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National Grid's 20 Year Plan Should Not Rely on Hydrogen for Homes or Buildings: Comments by the Institute for Energy Economics and Financial Analysis (IEEFA) to the NYS Public Service Commission regarding National Grid's 20 Year Plan

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National Grid's 20 Year Plan declares an intent to eliminate fossil fuels from its existing gas network by 2050, but it plans to do so, in part, "by delivering renewable natural gas and green hydrogen to our customers" to address the energy needs remaining after building electrification and other demand reduction measures are implemented (see p. 16 of the Plan).

IEEFA's comments focus on the "green hydrogen" portion of that plan.

Under its proposed Clean Energy Vision scenario, as described on pages 27-28, National Grid projects that 20% of non-residential users will rely on 100% hydrogen fuel by 2050 and 67% of industrial energy use will be 100% hydrogen. It further projects that all pipeline gas will be hydrogen-blended at a rate of 20% by volume (7% by energy) by 2050. Such a plan entails a heavy reliance on hydrogen as an energy source.

IEEFA is concerned that hydrogen, which presents significant shortcomings and unanswered questions, is not suitable for the role described by National Grid. National Grid makes several assertions about hydrogen that could be confusing, and fails to present important points of information that would better allow the New York State Public Service Commission and the public to evaluate options.

National Grid's reliance on hydrogen is more likely wishful thinking than real planning. The chemical is hard to manage, and requires enormous infrastructure development and significantly expanded monitoring. The costs and burdens are not justified by the limited impact it is likely to have, especially in blended form, on carbon dioxide emissions.

The filing also fails to analyze and address hydrogen's combustion-related emissions of nitrogen oxides (NO_x), including emissions of nitrous oxide (N_2O) from combined combustion of hydrogen and natural gas, as further discussed herein.

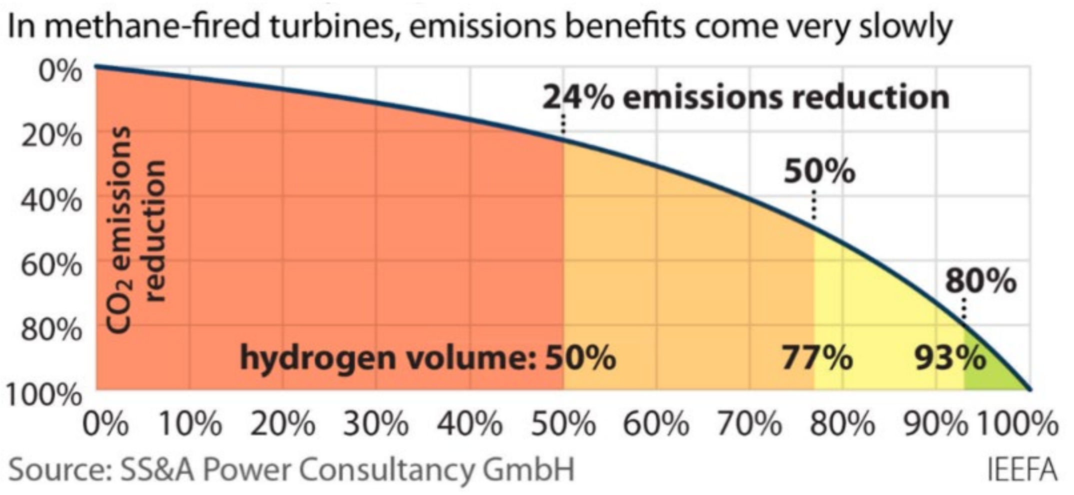
Hydrogen as an energy source is not ready for prime time, and during the years it would take to bring the chemical into such a position, it will likely be eclipsed by electrification, battery storage and other options.

Hydrogen Is Not an Efficient Source of Energy by Volume

Hydrogen gas could be called "energy light" because it produces very little energy per unit of volume. National Grid acknowledges in its 20 Year Plan that if hydrogen gas is blended with natural gas (methane) at a level of 20% by volume, the hydrogen would substitute for only 7% of the energy otherwise provided by methane (see p. 54). But the company fails to discuss the implications of the substantial difference in energy density between natural gas and hydrogen.

