COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

Investigation by the Department of Public Utilities on its own Motion into the Role of Gas Local Distribution Companies as the Commonwealth Achieves its Target 2050 Climate Goals	)))))	**D.P.U. 20-80**

THE OFFICE OF THE ATTORNEY GENERAL'S INITIAL STAKEHOLDER COMMENTS ON CONSULTANTS' TECHNICAL ANALYSIS OF DECARBONIZATION PATHWAYS REPORT

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May 6, 2022

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I. EXECUTIVE SUMMARY

Massachusetts stands at the crossroads of a clean energy transition that will transform the utilization of energy in our homes and the workplace. Aggressive, nation-leading emission reduction mandates touching all aspects of our energy economy have been enacted by the General Court. Implementation plans are underway among several state agencies charged with executing on the statutory mandates. The Secretary for Energy and Environmental Affairs (EEA) has observed that nearly a third of Massachusetts' GHG emissions stem from on-site fossil fuel consumption to satisfy building thermal needs.[1] Reducing buildings emissions by nearly one-half by 2030 is required to meet overall emission reduction mandates.[2]

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[1] *See* e.g., EEA, *Interim 2030 Clean Energy and Climate Plan*, ("Interim 2030 CECP") (Released December 30, 2020), at 27, *available at* https://www.mass.gov/doc/interim-clean-energy-and-climate-plan-for-2030-december-30-2020/download

[2] *See* EEA, *CECP Public Hearing Presentation* (April 15, 2022), at 10, showing required residential heating emission reductions by 2030 of 44 percent and Commercial & Industrial heating emission reductions of 47 percent, *available at* https://www.mass.gov/doc/2025-2030-cecp-public-hearings-presentationenglish/download

Critical to achieving required building emission reductions is the strategy to transition building thermal requirements from on-site combustion of fossil fuels to the adoption/installation of efficient electric heat technologies in very many buildings, and maybe nearly all. EEA has determined that at least 60 percent and as much as 95 percent of Massachusetts buildings must transition to efficient electric heating by 2050, under any plausible decarbonization scenario, for the Commonwealth to deliver on the statutorily mandated emission reductions. Interim 2030 CECP, at 13, 27. A recent EEA presentation on an updated 2030 CECP finds that for emission reductions to stay on target, nearly a third of all homes in the Commonwealth must be moved to efficient heat pumps and tighter building envelope improvements by 2030.[3]

Against this factual and policy backdrop, the gas distribution companies were asked to consider and present their enablement plans to aid the Commonwealth and its citizens in achieving "net zero" emissions in a just and equitable fashion. A year later, their collective response has been underwhelming and somewhat dissembling. Rather than lead an energy transformation, the gas companies largely stick to their century-old business plan: deriving a profit by delivering gas via underground pipes. The centerpiece of their plans and the gas industry's public relations juggernaut is to double-down on pipeline-delivered gas in a scenario they term "hybrid electrification." Under hybrid electrification, residents install air source heat pumps in their homes and businesses but they simultaneously install gas fired, backup heating systems for use in the coldest winter weather. Compliance with all emission reduction mandates under hybrid electrification can be attained *if and only if* sufficient quantities of carbon-neutral or carbon-free "renewable natural gas" can be secured by the local distribution companies

[3] EEA, *CECP Public Hearing Presentation* (April 15, 2022), at 12, *available at* https://www.mass.gov/doc/2025-2030-cecp-public-hearings-presentationenglish/download

("LDCs") to replace present natural gas throughput over time. And the upshot of the hybrid electrification plan for the gas companies is that they keep virtually all their building heat customers and fully retain and upgrade all of their existing gas delivery infrastructure and future improvements on which they are assured a Department-authorized return on investment.[4]

How the Department elects to think about the challenge ahead has major consequences for the Commonwealth. Prioritizing what can be done to ensure the continued profitability of gas utilities implies different action than how best to prepare Massachusetts residents for an equitable carbon-free energy future. As discussed below, the purported allure of the hybrid electrification scenario as envisioned by gas companies as good for the environment, good for customers, and good for gas utilities does not stand up to close scrutiny. There are too many known and unknown weaknesses in the gas companies' planned hybrid electrification strategy – in terms of customer cost and prospects of reducing emissions – to merit further consideration as a serious building emission reduction strategy. The Department should reject the hybrid electrification scenario proposed by the gas companies[5] from further policy consideration.

II. BACKGROUND

On March 18, 2022, the Massachusetts investor-owned gas local distribution companies ("LDCs")[6] filed with the Department of Public Utilities ("Department") in this proceeding,

[4] Department-allowed returns on equity (ROE) for investment by gas companies typically fall in the range of 9.0 to 10.0 percent.

[5] As more fully discussed in Section IV below, much of the transitional benefits of hybrid electrification can be attained by apportioning the Commonwealth's total building heat load – not the demand of each individual building customer – between electric and gas delivery systems for a transitional period.

