ASSESSING THE VIABILITY OF HYDROGEN PROPOSALS: CONSIDERATIONS FOR STATE UTILITY REGULATORS AND POLICYMAKERS

SARA BALDWIN, DAN ESPOSITO, AND HADLEY TALLACKSON[i]

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SUMMARY

Since 2020, natural gas and electric utilities have proposed at least 26 pilot projects across more than a dozen states involving the production and distribution of hydrogen[ii] for various end-uses, including as a heating fuel in buildings and for power generation.[iii,1]

In 2021, the bipartisan Infrastructure Investment and Jobs Act (IIJA) allocated $8 billion to support regional hydrogen demonstration hubs, including at least two hubs to explore the fuel's use for the same heating and power generation end-uses.

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[ii] Hydrogen is a colorless, odorless, highly flammable gas that emits only water when burned. While hydrogen is the most abundant element in the universe, it is scarce in the Earth's atmosphere and does not have naturally occurring deposits. Therefore, it must be produced from other compounds, and the source of those compounds as well as the way it is produced have an impact on its lifecycle greenhouse gas (GHG) emissions (see call-out box on page 6). Today, hydrogen is primarily produced using a highly polluting process for use in oil refining and ammonia production.

[iii] In 2021, developers announced more than 8 gigawatts (GW) of "hydrogen-compatible" power plants in the United States. Business Council for Sustainable Energy, *Sustainable Energy in America 2022 Factbook*, https://bcse.org/factbook.

ENERGY INNOVATION
POLICY & TECHNOLOGY LLC

www.energyinnovation.org

98 Battery Street, Suite 202
San Francisco, CA 94111
policy@energyinnovation.org

Hydrogen's promise as a viable fuel for these applications is premised on two assumptions: First, since hydrogen releases no greenhouse gases (GHG) when burned, it can be blended with fossil fuels (namely, natural gas[iv]) to support building and power sector decarbonization. Second, it will allow utilities to use or repurpose existing natural gas infrastructure, thereby minimizing costs and disruption to consumers. However, these are false premises.

The existing body of research suggests blending hydrogen with natural gas for use in buildings or for power generation is highly inefficient and does little to reduce GHG emissions. Instead, it might thwart more viable decarbonization pathways while increasing consumer costs, exacerbating air pollution, and imposing safety risks. Together, these barriers suggest hydrogen should play a far more limited role in supporting a carbon-free economy, reserved for the hardest-to-decarbonize end-uses for which no alternatives exist.

In the face of growing momentum and enthusiasm for hydrogen, state utility regulators and policymakers should be highly scrupulous and discerning of hydrogen blending proposals and avoid costly dead ends on the road to a decarbonized future.

This paper aims to help state utility regulators and policymakers (including legislators, air regulators, state energy offices, and governors) assess proposed hydrogen projects and programs intended to support decarbonizing certain end-use applications, particularly for heating in buildings and for electricity generation.[v] While hydrogen can be produced in many ways, this paper focuses on *green hydrogen*—produced from water and renewable electricity—as it is the only scalable source of GHG emissions-free hydrogen available today (see call-out box on page 6).

TOP-LINE RESEARCH FINDINGS INCLUDE:

- Using hydrogen in buildings creates major challenges and safety risks throughout the existing natural gas infrastructure system because of the difference in chemical properties between hydrogen and methane (the primary component of natural gas).

[iv] Natural gas is a gaseous fossil fuel, consisting largely of methane and occurring naturally underground, often in association with petroleum. It is used as a fuel for heating, cooking, and power generation, and as a feedstock for industrial processes. Natural gas emits carbon dioxide (CO_2) when burned. Additionally, methane leaked during natural gas production and throughout the pipeline transmission and distribution system is a more potent GHG with a global warming potential (GWP) of 28-36 over 100 years (compared to CO_2, which has a GWP of 1). That means that methane is 28 to 36 times as potent as CO_2 at trapping heat in the atmosphere. T. Lauvaux et al., "Global assessment of oil and gas methane ultra-emitters," *Science,* 375 (February 2022): 557-561, https://www.science.org/doi/10.1126/science.abj4351; U.S. Environmental Protection Agency, *Understanding Global Warming Potentials*, https://www.epa.gov/ghgemissions/understanding-global-warming-potentials.

[v] The scope of this paper is on the end-uses most applicable to state utility regulatory oversight; it excludes a more in-depth evaluation of hydrogen's other potential end-uses in applications such as heavy industry, commercial shipping, and aviation.

Hydrogen cannot be readily swapped for methane for use in heating or consumer appliances above a 5 to 20 percent blend with natural gas without enormous costs and disruption, and low blends achieve very few GHG emissions reductions while increasing nitrogen oxide (NOx) pollution.

- Electrification, which involves replacing building equipment and appliances that burn natural gas (or other delivered fuels such as propane or fuel oil) with high-efficiency electric alternatives, results in a far more efficient use of clean electricity than green hydrogen, giving this pathway a fundamental economic advantage. Achieving building sector decarbonization via electrification versus a transition to 100 percent green hydrogen would require less utility capital investment and bolster the reliability and resilience of the electric distribution system.
- Green hydrogen might be suitable to provide long-duration energy storage in the power sector to help decarbonize the last 10 percent of electricity generation on the path to 100 percent clean electricity. But the fuel has limited value until such grid services are needed, and other emerging technologies could potentially provide these services at lower cost or without exacerbating local air pollution from burning hydrogen in gas-fired power plants.
- Though not discussed at length in this paper, green hydrogen may be best suited for addressing harder-to-decarbonize sectors of the economy, such as industrial feedstocks, marine shipping, and aviation. However, these use cases do not necessitate converting most existing natural gas pipeline infrastructure to carry hydrogen, nor do they necessarily warrant approvals from utility regulators.

When considering a proposed building or power sector hydrogen project, utility regulators and policymakers should assess green hydrogen on its merits and limitations, within the context of available alternatives. Otherwise, these projects risk dead end outcomes, increased ratepayer costs, unnecessary public health and safety risks, and few emissions reductions. They can also distract from proven pathways for more rapid and cost-effective decarbonization of gas and electric utility systems.

TOP-LINE POLICY RECOMMENDATIONS INCLUDE:

- Utility regulators should exercise skepticism when considering ratepayer-funded proposals to blend hydrogen with natural gas for distribution in pipelines or use in power plants, and they should place a high burden of proof on utilities to demonstrate how these investments support a viable and cost-effective long-term decarbonization strategy relative to alternatives.

