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Hydrogen: Not a Solution for Gas-Fired Turbines

Billions of Dollars in Needed Infrastructure Investment Would Yield Only Marginal Environmental Benefits

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State regulators and potential project investors need to scrutinize assertions that hydrogen gas will be widely used in methane-fired turbines.

Lack of supply, lack of pipeline infrastructure, and lack of storage capacity will slow and perhaps entirely halt the widespread use of hydrogen as a replacement for methane in turbine generators.

The costs of wind, solar and storage are known today, while the ultimate cost of any "hydrogen-capable" turbine will not be known for years.

Hydrogen-related power projects require significant additional investments that will be extremely costly for ratepayers, may not actually work and will conflict with readily available and cheaper renewable options.

Executive Summary

Electric utilities and project developers have latched on to the “hydrogen-ready” and “hydrogen-capable” tags in describing their plans to build new methane gas-fired (popularly called natural gas-fired) power plants. State regulators and potential project investors need to scrutinize assertions that hydrogen gas will be widely used in methane-fired turbines. IEEFA concludes that these assertions amount to little more than marketing designed to obscure the myriad shortcomings and unanswered questions associated with using hydrogen in methane-fired turbines, particularly regarding the enormous cost and lengthy time that would be required to build out the infrastructure needed for such a transition.

Utilities and merchant developers have announced “hydrogen-ready” projects in at least 18 states in the past several years, running the gamut from technology demonstrations to large-scale commercial developments (see the appendix for the complete list). But the reality is that for at least the next 10 years, any “hydrogen-capable” gas-fired power plant is going to operate almost completely, if not completely, using methane. As such, those projects should be evaluated on that basis—not some hoped-for, potentially less environmentally damaging fuel that is years from broad commercial availability.

Duke Energy’s current effort to secure regulatory approval for two simple cycle combustion turbine projects near its existing Marshall coal plant and a new combined cycle gas turbine (CCGT) at its Roxboro coal plant site is indicative. In its filings about the projects, which would total 2,260 megawatts (MW) of capacity, Duke touts the need to build “hydrogen-capable gas turbines.” But dive into the details of its application, and you find that the utility doesn’t expect to begin using any hydrogen at the new units until 2035—and even then only at the miniscule blending rate beginning at 1% hydrogen/99% methane.[1]

Duke’s projects, and the others being proposed today, are nothing more than traditional gas plants with environmentally friendly verbiage. State regulators and the financial community need to evaluate them on that basis.

In the body of this report, we will examine three key hurdles that will slow and perhaps entirely halt the widespread use of hydrogen as a replacement for methane in turbine generators. These hurdles are:

- **Lack of supply.** The U.S. produces about 10 million tons of hydrogen every year, virtually all of which is consumed in the petrochemical and fertilizer sectors. Any hydrogen blending in the power sector would require new production, and a lot of it. As the table on page 10 shows, just running the 15 largest methane-fired CCGT plants with hydrogen would require doubling current U.S. production and would replace less than 10% of the electricity now generated annually from methane.

[1] Duke Energy. Integrated Resource Plan, Appendix K. August 17, 2023.

- **Lack of pipeline infrastructure**. Getting hydrogen to power plants would require the construction of thousands of miles of new pipelines.
- **Lack of storage capacity**. The gas industry is reliable because of the vast network of underground storage facilities spread around the country; there is no comparable hydrogen storage infrastructure. Building that infrastructure would be costly and time-consuming, with many questions still unanswered regarding the safety of storing hydrogen, particularly in depleted oil and gas fields that account for the bulk of current methane storage.

In evaluating these three massive infrastructure issues, it is essential to keep another key problem in mind: Hydrogen provides only marginal benefits in cutting carbon dioxide (CO_2) emissions until very high levels are blended into the methane, as the graphic below illustrates. At low hydrogen blending levels, the infrastructure costs would vastly outweigh any environmental benefit. At the other extreme, blending high levels of green hydrogen into methane would consume vast amounts of renewable energy that would be better used directly to replace existing fossil fuel generation.

Hydrogen has other environmental problems as well. It produces high levels of nitrogen oxides (NOx) during combustion. This could have a significant impact on local air pollution unless the emissions are controlled, which would require costly controls. Hydrogen also has an indirect impact on climate change that is the subject of continued research. One recent peer-reviewed paper indicated that hydrogen's global warming potential is 11.6 times stronger than CO_2 over a 100-year time frame when accounting for impacts on other gases (compared to 28 times for methane).[2]

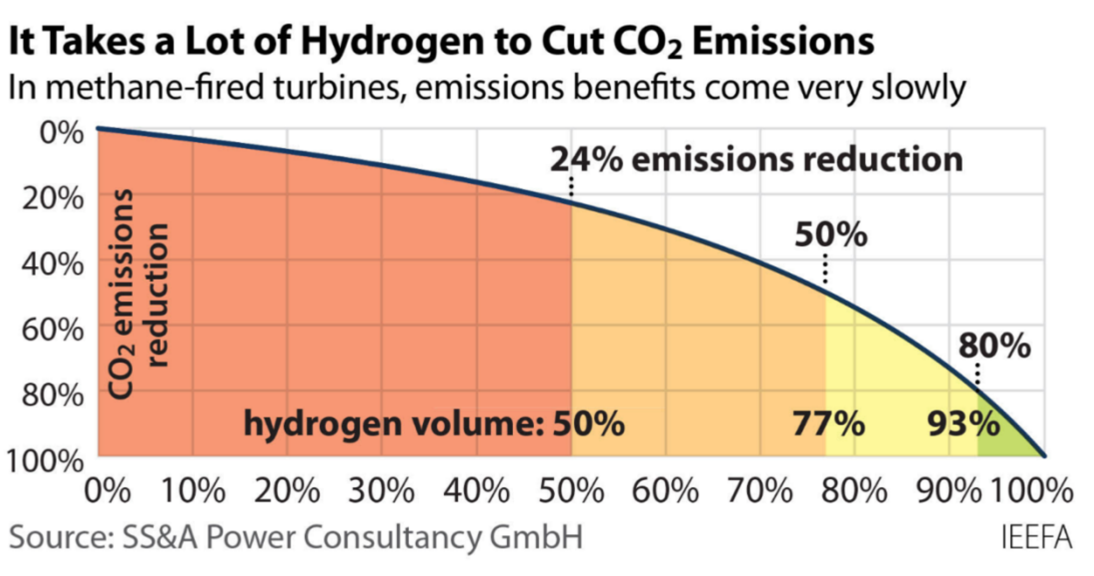
Given the problems associated with using hydrogen in methane-fired power plants, IEEFA has these recommendations for regulators:

- Utilities should be required to pay for any additional costs associated with building "hydrogen-ready" turbines rather than passing those costs to consumers. It is unlikely that hydrogen will play a significant role replacing methane in turbine-fired electricity generation. Capital dollars spent by utilities on hydrogen adaptability now will simply enable them to earn a return on their investment, benefiting their shareholders at the expense of consumers.
- Utilities should be required to disclose potential additional costs associated with any "hydrogen-ready" claims, particularly regarding fuel delivery. What will a dedicated pipeline cost? Can it be permitted? How long will it take to build?
- Utilities should be required to provide details on fuel sourcing. What company will produce the hydrogen? Will it be carbon-free?
- Utilities should be required to complete a full analysis comparing the costs of any hydrogen plans with options involving zero-carbon resources, including efficiency options and virtual power plants, as well as wind, solar and battery storage.

