Considerations for Low-Carbon Alternative Fuel Use in New York State

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NEW YORK STATE

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Considerations for Low-Carbon Alternative Fuel Use in New York State

Final Report

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Abstract

This report, commissioned by the New York State Energy Research and Development Authority (NYSERDA) and prepared by The Brattle Group, assesses the potential role of low-carbon alternative fuels in achieving New York State’s ambitious climate and clean energy targets under the Climate Leadership and Community Protection Act (Climate Act). While the majority of emissions reductions are expected to come from widespread electrification using clean power, certain sectors, such as aviation, heavy transport, and some industrial uses, are difficult to electrify and will require alternative fuels as a complementary solution. The report evaluates a wide range of low-carbon fuels, including biofuels, renewable natural gas (RNG) , and hydrogen, examining their end uses, production pathways, infrastructure needs, emissions impacts, and supply chain considerations. Findings highlight the importance of coordinated policy, infrastructure adaptation, and environmental safeguards, especially for disadvantaged communities (DACs). Strategic recommendations include developing regulatory and market incentives, optimizing limited feedstock use, minimizing emissions and local impacts, and aligning New York State’s efforts with regional, national, and international markets. Alternative fuels will play a limited but critical role in supporting a resilient, equitable, and decarbonized energy future for New York State.

Keywords

biodiesel, renewable diesel, electrification gaps, energy infrastructure repurposing, environmental justice (EJ) communities, greenhouse gas (GHG) emissions, hydrogen, low-carbon alternative fuels, renewable natural gas (RNG), sustainable aviation fuel (SAF), hard-to-decarbonize, biofuel, bioenergy

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Acronyms and Abbreviations

ºC	degrees Celsius
ACER	European Union Agency for the Cooperation of Energy Regulators
ACES	advanced clean energy site
AD	anaerobic digester
AFP	Alternative Fuels Portal
API	American Petroleum Institute
AR6	Sixth Assessment Report
ASTM	ASTM International
ATJ	Alcohol-to-Jet
ATJ-SKA	Alcohol-to-Jet Synthetic Paraffinic Kerosene with Aromatics
ATJ-SPK	Alcohol-to-Jet Synthetic Paraffinic Kerosene
Bcf	Billion cubic foot

BESS	Battery Energy Storage System
BT23	*2023 Billion-Ton Report*
CAC	Climate Action Council
CA-GREET	California Greenhouse Gases, Regulated Emissions, and Energy Use in Technologies
CAPEX	capital expenditures
CARB	California Air Resources Board
Central Hudson	Central Hudson Gas and Electric Company
CES	Clean Energy Standard
CH_4	methane
CH-SK or CHJ	catalytic hydrothermolysis synthesized kerosene
CI	carbon intensity
CJWG	Climate Justice Working Group
Climate Act	Climate Leadership & Community Protection Act
CNG	compressed natural gas
CO_2	carbon dioxide
CO_2/MJ	carbon dioxide equivalent per megajoule
CO_2e	carbon dioxide equivalent
CORSIA	Carbon Offsetting and Reduction Scheme for International Aviation
DAC	disadvantaged community
DCAS	New York City Department of Citywide Administrative Services
DEC	New York State Department of Environmental Conservation
DOE	U.S. Department of Energy
DRI-EAF	direct reduced iron-electric arc furnace
EAC	Energy Attribute Certificate
EIA	U.S. Energy Information Administration
EJ	environmental justice
EMTS	EPA Moderated Transaction System
EPA	U.S. Environmental Protection Agency
EUH2STARS	European Underground Hydrogen Storage Reference System
FAA	Federal Aviation Administration
FERC	Federal Energy Regulatory Commission
FFA	free fatty acid
FOG	Fat, oil, and grease
ft^3	cubic foot
FT-SPK	Fischer-Tropsch synthetic paraffinic kerosene
FT-SPK/A	Fischer-Tropsch with aromatics
gCO_2e/MJ	grams of CO_2 equivalents per megajoule
GHG	greenhouse gas

GO	Guarantee of Origin
GREET	Greenhouse Gases, Regulated Emissions, and Energy Use in Technologies
GWP20	20-year global warming potential
HC-HEFA-SPK	hydrocarbon-hydroprocessed esters and fatty acids
HEFA	hydroprocessed ester and fatty acid
HEFA-SPK	hydroprocessed esters and fatty acids from plant and animal oils
HFS-SIP	hydroprocessed fermented sugars to synthetic isoparaffins
ICAO	International Civil Aviation Organization
ILUC	Induced land use change
IPCC	Intergovernmental Panel on Climate Change
JFK	John F. Kennedy International Airport
kg	kilogram
km	kilometer
kt	kiloton
ktH_2/yr	kilotonnes of hydrogen per year
kWh	kilowatt hour
LCA	life-cycle analysis
LCFS	Low-Carbon Fuel Standards
LHV	lower heating value
LPP	leak prone pipe
LRT-CBTS	LCFS Credit Banking and Transfer System
LUC	land use change
MACH2	Mid-Atlantic Hydrogen Hub
MJ/m^3	megajoule per cubic meter
$MMBtu/m^3$	Million British thermal units per cubic meter
MMT	million metric ton
MSW	municipal solid waste
MW	megawatt
MWh	megawatt-hours
MWh/m^3	megawatt-hours per cubic meter
N_2O	nitrous oxide
New York State	New York State
NH_3	ammonia
NO_x	nitrous oxides
NREL	National Renewable Energy Laboratory
NYC	New York City
NYISO	New York Independent System Operator
NYSERDA	New York State Energy Research and Development Authority

OEM	original equipment manufacturer
OPGEE	Oil Production Greenhouse Gas Emissions Estimator
PEM	polymer electrolyte membrane
PHMSA	Pipeline and Hazardous Materials Safety Administration
PoS	proof of sustainability
ppm	parts per million
PSC	Public Service Commission
psig	pounds per square inch gauge
PTD	Product Transfer Document
REC	renewable energy certificate
RED	Renewable Energy Directive
RFS	renewable fuel standard
RIN	renewable identification number
RNG	renewable natural gas
RVO	renewable volume obligation
SAF	sustainable aviation fuel
SCR	silicon-controlled rectifier
SMR	steam methane reforming
STB	Surface Transportation Board
syngas	synthetic gas
TBtu	trillion British thermal units
USDA	U.S. Department of Agriculture
VOC	volatile organic compound
WEF	World Economic Forum
WTTP	wastewater treatment plant
WWRF	wastewater recovery facility

Summary

The New York State Energy Research and Development Authority (NYSERDA) engaged The Brattle Group to systematically review low-carbon alternative fuels and evaluate their potential role in achieving New York State's (NYS) energy and climate policy goals. These goals envision that the majority of the emissions reductions needed will come through the electrification (with clean electricity) of most traditional fuel-dependent end uses, but that low-carbon alternative fuels will also play a necessary role as a backstop energy source for some hard-to-electrify sectors and end uses, such as air travel, heavy transport, industrial applications, and electric reliability. Given this, New York State must closely coordinate its alternative fuel strategy with its broader clean energy transformation strategy and activities, as reflected in the Climate Act.