- Where ratepayer-funded pilot projects are already underway, utility regulators should define clear goals, outcomes, and metrics for assessing learning with specific relevance to the utility's jurisdiction. More general research on technological advancements of green hydrogen production and improvements of end uses is better suited for the federal government and the private sector.
- Utility regulators should look to proven, least-regrets alternatives to hydrogen that help electric and gas utilities (and states) achieve their decarbonization targets, such as electrifying buildings, bolstering energy efficiency programs, directing gas utilities to identify and seal methane leaks, and deploying more renewables and battery storage.[vi]
- State policymakers should explore using green hydrogen in the hardest-to-decarbonize sectors of the economy, such as industrial feedstocks, aviation, and marine shipping; however, regulated utilities' role in supporting this effort might best be limited to providing clean electricity to these sectors for electrolysis to produce green hydrogen.

CONTEXT

Today, hydrogen producers in the United States generate 95 percent of the fuel[2] via a highly carbon-intensive process using methane as the feedstock, with the majority[3] of this gray hydrogen destined[4] for use in oil refining (60 percent) and ammonia production (30 percent).[vii] Current hydrogen production accounts for around 1.3 percent of U.S. GHG emissions and causes other air pollution (primarily NOx).[viii] However, producers can reduce and even eliminate hydrogen's GHG

[vi] Modeling from Energy Innovation shows that meeting U.S. "Nationally Determined Contribution" for reducing GHG emissions at a scale and pace to remain below 1.5 degree Celsius of warming will require electrification across buildings, transportation, and industry. Electrifying all existing and new buildings is the key policy driver for emissions reductions from the buildings sector. Robbie Orvis and Megan Mahajan, *A 1.5°C NDC for Climate Leadership by the United States* (April 2021), https://energyinnovation.org/publication/a-1-5-celsius-pathway-to-climate-leadership-for-the-united-states/.

[vii] Gray hydrogen usage data was estimated from Mark F. Ruth et al., *The Technical and Economic Potential of the H2@Scale Concept within the United States,* NREL/TP-6A20-77610 (October 2020), https://www.nrel.gov/docs/fy21osti/77610.pdf, Table ES-1.

[viii] GHG emissions from hydrogen production relative to total U.S. emissions were calculated by applying an emission factor of 9.0 kilograms of CO_2 per kilogram of hydrogen produced via steam methane reformation to the 95 percent of the 10 million metric tons of hydrogen produced in the U.S. using this method. Pingping Sun et al., "Criteria Air Pollutants and Greenhouse Gas Emissions from Hydrogen Production in U.S. Steam Methane Reforming Facilities," Environ. Sci. Technol., 53, no. 12 (2019), 7103–7113; Office of Energy Efficiency & Renewable Energy, "Hydrogen Production," https://www.energy.gov/eere/fuelcells/hydrogen-production. The emission factor accounts for the CO_2 released from the reaction to produce hydrogen and the associated natural gas combustion emissions, excluding upstream methane and downstream hydrogen leakage. The value was then compared to the 2019 total U.S. GHG emissions of 6,588 million metric tons of CO_2e. Environmental Protection Agency, Inventory of U.S. Greenhouse Gas Emissions and Sinks: Public

emissions, such as by capturing and storing some of the associated carbon dioxide (CO_2), which is referred to as blue hydrogen, or by using electricity to strip hydrogen from water molecules through a process called electrolysis. Using renewable energy for electrolysis produces green hydrogen—currently the only viable option for producing fully decarbonized hydrogen at scale.

Many U.S. gas and electric utilities are exploring potential decarbonization pathways in response to legislation, regulation, investor interest, or public pressure. Their approaches vary, and most are still in the concept or pilot phase. However, since 2020, utilities have proposed at least 26 hydrogen pilot projects[5] across more than a dozen states. The projects range in scope from the production, transmission, distribution, and storage of hydrogen to end-use opportunities such as power generation, transportation, buildings, and appliances. Many of these proposals involve blending blue or green hydrogen with natural gas to reduce the carbon intensity of the fuel for use in buildings, industry, or power generation. Some projects are moving forward quickly—in October 2021, New Jersey Resources Corp. became the first U.S. gas utility to blend hydrogen into its distribution system to serve its customers.[6] Many utilities are also asking their state regulators for cost recovery from ratepayers for these projects.[7]

While hydrogen proposals claim to offer a swift route to decarbonization, closer scrutiny reveals a more difficult path. Green hydrogen likely cannot offer economically viable and scalable solutions to meet GHG reduction goals for the buildings sector and has limited economic potential in the power sector. To the extent hydrogen proposals are pursued at the expense of more viable alternatives, they may constitute a misuse of ratepayer dollars while preventing states from reducing emissions at the pace required for a stable climate future.

Nonetheless, these proposals may represent attractive capital investment opportunities for utilities (bringing associated rates of return for utility shareholders[8]) due primarily to pipeline replacement expenditures and other upgrades to support the integration of hydrogen into existing infrastructure, designed and built for natural gas or other fossil fuels. Theoretically, hydrogen offers an appealing path for gas utilities to continue business-as-usual without major disruption to their financial models in the face of the decarbonization imperative.

Review of Draft U.S. Inventory of Greenhouse Gas Emissions and Sinks: 1990-2020, https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks. The total hydrogen emissions value represents an underestimate because it assumes the 5 percent of non-SMR hydrogen production is zero-emissions for simplicity. The combustion of methane in steam methane reformation also contributes to NOx pollution.

What About Other Hydrogen Production Methods and "Clean Fuel" Alternatives?

Most hydrogen production methods and non-hydrogen-derived "clean fuels"[ix] have limitations, whether in scalability, economic viability, or their ability to meaningfully reduce GHG emissions and other pollutants.

For example, blue hydrogen[9] relies on methane as an input and carbon capture and storage (CCS) technologies for downstream carbon emissions.[10] However, the methane causes upstream GHG emissions via leakage from wellheads and distribution networks. CCS is expensive and requires substantial subsidies[11] (or a sufficiently high price on carbon) to be cost-effective at scale; it is also limited by geologic storage locations. Using CO_2 for enhanced oil recovery improves the economics, but such an end use would negate any GHG emissions benefits. In addition, while available data from facilities that capture carbon from fossil fuel combustion are limited, two coal-fired power plants show an average capture rate of only 55 to 72 percent,[12] which falls short of the 90 to 95 percent capture rates promised by future projects.[13]

Pink hydrogen,[x] electrolyzed exclusively with nuclear energy, is theoretically scalable but would require a nuclear renaissance in the U.S. to bring down the cost of this electricity source. Turquoise hydrogen, which involves converting methane into hydrogen and solid carbon (with no CO_2 emissions), has potential,[14] but it still suffers from upstream methane leakage and is untested at scale.