[6] The LDCs in this proceeding include The Berkshire Gas Company, NSTAR Gas Company and Eversource Gas Company of Massachusetts, each d/b/a Eversource Energy, Liberty Utilities (New England Natural Gas Corp.) d/b/a Liberty, Boston Gas Company and the former Colonial Gas Company d/b/a National Grid and Fitchburg Gas and Electric Light Company d/b/a Unitil.

among other things, their *Independent Consultant Technical Analysis of Decarbonization Pathways* ("Technical Report"). The Technical Report undertakes a comprehensive economy-wide analysis of eight sample pathways Massachusetts might undertake to successfully achieve its goal of "net zero" greenhouse gas ("GHG") emissions by 2050, or an 85 percent reduction in GHG emissions from 1990 baseline levels. The approach used in the Technical Report by the Consultants (Energy and Environmental Economics, Inc ("E3") and ScottMadden Inc.) is similar to the analysis the Commonwealth employed in the 2050 Roadmap analysis. The E3 analysis also was designed to ensure each pathway achieves the interim statutory emission reduction mandates required by 2030 (50 percent emission reduction from 1990 levels) and 2040 (75 percent reduction from 1990 levels).[7]

The Technical Report cautions, however —repeatedly and throughout— that the pathways *are not forecasts* of future decarbonization strategies or tactics. Compliance with all emission reduction mandates is assumed, not proven, within each scenario. Instead, each pathway represents a "what if" consideration of the factors, features and challenges of different plausible energy futures. Technical Report, at 11. Each pathway is first *assumed* to achieve all required GHG emission reductions and then E3 undertakes to catalog, compile, and model the myriad assumptions on customer adoption rates, costs, technical challenges and risks needed to bring about successful emission compliance within each pathway.

The eight studied pathways include three that are roughly analogous to pathways examined in the Massachusetts 2050 Roadmap: (1) a "high electrification" scenario; (2) a "low electrification" scenario; and (3) a 2030 interim CECP-compliant approach. To the foregoing

[7] *See* Act Creating a Next-Generation Roadmap for Massachusetts Climate Policy ("Climate Act"), St. 2021, c. 8, §§ 8, 10.

pathways E3 added five additional scenarios developed to pose and examine outcomes of specific interest to various stakeholders, including: (4) hybrid electrification; (5) targeted electrification; (6) networked geothermal heating; (7) efficient gas equipment; and (8) 100 percent gas system decommissioning.

Again, it bears repeating that the scenario analysis undertaken in the Technical Report *does not predict* the success of any particular future outcome, *nor is the scenario analysis intended or capable of forecasting* which pathway or portfolio of pathways might achieve effective results (in terms of emission reduction compliance at the overall least cost). Instead, the scenario analysis was cast by E3:

> [to] identif[y] decarbonization pathways that may be adopted and/or combined to transition to the Commonwealth's climate goal of net-zero [GHG] emissions. The pathways share a set of commonalities that are likely part of any decarbonization strategy, while maintaining optionality for longer-term technological advancements.

Consultant Report on *Considerations and Alternatives for Regulatory Designs and Support Transition Plans* ("Regulatory Design Report") (March 18, 2022), at 8. These commonalities among all studied pathways include energy efficiency, building electrification and the introduction/blending of biomethane as a purportedly "renewable natural gas." *Id.* By comparing and contrasting the relative costs, features, feasibility, and risks of the studied pathways, the Technical Report advances general conclusions as to the relative merits/drawbacks of each studied pathway.

All eight pathways are similar in that they each entail the transition of varying levels of building heating requirements to efficient electric technologies, coupled with the introduction of "renewable natural gas" into the pipeline system to decarbonize (in effect) the residual energy uses of natural gas. However, the outcomes of certain pathways (*e.g.*, the high electrification scenario or the 100 percent gas decommissioning scenario) rely to a greater extent on efficient electric heating alternatives while other pathways (*e.g.*, efficient gas equipment and hybrid electrification) rely on the future availability and affordability of renewable natural gas to a much larger extent.

By Hearing Officer Memorandum dated March 24, 2022, the Department elected to proceed with an evaluation of the Technical Report, but not through a formal, adjudicatory proceeding entailing full discovery, cross-examination of witnesses and presentation of opposing studies/analysis/testimony. Instead, the Department has invited stakeholder written comment by May 6, 2022 limited to:

> (1) the developed pathways set forth in the Report and the assumptions and modeling underlying the Report; and (2) the regulatory framework necessary to support the equitable and safe transition to net-zero greenhouse gas emissions by 2050.

Hearing Officer Memorandum, at 3. The Department subsequently advised: "The Department encourages comments that raise issues with the consultants' reports and the LDCs' individual proposals and comments that make alternative proposals, particularly alternative regulatory framework proposals." April 15, 2022 Hearing Officer Memorandum, at 2.

III. <u>THE TECHNICAL REPORT'S PROMOTION OF A HYBRID ELECTRIFICATION PATHWAY RESTS ON UNSOUND AND UNPROVEN ASSUMPTIONS</u>

A conclusion drawn by E3 in the Technical Report, which the LDCs then take as the keystone of their proposed recommendations and so-called "enablement plans," is that the pathway that the Consultants term "hybrid electrification" shows lower levels of challenge across a range of evaluation criteria. As characterized in the report, hybrid electrification entails broad customer-driven installation of air source heat pump ("ASHP") heating technologies, but with each customer also installing/retaining a gas-fired backup heating system which, over time, is fully transitioned to carbon-neutral fuels. The ASHP is used for heating and cooling whenever outside ambient air temperatures remain moderate, but building heat during the coldest winter weather (where ASHP efficiency and heating performance decline) would switch to the backup gas system which is assumed to deliver increasing shares of carbon-neutral gas.[8] Thus, while as many as 90 percent of buildings under hybrid electrification will adopt ASHP heating by 2050, all hybrid electrification participants remain customers of the LDCs, relying on renewable gas in winter peak periods. In this way, hybrid electrification ostensibly offers the most promising focal point of all the LDCs' near-term decarbonization strategies, because it offers the possibility of lowering overall emissions *but* retaining virtually all existing building heat customers, as well as full retention (albeit utilized only for limited times of the year – winter peaks) of each LDC's gas infrastructure.

