GTI ENERGY

RAISE

Reliable Affordable Infrastructure for Secure Energy

October 2026

Regional Emerging Fuel Pathways for a Reliable and Resilient U.S. Energy Future

TECHNOECONOMIC AND LIFECYCLE EMISSIONS EVALUATION



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Acknowledgements

GTI Energy designed the Resilient Affordable Infrastructure for Secure Energy (RAISE) collaborative to map the most valuable opportunities for leveraging gas infrastructure in current and future energy systems including the potential for integrating lower emission fuels. By mapping these opportunities, RAISE provides a holistic understanding of the natural gas infrastructure system and actionable recommendations on the research, technology development, partnerships and investments required to upgrade and evolve the country's vast network of gas pipelines and storage systems.

Contributors:
Esther Goita
Marina Slijepcevic
May Kwan
Zane McDonald

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Glossary

Term	Definition
Autothermal Reforming (ATR)	A hydrogen production method that involves natural gas reacting with steam and air to produce a gas mix that contains hydrogen, carbon monoxide, and carbon dioxide. The carbon monoxide in the gas mix is then converted to produce more hydrogen and carbon dioxide. The hydrogen is purified for use.
Balancing Authorities (BAs)	Responsible for managing the electric grid within a defined geographic area. In the U.S., there are over 60 balancing authorities.
Business-as-Usual (BAU)	OL-NEMS scenarios that represent a baseline for emerging fuels adoption, assuming no significant changes in current policies, technologies, or behaviors. These include: 1) Reference case, 2) Low Oil & Gas Supply case, 3) High Economic Growth and High-Zero-Carbon Technology. See "Description of Business-as-Usual (BAU) Scenarios" section for scenario descriptions.
Capacity	Annual facility production rate.
Capacity Factor (CF)	Percent of the year facility produces fuel.
Carbon Intensity (CI)	A quantification of the GHG emissions impact of particular fuel pathway; from production to end-use delivery. CI scores are often reported on a kg CO2eq/ energy content fuel produced.
Carbon Capture, Utilization, & Storage (CCS)	Recovery of CO_2 from industrial or natural sources, and storage into geological or synthetic storage.
Carbon Capture, Utilization, & Storage (CCUS)	Recovery of CO_2 from industrial or natural sources, utilization for the production of fuels, and storage into geological or synthetic storage.

Emerging Fuels	Low-carbon fuels that have the potential to replace conventional natural gas. For this case study, the emerging fuels considered are H_2 and RNG.
Greenhouse Gas (GHG)	Greenhouse gases trap heat in the atmosphere. These gases include carbon dioxide, methane, nitrous oxide, and fluorinated gases.
Hydrogen (H_2)	Low-density fuel, able to be produced from several renewable sources and can be blended into NG systems.
Landfill Gas (LFG)	Byproduct of the decomposition of organic materials in landfills. It typically consists of about 50% methane, approximately 50% carbon dioxide, and trace amounts of non-methane organic compounds.
Levelized Cost	Total lifetime cost of building and operating a plant divided by its total lifetime energy production.
Lifecycle Analysis (LCA)	Estimation of fuel-specific GHG emissions impacts.
Low Carbon (LowC)	Technologies which offer carbon emission reductions in comparison to traditional fossil fuel-dependent technologies and fuel pathways.
Municipal Solid Waste (MSW)	Discarded waste originating from mixed sources (i.e., households, commercial businesses) including organics such as yard trimmings, food waste which can be separated from non-organics such as plastics, waste electronics.
Natural Gas Combined Cycle (NGCC)	A gas turbine generates electricity, and its waste heat is used to produce steam, which drives a steam turbine to generate additional electricity.
OnLocation's National Energy Modeling System (OL-NEMS)	A custom version of EIA's NEMS developed to model long-term energy markets and associated climate impacts with specific fuel pathways, by integrating

	lifecycle, economic, and market level data. OnLocation is a division of KeyLogic.
Renewable Natural Gas (RNG)	Biomass-derived methane produced via micro-organisms or thermal processes, compositionally similar to NG and blendable into NG systems.
Steam Methane Reforming (SMR)	A hydrogen production method that involves reacting natural gas with high-temperature steam and a catalyst to produce hydrogen, carbon monoxide, and carbon dioxide; the carbon monoxide then reacts with steam to yield more hydrogen and carbon dioxide, after which impurities including carbon dioxide are separated to purify the hydrogen. This hydrogen production method is currently the most common.
Technoeconomic Analysis (TEA)	Cost analysis of fuel pathway.

Executive Summary

This report evaluates regional opportunities for deploying hydrogen and renewable natural gas to support a reliable, resilient, and lower-emissions U.S. energy future. The analysis integrates technoeconomic assessment, resource evaluation, and lifecycle analysis to assess pathway economics, emissions performance, infrastructure implications, and deployment potential across the five Petroleum Administration for Defense Districts (PADDs) regions.

Each of the considered fuel production pathways has unique facility scale considerations and process requirements that impact economics and lifecycle emissions (Figure 1).

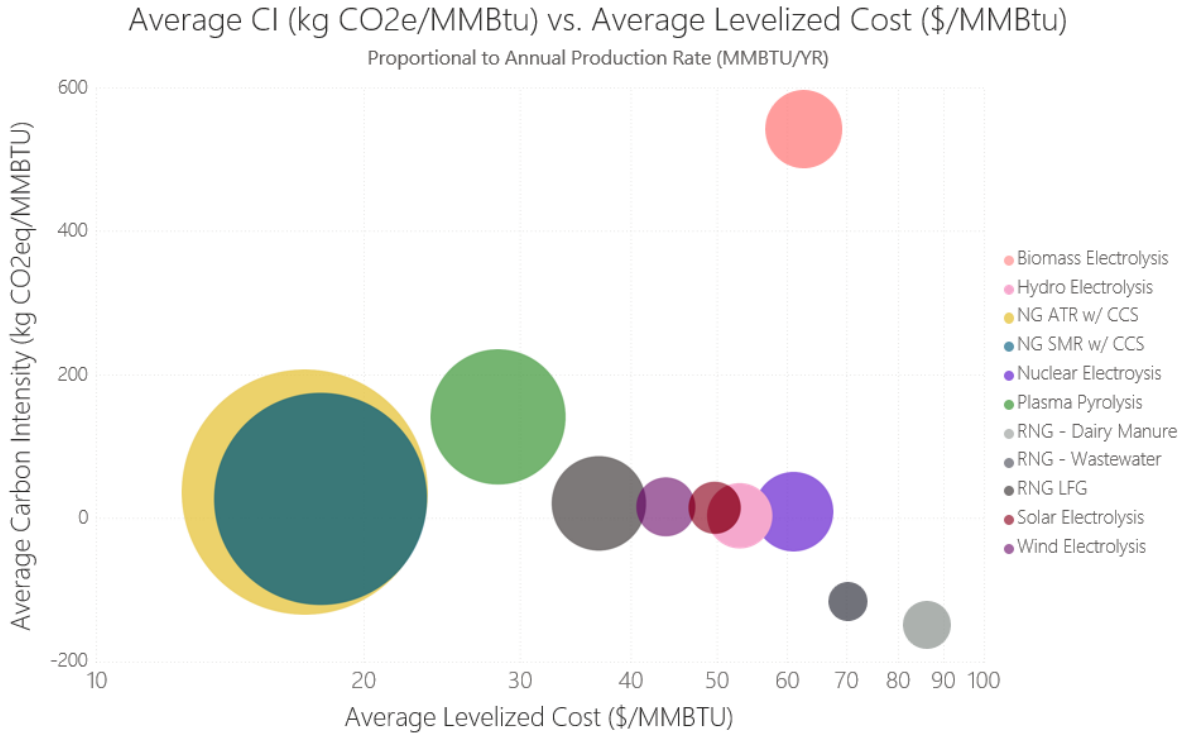


Figure 1. Average Carbon Intensity vs. Average Levelized Cost by Fuel Pathway

The results also suggest that pathway viability is highly regionally specific and shaped by natural gas and electricity prices, labor costs, feedstock availability, facility scale, pipeline interconnection potential, carbon storage access, and regional electricity sector emissions. For hydrogen production, natural gas pathways with carbon capture, particularly autothermal reforming (ATR) with carbon capture and storage (CCS) and steam methane reforming (SMR) with CCS, generally provide the lowest levelized costs

nationally while still providing significant emissions reduction benefits particularly in states with low-cost natural gas resources and access to CO_2 storage infrastructure, such as Texas, Louisiana, Oklahoma, Wyoming, and North Dakota. Emissions reduction is greatest in the East Coast, reflecting the combination of a comparatively low-carbon electric grid and a natural gas supply drawn largely from the Appalachian Basin, which has the lowest upstream methane emissions intensity of any major U.S. producing basin. Methane pyrolysis also emerges as a competitive option in regions with low-cost natural gas and electricity, particularly where markets for solid carbon co-products can enhance project economics. However, plasma pyrolysis is among the most carbon-intensive methane-based pathways assessed because its emissions scale directly with both electricity grid carbon intensity and upstream methane emissions, while producing no captured-CO_2 credit. In contrast, proton exchange membrane (PEM) electrolysis is the lowest-emitting hydrogen production pathway. However, its economic competitiveness remains more sensitive to electricity costs, with the strongest opportunities occurring in states with abundant low-cost renewable resources, including wind-rich states such as Texas, Iowa, Kansas, and Oklahoma, and solar-intensive states such as Arizona, Nevada, New Mexico, and California. For RNG, upgraded landfill gas represents the most cost-competitive pathway and offers significant near-term deployment potential in states with large landfill methane resources, including California, Texas, Pennsylvania, Georgia, Illinois, Ohio, and Florida. Wastewater-derived RNG shows promise where large treatment facilities, anaerobic digestion infrastructure, and pipeline access are available, while dairy manure RNG, despite higher production costs, provides substantial emissions-reduction benefits in states with concentrated dairy operations.

Translating these findings into deployment, the most promising implementation opportunities are those that meet regional blending targets with the fewest constructed facilities. At the facility scales evaluated, natural gas ATR and SMR with CCS require the smallest number of facilities: most Midwest states would need only one to six facilities of at least 20,125 kg H_2/hr. to reach a 5% system-wide H_2 blend, whereas Texas would require 10 to 14 facilities at the same scale because of its substantially higher natural gas consumption. Meeting the same blending target with H_2 from PEM electrolysis, or with RNG from wastewater, dairy manure, and upgraded landfill gas, requires deployment across a larger number of sites, reflecting the smaller facility scales typical of these pathways. Therefore, implementation strategies should pair a limited number of

large-scale CCS-enabled H_2 facilities in states with low-cost natural gas and CO_2 storage access, with a broader portfolio of smaller distributed RNG and electrolysis projects sited where feedstocks, low-cost renewable electricity, and pipeline interconnection already exist.

Introduction

The objective of this case study is to identify near-term opportunities and infrastructure strategies that can support the deployment of emerging fuels while enhancing energy system resilience, improving reliability, and maintaining the delivery of affordable energy to customers. The results provide region-specific insights into how infrastructure operators and other stakeholders can advance emerging fuel adoption over the next five to ten years.

This report summarizes the evaluation of both economic and emissions outcomes associated with the production of different renewable natural gas (RNG) and hydrogen (H_2) pathways in each contiguous U.S. state.

Table 1. Fuel Case Overview

Hydrogen	Natural gas reforming - steam methane (SMR) and autothermal (ATR) with carbon capture and storage (CCS), achieving 94-96% capture rates
	Plasma pyrolysis of natural gas producing H_2 and solid carbon with minimal CO_2 emissions
	PEM electrolysis using five low-carbon electricity sources (solar, wind, nuclear, hydro, and biomass)
Renewable Natural Gas	Upgraded landfill gas
	Anaerobic digestion of wastewater sludge
	Anaerobic digestion of dairy manure

Each pathway in Table 1 offers different approaches to producing low-carbon alternatives to conventional fuels, with varying infrastructure requirements and regional availability constraints.

Methodology Overview

This section outlines the analytical approach undertaken in this study, integrating technical, economic, and environmental considerations to evaluate the H_2 and RNG pathways.

1) Technoeconomic Analysis (TEA)

The TEA assesses the economics of the H_2 and RNG pathways on a levelized basis, considering the dollar per energy unit produced needed to be recovered to offset the total accumulated costs associated with the production of the fuel over the lifetime of the production facility. The TEA leverages 2023 fuel prices and labor rates and current literature on representative facility production scales and efficiencies to define parameter values for each fuel case in $/MMBtu.

2) Lifecycle Analysis (LCA)

The LCA quantifies the environmental impacts across the entire lifecycle of the energy systems, considering raw material extraction, manufacturing, operation, and disposal, as inputs to estimate greenhouse gas emissions in kg CO_2eq/kg. This study follows a cradle-to-gate system boundary and therefore includes emissions from raw material extraction, transportation, processing, and fuel production. It excludes downstream activities after the fuel leaves the production facility, such as distribution, storage, and final use.

For consistency, both the TEA and LCA use the lower heating value (LHV) as the basis for all fuel case calculations.

Technoeconomic Analysis: Methodology and Assumptions

The TEA calculates fuel-specific levelized cost, which considers the revenue required per unit of product produced during a facility production plant's operational life to meet all capital and operational costs (i.e., $/MMBtu H_2, $/MMBtu RNG). The National Energy Technology Laboratory (NETL)'s Quality Guidelines for Energy System Studies (QGESS)

Given the evolving literature on H_2 and RNG production, this study evaluates technology-specific facility scales and operating conditions to best reflect representative deployment conditions (Figure 2). Inherently, each fuel production technology favors specific facility sizes to optimize economics. Additionally, each fuel production pathway

is anticipated to experience differences in economies of scale, with some production methods more significantly benefiting from increased scaling to achieve optimized levelized costs on a dollar per MMBtu basis. Please see Table 2 in Appendix D, which summarizes the facility scale assumptions for each along with detailed information on the largest reported commercial facility, including planned and operational examples.