Synthetic natural gas may be considered a viable clean alternative fuel since it is technically possible to produce by combining green hydrogen with carbon monoxide and captured CO_2.[15] However, its production relies on three expensive processes (electrolysis powered by clean electricity, carbon capture, and methanation[16]). Producing synthetic natural gas may also result in upstream methane emissions.

Biofuels generated from landfill waste and other organic waste face limitations with respect to land requirements and waste methane availability[17] (e.g., the U.S. could only supply enough waste-derived biogas to meet 1.5 percent of national natural gas consumption[18]). Some biofuel sources, such as animal waste from industrial-scale pig farms, also cause water pollution[19] and adverse public health impacts in surrounding communities.[20]

To protect the public interest, utility regulators and state policymakers should consider appropriate hydrogen applications and limitations, within the context of more viable alternatives. Regulators should prioritize protecting gas and electricity customers from high and volatile costs, promoting public safety and reliability, and requiring utilities to achieve meaningful decarbonization with realistic, scalable, and affordable strategies.

[ix] Fuels derived from non-fossil fuel sources with processes that reduce their carbon intensity.

[x] Pink and turquoise hydrogen are out of scope for this paper due to uncertainties of feasibility or emissions reduction potential.

RESEARCH FINDINGS

This research demonstrates the primary barriers and opportunities for hydrogen use in buildings (served via fossil fuel pipeline distribution networks) and for electricity generation, based on available studies. The resulting analysis of hydrogen's applicability for the two sectors focuses on technological feasibility, economic comparisons, public health and safety considerations, and emissions reduction potential.

BUILDING SECTOR

Natural gas pipelines can only handle low hydrogen blends before imposing safety risks, and such blends max out on reducing GHG emissions by a mere 6 to 7 percent.

Hydrogen is the smallest molecule in the universe, which creates pipeline integrity and leakage challenges throughout the existing U.S. natural gas infrastructure system. Nearly all transmission pipelines are made of high-grade steel and transport gas at high pressures.[21] Under these conditions, hydrogen can exacerbate pipeline cracks and cause embrittlement, increasing leakage and explosion risks above certain case-specific concentrations.[xi]

Gas distribution mains and service lines—the focus of most hydrogen blending proposals—are mostly made of polyethylene (plastic)[22] and transport gas at lower pressures.[xii] While these characteristics result in fewer integrity concerns, hydrogen's small molecular size means it can still leak through pipeline walls and points of connection at much greater volumes than methane.[xiii]

Hydrogen is extremely flammable, and leaked fuel can spark more easily than methane. Blending as little as 5 to 20 percent hydrogen into existing gas pipelines can lead to unacceptably high risk of explosions in homes or urban areas,[23] such as by accumulating in poorly ventilated enclosures. For this reason, many utility proposals[24] aim to discern how much hydrogen they can blend before

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[xi] Hydrogen blends of up to 50 percent by volume can be transported in transmission lines with few modifications, but risks and costs increase significantly at higher levels. M. W. Melaina, O. Antonia, and M. Penev, *Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues,* NREL/TP-5600-51995 (March 2013), https://www.nrel.gov/docs/fy13osti/51995.pdf. For example, hydrogen can self-ignite when leaking from high-pressure pipelines. Scott Jenkins, *Facts at Your Fingertips: Hydrogen Flame Hazards and Leak Detection* (December 1, 2020), https://www.chemengonline.com/facts-fingertips-hydrogen-flame-hazards-leak-detection/#:~:text=Hydrogen%20flammability,is%20highly%20flammable%20and%20explosive.&text=Hydrogen%20can%20also%20self%2Dignite,a%20pipe%20at%20high%20pressure.

[xii] Most of the remaining lines are made of lower-grade steel, with marginal amounts of iron, copper, and other materials. See the National Renewable Energy Laboratory's "Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues," Figure 5.

[xiii] Specifically, hydrogen leaks through the walls of plastic pipes at a volumetric rate of four to five times that of methane and through threads and mechanical joints of steel or iron pipes three times faster than methane. Melaina, Antonia, and Penev, *Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues*.

encountering safety risks that would require pipeline retrofits, replacements, or monitoring systems to detect hydrogen leaks.[25]

The upper end of the known hydrogen blending limit for existing natural gas distribution pipeline infrastructure is around 20 percent hydrogen by volume. Because hydrogen molecules produce less energy than methane when burned, a 20 percent hydrogen blend would provide only 6 to 7 percent of the mixture's energy content.[26] As a result, gas utilities can achieve a mere 6 to 7 percent reduction in GHG emissions under the most optimal blending conditions—that is, after completing sufficient system-wide testing and infrastructure upgrades to accommodate a 20 percent blend of green hydrogen, given each distribution system has pipes of varying materials, conditions, and age.

Utilities would need much greater investments across their full system of distribution mains and service lines to accommodate hydrogen blends above approximately 20 percent, not including the challenge of replacing consumer appliances (discussed below) and industrial equipment.[xiv,xv]

In sum, hydrogen blending investments risk wasting time and ratepayer money en route to achieving minimal GHG emission reductions, only to face daunting financial and logistical roadblocks to achieving higher blends or a 100 percent green hydrogen fuel network.

[xiv] Even a 50 percent hydrogen blend (as is possible in some transmission lines) achieves less than a 25 percent GHG emissions reduction, not accounting for emissions from hydrogen leakage from pipelines. GE Power, *Power to Gas: Hydrogen for Power Generation* (February 2019), https://www.ge.com/content/dam/gepower/global/en_US/documents/fuel-flexibility/GEA33861%20Power%20to%20Gas%20%20Hydrogen%20for%20Power%20Generation.pdf. Hydrogen is an indirect greenhouse gas; while hydrogen emissions have a lower climate impact (5.8 times more potent than CO_2) than methane (28 times more potent than CO_2) over a 100-year period, hydrogen leakage could significantly increase near-term warming. R. Derwent et al., "Global Environmental Impacts of the Hydrogen Economy," *Int. J. of Nuclear Hydrogen Production and Applications*, 1, no.1 (2006): 57-67, DOI 10.1504/IJNHPA.2006.009869; Greenhouse Gas Protocol, *Global Warming Potential Values*, https://www.ghgprotocol.org/sites/default/files/ghgp/Global-Warming-Potential-Values%20%28Feb%2016%202016%29_1.pdf; Steven Hamburg and Ilissa Ocko, "For Hydrogen to Be a Climate Solution, Leaks Must Be Tackled," *EDF Voices Blog*, https://www.edf.org/blog/2022/03/07/hydrogen-climate-solution-leaks-must-be-tackled.