From a general review of the Technical Report in the time available, the AGO and its Consultants, The Brattle Group, discern several significant weaknesses in the hybrid electrification approach touted by the gas industry participants.

It is suggested at several junctures in the Technical Report that the hybrid electrification scenario entails lower overall costs than alternative pathways. "A hybrid [electrification] strategy reduces the cumulative cost of achieving net zero GHGs through 2050 by between $23-43 billion relative to scenarios that primarily rely on all-electric strategies …." Technical Report, at 14. The putative cost savings are perceived to be generally attributable to lower future electric system augmentation costs (that under hybrid electrification will not need to be scaled up to serve the winter extreme cold spells)[9] as well as up-front savings in ASHPs acquisition costs, due to (1) initial purchase of smaller and/or less efficient ASHPs and (2) a savings in extensive

[8] *See e.g.*, Technical Report, at 31.

[9] *See* Technical Report, at 60 and Figure 20.

building shell enhancements and weatherization improvements that would otherwise be needed to accommodate year-round occupant comfort and safety in an ASHP-only heating environment.[10]

Compliance with all statutory emission reduction mandates is achieved with the hybrid electrification approach *only* by burning large volumes of renewable natural gas that is assumed to be "carbon-neutral." Thus, E3's conclusions favoring a hybrid electrification pathway rest *on assumptions* of renewable natural gas availability and cost that have not yet been well studied or supported, and in some respects are simply wrong. As more fully discussed below, the Technical Report makes several forced errors and unsupported suppositions as to the availability, cost and climate efficacy of burning renewable natural gas in the hybrid electrification scenario as a decarbonization strategy for the Commonwealth.

A. There is no credible support that renewable natural gas can be made available in Massachusetts at the volumes needed to support 2050 residual gas use under hybrid electrification.

A key tenet of all decarbonization pathways is that whatever residual demand remains for gas for heating applications, after evaluating contributions from efficient electric heat technologies, will be met through delivery and consumption of "renewable natural gas" that is assumed to have net-zero emissions. For purposes of the Technical Report, E3 defines renewable natural gas ("RNG") as an umbrella term to include both (i) biomethane produced through anaerobic digesters or gasification, as well as (ii) renewable (a/k/a "green") hydrogen and (iii) synthetic natural gas ("SNG") produced with renewable hydrogen combined with a climate-neutral source of carbon (*e.g.*, either a by-product of biogas development or from direct air capture). Technical Report, at 9.

[10] *See* Technical Report, at 55.

The annual volumes of RNG needed in Massachusetts by 2050 under a hybrid electrification pathway were determined by E3 as roughly 70 trillion Btu (TBtu). Technical Report, at 50, Figure 15. But according to a gas industry report (Am. Gas Foundation, Dec. 2019 Report), the total available RNG output – nationwide – as of 2020 was only approximately 50 TBtu.[11] An additional complicating factor regarding future RNG availability in Massachusetts acknowledged in the Technical Report is that relatively limited resources for developing RNG presently exist in New England.[12]

The Technical Report overcomes the present insurmountable supply obstacles by extrapolating exponential growth in RNG production in the coming years. The Technical Report assumes future available RNG stocks will appear and be available in Massachusetts from among all states east of the Mississippi River. Appendix 1 to Technical Report ((Modeling Framework and Assumptions), at 16. The Report reasons that RNG stocks anywhere east of the Mississippi can be purchased and delivered to Massachusetts using the existing network of interstate gas pipelines (just as the pipelines are used today by the LDCs to obtain natural gas supplies). *Id.*

The Technical Report reasons that the availability in Massachusetts of 70 TBtu of RNG needed for the hybrid electrification scenario is feasible if RNG production nationwide grows precipitously *and* Massachusetts secures its "fair share" of available RNG supplies. Appendix 1 to Technical Report, at 16-17. E3 derives that "fair share" to be 3.7 percent of all RNG produced

[11] *See* American Gas Foundation, *Renewable Sources of Natural Gas: Supply and Emission Reductions Assessment*, at 10 n.5 *available at* https://gasfoundation.org/2019/12/18/renewable-sources-of-natural-gas/

[12] *See* Appendix 1 to Technical Report, at 16 ("It is important to note that biomass resource availability in New England is relatively low compared to other regions in the United States. [] New England has an estimated 0.63 dry tons of feedstocks available per person per year, whereas the average availability of feedstocks for the U.S. as a whole is 2.47 dry tons per person per year.") Thus, New England has only one-quarter as much biomass feedstock, per person, as the national average.

