STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

In the Matter of a Review of the Long-Term Gas System Plan of National Grid

Case 24-G-0248

Initial Comments of
Natural Resources Defense Council

Date: September 18, 2024

Contents

The Natural Resources Defense Council (NRDC) respectfully submits these Comments, which were developed with technical assistance and analysis from Synapse Energy Economics, Inc., on the Long-Term Gas System Plan (Long-Term Plan or LTP) of National Grid on behalf of its three local distribution companies (LDCs): Niagara Mohawk Power Corporation (NMPC), Brooklyn Union Gas Company (KEDNY), KeySpan Gas East Corporation (KEDLI), henceforth referred to collectively as National Grid or the Companies. We appreciate the effort that went into the development of the Companies' Long-Term Plan and the opportunity to provide comments.

1. Executive Summary

New York's Climate Leadership and Community Protection Act (CLCPA) demands decisive action to achieve its ambitious greenhouse gas (GHG) emissions reduction targets. Under the CLCPA, all sectors of the state's economy are collectively required to achieve greenhouse gas (GHG) emissions reductions of 40 percent by 2030 and 85 percent by 2050, relative to 1990 levels.[1] The CLCPA also required the development of a plan, called the Scoping Plan, to provide a framework for New York to reduce GHG emissions, increase renewable energy, and achieve climate justice. The final Scoping Plan was released in December 2022 and calls for a well-planned, strategic downsizing of the gas system,[2] reductions in statewide fossil gas use by at least 33 percent by 2030 and by 57 percent by 2035, and dramatic increases in electrification.

Pursuant to Commission order in case 20-G-0131, every three years, the gas utilities are required to file long-term plans. These plans should detail how the gas utilities plan to ensure compliance with state policies, including the CLCPA, while continuing to provide safe and adequate service. On May 31, 2024, National Grid filed its LTP for its three LDCs: NMPC, KEDNY, and KEDLI. National Grid's LTP includes one reference case and two scenarios with different demand- and supply-side resource options over a 25-year time span. These scenarios include the Clean Energy Vision (CEV) and the Accelerated Electrification (AE) scenarios.

- The **CEV scenario** represents the Companies' vision for the future of gas in the state. The CEV takes an approach that uses duplicative, expensive energy systems. In this scenario, heating demand in 2050 is met through a combination of electrification, energy efficiency, and low-carbon alternative fuels. The CEV scenario entails massive investments to transform the existing gas network into a system that widely delivers renewable natural gas (RNG) and blended hydrogen, in addition to a designated 100 percent hydrogen distribution system for certain hard-to-electrify customers.[3]

[1] NY State Senate Bill S6599. NY State Senate. June 18, 2019.

[2] New York State Climate Action Council. 2022. *New York State Climate Action Council Scoping Plan* (NYS Scoping Plan). https://climate.ny.gov/resources/scoping-plan/.

[3] National Grid. 2024. *Initial Gas System Long-Term Plan*, Case 24-G-0248, at v.

- The **AE scenario** plans to decommission 90 percent of system pipeline miles. It utilizes significant volumes of low-carbon alternative fuel, albeit at lower levels than the CEV scenario, and assumes higher levels of electrification.[4]

National Grid's LTP raises substantial concerns. These include the following:

- A long-term decarbonization strategy that relies primarily on RNG and hydrogen for building-sector energy needs is very risky and likely not compliant with the CLCPA, due to uncertainty in the price, availability, technical feasibility, and impact on emissions from these fuels.
- Non-pipeline alternatives (NPAs) are currently underutilized, and the NPA identification and implementation processes should be improved, through the collection and application of data like Pacific Gas and Electric's Gas Asset Analysis Tool[5], to enable greater adoption of NPAs and appropriate downsizing of the gas system consistent with the recommendations of the Scoping Plan.
- Current practices for replacement of aging pipes will lead to unnecessary investments and increase the risk of stranded costs in the future. NPA suitability criteria should be expanded to enable more of this pipe to be decommissioned through electrification NPA projects.
- The LTP's assumptions about alternatives to gas heating, including the efficiency of heat pumps and temperature set points for switching from heat pump operation to gas backup, are unreasonable.

In many cases, heating electrification is currently a lower-cost option than gas (e.g. for new construction). Over the term of the LTP, electric heating options are likely to become even more affordable. Comparing the cost of different heating options (e.g., gas furnace plus central air conditioning; heat pump with gas furnace as backup; and all-electric heat pump), full-heating electrification is much cheaper than maintaining gas as a primary heating source or for infrequent use as a backup (i.e., for so-called "hybrid" heating). Residential customers who fully electrify will face overall lower total energy bills compared to customers who remain fully or partially on the gas system.

As electric heating options become more affordable and gas service becomes more expensive,[6] it is likely that current gas customers will increasingly leave the system or reduce gas use. This will result in higher bills for the remaining customers, causing even more customers to defect, and leading ultimately to a "utility death spiral". A new scenario modeled by Synapse Energy Economics Inc. (Synapse), the Customer Defection scenario, shows what would happen if National Grid experiences an unanticipated level of customer departures while continuing to invest in the gas system consistent with the CEV scenario. The Customer Defection scenario demonstrates the significant risk of making massive investments in the gas system given the uncertainty of future gas demand. The modeling shows that

[4] Ibid.

[5] Pacific Gas and Electric Company's Opening Comments on Amended Scoping Memo, Track 2A, Questions 2.1(B)-2.1(K), in Case R.20-01-007, Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Safe and Reliable Gas Systems in California and Perform Long-Term Gas System Planning. June 15, 2022 https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M485/K545/485545029.PDF

[6] The cost of gas service is likely to increase as a result of, for example, New York's cap and invest program, potential changes to depreciation calculation methods, and the increased prevalence of liquid natural gas.

very high gas delivery rates and customer bills are likely to occur if prices are higher and more customers defect from the gas system than National Grid forecasts.

We reach several conclusions that point to critical flaws of National Grid's LTP:

- The CEV scenario as proposed is likely to result in unaffordable bills, higher than expected customer defection, and stranded costs, and does not align with the Scoping Plan.
- Maintaining the entire current gas system for infrequent "backup" use of combustion equipment and alternative fuels (thus, maintaining the majority of the current gas system) introduces more risk, is likely to be more costly for customers, and is unlikely to provide the emissions reductions that National Grid forecasts in its LTP.
- National Grid's claim that the short-term actions are the same under the CEV and AE scenarios is inaccurate. The CEV continues gas infrastructure investment, whereas the AE scenario would see that investment scaled back. However, widespread partial electrification of buildings is not a viable strategy for meeting CLCPA emissions targets, and status-quo infrastructure investment is unaffordable over the long run. Reliance on alternative fuels is not a viable near-term strategy.

2. Introduction and Overview

2.1 Regulatory Background

In 2019, New York passed the CLCPA, one of the most ambitious climate laws in the country. Under the CLCPA, all sectors of the state's economy are collectively required to achieve 40 percent GHG emissions reductions from 1990 levels by 2030. The legislation requires further cuts to achieve 85 percent emissions reductions from 1990 levels, and net zero emissions by 2050.[7]

The CLCPA created the Climate Action Council (CAC) and charged this body with developing a Scoping Plan. The Draft Scoping Plan included an analysis (Integration Analysis), commissioned by the New York State Energy Research and Development Authority (NYSERDA) and New York State Department of Environmental Conservation, that modeled statewide and economy-wide benefits, costs, and GHG emissions reductions of scenarios to achieve the CLCPA emission limits.[8] Initial modeling runs for the Integration Analysis included a business-as-usual reference case and a scenario based on the CAC Advisory Panel's initial recommendations (Scenario 1). However, neither were expected to meet CLCPA emission-reduction requirements.[9] The Integration Analysis projected that three alternative scenarios would reduce GHG emissions consistent with the requirements of the CLCPA; these include the Strategic Use of Low-Carbon Fuels (Scenario 2), Accelerated Transition Away from Combustion (Scenario 3), and Beyond 85% Reduction (Scenario 4).[10] The Integration Analysis yielded insights regarding the importance of certain strategies, including widespread building electrification, decarbonized electricity,

[7] NY State Senate Bill S6599. NY State Senate. June 18, 2019.

[8] New York State Climate Action Council. 2021. *New York State Climate Action Council Draft Scoping Plan* (Draft Scoping Plan). https://climate.ny.gov/resources/draft-scoping-plan/.

[9] Ibid., 69.

[10] Since the release of the Scoping Plan, the state has not kept pace with the efforts modeled in the Integration Analysis and, as a result, will likely need to take even more ambitious actions.

and aggressive energy efficiency, for achieving the CLCPA targets.[11] Likewise, the December 2022 Final Scoping Plan calls for a well-planned, strategic downsizing of the gas system;[12] reductions in statewide fossil gas use by at least 33 percent by 2030, and by 57 percent by 2035; and markedly greater levels of electrification.

The Public Service Commission ("PSC" or "Commission") opened the gas planning proceeding (Case 20-G-0131) in 2020. The goal of this proceeding is to "establish planning and operational practices that best support customer needs and emissions objectives while minimizing infrastructure investments and ensuring the continuation of reliable, safe, and adequate service to existing customers."[13] On May 12, 2022, the Commission issued the *Order Adopting Gas System Planning Process* (Gas Planning Order) in this docket. This Order requires the gas utilities to file long-term gas system plans every three years and file annual reports in interim years.[14] Analyses underlying each long-term plan must consider energy efficiency and non-pipeline alternatives (NPA), and the utility must include a "no-infrastructure" scenario that includes only NPA projects instead of building new gas infrastructure, unless it presents sufficient evidence that an NPA-only scenario is not feasible.[15] The Gas Planning Order also requires the utilities to present a likely and a preferred plan for its portfolio of investments, and to compare alternatives based on benefit-cost analysis, bill impact analysis, and emissions impacts.[16]

The Gas Planning Order also requires the gas utilities to file depreciation studies that include the following scenarios: [17]

- Full depreciation of all new gas infrastructure installed beginning 2022 by 2050
- Full depreciation of all gas plant by 2050
- 50 percent of customers leave the gas system by 2040 and only 10 percent remain by 2050

In another case, the Commission issued the CLCPA Implementation Order, which directs the gas utilities to propose a study to analyze the scale, timing, costs, risks, uncertainties, and bill impacts of pathways to achieve substantial reduction in GHG emissions. The CLCPA Implementation Order requires this analysis to include (1) a coordinated long-term gas sector decarbonization pathway analysis through 2050, (2) coordinated near-term plans to address actions needed to achieve statewide decarbonization

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[11] Energy and Environmental Economics and Abt Associates. 2021. *New York State Climate Action Council Draft Scoping Plan: Integration Analysis Technical Supplement,* p. 6 and 84. Prepared for the New York State Energy Research and Development Authority and New York State Department of Environmental Conservation. Available at: https://climate.ny.gov/-/media/project/climate/files/Draft-Scoping-Plan-Appendix-G-Integration-Analysis-Technical-Supplement.pdf.

[12] New York State Climate Action Council. 2022. *New York State Climate Action Council Scoping Plan* (NYS Scoping Plan). https://climate.ny.gov/resources/scoping-plan/.

[13] New York Public Service Commission. Case 20-G-0131 - Proceeding on Motion of the Commission in Regard to Gas Planning Procedures, Order Instituting Proceeding. (Mar. 19, 2020), at 4.

[14] New York Public Service Commission. Order Adopting Gas System Planning Process (Gas Planning Order). Case Nos. 20-G-0131 and 12-G-0297. (May 12, 2022).

[15] Gas Planning Order p 36-7. (NPAs, previously called Non-Pipeline Solutions, "include temporary supply, energy efficiency, electrification, and clean demand response" to "reduce or eliminate the need for gas infrastructure and investments." (State of New York Public Service Commission. Order Instituting Proceeding, March 19, 2020. Case 20-G-0131, p. 7.)).

[16] New York Public Service Commission. Order Adopting Gas System Planning Process (Gas Planning Order). Case Nos. 20-G-0131 and 12-G-0297. (May 12, 2022).

[17] Ibid.

targets through 2030, and (3) individual utility plans to achieve each utility's share of emissions reductions through 2050. [18]

2.2 Overview of Long-Term Plan

National Grid's May 31, 2024, LTP includes three scenarios: the Reference case, the Clean Energy Vision (CEV) scenario, and the Accelerated Electrification (AE) scenario. Some highlights of these scenarios include:

- The **Reference Case** reflects a continuation of current policies based on the best available forecasts, including actions the Companies can take without legislative or policy changes to support decarbonization. Importantly, the Reference Case will not achieve the state's or the Companies' objectives for a decarbonized and fossil fuel-free gas network by 2050.[19]
- The **CEV scenario** represents the Companies' vision for the future of gas in the state. The CEV is a duplicative, multi-infrastructure approach where heating demand in 2050 is met through a combination of electrification, energy efficiency, and low-carbon alternative fuels. The CEV scenario entails massive investments to transform the existing gas network into a system that widely delivers RNG and blended hydrogen in addition to a designated 100 percent hydrogen distribution system for hard-to-electrify customers.[20]
- The **AE scenario** plans to decommission 90 percent of system pipeline miles. It utilizes significant volumes of low-carbon alternative fuel, albeit at lower levels than the CEV scenario, and assumes higher levels of electrification.[21]

The Companies assessed these scenarios in terms of GHG emissions reductions and cost through 2050. According to the Companies, they utilized GHG accounting methods consistent with the requirements of the CLCPA, and they state that both the CEV and AE scenarios are consistent with CLCPA emission targets, as required by the Gas Planning Order.[22] The pathways vary in assumptions about the level of adoption of different energy technologies, as well as policy and customer-funded investment required to implement the objectives discussed in the LTP.

For the CEV scenario, the Companies project eliminating fossil fuels before 2050, replaced with a mixture of low-carbon hydrogen delivered through dedicated 100 percent hydrogen networks, renewable natural gas, blended hydrogen in the existing gas system, building electrification, and energy efficiency improvements. See Figure 1, below.

[18] New York Public Service Commission. Order on Implementation of the Climate Leadership and Community Protection Act. Case No. 22-M-0149. Issued May 12, 2022, at 26-27.

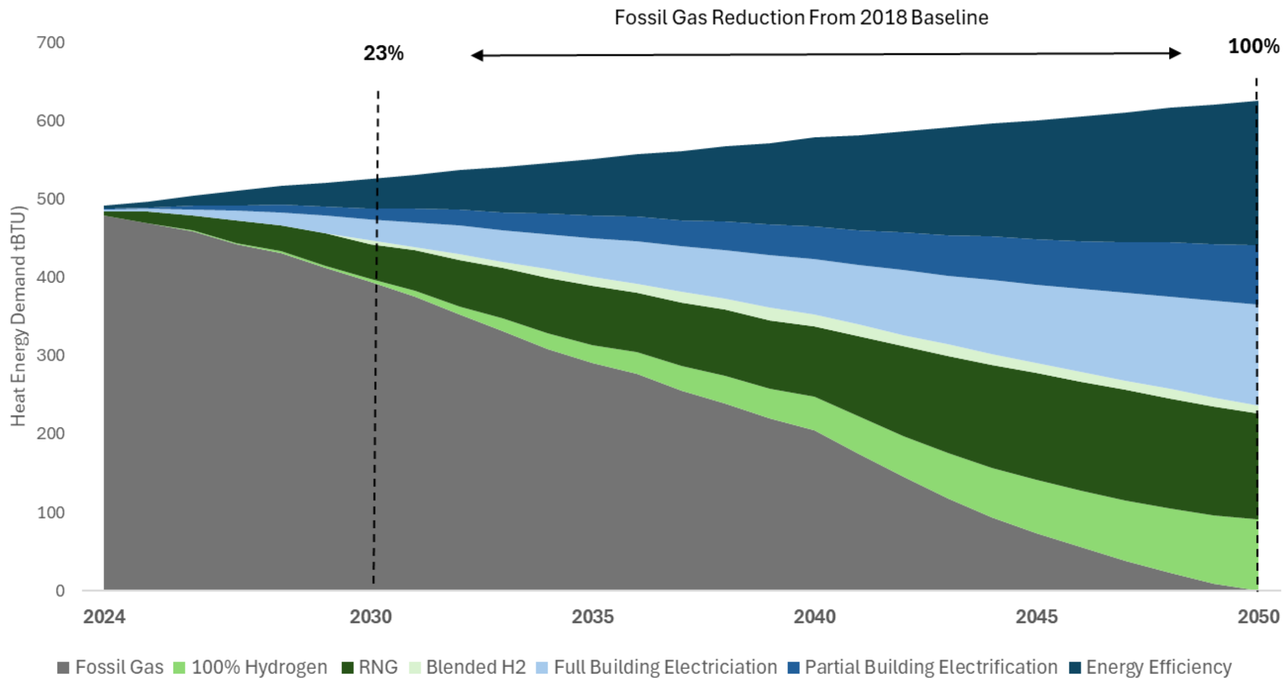
[19] National Grid. 2024. *Initial Gas System Long-Term Plan*, Case 24-G-0248, at v.

[20] Ibid.

[21] Ibid.

[22] Response to Discovery NRDC 56(b).

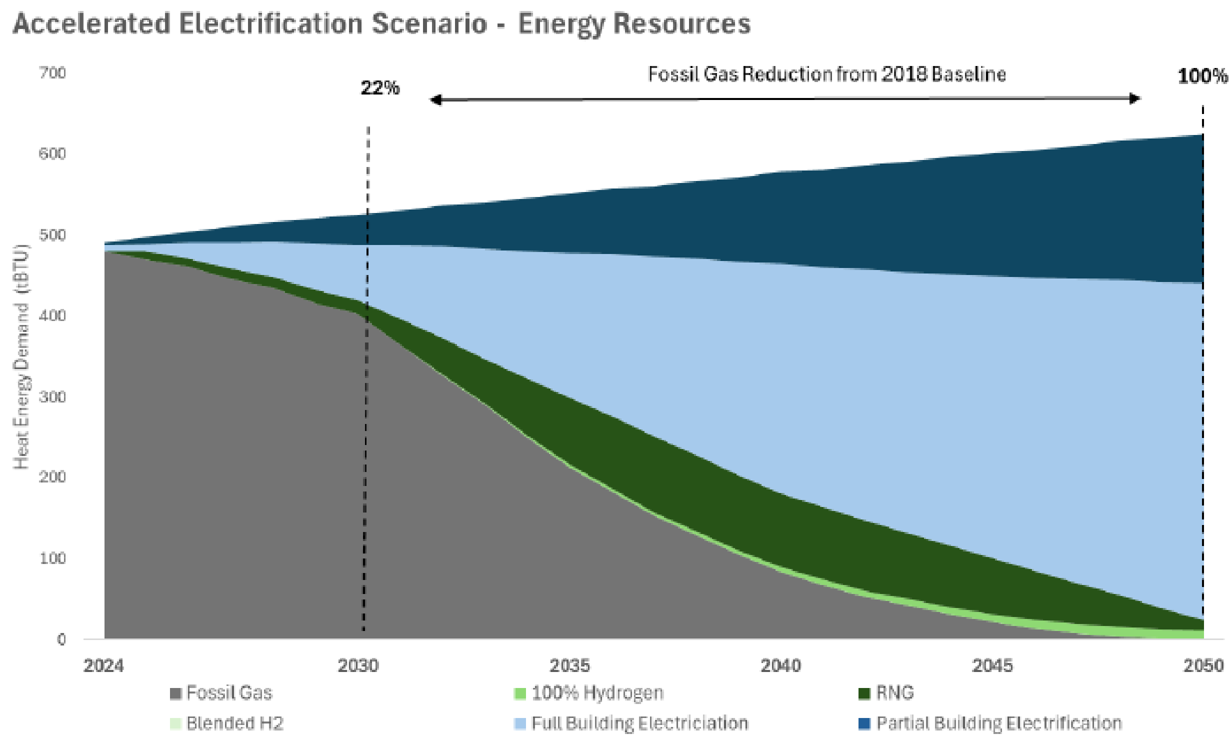
Figure 1. CEV Scenario: System Volumes and Composition



Source: Long-Term Plan, p. 18.