In some cases, total system adoption blending targets may be more economically achieved by adoption of fuel production pathways with higher levelized costs, but regionally opportunistic facility scales and local resources. According to the Department of Energy H2A models, economies of scale benefits are less anticipated with electrolysis and methane pyrolysis as compared to NG SMR and ATR facilities (U.S. DOE, 2024). At larger facility scales, the economics for producing H_2 via NG SMR and ATR improve most significantly among considered H_2 production pathways. However, as found by this RAISE study, regional resource availability and favorable economic conditions are deterministic factors in production pathway adoption in each region.

Assumptions and more detailed information on the TEA methodologies, including further discussion of facility scales, can be found in Appendix D.

Lifecycle Analysis Methodology and Assumptions

Two open-source tools were used:

1. **Open Hydrogen Initiative (OHI) Toolkit:** used to model all the hydrogen pathways and RNG pathways (wastewater and animal manure)
2. **Research & Development Greenhouse gases, Regulated Emissions, and Energy use in Technologies (R&D GREET)**: used to model the landfill gas RNG pathway

The LCA has a cradle-to-gate scope. The dominant sources of regional variation in each pathway were the upstream carbon intensity of the natural gas supply, including methane leakage, and the carbon intensity of delivered electricity. By default, OHI uses national averages for upstream inputs. To customize upstream carbon intensities for natural gas, the respective production and delivery regions in OHI were selected in the main inputs section to generate state-specific intensities. For electricity, the state-level upstream impacts were determined using a weighted GHG intensity for each state,

which is found by combining the GHG intensities of states via a consumption-weighted average, as in the following equation:

$$\text{Weighted GHG Intensity} = \frac{\sum(E_i \times I_i)}{\sum E_i}$$

Where E_i is the electricity consumption of state i (MWh) and I_i is the GHG intensity of state i in kg CO_2e/MWh. These weighted intensities were then applied to H_2 production pathways by overriding default OHI upstream electricity intensity values with region-specific results. This methodology ensures that upstream emissions reflect specific state grid and gas supply characteristics rather than generic regional averages. For the landfill gas pathway modeled in R&D GREET, similar customizations were made by overriding default electricity inputs to match OHI grid intensities utilized for the other RNG processes.

Hydrogen production process stream inputs and outputs are identical to those assumed for the TEA, and this process does not vary regionally. Accordingly, the inputs and outputs of the main inputs tab in OHI were customized. For the RNG pathways, the OHI and R&D GREET default process inputs and outputs were maintained as both models and the TEA assumptions are based on the same reference NETL studies. The avoided emissions are credited as negative emissions in the RNG pathways. In these cases, traditional waste management releases methane, which is eliminated when the gas is collected and utilized, resulting in net-negative CIs reported for the wastewater and animal manure pathways. Emissions are expressed per kilogram of product (kg CO_2e/kg H_2 and kg CO_2e/kg RNG) and characterized as global warming potential (GWP) using IPCC AR6 100-year GWP factors.

Further details on the LCA modeling approach can be found in Appendix E.

Findings: Fuel Production Economics and Resource Availability

This section presents the range of estimated state-level levelized costs by fuel case, which largely reflects differences in natural gas and industrial electricity prices as well as labor rates and in-state resource availability. Further discussion of driving factors in state-specific levelized costs is documented in Appendix D.

Renewable Natural Gas Cost Outlooks and Resource Potential

There are various other metrics besides $/MMBtu for comparing RNG cases to H_2 fuel production pathways. Current blending markets are dominated by RNG originating from upgraded landfill gas, animal manure digesters, and wastewater digesters. Although RNG cases generally exhibit higher levelized costs than specific H_2 cases due to considered facility scales (greater than $28/MMBtu LHV), existing incentives have continued to offset costs. For context, the Environmental Protection Agency (EPA) Renewable Fuel Standard Renewable Identification Number (RIN) credits enable a $28.00 to $32.00/MMBtu LHV recovery for D3 cellulosic biofuels (including RNG from anaerobic digestion of food waste, manure, sewage sludge, landfill gas upgrading). These reduced costs on a $/MMBtu basis for hydrogen compared to RNG are attributed to the much larger facility scales considered for NG SMR/ATR with CCS and plasma pyrolysis. RNG via upgraded landfill gas cases serve as an exception to this trend, as hydrogen via PEM electrolysis cases consistently yield higher levelized costs than the upgraded landfill gas cases. Additionally, several RNG cases notably possess significant emissions abatement potential, exhibiting some of the lowest carbon intensities of all market-ready RNG and H_2 pathways.

Upgraded Landfill Gas

Upgraded landfill gas is a key existing pathway for RNG production in the U.S. Figure 2 highlights existing RNG facilities and candidate landfills for RNG production in each U.S. region, as defined by EPA LMOP's database. As of 2024, the EPA Landfill Methane Outreach Program database identifies 444 candidate landfills across the U.S. that can potentially generate RNG.

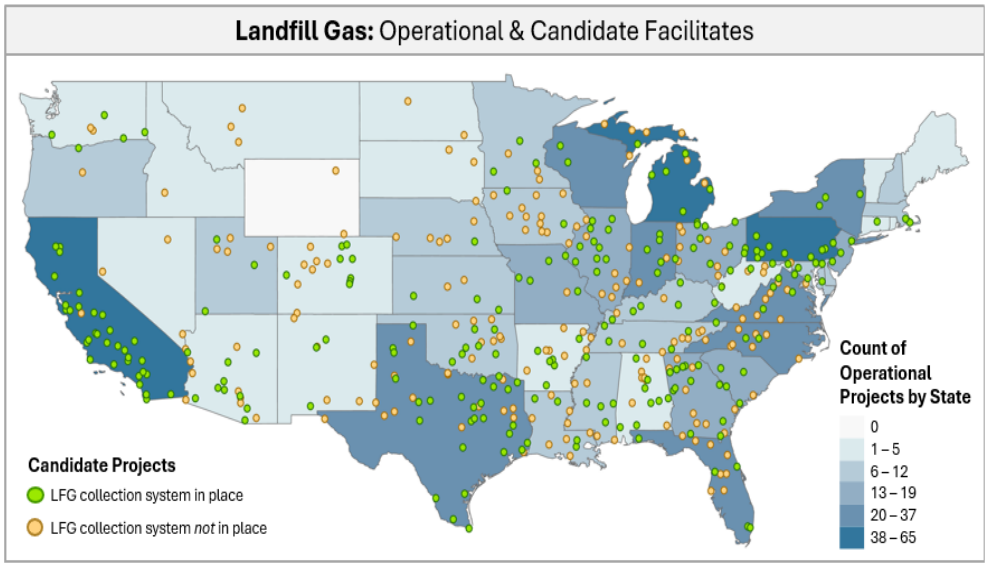


Figure 2. Operational Landfill Gas Projects and LFG Candidate MSW Landfills in the U.S.

Cost Findings

The lowest levelized costs of all considered pathways are represented by upgraded landfill gas, which generally ranges from $28 to $51.50/MMBtu. Figure 3 shows the distribution of levelized costs for RNG via landfill gas by U.S. region.

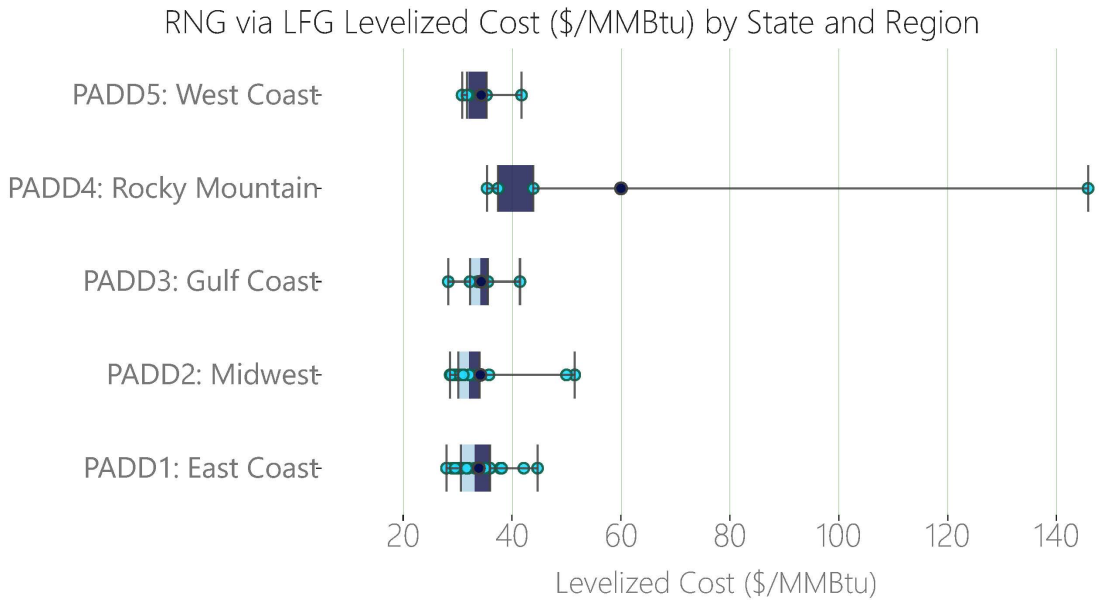


Figure 3. Regional Levelized Costs of RNG via Upgraded Landfill Gas

Among all fuel cases considered in this study, RNG via landfill gas demonstrates the greatest variability in capital costs, fixed O&M, and levelized costs. The lowest levelized costs (quartile 1) for RNG via upgraded landfill gas are observed in the Gulf Coast, Midwest, and the East Coast. Texas, Ohio, and Pennsylvania lead in lowest observed levelized costs. Higher estimated levelized costs for RNG via upgraded landfill gas are associated with higher variable O&M and capital costs. The highest costs for RNG via upgraded landfill gas are observed in the Rocky Mountain region, specifically due to higher estimated capital and fixed O&M costs compared to other regions.

While some states across the U.S. are found to have much lower levelized costs to produce RNG, most regions are found to have similar regional median levelized costs, indicating a present strategic need to focus on specific opportunity states based on costs and resource availability.

Resource Availability

As a result of different landfill sizes and ages, some states are projected to achieve higher methane reductions by developing RNG production at fewer facilities. This trend is particularly observed for Pennsylvania, Georgia, Wisconsin, Ohio, California, Missouri, Illinois, Alabama, Florida, and New Jersey (Table 2).

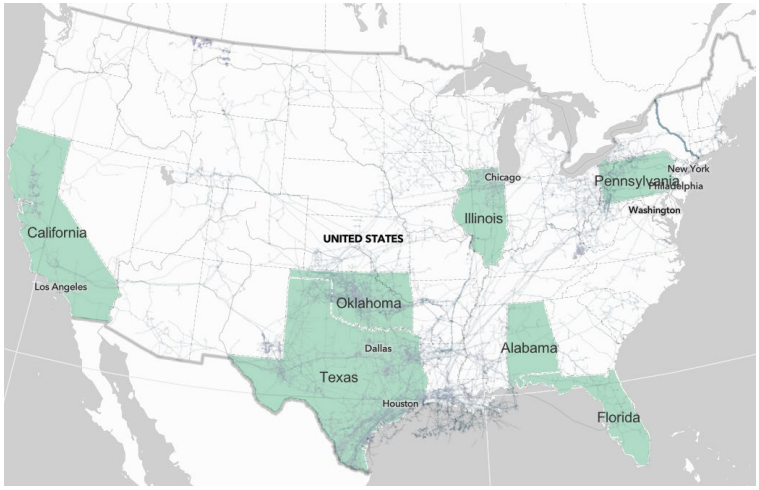
Lower implementation costs of new landfill gas upgrading projects are achievable for MSW landfills with existing and operational gas collection systems (GCS).

Table 2. Select States with Highest Methane Recovery Potential from Candidate MSW Landfills

State	Number of Candidate Landfills	Candidate MSW Landfills w/ GCS*	Total Estimated Projected Direct Reductions ($MMTCO_2e/yr$) – MW	Average Reductions per Candidate Landfill ($MMTCO_2e/yr$ per landfill)
CA	33	32	4.4569	0.1351
GA	22	12	3.8247	0.1739
TX	44	28	3.2325	0.0735
PA	11	11	3.0878	0.2807
IL	18	11	2.1160	0.1176
OH	15	7	2.0859	0.1391

AL	15	8	1.7375	0.1158
FL	12	5	1.3770	0.1148
AZ	18	10	1.3604	0.0756
MS	10	5	1.2237	0.1224

Strongest Opportunity States for RNG- LFG (≤$34/MMBtu)[1]



[1] *State has ≥ 10 candidate landfills for new landfill gas recovery and estimated total reduction potential >1.3 MMTCO$_2$e/yr direct emissions*

Key Opportunity States

California, Texas, Pennsylvania, Georgia, Illinois, Ohio, Florida

Figure 4. RNG via Upgraded Landfill Gas: Strongest Opportunity States

For instance, the candidate landfills in California and Pennsylvania identified already possess GCS at all observed landfills. However, each MSW landfill may require additional upfront GCS upgrades to scale with a new onsite gas upgrading system that interconnects with a natural gas pipeline. In general, MSW landfills are assumed to reach peak methane generation 20 years after burial of MSW. Texas and Georgia have the highest number of candidates MSW landfills constructed after 1980, suggesting a stronger potential for methane recovery than other states with older MSW landfills.