A 100% hydrogen substitution for natural gas would provide only 35% of the energy that had previously been provided by the natural gas. This means an enormous volume of hydrogen would be required to substitute for natural gas.

Figure 1: It Takes a Lot of Hydrogen To Cut CO_2 Emissions



The Availability of Large Volumes of Hydrogen Is Likely to Be Limited

Green hydrogen supply is likely to be extremely limited. The United States currently only produces about 10 million tons of hydrogen annually, nearly all of which is used in the petrochemical and fertilizer industries. In a recent report, IEEFA described how hydrogen supply-related issues have made it difficult even to conduct blending tests in natural gas turbines, while some sponsors of so-called hydrogen-capable gas-fired power plants have made it clear that they will not use any hydrogen for years, if ever.[1]

National Grid reports that the Clean Energy Vision scenario would require 1,206 trillion British thermal units (TBtus) of clean hydrogen through 2050, beginning sometime after 2030, and its Accelerated Electrification scenario (no fuel blending) would use 129 TBtus of clean hydrogen during the same period (see p. 139 of the Plan).

After years of what might be termed "hydrogen hype," reality is beginning to set in. The International Energy Agency's (IEA) *Renewables 2023* report tamped down expectations for the role of hydrogen in the energy transition, stating, "Current hydrogen plans and implementation don't match."[2]

Of the announced hydrogen projects at the time of the IEA report, totaling 360 gigawatts (GW) of potential power, the report stated, "only 3% (12 GW) of them had reached financial close or started construction, a smaller amount than expected in our *Renewables 2022* forecast."[3]

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[1] IEEFA. Hydrogen: Not a solution for gas-fired turbines. August 2024, pp. 7-12.
[2] International Energy Agency (IEA50). Renewables 2023: Analysis and forecasts to 2028. January 2024, p. 11.
[3] *Ibid.*, p. 90.

The IEA explained:

> "While almost all regions are still expected to increase the amount of renewable energy capacity dedicated to hydrogen production by 2028, the pace of growth is now less optimistic than in *Renewables 2022*. In fact, this year's forecast is 35% lower than in 2022 due to downwards revisions for all regions except China. The main reason is the slow pace of bringing planned projects to financial close due to a lack of off-takers and the impact of inflation on production costs. Overall, the amount of renewable energy capacity for hydrogen production growth represents only an estimated 7% of announced project capacity."[4]

In addition to production incentives, the IEA states:

> "More effort will be required to ensure that adequate infrastructure to store and transport hydrogen is in place, to clarify regulatory uncertainty, and to boost investment in R&D to improve technologies for new and existing uses."[5]

Although National Grid proposes to be the off-taker, the costs of production remain a challenge.

The Plan Does Not Rule Out Use of Methane-Based Hydrogen, an Ineffective Decarbonization Technology, if Green Hydrogen Is Unavailable

National Grid's 20 Year Plan generally refers to the use of "green" hydrogen produced from water through electrolysis (see pp. 54-55 of the Plan), but does not explicitly rule out methane-based hydrogen. Also, the discussion of alternative fuels in the "Action" section of the plan refers to "clean" hydrogen (p. 137 and 152)—a term that is federally defined to include methane-based hydrogen combined with carbon capture technology.

Methane-based hydrogen, sometimes called "blue" hydrogen, is neither clean nor low-carbon. A 2023 IEEFA report examined the assumptions of the GREET model (Greenhouse gases, Regulated Emissions and Energy use in Transportation) that the U.S. Department of Energy (DOE) uses to evaluate CO_2-equivalent (CO_2-e) emissions from methane-based hydrogen. The report found the model significantly understates the likely emissions associated with blue hydrogen production because it:

- Assumes an upstream methane fugitive emission rate of only 1%—far less than the level identified in recent peer-reviewed scientific analyses and by airplane and satellite surveys.
- Uses a 100-year global warming potential (GWP), which understates methane's impact in the short term, since its 20-year GWP is more than 80 times that of CO_2.
- Fails to consider the global warming impact of hydrogen, which has a 20-year GWP more than 30 times that of CO_2 because of its impact on methane in the atmosphere.
- Does not consider downstream emissions from the produced hydrogen or the electricity generation needed to compress, store and transport the hydrogen to end users.