The AE scenario projects a steep decline in the number of gas customers and a significant reduction in gas volumes through 2050, with a near-total elimination of all fossil and renewable gas on the system, replaced with full and partial building electrification. See Figure 2, below. National Grid claims that the AE scenario is based on Scenario 3 of the CAC's Integration Analysis. However, the AE scenario includes a higher amount of low-carbon alternative fuels compared to Scenario 3, which assumes very little use of low-carbon fuels. In this way, the AE scenario is fundamentally different from Scenario 3 and behaves as a false comparison to the CEV scenario.

Figure 2. AE Scenario: System Volumes and Composition



Source: Long-Term Plan, p. 19.

Note: In Response to discovery NRDC 60(a), National Grid explains an error in the LTP; the dark blue area at the top represents energy efficiency, not "Partial Building Electrification" as labeled.

National Grid clearly indicates its preference for the Clean Energy Vision scenario, though it maintains that the barriers to electrification and the near terms actions to achieve CLCPA compliance are the same in the CEV and AE scenarios.[23] This is problematic because the CEV scenario entails a significantly greater level of investment than the AE scenario, translating to substantial risk for stranded assets.

3. Concerns Regarding National Grid's LTP

3.1 Alignment with the Scoping Plan

The Gas Planning Order encourages the local gas distribution companies (LDCs) to incorporate the Scoping Plan's recommendations regarding the gas system transition into their planning processes.[24] Despite this, National Grid's LTP deviates from the path outlined by the Scoping Plan in its assumptions about the level of customer electrification and the use of alternative fuels.

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[23] National Grid. 2024. *Initial Gas System Long-Term Plan*. Case 24-G-0248, at xxii.

[24] Gas Planning Order, at 4.

First, the Scoping Plan states that "the vast majority of current fossil natural gas customers (residential, commercial, and industrial) will transition to electricity by 2050."[25] This expectation is not reflected in National Grid's LTP, where the AE scenario is the only scenario where the majority of customers fully electrify by 2050 (95 percent of demand is met through electrification); although many customers partially electrify in the CEV scenario, most remain on the gas system in 2050 (only 29 percent of demand in the CEV scenario is met through full electrification).[26]

Secondly, the Scoping Plan warns that additional analysis is needed to determine the feasibility and climate impact of alternative fuels prior to further investment.[27] Regarding the use of hydrogen specifically, the Scoping Plan warns that "the existing gas system was not designed to handle any substantial quantity of blending of hydrogen, so the safety and durability of the system must be addressed before hydrogen is introduced into existing infrastructure," and recommends that the use of green hydrogen be limited to transportation, industrial purposes, and electricity reliability.[28] In the CEV scenario, National Grid plans to meet a third of its fuel demand with hydrogen (5 percent from hydrogen blended with methane in existing pipes and 27 percent from 100 percent Hydrogen) to serve both residential and commercial customers. This strategy is inconsistent with the Scoping Plan's concerns about hydrogen blending and its recommendations for using hydrogen for hard-to-electrify end uses, such as industrial processes, only where technology alternatives to combustion do not exist. National Grid claims that one of the core components of the CEV scenario is to "deliver clean alternative fuels to customers with difficult to electrify heating needs;" however, this scenario uses blended hydrogen to serve all customers, not just difficult-to-electrify customers.[29]

3.2 Low Carbon Fuel Overview

Both the CEV and AE scenarios utilize low-carbon, "green" hydrogen (H_2)[30] and renewable natural gas (RNG)[31] to achieve the mid-century targets. Reliance on two untested fuels to meet the objectives of the CEV raises concerns about availability, price, and operational substitutability of RNG and H_2 for fossil gas.

The CEV scenario relies heavily on H_2 and RNG to move towards a 100 percent fossil-free gas network by 2050.[32] For the CEV scenario, the Companies project total heat energy demand to be 626 trillion BTUs (tBTU) in 2050, with roughly 38 percent coming from combustible fuel sources (22 percent from RNG

[25] NYS Scoping Plan, at 350.

[26] Response to Discovery NRDC 60 att. 1

[27] NYS Scoping Plan, at 351.

[28] NYS Scoping Plan, at 351.

[29] National Grid. 2024. *Initial Gas System Long-Term Plan*. Case 24-G-0248, at 120.

[30] The LTP defines green hydrogen as "hydrogen produced using renewable feedstocks…" National Grid. 2024. *Initial Gas System Long-Term Plan*. Case 24-G-0248, at 54.

[31] The LTP relies on the EPA's definition of RNG as "'a renewable energy source that, when used, can reduce methane emissions, and other environmental benefits. Derived from organic waste matter, RNG can be used as a substitute for natural gas[.] The biogas used to produce RNG comes from a variety of sources, including municipal solid waste landfills, digesters at water resource recovery facilities also known as wastewater treatment plants, livestock farms, food production facilities, and organic waste management operations.'" National Grid. 2024. *Initial Gas System Long-Term Plan*. Case 24-G-0248, at 49.

[32] National Grid. 2024. *Initial Gas System Long-Term Plan*. Case 24-G-0248, at 16.

and 16 from H_2), with the remainder supplied by full or partial building electrification and energy efficiency savings. In 2024, fossil gas made up nearly 100 percent of projected baseline for the CEV (see Table 1).[33] By 2050, the CEV requires fossil gas consumption to fall to zero, while H_2 demand increases to 92 tBTU, RNG increases to 135 tBTU, and H_2 blended with the RNG increases to 10 tBTU.

In the AE scenario, low-carbon gases are less critical to the Companies' mid-century strategy. Total heating demand in 2050 is projected to be roughly the same as in the CEV scenario with less than four percent of total demand met by fuels of any type (see Table 1).[34] Rather than untested and unavailable fuels, the AE scenario pathway relies almost entirely on full building electrification and energy efficiency to meet projected heating demand.

Table 1: Gas Requirements by Scenario through 2050 (tBTU/year)

		2024	2030	2040	2050
Clean Energy Vision Scenario	Fossil Gas	479	395	205	0
	100% Hydrogen	0	3	43	92
	RNG	5	44	90	135
	Blended Hydrogen	0	4	16	10
Accelerated Electrification Scenario	Fossil Gas	481	403	84	0
	100% Hydrogen	0	0	6	12
	RNG	0	17	91	13

Source: NRDC-060 Attachment 1 - CEV pillar allocation.

We have identified four areas of concern with the Companies' reliance on RNG and H_2 to meet projected heat energy demand:

- overly optimistic assumptions regarding the availability of RNG in-state and out-of-state jeopardize the ability of National Grid to meet their 2050 targets;
- issues with the retention of environmental attributes of RNG to meet their emission targets and negative environmental and health impacts from continued combustion;
- price assumptions that likely understate the expected commodity cost of RNG and $H_{2;}$ and
- cost, availability, and operational concerns regarding the use of H_2 in the existing gas system on a broad scale.

3.3 RNG

Overly optimistic assumptions regarding the availability of RNG Supply

The CEV scenario, which is the Companies' preferred scenario, requires an extraordinary volume of low-carbon gases to meet its 2050 goal.[35] The LTP CEV scenario relies on overly optimistic supply availability assumptions for in-state and out-of-state RNG production, jeopardizing the chances of meeting mid-century targets.

[33] Response to Discovery NRDC-060 Attachment 1.

[34] Response to Discovery NRDC-060 Attachment 1.

[35] National Grid. 2024. *Initial Gas System Long-Term Plan*. Case 24-G-0248, at xv.

The Companies acknowledge four potential barriers and risks to achieving this level of RNG availability: (1) competition for RNG from combined heat and power (CHP) systems, which are the most common users of biogas; (2) the viability of interconnecting to the gas network the state's dairy farm operations, should they continue to operate into the future; (3) the significant capital cost requirements to build RNG production facilities; and (4) competition for supply of RNG from other gas-using, non-residential sectors.[36] While these represent potential barriers to achieving the levels of RNG deployment necessary to meet the Companies' goals, we believe there are other, larger hurdles, including inadequate in-state and out-of-state supply.

In-State RNG Supply Analysis

National Grid estimates that the in-state supply of RNG is between 47 and 147 tBTU by 2040.[37] This range was provided by an analysis conducted by ICF for NYSERDA in 2022 (the NYSERDA study).[38] The NYSERDA study provides three scenarios and an estimate of total in-state technical potential for RNG. National Grid assumes, based on the NYSERDA study, that these volumes of in-state RNG will be available; however, the study does not (i) clearly explain the changes between similar in-state estimates by feedstock, (ii) account for the slow rate of in-state investment in RNG facilities, or (iii) account for projected growth rates in in-state capacity.

(i) Unexplained changes to in-state estimates by feedstock: The two primary production pathways for RNG are anaerobic digestion—which includes capturing biogas from digested feedstocks like animal manure, food waste, organic materials not diverted from landfills that produce methane gas, and human waste digested by the water resource recovery facilities at wastewater treatment facilities—and thermal gasification—which involves gasification through combustion of agricultural, forestry, and forest product residue feedstocks. The more recent 2022 NYSERDA study projects higher rates of RNG development for feedstocks, though it is unclear what supports these discrepancies between the 2022 NYSERDA study and an earlier ICF study for the American Gas Foundation (AGF) released in 2019. Table 2 outlines the limited/low versus optimistic/high RNG potential by feedstock as described in the 2022 NYSERDA study compared with the results from the 2019 AGF study. In the Limited/Low resource potential case, the totals are quite close to each other between studies. However, there is a large difference between what was estimated in the 2019 AGF study for the Optimistic/High resource potential scenario (see row *i*), largely driven by much larger estimates of potential from energy crops (see row *f*) and forestry and forest product residue (see row *g*). These two feedstock categories are some of the most carbon-intensive on a lifecycle basis (see Figure 5) and some of the most expensive.[39] It is unclear from the NYSERDA study, which the Companies relied upon for their estimated in-state RNG resource potential, why there is such a large and expected difference in the availability of RNG sourced from energy crops and forestry and forest product residue. An over reliance on dirtier and more expensive RNG feedstocks

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[36] National Grid. 2024. *Initial Gas System Long-Term Plan*. Case 24-G-0248, at 52-53.

[37] Ibid, 51.

[38] New York State Energy Research and Development Authority (NYSERDA). 2021. *Potential of Renewable Natural Gas in New York State*, NYSERDA Report Number 21-34.

[39] American Gas Foundation. 2019. *Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment*, Prepared by ICF, at 57.

in the Optimistic fuel availability scenario increases the risk that the Companies will not be able to source the necessary RNG should these estimates prove overly optimistic.

Table 2: State comparison of potential RNG production capacity by 2040 (tBTU/yr)

		Limited/Low Resource Potential		Optimistic/High Resource Potential	
	Study	2022 NYSERDA	2019 AGF	2022 NYSERDA	2019 AGF
Anaerobic Digestion	a. Animal Manure	6.1	4.5	12.1	9.0
	b. Food Waste	2.4	2.4	4.3	4.2
	c. LFG	13.9	19.7	24.8	32.8
	d. Waste Resource Recovery Facility	1.8	2.5	3.2	3.3
Thermal Gasification	e. Agricultural Residue	0.3	2.0	12.0	5.0
	f. Energy Crops	6.7	0.6	34.0	3.0
	g. Forestry and Forest Product Residue	1.3	2.0	25.0	4.0
	h. Municipal Solid Waste	14.9	19.3	31.1	43.5
	i. Totals	47.4	53	146.5	104.8

Sources: New York State Energy Research and Development Authority (NYSERDA). 2021. Potential of Renewable Natural Gas in New York State*, NYSERDA Report Number 21-34, at 8; American Gas Foundation. 2019.* Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment*, Prepared by ICF, at 64-67.*

ii) Unrealistic rate of in-state investment in RNG facilities: There is concern that known and projected growth in in-state RNG capacity is not likely high enough to satisfy 2040 RNG demand, let alone 2050. To date, the LTP notes that existing downstate and upstate RNG capacity is 1 million BTUs/day (about 1 Dth/day), far less than one percent of expected 2050 RNG demand.[40] While the LTP acknowledges that not all RNG will be sourced from the Companies' service territory or even within the state, the current low RNG capacity will require significant investment and attention to ensure that adequate capacity, both from in-state and out-of-state sources, are available under the CEV scenario. Currently, the Companies only have one contract for an in-state RNG facility. According to the LTP, National Grid partnered with the New York City Department of Environmental Protection to commission and operate the Newton Creek biogas facility. This facility produced 75,000 Dth of RNG in nine months, or approximately 275 Dth/day.[41] National Grid expects the facility to inject between 137,000 and 237,000 Dth of supply per calendar year.[42] However, the viability of the Newton Creek facility has recently been questioned given repeated breakdowns at the facility and flaring of captured methane. Between April 2023 and March 2024, the facility was offline for 46 percent of the year.[43] National Grid should expect delays in their efforts to build out new technology that may not be fully operational when expected.

[40] National Grid. 2024. *Initial Gas System Long-Term Plan*. Case 24-G-0248, at xvii and xix.

[41] Ibid, 45.

[42] Ibid, 45.

[43] Samanth Maldonado. 2024. "National Grid Want to Heat More Homes with Converted Food Waste – and Make You Pay For It." *The City*. Available at: https://www.thecity.nyc/2024/05/22/national-grid-rate-hike-food-waste-gas/.

In addition to the Newton Creek facility, the Companies have contracted for a portion of RNG produced at a Long Island waste-to-energy facility, and are supporting development at four additional projects in the downstate region.[44] Together, National Grid projects that these projects will inject 5,350 Dth/day into the system, meeting 4.4 percent of National Grid's total RNG demand in 2030, 2.2 percent in 2040, and just 1.4 percent by 2050.[45] Total RNG capacity that is operational or under construction in New York State as of August 2024 was 3,777,307 Dth/year, from approximately 21 facilities (see Table 3).[46] While substantial, this accounts for just 8.6 percent of 2030 RNG requirements in the CEV scenario, 4.2 percent in 2040, and 2.8 percent in 2050. Of the operational and under-construction facilities, only two are in counties in which National Grid operates.[47] If other gas utilities operate in those counties in which RNG facilities are located, then it is likely those gas utilities will increase demand for limited in-state RNG supplies, driving up the price.

[44] National Grid. 2024. *Initial Gas System Long-Term Plan*. Case 24-G-0248, at 45.

[45] Ibid, 45. The percentages of total National Grid RNG demand met by current capacity is equal to annualized daily capacity (5,350 Dth/day * 365) divided by National Grid's expected 2030, 2040, and 2050 RNG requirements in the CEV scenario (44 tBTU, 90 tBTU, and 135 tBTU, respectively).

[46] Argonne National Laboratory, Renewable Natural Gas Database. Available at https://www.anl.gov/esia/reference/renewable-natural-gas-database.

[47] New York State, Department of Public Service. n.d. "Electric and Gas Utility Service territory by County". Available at: https://dps.ny.gov/system/files/documents/2022/10/nys-electric-and-gas-utilities-by-county.pdf.

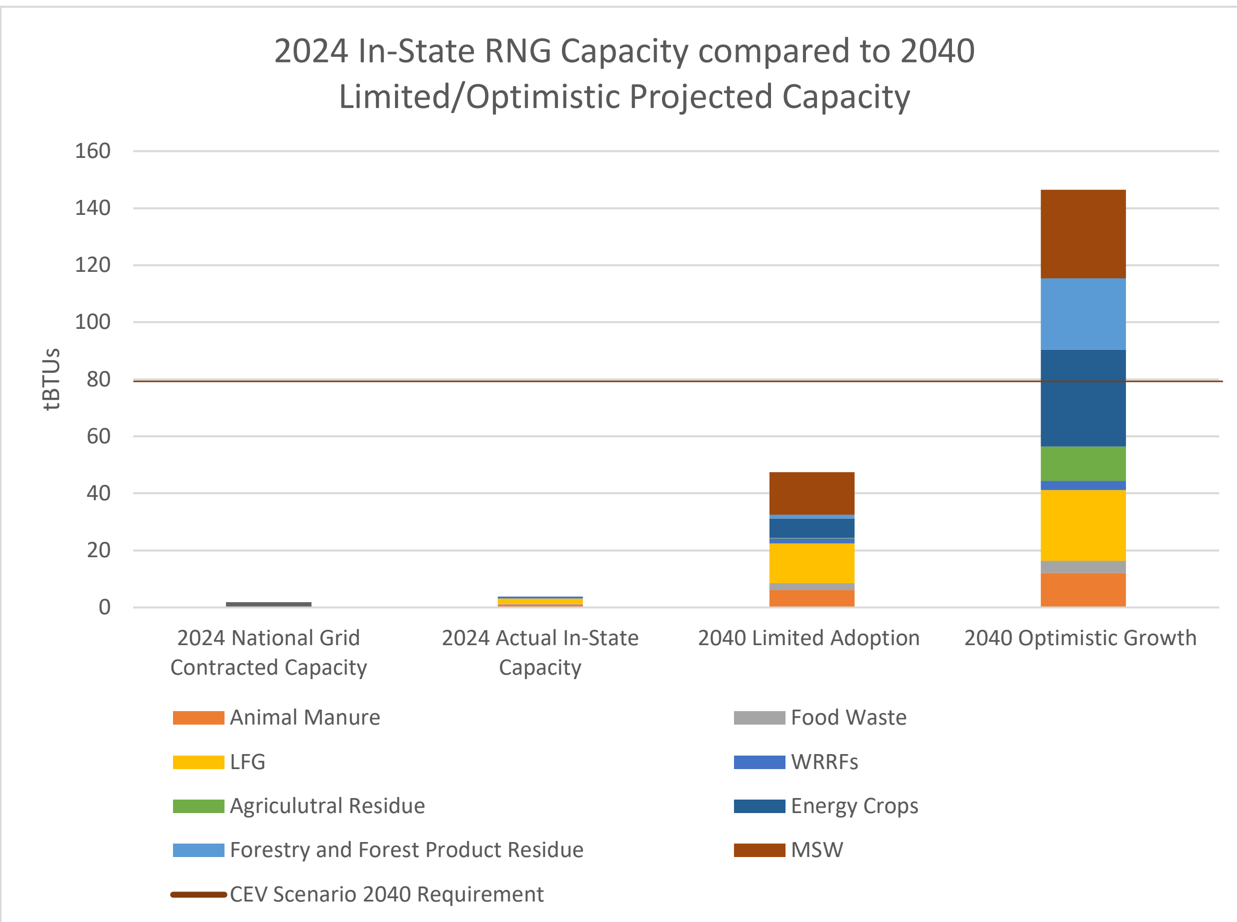
Table 3: Operational and Under Construction RNG Facilities in New York State, August 2024