RNG via Wastewater

RNG production through anaerobic digestion of wastewater biosolids has several co-benefits which have driven historical markets, such as leveraging existing anaerobic digester facilities often already developed, and improved financial outlooks for wastewater facilities. As defined in a 2022 Argonne National Laboratory study on RNG

potential from wastewater, there are key factors that impact RNG production at wastewater treatment facilities such as facility size (greater than 5 million gallons/day), whether the facility already leverages anaerobic digesters, and the facility's distance to a natural gas pipeline (Argonne National Laboratory 2022).

Figure 5 summarizes municipal wastewater facilities with current design flow above 5 million gallons per day (MGD), along with total combined municipal wastewater flow capacity by state. Note that RNG potential will be stronger for facilities with existing anaerobic digesters onsite and proximity to a natural gas pipeline.

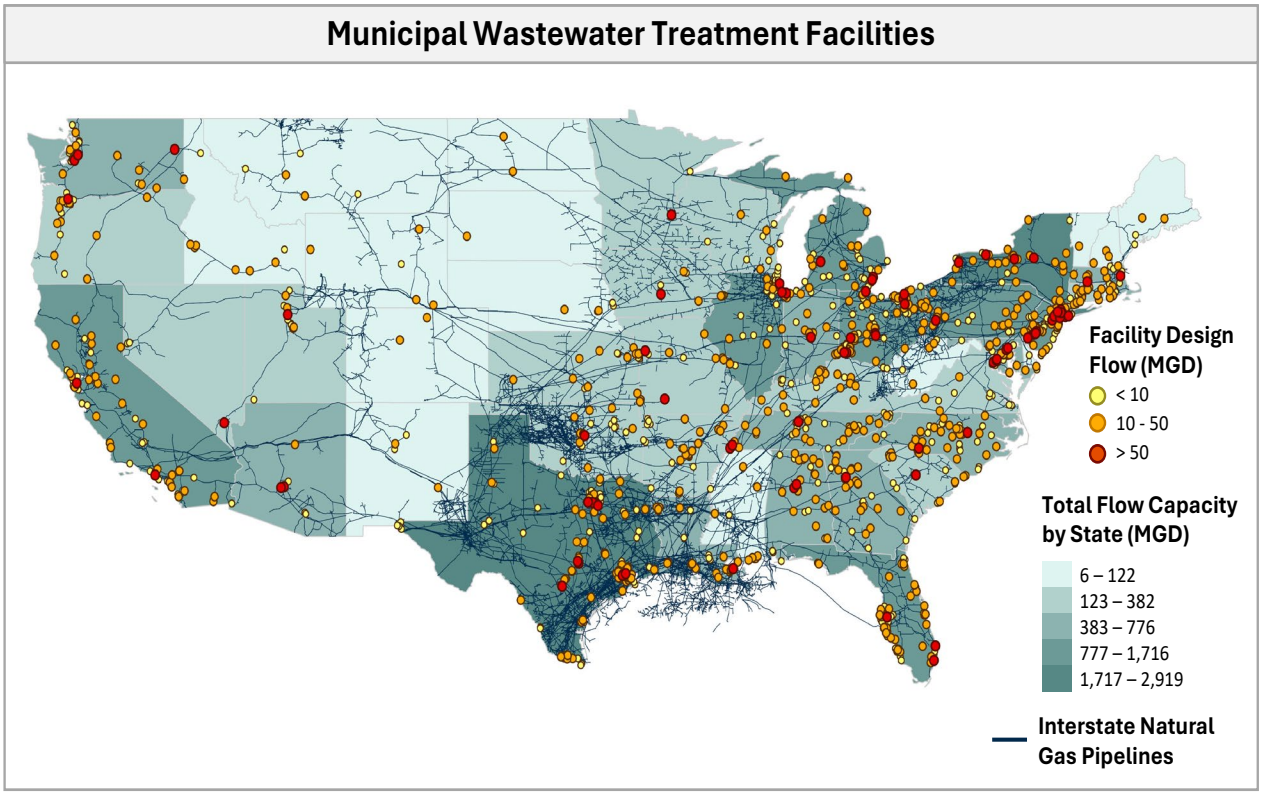


Figure 5. Municipal Wastewater Treatment Facilities (>5 MGD Current Design Capacity)

Cost Findings

Costs are generally in agreement across regions ($58 to 77/MMBtu), suggesting opportunities for RNG via wastewater will more significantly depend on local resource potential (Figure 6).

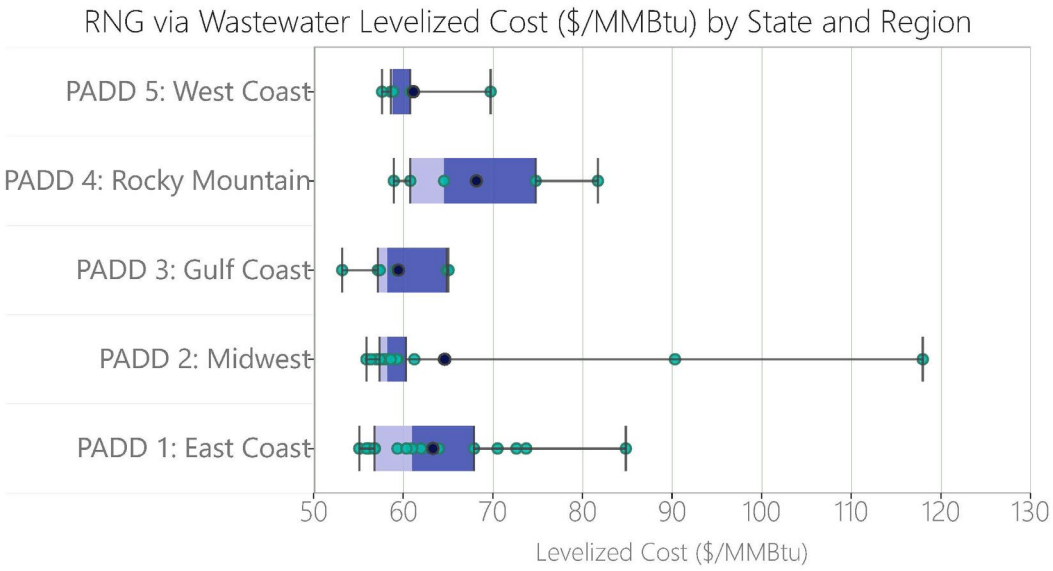


Figure 6. Regional Levelized Costs for RNG via Wastewater

A few states are found to have higher levelized costs ($80 to 130/MMBtu) for wastewater RNG (South Dakota, North Dakota, Vermont, Wyoming) due to higher estimated fixed O&M on a $/MMBtu basis, which is a result of lower estimated in-state resources.

Resource Availability

Based on available municipal wastewater facility design flow data and AGA RNG production assumptions, New York, Texas, Ohio, and Michigan possess exceptionally higher resource potential for RNG recovery from wastewater facilities. Table 3 summarizes the potential of RNG production by state, with the assumption that approximately 2,500 MMBtu RNG can be produced from each MGD processed at one facility.

Table 3. RNG via Wastewater Potential (summarized facilities >5MGD Design Flow)

High Potential for RNG via Wastewater (>2 million MMBtu/yr)	New York, Texas, Ohio, Michigan, California, New Jersey, Pennsylvania, Florida, Illinois
Moderate (>1 million MMBtu/yr)	Tennessee, North Carolina, Alabama, Indiana, Maryland, Georgia, Washington, Louisiana, Massachusetts, Arizona
Lower (<1 million MMBtu/yr)	All other remaining states

As shown in Figure 7, there are a variety of facility scales across wastewater treatment plants in each of the higher potential states.

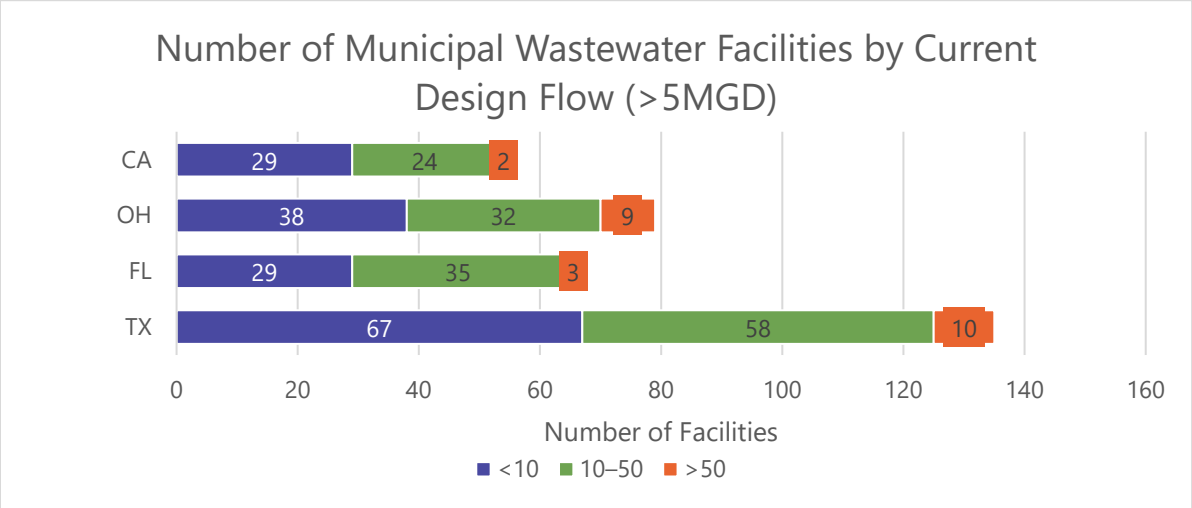


Figure 7. High Potential States: Number of Municipal Wastewater Facilities by Current Design Flow

While not explored further in this study, it is expected that states that leverage larger facilities for RNG production via wastewater will benefit from economies of scale.

RNG via Dairy Manure

Anaerobic digestion of animal manure is the second most common existing production method for RNG in the United States and is associated with highly negative carbon

intensities. The majority of these RNG agricultural projects are represented by dairy and some swine farms.

Cost Findings

Levelized costs for RNG via anaerobic digestion of dairy manure are found to range from approximately $77 to 93/MMBtu (Figure 8). These levelized costs are significantly higher than the LFG RNG cases ($42.23 to 58.26/MMBtu difference) but are sometimes more competitive than RNG via wastewater. There is a general agreement of levelized costs across regions (less than $80/MMBtu) with the exception of five Midwest states (Wisconsin, Indiana, Missouri, Illinois, and Ohio) and one East Coast state (Pennsylvania); all of which are found to have higher capital and fixed O&M costs than other states.

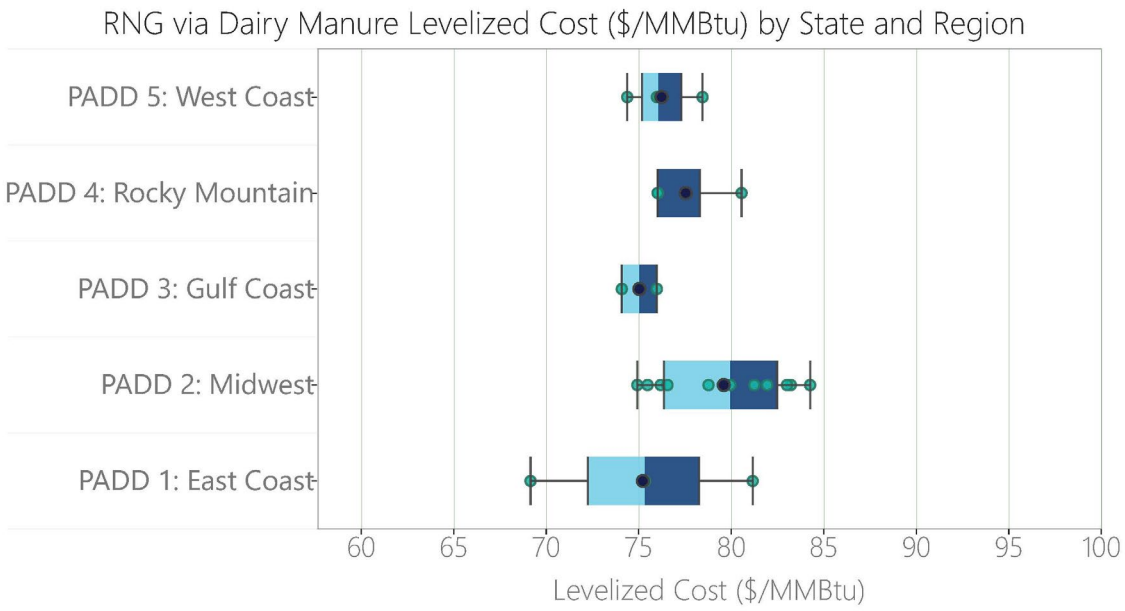


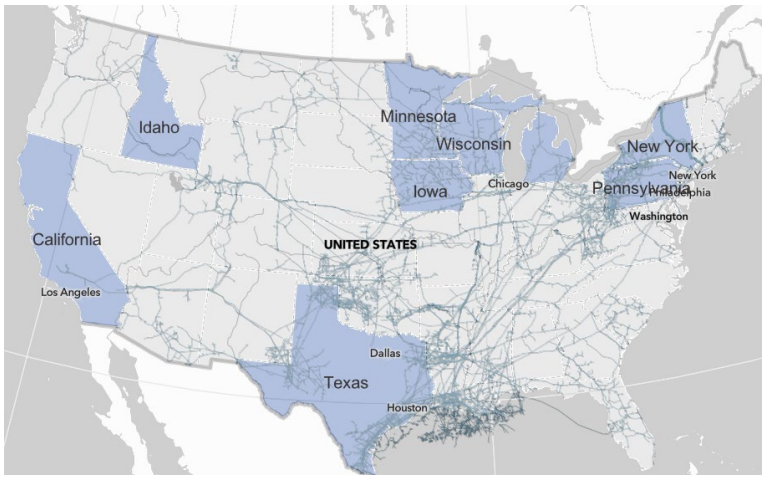
Figure 8. Regional Variations in Dairy Manure RNG Levelized Costs

RNG via Dairy Manure vs. Wastewater

There is a greater spread of levelized cost differences for RNG via wastewater compared to RNG via dairy manure. States exhibiting the greatest levelized cost advantage for producing in-state RNG from wastewater relative to dairy manure include Ohio, Illinois, Missouri, Pennsylvania, Indiana, Wisconsin, Michigan, and Texas, where wastewater-derived RNG is estimated to be more than $20/MMBtu lower in cost than dairy manure-derived RNG. Idaho, New Mexico, and New York show the weakest cost advantage for

RNG produced from wastewater relative to RNG produced from dairy manure among all states evaluated.

