RECOMMENDATIONS FOR A US NORTHEAST HYDROGEN HUB

By Joseph Webster
The Global Energy Center promotes energy security by working alongside government, industry, civil society, and public stakeholders to devise pragmatic solutions to the geopolitical, sustainability, and economic challenges of the changing global energy landscape.

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Executive Summary

The hydrogen future appears to be in sight. Russia’s invasion of Ukraine and the Inflation Reduction Act (IRA) have turbocharged investments in renewables and green hydrogen, and, potentially, served as tipping points in the energy transition. While hydrogen supply chains remain in their infancy and are subject to geopolitical risks, the energy sector appears poised to begin developing green hydrogen at scale, both domestically and internationally. To spur domestic hydrogen production, the US Department of Energy is awarding $8 billion to at least four hydrogen hubs across the United States. This paper will address the opportunities and challenges associated with a potential hydrogen hub in the northeastern United States, defined as Connecticut, Maine, Massachusetts, New Jersey, New York, and Rhode Island.

The northeast hydrogen hub enjoys several critical advantages and hydrogen-enabling conditions. Due to excellent offshore wind resources and substantial political support for clean energy, the northeastern hub states have set goals of collectively installing more than thirty-five gigawatts (GW) of offshore wind (OSW) generation capacity by 2035. Having become the nation’s leader in offshore wind development, the region is poised to leverage these resources to produce hydrogen. In addition, the region is in dire need of solutions that could limit electricity prices, as the northeast has some of the nation’s highest electricity prices, particularly during winter peak-demand periods. Hydrogen’s interseasonal storage capabilities could dampen regional electricity prices by shifting electrons generated from off-peak seasons to peak winter demand. A regional hydrogen-supportive supply chain is emerging, as the northeast possesses an electrolyzer industry and is developing several offshore wind ports. Moreover, the region enjoys a variety of use cases for hydrogen deployment, including blending in existing natural gas pipelines; desulfurization in refineries; industrial uses, such as steel and cement; and, potentially, over the long term, maritime transport. Finally, the region’s world-class education system offers a unique—if potentially undervalued—advantage in the hydrogen race. The northeast is one of the world’s leaders in producing science, technology, engineering, and mathematics (STEM) graduates, enabling it to research, develop, and quickly absorb new technologies—including hydrogen.

While the northeast’s prospective hydrogen has key advantages, it must also overcome several challenges. Green hydrogen may be most suitable for the northeast, but the region’s onshore wind and solar resources that could power hydrogen production are constrained by unfavorable geography; offshore wind projects in the Atlantic Ocean could face scheduling setbacks; and New York’s Great Lakes OSW potential might never reach fruition. Hydrogen demand also faces uncertainties over what percentage of hydrogen can be blended into existing natural gas infrastructure. Finally, there are unresolved questions in the hydrogen regional midstream economy surrounding regional storage, hydrogen pipeline blending vs dedicated pipelines, and cast-iron pipelines.

The report recommends that northeastern policymakers consider the following steps.

- **Support and accelerate clean energy production.** Additional offshore wind—and nuclear energy—capacity is crucial to maximizing local green hydrogen production. The region cannot produce blue hydrogen indigenously, while importing green hydrogen at scale from maritime sources will prove infeasible for years, probably more than a decade. The region is supporting Atlantic Ocean OSW through procurement contracts and infrastructure build-out, but it should also consider expanding Great Lakes OSW and nuclear energy capacity, to the greatest extent feasible.

- **Nimbly adapt policy to meet changes in hydrogen technology.** Policymakers must navigate uncertainty surrounding hydrogen technology. Hydrogen demand studies should consider blending mandates. While any mandates should start at low initial levels, it may be appropriate to escalate the acceptable level of hydrogen throughput, depending on the results of hydrogen blending studies. For instance, if blending studies find that existing natural gas infrastructure can safely and reliably accommodate a high percentage of hydrogen throughput, policymakers will need to act accordingly. Striking a balance amid uncertainty will admittedly be difficult. Regional policymakers and decision-makers should follow H₂ blending in natural gas pipeline studies very closely, and adjust their governmental or corporate strategies as conditions dictate. With even cautious studies suggesting that blending percentages of 5 percent are safe, and with clean hydrogen likely reaching cost parity with grey hydrogen due to provisions in the Inflation Reduction Act, policymakers should consider blending mandates. While any mandates should start at low initial levels, it may be appropriate to escalate the acceptable level of hydrogen throughput, depending on the results of H₂ blending studies.

- **Prepare the region’s infrastructure for the hydrogen economy.** Regardless of the results of hydrogen blending studies, regional policymakers must replace existing iron-cast pipelines with all possible haste. These pipes are not recommended for transporting hydrogen, and are highly not to emit methane even in existing pipeline systems. The region may also need to develop ammonia-related infrastructure for maritime shipping, but that is a more distant concern.

I. Hydrogen Basics: Energy Properties and H2Hubs

Hydrogen could economically decarbonize industrial applications at scale, and set the world on a pathway to net-zero emissions. While hydrogen fuel is currently produced via natural gas and coal, new technologies could enable hydrogen production from solar, onshore and offshore wind, nuclear power, and natural gas with carbon storage.

Hydrogen has several advantages over other fuels due to its chemical properties. Hydrogen is abundant, can be sourced from water, and emits only water vapor and heat. It can be repurposed for synfuel or electricity. Finally, hydrogen can be produced locally, close to demand centers—or even co-sited with end-users—whereas oil, natural gas, and coal typically require extensive transmission and distribution networks to reach final demand.

The two most common methods for producing hydrogen are steam methane reforming, or SMR, and electrolysis, which splits water via electricity. The SMR production technique is utilized by coal and natural gas producers, uses high-temperature steam to react with methane, and produces hydrogen, carbon monoxide, and carbon dioxide. Electrolysis, on the other hand, uses electricity to split hydrogen from water; it does not produce any byproduct other than hydrogen and oxygen. Electricity can be supplied from any renewable or fossil-fuel source. In addition to SMR and electrolysis, there are other methods of hydrogen production, including biomass and microbial techniques, and efforts that use solar to split hydrogen from water. These techniques, however, are in their infancy.