	Facility	County	National Grid Service Area (Y/N)	Status	Upgraded Dth/Year
Food Waste	American Organic Energy	Suffolk	Y	Under-Construction	185,849
Landfills	Chautauqua Green Energy Landfill RNG Project	Chautauqua	N	Operational	500,000
	Fresh Kills Landfill (Montauk)	Richmond	N	Operational	474,119
	Seneca Meadows SWMF (Progressive, Archaea)	Seneca	N	Operational	780,516
	Waga Energy Steuben County Landfill	Steuben	N	Under Construction	207,000
Livestock And Agriculture	Brightmark Helios Lawnhurst Farms	Ontario	N	Operational	63,000
	Yellowjacket Boxler Dairy Farm	Wyoming	N	Operational	66,750
	Yellowjacket Lamb Farms	Genessee	N	Operational	58,600
	Yellowjacket Lamb Lakeshore Dairy	Niagara	N	Operational	48,900
	Yellowjacket Swiss Valley Farms	Wyoming	N	Operational	26,017
	Yellowjacket Zuber Farm	Genessee	N	Operational	22,928
	Brightmark Helios Gardeau Crest Farm	Wyoming	N	Operational	63,000
	Brightmark Helios Willet Dairy	Cayuga	N	Operational	63,000
	Cayuga RNG Allen Farms	Cayuga	N	Operational	88,060
	Cayuga RNG El-Vi Farms	Wayne	N	Operational	49,500
	Nobles Farms	Chautauqua	N	Under Construction	Unknown
	Bilow Farms	Franklin	N	Under Construction	Unknown
	Synergy Dairy (CH4 Biogas)	Wyoming	N	Under Construction	101,664
	DTE Vantage Bluebird (Sunnyside/Aurora Ridge Dairies)	Cayuga	N	Under Construction	216,810
	HoSt Group NY Dairy Project A	Several counties	N	Under Construction	170,294
WRRFs	Newtown Creek Wastewater Treatment Plant	Kings County	Y	Operational	591,300
Total Capacity	3,777,307				

Source: Argonne National Laboratory. 2024. Renewable Natural Gas Database. Available at: https://www.anl.gov/esia/reference/renewable-natural-gas-database.

iii) Unrealistic projected growth rates in in-state capacity: To meet the total 2040 "Limited Adoption" potential of 47.4 tBTU estimated by the NYSERDA study, total project in-state RNG capacity growth must grow significantly (see Table 2). Meeting this projection would require scaling the state's total RNG capacity by 11 times between now and 2040, an annualized growth rate of 77 percent per year. To meet the most ambitious "Optimistic Growth" trajectory, the state's RNG capacity would have to grow 38 times over, or roughly 250 percent per year. While the technical potential in the state may allow for RNG growth approximating these estimated annual RNG production potential values, real-world growth rates are unlikely to match either the limited or optimistic growth trajectory. Figure 3 shows just how much in-state RNG capacity must grow between now and 2040 to meet the limited adoption and optimistic growth estimate in the 2022 NYSERDA report. The Companies have failed to provide any evidence to suggest that in-state RNG capacity will grow at the rates required to meet either the limited or optimistic adoption cases.

Figure 3: 2024 In-State RNG Capacity compared to 2040 Limited/Optimistic Projected Capacity



Sources: New York State Energy Research and Development Authority (NYSERDA). 2021. Potential of Renewable Natural Gas in New York State, NYSERDA Report Number 21-34, at 8; American Gas Foundation. 2019. Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment. Prepared by ICF, at 64-67.

Out-of-State RNG Supply Analysis

The Companies developed an RNG supply estimate to determine the total potential RNG available in the Eastern United States (defined as east of the Mississippi River) by 2050 and how much RNG would be available to both New York State and the Companies (see Table 4). The projected estimates of available RNG in the companies' service area range from a low-supply case of 83 tBTU to a high-supply case of 158 tBTU by 2050. Achieving the 2050 CEV scenario calls for roughly 135 tBTU of RNG, implying that anywhere from 61 to 117 percent of total RNG demand in the CEV scenario could be met from out-of-state sources (see Table 1 above).[48] The Companies claim that this level of supply is both achievable and within the range of their regional share of natural gas sales in New York in 2020.[49] However, these projected estimates rely on optimistic growth rates that may not be realized, resulting in under-availability of RNG and the Companies missing their targets.

Table 4: Estimated Annual RNG Production from Eastern U.S. States and RNG Potential Available to New York

RNG Supply Cases Defined by AGF	RNG Supply Potential in 2050			National Grid RNG Demand – CEV Scenario	
	Eastern U.S. (tBTU/year)	NY State (tBTU/year)	National Grid NY (tBTU/year)	tBTU/year	%
Low Supply Case	1,158	150	83	135	61%
High Supply Case	2,199	285	158	135	117%

*Source: Recreated from LTP at 52 – data from Guidehouse National Grid New York CLCPA Study (March 17, 2023) at 56; Estimated Share of Eastern U.S. RNG Supply in 2050 is based on the proportionate share of regional non-power, non-industrial fossil gas sales in 2020: 13.0% for New York State and 7.2% for National Grid companies. (1,158 tBTU*13%=150 tBTU; 2,199 tBTU*13%=285 tBTU; 1,158 tBTU*7%= 83 tBTU; 2,199 tBTU*7%= 158 tBTU).*

The values in Table 4 were derived from a March 2023 Guidehouse study that National Grid commissioned to help support National Grid's CLCPA study.[50] Table 4 shows that National Grid could meet their 2050 RNG demand through out-of-state supply alone, based on the High Supply Case. However, fully understanding how National Grid arrived at these potential 2050 estimates requires unpacking assumptions and data taken from a series of studies that are likely all favorable to the fossil gas industry and support the conclusion that RNG is technically and reasonably available viable pathway to decarbonizing the gas sector.

The Guidehouse study estimates out-of-state RNG potential for National Grid by relying on and updating a 2019 AGF study. First, the 2023 Guidehouse study estimated total potential RNG imports from out-of-state by relying on the American Gas Foundation (AGF) and American Gas Association's (AGA) 2022 study.[51] The 2022 AGA study, in turn, relied on a 2019 ICF-AGF study of RNG potential through 2040. The 2022 AGA study extrapolated the 2019 AGF study values through 2050 based on a set of

[48] National Grid. 2024. *Initial Gas System Long-Term Plan*. Case 24-G-0248, at 53.

[49] Ibid.

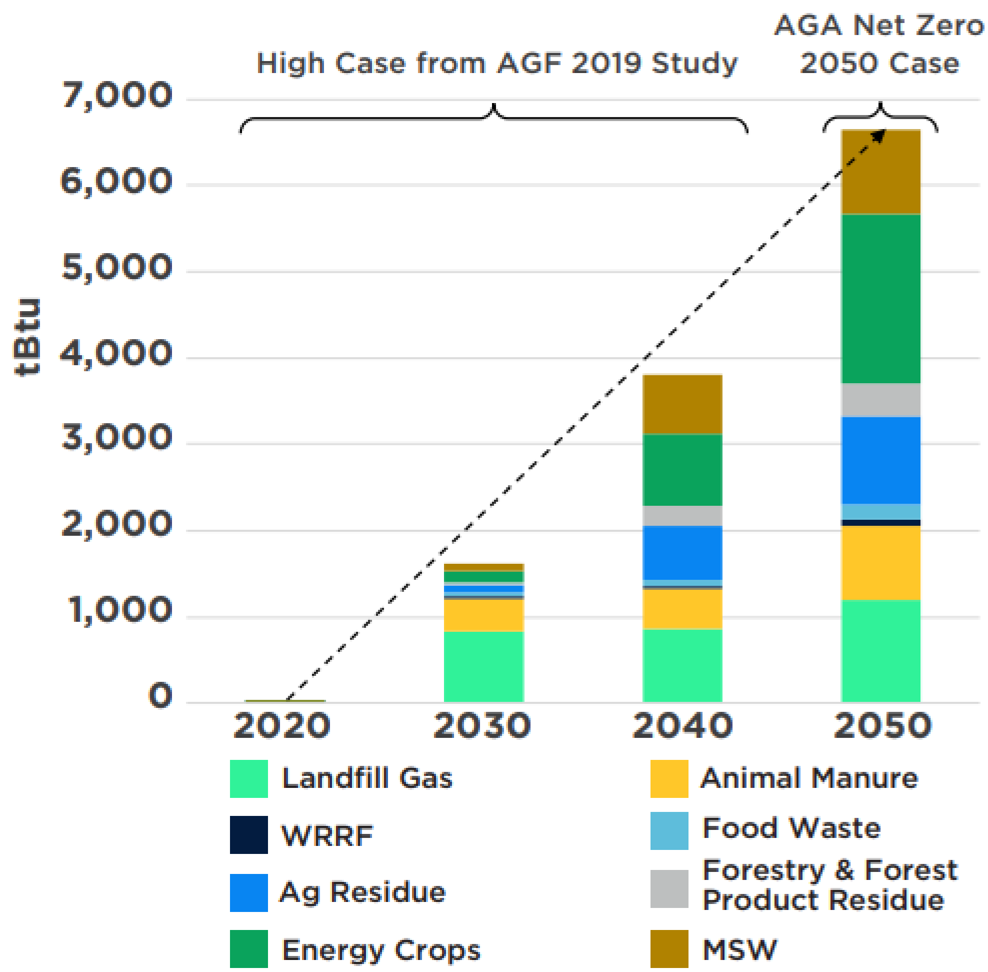
[50] Guidehouse. 2023. *National Grid New York Climate Leadership and Community Protection Act Study: Final Report*. Prepared for National Grid, at 56. Available at: https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={902EF186-0000-C23D-A661-816D62832879}.

[51] American Gas Association. 2022. *Net-Zero Emissions Opportunities for Gas Utilities*. Prepared by ICF.

assumptions, such as actual and projected growth in RNG markets in California and Canada, improved technology, and clustering of facilities to show that RNG availability would grow substantially.

Next, the AGA study took the 'High Resource Potential Scenario' from the AGF study for 2040 (3,834 tBTU/year) (not including RNG from Power-to-Gas/Methanation) and extrapolated to 2050 (6,645 tBTU/year), a total growth rate of 7.3 percent each year from 2040 to 2050 (see Figure 5).[52]

Figure 4: Comparison of 2040 and 2050 Case for RNG Supply (tBTU)



Source: American Gas Association. 2022. Net-Zero Emissions Opportunities for Gas Utilities. Prepared by ICF, at 99-100.

Guidehouse applied these growth rates between 2040 and 2050 to the regional breakdown from the 2022 AGA 'high' resource potential scenarios. The Guidehouse report determined the available New York State and National Grid estimated share of RNG supply in the eastern United States by multiplying the share of fossil gas sold to New York State and National Grid, respectively, in 2020 (13 percent and

[52] Ibid, 99-100.

7.2 percent in Table 4). It is misguided to assume that New York state and National Grid will be able to source RNG at the same levels that they currently source fossil gas, given that costs for RNG are likely higher and given there may be competing needs for RNG in other sectors.

The two key values that undergird National Grid's 2024 regional RNG potential availability are the 'low' and 'high' resource potential scenarios for states east of the Mississippi in 2040 found in the 2019 AGF study[53] and the rate of growth in RNG supply between 2040 and 2050 found in the 2022 AGA study.[54] If either of those scenarios or assumptions underlying those scenarios turns out to overestimate available RNG in the eastern United States, then the ability of National Grid to source RNG to meet their heating needs at the projected cost will be compromised.

RNG Emissions Accounting Concerns

National Grid takes an overly optimistic view of RNG emissions for two reasons. First, its LTP did not accurately reflect the expected emissions from RNG, when factoring in the feedstocks and production methods to generate RNG and their estimated lifecycle emissions. Second, National Grid used inconsistent accounting frameworks for RNG when estimating the total emissions associated with its LTP scenarios and calculating the benefit cost analysis (BCA). These two issues serve to dramatically overstate the decarbonization value of RNG in all of the LTP scenarios, but work to particularly distort the CEC scenario due to its very heavy reliance on RNG.

First, National Grid did not account for life cycle emissions rates of different RNG feedstocks because New York does not have an established framework for quantifying life cycle emissions.[55] Instead, it uses the same emission factors regardless of the feedstocks, production methods, and location of its RNG supply.[56]

In contrast to how its depicted in the LTP, RNG is not an inherently environmental solution**.** The actual carbon intensity of RNG varies substantially depending on certain factors such as feedstocks and production methods. It also varies based on production location and how the fuel is transported and distributed.[57] While RNG is often presented as "zero carbon" with little justification, an assessment of its climate impacts must account for (1) the energy required to produce it, (2) whether the source creates new methane (as occurs with thermal gasification), and (3) how much methane leaks during production

[53] American Gas Foundation, "Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment," (2019), Prepared by ICF, at 13-14.

[54] American Gas Association, "Net-Zero Emissions Opportunities for Gas Utilities," (2022), Prepared by ICF, at 100.

[55] NRDC-1-24a. (Q: "Did the Company account for the differing life cycle emissions rates of different RNG feedstocks in its modeling? If not, why not? A: "The Company did not account for life cycle emissions rates because New York has no established framework for quantifying life cycle emissions. National Grid supports the use of life cycle emissions and recommends incorporating life cycle analysis into all future policies or regulations related to the gas transition."

[56] National Grid Initial LTP at p.191, Table 11-14.

[57] American Gas Foundation, "Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment," (2019), Prepared by ICF, at 46.

and distribution. The 20-year global warming potential of methane is more than 80 times that of carbon dioxide, so methane leakage is a particular concern.[58]

As an example for how the emission reduction value of RNG can vary, a report from ICF and AGF found that RNG produced from food waste and dairy and swine manure feedstocks are likely to result in emissions reductions using ICF's methodology, when netting out the emissions reductions from the agriculture source, relative to combustion of fossil gas.[59] However, some of the more plentiful feedstocks—including landfill gas, beef/poultry manure, water resource recovery facilities, agricultural residue, forestry residue, energy crops, and municipal solid waste—all have positive lifecycle emissions factors using ICF's methodology.[60]

Second, National Grid's LTP uses inconsistent emission accounting frameworks for RNG to calculate its GHG emission reductions and to conduct the benefit cost analysis (BCA) of the CEV and AE scenarios, which has the effect of distorting the BCA results and dramatically overstating the comparative value of the CEV.

Specifically, National Grid's LTP uses two GHG emission reduction frameworks: 1) "gross" accounting for calculating total emissions, as required by the CLCPA and DEC regulations, and 2) "net" accounting (which the Companies refer to as "standard" accounting) for performing the BCAs. These two frameworks take dramatically different approaches to accounting emissions from biogenic fuels, which has significant implications for the LTP because of its heavy reliance on RNG.

The CLCPA establishes a gross GHG emission accounting framework that is implemented by Department of Environmental Conservation (DEC) and used to measure and enforce compliance with the Act's emission limits.[61] This gross GHG emission accounting framework flows from the CLCPA's definition of "statewide greenhouse gas emissions", which includes sources "*within the state*" plus emissions associated with imported electricity and fossil fuels.[62]

The gross GHG emission accounting framework is the foundation for multiple components of the CLCPA and is critically important for its successful implementation. The CLCPA requires DEC to "promulgate rules and regulations to ensure compliance with the statewide emissions reduction limits"[63] that "ensure that the aggregate emissions of greenhouse gases from greenhouse gas emission sources will

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[58] International Energy Agency 2021. Methane and climate change. Available at: https://www.iea.org/reports/methane-tracker-2021/methane-and-climate-change.

[59] It is important to note that RNG will still produce toxic air pollution and carbon dioxide when combusted, even if it is estimated to decrease GHG emissions.

[60] American Gas Foundation, "Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment," (2019), Prepared by ICF, at 72.

[61] *See* ECL Article 75.

[62] ECL § 75-0101(13) ("Statewide greenhouse gas emissions" means the total annual emissions of greenhouse gases produced within the state from anthropogenic sources and greenhouse gases produced outside of the state that are associated with the generation of electricity imported into the state and the extraction and transmission of fossil fuels imported into the state. Statewide emissions shall be expressed in tons of carbon dioxide equivalents.). *See also* ECL § 75-0105(3).

[63] ECL § 75-0109(1).

not exceed the statewide greenhouse gas emissions limits";[64] "include legally enforceable emissions limits, performance standards, or measures or other requirements to control emissions from greenhouse gas emission sources";[65] and reflect, in substantial part, the findings of the Climate Action Council's Scoping Plan, which outlines recommendations regarding regulatory measures and other State actions to ensure attainment of the statewide greenhouse gas emission limits. [66]

Of note, DEC's regulations implementing the statewide GHG limits, and thus the gross GHG emission accounting framework underlying them, apply to "all parts of the State and to all State agencies, offices, authorities, and divisions in the context of programs, regulations, decisions, and planning documents specified in the [CLCPA]."[67] DEC's emissions accounting regulations thus prohibit the Commission from using alternative emission accounting frameworks in its regulation of gas utilities, including for use in their LTPs.

Under New York's gross GHG emission accounting system, the emission reduction benefits of RNG are accounted for at the point of production, instead of at the point of consumption (as would be the case under a net accounting framework). In other words, when "fugitive" biogenic emissions are captured in the production of RNG, the emission reduction benefits are accounted for in the sector that created the feedstock for the RNG production (e.g., agriculture or waste)—the emission reduction shows up as the absence of "fugitive" biogenic emissions produced by the relevant sector. In contrast, when the RNG is combusted, the gross emissions accounts for the same emission impact as burning fossil gas (except without the associated upstream methane emissions from the extraction and transmission of fossil fuels) in the sector that consumes the gas (e.g., buildings, electricity, industry). This gross emission accounting system is consistent with what the Intergovernmental Panel on Climate Change considers best practice: i.e., for CO_2 emissions from the combustion of organic waste to be reported in the Energy sector, but not included in national totals.[68] From a statewide accounting perspective, the emissions reductions from the capture/avoided release of biomethane/production of RNG generally offset the emissions increases from combusting the RNG;[69] however, under New York's gross emissions accounting system, an end-use for gas delivered through the utility gas system that combusts RNG for fuel produces emissions and thus cannot be construed as "zero emissions".

Importantly, under the gross accounting framework, the only emission reduction benefit of RNG supply as opposed to fossil gas are the emission reductions associated with the extraction and transmission of fossil fuels imported into the state; emissions associated with the importation of biogenic fuels like RNG are not included in the gross accounting framework. This (inaccurate) quirk of New York's gross accounting framework arises from the CLCPA's definition of "Statewide greenhouse gas emissions," which expressly "means the total annual emissions of greenhouse gases *produced within the state* from

[64] ECL § 75-0109(2)(a).

[65] ECL § 75-0109(2)(b).

[66] ECL § 75-0109(2)(c).

[67] 6 NYCRR 496.2.

[68] Department of Environmental Conservation, 6 NYCRR Part 496, Statewide Greenhouse Gas Emission Limits, Regulatory Impact Statement at 10 of 42, available at https://dec.ny.gov/sites/default/files/2023-12/6nycrrpart496adopted2020.pdf.