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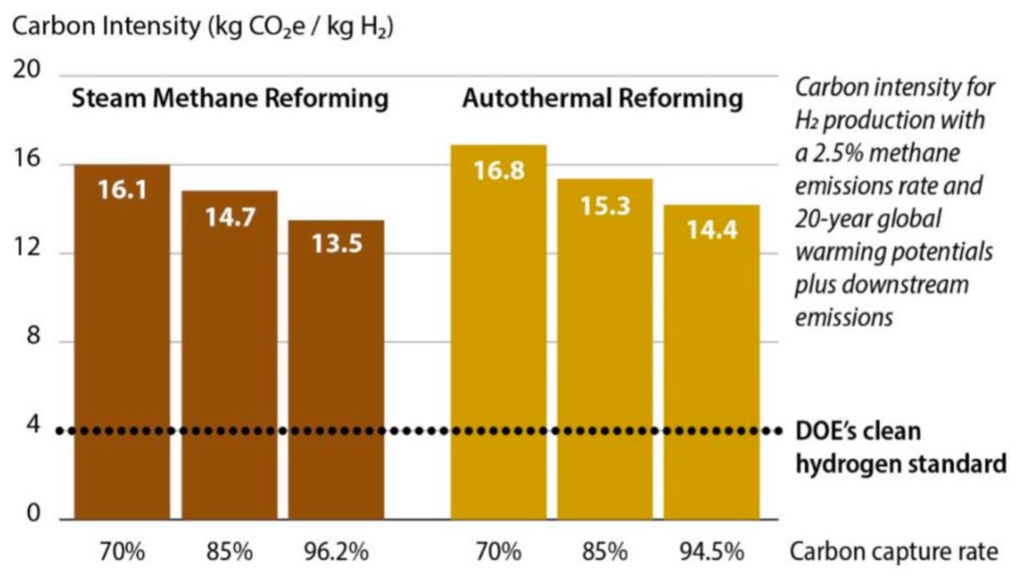
[4] *Ibid*.
[5] *Ibid*., p. 93.

- Makes overly optimistic assumptions about the effectiveness of carbon capture processes.[6]

IEEFA determined that just using methane's 20-year GWP and a more realistic 2.5% methane fugitive emission rate raises blue hydrogen's carbon intensity significantly, making it two to three times higher than the clean hydrogen production standard of 4.0 kg CO_2-e per kilogram of hydrogen, set by Congress and the DOE.[7]

Figure 2: The Carbon Intensity of Blue Hydrogen Using 20-Year GWPs and More Reasonable Ranges of Assumptions for Methane Emissions and Hydrogen Leakage, Related Downstream Emissions and Carbon Capture Rates



Source: DOE GREET model, IEEFA analysis.

Pipeline Transport of Hydrogen Presents a Challenge

National Grid's 20 Year Plan states it assumed that "hydrogen would be stored underground and delivered into the region" (see p. 56 of the Plan). The infrastructure to transport hydrogen or blended hydrogen as contemplated in the plan, however, does not yet exist. The United States only has about 1,600 miles of hydrogen-dedicated pipelines, nearly all of which are concentrated in Texas and Louisiana.[8] An unstated amount of new pipeline construction would likely be needed.

The plan asserts that a 20% blend can be run through existing gas networks "without significant upgrades to infrastructure or equipment" (p. 54). The premise, however, is open to debate.

[6] IEEFA. Blue Hydrogen: Not clean, not low carbon, not a solution. September 12, 2023, p. 5.
[7] *Ibid.*, p. 6.
[8] Congressional Research Service. Pipeline Transportation of Hydrogen: Regulation, Research and Policy. March 2, 2021, p. 5.

A 2022 National Renewable Energy Laboratory (NREL) technological assessment of hydrogen observed: “Gaseous hydrogen has a considerable effect on fatigue and fracture resistance of steels, including line pipe steels and any other steel components operating at pressure within a pipeline.”[9] The NREL identified several concerns regarding hydrogen blending into natural gas pipeline infrastructure, which include but are not limited to the following:

Enhanced fatigue crack growth in pipeline steel
Reduced fracture resistance in pipeline steel
Reduced energy transmission capacity
Increased pressure drop when meeting energy demand
Increased gas velocities
Increased required compression power
Increased centrifugal compressor rotational speed
Increased NO_x emissions for end users
Excessive combustion dynamics, flame lift-off and flashback
Valve leakage and durability
Hydrogen leakage in polymer piping[10]

