances, improved moisture management, and elimination of combustion-byproducts (such as carbon monoxide and particulates) and their associated risks. Indoor air quality expectations may also change in the wake of the COVID-19 crisis. Scenarios should account for these benefits (quantitatively where possible, but at least qualitatively) as part of the overall accounting for comparing scenarios, as well as to evaluate the impacts of particular potential programs or recommendations.

5. Customer Perspective and Impacts

The fourth set of criteria relate to customers, who will make the choices regarding infrastructure in their buildings and pay the bills to cover the costs of the energy and transmission and distribution infrastructure required; customers therefore bear ultimate cost and a substantial portion of the responsibility for the success of the energy transition. These criteria also address critically important equity concerns.

The analyses must reflect and respect the degree of customer choices regarding the fuels, appliances, and equipment used in their homes and businesses

The appliances and systems installed in customers' homes and businesses are selected by the customers, under the influence of policy (such as codes and standards and policy-influenced fuel prices). Where scenarios depend on customers making choices that are not straightforwardly cost-effective from a customer standpoint, they must include a discussion of the policy, incentive, or regulation used to result in that outcome. For example, if a scenario involves customers using hybrid (dual fuel) heating systems, it must explain how the rates and rate designs for both electricity and gas make this option more attractive to customers than full electrification over the lifetime of the installation and/or identify the policy or program that would drive this choice. If new utility infrastructure (such as new meters) is required to implement the necessary policy or rates, those costs should be included as well. Note that analyses should also include the possibility for customers to choose to use delivered fuels (such as liquified natural gas or propane), in addition to pipeline gas or electricity.

The analyses must account for the differences between customers in different classes, and reflect the impact of each scenario on customers in each class or category, including low-income, moderate-income, and renters within the residential class, as well as different types of commercial buildings and industrial consumption (such as electric generators, combined heat and power systems, and district heating)

Utility analysis often treats all members of a rate class as a single group. This illuminates important distinctions. However, further disaggregation to analyze the impacts on sub-classes is necessary to fully evaluate the equity implications of each scenario. Utilities should be thoughtful about the accuracy of their data sources, since some data sources on low-income populations do not capture all customers who qualify. Relevant sub-classes could be geographic as well, depending on whether the scenario includes geo-targeted efforts to prune the gas system and switch groups of customers to electricity or other types of heating systems.

The gas utilities have unique access to customer-level data on the demand for natural gas as a function of temperature, which enables them to assess the heating system capacity that each customer would require to meet their comfort needs during winter peak conditions. The utilities should use this distribution of customer needs, rather than average values, when assessing customer economics, equipment costs, and building retrofit opportunities.

The analyses must track the rate and bill impacts of each scenario on customers with reduced agency to make infrastructure choices in their homes, such as low- and moderate-income households and renters, and recommendations must be tailored to protect these customers and ensure that they see benefits throughout the study period

If pipeline gas rates increase substantially over the course of a given scenario, the customers who remain on the gas system for a longer time, especially those with higher consumption, will pay a higher fraction of the total costs. Renters are often unable to make efficiency improvements to their residences, and low- and moderate-income customers face challenges with access to capital to make changes to their building systems without specific policy or programmatic intervention. As a result, these customers could pay more for service than would be equitable. If there is a risk of such an inequitable outcome in an otherwise promising scenario, the report must include recommendations to mitigate the effect.

The analyses should reflect the impact of the differences between scenarios on economic development in Massachusetts, including the state’s ability to attract and retain growing and forward-looking firms

Energy costs are a relatively small portion of the cost of doing business for most companies, but are a large portion for some companies and industries. When evaluating the costs and benefits of different pathways, including their different effects on energy costs of different sorts, the analyses should account for the impact on firms of all types, and the resulting impact on the state’s economy. The analyses should assume that other jurisdictions and countries are taking aggressive actions to reduce emissions, in line with commitments under the Paris Agreement.

Massachusetts has also invested substantial resources in developing an ecosystem of innovative and high-growth companies that are primed to succeed in a clean energy transition, such as through support from the Massachusetts Clean Energy Center. To the extent that the pathways identified by the utilities extend and accelerate this leadership, these effects should also be identified—even if they are difficult to quantify. If particular kinds of firms are likely to be spurred by the transition (such as those related to innovative ways to retrofit buildings or develop new heating technologies) the analyses should identify that potential along with the workforce development impact and requirements for such growth.