The Department of Energy’s Hydrogen Hub Program

US President Joe Biden signed H.R. 3684—Infrastructure Investment and Jobs Act, or IIJA, into law on November 15, 2021. The IIJA established several key features of the Department of Energy’s Regional Clean Hydrogen Hub program (abbreviated to Hydrogen Hub or H2Hub throughout this document) and provided funding of $8 billion for this purpose. The IIJA defined a Hydrogen Hub expansively, saying that “the term ‘regional clean hydrogen hub’ means a network of clean hydrogen producers, potential clean hydrogen consumers, and connective infrastructure located in close proximity.”

In order to satisfy regional diversity requirements, the Department of Energy (DOE) letter of intent specified there will be at least four hydrogen hubs across the country. The DOE appears to have identified nine potential regional clusters, including the Great Lakes, New England, Appalachia, the Gulf Coast, Alaska and Hawaii, the Southwest, California, the Pacific Northwest, and the Central United States. This report will discuss the path forward for the potential Northeast Hydrogen Hub, which comprises the states of Connecticut, Massachusetts, New York, New Jersey, and Rhode Island.

Colors of Hydrogen and the Northeast

Hydrogen is often divided into different “colors,” with each color describing the underlying energy source or raw material used in production. While hydrogen combustion emits only water, carbon intensities and the economics of different hydrogen production processes vary considerably, even dramatically.

Some policymakers and industry leaders seek to move away from using colors to describe hydrogen, with some advocating an emphasis on “carbon, not color.” Indeed, the recent IIJA and IRA elevate hydrogen production method’s carbon intensity. In the IRA, clean hydrogen is eligible for a production tax credit (PTC) if the lifecycle greenhouse-gas (GHG) impact is less than four kilograms of carbon-dioxide emissions (CO2) per kilogram of hydrogen produced, with payouts rising inversely to emissions. Therefore, the largest PTC for hydrogen accesses to projects that enjoy a lifecycle GHG impact of less than 1.5 kilograms of CO2. While brown and grey hydrogen will not be eligible for the PTC, blue, green, and, potentially, turquoise hydrogen will enjoy various levels of access to the PTC.

Hydrogen derived from coal, referred to as brown hydrogen, accounts for 19 percent of world hydrogen production. If “byproduct hydrogen,” or hydrogen produced in facilities (such as refineries) designed for other products, is excluded, brown hydrogen’s share of pure hydrogen demand would rise to about 24 percent. According to the International Energy Agency (IEA), brown hydrogen production used one hundred and fifteen megatons of coal equivalent in 2020, accounting for 2 percent of global coal demand. Among hydrogen colors, brown produces the most pollution and consumes predominately from China.

Hydrogen derived from natural gas produced without any associated carbon capture, and accounted for the bulk (59 percent) of 2020 total hydrogen production. If byproduct hydrogen is excluded, grey hydrogen accounts for about 74 percent of pure hydrogen production. Grey hydrogen is not as polluting as brown hydrogen, but still produces approximately 9.2 kilograms of CO2 per kilogram of hydrogen.

Like grey hydrogen, blue hydrogen is produced from natural gas, but with an important exception: emissions are captured via carbon capture, utilization, and storage (CCUS). The blue hydrogen decarbonization debate is highly contentious, with some estimates suggesting that total carbon-dioxide-equivalent emissions for blue hydrogen are only 9–12 percent lower than grey hydrogen; other studies have found that overall CO2 capture rates vary between 50–90 percent. Although blue hydrogen is being closely examined in several natural gas-producing regions—such as Texas, Pennsylvania, and West Virginia—the method of production supplied less than 1 percent of the world’s total and pure hydrogen production in 2020. Blue hydrogen faces severe challenges in the northeastern hydrogen hub region; there is virtually no indigenous natural gas production, while CCUS geologic storage locations are limited.

The northeast’s lack of natural gas production will almost certainly prevent it from becoming a significant producer of blue hydrogen. In 2020, the last year for which full data are available, the entire region produced only 0.03 billion cubic feet per day (BCF) of natural gas, or about 0.002 BCF of natural gas withdrawn from wells. Moreover, the Empire State appears to be in no position to increase production, as the state banned hydraulic fracturing as part of its fiscal year 2021 budget. If the northeast region ever consumes blue hydrogen, it will almost certainly need to import by the fuel. The Marcellus basin states, especially Pennsylvania and West Virginia, are prolific producers of natural gas and...
may be able to ship blue hydrogen to the northeast, if hydro-
gen-dedicated pipelines can overcome permitting chal-
lenges. Similarly, the northeastern hub states could conceiv-
ably import blue hydrogen from international sources.

Nuclear power can produce hydrogen by powering the elec-
trolysis of water, which splits water into oxygen and hydro-
gen. This process, which produces pink hydrogen, is theo-
retically possible and releases virtually no carbon emissions.
Still, nuclear power’s contribution to northeastern hydro-
production may be limited by several factors. Nuclear power
plants tend to run at nearly full capacity. Accordingly, there
is relatively little room for nuclear plants to increase through-
put to power new production processes, such as hydro-
gen, without diverting generation from the grid. Moreover,
because nuclear power plants provide baseload energy for
the grid, it will be difficult for grid operators to divert electrons
without potentially compromising grid resiliency. Still, there
is an emerging discussion about “flexible” nuclear power
plants.19 If nuclear power can become more flexible, pink
hydrogen production could become more prevalent over
time during periods of renewable “overgeneration,” or curtail-
ment. Given the very low penetration of renewables on the
northeastern grid, however, local pink hydrogen production
is not expected to play a major role in regional H₂ produc-
tion for the foreseeable future, barring a dramatic expansion
of nuclear power generation capacity, renewables, or both.

Turquoise hydrogen, also referred to as “methane pyrolysis,”
uses electricity to split natural gas feedstocks into hydrogen
and solid carbon; the process is considered to fall between
blue and green hydrogen in terms of carbon intensity. Unlike
blue hydrogen, however, it does not require underground
carbon capture and storage (CCS) or carbon capture, utiliza-
tion, and storage (CCUS), and produces a solid carbon prod-
uct that can be used for other markets and manufacturing.
Furthermore, it can displace carbon-intensive processes that
produce solid carbon, such as coal used to produce carbon
black/graphene products. While turquoise hydrogen has yet
to be proven at scale, Monolith Materials received a $1-bil-
lion loan from the US Department of Energy’s Loan Program
Office, suggesting that the technology could become more
viable in future years.20

Finally, green hydrogen refers to the production of hydro-
gen via water electrolysis powered by renewables sources,
such as solar, wind, and hydropower. Although green hydro-
gen releases virtually no carbon emissions, it is also relatively
expensive to produce.21

The economics of green hydrogen production, however,
may be shifting rapidly. One estimate from the Independent
Commodity Intelligence Services, a market-data provider,
suggested that green hydrogen is cheaper than grey hydro-
gen in Europe amid record-setting natural gas prices spurred
by Russia’s invasion of Ukraine.22 Rapid price changes are
not confined to the continent, however, as US legislation has
dramatically altered the economics of green hydrogen.