[69] 2022 Statewide GHG Emissions Report: Summary Report, at 4, available at https://www.dec.ny.gov/docs/administration_pdf/ghgsumrpt22.pdf.

anthropogenic sources and greenhouse gases produced outside of the state that are associated with . . . the extraction and *transmission of fossil fuels imported* into the state."[70] (Emphasis added). By defining Statewide greenhouse gas emissions as the total annual emissions of greenhouse gases produced within the state, the CLCPA plainly prohibits any netting of out-of-state emission reductions against the emissions produced in New York to achieve the Act's emission reduction targets. It also does not expressly include emissions from the transportation of imported biofuels; however, this is arguably required by other provisions such as those requiring a "scientifically credible account" of emissions.[71]

Use of net accounting as opposed to gross accounting constitutes a fundamental transfer of the emission reduction benefits of RNG from the sectors that produce the RNG to the sectors that consume the RNG. Establishing this benefit transfer is the primary objective of gas utility support for net accounting because it ensures the emission reduction benefits of RNG accrue to the purchasers of utility gas, which helps facilitate the continued use of the utilities' gas system to the benefit of their shareholders and at the expense of all New York energy customers and the environment.

The (incorrect) use of net accounting would have two negative consequences for New York. First, it would dramatically elevate RNG use in buildings and electricity production, because whenever RNG is consumed in New York, it would be considered zero emissions for the purposes of compliance with the CLCPA emission limits. This contradicts the Scoping Plan, which highlights the importance of electrification and does not endorse any widespread use of RNG in buildings. Second, it dramatically increases the emission reduction benefit of out-of-state RNG by attributing the emission reductions that occur out-of-state from RNG production to in-state RNG use, which violates the plain meaning of the CLCPA's definition of "Statewide greenhouse gas emissions," which expressly "means the total annual emissions of greenhouse gases *produced within the state* from anthropogenic sources . . ."[72]

The gross emissions accounting system is the appropriate framework for state-level climate policy that is intended to remedy the in-state harms of fossil fuel use and deliver economic, environmental, and health benefits to New Yorkers. If the State's emissions accounting to measure and enforce achievement of the Climate Act's emission limits were to account for in-state emission reductions for RNG produced out-of-state, the policy would result in the economic, environmental, and health benefits occurring out of the state where the RNG is produced, and it would perpetuate the economic, environmental, and heath harms of combusting RNG in-state—harms indistinguishable from those caused by combusting fossil gas. For these reasons, gross accounting is required by the CLCPA.

In the LTP, National Grid accounts for GHG emission reductions using both gross accounting (*see* Table 7-7 at p. 134) and net accounting (*see* Table 7-8 at p. 135). National Grid, however, only uses net

[70] ECL § 75-0101(13).

[71] See e.g., ECL § 75-0105(7) ("The statewide greenhouse gas emissions report shall clearly explain the methodology and analysis used in the department's determination of greenhouse gas emissions and shall include a detailed explanation of any changes in methodology or analysis, adjustments made to prior estimates, as needed, and any other information necessary to establish a scientifically credible account of change.").

[72] ECL § 75-0101(13).

accounting to conduct its BCA.[73] Of note, NYSERDA has issued guidance that recommends using net accounting for monetization of avoided GHG emissions as a simplifying assumption,[74] while also noting that the guidance "is not intended to create any legal requirement and does not supersede or replace the Statewide GHG emission inventory report developed by DEC pursuant to Environmental Conservation Law (ECL) Section 75-0105, the DEC emission limit regulation in 6 NYCRR Part 496 established pursuant to ECL Section 75-0107, or any guidance of the appropriate agencies for any legal or regulatory requirement or submittals."[75]

The distortionary impact of using net accounting for a LTP that is heavily reliant on out-of-state RNG is dramatic. Under gross accounting, RNG can only avoid roughly 20% of fossil gas emissions (RNG produces 116.6 lbs/mmbtu CO2e vs. 144 lbs/mmbtu CO2e for fossil gas) because it only avoids the upstream emissions associated with fossil fuel use and not the emissions produced when the gas is combusted at the point of consumption.[76] In contrast, use of net accounting attributes zero lbs/mmbtu CO2e for RNG vs. the 116.6 lbs/mmbtu CO2e. Indeed, the use of a net-accounting would attribute approximately 3.25x greater emission reductions to RNG relative to fossil gas than it would under gross accounting, which accurately captures the actual emission reduction benefits for purposes of the CLCPA emission limits.

The net-accounting simplifying assumption of net zero emissions might serve as an understandable approach for identifying the emission reduction value to New York of RNG that is produced in-state, because the netted-out emissions are likely to occur in other sectors of New York's economy (i.e., the agricultural or waste sectors that produce the feedstock used to produce the RNG). However, net accounting becomes deeply problematic when it is applied to RNG that is produced out-of-state, because out-of-state RNG does not provide any emission reduction benefits within New York to offset the emissions produced when the RNG is consumed in-state (GHGs have been sequestered in another state's agriculture or waste sector and did not alter the emission from the combustion of the gas produced in New York).

To solve address the significant value distortion embedded in National Grid's BCAs, the Companies should recalculate its BCA using gross accounting emission factors for RNG, which would more accurately capture the value of RNG to its customers. As a sensitivity, it could also use net accounting for all the in-state RNG and gross accounting for all the out-of-state RNG in each scenario, which would more accurately capture the value of emission reductions from in-state RNG to New York State.

Retention of Environmental Attributes

Production of RNG can generate valuable tradeable environmental attribute credits (EACs) that have value independent of the physical methane commodity. RNG EACs can be bought and sold to meet state low-carbon fuel standard programs or to meet voluntary corporate obligations. The largest single

[73] National Grid Initial LTP at p130, fn. 129 ("Consistent with NYSERDA guidance, this analysis utilizes standard biogenic CO2 accounting for monetization of the value of GHG emissions reductions. *Referencing* NYSERDA, 2023. Fossil and Biogenic Fuel Greenhouse Gas Emissions Factors. Report Number 22-23, at p. 5, Revised May 2023.").

[74] NYSERDA, 2023. Fossil and Biogenic Fuel Greenhouse Gas Emissions Factors. Report Number 22-23, at p. 5, Revised May 2023.

[75] *Id*. at 1.

[76] National Grid Initial LTP at p. 191, Table 11-14:.

market for EACs is the California low-carbon fuel standard (LCFS) market. Because the California program accepts EACs generated anywhere in the United States and from select international markets, RNG facilities in the eastern United States or New York State can produce and sell the physical commodity locally while generating EACs that are sold in the California LCFS market, creating two products with two different revenue streams. Currently, the California LCFS market trades RNG EACs at around $54/ton, down from a high of $200/ton.[77]

National Grid, in the LTP, noted that the environmental attributes are sold in the open market in order to procure RNG in a financially competitive manner.[78] In discovery requests, National Grid noted that state legislative or policy changes would be required in order for the Companies to procure RNG at scale, with options to expand or continue to purchase supply produced by RNG facilities behind National Grid city gates driven by third-party developers and landowners.[79] Indeed, the Department of Public Service (DPS) staff, in rate case settlements approved by the Public Service Commission (PSC), has consistently taken the position that gas LDCs should be prohibited from purchasing any environmental attributes tied to RNG supply.[80] National Grid is not proposing to retain or purchase any renewable energy credits or other environmental attributes associated with the methane from their RNG facilities. Because National Grid is not retaining or purchasing these attributes, neither National Grid nor its customers can claim credit towards compliance with state climate policy or that the gas is net-zero emissions. If out-of-state entities purchase these attributes, these buyers can claim the emissions reductions towards their obligations, and New York does not benefit.

There is an additional concern that if National Grid markets its RNG procurement as an environmentally preferable alternative to fossil gas, customers may opt to stay on the gas system, at least in the short term. If the Companies do not retain the EACs for RNG supply, then the supply cannot be considered "renewable" or to be an environmentally preferable alternative to fossil gas. National Grid, therefore, requires state legislative or policy change that would allow the Companies to retain the EACs for any RNG procured or purchased and used in their system in order to be both financially competitive and to claim any environmental benefit. Otherwise, the increased cost to consumers (whether it be for RNG stripped of its environmental attributes or subsidies for interconnecting biomethane production facilities) is delivering no measurable climate or cost benefits to New Yorkers and potentially extending the system cost and life of the existing gas distribution system.

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[77] Neste, California Low Carbon Fuel Standard Credit price (last accessed September 16, 2024). Available at: https://www.neste.com/investors/market-data/lcfs-fuel-standard-credit-price.

[78] National Grid, Initial Gas System Long-Term Plan, Case 24-G-0248, (May 31, 2024), at 45.

[79] NRDC-1-33b.

[80] *See* Case 23-G-0225 et al., *Proceeding on Motion of the Commission as to Rates, Charges, Rules and Regulations of the Brooklyn Union Gas Company d/b/a National Grid NY For Gas Service*, Order Approving Terms of Joint Proposal and Establishing Gas Rate Plans, With Minor Modification And Corrections, (August 15, 2024) (KEDNY/KEDLI 2023 rate case order), at 110.

Air Emissions Impact of RNG Combustion

RNG is not an emissions-free fuel source. When it is combusted, RNG (like methane from any source) produces CO_2, NOx and other toxic air pollutants.[81,82] Nitrogen dioxide is a pollutant responsible for creating smog and can be an irritant for those with respiratory illnesses such as asthma. Burning RNG in existing buildings that are located in already-overburdened communities would do nothing to alleviate those burdens. Toxic local air emissions are also produced at the point of production. RNG thus has the potential to have a double impact on the local air quality, first at the point of production such as at wastewater treatment facilities and at landfills, and then again when combusted in buildings. Additionally, there are ongoing and developing concerns regarding the potential detrimental impact of fossil gas combustion on indoor air quality.[83] RNG is functionally equivalent to piped fossil gas, meaning it likely has similar negative indoor air quality impacts. In light of these facts, there are serious questions about air quality impacts—both indoor and outdoor—from relying on this fuel.

RNG Price Estimates

The LTP derived long-term RNG pricing from a production cost-based approach, essentially adding up technology cost assumptions to supply RNG to the system. This is different than a policy- or market-based approach such as basing prices on purchase of RNG credits.[84] The RNG prices used in the LTP are shown in Table 5, compared with estimated average fossil gas prices for the state.[85] National Grid's own cost estimates show that without changes to state policy, RNG prices are expected to remain more than three times as expensive as fossil gas. Currently, as noted above, National Grid sells the EACs for RNG on the open market in order to make the purchase of the alternative gas more financially viable, which results in the environmental benefits associated with the supply to accrue out of state, but for the harms of gas use to be retained in New York. When all the EACs for RNG are sold for other compliance purposes, National Grid is effectively burning commodity fossil gas, not RNG.

In a scenario in which National Grid retains the environmental attributes for the RNG it procures, the prices in Table 5 would be even higher given that the Companies would have to retain and retire the EACs generated from the RNG in order to claim the environmental benefits, rather than monetize a potential revenue stream. At \$50 per credit, the price per MMBtu of RNG would be approximately \$2.65 greater for each year; and at \$100 per credit, more than \$5.31 greater.[86] Thus, retaining and retiring the

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[81] Nitrogen can be removed from RNG, however doing so is expensive and adds to project costs. This is particularly true for RNG produced from landfill gas. (Haines, D. 2018. *Getting the Facts on Renewable Natural Gas: Making California's future renewable*. Available at: https://www.epa.gov/sites/default/files/2018-11/documents/7._deanna_haines-508.pdf.

[82] Lebel, E., Finnegan, C., Ouyang, Z. and Jackson, R. "Methane and NOx Emissions from Natural Gas Stoves, Cooktops, and Ovens in Residential Homes". Environ. Sci. Technol. 2022, 56, 4, 2529–2539. Available at: https://doi.org/10.1021/acs.est.1c04707.

[83] Harvard Chan-C-Change. 2022. "Natural Gas Used in Homes Contains Hazardous Air Pollutants." Available at: https://www.hsph.harvard.edu/c-change/news/natural-gas-used-in-homes/; Sebastian Rowland et. al. 2024. "Downstream natural gas composition Across U.S. and Canada: implications for indoor methane leaks and hazardous air pollutant exposures," *Environ. Res. Lett.* 19;. Seals, B., Krasner, A. 2020. "Gas Stoves: Health and Air Quality Impacts and Solutions" RMI. Available at: https://rmi.org/insight/gas-stoves-pollution-health.

[84] National Grid, Initial Gas System Long-Term Plan, Case 24-G-0248, (May 31, 2024), at 53.

[85] National Grid, Initial Gas System Long-Term Plan, Case 24-G-0248, (May 31, 2024), at 54 and Fuel Prices" tab of CLCPA Study Assumptions Appendix, filed 3/17/2023 under Case 19-G-0309.

[86] 1 LCFC credit = 1 metric ton (1,000 kg) of avoided emissions. Fossil gas has an emissions factor of 53.06 kg/MMBtu. 1,000 kg/53.06 kg = 18.85/\$50 = \$2.65/MMBtu; 18.85/\$100 = \$5.31/MMBtu.

credits to actually claim any environmental benefits would increase the costs even more than fossil gas, making it more expensive for consumers to rely on RNG as a decarbonization pathway.

Table 5: RNG Prices net of EACs sold, by Analysis Year

Fuel Type	Units	2020	2030	2040	2050
RNG	2020$/MMBtu	43.53	16.03	14.16	13.54
Fossil Gas (state average)		3.16	3.10	3.82	4.10

Source: National Grid, Initial Gas System Long-Term Plan, Case 24-G-0248, (May 31, 2024), at 54 and Fuel Prices" tab of CLCPA Study Assumptions Appendix, filed 3/17/2023 under Case 19-G-0309.

However, National Grid's cost estimate is misleading. Just as the lifecycle emissions of RNG differ based on the feedstock, the estimated costs vary by feedstock, with landfill gas typically being the cheapest ($6.5-$19/MMBtu)[87], while all other feedstocks have a range of $13-70/MMBtu.[88] Figure 6 shows AGF's projected RNG supply curve in 2040.[89] Nationally, at approximately $14/MMBtu, only about 400 tBTU of RNG will be available by 2040. As noted in Figure 1, National Grid expects to source about 90 tBTU by 2040 (i.e., almost one-quarter of all the nation's expected available RNG at $14/MMBtu or less).

To meet its projected RNG demand in the CEV, National Grid would likely need to pay significantly more than $14/MMBtu (and potentially even more if they choose to source RNG from in-state). Figure 7 shows a similar supply curve for RNG supply for New York state.[90] It shows that National Grid would struggle to meet its 2040 RNG demand as required by CEV scenario of 90 tBTU for a price less than $20/MMBTU. While National Grid's RNG pricing assumptions to meet their CEV scenario are ambitious, based on RNG supply curves, they are unlikely to be able to meet the Companies' total required demand at RNG prices used in their analysis in 2040 or after. Based on the AGF and NYSERDA analyses, RNG prices are expected to be much higher. This undermines the Companies' stated reliance on RNG in the CEV given that the actual price estimates by 2040 for RNG are expected to be much higher than what National Grid projected. At the very least, National Grid should conduct their analysis using a range of potential future RNG prices to test the sensitivity of their scenario to different project RNG prices.

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[87] American Gas Foundation. 2019. R*enewable Sources of Natural Gas: Supply and Emissions Reduction Assessment*. Prepared by ICF, at 53.

[88] New York State Energy Research and Development Authority (NYSERDA). 2021. *Potential of Renewable Natural Gas in New York State*. NYSERDA Report Number 21-34, at 44.

[89] American Gas Foundation. 2019. *Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment*. Prepared by ICF, at 60.

[90] New York State Energy Research and Development Authority (NYSERDA). 2021. P*otential of Renewable Natural Gas in New York State*. NYSERDA Report Number 21-34, at 45.

Figure 5: Combined RNG Supply-Cost Curve, less than $20/MMBtu in 2040

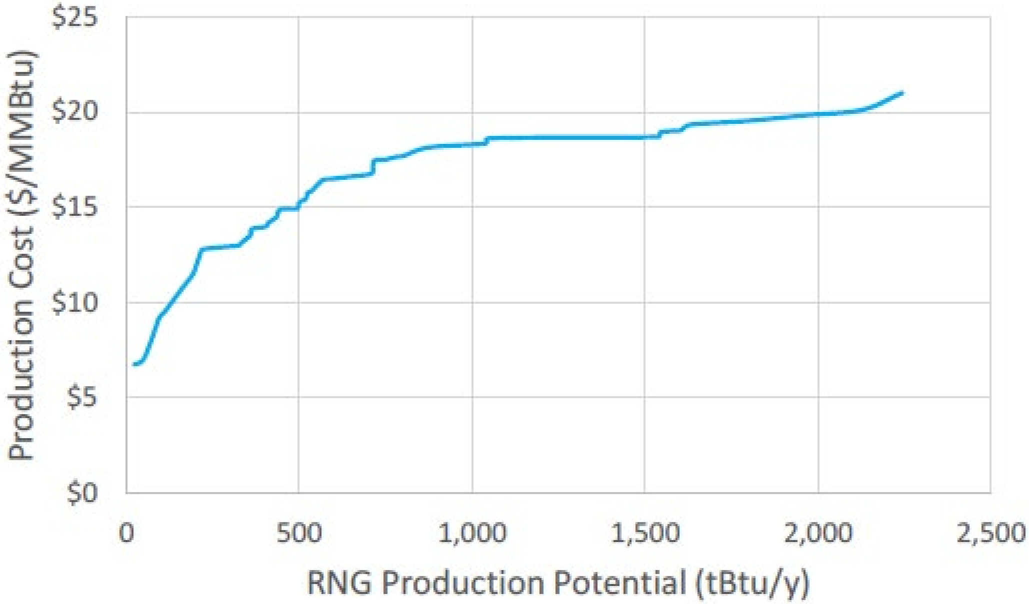
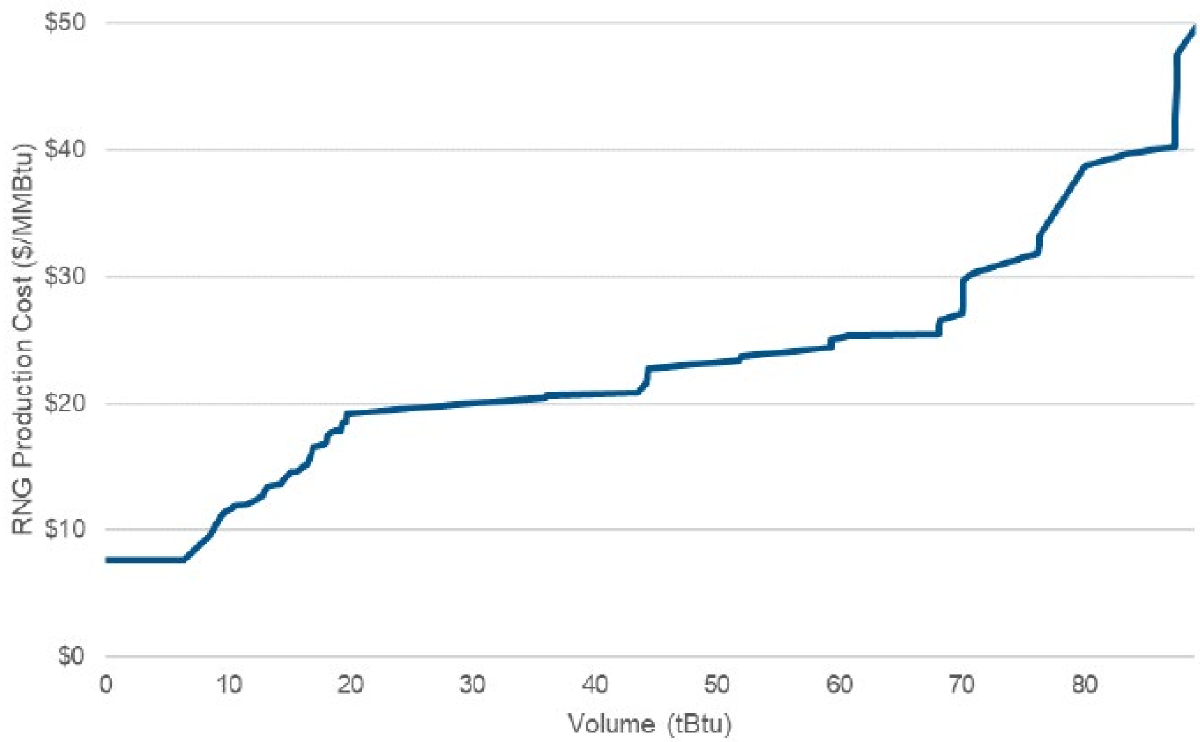