Low-carbon alternative fuels are likely to cost more than fossil fuels due to limited supply and because fossil fuel prices tend not to incorporate externality costs like greenhouse gas (GHG) and co-pollutant emissions. The State will likely utilize low-carbon alternative fuels in smaller volumes, consistent with their backstop role in sectors that are hard to electrify.

This report reviews alternative fuels from several perspectives: potential end-uses; production pathways, including cost and feedstock availability; infrastructure needs for production, transportation, distribution, storage, and the potential for repurposing existing fossil fuel infrastructure; the likely structure and geographic scope of markets; research and development needs; and the emissions impacts of alternative fuels.

Key findings of the review include:

- Biofuel availability may be limited by available feedstock, while in-state demand centers will face competition from neighboring states with similar clean energy goals and from other hard-to-decarbonize sectors. However, given that fuel use is expected to decline over the long term, the State may have sufficient alternative fuel potential to meet anticipated demand under most future scenarios.
- Some alternative fuels, like renewable natural gas (RNG) and renewable diesel, may be able to repurpose New York State's extensive existing infrastructure network for fuel transportation. However, their viability depends on proximity to production and demand centers (e.g., agricultural feedstocks are concentrated in Western and Central New York), necessitating investment in new first-mile infrastructure. Other fuels, like hydrogen, may require repurposing existing systems or building entirely new systems to support the supply chain. Siting new infrastructure should also consider mitigating negative impacts on local communities.

- Similarly, any environmental impacts of biofuels on local, disadvantaged communities (DACs) should be minimized where possible. Certain production pathways may deliver greater emissions reduction than others, although estimates remain uncertain. Careful assessment of avoided emissions benefits from waste management, and additional emission impacts from induced LCUs, is necessary to evaluate the full benefits of alternative fuels. In addition, in-state and imported fuels may offer different levels of contribution toward Climate Act emission reduction targets, which must be balanced with the State's other priorities.

Based on this review, the report outlines strategic guidelines for how New York State can direct research, development, and policy to maximize the benefits of alternative fuels, especially in decarbonizing hard-to-abate sectors, while enhancing reliability, resilience, and affordability of the energy system.

Strategic Element 1: Regulations and Incentives

New York State should consider regulatory and market incentives to facilitate and transform today's nascent alternative fuel markets. These measures should (1) optimize the use of limited feedstock effectively between different alternative fuels for their production, and (2) prioritize the use of these fuels for high-value end uses.

Current markets for low-carbon alternative fuels in the U.S. are nascent, with small volumes of low-carbon alternative fuels currently produced. While biofuel production has grown in recent years due to federal and State policies and tax incentives, biofuel volumes are still quite small relative to their traditional fossil fuel equivalents.[1] For example, in 2023, the energy output of fossil gasoline diesel produced was over 50 times greater than the combined energy output of all the renewable diesel and biodiesel produced in the U.S.[2, 3]

To convert end uses and develop the necessary production capacity, transportation, and markets for low-carbon alternative fuels, New York State will require significant policy, regulatory, and market initiatives to guide the development of supply and demand for these fuels. New York State can leverage the potential feedstocks and supplies within the State and region and may be able to import alternative fuels from more distant sources. However, as detailed in Section 2.2, organic feedstocks needed to produce many low-carbon alternative fuels are quite limited relative to current fossil fuel usage. Neighboring states and Canadian provinces are also pursuing similar strategies to meet their own climate and energy policy goals, significantly increasing competition for available supplies.

Over time, local, regional, and potentially national and international markets for low-carbon alternative fuels are likely to emerge, even if overall volumes are smaller. These markets may resemble current fossil fuel markets due to similar drivers, such as high value, ease of transportation, location of supply versus demand, differing product costs). Once developed, these broader markets can help direct both feedstocks and the low-carbon alternative fuels themselves to the highest value uses in New York State and elsewhere. The State should help shape the development of these markets and coordinate its policies and regulations to align state-level supply and demand with broader regional and national efforts.

Strategic Element 2: Alternative Fuel Infrastructure

New York State will need to develop infrastructure to support a low-carbon alternative fuels sector. Where feasible, the State should optimize and repurpose existing infrastructure to mitigate potential costs and avoid environmental and community impacts from new construction. Collaboration with neighboring states and provinces to plan and develop this infrastructure can further reduce these impacts, especially as alternative fuel markets extend well beyond New York State borders.

New York State should also consider developing distribution infrastructure to connect low-carbon alternative fuel supplies with demand. Where fuels are not drop-in replacements for fossil fuels, New York State may need to incentivize the production and deployment of end-use equipment that accommodates these alternatives.

The State already has an extensive array of existing energy infrastructure, including natural gas and petroleum pipelines, fueling depots, rail and marine transport, designed and built around connecting today’s (largely fossil) fuel supplies with demand. As New York State transitions toward a decarbonized future, it may retrofit or repurpose portions of this infrastructure for alternative fuel applications. However, as discussed in Section 3, this will require addressing certain technical and safety challenges. In some cases, new or upgraded infrastructure may also be necessary, for example, when low-carbon alternative fuel supply and demand differ geographically from existing current fossil fuel patterns; transportation infrastructure needs may change.

In addition, New York State may need to develop new “first-mile” infrastructure to connect new sources of energy feedstocks, such as crop waste or energy crops from agricultural regions, to production facilities. Where repurposing existing infrastructure is not feasible or economic, coordinated regional infrastructure planning with neighboring states and provinces may help reduce the need for new infrastructure, limiting costs and other negative impacts.

Strategic Element 3: Emissions

While alternative fuels typically emit fewer GHGs and copollutants than conventional fuels, they are not entirely emissions-free. New York State should quantify, track, and control these emissions at (1) the global scale, to maximize GHG reduction benefits, and (2) the local scale, to ensure that disadvantaged communities (DACs) and environmental justice (EJ) communities are not disproportionally affected by localized air, water, and land use impacts. New York State may also consider establishing standards, incentives, and renewable fuel attribute markets, in coordination with neighboring regions, to improve accounting accuracy, transparency, and transaction efficiency between producers and suppliers.

Alternative fuels' potential GHG, co-pollutant emissions, and land use impacts warrant further consideration and evaluation by New York State. Most alternative fuels still emit GHGs during combustion, sometimes at levels comparable to fossil fuels. Alternative fuels also produce co-pollutants during combustion, which will need to be quantified, tracked, and controlled to understand and limit local air quality impacts, particularly in relation to DACs and EJ communities. While total fuel demand is expected to decline, reducing total co-pollutant emissions, local concentrations must still be considered.

The production of alternative fuels also has land use implications that New York State should work to understand and address with policy solutions. For example, growing energy crops may divert agricultural land and resources from food or animal feed production, or require the conversion of new agricultural land to meet feedstock demand. In addition, considerable variability and uncertainty are involved with the commonly applied life-cycle analysis (LCA) methods, most specifically regarding land use impact and emissions. Establishing emissions standards (GHG and co-pollutants) and environmental impact standards will be important for the State, followed by the development of regulations or measures such as siting and permitting requirements and life-cycle analysis certification mechanisms.