Green hydrogen is on the rise. As part of the IRA, a clean
hydrogen credit, called 45V, will offer up to $3 per kilogram
in tax credits for producers on the basis of lifecycle green-
house gas emissions, as well as the producers’ compliance
with prevailing wage and apprenticeship requirements. It is
critical to note the significant policy shift this legislation
will bring. Green hydrogen will almost certainly be at the heart
of a northeast hydrogen hub. A post-IRA anal-
ysis by the Rhodium Group found that US green hydrogen
prices will fall to between $0.4–2 per kilogram by 2030, ver-
sus a “conventional hydrogen” price range of $0.99–$1.54
per kilogram.23 With that level of support, green hydrogen
can be expected to outcompete grey hydrogen in many key
locations and contexts.

Some analysts believe that green hydrogen will dominate
compared to blue hydrogen, particularly over the long term,
as the underlying renewables generation becomes cheaper
due to greater efficiency and policy support from the IRA.
One consultancy claimed in a May 2021 report that green
hydrogen will outcompete blue hydrogen “everywhere”
by 2030—and this was before Russia’s invasion of Ukraine
drove up world gas prices, and before the passage of incen-
tives in the IRA altered hydrogen economics.24 While geopo-
litical tensions present substantial and potentially underap-
preciated risks to renewable supply chains, green hydrogen
is rising a wave of favorable policy and economic trends.
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II. Northeast Green Hydrogen Production Fundamentals

Given renewables’ importance for green hydrogen, northeast electricity fundamentals will prove immensely important for a future regional hydrogen hub. Over the long term, the region’s ability to expand clean energy generation could determine its hydrogen future.

According to the US Energy Information Administration, existing renewables generation capacity in the six northeastern states of Connecticut, Massachusetts, Maine, New Jersey, New York, and Rhode Island stood at approximately 13.2 gigawatts (GW) in July 2022, out of an existing 86 GW of existing generation capacity.27 Hydropower accounted for 5.8 GW of total renewables capacity, utility-scale solar capacity stood at 4.0 GW, and onshore wind turbines added approximately another 3.4 GW.28 The six states also have an additional 9.2 GW of clean energy capacity via nuclear energy. There are no planned nuclear plant closures, according to the EIA.29 While the region is rapidly emerging as the nation’s leader in offshore wind, it has only one operating offshore wind turbine, Rhode Island’s Block Island Wind.

The region’s existing clean energy capacity pales in comparison to its operating fossil fuel generation capacity. The northeast has approximately 35.5 GW of natural gas combined cycle generation capacity, while lower-utilization plants, such as steam turbines and combustion turbines, account for another 20.5 GW of capacity.30 More surprisingly, at least for individuals outside of the region, petroleum-liquids capacity stands at 81 GW, as consumers and businesses in the northeast rely on fuel oil for heating in the winter.31 There are still two coal plants operating in New Jersey, with approximately 0.5 GW of capacity, although the Chambers and Logan coal-fired power plants are expected to close within the next five years.32 While New Hampshire is not currently in the northeastern hydrogen hub, it also has about 0.5 GW of existing coal capacity at the Merrimack plant.33

Unsurprisingly, the region’s electricity mix is dominated by natural gas, which accounted for half of all generation within the New York/New Jersey/Massachusetts/Connecticut/Rhode Island/Maine region.34 Still, clean generation (nuclear, hydropower, wind, and solar) reached 45 percent of all regional electricity generation in the same year.35 The region has nearly phased out coal, which accounted for less than 1 percent of electricity generation in 2021.36 As seen in Figure 1, however, wind and solar comprise only a small portion of the region’s electricity mix.

The northeast region’s generation mix has shifted over time, as clean energy production has actually fallen due to the closure of regional nuclear plants, including New Jersey’s Oyster Creek plant, the Pilgrim Nuclear Power Station in Massachusetts, and the Indian Point 2 and Indian Point 3 generating units in New York. Coal generation (included in the “other” category below) has also fallen steeply. While solar and wind generation continue to grow very rapidly, they are nevertheless starting from a very low base.

Figure 1: Northeastern Regional Electricity Generation by Fuel Source, 2021

The northeast region's generation mix has shifted over time, as clean energy production has actually fallen due to the closure of regional nuclear plants, including New Jersey’s Oyster Creek plant, the Pilgrim Nuclear Power Station in Massachusetts, and the Indian Point 2 and Indian Point 3 generating units in New York. Coal generation (included in the “other” category below) has also fallen steeply. While solar and wind generation continue to grow very rapidly, they are nevertheless starting from a very low base.

27 Preliminary Monthly Electric Generator Inventory (Based on Form EIA-860m as a Supplement to Form EIA-860), US Energy Information Administration, August 24, 2022. https://www.eia.gov/electricity/data/eia860m/.
28 Ibid.
29 Ibid.
30 Ibid.
31 Ibid.
32 Ibid.
33 Ibid.
35 Ibid.
36 Ibid.
The region’s geography will make it difficult to add new onshore wind and solar to the grid. Indeed, the EIA interconnection queue suggests that fewer than 8 GW of new renewables generation capacity will be added to the northeastern grid by 2029, versus total existing generation capacity of about 86 GW.

There are several caveats to the above estimate. First, there is considerable uncertainty around the EIA’s planned incremental renewable capacity additions: not every plant will open, of course, but additional incremental projects could come online. Second, estimates of offshore wind’s future generation capacity are subject to wide confidence intervals. Offshore wind (OSW) projects could face delays; alternatively, however, the region could conceivably enjoy double-digit gigawatt OSW generation capacity by 2030. Finally, the Inflation Reduction Act has dramatically altered the economics of new renewables sources and will likely lead, et ceteris paribus, to significant increases in renewables generation capacity.