The analyses should reflect both energy and non-energy benefits to customers and to broader society

In addition to the non-energy benefits to customers discussed above (for example, from toxin mitigation and comfort improvements) benefits of decarbonization can accrue to non-participants through improved local and regional air quality (from reduced combustion byproducts from homes, reduced pipeline leakage, and reduction in pollutants associated with reduced need for compressor stations and other infrastructure).

Retrofitting millions of homes and businesses to be more efficient and use non-emitting appliances will also have substantial impacts on the building trades. Analyses should quantify the job impacts of this increase in activity. Job and GDP impacts should be evaluated alongside traditional cost-benefit or cost-effectiveness analyses.

The analyses should be explicit regarding any customer switching from delivered fuels (propane, heating oil, and liquified natural gas) to pipeline natural gas, or vice versa, and identify the resulting impact on customer equipment purchases, early retirement of equipment, customer energy bills, and GHG emissions

Gas utilities have been encouraging oil heat customers to switch to pipeline gas to reduce cost and emissions. However, a customer making such a switch today and investing in new space and water heating systems could be creating a substantial cost before 2050 if that infrastructure is retired and replaced with a heat pump-based system. This cost could be particularly significant if the new gas systems would not reach end of life at the same time, resulting in additional early replacement costs. The analyses must take a full-time-period look at the overall costs associated with use of gas as a "bridge" fuel for such customers compared with direct transition to electricity. The analyses should account for the potential use of bio-heating oil as well, including in dual-fuel homes that add a heat pump to an existing oil system.

As mentioned above, the analyses should also consider that customers might switch from pipeline gas to delivered fuels if pipeline service becomes uneconomic, and include recommendations to mitigate any negative effects resulting from such choices.

6. INFRASTRUCTURE PLANNING

The fifth set of criteria for the report and analyses relates to the planning, investments, and ongoing costs associated with the operations and maintenance (O&M) of the gas and electrical distribution and transmission systems in the face of potentially dramatic changes in consumption patterns. These systems must remain safe and reliable, while enabling customers to meet their energy service needs. The systems are also the drivers of substantial ratepayer costs and the assets that would be at risk of becoming stranded if appropriate physical and financial planning are not undertaken. In addition, these assets can have considerable impacts on their physical environments. This section addresses the ethical, operational, and financial impacts of geographic targeting of infrastructure changes.

The analyses must assess the safety and reliability of the gas pipeline system (and the investments necessary to maintain safety and reliability) including any impacts from pipeline replacement programs, changes in fuel blend, or available funds for O&M

It is critically important that the gas pipeline system remain safe and reliable while accommodating the changes in use modeled in the analysis. This applies to both transmission and distribution pipelines. Analyses must therefore include the costs associated with pipeline safety programs and pipeline replacements (including impacts on both O&M and ratebase). Where the fuel used in pipes changes (for instance, to a hydrogen blend or pure hydrogen) the analysis must account for the ability of the pipes of different ages and materials to safely carry the fuel, including any impact on peak throughput, material degradation, and leakage rates. This analysis should be consistent with and strive for co-optimization with analysis of energy efficiency, load flexibility, and geographically targeted electrification to mitigate infrastructure costs.

The analyses should assess the impact of electrification on the electrical distribution system, including any differences between different portions of that system (e.g. radial vs, networked, or areas with different types of load)

As with the gas system, the electric system must also remain safe and reliable in the face of changes in load resulting from electrification of both transportation and building services. The distribution system may see uneven changes in peak loads from clustering of nearer-term adoption of heat pumps and electric vehicles, with other areas not seeing an increase at all or only seeing it later in the analysis period. The analysis should include time-resolved accounting (year by year, for example) of the operating and capital costs associated with making any necessary changes in the electric distribution or transmission systems. This analysis should be consistent with and strive for co-optimization with analysis of energy efficiency and load flexibility to mitigate peak impacts and infrastructure costs.