[xv] One cost estimate indicates that upgrading integrity and management plans for blending low levels of hydrogen into the distribution system would incur a 10 percent cost increase. Melaina, Antonia, and Penev, *Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues.* While cost estimates for pipeline retrofits to support 100 percent hydrogen are limited, a study of the German national pipeline infrastructure estimated retrofits to be only 20 to 60 percent less expensive than building out an entirely new pipeline system for hydrogen. Congressional Research Service, *Pipeline Transportation of Hydrogen: Regulation, Research, and Policy* (March 2, 2021), https://crsreports.congress.gov/product/pdf/R/R46700. Given that hydrogen pipelines can cost 68 percent more than natural gas pipelines, even a fraction of the cost is still significant. National Institute of Standards and Technology, *NIST Calculates High Cost of Hydrogen Pipelines, Shows How to Reduce It* (July 20, 2015), https://www.nist.gov/news-events/news/2015/07/nist-calculates-high-cost-hydrogen-pipelines-shows-how-reduce-it.

Hydrogen has low blending thresholds for use in consumer appliances designed to burn natural gas, and even these low levels pose higher safety and human health risks.

At present, it is unclear how to effectively mitigate the health and safety threats of hydrogen blends with today's natural gas appliances and equipment. Consumer appliance manufacturers currently design gas stoves, gas dryers, and gas water and space heating equipment to meet rigorous safety standards enforced by the U.S. Consumer Product Safety Commission.[27] Because residential appliances are optimized for natural gas, blending hydrogen above 5 percent and up to 20 percent requires extensive testing to limit dangers to consumers, with the safe blending percentage varying based on appliance type, age, and natural gas composition.[xvi]

Hydrogen ignites far more readily than natural gas[28] and carries a higher risk of flame flashback[29]—i.e., when a flame travels from a burner back into the gas line[30]—in appliances designed to run on natural gas, increasing explosion risk. Unlike methane, there are no known odorants compatible with hydrogen.[31] This means any room where pipes or appliances are delivering a high-hydrogen blend (or 100 percent hydrogen) may require a hydrogen detector with an audible alarm, lest a gas leak accumulate and increase the risk of fire or an explosion.[xvii]

Finally, hydrogen burns hotter than methane, and this could increase consumers' exposure[32] to NOx.[33] While additional studies are needed for home appliances, hydrogen combustion in industrial settings (including power generation) can generate NOx emissions up to six times higher than methane combustion.[34] Exposure to NOx via natural gas stove use, which releases combustion pollution directly into homes, is already a considerable health threat;[35] poorly ventilated gas stoves can increase the risk of asthma in children by 42 percent,[36] with disproportionate effects for low-income households.[37]

Decarbonizing the building sector via a 100 percent green hydrogen transition versus electrification would require far more utility capital investments and create more adverse impacts on consumers.

In the U.S., hydrogen is transported through about 1,600 miles of dedicated, hydrogen-specific pipeline[38] serving industrial hubs and owned by hydrogen manufacturers. Comparatively, the existing U.S. natural gas system consists of 3 million miles of pipeline,[39] supplying end-uses designed to receive natural gas.

[xvi] For industrial natural gas users, it might be necessary to recalibrate or replace equipment even at blends well below 20 percent.

[xvii] Specifically, there are no known odorants that diffuse quickly enough to provide warning before hydrogen exceeds its lower flammability limit. Further worsening explosion risk, hydrogen has a much wider range of concentrations at which it is flammable (at mixtures between 4 percent and 75 percent in air, compared to 5 percent and 15 percent in air for methane) and requires less energy to spark a reaction. H_2 Hydrogen Tools, "Hydrogen Compared with Other Fuels," https://h2tools.org/hydrogen-compared-other-fuels.

Blending hydrogen with natural gas beyond the current 20 percent by volume threshold would require utilities to retrofit or replace most or all pipelines in a given service territory, likely including modifying pipes within homes and buildings.[40] Even if appliances capable of handling higher hydrogen blends do become available on the market, utilities would still need to wait for the replacement of all natural gas-burning end-use appliances—including water heaters, furnaces, stoves, and dryers—across their entire service territory before they could distribute hydrogen blends beyond the 5 to 20 percent limit.[xviii] This collective transition would entail huge capital investments[41] and logistical challenges.

In contrast, electrification is substantially less disruptive. Equipment and appliance replacements can occur incrementally using existing electrical infrastructure. Many buildings have sufficient electrical capacity to switch to all-electric appliances today. Older buildings might require electrical upgrades, such as a new panel or wiring. In either case, electric appliances are readily available and pose none of the abovementioned public safety or health risks. In the U.S., 25 percent of homes use only electricity,[42] and almost half of single-family homes are appropriately wired for all-electric appliances.[43]

While electrifying substantially more homes and buildings would likely require distribution grid upgrades, these investments in the aging electric grid would also bolster grid reliability and resilience, benefitting 100 percent of U.S. residents that use electricity.[xix][44] Combined with demand response and distributed energy resources, all-electric buildings provide unique load flexibility and other system benefits, including supporting the integration of more renewable energy and expanded charging for electric vehicles (another flexible load[45]).[xx]

[xviii] Appliances would need to be advanced enough to handle any blend of methane and hydrogen to ensure all gas customers' appliances continue to operate normally during a transition to 100 percent hydrogen. While there is a technical possibility that existing appliances could be retrofitted for compatibility with 100 percent hydrogen (i.e., not blended with methane), obstacles to deployment—such as the large variation in existing products and reduction in appliance performance—reduce retrofit feasibility and likely favor total appliance replacement (whenever hydrogen-compatible appliances are commercially available). Frazer-Nash Consultancy, *Appraisal of Domestic Hydrogen Appliances* (February 2018), https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/699685/Hydrogen_Appliances-For_Publication-14-02-2018-PDF.pdf.
Appliances capable of burning 100 percent hydrogen are still undergoing research and development, with a few in prototype and testing stages. FuelCellsWorks, *UK's First Hydrogen Homes Entirely Fueled by Hydrogen Now Open to the Public* (July 16, 2021), https://fuelcellsworks.com/news/uks-first-hydrogen-homes-entirely-fueled-by-hydrogen-now-open-to-the-public/.

[xix] Electrification will also require transmission grid upgrades, but likely less so than a building decarbonization pathway heavily dependent on green hydrogen, as the latter requires much more renewable electricity than the former to provide the same services to buildings (as discussed later in this paper).

[xx] For example, heat pumps can pre-heat water and rooms in winter afternoons when solar generation is abundant, and electric vehicles can be set to charge in overnight hours when wind generation is ample.