Strongest Opportunity States for RNG - Dairy Manure (< $90/MMBtu)



Each state's dairy resources ≥ 0.4 million dairy head/state, ≤ $90/MMBtu)

Top Opportunity States:

New York, Texas, California, Iowa, Idaho, Michigan, Minnesota, Pennsylvania, Wisconsin

Leading state cases by region[1]:

East Coast: New York, Pennsylvania

Rocky Mountain: Idaho, Colorado

[1] *where at least one wastewater case is more expensive, in-state dairy head ≥ 0.2 million*

Figure 9. RNG via Dairy Manure: Strongest Opportunity States

Resource Availability

For reference, each point in Figure 10 represents 2,000 milk cows, which can produce approximately 20,000 MMBtu/yr RNG (USDA 2017). RNG projects associated with interconnections documented in the EPA AgSTAR database start at 1,160 dairy head farms (EPA 2025).

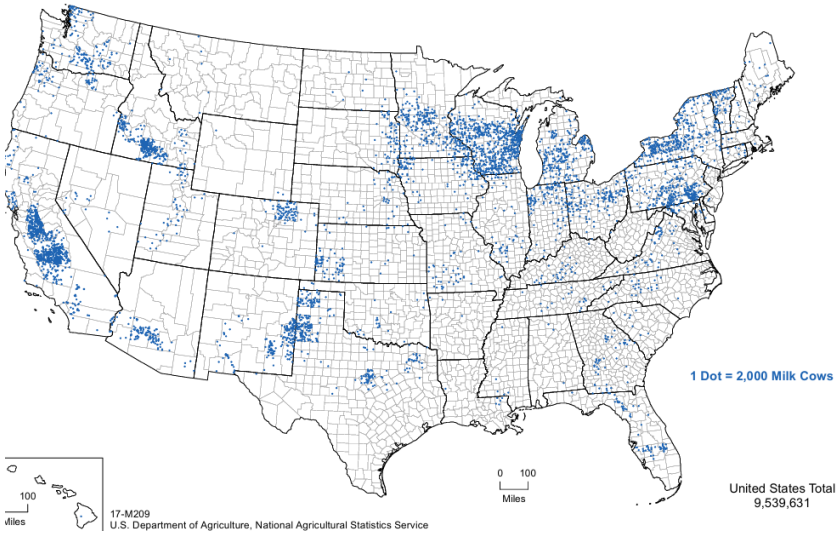


Figure 10. USDA Milk Cows – Inventory (2017)

There are concentrated opportunities for RNG production via dairy manure, particularly in the Midwest. However, extensive dairy farms exist in each region, with resources identified in California, Wisconsin, Pennsylvania, and New York.

Hydrogen Cost Outlooks and Resource Potential

Methane Plasma Pyrolysis

As shown in Figure 11, hydrogen produced via NG plasma pyrolysis demonstrates a wide range of estimated levelized costs ($15.16 to 65.81/MMBtu) across regions, with the lowest costs observed in the Midwest and the Gulf Coast regions (Oklahoma, Tennessee, Kentucky, Louisiana, South Carolina, and North Dakota).

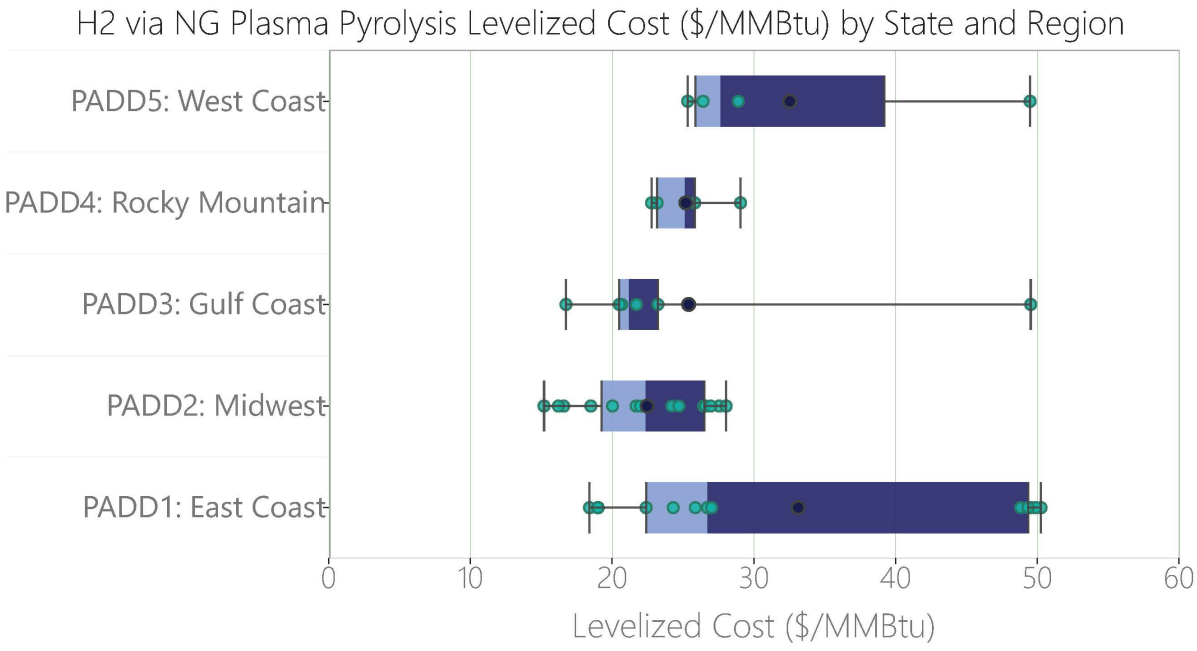


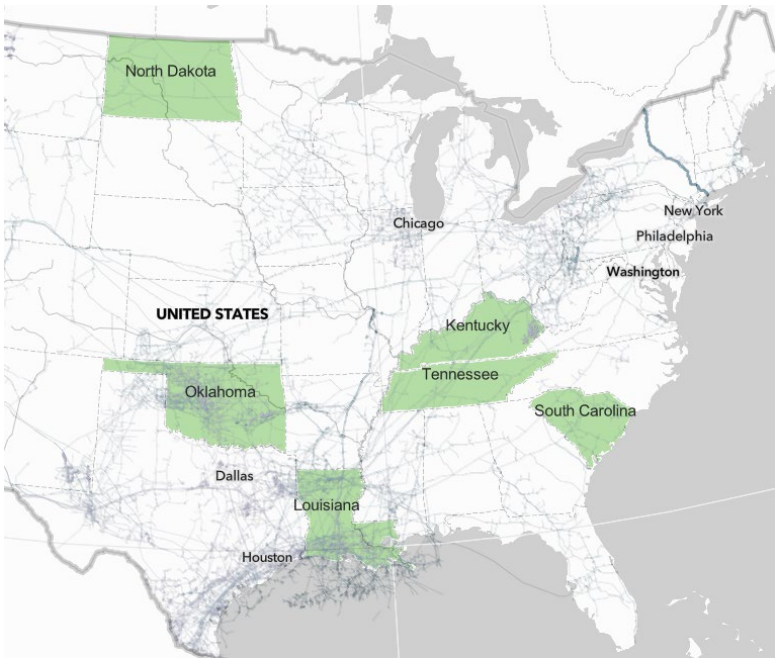
Figure 11. H_2 via Methane Pyrolysis Regional Levelized Costs ($/MMBtu)

More competitive methane pyrolysis-levelized costs are invariably found to be driven by the combined affordability of natural gas and industrial electricity in each state.

Across all fuel cases considered in this study, methane pyrolysis cases demonstrate the greatest variability in variable O&M costs across different states (a delta of approximately $57/MMBtu). These estimated variable costs are highly linked to industrial electricity prices in each state. States that have lower natural gas prices but have higher electricity prices (e.g., Minnesota, Virginia) are estimated to have higher variable O&M and thus higher total levelized costs for H_2 production.

Compared to NG SMR or ATR with CCS, NG pyrolysis state-level fuel cases assume a smaller facility capacity (7,800 kg/hr) and have much higher capital costs ($/MMBtu basis), which impacts the overall cost outlooks for NG pyrolysis in each state. Thus, offsetting the process costs of plasma pyrolysis through the sale of carbon black can play an important role in overall economics. For every kilogram of H_2 produced, 3.54 kg of carbon black is recovered, which can typically be sold at $1.20 to 1.95/kg depending on regional markets.

Strongest Opportunity States for H_2 via Plasma Pyrolysis (<18.50/MMBtu)



National average levelized cost: $39.25/MMBtu

< $18.50/MMBtu

Gulf Coast & Midwest: Oklahoma, Tennessee, Kentucky, Louisiana, South Carolina, North Dakota

< $24/MMBtu

Gulf Coast: Texas, New Mexico, Alabama, Mississippi
Midwest: Ohio, South Dakota
East Coast: North Carolina
Rocky Mountain: Montana, Idaho

Figure 12. H_2 via Methane Pyrolysis: Strongest Opportunity States (<$18.50/MMBtu)

PEM Electrolysis

Among the three major H_2 electrolyzer technologies (Proton Exchange Membrane, Solid Oxide, and Alkaline), the fuel cases focus on electrolysis with proton exchange membrane (PEM) technologies at a 2,083 kg/hr. facility scale. In this study, sourced renewable electricity is assumed to be new generation sources to be grid-delivered to electrolyzer facilities.

The economics of H_2 via electrolysis largely rely on specific technologies utilized, market prices of renewable electricity and capital costs. Renewable electricity plays a key role in electrolysis in meeting process fuel requirements and reducing overall carbon intensities of producing H_2.

Cost Findings

Lower-cost renewable generation sources, particularly solar and wind, result in more economical levelized costs for H_2 produced via PEM electrolysis, while biomass and nuclear-powered PEM cases are generally among the costliest pathways evaluated.

All H_2 via PEM electrolysis cases with levelized costs below $45/MMBtu are represented by wind powered fuel cases, which range from $43 to 44/MMBtu. Similar ranges of levelized costs are observed for PEM powered with Solar (approximately $48 to 51/MMBtu), Hydro (approximately $52 to 54/MMBtu), Nuclear ($60 to 61/MMBtu), and Biomass ($62 to 63/MMBtu).

Between solar PEM electrolysis and hydro PEM electrolysis cases for each state, there is a $2.31 to 3.25/MMBtu difference in levelized costs across the state level findings, favoring solar PEM electrolysis as the lower cost of the two cases (Figure 13). Although H_2 produced via solar PEM electrolysis is identified to yield lower costs compared to Hydro PEM electrolysis, hydroelectricity generation can leverage existing hydro infrastructure, reducing additional land use as compared to new solar generation. However, hydro resources are highly location-dependent and can be variable over time, unlike solar generation.

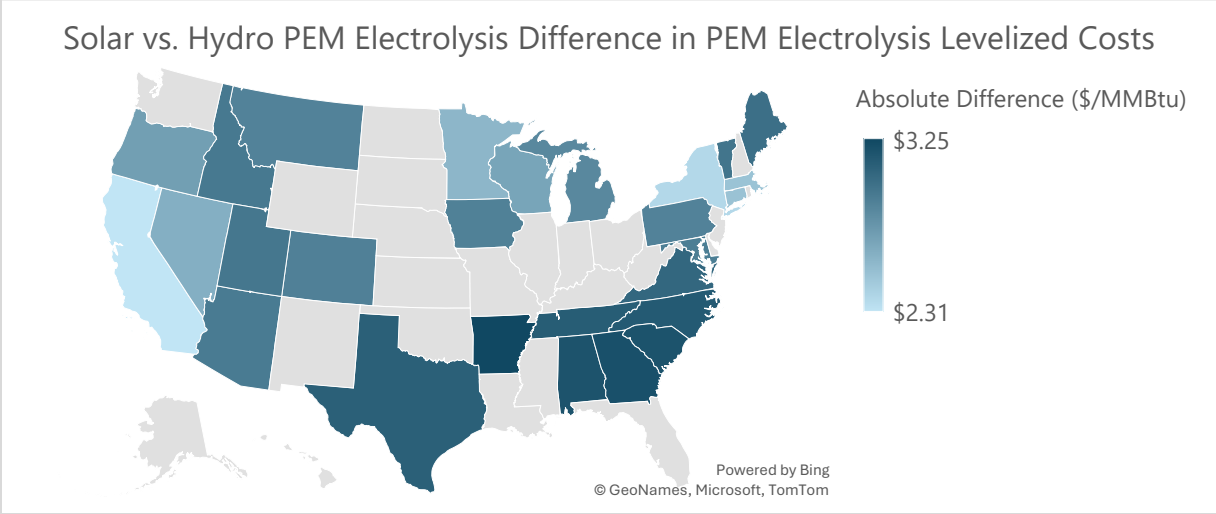


Figure 13. PEM Electrolysis w/ Solar vs. Hydro Levelized Cost Differences

State-specific levelized costs for H_2 produced via PEM electrolysis with solar are found to be $4.80 to 5.37/MMBtu higher than PEM with wind generation cases. However, levelized costs for solar PEM electrolysis generally agree across different states, ranging from $41.20 to 43.17/MMBtu H_2. Despite higher levelized costs observed with H_2 via

solar PEM electrolysis compared to wind powered, solar farms require less land compared to wind farms per MWh produced. This facility scale difference in solar generation has been a major contributing factor to the substantial historical market growth of solar farms compared to wind generation. Additionally, there is inherently greater confidence in solar power generation potential compared to wind generation potential in the future, which can impact the regional renewable electricity generation rates. Exceptional renewable electricity generation via solar is presently developed in California and Texas, largely due to significant land and solar resources in both states.