[2] Communications Earth & Environment. A multi-model assessment of the Global Warming Potential of hydrogen. June 7, 2023.

Although aimed at regulators, these questions are equally relevant for the financial community. Funding arranged now will be paying for the construction of a methane-fired power plant, and the risks associated with that decision should be factored into every financing decision.

Figure ES-1: Lots of Carbon-Free Hydrogen Required for Small CO_2 Reductions



Non-Existent Supply

Key Finding: The amount of gas needed is so large that regulators would be wise to dismiss utility claims about "hydrogen-capable" turbines; they would simply be new methane-fired turbines for the foreseeable future.

In 2022, Long Ridge Energy ran tests with a 5% hydrogen blend at its newly commercialized 485MW CCGT in Ohio. By all accounts, the tests (March 30 and April 12) were a success. But they also underscored the yawning gap between the hydrogen hype that has taken hold in many parts of the electric power sector and the cold reality of the current market.

In data filed with the Energy Information Administration (EIA), the company reported that it burned 325,000 cubic feet of hydrogen during the tests, producing 17 megawatt-hours (MWh) of power. According to EIA, the company has not used any hydrogen in the Long Ridge turbine since the 2022 demonstration.

In a subsequent webinar, executives from both Long Ridge and GE, the turbine's manufacturer, were enthusiastic about the test results, but they also acknowledged a couple of key points: It takes an enormous amount of hydrogen even for such a small level of blending because of its lower energy content compared to methane, and the costs associated with purchasing and transporting the hydrogen were significantly higher than anticipated.

Jeff Goldmeer, then the director of emerging technologies at GE, said it would take 100,000 cubic feet of hydrogen per hour to operate the Long Ridge turbine at the planned 5% blend—enough to empty a conventional-sized tube trailer truck.[3] In other words, a plant would need 24 conventional-sized trucks to operate around the clock. "It's one thing to talk about maybe a tube trailer or two," he added, but scaling up would be a big challenge.[4]

Long Ridge had, in fact, planned to supply the hydrogen initially via tube trailers, but Robert Wholey, president of Long Ridge, voiced concerns about it during the webinar. "Transporting hydrogen is expensive. It roughly doubles the cost," he said.[5]

For a company like Long Ridge, which operates in the competitive PJM service territory, those costs matter. Almost 29,000 MW of new combined cycle gas capacity were added in the 13-state region in the past decade, and most of those plants benefit from the same local, low-cost methane supplies that power the Long Ridge facility. Adding the costs of the hydrogen and its associated transportation would put Wholey's company at an economic disadvantage. Judging by the lack of additional hydrogen blending in the last two years, Long Ridge has come to the same conclusion.

[3] GE Power. Hydrogen & Gas Turbines: A Path Towards the Future.
[4] *Ibid.*
[5] GE Power, *op. cit.*

The lack of hydrogen supply has been highlighted in other blending tests. The Electric Power Research Institute (EPRI) wrote that the modifications for a demonstration at Georgia Power's Plant McDonough were done on a temporary basis because of the "lack of available H_2 flowing local that would be required to run the high level of H_2 needed to blend on a continual basis."[6] The test, on one of the six Mitsubishi Power M501G gas turbines at the 2,709MW combined cycle facility, was a success in EPRI's view, showing the turbine's ability to run on a gas blend including 20% hydrogen.

It is important to note that even at a 20% blending level, hydrogen would cut CO_2 emissions by no more than 7% due to its lower energy content—and perhaps significantly less, given new research on pipeline leaks with hydrogen/methane blends and hydrogen's indirect greenhouse gas impacts.

EPRI also reported supply-related difficulties during the 2022 testing on a 45MW GE LM6000 aeroderivative gas turbine at the New York Power Authority's (NYPA) Brentwood power station.[7] One of the lessons learned from the tests on the peaking plant, EPRI wrote, was the difficulty of maintaining a stable hydrogen blend when using tube trailer trucks for supply.

"Ensuring a stable hydrogen supply proved to be a challenge because of constantly adjusting the manual hydrogen regulators located separately on each hydrogen trailer. The team was able to make the system work with significant manual intervention … This would not be practical for normal plant operation."[8]

The institute's concern was echoed by NYPA's Alan Ettlinger, senior director of research, technology development and innovation: "The tremendous amount of hydrogen required was a challenge. This was overcome by spreading the test over a longer period of time so the hydrogen trucks could be replenished."[9]

Even before the testing began, GE's Goldmeer was voicing that same supply concern. GE can produce a turbine that burns hydrogen, many already do, he said. "The question becomes, can you get the hydrogen? Can you supply the hydrogen at the scales and volumes we need to do this?"[10]

For regulators looking at utility proposals for new "hydrogen-capable" gas turbines, supply is a key question. The supply requirements are enormous, and the supply doesn't exist now; indeed, the supply will not be available for the next decade or much longer.

Owners of the Long Ridge facility have said they intend to transition the turbine to 100% hydrogen over time. As we have seen, it has not even started the first step of the process, which was to begin

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[6] EPRI. Taking Gas Turbine Hydrogen Blending To The Next Level. September 2022, p. 6.
[7] Aeroderivative turbines are derived from jet engines. The LM6000 turbine is the same size as a 747 engine.
[8] EPRI. Hydrogen Cofiring Demonstration At New York Power Authority's Brentwood Site: GE LM6000 Gas Turbine. December 2022, p. 3.
[9] Power Magazine. Successful Green Hydrogen Demonstration Project Is A Step Toward A Carbon-Free Future. October 2, 2023.
[10] Public Utility Fortnightly. Green Hydrogen: Neva Espinoza and Jeff Goldmeer. December 2021.

running the turbine with a 25% hydrogen blend. Getting to 100% seems like a distant bet at best, particularly when you calculate the amount of hydrogen that would be required.

For that calculation, we used the amount of gas the plant consumed in 2023, reported to EIA as totaling 24,136,085 thousand cubic feet, or 24.14 billion cubic feet. Using an online tool available through Department of Energy's (DOE) Pacific Northwest National Laboratory, we can convert that methane consumption to hydrogen.[11] To fuel the facility's turbine, which is relatively small but ran at an extremely high capacity factor of 90.7%, would have required about 206,073 metric tons of hydrogen—more than 2% of total U.S. production that year.

To produce that amount of hydrogen cleanly via renewable powered electrolysis would require 10.3 million megawatt-hours (MWh) of electricity—more than 2.5 times the amount of electricity the facility sent to the grid that year.[12] That cannot be considered a sensible trade-off.

Broadening that calculation to the largest U.S. combined cycle gas plants underscores the enormity of the supply problem. There are 19 CCGT power plants in the U.S. with an installed net summer generating capacity of more than 1,500 MW (see table below). Their combined capacity, 37,915 MW, accounts for 12.9% of the total CCGT capacity in the U.S. Their combined generation in 2023 came to 199.5 million MWh, just over 13% of total gas generation.

To convert those 19 plants to run on 100% hydrogen would require almost 12 million metric tons—more than the current annual production in the U.S. In turn, to produce that hydrogen cleanly would take more than 562 million MWh of electricity, or essentially 100% of the 2023 output of the installed utility-scale wind and solar capacity in the United States.