In addition, increased electricity demand from building electrification and electric vehicle charging will spread grid upgrade expenses over a much larger sales volume, lowering the cost per unit of electricity for all ratepayers.[46] This is not the case for gas system upgrades to accommodate hydrogen, as the fuel substitution requires significant capital investment but does not lead to a higher sales volume.

Electric appliances utilize clean electricity far more efficiently than their hydrogen-burning counterparts, thus requiring less renewable energy generation capacity.

Energy efficiency means using less energy to perform the same task, thus minimizing energy losses (or waste). When comparing green hydrogen for use as a heating source versus direct electrification, energy-efficient electric equipment and appliances hold an insurmountable advantage over their hydrogen counterparts, which incur significant efficiency losses from electrolysis and combustion.

According to one estimate, it takes approximately five times more wind or solar electricity to heat a home with green hydrogen[47] than it takes to heat the same home with an efficient electric heat pump.[48] More broadly, direct electrification of space heating via heat pumps would use clean electricity three to six times more efficiently than what hydrogen-compatible equipment could deliver.[xxi] Notably, today's heat pumps perform well even in cold climates[49] and are two to four times more energy-efficient than natural gas-burning furnaces.[50] Induction stoves also have efficiency advantages,[51] outperforming gas stoves by about three to one.[xxii]

Due to the greater efficiency of electric appliances, a building decarbonization pathway heavily dependent on the use of green hydrogen would require the buildout of substantially more renewable generation capacity relative to that required for electrification. While high deployment of renewables is a crucial component of any decarbonized energy system, building excessive capacity to support inefficient green hydrogen generation would likely exacerbate existing

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[xxi] Electric heat pumps return roughly 200 to 400 percent of the original clean electricity input in heating value (after netting out transmission losses); in contrast, hydrogen appliances for heating buildings would return about 70 percent in heating value due primarily to energy losses from electrolysis, assuming high appliance efficiency on par with energy-efficient natural gas space heating equipment. Climate Change Committee, *Hydrogen in a Low-Carbon Economy* (November 22, 2018), https://www.theccc.org.uk/publication/hydrogen-in-a-low-carbon-economy/.

[xxii] Although hydrogen-compatible stoves do not yet exist, in theory they would be only 30 percent efficient compared to an induction stove (not accounting for efficiency tradeoffs that may be required to minimize NOx emissions). With induction stoves, up to 90 percent of the electricity consumed is transferred to the food, compared to about 74 percent for traditional electric systems and 40 percent for natural gas. Micah Sweeney, Jeff Dols, Brian Fortenbery, and Frank Sharp, *Induction Cooking Technology Design and Assessment* (2014), https://www.aceee.org/files/proceedings/2014/data/papers/9-702.pdf. If you were to add in the efficiency losses from electrolysis (67 to 75 percent) and use green hydrogen for cooking, then the hydrogen-compatible alternative is a highly inefficient fuel source for cooking.

challenges facing renewables growth, such as currently cumbersome interconnection and permitting processes.[52]

In contrast, an electrification pathway is a more cost-effective strategy for decarbonizing buildings due to lower-cost infrastructure requirements and the more efficient utilization of clean electricity. This finding is underscored by 15 independent studies arriving at a similar conclusion.[53]

Green hydrogen is much more expensive than natural gas and electricity for use in buildings.

At today's costs, blending green hydrogen with natural gas for use in households would increase consumer bills for heating and cooking. While the cost of green hydrogen in the U.S. ranges widely,[xxiii] the fuel is currently 6 to 14 times more expensive than natural gas; even a 20 percent blend of green hydrogen with natural gas could raise the fuel price two to four times more than 100 percent natural gas.[xxiv]

Green hydrogen prices would have to fall by roughly an order of magnitude to achieve parity with the price of natural gas for use in buildings. Put another way, it would need to cost around $0.50 per kilogram to break even by 2030—about half the value McKinsey & Company projects it may cost by 2050 in the most favorable locations for production in the world (such as Chile, the Middle East, and Spain).[xxv]

Alternatively, space heating with electric equipment is associated with lower energy bills than natural gas equipment on average for U.S. consumers.[54] Even in cold-climate states like Alaska, Connecticut, and Minnesota, residents are also likely to save money with electric over natural gas equipment.[xxvi] Total energy bill savings for customers heating with electricity would be even greater compared to the cost of heating with a hydrogen-gas blended fuel.

[xxiii] The three key determinants of the price of green hydrogen are the type of electrolyzer (its cost and efficiency), the cost of renewable electricity used for electrolysis, and the utilization rate of the electrolyzer. The latter two conditions are highly location-dependent (e.g., varying with resource quality and water availability). See Lazard, *Lazard's Levelized Cost of Hydrogen Analysis* (October 2021), https://www.lazard.com/media/451922/lazards-levelized-cost-of-hydrogen-analysis-version-20-vf.pdf (p. 16), for a range of how costs vary under some of these assumptions.

[xxiv] These estimates use the most favorable "natural gas equivalent cost" for green hydrogen from *Lazard's Levelized Cost of Hydrogen Analysis* –a 100 megawatt (MW) alkaline electrolyzer with a high efficiency (70 percent) and very high utilization (98 percent, i.e., nearly running around the clock on renewable electricity), see page 16. These values were compared to the range of annual average Henry Hub natural gas prices since 2009 (i.e., around the time hydraulic fracturing and horizontal drilling became much cheaper as technologies to produce shale gas) as reported by the U.S. Energy Information Administration, "Natural Gas," https://www.eia.gov/dnav/ng/hist/rngwhhdA.htm.

[xxv] See McKinsey & Company & the Hydrogen Council's *Hydrogen Insights* (February 2021), https://hydrogencouncil.com/wp-content/uploads/2021/02/Hydrogen-Insights-2021-Report.pdf, Exhibit 6 (showing cost projections for green hydrogen) and Exhibit 18 (showing projected breakeven costs of hydrogen by end-use).

[xxvi] Additionally, a case study of four cities across the U.S. shows that for new construction, heat pumps are economically favorable compared to natural gas heating and cooling systems. Sherri Billimoria, Leia Guccione, Mike Henchen, and Leah Louis-Prescott, *The Economics of Electrifying Buildings* (2018), https://rmi.org/insight/the-economics-of-electrifying-buildings/.

While electrification offers a more affordable path to decarbonize buildings, policymakers should carefully manage the transition to protect vulnerable consumers and communities.