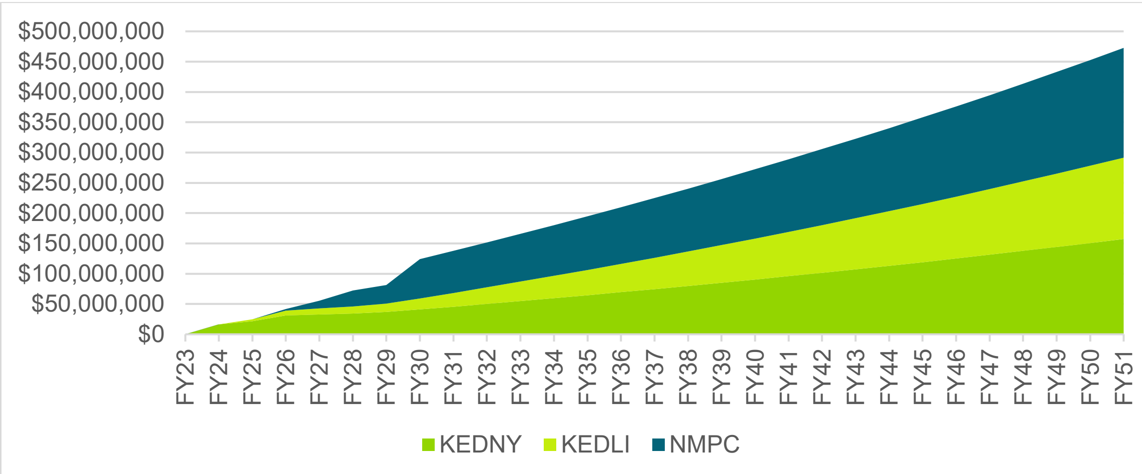
Figure 6: Combined RNG Supply-Cost Curve, New York State in 2040 ($/MMBtu)



In addition to commodity costs, there are capital costs associated with RNG, including interconnection for each operating company and costs to build out in-state RNG facilities. Between 2024 and 2050, the

Companies project to spend, on average, $17 million per year in capital expenditure to support their RNG interconnection strategy in the CEV scenario, or $473 million cumulatively (see Figure 8).[91]

Figure 7: Capex by Operating Company for RNG, Cumulative, CEV Scenario



RNG - Conclusion

In conclusion, National Grid's strategy under the CEV relies heavily on RNG, a fuel that presents significant risks and uncertainties, particularly in terms of supply availability and cost and when sourced from out of state is not compliant with the CLCPA emission accounting. The assumptions around the availability of RNG in both the eastern United States and in New York State are highly speculative, with significant challenges in scaling production to meet mid-century targets. National Grid's available estimates are premised on a dramatic increase in production capacity that is not likely to materialize. Currently, National Grid is struggling to have one facility fully operational. There is also likely to be competition for available RNG supplies from other sectors. RNG is not a carbon-neutral substitute for fossil gas given the CLCPA's prohibition on out of state emission reductions counting toward New York's goals, and the related feedstock emissions, and its use gives rise to concerns regarding the air quality impacts of RNG, including nitrogen dioxide formation. The benefit of in-state RNG to achieving CLCPA goals would be negated if National Grid continues to sell off the environmental attribute credits to make RNG more financially competitive. Without the EACs, RNG is equivalent to commodity gas. Moreover, the pricing estimates used in National Grid's model may underestimate the true cost of RNG, especially when accounting for environmental attributes and lifecycle emissions. Given the substantial investment required and the inherent uncertainties and concerns about RNG production and use, this strategy carries significant risk of being far less viable and cost-effective than National Grid has put forth, especially when compared to more reliable and efficient alternatives like electrification, and it would seriously hinder the State's ability to achieve its climate goals under the CLCPA.

[91] Response to Discovery NRDC-031 Attachment 1.xlsx

3.4 Hydrogen

National Grid's LTP also relies on hydrogen (H_2) as an energy carrier to meet its 2050 targets, positioning hydrogen as a partial substitute for fossil gas. However, the technology and market infrastructure to support hydrogen deployment, particularly green hydrogen, is underdeveloped. Examination of the availability, technological feasibility, and cost assumptions surrounding hydrogen in the context of National Grid's LTP raises concerns about the viability of relying on hydrogen to meet decarbonization goals. Hydrogen is an even less developed market than RNG. While the Companies' scenarios envision a smaller role for hydrogen, the continued reliance on untested, unavailable, and unaffordable fuel substitutes puts at risk achieving the CLCPA targets.

The CEV relies on hydrogen (H_2) as a substitute energy carrier for fossil gas. National Grid forecasts total H_2 demand of 102 tBTU by 2050, split between 92 tBTU of 100 percent H_2 and 10 tBTUs of blended H_2 gas (see Figure 1). The LTP notes that H_2 can be blended with fossil gas up to 20 percent by volume and 7 percent by energy.[92] However, studies on the effects of hydrogen blending into natural gas systems indicate that, without significant system retrofits, a practical upper limit for hydrogen content is approximately 5 percent by volume.[93] The LTP also projects that pure hydrogen "has the potential to serve fossil-free heating and other energy needs in dedicated 100 percent hydrogen clusters."[94] Clean hydrogen, to-date, is a much less developed market than RNG, producing less than 1 percent of national annual hydrogen production.[95] "Green hydrogen" is typically produced using renewable energy and different types of electrolysis technology that are energy intensive and costly.[96] Any plan that relies on H_2 requires that the technology, infrastructure, and energy be available at scale and be affordable. Nowhere on the National Grid system is there currently any hydrogen blending or hydrogen clusters, nor is there any significant amount anywhere in the country. Furthermore, as detailed below, there are clear operational concerns that have been identified with increased hydrogen blending in the existing gas network.

Technologically speaking, clean hydrogen does not have scalable technologies to service demand from the gas network. Almost all domestically produced hydrogen is produced in a carbon intensive process. While low-carbon hydrogen could be a partial substitute for fossil gas so long as it can be shipped, piped, stored, and burned in a safe and effective manner, it is unlikely to be available in the quantities required to meet the CEV scenario. Hydrogen availability and cost could change as a result of production tax credits in the 2022 Inflation Reduction Act and roughly $8 billion in hydrogen hub funding in the 2021

[92] National Grid. 2024. *Initial Gas System Long-Term Plan*. Case 24-G-0248, at 54.

[93] University of California, Riverside and Gas Technology Institute. 2022. *Hydrogen Blending Impacts Study*. Prepared for the California Public Utilities Commission (CPUC) at 107-108. Available at: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M493/K760/493760600.PDF.

[94] National Grid. 2024. *Initial Gas System Long-Term Plan*. Case 24-G-0248, at 54.

[95] Environmental and Energy Study Institute. 2022. "Green Hydrogen: Briefing Series: Scaling Up Innovation to Drive Down Emissions." Available at: https://www.eesi.org/briefings/view/042722tech.

[96] International Energy Association. 2023. "ETP Clean Energy Technology Guide." Available at: https://www.iea.org/data-and-statistics/data-tools/etp-clean-energy-technology-guide.

Infrastructure Investment and Jobs Act.[97] However, the regulations the IRA hydrogen tax credits have not yet been finalized, and DOE did not select any of the New York proposals for hydrogen hub funding. DOE did announce $750 million in support for a hydrogen hub for the Mid-Atlantic region, which could conceivably be used to supply the New York Companies, although it seems unlikely to fully meet National Grid's hydrogen demand.[98] Planned electrolyzer installations that use electricity to produce hydrogen from water, if built, would expand electrolyzer capacity in the United States from 116 MW to 4,524 MW.[99] If all the planned projects are implemented, annual production of hydrogen through electrolysis in the United States could total about 0.72 million metric tons (MMmt) compared with the current 10 MMmt of hydrogen currently produced from fossil fuels sources. While the United States is planning to build more electrolyzer capacity, it is uncertain that all of these projects will be built.

Moreover, combustion of hydrogen for heat and hot water in buildings is an inefficient use of energy when compared to heat pumps. Hydrogen boilers require approximately 5.5 times more primary energy than electric heat pumps to produce the same amount of heat.[100] This is largely due to the significant energy losses in the hydrogen production process, which involves using electricity to split water molecules via electrolysis, followed by the energy-intensive steps of storing and transporting the hydrogen. In contrast, heat pumps use electricity directly and are able to move heat rather than generate it, resulting in much greater energy efficiency. Given the limited availability of renewable energy resources and the inefficiency of hydrogen for these applications, heat pumps represent a far more sustainable and cost-effective solution for decarbonizing heating in buildings.[101]

Hydrogen Availability and Cost Considerations

The LTP notes that the use of green hydrogen that is produced locally or regionally is a key element of the CEV scenario in decarbonizing the gas networks.[102] Similar to their RNG pillar, the Companies did not conduct an analysis to estimate in-state versus out-of-state hydrogen procurement, despite potential challenges to the electric grid with generating H_2 and with transporting it.[103] The CEV scenario expects at least 7 tBTU by 2030, 59 tBTU by 2040, and 102 tBTU of clean H_2 by 2050 (see Figure 9).[104] Converting these energy values into metric tons of hydrogen required illustrates how much H_2 will be

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97 U.S. Department of Energy. (n.d.). *Regional clean hydrogen hubs*. Retrieved September 18, 2024, from https://www.energy.gov/oced/regional-clean-hydrogen-hubs-0#:~:text=The%20Regional%20Clean%20Hydrogen%20Hubs,clean%20hydrogen%20hubs%20across%20America.

98 U.S. Department of Energy. 2023. "Biden-Harris Administration Announces $7 Billion for America's First Clean Hydrogen Hubs, Driving Clean Manufacturing and Delivering New Economic Opportunities Nationwide." Available at: https://www.energy.gov/articles/biden-harris-administration-announces-7-billion-americas-first-clean-hydrogen-hubs-driving.

99 U.S. Department of Energy. 2024. *DOE Hydrogen Program Record*. Record Number 24001. Available at: https://www.hydrogen.energy.gov/docs/hydrogenprogramlibraries/pdfs/24001-electrolyzer-installations-united-states.pdf.

100 Agora Verkehrswende, Agora Energiewende and Frontier Economics (2018): The Future Cost of Electricity-Based Synthetic Fuels, at 13. Available at:
https://www.agora-energiewende.org/fileadmin/Projekte/2017/SynKost_2050/Agora_SynKost_Study_EN_WEB.pdf.

101 Energy Innovation. (2023). *Hydrogen policy's narrow path: Delusions and solutions*. Retrieved September 18, 2024, from https://energyinnovation.org/publication/hydrogen-policys-narrow-path-delusions-and-solutions/

102 National Grid. 2024. *Initial Gas System Long-Term Plan*. Case 24-G-0248, at 55.

103 Response to Discovery NRDC 1-35a.

104 Response to Discovery NRDC-060 Attachment 5.

required to meet just National Grid's expected demand. Using a high heating value, Table 6 converts National Grid's expected total H_2 demand into metric tons. By 2040, National Grid will have to source 435,000 metric tons of clean hydrogen and 750,000 Mt by 2050. DOE's national hydrogen framework details an optimistic pathway for clean hydrogen production.[105] DOE estimates that nationally, as much as 10 MMT of H_2 could be produced cost effectively by 2030, 20 MMT by 2040, and 50 MMT by 2050, implying that National Grid will purchase or procure 1.5 percent of all clean hydrogen produced in the United States by 2050, even in this optimistic national production scenario.

Producing all of this hydrogen from renewable energy will require a substantial buildout to support electrolysis. A completely efficient electrolysis system requires 39 MWh to produce 1 metric ton of hydrogen.[106] Current estimated efficiency of liquid alkaline electrolysis, the preferred technology pathway in the LTP, requires 55 MWh per metric ton according to the DOE. DOE's ultimate target system efficiency is 48 MWh per metric ton.[107] Table 6 uses the more ambitious ultimate target efficiency rate to determine total required renewable energy that is necessary to meet National Grid's 2030, 2040, and 2050 targets. In 2022, New York state total electricity generation was 125 million MWh, of which about 34 million MWh were generated from existing hydroelectric, wind, and solar (in that order).[108] This implies that by 2050, assuming the most aggressive electrolyzer efficiency target estimated by DOE, to produce the amount of green hydrogen necessary to meet the Companies' 2050 targets would require the equivalent of more than all of the renewable energy that is currently generated in the state, just for National Grid and just to power green hydrogen production. This does not even factor in the need for hydrogen in more appropriate sectors that lack a direct electrification alternative.

Table 6: Metric Tons of H_2 Required in CEV

	2030	2040	2050
CEV H_2 Required (tBTU), 100% and Blended H_2	7	59	102
Metric Tons of H_2 (HHV) [109]	57,032	435,380	759,054
Renewable Energy Required (MWh)	2,737,567	20,898,230	36,434,632

The CEV scenario does not expect H_2 supply to pick up until around 2026 with no blended H_2 before 2030 on the system. Hydrogen is expected to make up around 16 percent of the total energy resource demand by 2050 (see Figure 1).

[105] U.S. Department of Energy et. al., *U.S. National Clean Hydrogen Strategy and Roadmap,* at 20.

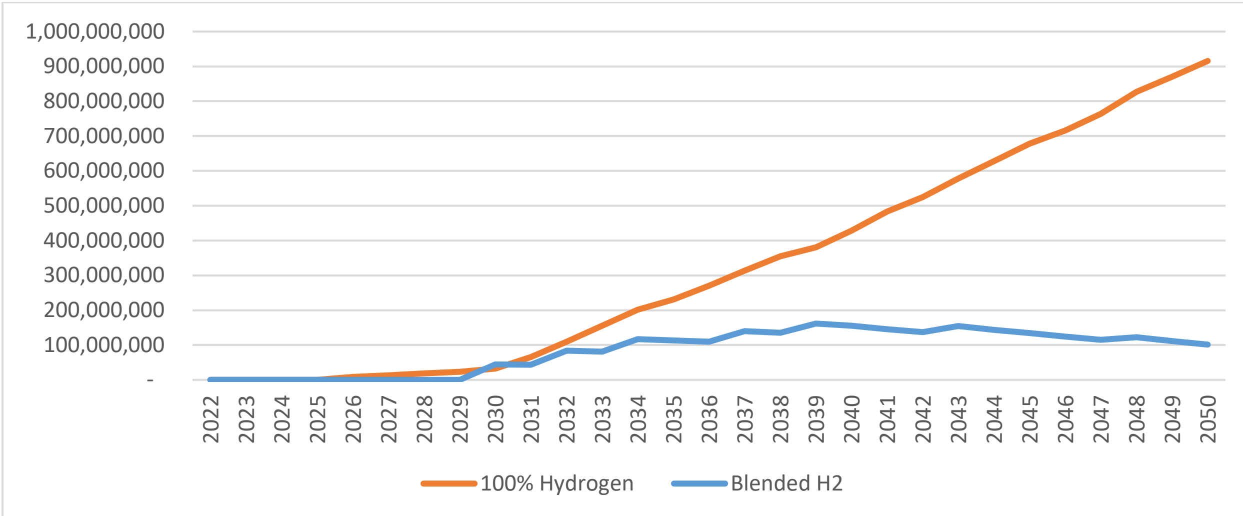
[106] U.S. Department of Energy, "Technical Targets for Liquid Alkaline Electrolysis," https://www.energy.gov/eere/fuelcells/technical-targets-liquid-alkaline-electrolysis.

[107] U.S. Department of Energy. "Technical Targets for Liquid Alkaline Electrolysis." Available at: https://www.energy.gov/eere/fuelcells/technical-targets-liquid-alkaline-electrolysis.

[108] U.S. Energy Information Administration. 2022. "State Electricity Profiles – New York State. Table 1-17." Available https://www.eia.gov/electricity/state/newyork/index.php.

[109] To convert from tBTU of hydrogen to metric tons of hydrogen, the high heating value (HHV) of 0.134 kg per MMBtu was used.

Figure 8: CEV Scenario H_2 Demand (therms)



Source: NRDC-060 Attachment 1 - CEV pillar allocation.

Figure 9 implies remarkable growth rates for the availability of 100 percent H_2, with an implied compound annual growth rate of 21 percent per year. The growth rate for blended H_2 availability is less aggressive at 3.5 percent per year, but blended H_2 plays a much smaller role in the CEV scenario. The LTP notes that the Companies are interested in seeking Commission approval for a series of hydrogen demonstration projects alongside purchases from third parties.[110] Third-party supply projects for in-state hydrogen production are expected to produce 15,330 MMBTU/year (114 MT) by 2025, with only one small pilot project capable of producing 74 tons of hydrogen per day currently under development in the state.[111] This represents about two percent of 2026 fossil gas demand.[112] Clean hydrogen is not currently and is not expected to be widely available until the mid-2030s, making meeting these early years' targets more difficult and risky to achieve by relying on hydrogen.[113]

More concerningly, low-carbon hydrogen is expected to face competing demand from the industrial, transportation, and power sectors. Hydrogen is a versatile fuel that is thought to be a key component of economy-wide decarbonization. Limited supplies of hydrogen should be prioritized so as to decarbonize end-user sectors without a direct electric alternative available, such as steel manufacturing and long-haul transportation. Figure 10, from the DOE's 2023 Hydrogen Liftoff report, notes that fossil gas blending of hydrogen is a relatively low potential decarbonization role for hydrogen and likely to remain a small market through 2050. Other end-use sectors such as ammonia production, oil refining, and steel

[110] National Grid. 2024. *Initial Gas System Long-Term Plan*, Case 24-G-0248, at 56.