As an interim strategy, the State may encourage blending alternative fuels with conventional fossil fuels (where feasible). This approach can reduce emissions in the near term while facilitating development of both supply and demand, which will be particularly useful in hard-to-decarbonize sectors and will rely on alternative fuels in the long run.

In this context, New York State may also benefit from developing renewable attribute markets in coordination with neighboring states to allow for ease of transactions and to encourage the development of renewable fuel markets that create the proper emissions and environmental incentives.

Strategic Element 4: Coordinate with Other Jurisdictions

New York State should engage and collaborate with government and market efforts in other jurisdictions to scale low-carbon alternative fuel markets. This coordination can help optimize feedstock supply, develop new infrastructure, and establish emissions and environmental attribute tracking and accounting systems.

New York State is not alone in addressing the challenges and opportunities of low-carbon alternative fuels. State, federal, and international initiatives are already underway to support their large-scale deployment. For example, New York State offers incentives to encourage the development and adoption of these fuels, such as the Alternative Fuel Infrastructure Tax Credit and Heavy-Duty Alternative Fuel and Advanced Vehicle Purchase Vouchers program.[4, 5] At the federal level, incentives include vehicle subsidies, funding for regional clean hydrogen hubs, and the U.S. Environmental Protection Agency's (EPA) Renewable Fuel Standard (RFS). Internationally, more than 65 countries, including the U.S., have published national hydrogen strategies and roadmaps.[6]

Several neighboring states and Canadian provinces that have decarbonization goals are similarly evaluating the role of alternative fuels in their decarbonization strategies. Massachusetts anticipates using a mix of alternative fuels and e-fuels[7] across sectors to serve nonelectrified demand.[8] Énergir, the largest natural gas distributor in Quebec and Vermont, plans to blend RNG and hydrogen into its gas systems.[9] Furthermore, New Jersey currently consumes approximately two-thirds of the renewable diesel imported to the East Coast.[10]

As the alternative fuel ecosystem evolves and becomes more mainstream, New York State should coordinate these and other policies across jurisdictions to ensure consistency and effectiveness. Coordinating with other states, provinces, the federal government, and even international governments will help harmonize with others in the region, nationally, and even globally.

Such coordination can facilitate the creation of consistent fuel product designations and specifications, emissions measurements and requirements, and environmental attribute definitions and tracking. This collaboration will facilitate the development of broad geographic markets, effective regional fuel transportation systems, and encourage both supply and demand growth for alternative fuels, ensuring their availability at scale in the longer term, at reasonable costs, and with credible emissions benefits.

1 Introduction: The Role of Alternative Fuels in Decarbonizing New York State's Economy

To meet its ambitious climate and clean energy goals, New York State (NYS) must transition away from fossil fuels and significantly expand its use of clean energy technologies. While electrification will drive most emissions reductions, low-carbon alternative fuels will play a limited and strategic role in decarbonizing sectors that are difficult to electrify. This section outlines New York State's climate policy framework, how alternative fuels are accounted for under state law, and their role in long-term energy planning and emissions accounting.

1.1 New York State Policy Context

New York State has enacted some of the most ambitious climate and energy policies in the country. On July 18, 2019, the Climate Leadership and Community Protection Act (Climate Act) was signed into law, which aims to reduce economywide greenhouse gas emissions (GHG) 40% by 2030 and no less than 85% by 2050, relative to 1990 levels.[11] These targets include all GHG emissions from in-state sources as well as GHGs produced outside New York State associated with the production of electricity and fossil fuels imported into the State.[12] The Climate Act also set a goal to achieve net-zero economywide emissions by 2050.[13] In addition, the Climate Act established several electricity sector-specific targets: 70% renewable power by 2030; 100% zero-emission power by 2040; procurement of at least 9,000 megawatts (MW) of offshore wind power by 2035; 6,000 MW of distributed solar power generation by 2025; and 3,000 MW of energy storage by 2030.[14]

The Climate Act also recognizes that disadvantaged communities (DACs), as defined by the Climate Act, suffer disproportionate environmental and inequitable socioeconomic impacts that are further heightened by climate change. The Climate Act includes mechanisms to ensure that DACs benefit from the energy transition. Specifically, it requires that at least 35%, and ideally 40%, of the overall benefits of spending on clean energy and energy efficiency programs accrue to DACs.[15] The Climate Act also established a community monitoring program to deploy air monitoring systems and develop strategies to reduce toxic and criteria air pollutants in DACs.[16] It established the Climate Justice Working Group (CJWG) to represent DACs and environmental justice (EJ) communities as New York State plans and implements the changes necessary to achieve its energy and climate goals.

To meet the Climate Act's goals, New York State must significantly change how it produces, transmits, and uses energy. Fossil fuel-based systems, such as those using natural gas and petroleum products, must transition to clean energy alternatives, such as renewable power or low-carbon alternative fuels. Achieving a low-carbon future will also require substantial infrastructure investments, including reinforcing or repurposing existing fossil fuel infrastructure or building new infrastructure to connect new sources of clean energy supplies with demand. In addition, continued collaboration and coordination across State agencies, with input from a broad array of stakeholders, is critical for the State to achieve its ambitious energy and climate goals.

The Climate Act created the Climate Action Council (CAC), a 22-member body composed of heads of various NYS agencies and appointees of the Governor and Legislature. The CAC was charged with developing a Scoping Plan with recommendations to achieve the statewide GHG emissions limits.[17] It was supported by seven sector-specific advisory panels and the CJWG.

1.2 New York State Climate and Energy Policy

The CAC issued the final Scoping Plan in December 2022. The Scoping Plan provided recommendations for sector-specific and economywide actions necessary to achieve the Climate Act's energy and climate goals.[18] It also enumerated various regulatory and legal changes, market mechanisms, and technologies essential to accomplish those goals, while ensuring the reliability of New York State's energy systems as well as the welfare, safety, and prosperity of New Yorkers in a cost-effective manner.[19]

The Scoping Plan's recommendations were underpinned by a comprehensive, science-based Integration Analysis of the benefits and costs associated with the recommendations.[20] The Integration Analysis evaluated five scenarios representing pathways to decarbonization that deploy various decarbonization technologies and determined if each strategy achieves the Climate Act's GHG emissions reduction goals and what the costs and benefits would be.[21] These scenarios technologies included low-carbon alternative fuels, which are gaseous and liquid energy sources produced from renewable feedstocks that, when used, produce no or fewer GHG emissions relative to traditional fossil fuels.

The Integration Analysis focused on three main categories of low-carbon alternative fuels across the three mitigation scenarios:

1. Advanced renewable biofuels, such as renewable natural gas (RNG), renewable distillate (which includes renewable diesel and biodiesel), and renewable jet fuel, that are chemically equivalent to existing fossil fuels and are a drop-in replacement for fossil fuels.