[11] The H2Tools site includes a significant amount of hydrogen-related resource material. The specific calculator used is available here.

[12] It takes about 50 kilowatt-hours of electricity to produce one kilogram of hydrogen, a production factor that is cited frequently in the literature: NREL. Electrolysis: Information and Opportunities for Electric Power Utilities. September 2006, p. 6. Also see: IRENA. Making The Breakthrough: Green hydrogen policies and technology costs. 2021, p. 14. Also see: Siqens. EHS most economical method for hydrogen production. October 4, 2023.

Table 1: Projected Hydrogen Use of Largest U.S. CCGT Plants

Plant Name	Generation (MWh)	Gas Consumption (mmcf)	H_2 Conversion Factor	Hydrogen Required (mt/y)	Hydrogen Required (mt/day)	H_2 Production (mt/y)	Plant Share (%)	Electric Sector Gas Use (Tcf)	Electric Sector Gas Use (mmcf)	Plant Share (%)	Plant Capacity (MW)	Capacity Factor (%)	Heat Rate (Btu/kWh)	CO_2 Emissions (tons)[1]
West County	19,965,749	137,013	8538	1,169,818	3,205	10,000,000	11.70%	12.93	12,930,000	1.06%	3,777	55.5	7,013	7,563,496
Jack McDonough CC	17,824,685	119,582	8538	1,020,995	2,797	10,000,000	10.21%	12.93	12,930,000	0.92%	2,471	75.11	6,920	7,366,519
Sanford CC	7,926,168	56,609	8538	483,329	1,324	10,000,000	4.83%	12.93	12,930,000	0.44%	2,352	38.08	7,306	3,791,178
Martin Combined Cycle	8,446,236	59,800	8538	510,569	1,399	10,000,000	5.11%	12.93	12,930,000	0.46%	2,209	41.26	7,249	4,028,704
Gila River Project	10,204,560	72,313	8538	617,407	1,692	10,000,000	6.17%	12.93	12,930,000	0.56%	2,280	47.2	7,334	4,486,371
Hines Energy Complex	10,951,633	79,180	8538	676,038	1,852	10,000,000	6.76%	12.93	12,930,000	0.61%	2,081	58.18	7,383	5,177,445
Union Power Facility	13,416,477	93,981	8538	802,409	2,198	10,000,000	8.02%	12.93	12,930,000	0.73%	2,012	66.28	7,221	5,526,411
Midland Cogenertion Venture	9,755,681	85,982	8538	734,116	2,011	10,000,000	7.34%	12.93	12,930,000	0.66%	1,846	54.61	7,647	
Franklin Combined Cycle	13,682,165	92,275	8538	787,840	2,158	10,000,000	7.88%	12.93	12,930,000	0.71%	1,902	79.01	6,954	4,874,876
Forney Generating Facility	10,423,121	73,624	8538	628,604	1,722	10,000,000	6.29%	12.93	12,930,000	0.57%	1,770	60.52	7,290	4,023,811
Barry CC	6,894,014	47,468	8538	405,283	1,110	10,000,000	4.05%	12.93	12,930,000	0.37%	1,862	41.42	7,012	3,464,236
Guernsey[2]	8,154,972	49,613	8538	423,598	1,161	10,000,000	4.24%	12.93	12,930,000	0.38%	1,875	49.65	6,488	
Fort Myers	9,436,566	66,748	8538	569,893	1,561	10,000,000	5.70%	12.93	12,930,000	0.52%	1,801	59.8	7,224	4,231,951
Crystal River CC (Citrus County)	12,257,187	81,491	8538	695,766	1,906	10,000,000	6.96%	12.93	12,930,000	0.63%	1,610	75.47	6,833	4,590,605
H.L. Culbreath Bayside	6,091,198	44,464	8538	379,634	1,040	10,000,000	3.80%	12.93	12,930,000	0.34%	1,630	37.81	7,460	3,230,555
Okeechobee Clean Energy Center	11,370,324	69,974	8538	597,437	1,637	10,000,000	5.97%	12.93	12,930,000	0.54%	1,723	75.33	6,322	3,551,440
Greensville Power Station	10,286,001	64,670	8538	552,149	1,513	10,000,000	5.52%	12.93	12,930,000	0.50%	1,585	68.67	6,502	4,286,145
Midlothian Energy Project	5,230,004	39,402	8538	336,411	922	10,000,000	3.36%	12.93	12,930,000	0.30%	1,605	35.43	7,533	2,278,595
Panda Temple Facility	7,236,365	50,991	8538	435,361	1,193	10,000,000	4.35%	12.93	12,930,000	0.39%	1,524	52.42	7,115	3,245,822
Top 19 CCGTs (>1500 MW)	**199,553,106**	**1,385,179**	**8538**	**11,826,658**	**32,402**	**10,000,000**	**118.27%**	**12.93**	**12,930,000**	**10.71%**	**37,915**			**75,718,160**

[1] CO_2 emissions data is from 2022.

[2] Guernsey did not begin commercial operation until Feb. 2023.

*Notes: Gas to hydrogen conversion formula is: gas consumption (mmcf) * 8538 = hydrogen (kg)*

S&P data presents annual gas use in mcf terms. For example, the West County plant combusted 137,013,163 mcf of gas in 2023. To use the H_2 conversion tool, this was converted to mmcf and the resulting hydrogen figure (expressed in kg) was converted to metric tons by dividing by 1,000.

Capacity figures are net summer capability (S&P).

Total installed CCGT capacity at yearend 2023 was 292,741 MW (EIA EPM).

Capacity of these 19 plants amounts to 12.9% of CCGT total (EIA EPM).

Total CCGT electric generation was 1,509,718 thousand MWh in 2023 (EIA EPM).

Generation from these 19 plants accounted for just 13.2% of CCGT total (EIA EPM).

This supply problem has been acknowledged by many of the same utilities touting their new projects as "hydrogen-capable."

Duke, which is racing forward with plans for new gas-fired generation in North and South Carolina using the "hydrogen-capable" label, is a prime example. It is proposing to build two large gas plants at existing coal facilities in North Carolina: a 1,360MW combined cycle facility at the Roxboro plant and 900 MW of combustion turbines at the Marshall site. These units, which the utility hopes to have online by early 2029, are touted in the utility's public pronouncements and regulatory filings as "hydrogen-capable."

They may be capable, but the reality is they won't use any hydrogen for years, if ever.

In its latest integrated resource plan (IRP), Duke said it didn't expect any hydrogen use on its system until 2035, when it estimated that it could begin using 1% hydrogen. This would increase marginally to 3% by 2041 and then remain flat until 2050.[13] So, for the first 20-plus years of the plants' operation, they would be burning almost 100% methane with its associated CO_2 emissions and upstream pipeline leaks.[14]

Duke is far from the only utility or developer latching onto the "hydrogen-capable" marketing mantra. Kindle Energy, a private equity-owned power developer, is building a 730MW CCGT in Louisiana that it says will be able to burn a blend of up to 50% hydrogen in its GE-designed turbine. Capable maybe, but regulatory filings tell a different story.