Similarly, nuclear and hydro power are best located near reliable access to larger water bodies. Levelized costs for PEM via hydro and PEM via nuclear demonstrate low variance across state cases but favor hydro (approximately $53/MMBtu) over nuclear (approximately $61/MMBtu). These higher costs in comparison to NG SMR with CCS are reflected as significantly increased variable O&M due to higher electricity costs. According to EIA, most currently operating nuclear power plants are located in the Midwest and East Coast. Both PEM with nuclear and PEM with hydro assume larger facility scales compared to PEM with other renewable electricity fuel cases (greater than 1 million MMBtu/year). However, the specific facility scales for PEM with renewable electricity will be highly dependent on local resource availability.

Strongest Opportunity States for H_2 via PEM Electrolysis (<$45/MMBtu)



States with Wind Potential:
as primary renewable source

Wisconsin, Minnesota, Michigan, Pennsylvania, New York, Maine

States with Solar/Wind Potential:
Montana, Wyoming, Colorado, New Mexico, South Dakota, Nebraska, Kansas, Oklahoma, Iowa, Texas, Missouri, Illinois, Indiana, Ohio

Several Midwest and Gulf Coast states have combined wind and solar potential.

Figure 14. H_2 via Wind PEM Electrolysis: Strongest Opportunity States

Resource Availability

Opportunities for PEM electrolysis will largely be determined by renewable resource potential, land availability, and renewable electricity affordability. Figure 15 summarizes the renewable energy resource abundance estimated across the continental United States (NLR 2021).

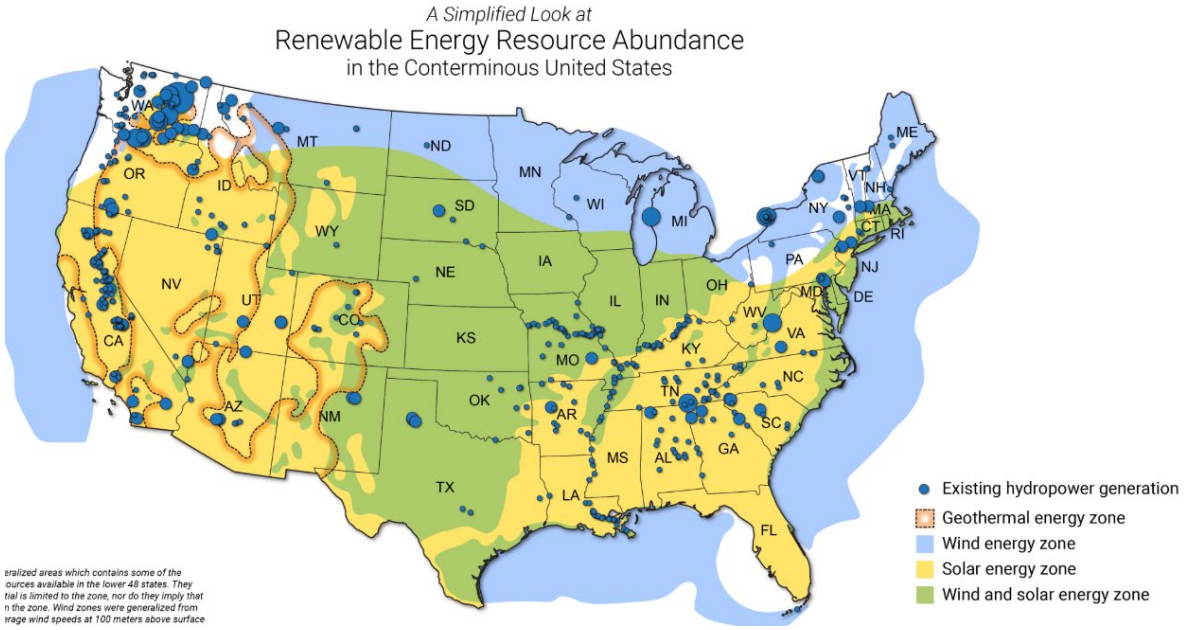


Figure 15. NLR Renewable Energy Source Abundance in the U.S. (2021)

Combined solar and wind potential is estimated for several Midwest states, as well as some Gulf Coast and Mid-Atlantic East Coast states. As of 2025, wind and solar electricity generation represents approximately 17% of U.S. renewable electricity generation (EIA 2025a). Hydropower potential is heavily concentrated in several states, with current generation in Western states (Arizona, Colorado, Idaho, Montana, Nevada, New Mexico, Utah, Wyoming, California, Oregon, and Washington) comprising approximately 60% of total U.S. current hydropower generation in 2024 (EIA 2024)_. Biomass electricity generation is geographically widespread but accounts for a smaller portion of renewable electricity generation. According to the Biomass Power

Organization, biomass power facilities can be found in each region but concentrated in the East Coast (51 facilities), Western U.S. (44 facilities), and Midwest (19 facilities) (Biomass Power Association 2025). According to EIA, current nuclear power generation represents approximately 17% of total U.S. electricity generation with over 57 facilities largely concentrated to the east of the Mississippi (EIA 2025b).

NG ATR with CCS and NG SMR with CCS

This study explores two similar routes for producing hydrogen via natural gas fed thermal methane reforming processes: steam methane reforming (SMR) and autothermal methane reforming (ATR). Although ATR and SMR possess similar thermal conversion rates to produce one kilogram of hydrogen, the ATR process is more thermally efficient than SMR and thus reduces additional process expenditures to maintain process temperatures.

Thus, NG SMR with CCS and NG ATR with CCS possess different facility capacities due to the process efficiency advantages assumed with the ATR process which reduce fuel/feed requirements per kilogram of H_2 produced. This translates to NG SMR consuming slightly more NG per kg H_2 produced compared to NG ATR and reflects as a moderately larger facility capacity for NG ATR with CCS cases (24,262,071 MMBtu LHV/yr) compared to NG SMR with CCS (17,755,425 MMBtu LHV/yr) cases. In both cases, carbon capture and transport to regional underground storage can achieve competitive lifecycle emission intensities.

Cost Findings

H_2 produced via natural gas autothermal methane reforming with CCS is one of the most cost-competitive fuel production pathways considered in this study, demonstrating cost competitiveness for 43 out of 48 states. Across different U.S. regions, levelized costs of hydrogen via SMR with CCS range from $12.24 to 25.44/MMBtu LHV, largely due to varying natural gas and electricity prices which impact fuel/feed and variable costs (Figure 16).

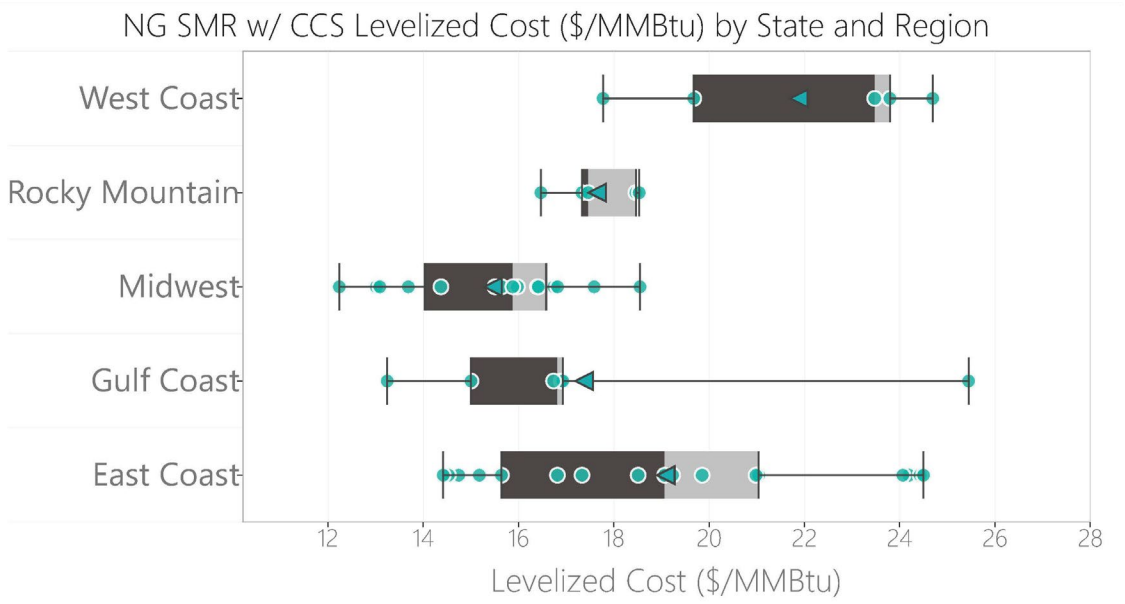


Figure 16. Regional NG SMR with CCS Levelized Costs

ATR v. SMR Cost Differences

In nearly all cases, NG ATR with CCS has lower capital, fixed O&M, and fuel/feed costs but higher variable O&M costs compared to NG SMR with CCS. However, there is less than a $1.50/MMBtu difference in levelized costs between NG ATR with CCS and NG SMR with CCS fuel cases for all continental U.S. states.

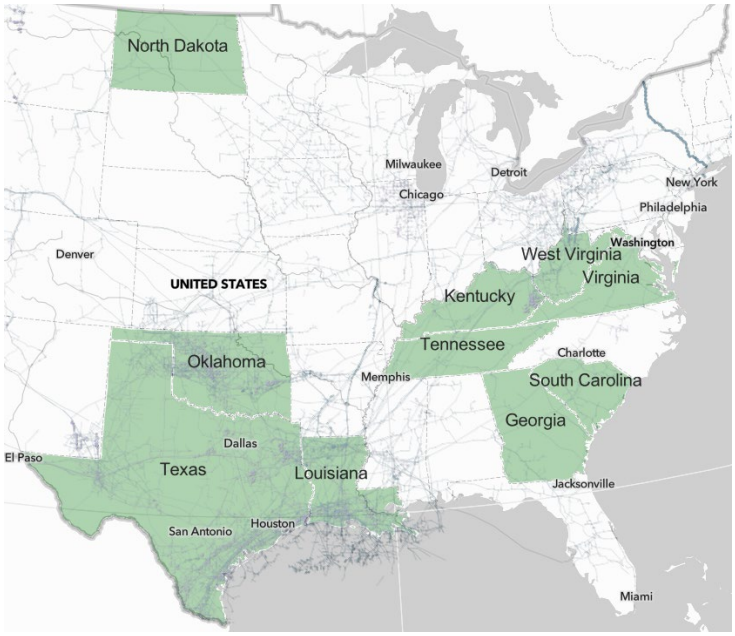
The greatest differences in levelized costs between NG SMR and ATR with CCS are observed for 18 states (approximately $0.80 to 1.32/MMBtu). NG SMR with CCS remains competitive with NG ATR with CCS for most remaining states (less than $0.80/MMBtu difference between levelized costs) not pictured in the figure above. There are only five states which favor SMR over ATR, including California, Rhode Island, Connecticut, Massachusetts, and New Hampshire; all of which demonstrate less than a $1/MMBtu difference from the NG ATR with CCS cases.

Overall, the levelized costs for NG ATR with CCS and NG SMR with CCS are generally in agreement for each state case but consider marginally different production scales. In the case of NG ATR with CCS cases, a larger facility capacity is assumed, which translates to an approximate additional 7.7 million MMBtu/year in comparison to the NG SMR with CCS cases.

The most competitive levelized costs for H_2 production via NG ATR or SMR with CCS are observed in the Midwest, Gulf Coast, and East Coast, led by Oklahoma ($11.38/MMBtu, ATR) and Kentucky ($12.10/MMBtu, ATR). However, the Midwest has the greatest number of states associated with levelized costs for SMR and ATR below $14/MMBtu (Oklahoma, Kansas, Kentucky, North Dakota, Oklahoma, Tennessee).

In nearly half of all states, levelized costs for NG SMR with CCS and NG ATR with CCS cases are below $17/MMBtu. The West Coast and Rocky Mountain regions are found to experience higher levelized costs for NG SMR with CCS and NG ATR with CCS fuel cases (greater than $16/MMBtu).

Strongest Opportunity States for H_2 via NG SMR with CCS, ATR with CCS (<13/MMBtu)



Lowest case: $11.36/MMBtu (Oklahoma, NG ATR with CCS)

< $13/MMBtu

Midwest: Oklahoma, Kentucky, Tennessee, North Dakota

≤$15/MMBtu

Gulf Coast: Louisiana
Midwest: Kansas, Nebraska, South Dakota
East Coast: West Virginia, Virginia, Nebraska, Georgia, South Carolina

Figure 17. H_2 via NG SMR with CCS, NG ATR with CCS: Strongest Opportunity States

While levelized costs for natural gas fed ATR and SMR with CCS cases are competitive in Georgia, South Carolina, Tennessee, and Virginia, scaling these H_2 production pathways in these states may require leveraging storage sites located in neighboring states or saline storage sites.