2. Conventional biofuels, like biodiesel, are not drop-in replacements and therefore must be blended with fossil fuels in most cases before being used in existing equipment They are therefore generally considered as an interim decarbonization strategy.
3. Electrolytic hydrogen is produced by using renewable electricity to split water molecules into hydrogen and oxygen using electrolysis.[22]

Appendix A provides further details on each low-carbon alternative fuel, including their production pathways, distribution processes, and potential end uses. The Integration Analysis projected that demand for low-carbon alternative fuels would be significantly lower than the current fossil fuel demand in New York State.

In 2020, fossil fuels accounted for approximately 80%, or 2,210 trillion British thermal units (TBtu), of final New York State energy demand.[23] In contrast, biofuels and electrolytic hydrogen were projected to only account for 7% to 25% (90–310 TBtu) of final energy demand, respectively, by 2050.[24] This is because low-carbon alternative fuels would be deployed in a limited and strategic manner for hard-to-electrify end uses across New York State's economy.

The Scoping Plan recognized the need for further analysis of how to prioritize and optimize low-carbon alternative fuel use, including how best to allocate limited feedstocks to produce the most-needed fuels that are consistent with building capacity for the long-term (2050) goals and support reliability and affordability.

As directed by Article 6 of the New York State Energy Law, the State prepared the State Energy Plan, which provides a comprehensive roadmap to build a clean, resilient, and affordable energy system. Article 6 of the Energy Law requires the State Energy Plan to assess emerging trends in energy supply and demand as well as the costs, risks, benefits, uncertainties, and market potential of various energy sources, including alternative fuels.

As part of the State Energy Plan, New York State completed a Pathways Analysis to model future energy demand and supply across a range of scenarios. The analysis also recognized the limited, though critical and strategic, role low-carbon alternative fuels will play in decarbonizing difficult-to-electrify end-uses. Though low-carbon alternative fuels are expected to grow, petroleum fuels will still play a prominent role in meeting New York State's energy needs in 2040.[25] Additional details are available on the State Energy Plan website.

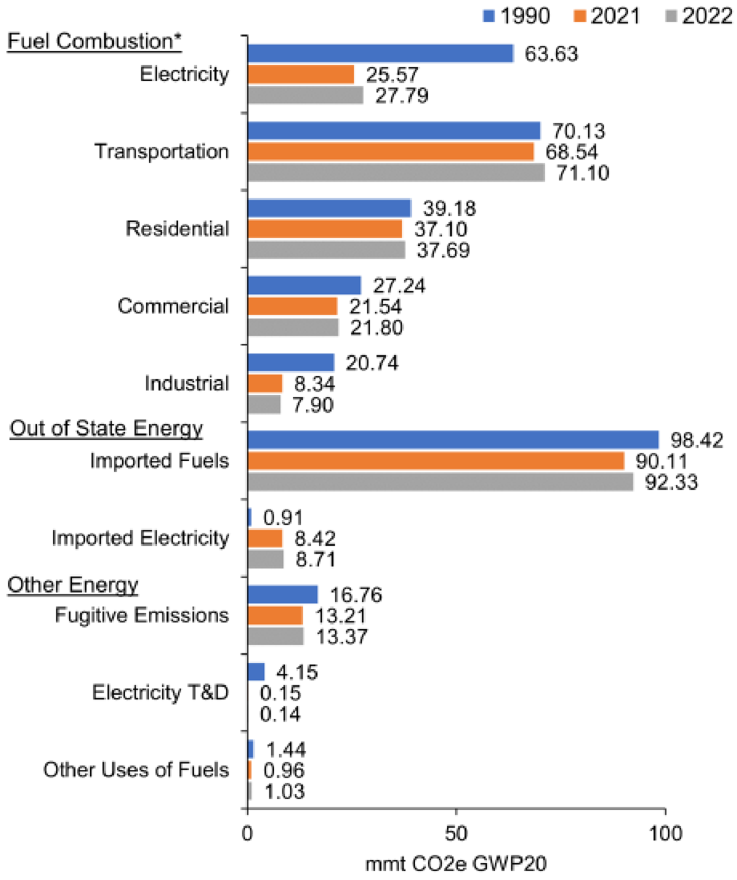
1.3 Climate Act Emissions Accounting

The New York State Department of Environmental Conservation (DEC) publishes an annual report on statewide GHG emissions, recording all anthropogenic emissions within the state's jurisdiction in a given year and updating historical inventories as improved methodologies improve. The inventory generally follows the Intergovernmental Panel on Climate Change (IPCC) guidelines for national inventories but adapts them to meet Climate Act targets.

To support compliance with the Climate Act, the DEC reports GHG emissions in gross terms, using the 20-year global warming potential (GWP20) convention. In 2022, 76% of statewide GHG emissions came from the energy sector, which includes all emissions associated with the generation and use of energy in New York.[26] Figure 1 provides a breakdown of these emissions by source.

Figure 1. Trends in New York State Energy Sector Emissions

Source: 2024 Statewide GHG Emissions Report[27]



Fossil fuel combustion and embedded emissions in imported fuels account for most energy-related emissions. New York State uses life-cycle methods to estimate these upstream embedded emissions, deriving coefficients that reflect the extraction, processing, and transportation of imported energy before it enters the State. However, per the Climate Act, embedded emissions from all products other than fossil fuels and electricity are not required to be included in inventory boundaries, per the Climate Act. This may have significant implications for biofuels.

For biofuels, the State currently estimates emissions only from their in-state end use, reporting methane (CH_4), nitrous oxide (N_2O), and the biogenic carbon dioxide (CO_2) emissions from combustion.

Biogenic CO_2, released from the decomposition or combustion of organic material such as biofuels, is considered part of the short carbon cycle, which regularly exchanges carbon between the atmosphere and the biosphere (e.g., plants and animals, soils). Plants capture CO_2 from the atmosphere and lock the carbon temporarily in the hydrocarbons that make up their tissues; as they are eaten or decompose, their hydrocarbon compounds are metabolized by animals, fungi, and microorganisms, and ultimately converted back into CO_2 and rereleased to the atmosphere, causing no net change in atmospheric CO_2 concentrations. Biofuels are one pathway in this short carbon cycle. The fuels are produced from plants or other organic material that recently captured carbon from the atmosphere, and so burning them rereleases the same carbon as CO_2.

Unlike typical LCA frameworks where this biogenic CO_2 does not contribute to a biofuel's net emissions impact because it is part of the short carbon cycle, the biogenic component of combustion does contribute to gross emissions inventories used for Climate Act compliance (but is assumed to net to zero when carbon uptake from agriculture is accounted for and is therefore omitted from reported net totals.) Importantly, this gross accounting does not credit carbon removals from agriculture or land use.[28] As noted earlier, under the current Climate Act guidelines, upstream emissions estimates are not required for biofuels imported for out-of-state.

To facilitate a more direct comparison between alternative fuels and conventional energy sources, including upstream impacts, this report reviews relevant LCA literature. It evaluates emissions from both a life-cycle and Climate Act inventory perspective. The life-cycle perspective includes emissions from raw material extraction through fuel production. The report compares the combined upstream and combustion emissions coefficients for fossil fuels to the upstream and combustion emissions coefficients of alternative fuels, using the DEC inventory data for combustion emissions. It excludes emissions associated with in-state transport and distribution emissions, recognizing the uncertainty of how infrastructure for this may materialize compared to existing systems, which may be assessed in a future review.