The NREL reported on a range of studies regarding the issues of hydrogen blending in gas pipeline infrastructure, but ultimately concluded:

> “The current state of literature indicates that substantial research remains before widespread hydrogen blending implementation can occur. There exists a need for additional testing on both steel and plastic pipeline materials implemented in the U.S. natural gas pipeline system to identify and confirm relationships between hydrogen presence and fatigue, crack growth, and failure rates. Additional research can also explore the impacts of hydrogen on previously installed valves, meters, and pressure regulators to clarify short-and long-term functionality over a wider range of conditions.”[11]

Even if the blending is achieved, it would not significantly reduce greenhouse gas emissions.

Hydrogen Does Not Burn Clean, Presents Leakage Risks, and Raises Greenhouse Gas Issues

The calculation that a blend of 20% hydrogen and 80% methane would substitute for only 7% of the energy produced by a 100% methane blend indicates that the blend would result in only a 7% reduction in CO_2-equivalent emissions (CO_2-e). But that does not take into consideration three additional factors of concern: Increased compression requirements; leakage of hydrogen and methane; and nitrous oxide (N_2O) emissions.

[9] K. Topolski, *et al.* Hydrogen blending into natural gas pipeline infrastructure: Review of the state of technology. NREL Technical Report. October 10, 2022 (hereafter, NREL 2022 Report), p. 8.
[10] *Ibid.*, p. 10.
[11] *Ibid.*, p. 43.

Increased compression requirements

At a DOE webinar in October 2023, Argonne National Laboratory scientists reported that the mechanism of moving hydrogen through pipelines consumes energy and leads to more leakage from the pipeline (both methane and hydrogen). The scientists explained that because of hydrogen's lower energy density, pipeline operators must replace each standard cubic foot of gas with three standard cubic feet of hydrogen to deliver the same amount of energy for end users. Such replacement, they reported, requires the pipeline operator to increase pipeline flow rate by about 30% and pressure by 70%—heightening the risk of leakage—and also to use more energy to double the amount of compression power.[12]

As a result, they concluded, even a blend of 30% hydrogen likely would only net a 6% reduction in CO_2-e emissions in a lifecycle analysis.[13]

Leakage of hydrogen and methane

Hydrogen leaks faster than methane. The NREL's 2013 technical report explains:

> "Hydrogen is more mobile than methane in many polymer materials, including the plastic pipes and elastomeric seals used in natural gas distribution systems… Permeation rates for hydrogen are about 4 to 5 times faster than for methane in typical polymer pipes used in the U.S. natural gas distribution system."[14]

The report cited evidence that the hydrogen permeation coefficient in U.S.-grade plastic distribution pipes is five or six times higher than that of methane, and adding 20% hydrogen to natural gas in plastic pipes doubles the total gas loss.[15]

Hydrogen leakage is of concern from a climate perspective because hydrogen molecules in the atmosphere lead to a decrease in hydroxyl radicals (OH). Hydroxyl radicals react with, and reduce, methane molecules in the troposphere.[16]

Formation of nitrous oxide emissions from combustion of hydrogen

Although National Grid declares in its 20 Year Plan that when burning hydrogen gas, "the main byproduct is water vapor" (see p. 54 of the Plan), this description is incomplete and inadequate.

In the typical process of hydrogen combustion, the hydrogen gas (H_2) reacts with air to produce water (H_2O) and nitrogen. By volume, the atmosphere is 78% nitrogen (N_2) and 21% oxygen (O_2).[17] The chemical equation is $2H_2 + (O_2 + 3.7N_2) = 2H_2O + 3.7N_2$. But various intermediate

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[12] Argonne National Laboratory. LCA of NG/H2 blend for various end use applications. DOE H2IQHour—HyBlend Initiative webinar presentation. October 26, 2023, pp. 5 and 38-39.
[13] *Ibid.* Also see: S&P Global. Hydrogen blending in gas pipelines faces limits due to leakage: US DOE lab. October 27, 2023.
[14] M. W. Melaina, *et al.* Blending hydrogen into natural gas pipeline networks: A review of key issues. NREL Technical Report NREL/TP-5600-51995. March 2013 (hereafter, NREL 2013 Report), p. ES-x.
[15] NREL 2013 Report, p. 21.
[16] Argonne National Laboratory, *op. cit.*, p. 44.
[17] Engineering Toolbox. Air – Composition and molecular weight. Accessed August 22, 2024. The remaining 1% is comprised of water, argon, carbon dioxide, and trace gases.