Regional CCS Potential

Affordable natural gas, industrial electricity and regional underground storage potential are core requirements of these two H_2 pathways. Existing CO_2 storage sites are heavily associated with enhanced oil recovery (EOR) depleted oil and gas fields, but total saline storage capacities in the U.S. are estimated to be more significantly associated with untapped deep saline formations.

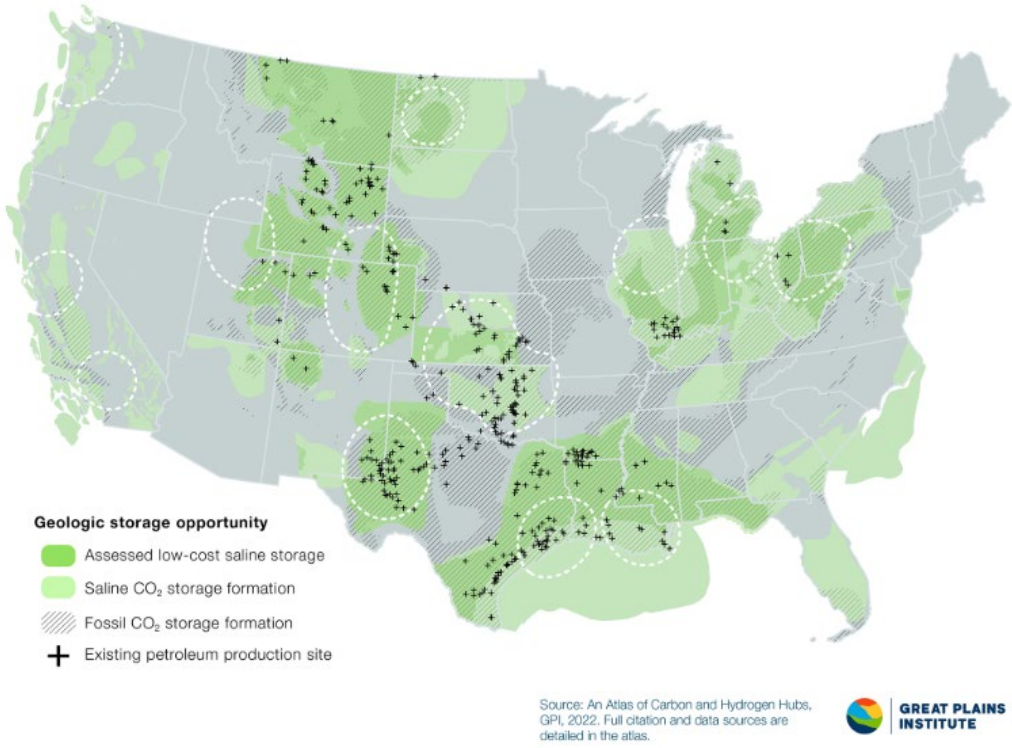


Figure 18. Regional Geologic Storage Opportunities (Great Plains Institute, 2022)

Primary saline storage opportunities are identified in North Dakota, South Dakota, New Mexico, Florida, South Carolina, and North Carolina, while substantial oil and gas geologic storage potential is concentrated in the Gulf Coast (Texas, Louisiana, Oklahoma, Mississippi), Midwest (Illinois, Ohio), and East Coast (Pennsylvania, West Virginia).

Active CO_2 geologic storage projects are currently developed in Texas, Wyoming, Louisiana, West Virginia, Illinois, and North Dakota.

CO_2 Enhanced Oil Recovery

Underground CO_2 storage can also provide local benefits by enabling EOR in basins with remaining oil reserves. A 2022 U.S. Geological Survey (USGS) assessment estimated that the majority of CO_2 storage potential associated with EOR is concentrated in underground storage basins in West Texas and Eastern New Mexico (44%), the Gulf Coast (17%), Midcontinent states (14%), and the Rocky Mountain and Northern Great Plains regions (12%) (Figure 19) (U.S. Department of the Interior et al. 2022).

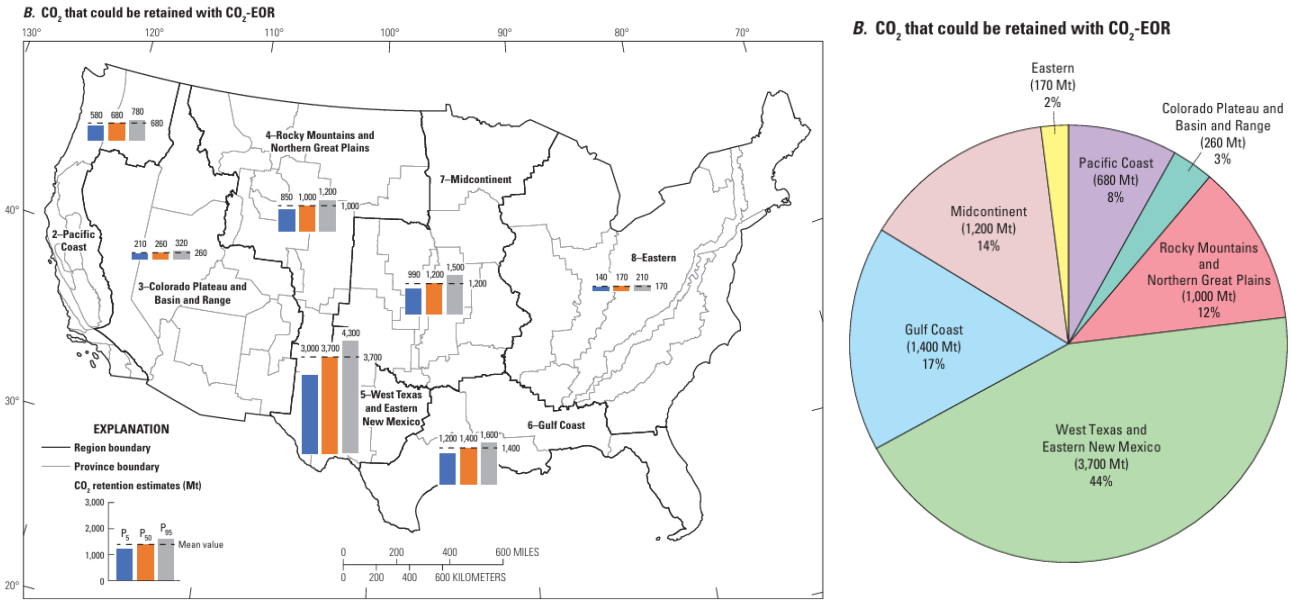


Figure 19. CO_2 Underground Storage Potential in EOR applications (USGS, 2022)

Future CO_2 storage potential in specific basins will also vary with regional storage needs and demand for CO_2, particularly in the production of advanced synthetic fuels such as sustainable aviation fuel, methanol, gasoline, and diesel. Based on these USGS estimates of CO_2 underground storage potential, most regions appear capable of accommodating the lifetime CO_2 sequestration requirements of at least five NG SMR or ATR facilities with CCS, assuming 30 years of operation, the facility scales considered in this study, and the applicability of CO_2 injection for EOR. Additional storage capacity may also be available through deep saline formations and depleted oil and gas reservoirs, as discussed above. A cost advantage is anticipated when leveraging CO_2 storage in CO_2 enhanced oil and gas reservoirs compared to deep saline storage due to the potential for revenue generation and the availability of existing infrastructure commonly associated with active oil and gas fields.

In some states, estimated deep saline CO_2 storage capacity exceeds that associated with existing oil and gas reservoirs. For instance, Illinois, Indiana, Michigan, Pennsylvania, West Virginia, Ohio and Kentucky possess greater potential for CO_2 storage in deep saline formations, reflecting the comparatively limited availability of depleted oil and gas reservoirs in these states.

Lifecycle Emissions Findings

Across all five regions, the relative ranking of the production pathways remained largely consistent, with only their magnitudes shifting from one region to the next. The only model input parameters that varied between states and regions were those related to the feedstock and energy source, so regional differences manifest as changes in magnitude rather than in pathway order. It should be noted that the upstream material models are resolved at differing levels of granularity depending on the supply source, for example, at the regional natural gas delivery regions versus the balancing authority level. This may contribute to some of the observed inter-state variations. Results are reported by pathway for each region and as a national average below (Table 6). It must be noted that the national averages attribute equal weights to each state and do not account for differences in production rate.

Table 4. National and Region Average LCA Emissions by Production Pathway

Production Pathway		East Coast	Midwest	Gulf Coast	Rocky Mountain	West Coast	National	Lowest Emitting State	
								State	CI
g CO_2e / kg H_2	SMR + CCS	**1.94**	3.15	3.56	4.87	3.79	3.46	New York	1.72
	ATR + CCS	**2.83**	4.38	4.72	6.72	4.28	4.59	New York	2.48
	Pyrolysis	**11.35**	17.24	18.67	28.83	12.35	17.69	New York	9.27
	PEM Solar	**1.52**	1.63	1.63	1.81	1.53	1.62	South Carolina	1.46
	PEM Wind	**1.66**	1.76	1.75	1.92	1.66	1.75	South Carolina	1.59
	PEM Nuclear	**0.95**	1.00	1.00	1.09	0.96	1.00	South Carolina	0.91

Production Pathway		East Coast	Midwest	Gulf Coast	Rocky Mountain	West Coast	National	Lowest Emitting State	
								State	CI
kg CO_2e / kg RNG	PEM Hydro	0.33	0.33	0.33	0.34	**0.32**	0.33	Washington	0.31
	PEM Biomass	65.80	48.30	49.69	**36.27**	85.33	57.08	Montana, Utah, and Wyoming	36.27
	RNG (LFG)	**0.93**	1.02	1.05	1.31	**0.93**	1.05	New York	0.83
	RNG (Wastewater)	**-5.90**	-5.86	-5.85	-5.73	-5.89	-5.85	South Carolina	-5.94
	RNG (Animal Manure)	**-7.88**	-7.84	-7.83	-7.72	**-7.88**	-7.83	South Carolina	-7.92

The Rocky Mountain region exhibits the highest carbon intensity for nearly every pathway assessed. This is due to its electricity supply, which remains heavily coal-based, resulting in the highest delivered-electricity emission factors in the country. Consequently, the electrolytic hydrogen pathways and the electricity demand of reforming, compression, and CO_2 capture lead to higher carbon intensities. The East Coast sits at the opposite end for almost all pathways, reflecting the combination of a comparatively low-carbon grid with substantial nuclear and, in New York, hydroelectric generation and a natural gas supply drawn largely from the Appalachian basin, which has the lowest upstream methane emissions intensity of any major U.S. producing basin. State-to-state variation is greatest on the West Coast, which spans nearly the full national range of grid carbon intensities, from the near-zero-carbon hydro grids of the Pacific Northwest to the more fossil-reliant Southwest.

RNG is the least emissions-intensive emerging fuel pathway overall, primarily because of the avoided-emissions credits incorporated into its lifecycle assessment. By capturing and utilizing biogenic methane that would otherwise be released to the atmosphere, RNG can significantly reduce lifecycle greenhouse gas emissions relative to conventional fuel pathways. RNG produced from animal manure has the lowest emissions of any pathway assessed, averaging -7.88 kg CO_2e/kg RNG nationally and reaching -7.92 kg

CO_2e/kg RNG in South Carolina. For all three RNG pathways investigated, the lowest emissions consistently occur on the East Coast, with the West Coast matching the East Coast for the animal manure and landfill gas pathways. Figure 20 illustrates the RNG production emissions by state.

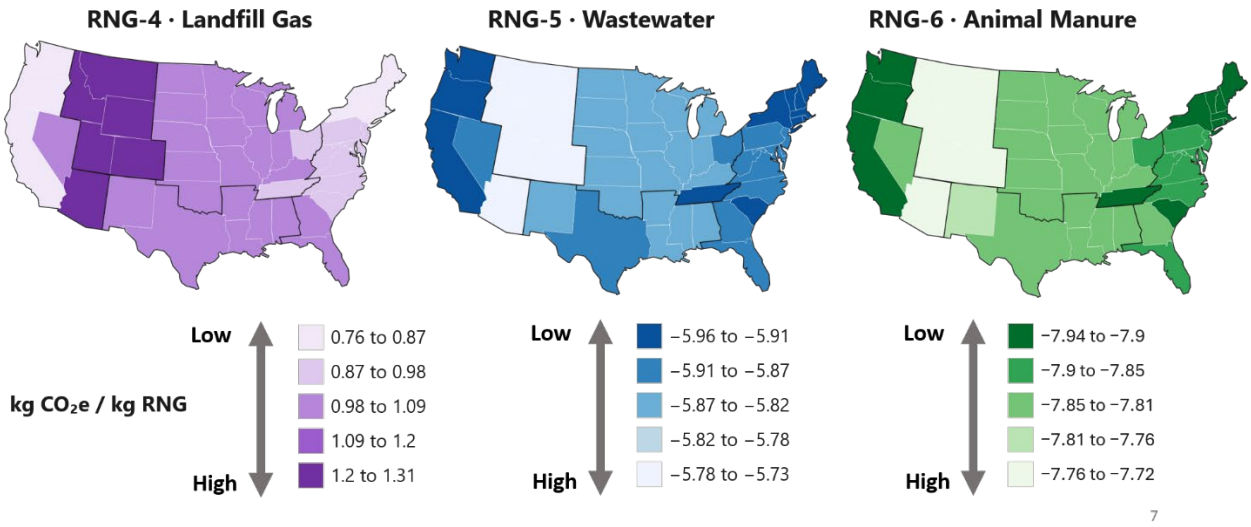


Figure 20. RNG Production Emission Intensity by Pathway

PEM electrolysis with hydropower is the lowest-emitting and most consistent pathway of all, varying only by 0.02 kg CO_2e/kg H_2 between regional averages (0.32-0.34) because the pathway is supplied by dedicated hydroelectric generation with near-zero operational emissions rather than by the regional grid. Its residual footprint derives almost entirely from upstream infrastructure and equipment manufacturing, which do not vary regionally. Conversely, biomass-powered PEM electrolysis was consistently the highest. This is driven by low conversion efficiency of biomass combustion together with upstream cultivation, harvesting, drying, and transport burdens.