annually in all states east of the Mississippi River. *Id.* This assumption that 70 TBtu of RNG represents 3.7 percent of RNG available in the eastern half of the country implies that total RNG supplies in all states east of the Mississippi will be nearly 2,000 TBtu [2,000 x 0.037 = 74 TBtu] by 2050. However, RNG production in 2020, *from all states* in the U.S. was only 50 TBtu. For 2,000 TBtu of RNG to appear by 2050 in the eastern United States suggests nationwide RNG annual production climbs from 50 TBtu in 2020 to 4,000-6,000 TBtu by 2050. As a point of reference, total annual natural gas delivery nationwide averaged 4,846 TBtu between 2009 and 2018 for the residential sector alone. American Gas Foundation 2019 Renewables Study, *supra* at 2 n. 11. Growth in RNG production by 2050 can be expected, but the kind of exponential growth prospect assumed by the Technical Report is without precedent.

Further troubling, beyond the assumption of a phenomenal RNG supply growth rate by 2050, is the Technical Report's derivation of the Massachusetts "fair share" of available RNG supply at 3.7 percent. The Report undertakes no technical, commercial, or probabilistic analysis of RNG amounts that can be acquired by the LDCs but *assumes* the Commonwealth can lay claim to 3.7 percent of the RNG supply merely because Massachusetts represents roughly 3.7 percent of the population east of the Mississippi (and despite that New England has a much smaller share of biomass resources). Appendix 1 to Technical Report, at 16-17. Perhaps if a product or commodity's supply and availability were truly unlimited, it might be reasonable to assume that supply in a competitive market is distributed roughly by relative population shares. But there is likely to be fierce competition among all states – indeed, among nations – for available RNG production by 2050, and even greater competitive pressure to obtain RNG from "hard-to-decarbonize," "hard-to-electrify" energy applications. (By contrast, the Commonwealth's use of gas for building heating is a reasonably "easy-to-electrify" application that can be met more efficiently and likely at lower costs through electrification, rather than needing to rely on RNG). The Technical Report's *assumption* that Massachusetts will successfully acquire all RNG stocks needed in the hybrid electrification scenario to meet its 2050 emission reduction mandate (and all interim reduction mandates) in proportion to its share of the relative population is unintuitive and unsupported.

Further eroding E3's RNG availability assumptions in the hybrid electrification scenario is how RNG would be transported to the LDCs for delivery in Massachusetts. The Technical Report assumes that natural gas pipelines east of the Mississippi used by the LDCs to transport natural gas today to New England will be increasingly re-purposed for transport of RNG. But these pipes are common; there is no practical way to segregate and transport separately within the pipes the RNG molecules from natural gas molecules. Thus, under E3's transport assumptions all off-takers of the interstate gas pipeline system, and all state and federal administrative agencies that regulate such facilities and users, must agree to the regulatory and technical risks to comingle RNG and natural gas within the pipes. While a future can perhaps be imagined where modest amounts of biomethane are blended and commingled with natural gas without material operational complications or administrative objection, recall that "RNG" for purposes of the Technical Report also includes hydrogen and hydrogen-derived SNG. Not all shippers and end-users, as well as the regulatory agencies overseeing such markets, might willingly and unanimously assent to commingling natural gas with hydrogen. Further complicating the permitting and approval process for transporting hydrogen is that the Federal Energy Regulatory Commission ("FERC"), the federal agency with preemptive siting and regulatory oversight of interstate natural gas pipelines, does not and cannot now regulate interstate transport of hydrogen.[13]

For all the foregoing reasons, the Department should hold grave doubts that (1) the RNG stocks needed to ensure the environmental success of the hybrid electrification pathway will grow sufficiently in total supply east of the Mississippi and can actually be acquired by the LDCs in sufficient quantities as needed; and (2) that all users and regulators of interstate gas pipelines with eight decades of experience under the Natural Gas Act and comparable state laws will pivot, in unison, to timely embrace under Massachusetts emission reduction timetable the complex blending of gas, biomethane, hydrogen and SNG. The availability of RNG in sufficient quantities in Massachusetts for the hybrid electrification pathway to successfully achieve all GHG emission reduction mandates is thus an unsound and unsupported assumption.

B. E3's estimation of RNG supply costs runs counter to its own modeling methodology and competitive market outcomes.

Even if the Department accepts all of E3's assumptions on future RNG availability (which as discussed above, it should not), the Technical Report deliberately and significantly understates in its hybrid electrification analysis the costs of obtaining RNG. Curiously, the Technical Report does so by first correctly explaining the economic and pricing dictates of a

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[13] The Federal Energy Regulatory Commission's jurisdiction is limited under the Natural Gas Act of 1938 to the interstate transportation and sale for resale of natural gas. 15 U.S.C. §717. Thus, legal commentators have noted FERC's jurisdiction over pipeline siting and regulation does not extend to hydrogen. Safety and operations concerns regarding shipment of hydrogen by pipeline fall under the federal Pipeline and Hazardous Material Safety Administration (PHMSA) and limited economic interest of pipeline delivery of hydrogen are regulated by the federal Surface Transportation Board. *See generally* https://www.bakerbotts.com/thought-leadership/publications/2021/october/us-lawmakers-contemplate-regulatory-framework-for-hydrogen-transportation

competitive commodity marketplace, but then discarding, without explanation, its own economically correct commodity pricing constructs when it comes to RNG.