Kindle's main customer is the 1803 Electric Cooperative, which was formed to buy power for five distribution co-ops in the state. It has signed a 20-year power purchase agreement (PPA) with Kindle for 409 MW of the Magnolia plant's output. Testimony before the Louisiana Public Service Commission shows that the co-op isn't committed to purchasing and burning hydrogen.

"The Magnolia Agreement does not obligate 1803 to agree to burn hydrogen in the future, nor pay for any hydrogen fuel or infrastructure costs in the future or make any commitment to burning hydrogen at the Magnolia facility. It is an option that provides flexibility and potential future environmental benefits if such become attractive for economics, reliability, or environmental considerations," wrote Brian Hobbs, a consultant with Pain, Garland and Hobbs LLP, on behalf of 1803.[15]

In another filing, 1803 wrote: "The Magnolia Power plant will be constructed with the ability to utilize hydrogen. However, at this time, hydrogen is not a cost-effective or readily available fuel source in the area. If and when hydrogen becomes a cost-effective fuel source, or state or federal mandates provide incentives to use hydrogen as a fuel source, then 1803 and the other off takers may determine whether

[13] Duke Energy, *op. cit.*, p. 8.
[14] Assuming the hydrogen is generated from renewable energy, a 10% H_2 – 90% methane blend would only reduce CO_2 emissions by about 3.4%. A 3% blend might result in a 1% reduction.
[15] Louisiana Public Service Commission. In re: Application Cooperative, of Power Inc. of 1803 for Electric Approval Purchase and for Cost Agreements Recovery. September 24, 2021.

the expense of installing hydrogen fuel handling facilities necessary to use hydrogen as a fuel source is economic at that time."[16]

So, 1803 isn't interested. Further, Kindle will be marketing the rest of the plant's output in the southern zone of the Midcontinent Independent System Operator (MISO) market, putting it head-to-head with other gas-fired generation. That makes the still-undetermined expense required to secure the fuel and transport it to the plant even more problematic, regardless of the rhetoric.

[16] Louisiana Public Service Commission. Docket No. U-35927, p. 13.

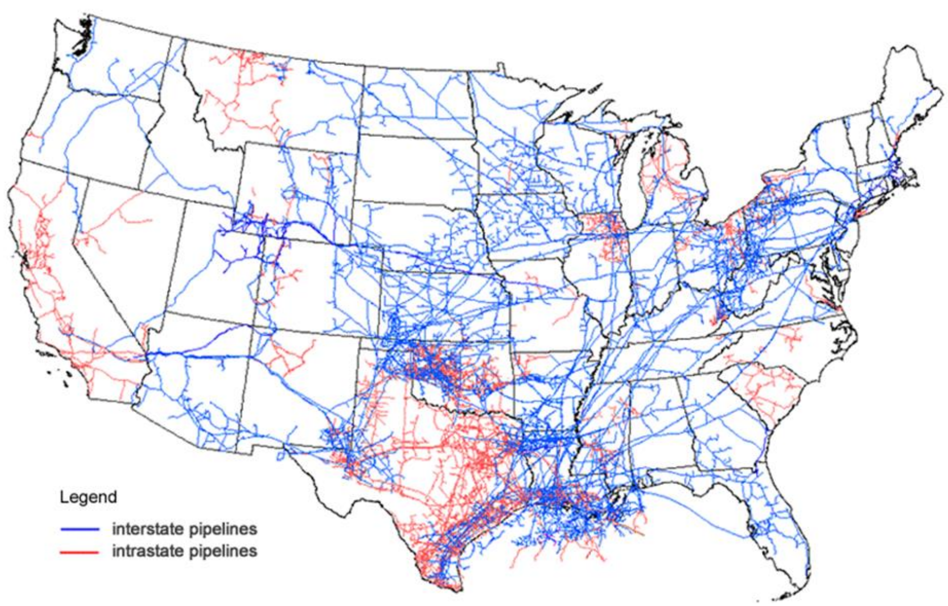
Non-Existent Pipeline Network

Key Finding: No pipeline network exists to distribute the fuel to the "hydrogen-capable" turbine generators being proposed in the U.S. Building such a network would take years and cost billions of dollars. The time and effort required for this network buildout would slow the transition from fossil fuels.

The problem identified by the 1803 project—that hydrogen is not a readily available fuel source in the area—is nationwide in scope. And even if sufficient hydrogen were available, there would be no way to transport it where needed. A look at the existing gas and hydrogen pipeline networks illustrates the problem.

The U.S. has a sprawling natural gas pipeline network, with approximately 305,000 miles of inter- and intrastate transmission lines, plus more than 2.2 million miles of smaller distribution lines.[17] In contrast, there are only roughly 1,600 miles of hydrogen-dedicated pipelines in the U.S. Virtually all the existing infrastructure is concentrated in Texas and Louisiana.[18]

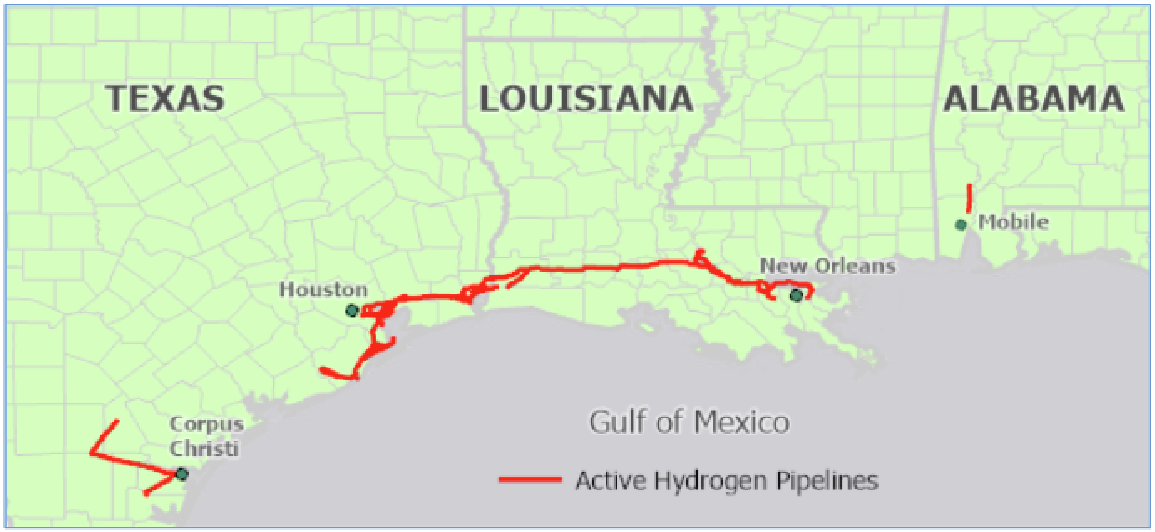
Figure 1: Inter- and Intrastate Methane Pipeline Network



Source: DOE.

[17] U.S. Department of Energy. Alternative Fuels Data Center. Accessed June 4, 2024.
[18] Congressional Research Service. Pipeline Transportation of Hydrogen: Regulation, Research and Policy. March 2, 2021, p. 5.

Figure 2: U.S. Gulf Coast Hydrogen Pipeline Network



Source: CRS using data from Texas Railroad Commission, Public GIS Viewer, 2020, https://www.rrc.state.tx.us/about-us/resource-center/research/gis-viewers/; PHMSA, National Pipeline Mapping System, Public Map Viewer, 2020, https://pvnpms.phmsa.dot.gov/PublicViewer/; PHMSA, Gas Transmission and Gathering Annual, online database, 2020, https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids; and Esri Data and Map, 2019.