Estimation methodologies for upstream GHG emissions from alternative fuels vary and require careful review. Beyond the biogenic combustion assumption, some emissions accounting frameworks introduce further complexity by broadening the life-cycle boundary to account for the emissions avoided by redirecting waste materials to low-carbon fuel production. This approach is particularly relevant to RNG, for which waste is generally the main feedstock; this raises the question of what emissions avoidance would be required in the baseline condition (e.g., collection or flaring of methane at landfills). A final layer adding complexity to the emissions assessment is induced land use change (ILUC). ILUC estimates the emissions from converting virgin land (or lower-intensity cropland) to energy crops like soy, corn, and rapeseed. This assumption figures prominently in LCAs for biodiesel, renewable diesel, and sustainable aviation fuel (SAF), but is omitted from studies of other fuels reviewed for this report. Like avoided emissions credits, ILUC estimation relies on ascribing assumptions to a broad range of contingencies, yielding disparate estimates of uncertain accuracy.[29]

Emissions coefficients in this report are reported in grams of CO_2 equivalents per megajoule (gCO_2e/MJ), estimated using the IPCC's *Sixth Assessment Report* (AR6) GWP20 conversion coefficients, unless otherwise indicated.

2 Biofuels

Biofuels are a key category of low-carbon alternative fuels that New York State may use strategically to decarbonize hard-to-electrify sectors. This section outlines their markets, infrastructure needs, and emissions impacts.

2.1 Introduction

The following section focuses on the potential markets, infrastructure needs, and emissions and environmental impacts of biofuels as New York State strives to achieve its climate and energy policy goals. The section focuses on the primary biofuels discussed in the State Energy Plan: RNG, renewable diesel, biodiesel, and SAF.

It first analyzes the existing markets for biofuels and the potential changes that these markets may experience as New York State increases the use of these low-carbon alternative fuels. This section provides an overview of the production processes,[30] relevant end uses, and market dynamics.

It then explores the infrastructure requirements necessary to support the production, transportation, storage, and delivery of biofuels. The costs and technical feasibility of developing this infrastructure can significantly affect the extent and role that biofuels may play in New York State's decarbonized future. The State can leverage its extensive tapestry of existing gaseous and liquid fuel infrastructure that currently serves the State's energy needs. Additionally, this section considers the potential for new infrastructure where existing assets may not be suitable or cost-effective for transporting biofuels. New York State must carefully study and plan the extent to which it relies on repurposing existing infrastructure versus building new infrastructure, working with stakeholders as well as other states and industry participants to limit costs, avoid stranded assets, and minimize environmental and land-use impacts, particularly in DACs and EJ communities.

In addition, this section reviews the life-cycle emissions of biofuels, comparing production pathways most relevant to the State Energy Plan and Pathways Analysis and their emissions reduction potential relative to conventional fossil fuels. The section examines the environmental impacts on water, land, and air quality, identifying the most impactful stages within each fuel's life cycle. Their adoption also reshapes local economies by displacing jobs tied to fossil fuel production while creating new supply chains with distinct environmental impacts.

This review aims to inform New York State’s strategies for deploying biofuels to achieve its climate and energy policy goals. To this end, the section concludes with several key considerations for deploying biofuels in New York State, considering the State’s unique conditions, the anticipated limited role of biofuel (relative to today’s conventional fossil fuels), and the nascent nature of biofuel markets.

2.2 Markets, Infrastructure, and Greenhouse Gases

This section evaluates RNG, focusing on its supply and demand dynamics, infrastructure requirements, and GHG implications.

2.2.1 Renewable Natural Gas

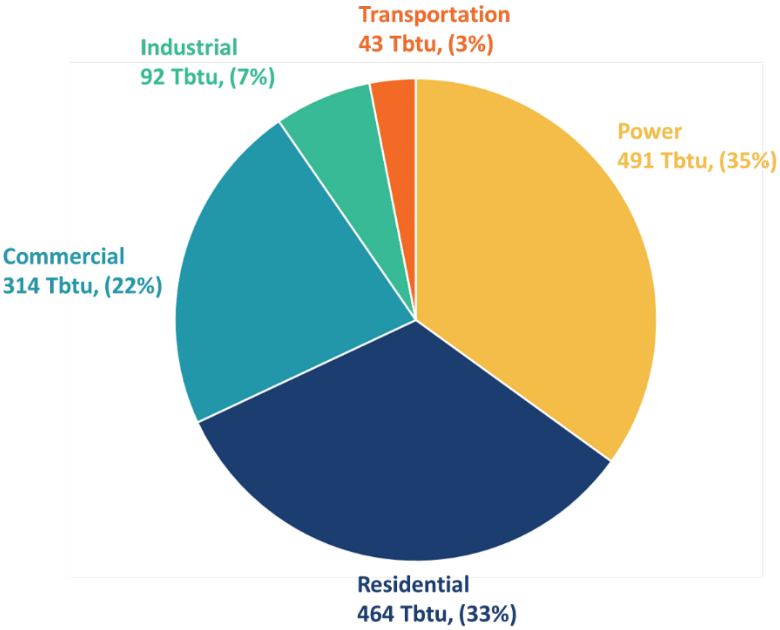
RNG is a low-carbon fuel with potential as a drop-in substitute for fossil natural gas in multiple sectors of New York State’s economy.

2.2.1.1 Supply and Demand Dynamics

RNG is methane produced from biomass (e.g., wastewater, landfill gas, agricultural wastes) through anaerobic digestion or gasification. RNG is chemically identical to natural gas, making it a versatile drop-in replacement with a variety of potential end uses, including power generation, space heating, industrial processes, and transportation. These applications are widely prevalent in New York State today. The State is the sixth-largest natural gas consumer in the country and used roughly 1,403 TBtu in 2022. Of this total use, 35% was for electricity generation, while the remainder was used primarily for space heating and industrial processes (Figure 2).

Figure 2. New York State Natural Gas Use by Sector, 2022

Source: Patterns and Trends[31]



Given existing reliance on natural gas, demand for RNG is expected to be relatively high as end users in different sectors decarbonize their energy supply, particularly in the buildings sector for supplemental heating as electrification increases and in the industrial sector for high-heat processes[32].

Several studies have estimated future RNG supply in New York State. The American Gas Foundation estimates 2040 RNG potential between 53 and 105 TBtu for New York State, and between 130 and 254 TBtu for the Mid-Atlantic region.[33] NYSERDA's RNG potential study estimates a 2040 supply range of 47 to 272 TBtu, with the higher-end estimate relying more heavily on thermal gasification.[34]

Anaerobic digestion is the more mature RNG production process, while thermal gasification has not yet reached full commercialization.[35] The timing and extent of anaerobic digestion and thermal gasification deployment in the State will have strongly influence total RNG availability.