Any route policymakers choose to decarbonize the building sector must consider impacts on lower- and fixed-income households, small businesses, and rural and underserved communities, lest they bear disproportionately higher energy costs during the transition. As discussed above, a hydrogen-based pathway would likely cost more to create and maintain, fails to address public health and safety issues, and does not secure significant near-term GHG emission reductions. In contrast, building electrification allows for the incremental replacement of gas appliances with more efficient, electric alternatives (and in some cases requiring electrical upgrades), achieving steady emissions reductions using existing technologies as the power system continues to decarbonize.

Despite the lower overall cost of electrification, without direct incentives and financing options for all consumers, households will bear the upfront costs of switching to electric appliances. Without regulatory intervention, those who are last to transition—especially those unable to afford the necessary investments and upgrades—would also likely incur higher natural gas bills as gas utilities spread their remaining fixed costs across fewer customers. Regulators and policymakers will need to proactively manage the transition to all-electric buildings to ensure gas consumers are not stuck with inordinate rate increases. Both options have trade-offs that must be considered, but the uncertainties and higher costs of the hydrogen pathway are more likely to cause hardships for low-income customers.

POWER SECTOR

Hydrogen-fired turbines are not yet commercially available, and the prospect of transitioning natural gas power plants to run on hydrogen might not be feasible and risks stranded costs.

Several electric utilities are proposing new investments in natural gas-fired power generators under the premise that they can gradually decarbonize their power generation assets' fuel via blending with hydrogen, ultimately converting them to run on 100 percent green hydrogen.[55] However, these proposals carry stranded asset risk for ratepayers if utilities or developers can't find cost-effective ways to manage hydrogen's different chemical properties and control the local air pollution from its combustion.

A significant lack of research exists on the feasibility of retrofitting natural gas-fired turbines to accommodate higher hydrogen blends.[56] Retrofitting existing turbines to accept more hydrogen might require replacements and additions for larger fuel delivery systems (for the same power output), new materials less susceptible to embrittlement, tighter seals, updated systems capable of mitigating flashback risk, improved ventilation, and new hazardous gas detection systems.[57]

In addition, hydrogen achieves relatively few CO_2 emission reductions at lower blends while significantly increasing NOx emissions, driving higher local air pollution that disproportionately impacts overburdened communities due to where the plants are typically sited.[58] Hydrogen's lower energy density means a 30 percent hydrogen blend by volume (representative of current utility proposals[59] and existing turbine capabilities[60]) achieves only a 12 percent reduction in CO_2 emissions.[xxvii,61]

Perhaps most importantly, hydrogen's higher flame temperature means a 50-50 blend with natural gas would drive 35 percent higher NOx emissions relative to burning 100 percent natural gas.[62] Compliance with existing or future regulations may require that project owners install larger or more efficient NOx control (selective catalytic reduction) systems or reduce assets' flame temperature (which also reduces their power output and, in turn, their heat efficiency and competitiveness). While turbine manufacturers are exploring new technologies to limit NOx emissions from burning hydrogen,[xxviii,63] they have yet to find viable solutions.[xxix,xxx]

Building new natural gas power plants based on the premise of utilities eventually transitioning them to burn 100 percent green hydrogen may risk these assets being stranded, with such costs flowing to ratepayers or harming utilities' financial position.[xxxi] This may occur if state clean electricity requirements increase before hydrogen retrofits are feasible or cost-effective, or if retrofits can't meet local, state, or federal air pollution standards.

Hydrogen combustion will remain uncompetitive in the power sector until the grid needs long-duration energy storage services. Even then, other emerging technologies could potentially provide such services at lower cost or with less pollution.

While natural gas power plants are often competitive as a baseload capacity resource and for intraday balancing (to manage peak demand), green hydrogen will never be prudent in these roles. Electrolyzing hydrogen and then burning it for power has a round-trip efficiency of anywhere

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[xxvii] A 75 percent hydrogen blend by volume is required to achieve a 50 percent cut in CO_2 emissions. GE, *Hydrogen as a Fuel for Gas Turbines*, https://www.ge.com/content/dam/gepower-new/global/en_US/downloads/gas-new-site/future-of-energy/hydrogen-fuel-for-gas-turbines-gea34979.pdf.

[xxviii] GE is exploring dry low emissions and dry low NOx systems, but these systems face limits in the amount of hydrogen they can handle due to flashback and flame holding risks.

[xxix] One study notes "some flexibility might be needed on NOx limits in the future" if hydrogen combustion is to play a role in the power sector. ETN Global, *Hydrogen Gas Turbines*, https://etn.global/wp-content/uploads/2020/01/ETN-Hydrogen-Gas-Turbines-report.pdf.

[xxx] The New York Department of Environmental Conservation cited several of these technical challenges as part of its grounds for denying a Title V Air Permit to the proposed Danskammer Energy Center–a 536 MW natural gas-fired combined-cycle power generation facility whose application cited the possibility of an eventual transition to burning hydrogen. New York Department of Environmental Conservation, "Notice of Denial of Title V Air Permit, DEC ID: 3-3346-00011/00017, Danskammer Energy Center – Town of Newburgh, Orange County" (October 27, 2021), https://www.dec.ny.gov/docs/administration_pdf/danskammer10272021.pdf (pages 10-11).

[xxxi] If regulators disallow utility cost recovery from ratepayers for a stranded asset, the cost will be borne by shareholders. This could increase the perceived or actual risk of investing in the utility, which could raise the utility's cost of capital for new investments, thus undermining the utility's creditworthiness, impacting its stock value, or resulting in other financial harms.

from 18 to 46 percent.[xxxii,64] Direct use of clean electricity, on the other hand, is a far more efficient way to meet baseload power demand.[xxxiii] Likewise, lithium-ion batteries' efficiency of 80 percent makes them much more competitive for intraday balancing (e.g., charging during afternoon solar peaks and discharging during evening demand peaks),[65] and batteries' responsiveness makes them better suited to manage instantaneous changes in supply or demand.

Numerous studies agree that an 80 percent to 90 percent clean electricity U.S. power grid would be dependable without new "clean firm" or long-duration energy storage assets, and they concur that the most cost-effective, least-regrets investments in the near- and medium-term are renewables and battery storage.[66]

Although hydrogen-fired combustion turbines may be suitable to serve multi-day or seasonal energy storage needs as a means to decarbonize the last 10 percent of electricity generation,[67] many emerging technologies are hoping to compete for this niche. At this point, other long-duration storage technologies such as iron-air batteries,[68] advanced compressed air energy storage,[69] and gravity energy storage systems[70] all claim potentially higher efficiencies, fewer geographic constraints, or less pollution compared to hydrogen.[xxxiv] Hydrogen-fired turbines could come out ahead if developers can solve the NOx pollution challenge, repurpose existing infrastructure, or trade fuel in regional, cross-sectoral marketplaces (as hydrogen has demand in other applications like fertilizer production). The winning technologies will not be known, nor have a market for their services, for many years.