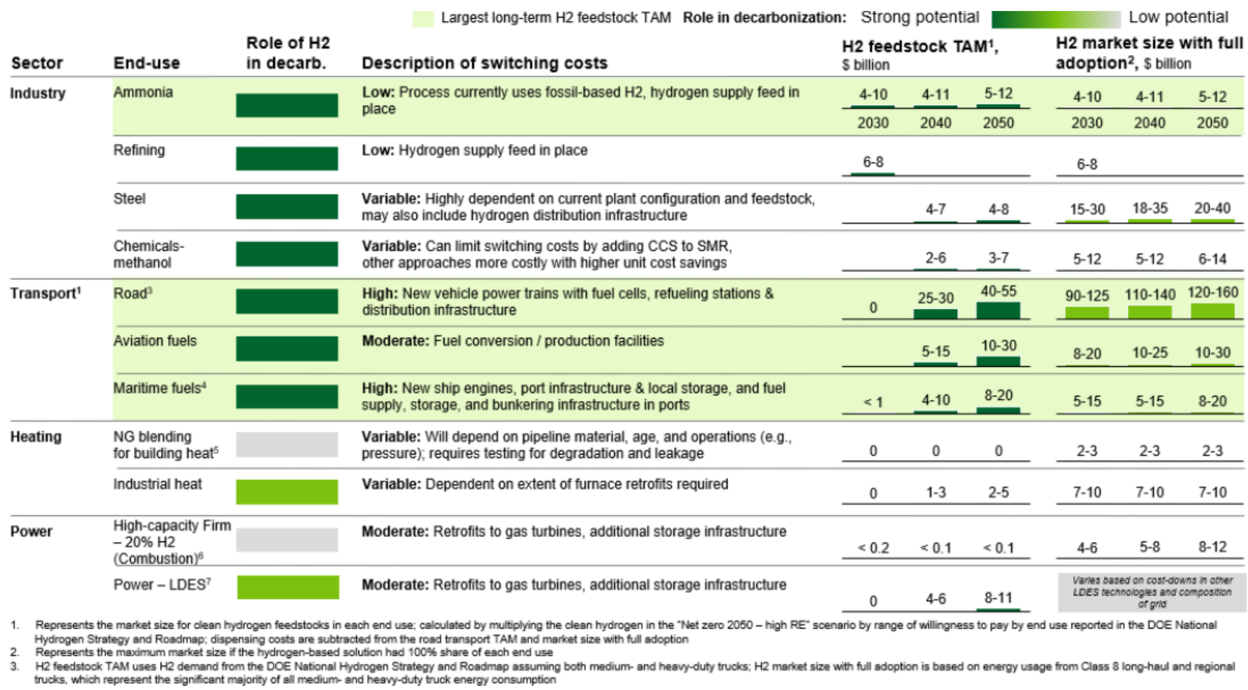
[111] Inside Climate News. 2023. "As New York Officials Push Clean Hydrogen Project, Indigenous Nation Sees a Threat to Its Land." *Justice and Health.* Available at: https://insideclimatenews.org/news/22112023/new-york-clean-hydrogen-indigenous-nation-sees-threat/

[112] National Grid. 2024. *Initial Gas System Long-Term Plan*, Case 24-G-0248, at 56. These projects can provide 42 MDth/day, or 15,330 MDth/year. Converting this into metric tons of H_2 at a high heating value of 0.134 kg per MMBtu equals 114 metric tons.

[113] U.S. Department of Energy et. al., *U.S. National Clean Hydrogen Strategy and Roadmap*, at 57.

manufacturing are all expected to be more impactful decarbonization end-use sectors for hydrogen and larger markets.

Figure 9: End Use Sectors and Potential for H_2 in Decarbonization



Largest long-term H2 feedstock TAM **Role in decarbonization:** Strong potential – Low potential

Sector	End-use	Role of H2 in decarb.	Description of switching costs	H2 feedstock TAM[1], $ billion 2030	2040	2050	H2 market size with full adoption[2], $ billion 2030	2040	2050
Industry	Ammonia		**Low:** Process currently uses fossil-based H2, hydrogen supply feed in place	4-10	4-11	5-12	4-10	4-11	5-12
	Refining		**Low:** Hydrogen supply feed in place	6-8			6-8		
	Steel		**Variable:** Highly dependent on current plant configuration and feedstock, may also include hydrogen distribution infrastructure		4-7	4-8	15-30	18-35	20-40
	Chemicals-methanol		**Variable:** Can limit switching costs by adding CCS to SMR, other approaches more costly with higher unit cost savings		2-6	3-7	5-12	5-12	6-14
Transport[1]	Road[3]		**High:** New vehicle power trains with fuel cells, refueling stations & distribution infrastructure	0	25-30	40-55	90-125	110-140	120-160
	Aviation fuels		**Moderate:** Fuel conversion / production facilities		5-15	10-30	8-20	10-25	10-30
	Maritime fuels[4]		**High:** New ship engines, port infrastructure & local storage, and fuel supply, storage, and bunkering infrastructure in ports	< 1	4-10	8-20	5-15	5-15	8-20
Heating	NG blending for building heat[5]		**Variable:** Will depend on pipeline material, age, and operations (e.g., pressure); requires testing for degradation and leakage	0	0	0	2-3	2-3	2-3
	Industrial heat		**Variable:** Dependent on extent of furnace retrofits required	0	1-3	2-5	7-10	7-10	7-10
Power	High-capacity Firm – 20% H2 (Combustion)[6]		**Moderate:** Retrofits to gas turbines, additional storage infrastructure	< 0.2	< 0.1	< 0.1	4-6	5-8	8-12
	Power – LDES[7]		**Moderate:** Retrofits to gas turbines, additional storage infrastructure	0	4-6	8-11	*Varies based on cost-downs in other LDES technologies and composition of grid*		

1. Represents the market size for clean hydrogen feedstocks in each end use; calculated by multiplying the clean hydrogen in the "Net zero 2050 – high RE" scenario by range of willingness to pay by end use reported in the DOE National Hydrogen Strategy and Roadmap; dispensing costs are subtracted from the road transport TAM and market size with full adoption
2. Represents the maximum market size if the hydrogen-based solution had 100% share of each end use
3. H2 feedstock TAM uses H2 demand from the DOE National Hydrogen Strategy and Roadmap assuming both medium- and heavy-duty trucks; H2 market size with full adoption is based on energy usage from Class 8 long-haul and regional trucks, which represent the significant majority of all medium- and heavy-duty truck energy consumption

Source: U.S. Department of Energy 2023. Pathways to Commercial Liftoff: Clean Hydrogen. Available at https://liftoff.energy.gov/wp-content/uploads/2023/03/20230320-Liftoff-Clean-H2-vPUB.pdf.

Hydrogen Cost Assumptions

The LTP projects ambitious cost declines in the price of hydrogen from roughly $3.88/kg in 2020 to $2.39/kg by 2050, which is still far more expensive than current and projected fossil gas prices (see Figure 11). The LTP acknowledges that the price of green hydrogen is largely driven by the cost of renewable power, the efficiency of the electrolysis process, and the cost of delivery to an injection point in the gas transmission or distribution system.[114] The LTP relies on alkaline electrolysis cells under the assumption that this is the most mature and low-cost pathway. While the price estimates below are achievable given projected cost decreases through cheaper renewable costs and improved electrolysis technology, hydrogen is likely to have competing demand from industrial sectors. With limited available supply and increasing demand, there is likely to be upward pressure on price.

Figure 10: CEV Hydrogen Price Projections

Fuel Type	Units	2020	2030	2040	2050
Import: Hydrogen	2020$/MMBtu	28.95	25.85	20.71	17.81
Fossil Gas (state average)		3.16	3.10	3.82	4.10

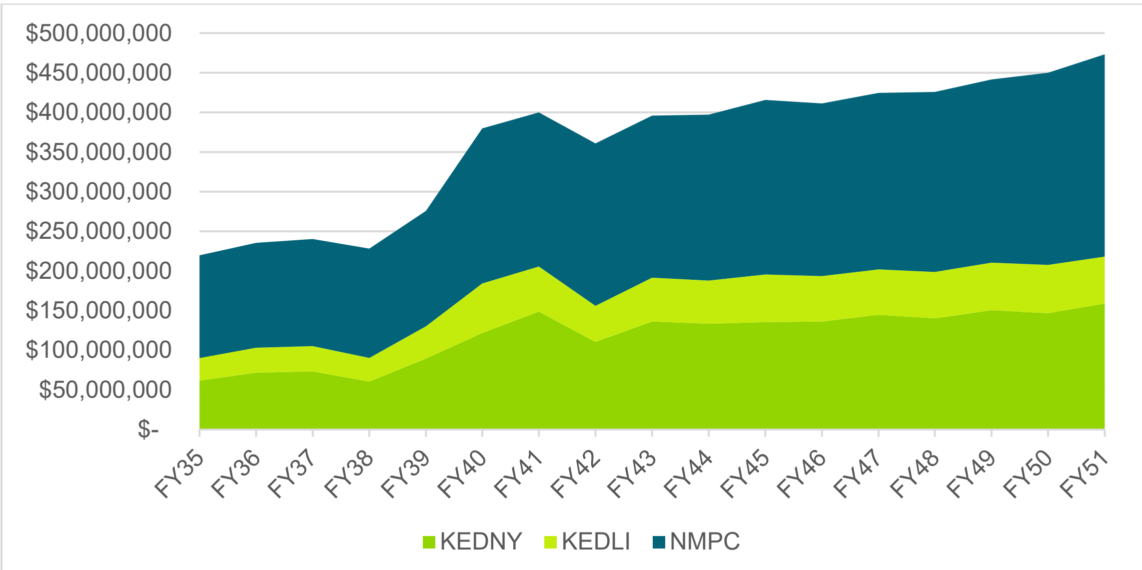
[114]National Grid, *Initial Gas System Long-Term Plan*, Case 24-G-0248, (May 31, 2024), at 55.

Hydrogen	2020$/kg	3.88	3.46	2.78	2.39

Source: National Grid. 2024. Initial Gas System Long-Term Plan. Case 24-G-0248, at 55.

While National Grid expects hydrogen to be a fuel resource starting in 2030, the Companies' capital expenditures are not expected to begin until 2035. The Companies' expected annual capital expenditures for hydrogen blending and storage are substantial, rising from $220 million in 2035 to as much as $474 million in 2050 (see Figure 12).

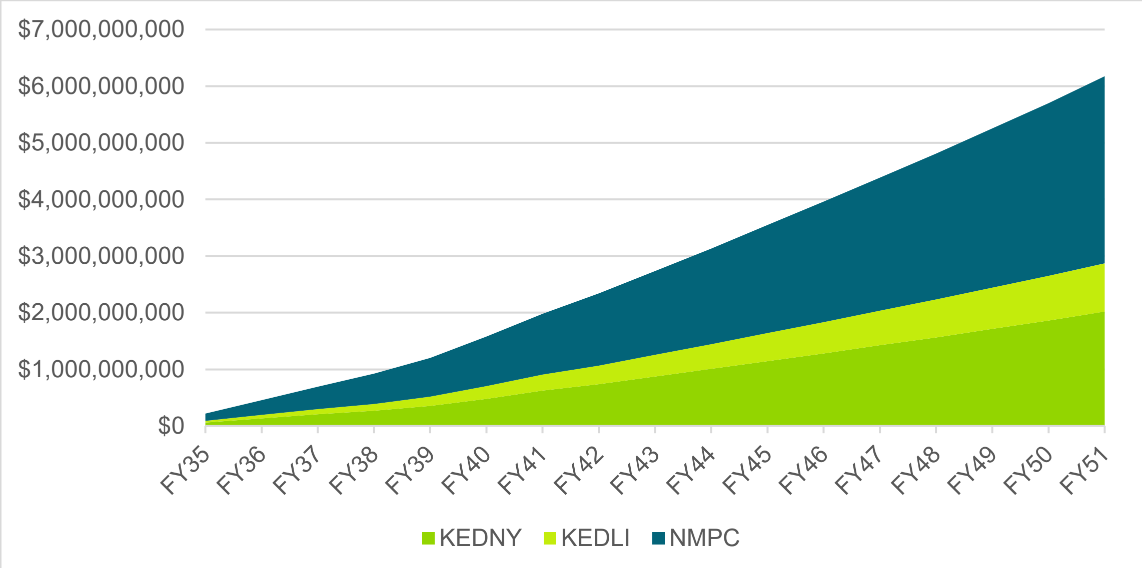
Figure 11: Annual Capex for H_2, CEV Scenario



Source: Response to Discovery NRDC-031 Attachment 1.

Cumulative expenditures for the Companies' hydrogen are expected be around $6.2 billion from 2035 to 2050 (see Figure 13). This is a significant cumulative cost given that H_2 is expected to only meet roughly 16 percent of the Companies 2050 energy demand.

Figure 12: Cumulative Capex for H_2, CEV Scenario



Source: Response to Discovery NRDC-031 Attachment 1.

Hydrogen Operational Considerations

Hydrogen has several characteristics that introduce risks when blended into the existing gas system. These include an increased likelihood of pipeline leakage due to hydrogen's smaller molecular size compared to methane, which allows it to escape more easily. There is also a heightened risk of fire hazards from leaks because hydrogen has a broader flammability range and requires less energy to ignite than methane. Additionally, because hydrogen has a lower energy content, a greater volume is needed to deliver the same amount of energy as methane, potentially leading to higher operating pressures.[115] Furthermore, blending even as little as one percent hydrogen by volume can cause pipeline embrittlement, fatigue, and fractures, which can further exacerbate leakage hazards.[116]

Hydrogen Conclusion

In summary, while hydrogen is often hailed as a key component of the energy transition, its availability, technological maturity, and cost-effectiveness present significant challenges, particularly in the timeframe required to meet National Grid's CEV scenario targets. The reliance on clean hydrogen remains speculative, with current production levels and planned expansions falling far short of the anticipated demand. Moreover, using hydrogen for building heating and hot water results in health and environmental concerns and is inefficient compared to alternatives such as heat pumps, which provide a more energy-efficient pathway for decarbonization. Truly clean hydrogen is much better deployed in other sectors where it can deliver more abatement per ton of hydrogen and there is no more efficient alternative. As such, hydrogen's deployment in National Grid's system, especially in the near term, faces

[115] University of California, Riverside and Gas Technology Institute. 2022. *Hydrogen Blending Impacts Study.* Prepared for the California Public Utilities Commission (CPUC), at 37. Available at: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M493/K760/493760600.PDF.

[116] Ibid, 67.

substantial hurdles, raising questions about the prudence of this strategy for achieving decarbonization goals, particularly when more viable alternatives are available.

3.5 Non-pipeline Alternatives

Non-pipeline alternatives (NPAs) are discussed in sections 5.1.4 and 5.2.4 of the LTP. As of the Initial LTP filing date, National Grid had only successfully implemented one NPA, disconnecting three customers from the gas system.[117] This contrasts with other utilities, which have demonstrated greater progress identifying and implementing NPAs, including Con Edison.[118] The lack of NPA projects in National Grid's service areas points to a problem with the Companies' overall approach to NPAs.

The Gas Planning Order requires each LDC in New York to file a proposal for NPA screening criteria.[119] National Grid's NPA Screening and Suitability Criteria proposal[120] includes NPA screening for new connection projects, leak prone pipe (LPP) removal projects, and Reliability & Reinforcement ("R&R") projects, and excludes NPA screening for projects that pose an imminent threat to safety or reliability, conflict with the obligation to serve, or are expected to be completed within two years.[121] The Company has different approaches to screening and customer outreach for each type of project. Leak-prone pipe projects are evaluated using a set of ten criteria, and outreach occurs once an LPP project is deemed eligible for an NPA.[122] New customer connection projects are evaluated for an NPA if they serve five or more customers and extend greater than 500 feet, and outreach occurs once the Company receives the new connection application.[123] For R&R projects, the Company seeks third-party vendors to implement demand-reduction and outreach.[124]

Leak Prone Pipe NPAs

National Grid assesses ten criteria to determine whether an LPP project is a suitable candidate for NPA consideration. A project must pass all criteria to be considered for an NPA.[125] Projects that pass the initial screening are then further evaluated to determine which five projects (per operating company) are most likely to succeed as NPAs, prioritizing customer count, LPP risk, and dead-end segments.[126]

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[117] National Grid. 2024. *Initial Gas System Long-Term Plan*. Case 24-G-0248, at 81.

[118] For example, Con Edison put out a market solicitation for the Soundview Area project in the Bronx in December 2021 with the goal of avoiding traditional system upgrades and projects. In 2022, the Commission approved the amortization period and shareholder incentive mechanism for multiple area load relief NPA projects, including the Soundview Area project. Based on Con Edison's current plans, the Soundview NPA portfolio of projects is required to reduce at least 1,136 Dth/dy of peak gas demand. All measures are to be installed and operational by November 1, 2024. Please see, Consolidated Edison Company of New York. 2022. *Non-Pipeline Alternatives Implementation Plan*. Case 20-G-0131. Available at: https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B6A490BBB-0E8B-41F9-9040-9342758D8AE2%7D.

[119] Gas Planning Order, p. 38, 41.

[120] Proceeding on Motion of the Commission in Regard to Gas Planning Procedures, "National Grid's Proposal for Non-Pipe Alternative Screening and Suitability Criteria," Case 20-G-0131, (filed August 10, 2022).

[121] National Grid. 2024. *Initial Gas System Long-Term Plan*. Case 24-G-0248, at 80.

[122] Response to Discovery NRDC 6(a).

[123] Response to Discovery NRDC 4(a).

[124] Response to Discovery NRDC 6(a).

[125] Response to Discovery NRDC 6(a).

[126] Response to Discovery NRDC 6(b)

Only once the five potential projects have been identified does the Company reach out to customers to gauge interest in an NPA.

Since 2021, National Grid has screened a total of 2,570 LPP projects, only 234 of which passed all ten criteria in the initial screening.[127] Of the ten criteria, projects were most frequently rejected based on criterion 3, "[r]etirement of the main must not negatively impact the overall performance of the distribution system," criterion 1, "[t]he main should not be a critical main… [including] (a) [a]ny main that operates at a pressure equal or above 125 psig… (b) [a]ny main that, if taken out of service when the temperature is 15 degrees F warmer than a design day, would impact 1,000 or more customer accounts," and criterion 10, "[t]he length of main to be retired should not exceed 1,500 feet." [128] Over almost four years, National Grid has implemented just one LPP NPA (also its only NPA, full-stop).

National Grid's process for assessing LPP NPAs is concerning for several reasons. First, over the last two years, only 9 percent of projects passed the initial screening criteria. National Grid has not provided justification for the purpose of each criterion. It is unclear why projects that fail criterion 1(b) and criterion 10, as described above, are unsuitable for an NPA. The historically low passing rate indicates that National Grid is likely overlooking projects that are potentially suitable NPA candidates. An excessive number of criteria and vague criteria language may lead to unnecessary project rejections.

Second, the criteria and purpose of the second evaluation step (i.e., determination of which five projects are most likely to succeed as NPAs, prioritizing customer count, LPP risk, and dead-end segments) is unclear and significantly shrinks the number of opportunities for NPA implementation. The number of projects that pass the initial screening step is practically irrelevant, because the Company will only select five projects in the second evaluation step regardless of the number of NPA suitable projects.[129] A second round of evaluation is warranted; however, National Grid should not limit itself to considering only five candidate projects, but should instead broaden its scope to include all projects that are feasible and have the potential for successful implementation.

Third, conducting customer outreach only after the five candidate projects have been selected greatly reduces the chances of NPA implementation. Customer outreach could take place before the second round of evaluation occurs, which would allow National Grid to take customer consent into account in their prioritization ranking. Currently, customer outreach occurs 6-12 months in advance of the need for residential customers and 2-5 years in advance for commercial customers. Customers are contacted once via mail, once via email, and up to twice via phone.[130] If the Companies are able to conduct outreach 2-5 years in advance for commercial customers, then they should be capable of conducting more advanced outreach for residential customers and increase the number of contact attempts.