reactions and subsequent reactions can occur, especially given the high temperature of hydrogen combustion, resulting in emissions of nitrous oxide (N_2O) and other oxides of nitrogen (NO_x).[18]

A study of hydrogen blends in a constant-volume chamber found that higher percentage blends of hydrogen reduce hydrocarbons and CO_2 emissions but increase NO_x emissions.[19] The properties of hydrogen, as an energy source, exacerbate the emissions problem. The New York State Department of Environmental Conservation (NYSDEC), in denying a permit for the Danskammer Energy Center peak power plant in Newburgh, NY, rejected the argument that a possible blending or switch to hydrogen would allay the agency's concerns. Noting hydrogen's lower volumetric heating value (energy density) compared to natural gas, the NYSDEC stated:

> "A lower volumetric heating value means that more fuel needs to be fired to achieve the same output. The additional volume of fuel fired, combined with the higher flame temperature when firing hydrogen, is expected to cause higher emissions of Oxides of Nitrogen (NO_x) without the installation of additional NO_x controls."[20]

Nitrogen oxides emissions can have local and regional air pollution effects, as a result of direct emissions and due to interaction with volatile organic compounds in the atmosphere to form tropospheric ozone pollution (a component of smog).[21]

A 2017 study documented that combined combustion of hydrogen and natural gas increases emissions of nitrous oxide (N_2O), a long-lived chemical that is the third most significant greenhouse gas after carbon dioxide and methane, and also poses risk to the atmosphere's protective ozone layer.[22] Nitrous oxide is of special concern because it is the third most significant greenhouse gas, following carbon dioxide and methane.[23] It is also currently the dominant depleting substance of stratospheric ozone (in the wake of the Montreal Protocol, which reduced emissions of chlorofluorocarbons, or CFCs) and it persists in the air, with an atmospheric lifetime of more than 100 years.[24]

Although the DOE has expressed general optimism that engineers can reduce NO_x emissions in combustion turbines by controlling excess air or other "levers,"[25] more analysis is needed.

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[18] L. Jung, *et al.* Numerical investigation and simulation of hydrogen blending into natural gas combustion. Energies 17(15):3819. August 2, 2024, p. 3.
[19] S. Lee, *et al.* Combustion and emission characteristics of HCNG in a constant volume chamber. Journal of Mechanical Science & Technology 25:489-494, March 19, 2011.
[20] NYS Department of Environmental Conservation (NYSDEC). Notice of Denial of Title V Air Permit ID No. 3-3346-00011/00017. October 27, 2021.
[21] U.S. Environmental Protection Agency. Basic information about NO2. Last updated July 16, 2024.
[22] A. Colorado, *et al.* Direct emissions of nitrous oxide from combustion of gaseous fuels. International Journal of Hydrogen Energy. 42(1):711-719. January 5, 2017.
[23] World Meteorological Organization. State of the Global Climate 2023. WMO-No. 1347. 2024, p. 2.
[24] H. Tian, *et al.* Global nitrous oxide budget (1980-2020). Earth Systems Sci. Data. 16:2543-2604. June 11, 2024.
[25] DOE. DOE Low NO_x targets and state-of-the-art technology for hydrogen fueled gas turbines. The H2IQ Hour webinar PowerPoint presentation. December 2022, p. 25.

A new study by Switchbox, commissioned by the Environmental Defense Fund, finds blending 20% hydrogen by volume into the gas pipeline system to heat homes would consume nearly eight times more electricity than heating the same number of homes with heat pumps, reducing emissions from gas-heated buildings by only 7%. Using heat pumps instead would nearly eliminate building sector emissions, consuming 87.2% less electricity.[26]

At this point, more questions than answers dominate the discussion on emissions from hydrogen-blended fuel.