To estimate the cost of the future RNG supplies necessary for the climate success of hybrid electrification, E3 first constructs its own supply cost curves. *See, e.g.*, Appendix 1 to Technical Report, at 20, Figures 9 and 10. For convenience, these Figures are reproduced below.

Figure 9. Renewable gas supply curves in 2050 for optimistic and conservative Efficient Gas scenario.

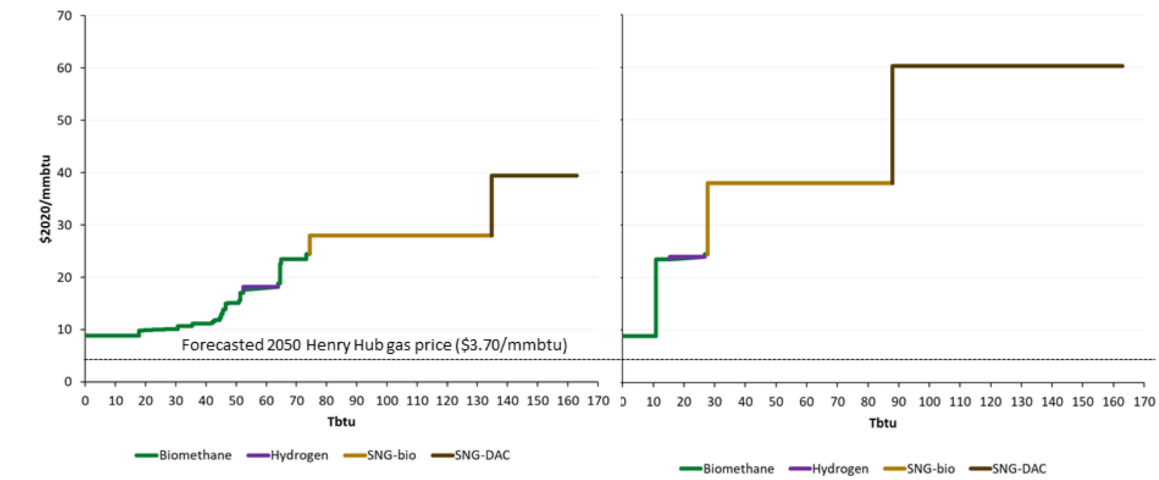
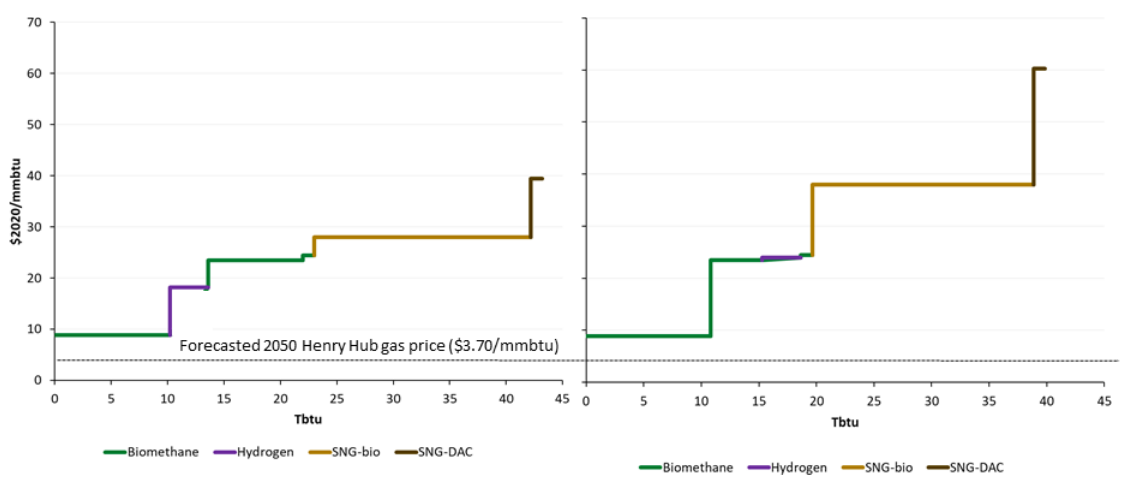


Figure 10. Renewable gas supply curves in 2050 for optimistic and conservative High Electrification scenario. Note the different horizontal axis compared to Figure 9.



To capture the future uncertainty in RNG pricing, E3 develops, to its credit, both "optimistic" and "pessimistic" views on renewable fuel supply curves. The x-axis (horizontal) on each graph represents quantities of RNG available and the y-axis (vertical) corresponds to the unit price at each level of demand. The upward "steps" in prices as quantities increase along the x-axis reflects the much higher production cost for incremental quantities of biomethane, then hydrogen, and finally SNG as demand overall for RNG increases. (The AGO has not independently confirmed the reasonableness of the forecast quantities and prices of RNG in the foregoing cost curves, but for the sake of argument here assumes them to be reasonable.)

The Technical Report proceeds to explain how to properly employ such cost curves in a competitive commodity market:

> The cost of renewable gas in each pathway is based on the *market clearing price* of the above supply curves each year. That is, if 60 TBtu of biomethane would be needed from the Efficient Gas pathway (Figure 9), hydrogen *sets the market clearing price* of ~$17/MMBtu *for all 60 TBtu* in the optimistic case.