[127] Response to Discovery NRDC 6(b)

[128] Response to Discovery 76 att. 1

[129] Response to Discovery NRDC 6(b)

[130] Response to Discovery NRDC 5(a)

New Customer Connection NPAs

New customer connection projects are currently only assessed for NPAs if they serve five or more customers and if the project would require at least 500 feet of installation (the "5x500" rule).[131] This rule unnecessarily eliminates many potential NPA opportunities. Outreach begins via phone when a customer submits a new connection application that satisfies the 5x500 rule. If the customer expresses interest in an NPA, follow-up ensues with discussion of financial incentives and technical considerations.[132]

National Grid indicates that it is very difficult to influence groups of customers to consider an NPA, which has driven the switch to the 1x100 criteria.[133] In the Joint Proposal in Case 23-G-0225 and 23-G-0226, National Grid changed this criterion to 1x100 instead. Requiring only 100 feet of installation expands opportunities for NPA projects. Nonetheless, the lack of successful new connection NPAs is concerning for achievement of CLCPA targets, especially considering that both the CEV and AE scenarios include downsizing the system.

Reliability and Reinforcement NPAs

Reliability and Reinforcement (R&R) projects are assessed for NPAs by third-party vendors. National Grid seeks bids through a Request for Proposals process and then works in collaboration with the third-party vendor to engage with customers and develop implementation plans.[134] National Grid has not provided any information about how it identifies R&R project needs or how it decides to submit requests for proposals. The lack of transparency about the Company's selection process and lack of successful R&R NPA projects are both concerning.

3.6 Leak Prone Pipe

The Company plans to retire and replace 4,654 miles of pipe across all three operating companies in the next twenty years,[135] 3,997 miles of which is LPP "that is replaced proactively based on integrity and risk"[136] under the Proactive Main Replacement Program (MRP). NMPC will complete 351 miles of LPP replacement by the end of 2036, and KEDNY and KEDLI will complete 831 and 2,815 miles of LPP replacement, respectively, by the end of 2045.[137] When asked in discovery about how many miles of LPP will be retired without replacement, the Company indicated that 119 miles of LPP will be decommissioned under both the CEV and AE scenarios.[138]

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[131] National Grid. 2024. *Initial Gas System Long-Term Plan*. Case 24-G-0248, at 80.

[132] Response to Discovery NRDC 4(a)

[133] Ibid.

[134] Response to Discovery NRDC 5(a).

[135] Response to Discovery NRDC 12 att. 1.

[136] Response to Discovery NRDC 71(a).

[137] Response to Discovery NRDC 12 att. 1

[138] Response to Discovery NRDC 12 att. 2.

National Grid's plans to replace 3,878 miles of pipe[139] over the next twenty years is problematic given that the vast majority of these replacements will be decommissioned by 2050 under the AE scenario's projected 90 percent system downsizing.[140] There are just under 21,500 miles of pipe currently in National Grid's gas system.[141] After decommissioning 90 percent, as planned in the AE scenario, just under 2,000 miles of pipe would remain in 2050 (assuming no further expansions).[142] This implies that nearly *half* of the Company's LPP replacements would be decommissioned soon after they are replaced. This is a generous estimate, because it assumes that the only segments of pipe remaining in 2050 are the ones that were replaced under the MRP. More likely, far more than half of the LPP replacements would be decommissioned by 2050. The same concern exists for the CEV scenario, though to a lesser extent because the scenario only projects 10 percent system downsizing.[143]

The Company's planned level of expenditure on leak prone pipe replacement also raises concerns. LPP capital expenditure reaches as much as 53 percent of total capital expenditure in KEDNY, and up to 66 percent of total capital expenditure in KEDLI.[144] LPP expenditure as a percent of total capital expenditure is highest in the AE scenario. The Reference and CEV scenarios have a similar level of LPP expenditure (i.e., around 27 percent for KEDNY and 36 percent for KEDLI).[145] NMPC has much lower LPP expenditure as a fraction of total capital expenditure—reaching 18 percent at most, and averaging around five percent for all scenarios.[146] It is unreasonable for National Grid to invest in LPP at this level given the uncertainty of future gas demand. This excessive investment heightens the risk of stranded costs, potentially leading to inequitable and unmanageable consumer bills, while also perpetuating reliance on fossil gas infrastructure that conflicts with long-term decarbonization goals.

While National Grid has a responsibility to maintain safety and reliability, traditional infrastructure investments are not the only way to do this. Ample opportunity exists to replace LPP with NPAs given enough time and advanced planning and coordination with affected customers, as discussed above in Section 3.5. National Grid's planned level of LPP investment is risky given the uncertainty of future gas demand and the potential consequences of stranded costs.

3.7 Assumptions around Electrification

National Grid's preferred CEV scenario relies heavily on buildings with heat pumps retaining gas backup systems that are programmed to be switched on during low outside temperatures. The CEV scenario assumes that by 2050, over 40 percent of residential and commercial buildings will have such a "hybrid"

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139 Calculated by subtracting the 119 miles of LPP planned to be decommissioned from the total 3,997 of LPP in need of replacement.

140 Response to Discovery NRDC 18(a).

141 Response to Discovery NRDC 17 att. 2.

142 Response to Discovery NRDC 51 att. 1

143 Response to Discovery NRDC 19(a).

144 Response to Discovery PA-029 att. 1 "RevReq" tab.

145 Ibid.

146 Response to Discovery PA-029 att. 1 "RevReq" tab.

heating system.[147] In comparison, the Integration Analysis did not include any scenarios with more than 10 percent of buildings using fuel backup.[148] Partial building electrification unnecessarily prolongs customer use of the gas system, delays progress towards decarbonization, and increases societal costs by maintaining multiple huge, expensive energy distribution systems.

In addition, National Grid makes some unreasonable assumptions around heat pump efficiencies and usage. National Grid assumes a heat pump coefficient of performance (COP) of 2.46 for residential air-source heat pumps through 2050 and does not assume any performance improvements from today through 2050.[149] As the market for heat pumps grows, heat pump technologies and performance will improve. For example, analysis from National Renewable Energy Laboratory's (NREL) *Electrification Futures Study* estimates that residential air-source heat pumps' COP will improve by roughly 65 percent to be over 4.0 by 2035 under NREL's "moderate advancement" scenario.[150] Furthermore, National Grid assumes throughout the LTP that customers will operate their heat pumps with a 30 degree Fahrenheit switchover temperature, below which natural gas backup systems will be used. While heat pump efficiency declines with temperature, cold-climate heat pumps operate efficiently even as low as five degrees Fahrenheit.[151] All existing programs that subsidize heat pumps in New York require high-efficiency cold climate heat pumps.

These biased assumptions underestimate the potential for electric heat pumps to replace gas heating load, especially in downstate territories, including Long Island, which are particularly well-suited for full electrification due to their more moderate climates. Full electrification in these regions is especially critical given that they are home to most the state's population and emissions. Overestimating natural gas backup use in such favorable regions could hinder progress toward decarbonization where it is most urgently needed.

4. Modeled Alternatives

4.1 Customer Defection

Synapse modeled a new scenario, the Customer Defection scenario, to show what will happen if National Grid continues to invest in the gas system but experiences an unanticipated level of customer departures by 2050. The results show the impact on delivery rates, customer bills, and stranded costs that might occur in this scenario. As electric heating options become more affordable and gas service

[147] National Grid. 2024. *Initial Gas System Long-Term Plan*, at 28.

[148] Scenarios 3 (Accelerated Transition Away from Combustion) and 4 (Beyond 85% Reduction) see no fuel backup of heat pumps in buildings. Even the Integration Analysis's Scenario 2, Strategic Use of Low-Carbon Fuels, assumed only 10 percent of heat pumps would have fuel backup. (IA-Tech-Supplement-Annex-2-Key-Drivers-Outputs.xls, Scenario Detail tab.)

[149] Response to Discovery NRDC-17 Att. 2

[150] NREL. 2017. *Electrification Futures Study: End-Use Electric Technology Cost and Performance Projections through 2050.* Figure 20. Available at: https://www.nrel.gov/docs/fy18osti/70485.pdf.

[151] Cadmus Group. 2017. *Evaluation of Cold Climate Heat Pumps in Vermont*, Figure 14. Available at: https://publicservice.vermont.gov/sites/dps/files/documents/Energy_Efficiency/Reports/Evaluation%20of%20Cold%20Climate%20Heat%20Pumps%20in%20Vermont.pdf.

becomes more expensive,[152] it is likely that current gas customers will increasingly leave the system. This will result in higher bills for the remaining customers, causing even more customers to defect, and leading, ultimately, to a "utility death spiral". The Customer Defection scenario demonstrates the consequences of making risky investments in the gas system given the uncertainty of future gas demand.

The Customer Defection scenario uses the level of investments from the CEV scenario and the level of sales from the AE scenario to demonstrate the impact of accelerated customer departures if National Grid follows the CEV pathway. Values for capital expenditure, capital retirements, non-customer related operational expenditure, and fuel prices are taken from the CEV scenario, and customer count, sales, and customer related operational expenditure are taken from the AE scenario. A portion of operational expenditure is taken from the AE scenario to better reflect the customer-related expenses such as upkeep of services and meters. National Grid's CEV scenario has about twice the level of cumulative capital expenditure as the AE scenario, and the AE scenario arrives in 2050 with just seven percent of customers remaining in the CEV scenario.[153] The figures below show values for all three operating companies (i.e., KEDNY, KEDLI, and NMPC) combined.

Figure 14 shows total rate base for each scenario through 2050. The CEV and Customer Defection scenarios have the same rate base, because the Defection scenario is modeled using the same amount of capital additions and capital retirements as the CEV scenario. In the Reference, CEV, and Defection scenarios, rate base climbs steadily through 2050, while in the AE scenario, rate base peaks in 2043 and then starts to decline.

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[152] The cost of gas service is likely to increase as a result of New York's cap and invest program, potential changes to depreciation calculation methods, and the increased prevalence of liquid natural gas.

[153] Cumulative capital expenditure in the CEV scenario is $57 billion and $32 billion in the AE scenario (in real, 2024 dollars from 2024-2050), while the 2050 meter count is 1.9 million in the CEV scenario and 137 thousand in the AE scenario. (Response to Discovery PA-029)

Figure 13. Utility Rate Base

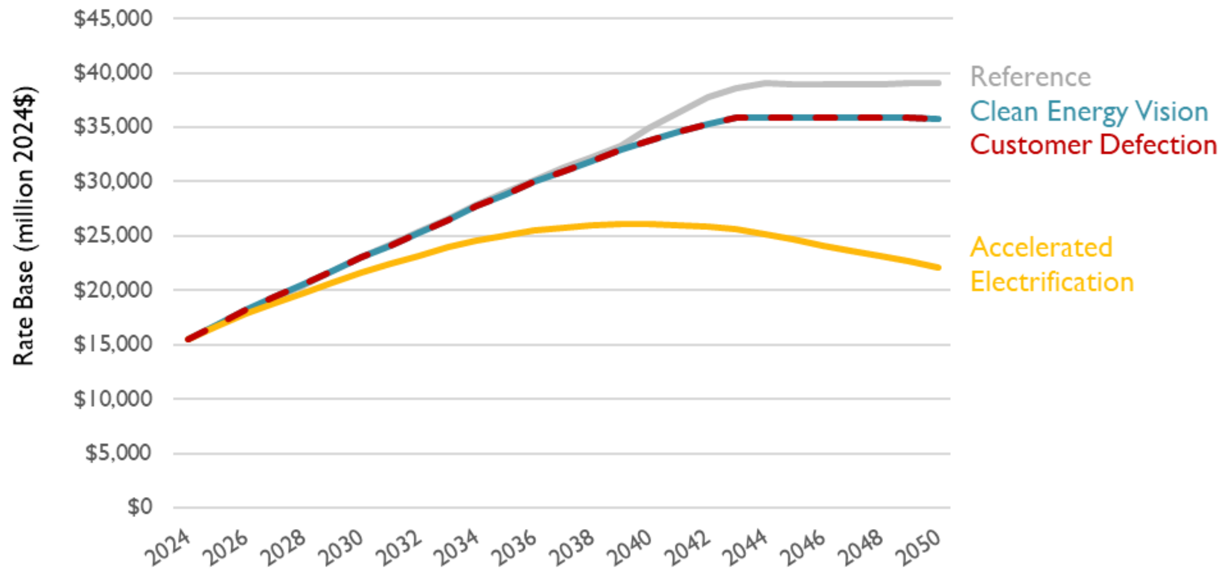


Figure 15 and Figure 16 show fuel sales and fuel costs for all customer classes through 2050 according to National Grid's projections. Fuel sales in the CEV scenario fall to about half the fuel sales in the Reference case, yet fuel costs are 50 percent greater in the CEV scenario than in the Reference case. This is because the CEV scenario uses expensive alternative fuels; by 2050, 57 percent of its fuel mix comes from RNG and 43 percent from hydrogen.[154] By comparison, the AE and Defection scenarios have just five percent of the CEV scenario's level of fuel sales and a quarter of the fuel costs.

[154] Response to Discovery NRDC 60 att. 5

Figure 14. Fuel Sales Volume

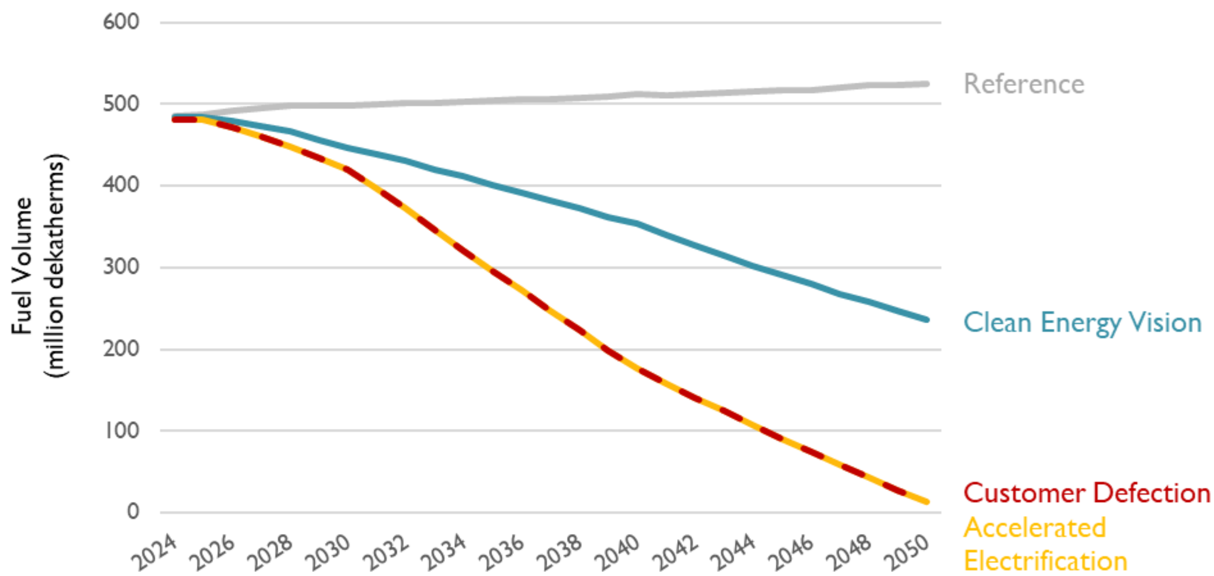


Figure 15. Total Fuel Costs

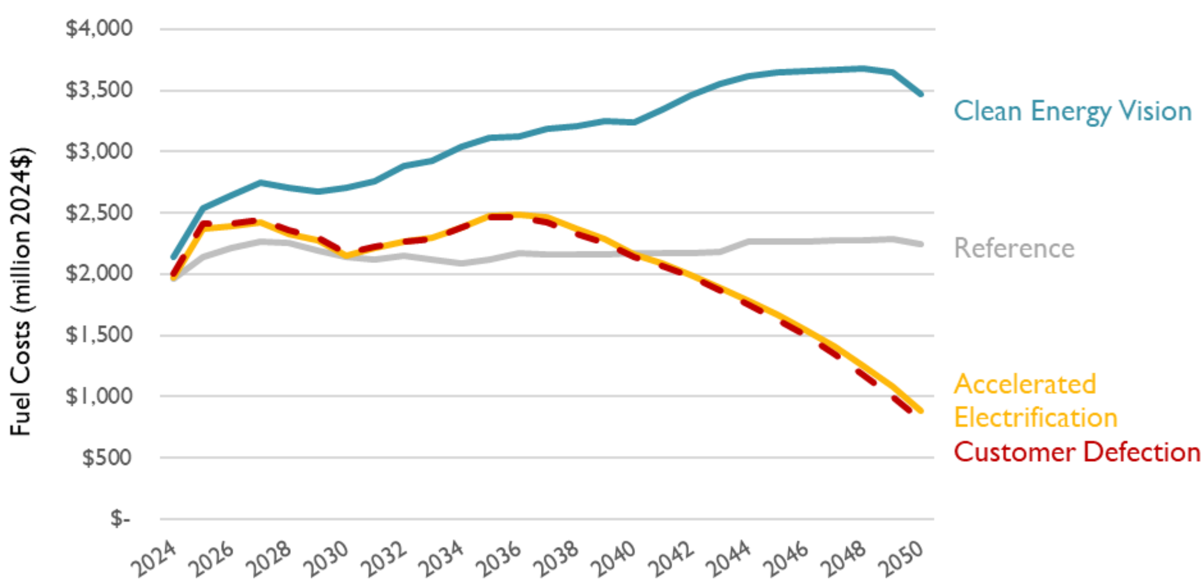


Figure 17 shows the delivery rates without fuel costs for all customer classes through 2050, presented as a weighted average by sales volume of all three operating companies. The delivery rate reflects the utilities' capital expenditure and operational expenditure on gas distribution per unit of energy sold. Delivery rates increase drastically in the AE and Defection scenarios, starting around 2040 as customer departures increase. By 2050, delivery rates in the Customer Defection scenario are twice as large as the AE scenario, and almost twenty times larger than in the CEV scenario. The incremental difference between the AE and Defection scenarios reflects the impact that continued infrastructure investment would have on rates if customers were to leave the system "unexpectedly" in the CEV scenario. Figure 18 compares residential delivery rates in the Customer Defection scenario by operating company. KEDNY has the highest projected residential delivery rates at $660 per dekatherm, compared with $156 for KEDLI and $99 for NMPC in 2050.