Use of Blended Gas (Hydrogen and Methane) in Pipelines and Homes or Buildings Poses Safety Risks and Uncertainties

Hydrogen presents management and safety issues, particularly at the local service level. As the NYSDEC observed in its Danskammer decision, "When compared to natural gas, hydrogen has a higher explosive potential, a higher leak potential, a lower volumetric heating value, and a higher flame temperature."[27] The DOE reports that hydrogen flames are "virtually invisible in daylight."[28] An NREL report cautions:

> "Because hydrogen has a broader range of conditions under which it will ignite, a main concern is the potential for increased probability of ignition and resulting damage compared to the risk posed by natural gas without a hydrogen blend component."[29]

The risk is more problematic for local service lines. Such lines operate at lower pressure than distribution lines, which can reduce leakage risk,[30] but their location can present accumulation risks. Although an NREL 2013 technical report concluded that higher concentrations of hydrogen in distribution mains, up to 50%, present a "minor" increase in overall risk, NREL cautioned:

> "Risks associated with service lines are different because service lines are often found in confined spaces where leaked gas would be more likely to accumulate. If hydrogen concentrations exceed 20% in service lines, the increase in overall risk is more significant than for distribution mains. For both distribution mains and service lines, proper risk management practices, such as the installation of monitoring devices, reduces overall risk. However, adding more than 50% hydrogen to either distribution mains or service lines results in a significant increase in overall risk. Again, these risk results are associated with introducing hydrogen blends into the existing U.S. natural gas pipeline system and do not apply to new, dedicated hydrogen pipelines carrying pure hydrogen, which

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[26] Switchbox. Blending Hydrogen and Natural Gas: A road to nowhere for New Yorkers. Commissioned by the Environmental Defense Fund. September 12, 2024.
[27] NYSDEC, *op cit.*, p. 10.
[28] DOE. Hydrogen Data. Accessed August 21, 2024.
[29] NREL 2013 Report, p. vii.
[30] *Ibid.*, p. 21.

> would be designed and managed differently than the existing natural gas pipeline system."[31]

NREL's 2013 technical report also highlighted the issue of maintenance, stating:

> "The level of hydrogen that is acceptable for transmission pipelines may need to be reassessed for distribution systems in terms of the frequency and severity of fire or explosion in a highly populated area. In addition, the hazards arising from gas leakage in a distribution system may be more severe than in transmission pipelines, especially in a confined service area. The integrity management for distribution systems under hydrogen services may require a leak detector or a monitoring device or sensor. The maintenance costs for distribution systems under hydrogen service likely will increase because these systems will need to be inspected more frequently and likely will require additional leak detection systems."[32]

NREL cited a study (Florisson 2010) estimating that modifications to existing integrity management practices may incur an additional 10% cost increase due to hydrogen blends.[33]

National Grid's plan to establish 100% hydrogen service areas poses an elevated safety risk. The NREL 2013 technical report cautioned:

> "Compared with explosions of pure natural gas in confined areas, the relative increase in the severity of confined vented explosions was modest for blends with less than 20% hydrogen. A more significant increase in overpressure, and therefore risk or damage, was observed for blends with more than 50% hydrogen. Vapor cloud explosion overpressure can be significantly reduced for higher hydrogen concentrations if ventilation is used or if the structural congestion causing confinement is reduced (Florisson 2010; Lowesmith 2009)."[34]

Even an Energy Futures Initiative report that makes recommendations to increase production and use of hydrogen nevertheless cites the need for new regulations on hydrogen safety. It states:

> "Hydrogen infrastructure will also require specific codes and standards to manage the safe production, transportation, and distribution of hydrogen. Dedicated hydrogen pipelines must be built to withstand hydrogen embrittlement. Hydrogen pipeline maintenance programs also must account for the fact that hydrogen is a highly flammable gas. Protocols and safety systems will have to be developed to protect pipeline workers as well as the communities that hydrogen pipelines traverse."[35]

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[31] *Ibid.*, p. viii.
[32] *Ibid.*, p. ix.
[33] *Ibid*., p. ES-ix.
[34] *Ibid.*, p. 16.
[35] Energy Futures Initiative. The U.S. Hydrogen Demand Action Plan. February 9, 2023, p. 83.