Neighboring states with similar decarbonization goals, such as Massachusetts, will also demand a share of the region's supply. The level of future RNG availability is uncertain, and while a range of feedstocks are used to produce RNG (agricultural and food wastes, energy crops, landfill gas, wastewater), much of the supply will be more expensive than existing natural gas. Competition for limited supply will likely price out end uses that have alternative decarbonization options. These same feedstocks can also produce other alternative fuels, like biodiesel, renewable diesel, and SAF, as discussed later in this section, creating further competition for available feedstocks.

In a broader context, the role of gas use in New York State is expected to decline substantially as many end uses currently served by gas are electrified. While RNG is a drop-in replacement for natural gas, it is not expected to replace all the State's current gas use due to its limited availability and the ability of current end uses to electrify.

2.2.1.2 Infrastructure

RNG infrastructure includes production, transportation, and storage systems that determine the feasibility, cost, and emissions impacts of scaling RNG in New York State.

Production

Biogas is produced from the breakdown of biological matter, such as the organic fraction of municipal solid waste, wastewater solids, and agricultural and forest residues.[36] The raw biogas produced from decomposing materials would otherwise release GHG emissions to the atmosphere, but capturing it enables productive energy use. These feedstocks will primarily come from rural, agricultural areas of New York State and surrounding areas or from landfill and wastewater treatment facilities located near population centers.

The primary production pathways for biogas are through the natural decomposition of materials in a landfill or assisted through the use of an anaerobic digester or thermal gasification unit. The resulting raw biogas is a combination of methane, carbon dioxide, and other gases and therefore has a relatively low methane content and heating value. Before use, raw biogas must undergo several rounds of treatment to remove moisture, particulate matter, siloxane, and sulfuric compounds from the gas stream and then be compressed to higher pressures.

The investment and land requirements for this equipment will likely make it impractical for some agricultural or forest residue feedstock suppliers to treat raw biogas on-site. To increase biogas potential, New York State could develop centralized biogas facilities that gather feedstocks and/or raw biogas from local producers. This will require "first-mile" infrastructure to transport feedstocks produced in the area to a centralized processing facility. This will likely require on-road trucking to transport solid waste or organic matter from agricultural sites a short distance to the centralized processing facility. However, certain feedstocks with high water content, such as animal manure or sludge, are significantly more expensive to transport in this manner.[37] These feedstocks will need to be dried before transport, transported shorter distances, and/or employ other transportation methods. The environmental impacts of gathering the feedstock in this manner will need to be carefully considered and offset against emissions reduction benefits from capturing the raw biogas.

Case Study
Centralized Digester Systems in Europe

In Europe, centralized digester systems co-digests animal manure and other organic matter feedstocks from several farms. These systems use large digesters of up to 300,000 cubic feet (ft^3). Some of the resulting digestate returns to the farms for use as fertilizer, while the rest is sold to other farms.[1] The U.S. also has stand-alone digesters that accept feedstocks from multiple sources, but they are primarily process food waste.[2] New York State has few stand-alone digesters that co-digest feedstocks (ex. Cayuga Regional Digester).[3] Due to the availability of manure and agricultural residues in rural New York State, opportunities exist to construct more stand-alone digesters near gas pipelines, which could streamline the RNG production process.

[1] Juliana Vasco-Correa, Ashish Manandhar, Ajay Shah, “Economic Implications of Anaerobic Digestion for Bioenergy Production and Waste Management,” n.d., Ohio State University Extension, https://ohioline.osu.edu/factsheet/fabe-6611

[2] U.S. Environmental Protection Agency (EPA), “Types of Anaerobic Digesters,” n.d., https://www.epa.gov/anaerobic-digestion/types-anaerobic-digesters

[3] Cayuga Regional Digester, “FAQ,” n.d., https://www.cayugadigester.com/faq

In contrast, landfills and wastewater treatment facilities have existing processes to gather municipal solid waste and wastewater from local population centers. These facilities are more likely to invest in facilities required to treat raw biogas. When wastewater treatment facilities or landfills cannot treat the raw biogas produced on-site (e.g., space restrictions, lack of funding), New York State could work with these facilities to develop the infrastructure to collect the raw biogas and transport it elsewhere for treatment, such as centralized processing facilities. Similarly, as RNG demand is expected to peak in the 2030s and 2040s, infrastructure will need to collect excess biogas from these facilities and transport it to facilities that produce other biofuels.

Once treated, biogas can be combusted to serve on-site end uses, such as heating, industrial processes, power generation, or as a non-road transportation fuel. On-site consumption of biogas has several advantages. First, it can displace existing fossil fuel use. Second, the infrastructure requirements to transport the biogas from the processing equipment to on-site end-use equipment are relatively limited (e.g., yard piping or gas pipes within a building). Third, commercially mature end-use equipment already exists and can run on biogas. Lastly, using locally sourced energy can increase the reliability and resiliency of critical civic infrastructure, such as wastewater treatment facilities.

Where using biogas on-site is not practical or feasible, the biogas can be further treated to remove additional impurities, such as carbon dioxide, nitrogen, and oxygen, to improve the methane content and increase the heating value. Biogas thus treated becomes RNG, which is chemically equivalent to fossil natural gas, making it a drop-in substitute for the current natural gas supply. Importantly, the natural gas industry has developed guidelines and standards for the treatment of biogas, so that the resulting RNG meet gas quality standards for the treatment of biogas so that the resulting RNG meets gas quality and can be injected into gas pipelines.[38] This allows RNG to take advantage of the existing natural gas pipeline and storage facilities to serve end users. However, the extent to which RNG is transported using the existing natural gas pipeline and distribution system should be consistent with the State Energy Plan's framework for the future of the gas system.[39]

Most RNG projects today inject the gas directly into natural gas utilities' distribution systems to serve residential, commercial, and industrial customers. Doing so provides an opportunity to scale local RNG production to serve a large and diversified source of demand. However, many of these end uses, like residential heating or cooking, have readily available electrification options. Other, difficult-to-electrify end uses connected to the gas distribution system may be suitable applications for RNG. Over time, the natural gas distribution system could be configured to provide RNG to difficult-to-electrify end users while scaling down other portions of the gas distribution system that serve easy-to-electrify end users.

Although less common today, RNG can also be injected directly into intra- and interstate natural gas pipelines. This configuration provides the opportunity to reach a broader set of RNG producers in a region (i.e., those located near the pipeline right-of-way). It can also give producers access to multiple natural gas distribution utilities, as well as large industrial or power generation end users that interconnect with the pipeline. Injecting RNG into interstate pipelines to serve these end users may be advantageous if those large industrial facilities are difficult to electrify and/or if the power plants are needed to provide firm, dispatchable capacity to the electric system.