[xxxii] Due to losses incurred via electrolysis, combustion, and (if needed) the combination of compression, storage, and transportation.

[xxxiii] Because of this, proposals to build "hydrogen-capable" combined cycles—which typically are financed on the presumption of running at 30 to 70 percent capacity factors—might not make sense, as green hydrogen will only be competitive for long-duration storage services that might only be needed in roughly 10 percent of all hours. U.S. Energy Information Administration, "Natural Gas Combined-Cycle Plant Use Varies by Region and Age" (May 20, 2021), https://www.eia.gov/todayinenergy/detail.php?id=48036.

[xxxiv] For example, Form Energy claims its iron-air batteries can store energy "at less than 1/10th the cost of lithium-ion battery technology" and be sited anywhere with no emissions. Form Energy, "Enabling a 100% Renewable Grid," https://formenergy.com/technology/battery-technology/. Hydrostor claims its advanced compressed air energy storage systems have roundtrip efficiencies of approximately 60 percent, can be sited "where needed" given its "purpose-built air caverns," and have no emissions. Akshat Rathi, "Storing Energy in Compressed Air Could Finally Become Cheap Enough for the Big Time," *Quartz* (September 19, 2019), https://qz.com/1711536/canadian-startup-hydrostor-is-storing-energy-in-compressed-air; Hydrostor, "Distinctive & Superior Characteristics for Today's Most Difficult Energy Challenges," https://www.hydrostor.ca/why-advancedcompressedairenergystorage/. Energy Vault claims its gravity energy storage systems have a roundtrip efficiency of over 80 percent, can be sited in "most industrial and non-urban or suburban locations," and have no emissions. Energy Vault, "Gravity Energy Storage," https://www.energyvault.com/newsroom/gravity-energy-storage. The authors have no affiliation with these companies, referring to them strictly to illustrate the uncertainty around which technologies may ultimately be best suited to provide long-duration energy storage services.

Given these uncertainties, regulated electric utilities seeking returns on investment on hydrogen using ratepayer funds are asking their customers to bear a higher amount of risk. At any stage in the transition from natural gas to 100 percent green hydrogen for electricity generation, gas turbines might be shuttered—likely at ratepayer expense—due to other technologies undercutting green hydrogen, an inability to meet existing or more stringent NOx standards, or prohibitive retrofit costs.

Stationary fuel cells may provide another avenue for the use of green hydrogen in the power sector, but this use case should not presume the need for hydrogen-capable pipelines.

Fuel cells are a mature technology, capable of accepting a variety of fuels including natural gas and hydrogen to generate electricity, with heat and water as the only byproducts. While fuel cells have a relatively high efficiency in converting gas to electricity (i.e., up to 60 percent for power only[71] and upwards of 85 percent in combined heat and power systems[72]), they still incur additional losses from electrolysis, compression, storage, and transportation when using green hydrogen as their input. Historically, challenges with reducing costs have hindered the commercialization of fuel cells for utility-scale power generation.[xxxv] Instead, their advantage lies in being quiet, modular, and clean (emitting only water vapor), thereby allowing them to be scaled and sited to serve bespoke applications.[xxxvi]

Narrow opportunities may exist to build hydrogen-capable pipelines to serve fuel cells located on key circuits (including microgrids) or at critical facilities[xxxvii] to bolster electric system resilience. However, even these applications may be best served by delivering compressed or liquified hydrogen by truck.[73] The potential benefit of maintaining a few dedicated hydrogen pipelines should not serve as grounds for utilities to blend hydrogen with natural gas or otherwise indiscriminately upgrade the rest of the gas distribution network to accommodate hydrogen or hydrogen-gas blends.

[xxxv] The U.S. Department of Energy states "reducing cost and improving durability are the two most significant challenges to fuel cell commercialization." Fuel Cell Technologies Office, "Fuel Cells" (November 2015), https://www.energy.gov/sites/prod/files/2015/11/f27/fcto_fuel_cells_fact_sheet.pdf.

[xxxvi] For example, a 3 MW fuel cell bank at a hospital could provide zero-carbon emergency backup power with green hydrogen, where a diesel generator (as often used today) would negate climate and air pollution reduction goals. Fuel Cell & Hydrogen Energy Association, *Fuel Cells and Hospital Applications*, https://www.californiahydrogen.org/wp-content/uploads/files/Hospitals.pdf.

[xxxvii] Critical facilities include "hospitals, fire stations, police stations, storage of critical records, and similar facilities." Federal Emergency Management Agency, "Critical Facility" (July 7, 2020), https://www.fema.gov/glossary/critical-facility.

RECOMMENDATIONS

This section offers recommendations to help policymakers evaluate the benefits and risks of hydrogen pathways in buildings, the power sector, and hard-to-decarbonize sectors such as industry.

Utility regulators should exercise skepticism when considering ratepayer-funded proposals to blend hydrogen with natural gas for distribution in pipelines or use in power plants, and they should place a high burden of proof on utilities to demonstrate viability.

Utilities may seek approval for ratepayer-funded hydrogen pilot programs or blending proposals that look promising but quickly face roadblocks when they reach their decarbonization limits. As utilities stand to increase profits through a hydrogen or "clean fuels" investment strategy, they should face a high burden of proof in demonstrating how their actions serve the public interest and achieve relevant climate and clean energy goals.

Plans to blend hydrogen into pipelines or invest heavily in hydrogen-ready infrastructure ought to demonstrate a clear, long-term strategy to achieve full decarbonization[xxxviii] and provide compelling reasons for why hydrogen would be better suited to the use case than competing options like electrification.[xxxix] These burden-of-proof requirements can help protect ratepayers from shouldering the higher costs of hydrogen fuel or of abandoned hydrogen-ready infrastructure.[xl] Any programs pursued, whether ratepayer-funded or not, will require coordination with users to ensure end-use equipment and customer-owned pipes (e.g., inside buildings) are appropriately updated. To the extent such programs proceed, efforts should be made to protect low-income ratepayers from incurring additional and unnecessary costs.

Where ratepayer-funded pilot projects are already underway, regulators should define clear goals and outcomes, as well as metrics for assessing utility learning with specific relevance to the

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[xxxviii] This requirement should hold even if current legislation or regulation requires less-than-full decarbonization. The cost risk to ratepayers is high if hydrogen infrastructure is built out to achieve a 20 percent emission reductions target and then abandoned for other strategies if or when full decarbonization is mandated. Additionally, options such as reducing pipeline leaks and electrifying current uses of gas may be more cost-effective and less risky for meeting these present or interim goals.