Although National Grid asserts that its leaking pipeline replacement program (LPP) is upgrading pipeline segments to accommodate hydrogen-blended gas, its 20 Year Plan puts the New York State Public Service Commission on notice (see p. 56 of the Plan) that a hydrogen strategy would require substantial additional work, stating:

> "Investments are needed to establish and grow areas in our existing gas network that are capable of safely delivering hydrogen blended gas to our customers. This includes work to eliminate all remaining LPP in an area and confirming the blended hydrogen in the network will not result in any long-term reliability concerns due to the lower Btu value per cubic foot of hydrogen blended gas."

The amount of work required is not explicitly stated here. National Grid goes on to caution that the blending process itself will require research and demonstration projects (see p. 56), stating:

> "Additional research, and demonstration projects, may be needed to enable hydrogen blending upstream from our distribution system—including gas transmission, pressure regulation and LNG assets—and deploying dedicated hydrogen clusters."

National Grid's Projection that 67% of Industrial Energy Use by 2050 Will Be 100% Hydrogen Does Not Appear Realistic

National Grid speaks of hydrogen as an important tool for decarbonizing industrial energy demand, projecting that 67% of industrial energy use by 2050 will be 100% hydrogen. This appears unlikely.

A McKinsey report found that roughly 49% of the fuel used for industrial activity could be replaced by electrification using technologies that already existed in 2020.[36] The industrial sectors included low-temperature, medium-temperature, and high-temperature (400◦-1000◦C) industrial processes. The report stated that for electrification of very-high-temperature processes (greater than 1000◦C)—which included calcination of limestone for cement production, and other processes—technology was still in the research or pilot phase.[37] Such research is progressing, with assistance from the DOE. The speed and extent to which such technologies may take hold is not known, but an assumption that roughly two-thirds of industry in the National Grid service area will rely on 100% hydrogen does not appear realistic.

Storage of Hydrogen Raises Issues—and Battery Technology Offers Better Certainty as an Energy Storage Resource

National Grid's 20-Year Plan asserts: "Hydrogen can be made during periods when wind or solar resources are able to produce more electricity than the grid needs and then stored for later use, thereby maximizing the benefits of renewable energy resources" (see p. 54 of the Plan). Hydrogen storage, however, faces challenges.

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[36] McKinsey & Company. Plugging in: What electrification can do for industry. May 2020, p. 3.
[37] *Ibid.*

IEEFA's examination of hydrogen storage resources in the United States found that little exists, and only in Texas. Just three underground salt cavern hydrogen storage facilities operate in the United States, and all the potential storage options for hydrogen have risks and cost questions, especially related to the issue of hydrogen leakage.[38]

The 2022 NREL report identifies concerns related to hydrogen storage, including biochemical hydrogen conversion and hydrogen loss through cap rock in underground storage.[39] The DOE, citing such concerns, concluded that "significant technological advancements are needed" before underground hydrogen storage can grow substantially.[40] Although National Grid suggests excess hydrogen can simply be stored within its pipeline system, the leakage and safety issues discussed above would be of concern.

To the extent that excess wind and solar power is available for use, it is likely more helpful to direct the energy to electric battery storage. Such battery storage technology is making substantial strides. The IEA reports that battery storage in the power sector was the fastest-growing commercial energy technology worldwide in 2023. At the same time, battery costs have dropped 90% since 2010, and IEA projects the costs could fall an additional 40% by 2030.[41]

Conclusion

Hydrogen is the most ubiquitous chemical on earth, and the main technology proposed for its use—combustion—is not new. Hydrogen has not become a leading energy source because the barriers to its use are substantial and the benefits are limited. Although hydrogen's most helpful role could be in long-duration storage, it is likely to be eclipsed by batteries and other storage options. For economic, environmental and public safety reasons, National Grid should reconsider its proposal regarding hydrogen and hydrogen blending.

[38] IEEFA. Hydrogen: Not a solution for gas-fired turbines, p. 19.
[39] NREL 2022 report, p. 10.
[40] A. Goodman Hansen, *et al.* Subsurface Hydrogen and Natural Gas Storage (State of knowledge and research recommendations report). DOE National Energy Technology Laboratory. DOE/NETL-2022/3236. April 2022, p. 65.
[41] International Energy Agency. Batteries and secure energy transitions. April 2024, pp. 11 and 13.