Injecting produced RNG volumes into existing natural gas infrastructure will allow New York State to develop and scale RNG supplies and markets adequate to meet the State's energy needs, consistent with its policy objectives. However, the extent to which RNG is transported using the existing natural gas pipeline and distribution system should be consistent with the State Energy Plan's framework for the future of the gas system.[40]

Transportation and Storage

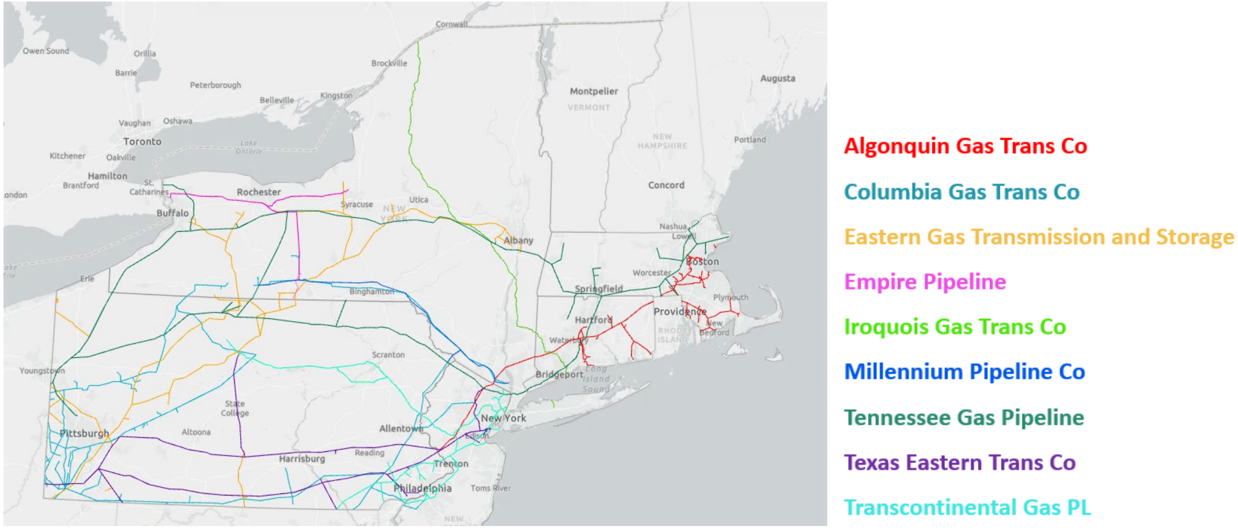
Most existing RNG pipelines are gathering lines that transport gas a short distance from the treatment facility to either a transmission pipeline or a local gas distribution system.[41] As RNG processing facilities develop across New York State, the State will need to provide strong oversight of the construction, maintenance, and eventual retirement of RNG gathering lines to ensure the safe operations of facilities and to limit environmental and land use impacts, particularly in or near DACs and EJ communities.

Gathering lines that interconnect with high-pressure natural gas transmission pipelines can transport RNG long distance to end users far from the RNG production site. As of today, no intra- or interstate pipelines in the U.S. transport pure-RNG; instead, producers blend RNG with the existing natural gas stream at the RNG treatment facility's interconnection point.

Relative to other low-carbon alternative fuels, RNG faces few technical or safety challenges in existing gas pipelines. The natural gas industry has made significant efforts to develop pipeline quality standards for RNG that are compatible with existing natural gas quality standards, enabling safe injection into the existing natural gas pipeline network.[42] These standards require RNG to undergo treatment that improves the heating value of the gas stream, removes contaminants that could damage equipment, and adds odorization agents.[43] Importantly, these standards vary depending on the heating value and contaminant levels in the gas stream, which are influenced by the biomass feedstock used.[44]

Nine major intra- and interstate natural gas pipelines serve New York State (Figure 3). Several of these pipelines pass through agricultural areas with high concentrations of potential RNG feedstocks. The Tennessee Gas Pipeline, Empire Pipeline, and Millennium Pipeline cross agricultural districts in Western New York, the Finger Lakes, the Southern Tier, and the Mid-Hudson regions. The Iroquois Pipeline originates near agricultural districts in the St. Lawrence River Valley. The extensive intra- and interstate pipeline network gives New York State access to RNG produced both in-state and out-of-state.[45]

Figure 3. New York State Natural Gas Transmission Pipeline Map



RNG has been blended into natural gas pipelines for some time, although the volumes are typically extremely small relative to the volume of natural gas. The pipeline industry is anticipating an increase in RNG volumes as shippers grow more interested in RNG and in natural gas that meets specific environmental criteria (e.g., certified natural gas). As a result, pipelines are proposing changes to their gas quality specifications and tariffs to offer RNG-transportation products to customers—these changes require approval from the Federal Energy Regulatory Commission (FERC) or the State before implementation.

Pipeline quality standards govern gas stream composition, including the heat content (i.e., energy per unit of volume), and the amount of contaminants and inert gases. RNG may not meet existing gas quality standards because it typically has a lower heat content than natural gas and may have a different composition of contaminants, depending on its feedstock.[46] Upgrading and treating biogas during RNG production can resolve these issues and remove impurities. Pipelines use their published gas quality standards as a benchmark that RNG must meet before it can be injected as a drop-in replacement for natural gas. However, many existing natural gas pipeline standards have been in place for years, and they typically do not account for RNG's characteristics. This oversight can prevent RNG from being injected into the pipeline due to the potential presence of contaminants in RNG that are not commonly found in natural gas, which may pose safety or operational issues for pipelines.[47] As a result, pipelines are proposing tariff changes to introduce RNG-specific standards.

In 2006, FERC published a policy statement that laid out a framework to ensure natural gas quality specification changes are just, reasonable, and not unduly discriminatory or preferential.[48] While the 2006 policy statement was not developed to address RNG, FERC has applied this framework when evaluating recent proposals by pipelines to modify their tariffs to include RNG quality specifications. Specifically, FERC prefers that pipelines and shippers (including RNG producers and off takers) collaborate on solutions consistent with the 2006 policy.[49]

For example, in December 2024, FERC approved a settlement allowing Florida Gas Transmission to modify its tariff to define RNG and set gas quality standards for receiving and delivering RNG on its system.[50] FERC had previously rejected the company's petition following a technical conference where the pipeline failed to demonstrate that the restricted constituents would cause a specific problem on the pipeline's system.[51] The approved settlement established a technical working group to review operational issues and define gas quality standards based on pipeline-specific data and studies.[52]

As of today, none[53] of the nine pipelines serving New York State have proposed or implemented tariff revisions to allow the transportation of RNG (Table 1). To fully leverage this infrastructure resource, New York State should work closely with the pipeline companies, RNG producers, pipeline shippers, and regulators to ensure RNG supplies, produced both in-state and elsewhere, can reach end users across the State.