The analyses must present transparent and justified forecasts of energy service demand, alongside fuel demand, on an energy and peak-demand basis, incorporating the impacts of state and local policies (such as building codes and performance standards)

Since cold climate heat pump technologies became readily available several years ago, the space and water heating equipment markets have started to change, showing increased fuel switching from fossil-based heating systems to heat pumps. Further, both the state and a growing number of local governments are adopting building decarbonization policies and programs to reduce GHG emissions (for instance, net-zero energy stretch codes, building performance standards, fuel switching incentive for heat pumps). These trends are expected to escalate further to reduce natural gas consumption into the future. Conventional load forecasting approaches such as econometric modeling are not well equipped to capture these new trends, because they rely on long-term historical trends. Thus, it is critical for the analysis to explicitly assess and incorporate the expected impacts on annual and peak gas usage from market trends, as well as both existing policies and new policies that are expected to be adopted in the near future.

Each scenario must include a clear statement as to how it treats the obligation to serve new customers and existing customers

Today, if a customer requests service from a gas utility, the company generally has an obligation to provide service at some cost. (The cost to connect may be high, depending on the customer's situation.) At the same time, there are several regions of Massachusetts in which pipeline capacity constraints have resulted in moratoria on new gas connections. In the context of deep decarbonization scenarios, new connections may have a detrimental effect on utility or customer economics. Utilities could mitigate these effects in the scenarios analyzed. For example, utilities could change how costs for new service are recovered; expand or create new moratoria; be allowed to meet the obligation by offering an alternative service such as heat pumps, district heat, or shared ground-source reservoirs; or create other new innovative approaches. Any approach used (including maintaining the traditional obligation to serve) should be detailed and quantified in a manner sufficient to allow careful review and understanding by the DPU and stakeholders.

The analyses should identify and incorporate the use of a full range of existing and emerging potential non-pipeline alternatives and evaluate the benefits and costs of such options in a comprehensive manner

Given the reduction in the pipeline gas in most net-zero-compliance scenarios, it is important not to build more gas infrastructure than is absolutely required, in order to minimize any stranded cost risk. Non-pipeline alternatives (NPAs) such as heat pumps, gas demand response, and conventional gas efficiency measures can be utilized to meet any local growth in heating demand instead of building new gas facilities. To do this, gas utilities will need to develop location-specific forecasts and assess the benefits and costs of all available NPAs in a comprehensive manner. The scenarios, analyses, and recommendations developed through this process should identify how the gas utilities plan to utilize NPAs, and the processes they will use to develop them. NPA cost-benefit analyses should include not just the avoided costs of traditional gas infrastructure investments (for example, transmission and distribution pipelines and compressed natural gas trucks) but also the avoided costs of GHG emissions, including methane leaks, and potential health impacts.

For scenarios that include a substantial reduction in the number of pipeline gas customers, the analyses must include an assessment of the impacts of geographical clustering of customers leaving the gas system relative to an un-clustered approach

Geographical clustering offers the opportunity to strategically retire pipeline assets, reducing the ongoing O&M needs and ratebase. If these reductions are in proportion to reductions in volumetric sales, gas delivery rates would see reduced pressure to rise. On the other hand, clustered transitions off pipeline service could incur costs associated with early retirement of operating assets or switching to delivered fuels. Geotargeting is also associated with, and should take into account, any consideration of alternative busines models regarding networked heating approaches (district heat, shared ground-source loops, etc.)

It would be especially helpful if the reports included explicit identification of the information required to plan for geo-targeted approaches and which of that information is available today or would require additional data collection.

Analyses should identify particular benefits or costs accruing if retirement targets the most harmful assets and those impacting environmental justice populations first

Geographic clustering of asset retirement that begins in environmental justice communities could ensure that those communities do not bear undue costs for the legacy of the gas system. These costs are both financial (relating to the utilities' desire for a return of and on the capital invested in the system before it is retired) and environmental (linked to the byproducts of gas consumption in these homes and neighborhoods). Utilities have unique information regarding the state of the infrastructure, consumption, and building stock in these communities and can therefore examine this type of targeting as part of their scenario design and selection.

7. Business Model

The final set of criteria relate to the business model of gas utilities (and, where appropriate, their associated electric utilities). While states have considered changes to the traditional cost of service ratemaking paradigm for many years, the transformation required of gas utilities in order to meet net-zero GHG targets will likely require changes far beyond those considered in past proceedings. Planning this transition is a major management challenge for utilities and a regulatory challenge for policymakers. This is due to the requirement to meet customer needs at all times throughout the transition while charging just and reasonable rates.