The natural gas reforming pathways with CCS fell in the middle of the range relative to all the hydrogen production pathways, with interstate variation entirely dependent on differences in natural gas production and delivery regions. Plasma pyrolysis is among the most carbon-intensive methane-based pathways because it is doubly exposed to the two dominant drivers of variation. It consumes natural gas as a feedstock and requires substantial electrical input for the plasma torch while producing no captured-CO_2 credit, leaving its emissions to scale directly with both grid carbon intensity and upstream methane.

Figure 21 illustrates the hydrogen production emissions by state. It highlights where stark differences between regions exist and details inter-state variations.

Please refer to Appendix E for additional LCA results on regional variations.

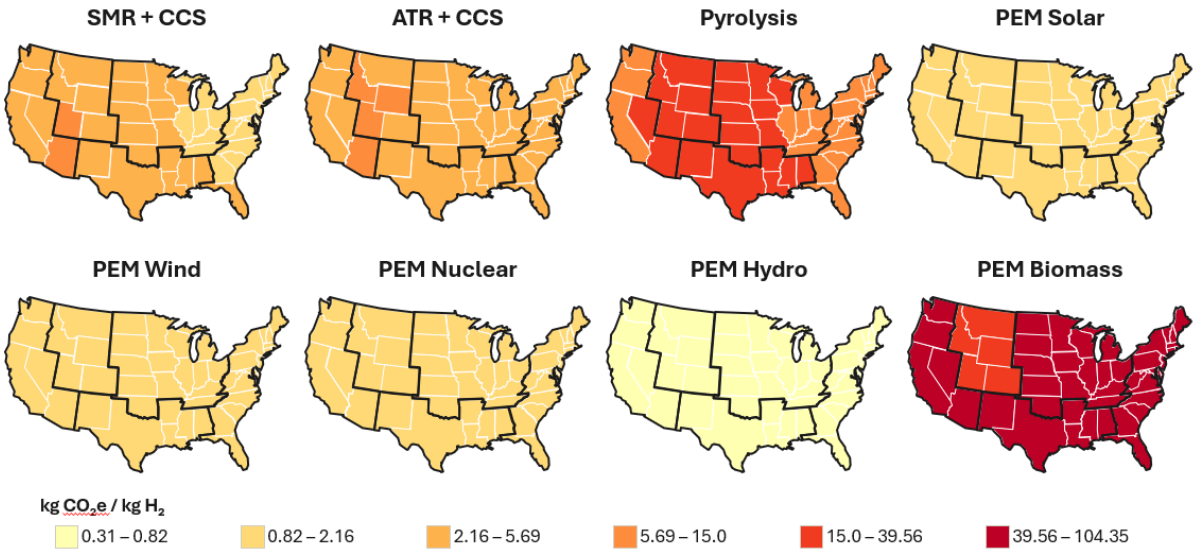


Figure 21. Hydrogen Production Emission Intensity by Pathway

Emissions Reduction Progress

The most effective way to reduce lifecycle carbon intensity is to lower emissions associated with upstream natural gas feedstocks and electricity inputs, which is an objective the energy industry is already actively pursuing.

Upstream natural gas operators continue to reduce methane emissions through expanded leak detection and repair programs, including replacing high-bleed pneumatic equipment, installing vapor-recovery systems, electrifying operations, improving flare performance, and utilizing operational measures that limit venting. The U.S. Environmental Protection Agency's national inventory shows that methane emissions from natural gas systems declined by 21% compared to 1990 levels (EPA 2026a). Upstream emissions intensity continues to decrease but performance varies by basin, operator, and equipment configuration. Midstream and downstream operators are also making strides to reduce methane emissions. According to the American Gas Association (AGA), methane emissions declined by more than 70% between 1990 and 2024 (AGA 2025). For example, National Fuel reported a 28% reduction in consolidated

methane emissions since 2020 and substantial progress toward segment-level methane intensity targets (National Fuels 2025). ONE Gas is set to reduce 55% of emissions originating from distribution pipelines and to date has steadily reduced Scope 1 emissions by 51% through its vintage pipeline replacement and protection program (ONE Gas 2025). Atmos Energy reported that its system modernization projects have reduced methane emissions for EPA-reported distribution mains and services by approximately 20% since 2017 (Atmos Energy 2022). Various other efforts are being led throughout the industry. Progress in reducing lifecycle emissions also depends on lowering the carbon intensity of the energy used for production, processing, compression, transport, and carbon capture. Retirement of higher-emitting coal capacity, deployment of more efficient generation, and additions of renewable, nuclear, and carbon capture-enabled resources can reduce delivered-electricity emissions and improve the lifecycle performance of electricity-intensive fuel pathways.

Existing projects also demonstrate that lower-carbon gaseous fuels are already being integrated into natural gas systems across the country, although deployment is more mature for RNG than for hydrogen. EPA's national project map documents a total of 135 operational landfill- and agricultural-based RNG facilities distributed across the country, with upgraded gas delivered by both transmission and distribution pipelines (EPA 2026b). Utility programs and interconnections similarly supply RNG from landfills, wastewater treatment plants, and agricultural digesters to existing customers (AGA 2024). Hydrogen blending remains primarily at the pilot and demonstration stage, but operating examples include CenterPoint Energy's Minneapolis project, which blends up to a 5% hydrogen blend into a distribution system (Center Point Energy 2022).

Key Insights

This section discusses the key insights from the case study, highlighting the considerations, potential opportunities, and strategic recommendations for deploying emerging fuels in natural gas infrastructure.

Near-Term Deployment Strategies and Considerations

A core advantage of RNG and H_2 is the potential compatibility with existing infrastructure and end use equipment, enabling adoption of alternative low-carbon fuels while minimizing extensive retrofits, upgrades, and asset decommissioning.

Strategic interconnections with existing pipeline infrastructure can support efficient adoption of RNG and H_2 blends. Several considered fuel pathways are associated with existing facilities that are often located in close proximity to existing natural gas infrastructure, including RNG production at wastewater treatment facilities and MSW landfills, as well as hydrogen production via NG SMR or ATR with CCS near depleted oil fields.

Pipeline injection enables the transport and utilization of larger volumes of RNG than on-site or local applications such as vehicle fuel, thermal uses, or virtual pipeline delivery. A pipeline interconnection typically consists of two components: a point of receipt and a pipeline extension. Where a nearby pipeline connection is not available, the RNG project must construct a pipeline extension to connect to the natural gas network. As a result, a common best practice is to minimize the distance between the RNG production site and the point of injection or end use whenever practical (EPA 2022). Leveraging existing natural gas infrastructure can reduce interconnection costs, simplify project development, and support the efficient transport of larger RNG volumes.

As found by a 2025 DNV study, integration of H_2 interconnections with operational pipelines is estimated to be 10 to 35% of new, greenfield pipeline construction costs on a \$/kg H_2 delivered basis (DNV 2025). Repurposing existing pipeline infrastructure also provides the opportunity to avoid right-of-way acquisition logistics, reduce construction emissions, and fast-track project timelines. These benefits may be greatest in regions with extensive natural gas delivery networks, which offer greater flexibility in siting new H_2 production facilities.

Realizing these benefits, however, requires asset-specific evaluation. Localized assessments of pipeline materials, operating conditions, integrity, and remaining useful life are necessary to identify infrastructure segments suitable for repurposing. Where existing assets are determined to be compatible, repurposing can provide a cost-effective alternative to constructing new greenfield pipeline infrastructure while supporting the expansion of low-carbon fuel pathways.

The Importance of Centralized Facilities

Centralized facilities can play a critical role in accelerating the deployment of RNG and H_2, offering advantages in economics, lifecycle emissions, and deployment timelines. For RNG production, centralized facilities can aggregate feedstocks from multiple local

sources (e.g., local farms, food waste), enabling economies of scale and higher production volumes. For example, feedstock cluster regions in the Midwest can support more streamlined scaling of RNG via dairy manure through centralized, multi-farm partnerships.

Similarly, centralized facilities for H_2 production can integrate production closer to storage sites, leveraging larger renewable electricity installments in prime resource regions and reducing integration costs associated with smaller distributed facilities. Large production hubs can also benefit from access to existing transmission infrastructure and geologic storage resources, particularly in regions where depleted oil and gas reservoirs and carbon storage opportunities are available. Existing gas transmission infrastructure in the Northeast and Gulf Coast can drive near-term deployments dependent on CCS infrastructure.

Strategic facility siting is a key consideration for scaling hydrogen production. Locating facilities near low-cost renewable resources, carbon storage opportunities, existing pipeline infrastructure, or major demand centers can improve project viability and reduce transportation costs. This is particularly important for serving industrial sectors that are often more challenging to electrify. Major industrial natural gas demand centers are concentrated in the Gulf Coast, Midwest, Northeast, and portions of the West Coast, highlighting the importance of aligning hydrogen production and delivery infrastructure with regional energy demand and resource availability (Figure 22).

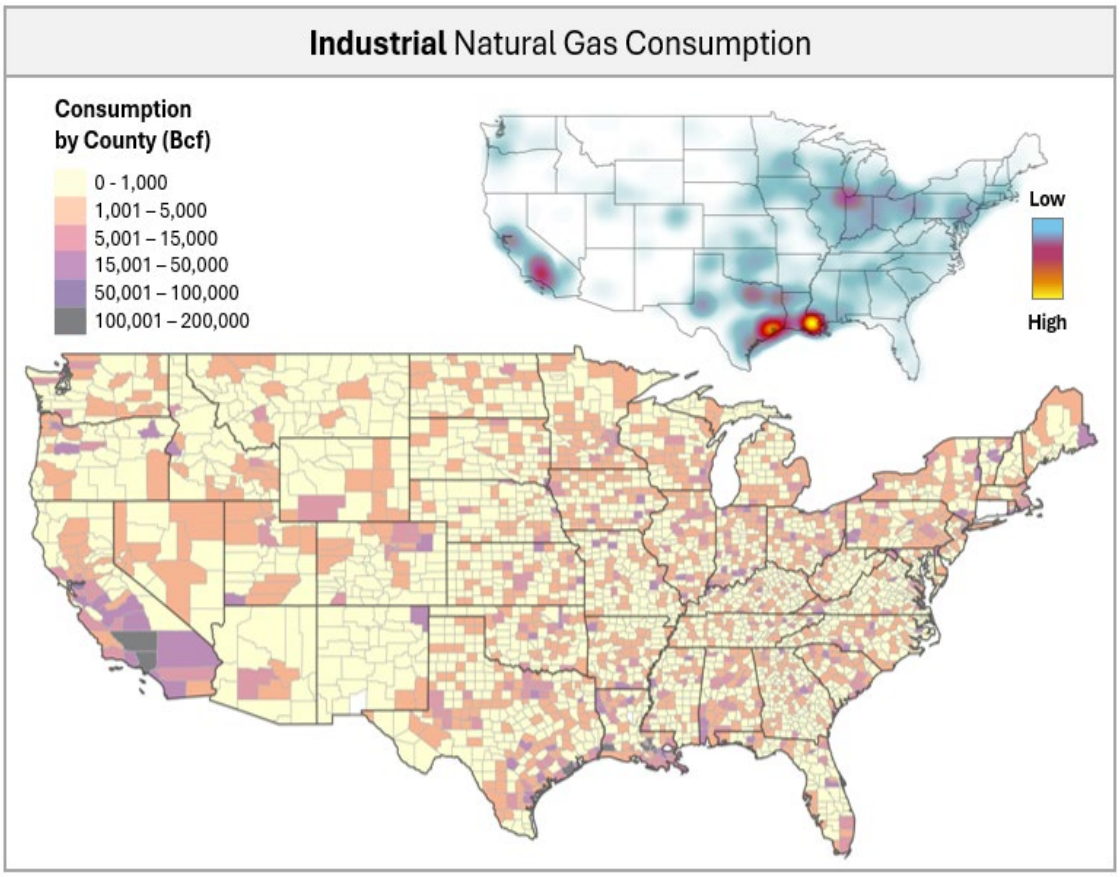


Figure 22. Industrial Natural Gas Consumption (EIA, 2024)

These industrial natural gas demand centers are expected to be among the earliest adopters of hydrogen and RNG blends, including fertilizer, chemical, glass, cement, steel, and food manufacturing, petroleum refining, pulp and paper production, heavy-duty transportation, data centers, and backup power generation.

Continued Expansion of RNG in Natural Gas Systems

RNG blending is currently deployed across portions of the U.S. natural gas system but overall adoption remains relatively limited compared to its estimated resource potential. Although estimated RNG production potential across the pathways evaluated is substantially lower than estimated hydrogen production potential when expressed as a fuel blend percentage, scaled RNG production can yield higher abatement levels with fewer facilities than the considered H_2 fuel production cases.