Appendix 1 to Technical Report, at 20 (emphasis supplied). This competitive commodity pricing determination of "market clearing price" is grounded in basic economics and is a mainstay of economic modeling. As E3 acknowledges above, when overall market demand rises in the hybrid electrification scenario to 70 TBtu, no competitive supplier of biomethane will agree to sell at anything less than the market clearing price. Thus, all supplies are "priced at the margin" because that is how competitive commodity markets work in practice. In the optimistic case of Figure 9, above, no supplier will agree to sell 10 MMBtu at something like $8 if the market is currently obtaining $17 per MMBtu at the margin. Accordingly, as the authors of the Technical Report readily acknowledge, the entire supply stack must be priced at the incremental price of the last (or marginal) unit of supply.

Inexplicably, and contrary to sound economic theory and its own pricing convention, the Technical Report disregards marginal (*i.e.*, market clearing) pricing when SNG is needed, in pathways with high gas demand. Whenever total RNG demand outstrips biomethane supplies in

E3's analysis, reaching into the SNG portion of the supply curve, the Technical Report abandons the concept of marginal pricing and a market clearing price. Instead, E3s pricing model is constructed to price the relatively small marginal quantities of SNG at the cost of SNG, but then proceeds to price the remaining RNG quantities at the lower cost of biomethane, below the margin of the supply curve.

> An exception is made for SNG, which is modeled as a separate market, with utilities procuring resources through bilateral market contracts. Therefore, SNG supply is assumed to be blended in at the weighted average price of biomethane and SNG.

Technical Report, Appendix 1, at 20.

What results from the Technical Report's special SNG pricing contrivance is a kluge of out-of-market RNG prices that imagines that most RNG is obtained at the (relatively low) cost of biomethane, and only the last, small incremental RNG requirement is priced at the much higher cost of SNG. In short, the Consultants' approach disregards competitive economics and the notion of a market clearing price. The resulting "weighted average" of lower contrived prices for biomethane but higher prices *only* for limited SNG quantities is counterfactual and economically unsupported, and significantly understates the cost of the gas-reliant pathways.

This pricing contrivance for SNG is no small error. As can be readily seen from Figures 9 and 10, above, the marginal, market-clearing prices of SNG ($28-$40/MMBtu for "optimistic" and $40-$60/MMBtu for "conservative" case) are multiples higher than the price for other RNG stocks. In the "optimistic" case, the Study assumes 63 TBtu (of the total 2050 requirement of 70 TBtu) can be attained from biomethane and hydrogen (Technical Report, at 52, Figure 16) leaving only 7 TBtu of higher cost SNG to be acquired at bilateral contract prices. But under the "conservative" case, only 16 TBtu of biomethane is available and the balance of 54 TBtu must be acquired from higher cost SNG stocks.

The resulting "Commodity Cost of Gas" shown in Figure 11 of Appendix 1 to the Technical Report could, if SNG were priced correctly, be roughly twice the cost E3 uses in its analysis. Market pricing of RNG would likely yield overall commodity gas costs far higher than the $22-$28 range shown for the Hybrid scenario in Figure 11. How much higher is not readily determined from the available information. The Department should insist that E3 correct its faulty SNG pricing contrivance and re-calculate the costs for all scenarios. The results would show that the overall savings the hybrid electrification scenario purportedly enjoys over high electrification scenarios would likely disappear (assuming, without conceding the point from Section III.A, that sufficient stocks of RNG could be found *at any price*).

What is clear is that the conclusions drawn by the LDCs on the putative merits of hybrid electrification are faulty because the Technical Report's pricing of RNG supplies, necessary for a hybrid electrification scenario to meet the emission reduction mandates, is unsound and unsupported.

C. The success of the hybrid electrification pathway at attaining all required GHG emission reductions hangs on a questionable and highly contentious assumption that RNG is truly "carbon-neutral."

Laying aside the problems discussed above regarding RNG availability and price, there is still a more foundational weakness in the hybrid electrification scenario —indeed on any pathway premised on high reliance on so-called renewable, "carbon-neutral" fuel substitutes. In fact, most RNG (both biomethane and SNG) is NOT carbon-free. When such "carbon-neutral" fuels are burned they release essentially the same CO_2 emissions occasioned when burning natural gas. Moreover, when biomethane or synthetic methane escapes from leak-prone gas infrastructure it has the same climate impacts as leaked methane from natural gas would – and these can be significant.[14]

What enables proponents of RNG to claim a favorable environmental impact from purportedly "carbon-neutral" fuels is only an assumption that is incorporated within the present regime of accounting for GHG emissions. In general, if methane from an agricultural practice that *would otherwise reach the atmosphere* can be captured and re-purposed as biomethane RNG, its resulting emissions in effect are "credited" for the emissions saved in the agricultural sector.

Longer-term, however, there is wide concern among experts on the practicality and efficacy of trading emissions on the GHG emission ledger sheet. What is needed to address the world's climate change dangers is a radical and permanent reduction in emissions from *all* sources, both agricultural and oil/gas in this example. Some level of emission exchanges will be necessary particularly to reduce emissions in the hard-to-electrify, hard-to-decarbonize sectors of the world energy economy. But to consume emission flexibility on "renewable" building heating fuels in New England (that can more directly be decarbonized through efficient electric heating technologies) will not suffice as a reasonable, sustainable long-term emission reduction strategy.