Figure 16. Delivery Rates (without Fuel Costs)

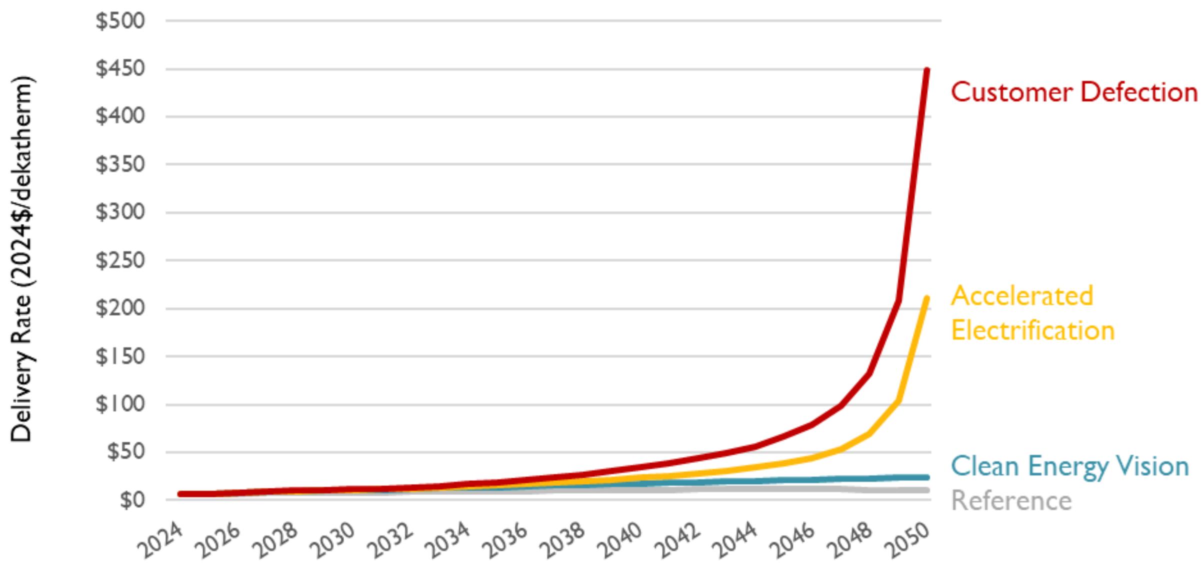


Figure 17. Customer Defection Scenario Residential Delivery Rates (without Fuel Costs) by Company

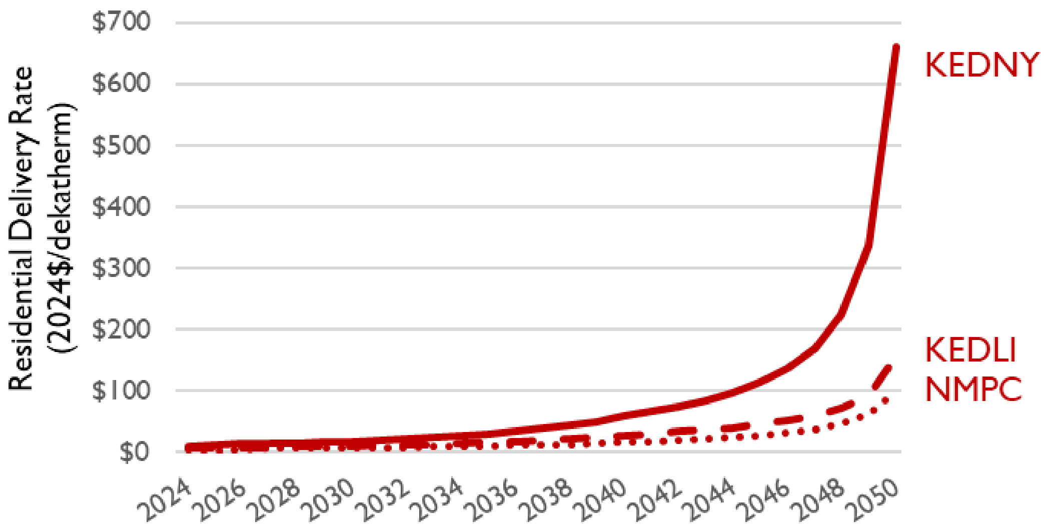
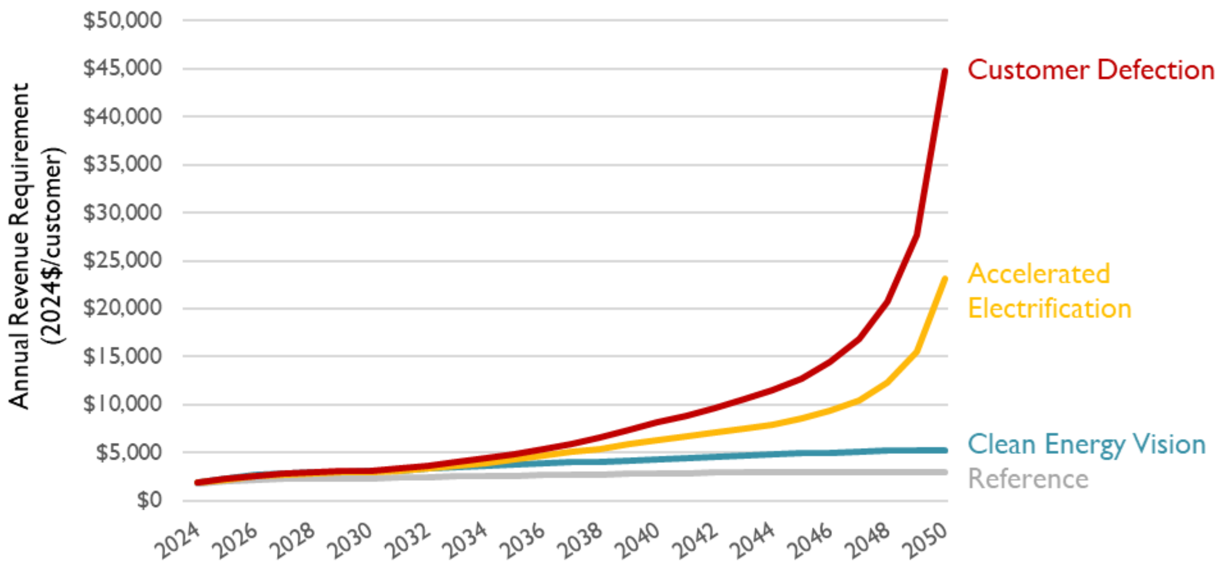


Figure 19 shows the weighted average bill impacts for all customers calculated as total revenue requirement divided by customer count (weighted by the sales volume of each operating company). Similar to the AE scenario, the Defection scenario shows an acceleration in bill increases towards the mid-to-late 2040s. Annual customer bills reach almost $45,000 per customer in the Defection scenario. This is twice as large as the annual bills in the AE scenario, eight times as large as the CEV scenario, and fifteen times as large as the Reference case.[155] Bill impacts are greatest in KEDNY, reaching $64,000 in revenue requirement per customer, followed by KEDLI with $30,000 and NMPC with $18,000 in 2050 in the Customer Defection scenario. Section 4.2 discusses the results of Synapse's bill impact analysis comparing different heating equipment, including heat pumps.

[155] Customer bills represent the annual revenue requirement that the Company must collect from each customer, including the cost of fuel.

Figure 18. Annual Bill Impacts



National Grid's revenue requirement modeling assumes for the AE scenario that all retired, undepreciated assets (i.e., assets that are decommissioned before the end of their useful life) are included in the operating companies' rate base. This modeling method ensures that the companies recover all of their sunk costs by 2050 without any stranded costs. However, it also means that customers are paying for the full cost of investments that were only used and useful for a fraction of their life. National Grid assumes a business-as-usual approach for recovering these costs instead of implementing a proactive cost recovery method that would distribute the cost burden across more customers in the near-term while they are still on the system. As a result, the few customers that remain on the system in 2050 bear an immensely disproportionate share of the revenue requirement at rates that hardly any customer would be able to afford. In this way, the AE scenario is highly unrealistic and places the burden of undepreciated costs entirely on ratepayers.

The Customer Defection scenario demonstrates the consequences that National Grid and its customers might face if the Company prolongs its investments in the gas system unnecessarily. Rate base more than doubles in the CEV and Defection scenarios by 2050, growing to $35 billion (in real 2024 dollars) in the CEV scenario by the mid-2040s. National Grid will face devastating consequences from stranded costs in the CEV scenario if customers leave in an unmanaged way. Fuel costs will rise 160 percent from today’s values in the CEV scenario, driven by expensive alternative fuels, causing customer bills to increase to unaffordable levels, as discussed more in the following section.

4.2 Bill Impact Analysis

Synapse conducted an illustrative analysis of residential energy bills under both the AE and CEV scenarios for two of the Company’s three New York operating companies: KEDNY and NMPC. We conducted this analysis for annual gas and electric bills through 2050 for three types of residential customers in New York:

- **Full Electrification**: A household that switches all gas equipment to electric equipment. This household uses heat pump technologies for space and water heating and electrifies cooking and clothes drying.
- **Partial Electrification**: A household that uses a heat pump to provide space heating for most of the year while retaining gas heating equipment for use below the 30-degree Fahrenheit switchover temperature, and uses gas for water heating, cooking, and clothes drying. This household uses electricity for end uses such as lighting and electronics.
- **No Electrification**: A household that continues to use gas appliances for space heating, water heating, cooking, and clothes drying. This household uses electricity for end uses such as lighting and electronics.

Based on EIA's Residential Annual Energy Consumption Survey (RECS) data[156] and data from National Grid's modeling, Synapse developed average gas and electric consumption levels for the three types of residential homes. For the Partial Electrification homes, we adopted National Grid's modeling assumptions on the share of electricity and gas usage for space heating, which appears to account for the differences in climate across the utility jurisdictions. For KEDNY, 79 percent of the space heating load is served by heat pumps based on a 30 degree switchover temperature, and the remaining 21 percent is served by gas. For NMPC, 57 percent of space heating load is served by heat pumps.[157] We estimated average annual electricity consumption by converting gas usage to electric usage based on the efficiencies of gas and electric appliances for each end use.[158]

We developed total electricity price forecasts for the AE scenario and the CEV scenario through 2050 by converting the incremental transmission and distribution (T&D) investments projected by National Grid to support electrification into T&D delivery rates and combining them with our forecast of baseline electricity rates for the residential sector. We developed our price forecasts for two of the electric utilities which overlap areas of National Grid's gas territory (i.e., Con Edison and Niagara Mohawk) as these service areas cover a wider range of electricity rates.

Our rate analysis started with the development of an electricity rate forecast for a business-as-usual or baseline case for the two electric utility jurisdictions and was based on the current average electricity rate (including monthly customer charges) and the electricity rate forecast by the Energy Information Administration (EIA)'s Annual Energy Outlook for the relevant areas in the state. We then adjusted the baseline T&D delivery rate forecast by taking into account (a) the upward rate pressure from the incremental T&D investments due to building electrification and (b) the downward rate pressure stemming from increased electricity sales due to building electrification. (We obtained both the incremental T&D investments and sales from PA-031 Attachment 1). We assume that all the T&D

[156] U.S. EIA. 2023. 2020 Residential Energy Consumption Survey (RECS). "Table CE.5.3 Detailed household site electricity end-use consumption – averages" and "Table CE5.4 Detailed household natural gas and propane end-use consumption – averages." Available at: https://www.eia.gov/consumption/residential/data/2020/.

[157] Based on NRDC-015 Attachment 1.

[158] Efficiencies of heat pumps from NRDC-017 Attachment 2

investments projected by National Grid are incremental to the Annual Energy Outlook rate forecasts. Further, we assume that the electricity supply rate forecast is the same across all scenarios.

We estimated the annual electric and gas bills for each customer type through 2050 as shown in Figure 20 and Figure 21 below. For residential customers in NMPC's territory, by 2035, annual household energy bills are cheaper for fully electric households in both the AE and CEV scenarios. For residential customers in KEDNY's territory, by the late 2020s in both scenarios, annual household energy bills are cheaper for fully electric households. The relative economics of gas and electric bills in the later years may incentivize households to switch away from gas, potentially increasing gas rates, which could increase the rate of customer departures over time. These impacts are much more dramatic for KEDNY customers, where gas bills more than triple by 2040 from today.

Figure 19. Annual total energy bills for KEDNY residential customers through 2050 in the CEV (left) and AE (right) scenarios

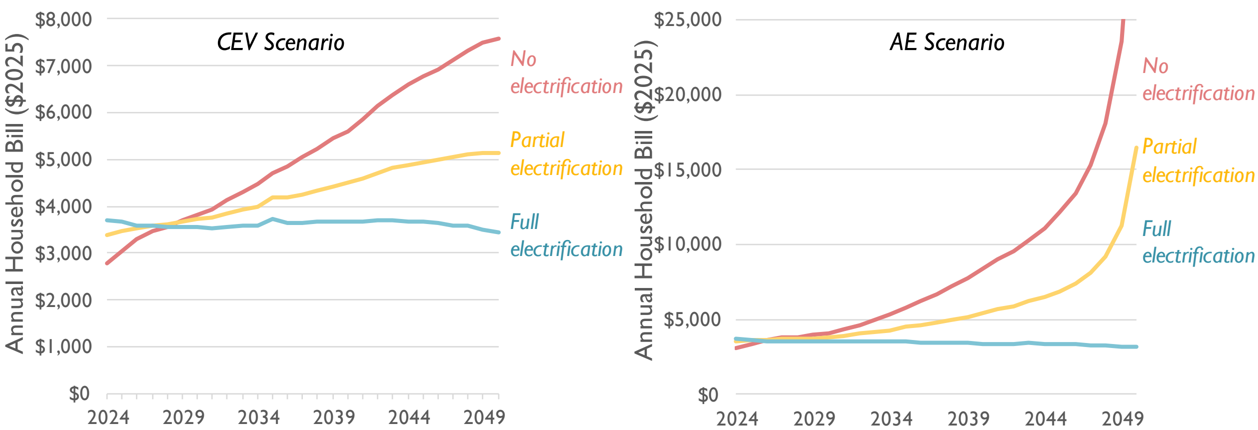
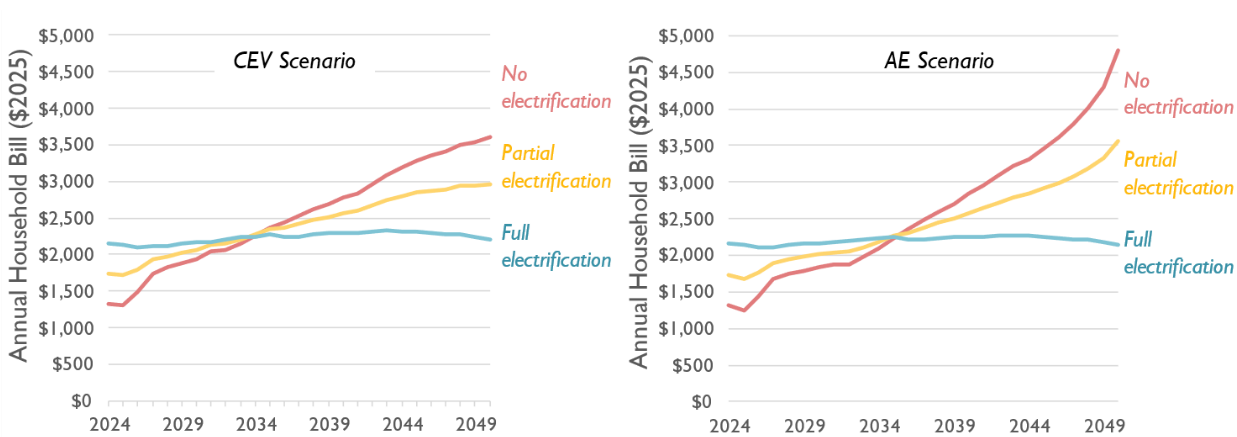


Figure 20. Annual total energy bills for NMPC residential customers through 2050 in the CEV (left) and AE (right) scenarios



5. Recommendations

5.1 Alignment with the Scoping Plan

Currently, the LDCs are not required to employ the Scoping Plan's strategies and recommendations. However, the Commission should consider the benefits of requiring standard approaches that align with the Scoping Plan across all utilities in all future LTPs and annual updates to the LTPs. Without such an approach, it is unlikely that the LDC efforts will adequately support attainment of CLCPA emissions reduction targets.

5.2 RNG and Hydrogen

National Grid should not base near-term decisions or investments on the risky expectation that alternative fuels will be available, affordable, feasible and that their use would be consistent with the CLCPA. Instead, National Grid should take actions that keep alternatives open, for example, by emphasizing deployment of full electrification rather than alternative fuels. The transition to full electrification will take time, and it will be increasingly difficult to ramp this market up as 2050 draws near. In addition, full electrification yields higher societal benefits and lower costs than alternative fuels by reducing co-pollution and improving health.

5.3 Non-Pipeline Alternatives

National Grid must significantly improve their NPA screening and outreach processes in order to achieve targeted levels of demand reduction, cost savings, electrification, and system downsizing in both the CEV and AE scenarios. The following is recommended:

1. Conduct a review of the system. National Grid should conduct a review of its entire system, through the collection and application of data like Pacific Gas and Electric's Gas Asset Analysis Tool,[159] to identify locations to implement NPA projects or system downsizing. National Grid should report on the results of this geospatial analysis as a compliance filing in this LTP process.
2. Expand the type of projects eligible for NPA consideration. National Grid should be required to screen all proposed investments for NPAs. Also, the Companies should implement more advanced planning so that fewer projects fall within the two-year threshold, or otherwise National Grid should streamline its NPA implementation processes and reduce the two-year threshold.
3. Make screening criteria less restrictive. Regarding the ten evaluation criteria for screening LPP projects, National Grid should identify which criteria are most commonly failed and why, and as appropriate revise the criteria to minimize unnecessary rejections. Also, criteria should be clearly stated. For example, criterion #3, "[r]etirement of the main must not negatively impact the overall performance of the distribution system," should be revised to transparently define a range for what is considered a 'negative impact.' For new customer connection projects,

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[159] Pacific Gas and Electric Company's Opening Comments on Amended Scoping Memo, Track 2A, Questions 2.1(B)-2.1(K), in Case R.20-01-007, Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Safe and Reliable Gas Systems in California and Perform Long-Term Gas System Planning. June 15, 2022. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M485/K545/485545029.PDF

changing the criteria from 5x500 to 1x100 is a step forward;[160] however, National Grid could go even further to assess new connections of less than 100 feet for NPA opportunities, and potentially any project where the line extension would extend past the public domain and onto private property. Proposed changes to the 100-foot rule are currently out for comment in case 20-G-0131. National Grid should revise its rules according to the final adopted rules for interconnection subsidies.

4. Improve proactive customer outreach and education practices. National Grid should improve their customer outreach strategies to contact and educate customers about opportunities for NPAs further in advance compared with their current practices. Since National Grid already knows the location of LPP on the system, there is no reason why customer outreach couldn't begin imminently. For new connections, National Grid could provide educational material and economics on NPAs for customers to review as a prerequisite before submitting new connection applications.
5. Pursue targeted NPAs for easy-to-convert areas and low-income communities. In addition to screening projects for NPAs as they arise, National Grid should proactively identify and pursue projects that are known to be well-suited for NPAs, such as LPP replacement on dead-end segments. Also, National Grid should prioritize NPAs for low-income and disadvantaged communities to protect against these customers being saddled with rising heating and hot water costs when other customers reduce their gas demand or defect from the system.

5.4 Leak Prone Pipe

National Grid should pursue LPP NPAs more aggressively. Although the Joint Proposal establishes a target for LPP NPA identification, National Grid should establish targets for LPP NPA implementation – targets that align with CLCPA emission reduction goals and CEV and AE scenario goals. Where NPAs are not feasible, National Grid should pursue leak detection and repair where safety issues warrant. Advanced planning, supported by detailed reporting such as mapping for LPP projects will enable National Grid to avoid expensive pipe replacements and implement more NPA solutions.

5.5 Assumptions Around Electrification

When modeling electrification, National Grid should use a much lower heat pump switchover temperature, such as 10 degrees Fahrenheit, rather than 30 degrees. In addition, National Grid's modeling should assume improvements in heat pump efficiency. Assumptions regarding the extent of homes using fuel backup should be more aligned with the Integration Analysis, which did not model substantial use of gas backup heating because of the cost of upgrading and maintaining duplicative energy infrastructure.

[160] Response to Discovery NRDC 4(a).