Each scenario analyzed must include a projection of delivery and supply rates for each major class of customers

Both marginal and average rates are critical inputs to customer decisions regarding fuel and appliance choice, as well as investments in efficiency. Both electric and pipeline gas rates are necessary in order to evaluate the customer economics of electrification. Supply rates should account for the impact of a heating sector emissions cap[18] on the GHG intensity of fuels, while delivery rates should account for changes in the volume of fuel delivered (due to the emissions cap, electrification efforts, and other drivers). Where the analysis indicates, or the report recommends, a change in the approach to rate design (for instance, increasing customer charges to reduce volumetric rates) the utilities must be explicit about the rate designs considered and the resulting effects on customer economics, choices, and emissions.

The analyses must incorporate the expected used and useful lifetime for each asset or class of assets (including both existing and new assets) including whether and to what extent new and/or existing assets are at risk of becoming stranded along with any impacts on depreciation rates

Gas pipeline assets are typically assumed to have a lifetime for ratemaking purposes of many decades. However, some pathways analyzed in these reports (including the pathway based on the All Options case in the 2050 Roadmap) will include asset retirements well in advance of 2050. Many pipe assets installed within the last few decades would not normally be fully depreciated by 2050 and would therefore be at risk of stranding if their depreciation rates are not increased. The utilities' analyses must account for these assets, as well as for any new assets that the modeling indicates must be installed between now and 2050 to maintain a safe and reliable system. If assets' costs would be recovered through nontraditional means (such as securitization or recovery from tax revenues) this should be explicitly discussed and modeled.

The analyses must include changes in O&M costs that are appropriate to the changes in the gas pipeline system considered in each scenario

O&M costs have the potential to be a key driver of rate increases if they do not reasonably fall in proportion to sales over the course of the analysis. For example, if many customers implement fuel-switching measures, then a smaller number of customers could end up being responsible for covering the same amount of operating costs. For this reason, the gas utilities must transparently discuss how pipeline system O&M costs are expected to change as a result of the assumptions for any given scenario.

The analyses must evaluate the impact of changes on the utility's workforce, including changes in the number and type of employees, opportunities for employees to move to other

[18] Or other cap as may be required by the final 2030 CECP and any legislation enacted in 2021.

positions within the company (such as those not related to the regulated gas pipeline utility business), and needs for new skills

Transitioning away from natural gas would result in large impacts on current employment within each utility. As part of this study, each gas utility should assess the expected workforce shifts (while accounting for the demographics of its workforce) and discuss how current employees can best adapt as the company's business model changes. For example, the analyses should consider how certain business models have the potential to maintain the expertise of their current employees or transfer them to the electric utility side of the business (where relevant).

Each scenario should include an assessment of the potential impact of changes in the gas utility business and business model on the company's access to capital (both debt and equity) and appropriate return on equity

A regulated utility's allowed return on equity is intended to be set at the level corresponding to its relative level of risk for investors. Assessment of the gas utilities' future should include assessment of how the changes impact the level of risk in the business. In addition, the assessment should address the extent to which the utility will need to raise outside capital, informed by the trajectory of its ratebase of assets. And it should answer the question of whether or not utilities would instead use internal funds derived from operations. This criterion seeks to evaluate the realism of the analyzed pathways from the investor perspective.

Analysis of any scenario that includes a substantial reduction in the volume of pipeline gas sales must include an explicit discussion of how the utility will avoid an unplanned or catastrophic reduction in revenue from accelerated customer departures or further reductions in sales

The 2050 Roadmap identifies a risk that, due to the increase in gas rates (delivery plus supply) in the Pipeline Gas scenario, "[i]f adoption of electric technologies is seen by customers as cost effective based on the relative retail rates of gas and electricity, there could be an uncontrolled exit from the gas system and escalating rates for the remaining customers."[19] Even in cases with expected transitions off the gas pipeline network, a similar dynamic could result in customer departures at a rate above the planned rate. Due to the potentially extreme results for remaining customers, who are likely to be those with the least ability to make changes (such as low-income customers and renters), the reports must include explicit discussion and recommendations on how to mitigate this risk.