Notes: The map includes pipelines designated by PHMSA as carrying hydrogen, "other gas" including hydrogen, and synthetic gas known from company references to include high hydrogen concentration. The Texas and Louisiana pipelines do not comprise a single, integrated system, but rather, several systems owned by different companies with limited interconnections. Pipeline locations are approximate.

Source: Congressional Research Service.

Using the Existing Gas Infrastructure

Blending?

Blending hydrogen into existing methane pipelines has been proposed as a possible alternative. But current research has raised more questions than answers about the technical and safety implications of introducing hydrogen into the existing system.

The materials science is beyond the scope of this analysis, but a layperson's summary of the problem is that introducing hydrogen into methane gas pipelines will weaken the steel, potentially leading to cracks, leaks and complete failure. This has been highlighted numerous times by the DOE and independent researchers over the last several years:

- A 2022 literature review by the DOE's National Renewable Energy Laboratory summarized it as follows: "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."[19]

- A researcher from the DOE's Sandia National Laboratory told a 2022 webinar sponsored by the department's Hydrogen and Fuel Cells Technology Office that the lab's research showed "that even small fractions of hydrogen can have very substantial effects on the fracture resistance of the material, which has important implications for structural integrity. And even less than one atmosphere, one bar of hydrogen, can have very substantial effects on the fracture resistance, reducing the fracture resistance by more than 50 percent."[20]

- A Congressional Research Service (CRS) report in 2021 noted that, "The presence of hydrogen can deteriorate steel pipe, pipe welds, valves and fittings through a variety of mechanisms. In particular, atomic (unpaired) hydrogen can diffuse into the material and cause 'hydrogen embrittlement,' which can lead to cracking, blistering and weakness under tension. These effects can lead to acute pipeline failure ..."[21]

Another broader point was highlighted by NREL in its 2022 review. The lab pointed out that most of the research to date has been on steels and welds manufactured since 1990, but more than half of the currently operating pipelines were installed before the 1970s.[22] That is a problem, the lab said: "This vintage steel line pipe may contain higher quantities of defects due to initial lower manufacturing quality and inherent wear from operation … The material qualities of these vintage pipes and their response to hydrogen environments introduce considerable operational uncertainty and safety risks."[23]

A complete list of the issues identified by NREL that are involved with blending hydrogen into the methane gas pipeline network are presented in the following table.[24]

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[19] National Renewable Energy Laboratory. Hydrogen Blending into Natural Gas Pipeline Infrastructure: Review of the State of Technology. National Renewable Energy Laboratory. October 2022, p. 8.
[20] U.S. Department of Energy. DOE Hydrogen and Fuel Cells Technology Office webinar. April 15, 2022.
[21] CRS, *op. cit.*, p. 3.
[22] NREL, *op. cit.*, p. 43.
[23] *Ibid.*, p. 43.
[24] NREL, *op. cit.*, p. 10.

Figure 3: Challenges With Blending Hydrogen Into Gas Pipelines

Challenges With Hydrogen Blending	Natural Gas Pipeline System Section Impacted
Enhanced fatigue crack growth in pipeline steel	Transmission and distribution networks
Reduced fracture resistance in pipeline steel	Transmission and distribution networks
Reduced energy transmission capacity	Transmission and distribution networks
Increased pressure drop when meeting energy demand	Transmission and distribution networks
Increased gas velocities	Transmission and distribution networks
Increased required compression power	Transmission networks
Increased centrifugal compressor rotational speed	Transmission networks
Shifted centrifugal compressor operating envelope	Transmission networks
Increased NO_x emissions for prime movers and end users	Transmission and distribution networks
Excessive combustion dynamics, flame lift-off, flashback	Transmission and distribution networks
Fuel pre-ignition in internal combustion engines	Transmission networks
Meter accuracy and durability	Transmission and distribution networks
Valve leakage and durability	Transmission and distribution networks
Gas composition analysis accuracy	Transmission and distribution networks
Hydrogen leakage in polymer piping	Distribution networks
Biochemical hydrogen conversion in underground storage	Transmission networks
Hydrogen loss through cap rock in underground storage	Transmission networks

Source: NREL.

In addition to these safety concerns, blending would not significantly reduce greenhouse gas emissions. Standard calculations have demonstrated that a blend of 20% hydrogen and 80% methane, which is seen as the upper limit for blending, would only result in a 7% reduction in CO_2 equivalent (CO_2e) emissions, and that's assuming the hydrogen is produced from 100% renewable energy and pipeline leaks are minimal.[25] New research shows the emissions reductions may not even be that high.

Scientists from Argonne National Laboratory reported in a 2023 webinar that even a blend of 30% hydrogen likely would only achieve a 6% decline in greenhouse gas emissions, due to the significant increase in energy use for compression power required to push through enough of the blended gas to account for hydrogen's significantly lower volumetric energy density and pipeline-related leaks.[26] The Argonne analysis also does not include any estimate of the environmental impact of hydrogen leakage, meaning it overstates the total emissions reductions since hydrogen is an indirect greenhouse gas that has a higher global warming potential than CO_2.[27]

[25] Paul Martin, LinkedIn. Why Hydrogen Blending Into the Gas Network is Bollocks. Posted December 17, 2023, Updated April 27, 2024.
[26] U.S. Department of Energy. H2IQHour webinar. October 26, 2023, p. 38.
[27] U.S. Department of Energy, *op. cit.*, p. 39. Also see: Nature. A multi-model assessment of the Global Warming Potential of hydrogen. June 7, 2023.

Dedicated H_2 Pipelines

Conversions and New Construction

If blending is not a viable option, that leaves just one alternative—dedicated hydrogen transportation either by converting existing methane pipelines to distribute hydrogen or building entirely new hydrogen infrastructure. Both options have serious drawbacks.

Existing natural gas pipelines can technically be converted to carry 100 percent hydrogen, but they raise the same safety questions as blending—hydrogen and steel don't really get along. "Pipeline conversion typically would involve measures such as modifying compressors, valves, seals, meters and other components; replacing pipeline segments or reworking welds with compatible materials; modifying leak detection systems and installing new controls to monitor and manage hydrogen flows,'' CRS pointed out.[28]

Safety issues are of concern as well, particularly related to the conversion or retrofit of pipelines that are 30 or more years old. Professor Milos Djukic, a hydrogen expert at the University of Belgrade, made that point in a 2022 webinar: "It is widely believed that existing gas pipelines that are retrofitted for transportation of natural gas-H_2, CH_4-H_2 and N_2-H_2 gas mixtures, and repurposed for 100% H_2 transport, are viable options and safe for long term future usage. However, despite the fact that gaseous H_2 transport via existing gas pipelines is a low-cost option for delivering large volumes of H_2, **there is a serious threat of hydrogen damage and catastrophic failure, particularly for old-aged gas pipelines, after future long-term H service.**" [emphasis in original][29]

But the key limiting factor in using converted gas pipelines is likely to be hydrogen's lower volumetric energy density. In theory, this could be compensated for by increasing the operating pressure of the pipeline. Because of hydrogen's documented impact on the material integrity of steel, however, operating pressure will likely have to be lowered to comply with regulations set out by the American Society of Mechanical Engineers.[30]