The northeast will require significant new indigenous renewables generation capacity for green hydrogen production. Most incremental northeastern renewables generation will likely consist of offshore wind—primarily in the Atlantic Ocean, but potentially in the Great Lakes as well.
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Regional Electric Prices

The northeastern hydrogen states pay some of the highest retail electricity prices in the nation, creating opportunities for renewables development and hydrogen. All states in the hub program paid at least $1.34 per kilowatt hour in 2021, the most recent data available from the EIA, placing them in the eleven most expensive states. Moreover, two other northeastern states—New Hampshire and Vermont—also suffer from elevated electricity prices. In 2020, eight of the eleven most expensive state retail electricity markets were in the United States' northeast.

Figure 4: Average Electricity Retail Price, by State

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<tr>
<th>State</th>
<th>Average Retail Price, 2020 (Cents/KWh)</th>
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<tbody>
<tr>
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Not only does the region's high levelized cost of electricity ($105–$120 per megawatt-hour), but also the potential of cold winters and seasonal electricity spreads may render hydrogen an economic source for inter-seasonal storage. As seen in the chart below, the northeast's frigid weather often produces winter price spikes.

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Offshore Wind Capacity: the Atlantic Ocean

The northeast region is arguably the nation's leader in offshore wind. Rhode Island's 30-megawatt (MW) Block Island Wind Farm became the United States' first operating commercial offshore wind farm in December 2016. Nearly six years later, the US Bureau of Ocean Energy Management closed a record-breaking sale of $4.37 billion for six leases along the coasts of New York and New Jersey. This lease sale, by itself, could ultimately provide between 3.6–7.0 GW of offshore wind capacity. New York is also launching its third offshore wind solicitation, which could provide an additional 2 GW of capacity.

The region has set ambitious offshore wind targets. New York's Climate Leadership and Community Protection Act calls for the development of 9 GW of offshore wind energy by 2035. Massachusetts' Bill H 5060 authorizes OSW nameplate capacity procurements of 5.6 GW by June 2027. Connecticut's Public Act No. 19-71 mandated procurement of 2 GW of offshore wind by 2030, and New Jersey has set a goal of reaching 7.5 GW of OSW generation capacity by 2035.43 While ends must be matched with means, the region's ambitions and, importantly, predictable procurement programs are sending positive signals to renewables and green hydrogen market actors, helping to solve the "chicken-and-egg" problem of creating new supply chains from scratch.

The northeast is also making significant strides in building out regional offshore wind supply chains, particularly port infrastructure. The New Jersey Wind Port is the first purpose-built offshore wind port in the United States. New York's South Brooklyn Marine Terminal is a private and public sector partnership between Equinor, BP, Sustainable South Brooklyn Marine Terminal (SSBMT), and the New York City Economic Development Corporation (NYCEDC), and Massachusetts is investing $100 million in the development of three offshore wind ports.44

The region's offshore wind complex is arguably more advanced than that of any other region. The region's offshore wind port system is progressing rapidly; there is an emerging OSW labor ecosystem, and policymakers have demonstrated their seriousness in establishing the region's offshore wind capabilities.

Offshore Wind Capacity: the Great Lakes

The Great Lakes could present significant, long-term opportunities for northeastern renewables and hydrogen production. Initial estimates suggest that the potential of offshore wind generation capacity of the Great Lakes (Superior, Michigan, Huron, Erie, and Ontario) could theoretically total 700 GW, or about one-fifth of the United States' total offshore potential.45

While there has been tangible progress on the Great Lakes, NYSERDA is conducting a Great Lakes Wind Feasibility Study, suggesting that northeastern policymakers are engaged on the issue.46 There are also signs of increasing amounts of commercial interest in the Great Lakes project region. Icebreaker, a proposed 21-megawatt, $127 million offshore wind plant in Lake Erie, has survived a court challenge in the Ohio Supreme Court.47

In addition to court challenges and standard "not-in-my-backyard" problems, Great Lakes OSW faces other development hurdles. According to preliminary findings from NYSERDA, locks on the St. Lawrence Seaway limit vessel sizes, and Federal Aviation Administration (FAA) regulations may restrict offshore wind capabilities.

49. Ibid.
Hydrogen’s long-duration storage capabilities could dampen the region’s winter price spikes by shifting electricity generated in the summer or the shoulder seasons to the winter, when demand is highest. It’s also worth noting that the region may be able to ameliorate winter pricing peaks by improving transmission connectivity to Canadian hydropower.

In addition to potentially reducing winter pricing peaks, hydrogen deployment from long-duration storage could also significantly reduce carbon emissions. Some of the region’s most polluting hydrocarbon-generation sources, such as coal, are replaced with hydrogen; there is no consensus on what percentage of coal, fuel oil, and natural gas from liquefied natural gas (LNG), most polluting hydrocarbon-generation sources, such as coal, fuel oil, and natural gas from liquefied natural gas (LNG), may be able to ameliorate winter pricing peaks by improving transmission connectivity to Canadian hydropower.

Electric Choice found that Rhode Island, New York, Maine, Massachusetts, and Connecticut residents suffered, respectively, the second, third, fourth, fifth, and eighth highest electricity bills as a percentage of salary in the nation.52 Given that individuals with lower incomes are disproportionately affected by rising electricity prices, particularly during the winter, inter-seasonal supply-demand balancing via long-duration hydrogen storage could benefit individuals with lower incomes and historically underserved communities.

Green Hydrogen, Equity, and Energy Insecurity

While the northeastern states are relatively wealthy, they also suffer from some of the highest residential electricity bills in the country, increasing energy insecurity among the region’s poorest residents. Using data from the EIA’s latest publicly available “Residential Energy Consumption Survey,” Electric Choice found that Rhode Island, New York, Maine, Massachusetts, and Connecticut residents suffered, respectively, the second, third, fourth, fifth, and eighth highest electricity bills as a percentage of salary in the nation.52

To put that in perspective, the US natural gas pipeline network represents a fraction of household income spent on electricity in the Northeast, with the highest percentages in Rhode Island, New York, Maine, Massachusetts, and Connecticut, respectively. While the northeastern states are relatively wealthy, they also suffer from some of the highest residential electricity bills as a percentage of salary in the nation.52 Given that individuals with lower incomes are disproportionately affected by rising electricity prices, particularly during the winter, inter-seasonal supply-demand balancing via long-duration hydrogen storage could benefit individuals with lower incomes and historically underserved communities.52

Blending Hydrogen in Natural Gas Pipelines

If hydrogen can be safely blended in existing natural gas pipelines, it could be a game changer for US climate goals—and the northeast hydrogen hub. There are about 1600 miles of existing, hydrogen-dedicated pipelines across the United States.53 To put that in perspective, the US natural gas pipeline system, including mainlines and other pipelines, comprises three million miles.54 Repurposing even a fraction of the existing natural gas pipeline network for hydrogen safety, reliably, and economically would, therefore, accelerate US economic, security, and climate objectives.