[xxxix] Factors for consideration include affordability, safety, public health, and reliability.

[xl] Regulators should apply similar requirements to "clean fuels" pathways. Proposals with regional scope could make persuasive arguments for combinations of hydrogen, biofuels, and CCS; however, when other jurisdictions and industries apply similar decarbonization requirements, biofuel supply and geologic CO_2 storage capacity may face practical limits, raising costs relative to other pathways. Further, since the industrial sector already has hydrogen infrastructure built out for existing uses of carbon-intensive hydrogen, it may be the more appropriate entity to test (and bear the cost of testing) the viability of "blue" hydrogen, as they need only bolt on CCS equipment; until it can reliably achieve high (over 90 percent) capture rates, the technology's poor track record carries high risk for ratepayers.

utility's jurisdiction. More general research is better suited for the federal government and private investors.

Ratepayer-funded pilots should provide meaningful insights and avoid costly dead-ends that delay more substantive action for reducing GHG emissions. For pilots already underway, regulators and their utilities should establish clear goals and outcomes, as well as concrete metrics that outline pilot program success and usefulness to guide a utility in next steps once the pilot is completed.

Pilot proposals for research and development of technologies that stand to benefit utility decarbonization plans, but are considered high risk, should be evaluated based on whether the utility is best positioned to pursue the research, or if another entity is better suited. For example, the U.S. Department of Energy is currently funding substantial research on hydrogen production, delivery, infrastructure, and storage,[74] and is better poised to manage higher-risk technological studies that have scalable impacts on utilities across the country. Similarly, the IIJA has nearly $10 billion earmarked for hydrogen research and development. If a utility wishes to proceed with higher-risk technological pilots or research, regulators should consider options other than ratepayer funding such as federal grants or public-private partnerships, so as not to saddle local utility customers with the costs of nationally relevant research and development.

Regulators should look to proven, least-regrets alternatives to hydrogen that allow electric and gas utilities (and states) to meet their decarbonization targets.

Electric utility plans to support building electrification and deploy renewables and storage, as well as gas utility proposals to identify and seal methane leaks, all pose substantially lower stranded asset risk than green hydrogen. For example, electric heat pumps and induction stoves are mature technologies that leverage existing electric transmission and distribution networks. Outside of electrical panel and distribution network upgrades that also benefit existing electricity uses, each additional electric appliance reduces GHG emissions without locking jurisdictions into technological path-dependency. They are also proven decarbonization strategies as grid emissions continue to fall. These electrification investments represent low-hanging fruit where much progress can be made in the near-term, while longer-term issues, such as how to manage the broader transition of the gas distribution system, are fully considered and addressed thoughtfully.

State policymakers should explore using green hydrogen in the hardest-to-decarbonize sectors of the economy, such as industrial feedstocks, aviation, and marine shipping. Regulated utilities' role in supporting this effort might be best limited to providing clean electricity to these other sectors for electrolysis to produce green hydrogen.

Although green hydrogen is not a "silver bullet" decarbonization solution for all end-uses, it has high value applications where no viable alternatives exist,[xli,75] meaning green hydrogen should be reserved for such applications. For example, there is currently no substitute for hydrogen to produce ammonia for use in chemical fertilizer[76]—responsible for about 2 million metric tons of hydrogen use in the U.S. annually,[77] nearly all of which is supplied via highly polluting processes.[xlii] Hydrogen may also be needed to decarbonize marine shipping and long-distance aviation, either directly or as an input to more dense fuels like ammonia and methanol.

Policymakers designing and implementing economy-wide decarbonization plans may want to create programs or provide funding to assess the viability of green hydrogen for use in these applications. However, decarbonizing these sectors does not require (nor would they benefit from) utilities blending hydrogen into natural gas distribution pipelines or building hydrogen-ready infrastructure to serve homes and businesses.[xliii] Furthermore, production of green hydrogen relies on renewable electricity, which has competing uses, making it inherently more resource-intensive than electrification.

Utility regulators could explore the merits of a utility's proposal to provide renewable electricity to green hydrogen producers for the fuel's use in hard-to-decarbonize sectors. For example, electric utilities could pilot special rates for ammonia producers (that currently use gray hydrogen) to electrolyze green hydrogen using low-cost renewable electricity.[xliv] In doing so, utilities could contract with flexible load industrial customers, which could bring grid benefits for all ratepayers.

[xli] President Biden's Buy Clean Task Force, announced in February 2022, is intended to spur decarbonization of the U.S. industrial sector, in part by replacing natural gas and coal with green hydrogen. Scott Waldman, "Biden Presses Industry, a Climate Laggard, to Decarbonize," *ClimateWire*
(February 15, 2022), https://subscriber.politicopro.com/article/eenews/2022/02/15/biden-to-federal-agencies-think-green-when-you-buy-00008818.

[xlii] Steam methane reforming uses steam–typically generated from burning natural gas–to strip hydrogen from another stream of natural gas. U.S. Department of Energy Hydrogen and Fuel Cell Technologies Office, "Hydrogen Production: Natural Gas Reforming," https://www.energy.gov/eere/fuelcells/hydrogen-production-natural-gas-reforming.

[xliii] Aviation, shipping, and larger industrial facilities all have such high energy demands that may make it more economic to electrolyze green hydrogen on site (or have it transported via an industrial-grade hydrogen-ready pipeline from a nearby hydrogen production facility). In general, industrial facilities may not be capable of handling even low blends (less than 20 percent) of hydrogen without replacing equipment. In the long term, narrow opportunities may exist to build hydrogen-capable pipelines to supply the relatively few industrial facilities served by local distribution companies (which in turn are clustered via municipal zoning requirements) or a targeted network of fuel cells (to back up critical facilities or microgrids); however, these prospects are limited, may circumstantially be better served by transporting compressed or liquified hydrogen by truck, and do not justify building or upgrading a vast pipeline network capable of supplying homes and businesses. U.S. Energy Information Administration, "U.S. Homes and Businesses Receive Natural Gas Mostly from Local Distribution Companies"
(July 31, 2020), https://www.eia.gov/todayinenergy/detail.php?id=44577.

[xliv] Substituting green hydrogen for "gray" hydrogen in existing industrial processes supports a clear decarbonization pathway (making it less risky than hydrogen blending pathways that may be upended by electrification) and has a clear

In conclusion, state utility regulators and policymakers should require a high burden of proof from utilities to demonstrate the value, scalability, cost-effectiveness, and environmental justice impacts of any hydrogen program or proposal. And, given the imperative to decarbonize all sectors of the economy as swiftly as possible, green hydrogen should be reserved for highest value applications for the fuel where no viable alternatives exist.

Notes

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