The issue is straightforward, according to Paul Martin, a chemical engineer with a long history in the hydrogen sector: "Can they be re-used at their existing design pressure and hence at their existing energy carrying capacity? The answer to that is almost certainly NO. At bare minimum, de-rating of the design pressure would be required, likely to a significant extent. This would necessitate either twinning the line with new pipe to carry the same amount of energy, replacing the existing pipe, or accepting the reduced capacity."[31]

Michael Liebreich, founder of BloombergNEF and creator of the hydrogen ladder—which lists power generation using non-stored hydrogen as the least competitive use of the resource—is equally direct: "As for pipelines, the gas industry is promising that they can repurpose existing pipelines, but by the

[28] CRS, *op. cit.*, p. 7.
[29] Hydrogen Embrittlement and Material Selection. Sept. 21, 2022. Webinar accessed via YouTube.
[30] NREL, *op. cit.*, p 14.
[31] Paul Martin, LinkedIn. Are German Gas Pipelines "Fundamentally Suitable" for Carrying Hydrogen? April 5, 2023.

time you account for hydrogen's extremely low density, the reduction in pressure required to avoid embrittlement and the increase in power requirement for big new compressors, their energy carrying capacity could easily be reduced by 75%. Most hydrogen pipelines will be purpose-built, and it is hard to see any commissioned this side of 2030."[32,33]

That leaves the new construction option. Little information is available about the potential cost of building a large-scale hydrogen pipeline distribution system, but the DOE has acknowledged that the capital costs associated with new construction are a major barrier to future infrastructure expansion.[34]

The cost overruns and permitting fights that have entangled recent proposals for CO_2 and methane pipelines are a good proxy, and they show clearly that it would be both extremely costly and time-consuming to build new hydrogen infrastructure in the U.S.

The Mountain Valley Pipeline was first announced in 2014 by EQT, a leading U.S. gas producer, and NextEra Energy, the Florida-based utility holding company. The 330-mile-long pipeline, which will transport gas from West Virginia to Virginia, was initially supposed to cost $3.5 billion and be in commercial operation by the end of 2018.[35, 36] The pipeline finally entered commercial service in June; its cost skyrocketed to $7.85 billion.[37]

Similar slowdowns and cost increases have hit Summit Carbon Solutions' planned CO_2 pipeline in the Midwest. The 2,000-mile-long pipeline would run from Iowa to North Dakota, with feeder lines collecting CO_2 from ethanol production facilities in those two states, plus Nebraska, South Dakota and Minnesota. The CO_2 would be sequestered in North Dakota. The project, dubbed the Midwest Carbon Express, was proposed in 2021 and was supposed to be operational in the first half of 2024. A company study from April 2022 estimated that the total construction cost would be $3.7 billion.[38] Projected costs have climbed steadily since: By late 2022, estimated costs had risen to $4.5 billion; in June 2023 they hit $5.5 billion; and by May 2024, the projected cost had soared to $8 billion—and construction has still not begun.[39,40,41]

Facing the same public opposition and regulatory uncertainty that has slowed Summit, Navigator CO_2 Ventures canceled its Heartland Greenway project in October 2023. Their project would have run the other direction from the planned Summit line, beginning in South Dakota and collecting CO_2 from ethanol plants there and in Nebraska, Minnesota, Iowa and Illinois before sequestering the gas in

[32] Hydrogen Ladder Version 5.0. Accessed June 15, 2024.
[33] BloombergNEF. Liebreich: Clean Hydrogen's Missing Trillions. December 13, 2023.
[34] U.S. Department of Energy. Hydrogen Pipelines. Accessed June 10, 2024.
[35] EQT. EQT and NextEra Energy Announce Southeast Pipeline Project. June 12, 2014.
[36] Dow Jones. Mountain Valley Pipeline Cost Now Estimated at $7.85 Billion – OPIS. April 30, 2024.
[37] *Ibid.*
[38] Summit Carbon Solutions. New Study Shows Summit Carbon Solutions Will Drive Economic Growth Across the Midwest. April 19, 2022.
[39] Summit Carbon Solutions. Big Elk Energy Systems Partners with Summit Carbon Solutions on $4.5 Billion Private Clean Energy Investment Project. November 3, 2022.
[40] Governing. Midwest Officials Debate Cost, Benefits of Pipeline Plans. June 21, 2023.
[41] North Dakota Monitor. Summit says power supply, blackouts not a concern for pipeline. May 28, 2024.

southern Illinois. The planned 1,300-mile-long pipeline had been forecast to cost $3.2 billion when it was proposed and be completed by 2025.[42]

Plans for large interstate hydrogen pipelines almost certainly would face the same public opposition, regulatory uncertainty, construction delays and cost increases. In turn, this would raise costs for the "hydrogen-capable" turbines being touted across the country. Utilities and developers say their projects will be able to burn hydrogen immediately once their projects are online, but those pledges are being made without cost analyses or the certainty that any hydrogen, green or otherwise, will even be available. Utility regulators need to require those in-depth cost calculations and fuel availability analyses to weigh whether the hydrogen marketing claims will actually have any ratepayer benefits. We do not believe they will.

Non-Existent Storage Resources

Key Finding: The key to the smooth operation of the U.S. gas network is the system's significant amount of storage capacity, which exceeds 4,600 billion cubic feet, or more than 100 days, of estimated summer gas consumption by the electric power sector.[43, 44] In contrast, only three underground salt cavern hydrogen storage facilities operate in the U.S. (all in Texas), with the capacity to store 0.013 million metric tons of hydrogen, which amounts to 0.1% of current demand.[45] Expanding that capacity would be costly and time-consuming.

The national laboratories and other groups are conducting research on the possibility of storing hydrogen underground in four different types of geologic areas: Depleted oil and gas fields; salt caverns; saline aquifers; and hard rock and other caverns. The U.S. has 672 underground methane gas storage facilities, and 74% are depleted oil and gas fields that account for 80% of the stored working gas.[46]

All the potential storage options have risks and cost questions that require additional research, DOE has found. For depleted underground oil and gas fields, the key concern is potential hydrogen leakage through legacy wells that are not properly sealed. This is a particular concern, DOE said, because "the properties of H_2 gas increase its potential for leakage through impaired wells."[47]

The best-known case of leakage from underground gas storage is the massive Aliso Canyon accident in 2015. It released an estimated 1,300 metric tons of methane into the atmosphere daily for more than

[42] Pipeline & Gas Journal. Navigator to Submit Expanded Proposal for 1,300-Mile Carbone Pipeline Project. February 16. 2023.
[43] EIA. Underground Natural Gas Working Storage Capacity. April 30, 2024.
[44] EIA. Our U.S. summer natural gas consumption forecast for electric power matches 2023 record. May 30, 2024.
[45] Geophysical Research Letters. Characterizing Hydrogen Storage Potential in U.S. Underground Gas Storage Facilities. February 10, 2023, p. 6.
[46] U.S. Department of Energy. Subsurface Hydrogen and Natural Gas Storage: State of Knowledge and Research Recommendations Report. April 2022, p. 10.
[47] U.S. Department of Energy, *op. cit.*, p. 42. The properties cited by DOE include hydrogen's lower molecular weight, density and viscosity, all of which "increase its mobility in the subsurface."

three months.[48] The cause of the leak ultimately was linked to a well installed in 1953 and then repurposed for storage operations in 1973.