Blending hydrogen in existing natural gas infrastructure could significantly reduce US GHG emissions. In 2020, US CO₂ emissions from natural gas totaled 1,647 million metric tons.55 It is, as seems likely, at least 2–5 percent of natural gas-related emissions can be eliminated by substituting hydrogen for natural gas in existing pipelines, and assuming negligible emissions from the additional hydrogen production, US emissions would fall by 33–82 million metric tons. That emissions reduction is the equivalent of removing approximately 7.2 million to 17.8 million passenger vehicles from US roads, based on a typical passenger vehicle emission of 4.6 metric tons of carbon dioxide per year.56

Despite the potentially seismic importance of hydrogen blending in pipelines, there are several location-to-location variation. The United Kingdom’s HyDeploy study found, however, that all tested domestic appliances could operate safely with hydrogen concentrations of up to 28.4 percent.58 It’s worth noting that end-use applications tend to impose the most significant constraints on hydrogen-blending percentages, as many devices optimized to throughput pure natural gas.59

The hydrogen-blending percentage debate will not be settled conclusively for some time. Several initiatives, including Pacific Gas and Electric’s Hydrogen to Infinity project, are evaluating blending percentages under real-world conditions.56,60

Figure 5: Northeastern Electricity Peak Average Prices

[Graph showing weighted monthly Nepol MH De LMP peak average prices ($/MWh)]

III. Regional Hydrogen Demand

In order to establish an effective hydrogen hub, long-term demand sources and off-takers must be identified. There are several potential hydrogen demand end-use cases in the northeast. These potential end-use cases include hydrogen blending in existing natural gas pipelines; refineries; industrial applications, such as steel and cement; and, over the long term, the maritime shipping sector. This section will examine these potential use cases, while clarifying hydrogen’s limitations in the transportation sector.


dions, while many domestic and international initiatives are studying blending percentages. Federal and state governments, along with university research centers, should seek to accelerate research and development on hydrogen blending in existing natural gas pipelines.

There has been relatively little federal support of research and development in hydrogen blending in existing natural gas pipelines, despite its potentially game-changing importance and role in accelerating clean hydrogen deployment at scale. The DOE reports $11 million of federal funding for its HyBlend Initiative, which seeks to address technical barriers to blending hydrogen in natural gas pipelines.63 This level of funding is inadequate, as hydrogen could easily become a trillion-dollar industry by 2050 (or even 2030).64 Blending in natural gas pipelines will likely prove to be a key accelerator, the technology’s environmental benefits could prove momentous, and the outlays required to investigate blending issues are miniscule, implying potential outsized returns on investment (ROI). The federal government must resource this priority adequately.

Additional areas for greater federal involvement include the collection and sharing of safety data. Several experts say there is not enough information sharing in the hydrogen space, particularly surrounding blending in pipelines, hydrogen in appliances, and safety data.65 While companies understandably want to protect their intellectual property, both state and federal authorities should consider creating an authoritative safety clearinghouse database. Indeed, European policymakers have already begun intensive efforts in this area.66

**Natural Gas Fundamentals in the Northeast Hub**

While the northeast lacks natural gas to produce blue hydrogen, the fuel could nevertheless play a vital role for any northeast hydrogen hub. Natural gas in pipelines can be safely “blended” with hydrogen and used in many of the same applications, which means that existing natural gas consumption and infrastructure provide opportunities to spur hydrogen development. While decarbonization efforts will ultimately require the removal or remediation of carbon dioxide from natural gas production and consumption, the fuel may ultimately prove to be a bridge to hydrogen and a cleaner future. The northeast’s natural gas consumption and natural gas pipeline system may provide significant opportunities for hydrogen.

Northeastern consumption of natural gas stood at approximately 75 Bcf/d in 2020, the last full year that data are available from the EIA.67 Northeast natural gas consumption has edged upward over time on cheaper prices resulting from the shale boom, population growth, and coal- and nuclear-plant decommissionings, rising from about 75 Bcf/d in 2010 to nearly 75 Bcf/d in 2020, when demand was suppressed by the COVID pandemic.68

Expanding research-and-development (R&D) funding for hydrogen-blending demonstration projects and enhancing safety-data cooperation could prove instrumental in accelerating hydrogen hubs. Indeed, according to the IEA, “by providing a temporary solution until dedicated hydrogen transport systems are developed, blending hydrogen in gas networks can support initial deployment of low-carbon hydrogen and trigger cost reductions for low-carbon hydrogen production technologies.”69

**RECOMMENDATIONS FOR A US NORTHEAST HYDROGEN HUB**

While northeastern natural gas consumption figures for 2021 are not yet finalized by the EIA, it is worth noting that demand does not appear to have experienced a resurgence in the post-vaccination period. Based upon initial data reported from the EIA, the author estimates that total 2021 regional consumption will likely range somewhere between 7.4–7.8 Bcf/d. Northeastern electricity-sector natural gas demand stood at about 2.5 Bcf/d in 2020, accounting for about 36 percent of all regional natural gas demand in the same period.69 Reducing natural gas demand in the northeast electricity sector via renewables generation could improve hydrogen fundamentals in two distinct but related ways: greater solar and wind uptake would likely lead to regional economies of scale and accelerate declines on the cost curves. Moreover, reducing electricity-sector natural gas demand would ease physical capacity constraints along existing natural gas pipelines, particularly in the winter, creating more opportunities for hydrogen fuel blending.

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64 Ibid.
65 “Global Hydrogen Review 2021,” HS.
67 Ibid.
68 Ibid.
Regional Refineries

Refineries could play an important role in fostering the adoption of the hydrogen economy. While US refineries currently use natural gas feedstocks to produce hydrogen, refineries may increasingly turn to cleaner feedstocks for hydrogen.