There are other environmental concerns with RNG. Its emissions perhaps appear today as "carbon-neutral" under present GHG accounting, as measured as a direct emission. Again, there is growing consensus among experts to instead measure and consider full life-cycle

[14] Importantly, leakage from distribution pipelines does not decline with reductions in throughput. Therefore, in scenarios that assume a robust continued use of the full gas distribution system, even for greatly reduced volumes, the emissions from methane leakage remain.

emission profiles that capture emissions gains and losses throughout the entire production process.

The Technical Report acknowledges both of these uncertainties and concedes (tacitly) that if the GHG emission accounting conventions change, the eligibility of RNG as a "carbon-neutral" fuel vanishes, in which case: "If th[e] [GHG inventory] framework changes, the GHG emission savings from biomethane will diverge from the values identified in this Study." Technical Report, at 18 n. 12. Thus, E3 cautions: "As discussed in Consultant Decarbonization Pathways Report, renewable fuels are *assumed* to have net zero GHG impact under the Massachusetts GHG accounting framework." Regulatory Designs Report, at 8 n. 7 (emphasis supplied). The Technical Report, at 14, adds: "pathways that rely more heavily on renewable fuels carry risks related to lifecycle emissions and GHG accounting methods." "Following the [present] conventions of the Massachusetts Greenhouse Gas Inventory, this study treats renewable fuels as carbon neutral. In practice, the lifecycle emissions of renewable fuels may vary …." *Id.*, at n. 11.

Finally, there is this more robust acknowledgment in Appendix 1 to the Technical Report, at 27-28:

> As described above, an important component of the GHG emissions accounting framework is the treatment of renewable fuels. In this study, consistent with the Massachusetts GHG Inventory, the use of renewable fuels throughout the economy *is assumed to not result in any net emissions* []. Similarly, the gross emissions accounting framework does not account for lifecycle emissions of fuels []. . . . .
>
> *The Consultants realize that treating renewable fuels as carbon neutral is a simplification of the complex carbon flux associated with fuel production.* For example, fossil fuel use in feedstock production or key feedstock conversion steps *can increase the embodied carbon emissions of renewable fuels*. . . . .
> As a result, treating renewable fuels as having net-zero carbon emissions may overestimate their decarbonization potential, especially considering that emissions accounting frameworks in the Commonwealth may evolve.

> *Such an overestimation increases the risk of not meeting the Commonwealth's decarbonization goals, especially under those economy-wide transitions that rely on high levels of renewable fuels, such as the Efficient Gas Equipment pathway.*

Id. (emphasis supplied). To reiterate E3's professional disclaimer above —over-reliance on the carbon neutrality of RNG, long-term, "increases the risk of not meeting the Commonwealth's decarbonization goals, especially under those economy-wide transitions [such as the hybrid electrification pathway] that rely on high levels of renewable fuels …."

Accordingly, for all the foregoing infirmities regarding RNG (i) availability, (ii) price and (iii) environmental efficacy, the Department should reject any reliance on the hybrid electrification pathway advocated by LDCs and steer away from all decarbonization transitions heavily reliant on the substitution of RNG in place of natural gas.

IV. CLAIMED BENEFICIAL IMPACTS OF HYBRID ELECTRIFICATION ON ELECTRIC SYSTEM INFRASTRUCTURE ADDITIONS CAN BE ATTAINED BY FOCUSING ON BUILDING ELECTRIFICATION IN THE NEAR TERM

A major premise in the Technical Report's predisposition towards hybrid electrification is that retaining some gas use for winter peak heating needs will result in savings in future costs, largely by avoiding the need to augment the electric system to accommodate full building electrification and the resultant winter heating peak. But the Commonwealth need not and should not commit to individual building hybrid electrification to attain this tradeoff.

Even under aggressive, full and efficient building electrification (*i.e.*, where efficient cold climate ASHP and building shell improvements are undertaken as the whole heating solution for many buildings) the majority of gas heating customers in 2030, who in the near term have not yet migrated to efficient electric heat, will stay on gas during winter peaks. This full and efficient building electrification strategy provides the same level of flexibility in winter energy sources as if, under hybrid electrification, 90 percent of customers electrify but retain gas heating for winter peaks. For example, assume for the next ten years Massachusetts aggressively promotes full electrification and that 40 percent of customers adopt efficient electric heat technologies in this period. With this initiative the electric system is not confronted with an extreme level of winter peak demand because 60 percent of customers remain (for now) on natural gas heating. There will be time between 2030 and 2040 to assess the impact on electric system costs of full building electrification and to make compensating adjustments in the pace of full building electrification.

Additionally, EEA has already determined that the number of buildings that need to convert to efficient electric heat by 2030, for Massachusetts to stay on target with its required emission reduction trajectory, is essentially the same under any alternative pathway.

> [T]o achieve Net Zero in 2050 via either a lower-risk, lower-cost "high electrification" scenario or a higher-risk, higher-cost "decarbonized gas" scenario, the core required transformations in the building sector over the next 10 years are the same. The number of buildings using natural gas, fuel oil, and propane for space and water heating must begin to steadily and permanently decline.