DOE noted significant implications for using depleted fields for hydrogen storage: "Currently, most available depleted fields were produced between 1929 and 1958. If H_2/CH_4 [CH_4 is the symbol for methane] storage operations are conducted in depleted oil and gas reservoirs, older wells with outdated designs will pose a significant leakage risk."[49]

Other DOE concerns include:

- The risk of steel embrittlement and subsequent cracking and potential failures (like the above-ground pipeline blending risks discussed earlier).
- The risk that the materials now used for seals and fittings in methane gas storage facilities will not work with hydrogen: "Hydrogen permeation into these seal elements may increase their rate of degradation and result in failure over shorter time scales than typically observed in NG storage wells."[50]
- The risk that the public will not embrace hydrogen storage, a problem that has clearly slowed/halted the buildout of CO_2 and methane gas pipelines in recent years.

DOE concluded that it is clear that "significant technological advancements are needed" before underground hydrogen storage can grow substantially.[51] For regulators and investors, this is another bright red warning sign. The "hydrogen-capable" turbines being proposed today are unlikely to be anything more than green-branded methane gas generation facilities, given the massive infrastructure buildout that would be required to enable such a methane-to-hydrogen transition.

And if it's ever built, the cost of that infrastructure would certainly run into the billions of dollars and ultimately would be paid by customers. Regulators should not be approving supposedly emissions-free "hydrogen-capable" gas turbines today as if they are the least-cost option when compared to renewables and battery storage. The costs of wind, solar and storage are known today, while the ultimate cost of any "hydrogen-capable" turbine will not be known for years.

[48] U.S. Department of Energy, *op. cit.*, p. 44.
[49] *Ibid.*
[50] U.S. Department of Energy, *op. cit.*, p. 49.
[51] U.S. Department of Energy, *op. cit.*, p. 65.

Hydrogen's Other Problems

The unbuilt infrastructure is clearly the key stumbling block for large-scale use of hydrogen in the power sector. But there are several other concerns that bear mentioning in the discussion about hydrogen's suitability as a transition fuel. These include:[52]

- Flame flashback, which can cause significant damage to turbine combustors.
- It is more flammable and easier to ignite, making fires from leakage a much greater hazard than comparable methane leaks.
- Higher nitrogen oxides (NOx) emissions, particularly at high percentage levels of hydrogen. GE estimates that NOx emissions could double when a turbine is operating at or near 100% hydrogen. Controlling these emissions would require larger or more efficient selective catalytic reduction (SCR) equipment or a plant derate, GE said. Both options would be costly, either in additional capital investments or lower generation, cutting into sales.
- Reduced component lifetime compared to conventional methane gas turbines due to greater moisture content in the exhaust.
- The expected need for new combustors at hydrogen levels above 75%, which would require significant new capital investment for the current generation of proposed "hydrogen-capable" turbines in the future.

One of the more interesting problems facing hydrogen adoption in the power sector was flagged in a 2023 report by the Clean Air Task Force. Essentially all the hydrogen produced worldwide is spoken for; there isn't enough supply to conduct thorough testing of high percentage hydrogen blends (or full hydrogen operation) in new turbines.

"The commercialization timelines for high hydrogen turbines will depend on the availability of hydrogen to validate turbines at full scale and their ability to meet performance, emissions and operability requirements. Lack of adequate hydrogen supply will extend these timelines," the task force observed.[53]

[52] These problems were drawn from DO, national lab and industry reports. See: NETL. Hydrogen Safety Review for Gas Turbines, SOFC and High Temperature Hydrogen Production. March 30, 2023. Also see: U.S. Department of Energy. Department of Energy Hydrogen Program Plan. November 2020. Also see: GE. Hydrogen for power generation. March 2022.
[53] CATF. Emissions and performance Implications of Hydrogen Fuel in Heavy Duty Gas Turbines. June 2023, p 3.

The fuel availability issue will be of particular importance as turbine developers roll out machines designed to operate on hydrogen concentrations of 50% and higher, the authors continued. This will require showing that the whole system, not just individual components, can handle real-world operating requirements. "Absent sufficient hydrogen supply to complete acceptance testing, it will be difficult to move forward with the next phases of technology development for higher hydrogen blends."[54]

[54] CATF, *op. cit.*, p. 45.

Hydrogen and Long-Duration Storage

A Possible Application

The ACES Project

Hydrogen is not a feasible option for widespread use in the power sector, and regulators need to question every “hydrogen-capable” turbine proposal that comes before them. There is, however, one area where hydrogen may be useful as a fuel source for methane-fired turbines: As a long-term storage resource.

An early version of this option is being developed in Utah at the Intermountain Power Project, now called the Advanced Clean Energy Storage Hub, or ACES. The project is backed by Mitsubishi Power and Chevron. According to company documents, the project will include:

- 220 MW of alkaline electrolysis capacity comprised of 40 5.5MW units from HydrogenPro, a Norwegian electrolyzer developer. These were delivered to the site in October 2023.
- Two Mitsubishi M501JAC turbines operating as an 840MW combined cycle plant that will be capable of combusting 30% hydrogen upon commercialization, now scheduled for 2025. The turbines were delivered to the site in August 2023.
- Two adjacent underground salt caverns. They are designed to store enough hydrogen to generate 300 GWh of electricity.

It is a tidy package designed to use renewable energy to produce green hydrogen, which can then be used directly or stored.

But there are still plenty of questions. In particular, where will the renewable energy come from that will be used to run the electrolyzers?

Company officials have said the project would use a variety of sources to supply the renewable energy, pointing to the possibility of using surplus green energy from California to power the electrolyzers.[55, 56]

But there are problems with that plan. California solar production has jumped this year, but the amount available for export is limited. According to data from Grid Status, even in June when the days are at their longest, surplus energy from the California ISO seldom tops 220 MW for more than 10 hours at a time, leaving many hours of supply unaccounted for.

[55] Power Magazine. MHPS Secures First Order for Hydrogen-Capable J-Series Gas Turbines. May 10, 2020.
[56] Power Magazine. ACES Delta’s Hydrogen Electrolyzers Arrive in Big Boost for Hub’s Progress. October 26, 2023.

Some have suggested ramping electrolyzers up and down to match this availability, but a growing amount of research shows that this has a significant negative impact on performance and longevity. A meta-review of 130 studies concluded: “Quantitative studies incorporating intermittent profiles from renewable energies have shown that the average efficiency of electrolyzers is lower than under steady nominal conditions. There is unanimous agreement among studies that variations in temperature and electrical load strongly impact efficiency, gas purity and durability.”[57]

This reduction in performance will obviously raise the fuel’s cost and worsen its economic competitiveness.

The project also seems to be trying to do two conflicting things at the same time. The current plant, a two-unit, 1,800MW coal facility, has generated an average of 6.4 million MWh annually for the past five years. The gas turbines are being installed to replace that capacity while meeting the environmental goals of the facility’s largest customer, the Los Angeles Department of Water and Power, which are first to get out of coal, and then to be CO_2 emissions-free. To generate a similar amount of power, the new CCGT would have to operate with an annual capacity factor of more than 85%.