The northeast region has two oil refineries. P66’s Bayway refinery in Linden, New Jersey, has a crude throughput capacity of approximately 258,000 barrels per day and is, as of this writing, the region’s only operating refinery.70 PBF’s Paulsboro refinery, meanwhile, has been shut down since 2020 amid declining demand from COVID. While there has been interest in restarting the Paulsboro refinery as late as January 2022, the facility remains shut down as of this writing.71 Regional refineries are expected to contribute a limited, but important, amount of hydrogen demand. The Paulsboro refinery will not use hydrogen as long as it remains idle. The Bayway refinery, meanwhile, uses only a limited amount of hydrogen due to its relatively low Nelson Complexity Factor of 77.72 Refineries use hydrogen to lower the sulfuric content of diesel fuel.73 Therefore, lower complexity scores imply that refineries process relatively lighter, sweeter (i.e., less sulfuric) barrels of crude oil, limiting their hydrogen desulfurization needs. Indeed, in 2021, the East Coast PADD 1 region, which includes the entire eastern seaboard, not just the northeast, used only 4 percent of the country’s natural gas feedstock for hydrogen production at refineries.74

While the region’s refineries have only limited hydrogen needs, especially compared to other regions such as the Gulf Coast, they could nevertheless play an important role in kicking off a regional hydrogen hub. The Bayway refinery is already an important user of hydrogen and a target market for any green hydrogen supplier. Notably, Phillips 66 and Plug Power signed a memorandum of understanding (MOU) to advance green hydrogen in October 2021.75

Moreover, the Bayway refinery—and refineries more generally—could help solve green hydrogen’s “chicken-and-egg problem.” Unlike many other use cases, refineries’ demand for hydrogen already exists and is quite sizable: refineries accounted for about 44 percent of total world hydrogen demand in 2020.76 The Bayway refinery could prove to be an important early clean hydrogen off-taker for the northeast regional hydrogen hub.

Industrial Uses: Steel and Cement

While the northeast is often regarded as a post-industrial economy, there are still significant steel, cement, and paper facilities located across the region. These industries are studying ways to integrate hydrogen into their operations. While these industries may have limited scope for the initial “chicken-and-egg” problem of supply and demand, they may have significant impacts on medium- and long-term demand.

The northeast’s steel industry is noteworthy, and may be growing. According to the Global Energy Monitor, the Commercial Metals Company, or CMC, operates a 653,000-ton/year steel plant, an electric arc furnace (EAF) in New Jersey.77 CMC is also considering opening another plant that would “primarily serve the Northeast, Mid-Atlantic, and Mid-Western United States markets.”78 Auburn, New York, is also home to Nuco Steel Auburn, a scrap-based steel mill.

According to the United States Geological Survey (USGS), there were four operating cement plants in Maine and New York in 2020, when they produced 1,719 thousand metric tons of cement (to preserve company-level anonymity, the USGS does not provide more granular state-level data).79 There are three cement plants in the Empire State; two are owned by Lehigh Northeast, while Holcim owns the Ravena cement plant.

Steel and cement, as well as paper and pulp, are industries that could become potential hydrogen off-takers. Still, participants in these industries express concern that, because they operate in commodity industries and can be undercut on price alone, they will require policy support before introducing hydrogen at scale.80

Figure 7: Electricity-Sector Natural Gas Demand

Source: “Preliminary Monthly Electric Generator Inventory (Based on Form EIA-860M as a Supplement to Form EIA-860),” US Energy Information Administration, October 25, 2022. https://www.eia.gov/electricity/data/eia860m/.

Regional Electricity-Sector Natural Gas Demand (Bcf/d)

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</table>

80 “Hydrogen Hub Roundtable.”
electric vehicles, or FCEVs, were sold in the United States.87 Conversely, US hybrid vehicle sales stood at about eight hundred thousand vehicles in 2021, while BEVs accounted for about 435,000 vehicle sales.88 Electricated vehicles accounted for 12.6 percent of all US vehicle sales in the second quarter of 2022, up from 8.9 percent in the same prior-year period.89 It remains to be seen if FBEVs and PHEVs can continue to increase market share, but some analysts have projected EV cost parity with traditional internal combustion engines (ICEs) by 2027.90 Moreover, the Inflation Reduction Act’s pro-EV and pro-renewables provisions could dramatically accelerate the cost-parity timeline.

With EV adoption likely to receive a major boost from provisions in the Inflation Reduction Act, the technology will likely continue to charge ahead of hydrogen-fueled personal automobiles. Indeed, there are no US hydrogen-fueled stations outside of the state of California.91 Hydrogen-fueled personal automobiles will almost certainly provide little to no north-eastern hydrogen demand for the foreseeable future.

Buses are a potential hydrogen demand source for a north-eastern hydrogen hub. There is an ongoing debate about the relative advantages and disadvantages of hydrogen-fueled buses vis-à-vis electric buses. Hydrogen buses often have a larger range, enjoy shorter refueling times, and can operate more efficiently than battery-electric buses in very hot and very cold climates. BEVs appear positioned to beat out hydrogen in the bus market, however, due to costs and infrastructure. Unlike EVs, which “only” need a connection to the grid, there is little to no hydrogen-vehicle refueling infrastructure, and many cities are finding that electric buses are much less expensive than their hydrogen counterparts. A city in France, for instance, canceled an order for fifty hydrogen fuel cell buses after determining they would cost six times as much to operate as battery-electric buses.92

Battery-electric buses’ storage capabilities can deliver important advantages over hydrogen-fueled buses in many contexts. For instance, electric school buses may enjoy enormous advantages over hydrogen due to specific use factors. School buses currently have an extraordinarily low utilization rate throughout the year: on school days, they are idled except while transporting students, or while transiting to and from bus depots. When schools are closed—during the summer vacation—bus capacity is nearly completely idle. Predictable diurnal use patterns and long stretches of idle capacity suggest that electric buses could double as a grid-balancing service, storing electricity during peak renewables generation periods while discharging to the grid during peak-demand hours. While electric-battery charging times may preclude certain diurnal grid-balancing operations during school days, so-called vehicle-to-grid (V2G) technologies could help balance the grid on days when schools are closed. These V2G technologies could provide limited but sizable electricity storage: the Environmental Protection Agency (EPA) estimates that if half of all US school buses went electric, they could store enough power to electricity more than half of Vermont’s homes for up to three days.93

Northeastern states may already be coercing around electric school buses—and, potentially, electric buses in general. An electric school bus in Beverly, Massachusetts, used V2G technology to power the grid in the summer of 2022.94 Other states are building out their electric school-bus fleets. New York has created a $45-million electric school-bus program, Boston public schools are launching an electric school-bus pilot program during the 2022–2023 school year, and New York City’s Metropolitan Transportation Authority announced in April 2022 that it will deploy sixty electric buses with zero tailpipe carbon emissions.95 Hydrogen-powered buses could eventually dominate the segment, but initial signs suggest that BEVs have a head start.