2030 Interim CECP, at 27. Accordingly, for at least the coming decade Massachusetts can achieve the same flexibility in the diversity of winter heating sources under an aggressive electrification pathway as it could attain under the LDCs' hybrid electrification. Moreover, full electrification (for now) of a subset of buildings maintains flexibility later to pursue either (a slightly different version of) hybrid electrification, or a high electrification pathway.

The claimed system cost savings through hybrid electrification are illusory. When the hybrid electrification scenario fails to achieve the required emission reduction mandates (and for the reasons discussed in Section III, *infra*, it likely will fail) all investments in hybrid electrification will be sunk. All of the low-efficiency ASHPs installed under hybrid electrification will now need to be replaced with high-efficiency units. EEA estimates that nearly a million gas/oil/propane furnaces and boilers will reach end-of-life status in the next ten years. Interim 2030 CECP, at 28. It will be a colossal, wasted opportunity if they are replaced with low-efficiency ASHPs, which customers will not prematurely update with more efficient units. Moreover, all amounts spent maintaining the present gas infrastructure under hybrid electrification (for seasonal winter peaks) instead of looking for gas system cost reduction opportunities through targeted electrification and ASHP deployment also will be sunk when the Commonwealth must ultimately pivot towards full electrification. Accordingly, the likely sunk costs of hybrid electrification makes it a strategy that limits, not enlarges, the Commonwealth's subsequent policy options to modify implementation based on later-acquired facts.

The Department should reject consideration of the LDCs' hybrid electrification scenario in favor of measured, yet aggressive, adoption targets for efficient building electrification (with no provision for backup gas heating).

V. E3's TECHNICAL REPORT FAILED TO VIGOROUSLY PURSUE POTENTIAL GAS INFRASTRUCTURE COST SAVINGS

The Technical Report (at 12, Figure 1) suggests a \$23-\$43 billion savings in cumulative energy system costs by 2050 from the hybrid electrification scenario compared to a full electrification pathway. However, as shown in Section III, *infra*, E3's cost analysis significantly understates RNG supply costs under hybrid electrification. It is likely that any cumulative cost savings advantage of hybrid electrification will disappear once RNG supply is properly priced.

A further conceptual weakness in the Technical Report's comparative cost analysis is that the analysis fails to undertake any rigorous consideration of future gas system cost savings (both capex and op-ex) enabled by electrification scenarios. While the Technical Report advises that gas system cost reduction measures were considered, there is little description how such savings were calculated. To the contrary, the Technical Report advises:

> In scenarios with declining customers, throughput, and/or demand on the gas system, there may be opportunities to reduce gas system costs

> relative to a static system. However, these opportunities are uncertain. There is little historical evidence for what level of cost reductions may be possible, as few gas utilities have faced declining throughput and no gas utilities have seen widespread customer departure.

Appendix 1 to the Technical Report, at 49. E3 cautioned "there are many open questions about how targeted electrification could be achieved"[15] and that the cost savings it purportedly identified "are not based on empirical data from Massachusetts LDCs." Appendix 1 to the Technical Report, at 49. Accordingly, the Technical Report puts off, for another day, any "detailed study by the LDCs [] required to establish LDC-specific ranges of potential cost avoidance opportunities." *Id.*

What is clear is that E3 assumed in its analysis all existing capital assets are replaced routinely at their end of life. Appendix 1 to Technical Report, at 45. It also appears E3 included in its analysis all $15.9 billion of the "business as usual" LDC-proposed future GSEP spending. *Id.,* at 43. Also, E3 breaks all capital spending in its model into two broad categories: "Meters and Services" and "Mains and Other." While E3 apparently enabled future investment in Meters and Services to vary somewhat as customers left the distribution system, the Mains and Other category "reflects assets that are used by many gas distribution customers or by the LDC as part of its standard operations and cannot necessarily be decommissioned with customer departures." *Id.*, at 42.

The picture that emerges from the Technical Report not only understates the cost of the hybrid electrification, but also overstates the cumulative system cost of aggressive electrification pathways by including no (or minimal) gas system cost savings as offsets to the costs of electrification. The Department cannot let the LDCs put off to another proceeding any serious consideration of capital costs savings, including planned costs for future GSEP spending, that

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[15] Technical Report, at 18.

can be avoided with aggressive and targeted electrification pathways. The Department should insist that E3 re-do its scenario analysis with reasonable and realistic savings opportunities in all capital and O&M spending – particularly including "business as usual" GSEP spending – that can reasonably be avoided through targeted electrification initiatives.

VI. CONCLUSION

The analysis in the Technical Report, which tilts heavily towards a hybrid electrification pathway to emission reduction mandates in the buildings sector, rests on too many assumptions that are untried, untested and/or unsupported. Under any successful decarbonization pathway Massachusetts must aggressively begin to transition its building stock to clean, efficient electric heating technologies. Hybrid electrification, as posed by the LDCs, is a diversion that is unlikely to succeed due to its heavy reliance on expensive, unproven renewable natural gas. Any cost advantages claimed for hybrid electrification are due to incorrect assumptions about the availability and pricing of RNG supplies, and from the Technical Report's failure to reasonably evaluate and consider future gas infrastructure cost savings achievable through aggressive and targeted electrification scenarios.

Respectfully submitted,

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May 6, 2022