Due to in-state resources, scaling RNG produced from wastewater in New York, Michigan, Ohio, Utah, and Illinois have the greatest estimated emissions reduction

potential relative to in-state natural gas consumption among all contiguous states. In New York, for example, available wastewater resources could provide emissions reductions comparable to those achieved through a system-wide 5% hydrogen blend, while requiring a substantially lower overall fuel blend percentage (less than 1% RNG) and potentially lower total system investment.

Achieving H_2 Blend Targets

To meet a 5% blend target, the natural gas SMR and ATR with CCS pathways are generally the most efficient options evaluated in terms of the number of production facilities required. Several states with recognized underground storage potential require only one facility to meet a 5% H_2 blend target at the assumed production scale, including Colorado, Kentucky, New Mexico, and Utah. Similarly, only two facilities are required in states such as Alabama, Georgia, Illinois, Indiana, Michigan, Mississippi and Oklahoma.

A 20% blend of H_2 produced via H_2 SMR or ATR with CCS in the Rocky Mountain states, and some western Midwest states would require fewer than six facilities in each state. Existing underground storage in Wyoming and North Dakota has created precedence for the planning of several CO_2 pipelines connected to underground storage projects, moving CO_2 sourced across the Midwest and Rocky Mountain states. More broadly, a 20% hydrogen blend could be achieved with 10 or fewer NG ATR with CCS facilities (assuming a capacity of 27,500 kg/hr. H_2) in 42 states, and with fewer than 16 facilities in Pennsylvania, Ohio, Florida, California, and Louisiana.

Texas represents a unique case due to its combination of abundant energy resources, extensive existing infrastructure, and high natural gas consumption. As a result, achieving comparable hydrogen or RNG blending targets would require substantially greater deployment of production capacity than in most other states. For example, an estimated 10 and 39 NG ATR facilities with CCS would be required to achieve statewide hydrogen blending levels of 5% and 20%, respectively. Texas also benefits from significant CO_2 storage resources that could support CCS-based hydrogen production. In particular, Western Texas and the Gulf Coast region (Western Gulf, East Texas Basin and Louisiana-Mississippi Salt Basin Provinces) offer extensive storage opportunities in oil and gas reservoirs suitable for CO_2 EOR, as well as nationally significant deep saline storage formations.

Other Near-Term Blending Considerations

Although achieving a 5% hydrogen blend in New York would require an estimated four new natural gas SMR or ATR facilities with CCS, opportunities to expand RNG production from wastewater resources may support more rapid localized deployment. Similar findings are observed for RNG production from dairy manure in New York and Pennsylvania. Both states possess extensive dairy resources and exhibit emissions reduction potentials from RNG deployment that are comparable to those estimated for a 5% systemwide hydrogen blend produced through natural gas SMR or ATR pathways with CCS.

In several cases, producing in-state H_2 to meet a 5% blend at the considered facility scales and present consumption rates would create a surplus of produced hydrogen or could be achieved with smaller facility scales than considered in this study. For example, Pennsylvania, New York, Indiana, Colorado, Florida, Alabama, Georgia, Oklahoma, Louisiana, Mississippi would meet a 5% H_2 blend with fewer than 7 natural gas SMR or ATR with CCS facilities at the considered scales. At these assumed facility scales, these states would also generate a surplus of greater than 15,000,000 MMBTU annually, equivalent to nearly two methane pyrolysis facilities or more than 5 PEM electrolysis facilities at the scales considered.

Taken together, the results indicate that a combination of hydrogen and RNG deployment pathways may provide greater flexibility for achieving near-term decarbonization objectives while leveraging regionally available resources and infrastructure.

Summary of Most Promising Implementation Opportunities

Figure 23 summarizes the lowest cost fuel case opportunities in states with exceptional resource availability related to each fuel case. Several states demonstrate multiple fuel case opportunities, namely Texas, New York, California, Illinois, Ohio, Oklahoma, and Pennsylvania.



Figure 23. Regional Fuel Case Opportunities by Cost and Resource Availability

Specific fuel cases hold an advantage in achieving regional fuel production targets with fewer constructed facilities. At the facility scales considered, NG ATR and SMR with CCS require the least number of constructed facilities to meet a blending target. For instance, when targeting a 5% total system blend of H_2, most states in the Midwest require 1 to 6 facilities at a facility scale of at least 20,125 kg H_2/hr. Alternatively, due to the higher consumption of natural gas in Texas, more facilities (10 to 14) at the considered SMR and ATR facility scales would be required to meet a 5% blend target for H_2. For the same hydrogen blending target, a greater number of production facilities are required for hydrogen generated via PEM electrolysis and for RNG produced from wastewater treatment plants, dairy manure, and upgraded landfill gas. This is primarily due to the smaller facility scales typically associated with these production pathways, necessitating deployment across a larger number of sites to achieve an equivalent fuel supply volume.

Development of PEM electrolysis facilities is expected to be most favorable in states with relatively high natural gas prices, low-cost land availability, and strong renewable energy resources. Several states, including Missouri, North Dakota, Nebraska, South Dakota, and Kansas, demonstrate levelized hydrogen production costs below $40/MMBtu for PEM electrolysis, possess significant wind and solar resource potential, and would require fewer than 20 facilities, at the assumed facility scales, to achieve an in-state 5% hydrogen blend. These characteristics suggest favorable conditions for near-term deployment of electrolytic hydrogen production infrastructure in these states.

RNG Opportunities

Maximizing Abatement

Based on the LCA results, emerging fuels deployment should be matched to regional feedstock and grid characteristics rather than pursued uniformly. Where suitable biogenic feedstocks are available, RNG offers the greatest emissions reduction benefit, delivering net carbon-negative lifecycle emissions and outperforming every hydrogen pathway assessed. These routes therefore warrant priority where feedstock supply and collection infrastructure allow. Although RNG production pathways considered in this study possess higher calculated levelized costs on a $/MMBtu produced basis, existing incentives (e.g., EPA RFS credits, state-level low-carbon fuel standard program credits) can improve overall economics.

Targeting Low-Cost, High-Impact RNG Feedstocks

- RNG blending targets will need to be met by multiple resource streams.
- RNG produced from wastewater treatment facilities demonstrates a significant cost advantage over RNG from dairy manure in Ohio, Illinois, Missouri, Pennsylvania, Indiana, Wisconsin, Michigan, and Texas, with levelized cost differences exceeding $20/MMBtu. However, RNG via dairy manure emissions are on average 33.76% lower than RNG via Wastewater over the considered fuel case assumptions.
    - Idaho and New York exhibit the smallest cost differential between RNG produced from wastewater and RNG produced from dairy manure among all states evaluated. New York is notable for its strong availability of both wastewater and dairy manure resources, whereas Idaho possesses comparatively stronger dairy manure resources relative to wastewater resource potential.
- There is a stronger contrast in wastewater and dairy manure resource availability in in Tennessee, North Carolina, Alabama, Maryland, Georgia, Louisiana, Massachusetts, and Arizona, where wastewater resources significantly exceed dairy manure resource potential and may offer greater opportunities for RNG development.

Scaling to RNG Blending Targets

Due to regional resource availability, scaling RNG will need to be achieved with diverse facilities. While RNG via upgraded landfill gas is consistently identified as the lowest cost

RNG production method, in-state estimated landfill gas resources in several states, (e.g., Louisiana, New York, Florida, Nevada, Oregon) are insufficient to support total system blend targets above 5%. However, for blend targets below 5%, these states can more heavily rely on upgraded landfill gas to achieve these blending targets.

- In consideration of existing in-state resources, a 10% RNG blending target in numerous states can be met with the lowest number of facilities with landfill gas RNG (7 to 33 candidate facilities, 17 states) but cannot be completely achieved with dairy manure RNG alone. However, in combination, these pathways are particularly favorable in regions with pipeline adjacent dairy manure and existing MSW landfills of optimal size and age.
- Diversifying feedstocks at one RNG facility(i.e., co-digesting) is an opportunity for increasing RNG production and is most often discussed with incorporating locally supplied food waste into a wastewater or animal manure digester. The opportunities for co-digestion depend on facility capacity.
- Another emerging opportunity for increasing RNG production in a region is developing larger centralized facilities, which process feedstocks from multiple sources. An example of this type of centralized facility is in Wisconsin, at the 16-digester BC Organics facility which processes agricultural manure from several different farms (BC Organics 2023).

H_2 Opportunities

Maximizing Abatement

For hydrogen, the lowest-emission option is PEM electrolysis powered by low-carbon electricity. Therefore, electrolytic capacity is best suited where grids are cleanest, notably hydro-rich regions and nuclear-heavy grids. Where natural gas-based hydrogen is pursued, reforming with CCS is most advantageous, especially on the East Coast, where the comparatively low-carbon grid and low-methane Appalachian gas supply yield the lowest upstream burden. In comparison, the electricity intensive plasma pyrolysis and biomass-powered electrolysis pathways are not ideal for mass-scale production due to their high carbon intensities. Finally, because fuel carbon intensity is driven chiefly by the emissions of delivered electricity and natural gas, continued energy decarbonization through grid modernization and methane mitigation in the natural gas supply chain would lower emissions across nearly all pathways and should accompany any production build-out.

Targeting Low-Cost, High-Impact H_2 Feedstocks

- Specific states have an advantage to scale NG SMR with CCS and NG ATR with CCS due to affordable NG and in-state CCS saline and mature oil/gas reservoir storage potential.
- Scaling low-carbon H_2 with plasma pyrolysis will require additional strategies to achieve competitive carbon intensities compared to other considered pathways, particularly when results are compared on an energy content basis ($/MMBtu LHV) rather than a mass basis (kg H_2).
- Specific states have an advantage to scale NG SMR with CCS and NG ATR with CCS due to affordable NG and in-state CCS saline and mature oil and gas reservoir storage potential.
- There is general agreement in plasma pyrolysis fuel cases by state, but local carbon markets will strongly affect overall economics. Strong markets for carbon black exist in the Gulf Coast, East Coast, and Midwest.
- The lowest levelized hydrogen production costs for PEM electrolysis are achieved when powered by wind or solar electricity, ranging from approximately $43 to $61/MMBtu. The most competitive costs are observed in the Midwest and select Gulf Coast and East Coast states, where levelized costs fall below $45/MMBtu and are supported by strong renewable energy resource potential.

Scaling to H_2 Blending Targets

- At the facility scales evaluated, a 10% hydrogen blending target in most regions can be achieved using natural gas-based SMR or ATR with CCS through deployment of less than five facilities in each state and as few as 10 facilities in PADD4. These pathways are particularly favorable in regions with access to low-cost natural gas supplies and strong carbon storage potential.
    - Specific Gulf Coast and Midwest states stand out as strong opportunities.
- Plasma pyrolysis and PEM electrolysis generally exhibit smaller lifecycle greenhouse gas emission reductions in regions with carbon-intensive electricity grids.

Recommendations

The case study findings indicate that regional fuel production opportunities are primarily driven by industrial natural gas prices, electricity prices, labor costs, feedstock

availability, and access to supporting infrastructure such as carbon storage and natural gas pipeline interconnections.

Across the pathways evaluated, natural gas-based hydrogen with CCS, especially ATR and SMR with CCS, generally shows the most competitive levelized costs in many states, while methane pyrolysis offers attractive opportunities in regions with low-cost natural gas and electricity and where solid carbon markets can improve project economics. The strongest opportunities for SMR and ATR with CCS are concentrated in select Gulf Coast, Midwest, and East Coast states, including Oklahoma, Texas, Louisiana, North Dakota, Kentucky, and Tennessee. These states exhibit some of the lowest estimated levelized costs, generally below $15/MMBtu, while also benefiting from access to geologic formations suitable for carbon storage. Similar geographic trends are observed for methane pyrolysis, with the lowest estimated production costs, generally below $18.50/MMBtu, occurring in Oklahoma, Tennessee, Kentucky, Louisiana, North Dakota, and South Carolina, largely due to favorable natural gas and electricity prices.

PEM electrolysis remains more cost-sensitive to renewable electricity prices, with wind-powered cases generally showing the lowest electrolysis costs and solar-powered cases offering broader deployment potential where land and solar resources are favorable, especially in Midwest and Gulf Coast states.

RNG pathways show strong emissions-reduction potential but vary substantially in cost and scalability by feedstock. Upgraded landfill gas is the lowest-cost RNG option among the RNG cases reviewed and has meaningful near-term potential in states with large candidate landfills and high recoverable methane potential, including California, Texas, Pennsylvania, Georgia, Illinois, Ohio, and Florida.

Wastewater-derived RNG appears most promising where large municipal wastewater treatment facilities, existing anaerobic digestion capacity, and pipeline proximity align, with higher resource potential identified in states such as New York, Texas, Ohio, Michigan, California, New Jersey, Pennsylvania, Florida, and Illinois. Dairy manure RNG has higher levelized costs than landfill gas and wastewater RNG but provides substantial carbon intensity benefits and remains regionally relevant in states with large dairy resources, particularly in the Midwest and select East Coast and West Coast states.

Overall, the findings suggest that near-term deployment strategies should prioritize region-specific pathway matching rather than a single national fuel strategy. The most

promising opportunities are likely to occur where low-cost feedstocks or energy inputs, favorable facility scale, existing infrastructure, and high emissions-abatement potential overlap. For hydrogen, this points to targeted development of NG ATR or SMR with CCS in regions with low-cost natural gas and geologic storage access, methane pyrolysis in low-cost natural gas and power regions with viable carbon product markets, and PEM electrolysis where low-cost renewable electricity and land or renewable resource availability are favorable. For RNG, deployment should focus first on landfill gas and wastewater opportunities with strong resource availability and infrastructure access, while dairy manure projects may be best suited for states where emissions benefits and agricultural resource concentration justify higher production costs.

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