According to the electrolyzer developer, each of its 5.5MW units can produce 100kg of hydrogen per hour or 2.4 tons per day.[58] Together, the 40 units could produce 96 tons of hydrogen daily. As we saw in the first section, it almost certainly will require much more hydrogen than that to come anywhere near the planned 30% blending level. So little if any of the hydrogen will be stored, undercutting the project’s touted long-term/seasonal storage capability.

[57] International Journal of Hydrogen Energy. Impacts of intermittency on low-temperature electrolysis technologies: A comprehensive review. June 12, 2024, p. 14.
[58] HydrogenPro. Integrated Report 2022, p. 6.

Conclusion

Hydrogen is not the solution for decarbonizing the U.S. power grid. It would require a costly and time-consuming buildout of new production, transportation and storage capacity that largely misses the point. The tools are available now to move toward a largely decarbonized grid, a point made, perhaps inadvertently, by Southern Company in its comments on the Environmental Protection Agency's proposed power plant greenhouse gas rules: "Furthermore, deploying the gigawatts of clean generating resources that are necessary to produce the amount of low-GHG hydrogen … that would be needed to support base load hydrogen-based generation would largely negate the need for those resources."[59]

Precisely. Regulators and financiers should re-read that sentence. Utilities and developers are tying proposals for new methane gas-fired power plants to some far-off future when these new resources might be converted to run on hydrogen. That is not likely.

In the interim, many of these same companies are also promising that their new projects will blend in hydrogen to cut CO_2 emissions. Here too, Southern has the right take: "Blending hydrogen is not an efficient way of reducing CO_2 emissions."[60] As we have seen, small amounts of hydrogen blending yield almost zero emissions benefits. By the time significant benefits do emerge, roughly when the hydrogen level reaches 50%, significant turbine modifications are required, and the infrastructure issues discussed above come roaring into play.

Hydrogen may have a limited role in long-term storage, but even that is not certain with the development of better battery technologies and the promise of other alternatives such as enhanced geothermal.

Utility regulators need to take a hard look at hydrogen-related power projects. They will require significant additional investments in the future that will be extremely costly for ratepayers, may not actually work and will conflict with readily available and cheaper wind, solar and battery storage options.

The Department of Energy should also take a second look at its hydrogen promotion plans. The guiding principle of its multibillion-dollar effort to build a hydrogen economy is to focus on hard to decarbonize sectors that lack clean alternatives and avoid "competing with alternative low-cost and efficient decarbonization technologies ..."[61] Producing hydrogen to blend with methane and then combust in a turbine to generate electricity fails that test.

[59] Southern Company. EPA docket EPA-HQ-OAR-2023-0072-0001. August 8, 2023, p. 34.
[60] Southern Company, *op. cit.*, p. 32.
[61] Department of Energy. DOE National Clean Hydrogen Strategy and Roadmap. September 2022, p. 40.

Appendix A

Table A-1: Current U.S. "Hydrogen-Capable" Turbine Projects

Project/Plant Name	Developer	State	Size (MW)	Turbine Type	Turbine Manufacturer/Model	Initial Blend (%)	Cost ($M)	Proposal Date	Test or Date of Operation	Status
Demonstrations/Pilots										
Crickett Valley Energy Center	Advanced Power, JERA	NY		GT	GE 7F.05	5		2021	2022	Demonstration complete
A.J. Mihm	WEC Energy	MI	18	Reciprocating	Wartsila	Up to 25			2023	Demonstration complete
Eight Flags Energy CHP	Chesapeake Utilities	FL	21	CT	Solar Turbines	4			2022	Demonstration complete
Brentwood	NYPA	NY	45	Aero	GE LM6000 SAC	5 to 44			2022	Demonstration complete
Hillabee	Constellation	AL	753	CCGT	Siemens SGT6-6000G	38			2023	Demonstration complete
Plant McDonough	Georgia Power	GA	265	GT	Mitsubishi M501G	20			2022	Demonstration complete
Long Ridge Energy Terminal	New Fortress Energy	OH	485	CCGT	GE 7HA.02	Up to 20			2022	Demonstration complete
Operating										
Plant Barry	Alabama Power	AL	727	CCGT	Mitsubishi J-Class				2023	Operating
Cavendish Hub	FP&L	FL	377	CT	GE 7HA.02	5	65	2022	2024	Operating
DeBary	Duke	FL	83	GT	GE 7E	100		2023	2024	
Newman East	El Paso Electric	NM	228	CT	Mitsubishi M501GAC	30	211	2021		Operating
Linden Cogen	JERA Americas	NJ	160	GT	GE 7F.04	Up to 40		2021	2023	Operating
New Builds/Conversions										
Magnolia Power Project	Kindle Energy	LA	725	CCGT	GE 7HA.03	Up to 50	750		2025	Under construction
Orange County	Entergy	TX	1200	CCGT	Mitsubishi M501JAC	30	1500		2026	Under construction
Intermountain	LADWP	UT	840	CCGT	Mitsubishi M501JAC	30	1000		2025	Under construction
Grand River Energy Center	Grand River Dam Authority	OK		GT	Mitsubishi M501JAC			2023	2026	Construction slated to begin in 2024
Legend	Entergy	TX	745	CCGT				2024		Proposed under new Texas Energy Fund
Lone Star	Entergy	TX	453	CT				2024		Proposed under new Texas Energy Fund
Spenser	Engie	TX	483	Peaker				2024		Proposed under new Texas Energy Fund
Chesterfield	Dominion	VA	1000	CT		10		2023	2027	Air permit filed
	Evergy	MO	2500					2024	2029-2032	Proposed in 2024 IRP
	Xcel	MN	800	CT						Pending approval from state regulators
Heartland Hydrogen Hub	Xcel	MN								
Nemadji Trail Energy Center	Minnesota Power	WI	625	CCGT		Up to 30				Proposal includes "the potential to burn hydrogen"
Lincoln Land Energy Center	EmberClear	IL	1277	CCGT	Siemens	30	1400		2027	Company says construction could begin this year
Marshall	Duke Energy	NC	900	CT				2023-2024	2029	Included in company's updated IRP
Roxboro	Duke Energy	NC	1360	CCGT				2023-2024	2029	Included in company's updated IRP
	Oklahoma Gas & Electric	OK	727	CT				2024	2028	IRP includes "hydrogen capable" turbines
	Austin Energy	TX		CCGT		Up to 80			2035	Part of city's pending new resource plan
Cadiz/Harrison	EmberClear	OH	1084	CCGT	Mitsubishi M501JAC		1000			Project no longer listed on the company's website
	Wisconsin Electric	WI	1,200	CT	GE 7FA.05				2027-2028	Planning for hydrogen ready turbines
Bayonne Energy Center	Morgan Stanley	NJ	60	CT			150	2022	2025	Announced

Cancelled										
Cadiz/Harrison	EmberClear	OH	1084	CCGT	Mitsubishi M501JAC		1000			Project no longer listed on company website
Danskammer Energy Center	Tiger Partners	NY	600	CCGT	Mitsubishi M501JAC	30	400	2019	-	Company withdrew project in June 2024
Chickahominy	Balico	VA	1600	CCGT	Mitsubishi M501JAC	30			-	Canceled

Note: Data is current as of July 2024; details such as project name, turbine supplier and so forth are blank when that information has not yet been announced by the develop.

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