The maritime industry is a potential H₂ off-taker, but not in the near term. There are concerns about retrofitting ships for liquid hydrogen, as the fuel’s low energy density requires greater space than conventional fuels, limiting room for cargo. According to some experts, any liquid hydrogen-fueled vessels built within the next half decade will likely be small and produced for niche markets, such as the passenger market or for small-scale, short-sea shipping.96

Ammonia, which is produced by reacting hydrogen from electrolysis and with atmospheric nitrogen, is potentially a much more economical alternative to liquid hydrogen for the maritime industry.97 Still, there is little prospect of major maritime ammonia shipping in the near term: Yara International, a major ammonia producer, is constructing the world’s first carbon-free ammonia fuel-bunker network servicing the local Scandinavian market, with a planned delivery date of 2024.98 Given that the planned start date may be ambitious, even the reach of Yara and expected policy support from Scandinavian governments, there is little prospect of the northeast requiring ammonia for the maritime sector in the near term. Still, over the long term, Northeastern policymakers may need to reevaluate ammonia’s role in maritime shipping and consider adjusting the region’s infrastructure.

In sum, there is little evidence that hydrogen will serve as a major transportation fuel in the northeast for years. Battery-electric vehicles and plug in hybrid electric vehicles will likely continue to dominate zero-emissions vehicle sales, while electric buses may have a first-mover advantage over hydrogen buses, partly due to electric school buses’ use-case benefits. Meanwhile, the maritime sector is unlikely to emerge as a significant H₂ demand source for years, perhaps more than a decade. Hydrogen could play a role in Northeastern transportation, but not for many years.

**IV. Midstream, Supply Chains, Infrastructure, and Storage**

Energy systems, including hydrogen hubs, need more than just supply and demand. A northeast HGHub will require midstream connections between supply and demand; stable supply chains; relevant infrastructure, such as electrolyzers; a capable workforce; and storage for diurnal and, potentially, inter-seasonal balancing. While the region faces transmission challenges, the northeast already has developed significant electrolyzer capacity and possesses a highly skilled technology workforce.

**Inter-regional and Intra-regional Transmission**

Hydrogen’s success in the northeast could ultimately depend on the region’s ability to build out more inter-regional and intra-regional electricity transmission and pipeline networks. Additional renewables capacity may need to be constructed in places where there is little to no existing transmission capacity. Moreover, some industrial facilities may co-site renewables generation with green hydrogen production. Therefore, the northeast must be able to quickly site new transmission and distribution capacity, retrofit existing natural gas pipeline networks for hydrogen, or even build new, hydrogen-dedicated pipelines.

The region’s ability to incorporate electricity grid transmission at scale is uncertain. On November 3, 2021, Maine voters rejected a $1 billion transmission project that would have delivered clean, renewable hydropower from Quebec to New England. Conversely, in July 2022, New York completed a new, twenty-mile, 345-kilovolt line called Empire State Line, enabling the transmission of 3.7 GW of renewable energy throughout New York. In addition to standard “not in my backyard” opposition to new transmission, some research indicates the northeast could suffer from “regionalist” biases, with some slice of voters more likely to oppose wind power projects if the generated electrons flow to another, rival state.

As discussed extensively in the demand section, hydrogen blending in pipelines is of major concern to the northeast’s hydrogen hub, but an issue fraught with uncertainty. One area in which policymakers can and should act immediately, however, is replacing the region’s cast-iron pipeline infrastructure. Cast-iron pipelines are not recommended for hydrogen gas service, according to the American Society of Mechanical Engineers. Moreover, cast-iron or wrought-iron pipelines comprise a substantial fraction of the northeast’s distribution mains: 16.7 percent in Massachusetts, 14.4 percent in New York, 14.3 percent in Connecticut, and 9.4 percent in New Jersey. Because cast-iron pipelines account for a disproportionate level of methane emissions, regulators and policymakers should prioritize their replacement, even in the absence of any hydrogen requirements. Moreover, because safety incidents could disrupt the regional, or even national, transition to a hydrogen economy, policymakers must prioritize removal of unsafe, unreliable, and leak-prone cast-iron pipelines.

Regional policymakers should also begin to consider how to streamline permitting and construction for hydrogen-dedicated pipelines in case they are needed. While utilizing the northeast’s existing natural gas pipeline system for hydrogen is surely preferable to constructing new pipelines, the region may ultimately need to construct new hydrogen-dedicated pipelines, depending on the results of hydrogen-blending safety studies. The region’s states should support efforts to create—or at least identify—a federal entity, such as the Federal Energy Regulatory Commission (FERC), responsible for the siting and approval of hydrogen-dedicated pipelines. The future of northeastern hydrogen-transmission requirements is uncertain. Much will depend on a complex interplay of technology, regulation, politics, and economics. Regional policymakers, therefore, must be able to respond rapidly and decisively to changing technologies and market conditions, adapting the region’s transmission and pipeline networks to meet shifting requirements.

**Storage Considerations**

As discussed previously, hydrogen could be used for the power sector to balance inter-seasonal demand, matching generation during low-demand months with peak winter electricity needs. However, the long-term storage of hydrogen is an important but unsettled question. While the DOE is investigating alternatives to salt caverns, it also notes that “large-volume underground hydrogen storage has been demonstrated to be safe and effective only in salt dome structures or caverns.” Other studies suggest that “underground hydrogen storage in geological formations could be a cheap and environmentally friendly medium- and long-term storage route.”