---

[19] Massachusetts Executive Office of Energy and Environmental Affairs. 2020. *Energy Pathways to Deep Decarbonization: A Technical Report of the Massachusetts 2050 Decarbonization Roadmap Study*. Available at: https://www.mass.gov/doc/energy-pathways-for-deep-decarbonization-report/download. Page 4.

The analyses should describe how regulation of energy efficiency programs would need to change to achieve the goals or levels of deployment described in each scenario

As discussed above, efficiency program designs will need to change in any case consistent with the 2030 CECP and the 2050 Roadmap. This will necessitate changes in the regulatory and even statutory structure around these programs. Changes could relate to cost allocation between electric and gas ratepayers (or even by delivered fuel customers), treatment of and participation by municipal light plants, how program performance is measured, and how utilities are compensated for operating these programs. Total program scope and scale may also need to change in some or all scenarios in order to achieve the required deployment levels; analysis should also account for market transformation. Rates and fuel costs used for customer economic analysis, for example, must reflect the costs of these programs.

For any scenario which involves the utility engaging in the delivery of heat service through a means other than pipeline gas (such as through geothermal loops or district heating, or through utility provision of heat pumps) the analysis should include a sufficiently complete business model analysis to allow evaluation of the likelihood of business success for such a venture

Some gas utilities may look for alternative business models to delivering natural gas as a way to adapt to the state's regulations. Before investing in new infrastructure or services to provide heat, the companies should conduct analyses to ensure that they would provide value to customers. It would be imprudent to bank on a shift to a business model that doesn't work.

Any scenarios that include activities by unregulated affiliates of regulated utilities must clearly differentiate and identify which actions and investments are the actions of the affiliates, and which of the regulated utility

Services provided by regulated utilities are governed differently than those provided by unregulated affiliates; these services must be distinguished as such to ensure the transparent allocation of costs to ratepayers, avoid undue risks for ratepayers, and avoid antitrust concerns. Proposed investments and future operations by the two different groups should be clearly defined in the analyses so that it is clear which activities will be funded by ratepayers versus shareholders.

The analyses and recommendations should identify the level of coordination between electric and gas utilities that may be required, with a particular attention to differentiating between areas served by the same company for both fuels, or served by different companies

Where building or industrial heating systems are transitioned to electricity, the local network impacts on both the gas and electric networks could be substantial. This is especially true in the case of geographic clustering or targeting of transitions but could also create challenges in other cases: What level of operational and planning coordination between electric and gas utilities is required in each case analyzed? How would that coordination be accomplished? What information is required in order to best meet the needs of customers and minimize costs? The analysis and recommendations should reflect cases where electric and gas service are provided by parts of the same parent company, and cases with different electric and gas companies (including both electric companies regulated by the DPU and municipal light plants).

Each scenario and associated analyses should be explicit regarding assumptions and modeling of competition between electric and gas utilities

Both electric and gas utilities are rate regulated because they are perceived to be natural monopolies to provide their commodity and associated services. However, it is clear that electricity and gas are actually competing to provide heating service, on a playing field that is designed and shaped by public policy and regulation. The analysis may be founded on assumptions regarding how this competition will be mediated and constrained by regulatory or legislative actions. These assumptions must be made explicit so they can be evaluated, and the associated actions may be considered as part of the DPU's roadmap. In addition, the reports should be explicit about any utility-led actions that may be considered or included in one or more scenarios, such as accepting a rate of return below the allowed rate of return in order to maintain market share.

8. CONCLUSION

The transition to net zero is an unprecedented challenge for utility regulation, policymaking, and utility management, as well as for Massachusetts's residents and businesses. Time is tight to complete the net-zero transition by 2050, and there will be few if any opportunities to pursue fruitless paths or to delay action in the hope of increasing certainty. As a result, it is critical that the roadmap and the first set of decisions made on the path be timely, robust, informed, and part of a comprehensive and long-term approach. If the gas utilities and their consultants deliver analyses, reports, data, and recommendations that live up to the criteria laid out in this white paper, the DPU will have the information it requires to develop its regulatory and policy roadmap to the decarbonization transition while protecting customers. Further, stakeholders will have the information necessary to meaningfully participate in that process.