The region may enjoy an ability to store hydrogen locally, near demand centers. In May 2021, Mitsubishi Power and Texas Brine Company signed an agreement to develop large-scale, long-duration hydrogen-storage solutions across the eastern United States, including in New York state.
The Northeast’s Hydrogen Supply Chain: Electrolyzers and Human Capital

The Northeast’s hydrogen-related supply-chain infrastructure is expanding rapidly. The region enjoys some of the nation’s most advanced hydrogen infrastructure. The northeast is developing offshore wind resources that could ultimately produce hydrogen; is investing in parts that will service offshore wind; and enjoys local electrolyzer production, which could enable green hydrogen production using the electrolysis method. Moreover, the region’s immense reserves of human capital allow it to flexibly adjust to any new H₂ developments, drive innovation, and absorb new technologies and best practices.

A green hydrogen ecosystem is emerging in the northeast. Construction has begun at a Plug Power’s green-hydrogen production facility in Genesee County; when completed, the facility will be the largest green hydrogen plant in North America. Air Products, one of the world’s largest hydrogen producers, is investing $500 million to construct a green hydrogen production and distribution facility in Massena, New York. Plug Power is one of the world’s largest manufacturers of proton-exchange membrane (PEM) electrolyzers, and is headquartered in Latham, New York. The industrial gas company Linde, meanwhile, announced it will build its first North American PEM electrolyzer plant in Niagara Falls, New York, after strategic investment facilitation from the New York state government’s Empire State Development. The region’s existing and planned PEM infrastructure could prove to be an enormous advantage, as it seems likely PEM electrolyzers enjoy cost advantages over their alkaline competitors, particularly as system size increases.

The Northeast’s highly educated workforce and outstanding educational system could provide enormous advantages for establishing a hydrogen hub. One survey by Wallet Hub found that Massachusetts, Connecticut, and New Jersey earned the highest three rankings for US public high schools. The region is also home to a variety of leading research institutions, and routinely absorbs some of the world’s brightest minds in science, technology, engineering, and mathematics fields. The northeast’s highly educated workforce is extremely productive, dynamic, and able to integrate new technologies, including hydrogen.

Supply Chain: Electrolyzers

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Conclusion and Recommendations

H

drogen is a dynamic, existing field, but one filled with uncertainty. While some technical issues, including the feasibility and safety of blending hydrogen into natural gas pipelines, will likely be resolved in the near term, other key questions, such as the economic competitiveness of clean hydrogen, will not be answered for some time—potentially a decade or longer. Building hydrogen-supporting supply chains will take years, so policymakers will have to act decisively under conditions of uncertainty. In order to maximize the region’s hydrogen potential, northeastern policymakers will need to strike a difficult balance between humility, flexibility, and decisive-ness; they may need to execute industrial policy in the face of uncertainty.

Despite macro uncertainty in hydrogen markets, policy-makers and market participants in the region can act now, in the near term, without waiting for resolution of important debates.

- Support expanded clean energy production. Additional offshore wind and nuclear energy capacity is crucial to maximizing local green hydrogen production. The region cannot produce blue hydrogen independently, while importing green hydrogen at scale from maritime sources will prove infeasible for years, potentially more than a decade. While offshore wind should be at the center of the region’s clean energy generation strategy, nuclear energy could play a key role in improving the capacity factors of electrolyzers by increasing the amount of aggregate clean energy on the grid. Alternatively, nuclear energy could power the production of pink hydrogen. Regional policymakers should continue to prioritize rapid adoption of all forms of clean energy, including via policy support, but also by reducing permitting timelines. Importantly, while expanding clean energy production could deliver major benefits for a hydrogen economy, it could also, by itself, lower electricity prices and decarbonize the electricity sector.

- Great Lakes offshore wind presents intriguing possibili-ties for providing the energy required to produce hydro-gen in the northeast, particularly over the medium and long terms. Developing Great Lakes offshore wind could require the involvement of federal institutions, however, due to FAA limitations on wind turbine heights.

- Prepare the region’s infrastructure for the hydrogen economy. Regardless of the results of hydrogen-blending studies, regional policymakers must replace existing cast-iron pipelines with all possible haste. These pipes are not recommended for hydrogen service, and are high emitting even in existing pipeline systems.

- Current federal efforts to study hydrogen blending in pipelines are insufficient. The federal government should seek to identify what levels of hydrogen can be blended into existing natural gas pipelines and infrastructure, and under what conditions. The current approach, which relies on individual states and stakeholders to conduct their own safety studies, appears duplicative, wasteful, and inefficient.

- The region’s states should support efforts to create—or at least identify—a federal entity responsible for the siting and approval of hydrogen-dedicated pipelines.

- The northeast must address obstacles to intra-regional clean deployment and inter-regional clean energy transmission.

- Northeastern policymakers should, over the medium and long terms, consider supporting regional ammonia-

lated infrastructure, given the fuel’s potential use in the
northeast’s maritime sector.

As the field of hydrogen continues to evolve, regional deci-
sion-makers will need to attune policy to the latest develop-
ments. H₂ market conditions and technology will not remain
static; pipeline blending percentages, offshore wind econom-
ics, and maritime transport dynamics could all change signifi-
cantly over the next decade. The northeast hydrogen mar-
ket will have to adapt to changing realities. There are plenty
of reasons to think the region can rise to the challenge: a
regional hydrogen-supportive supply chain is emerging, pol-
 icymakers and the public are largely supportive of climate
goals, there is a real need to lower regional electricity prices,
and the northeast enjoys a world-class education system,
including in STEM. Still, the northeast must overcome signif-
icant challenges, including limited onshore solar and wind
resources, while the region’s cast-iron pipelines need to be
replaced with all possible haste. Offshore wind is arguably
the most important element in the success of a future north-
east hydrogen hub: if the region can successfully develop
its OSW potential in the Atlantic Ocean (and, preferably, the
Great Lakes as well), climate goals will be in easier reach.
The northeast needs to keep working if it is to develop its
full hydrogen potential. If it does, the future will be bright—
and green.
About the Author

Joseph Webster is a senior fellow at the Atlantic Council’s Global Energy Center, where he serves as hydrogen and offshore wind lead. Webster previously worked as a fundamentals energy consultant at a boutique energy firm in Houston, Texas, where his project work included topics across hydrogen, ammonia, electricity, liquefied natural gas, and oil and gas markets.

Parallel to his energy work, Webster edits the China-Russia Report, an independent, nonpartisan newsletter covering developments within and between the two authoritarian superpowers; he also writes a weekly column on China-Russia relations for The China Project. He is proficient in Mandarin Chinese and has been published or cited by The China Project, Politico Europe, Eurasianet, The Bulwark, and more.

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