Table 1. Natural Gas Transmission Pipelines in New York State

Pipeline	Type	Operator	NYS Region Served	Existing RNG Tariff?
Transcontinental Gas Pipeline	Interstate	Williams	New York City, Long Island	No
Texas Eastern Transmission	Interstate	Spectra	New York City	No
Algonquin Gas Transmission	Interstate	Spectra	Mid-Hudson	No
Tennessee Gas Pipeline	Interstate	Kinder Morgan	Western New York, Finger Lakes, Central New York, Mohawk Valley, Capital Region, Southern Tier, Mid-Hudson, New York City	No
Iroquois Gas Transmission System	Interstate	TC Energy	North Country, Mohawk Valley, Capital Region, Mid-Hudson, Long Island, New York City	No
Columbia Gas Transmission	Interstate	TC Energy	Southern Tier	No
Eastern Gas Transmission and Storage	Interstate	Berkshire Hathaway Energy	Western New York, Finger Lakes, Central New York, Mohawk Valley, Capital Region, Southern Tier	No
Millennium Pipeline	Intrastate	TC Energy	Southern Tier, Mid-Hudson	No
Empire Pipeline	Intrastate	National Fuel Gas	Western New York, Finger Lakes.	No

Less common methodologies of transporting natural gas include truck, rail, and barge, which may also be suitable alternatives to transporting RNG in the future. Trucks can transport natural gas on-road either as compressed natural gas (CNG) or as a liquid. CNG can be injected into pipelines or dispensed at fueling stations, whereas liquified natural gas must be delivered to facilities equipped with vaporization capabilities.[54] Trucked natural gas provides a flexible, short- to medium-distance option where gas pipelines are unavailable. However, truck tankers have limited capacity and may require round-the-clock deliveries to meet high demand, and that approach becomes challenging due to weather dependency and road restrictions. Local laws and regulations may further limit access to specific roads, bridges, or tunnels that these trucks use.

Rail offers another option for transporting natural gas, either as a compressed gas or a liquid, but faces similar limitations: volume restrictions, weather dependency, and safety concerns.[55] In addition, the loading and unloading of CNG railcars can be time-consuming. Barges can similarly transport CNG or liquid natural gas and face similar operational challenges. Jones Act restrictions further constrain barge use by requiring vessels transporting goods between U.S. ports to be U.S.-built, U.S.-owned, and U.S.-crewed.[56]

Despite these constraints, barges offer an additional benefit in that they can be floating storage facilities and supply gas during peak periods. While trucks, rail, and barges are less commonly used for natural gas transport, and even less so for RNG, they may become valuable tools for reaching areas without pipeline access.

RNG production remains small enough that no RNG-specific storage infrastructure is currently needed. In the future, as RNG resources are developed and end users convert to the fuel, storage will play an important role in balancing differences between RNG production and demand. RNG is produced at a relatively steady rate as biological feedstocks decompose, and the resulting biogas is upgraded to RNG. Conversely, demand for RNG can fluctuate seasonally or daily due to temperature fluctuations or cyclical shifts in industrial production. The amount of RNG storage capacity needed will depend on market forces, including the timing of supply development and demand growth; the relative amounts of supply and demand; and the geographic alignment of supply and demand sources.

One option for future RNG storage is to use existing natural gas storage facilities. These storage facilities are connected to pipelines and serve to manage timing differences between supply production and demand, and they can be used to provide other economic and reliability benefits. Today, approximately 4,844 billion cubic feet (Bcf), or 4,844 TBtu, of working gas storage exists in the U.S., of which 125 Bcf (125 TBtu) is located within New York State.[57] Depleted reservoirs and a limited amount of salt dome storage located in Western New York, the Finger Lakes, and the Southern Tier could store RNG. The State can also rely on other storage facilities in the Mid-Atlantic region. While these types of facilities have not stored RNG at scale, the limited number of studies investigating the technical feasibility of doing so have not found significant concerns.[58] However, storage operators would likely need to develop gas quality standards and monitor any potential impacts to their facilities.

RNG volumes must be transported to and from these storage facilities on inter- or intrastate pipelines. Similar to the pipelines, storage operators must modify their tariffs and gas quality standards to allow for RNG storage within the storage field, requiring FERC and/or State approval. This further adds to the complexity and need for New York State to coordinate with pipelines, the RNG industry, and regulators to leverage existing gas storage facilities.

Other RNG storage technologies could be deployed where existing infrastructure does not exist or repurposing existing infrastructure is not technically feasible. Aboveground steel storage tanks could be built near RNG production facilities and/or end users. Gaseous RNG can be stored in these tanks, providing a relatively small volume of backup fuel to those end users. Alternatively, operators can compress or liquify RNG to store larger volumes of gas for longer durations. If these end-use storage tanks do not connect to the interstate pipeline system or a gas distribution system, alternative forms of RNG transportation must be developed to service these storage tanks, such as truck, rail, and barge, as discussed above. Evaluators would need to assess the cost and emissions impacts of such an approach.

Gas Distribution System

RNG volumes can reach the gas distribution system through existing citygate connections with the gas transmission system. In addition, facilities producing RNG at landfills, wastewater treatment facilities, and other sites located near population centers can directly connect to the gas distribution system. For example, the Fresh Kills Landfill on Staten Island and the Newtown Creek Wastewater Treatment Facility in Brooklyn inject RNG into National Grid’s gas distribution system. Lastly, operators can transport RNG to a gas utility’s service territory via truck or barge and then inject it into the distribution system.

As gas demand declines, the entirety of the existing natural gas distribution likely will not be needed to serve this limited demand. Through this long-term gas planning process, New York State should work closely with gas utilities and end users to ensure that the limited RNG resources serve the highest-value end uses on the gas distribution system. Portions of the system that serve these high-value end uses will require ongoing maintenance to provide safe and reliable service to customers. Substituting RNG for natural gas does not change the urgency of mitigating leakage: RNG is methane and, if leaked during transport, can have significant climate impacts.[59, 60] In addition, RNG is substantially more expensive than natural gas, so losses of RNG impose greater economic burdens than losses of natural gas. Analysts should carefully study and weigh the costs and emissions implications of replacing leak-prone pipe distribution pipe to deliver RNG against other ways to distribute RNG (e.g., trucking) or the use of alternative decarbonization technologies. Notably, the need to prevent eventual leakage of RNG should not serve as a pretext to limitlessly invest in leak-prone pipe (LPP) replacement; instead, given the high customer cost of these programs, leak-prone pipe replacement as it relates to RNG should focus on those parts of the system most likely to continue to be needed as the gas distribution system declines in size and reach.

2.2.1.3 Emissions and Environmental Impacts

Currently, the most mature methods of producing RNG are anaerobic digestion and thermal gasification, processes that promote the controlled release of gases from organic feedstock that operators can upgrade into RNG. Anaerobic digestion produces biogas (mostly methane and carbon dioxide) through the decomposition of organic waste feedstocks such as municipal solid waste (MSW), animal manure, and wastewater sludge in the absence of oxygen. Once captured, operators treat and upgrade biogas into RNG, a substance chemically equivalent to fossil natural gas and ready to be compressed, transported, and distributed through pipelines for combustion at end-use sites. The thermal gasification process, although similar in end-product (purified, methane-dominant biogas), differs in that it uses high heat to break down biomass like forest or agricultural residues into synthetic gas (syngas) composed of a varied mixture of flammable compounds including hydrogen, carbon dioxide, and methane. Operators must also clean and upgrade syngas before integrating it into existing end-use infrastructure. Due to its greater commercialization, this report focuses on the anaerobic digestion pathway.

To differentiate the emissions and environmental impact of various alternative fuel pathways, the NYS Scoping Plan recommends the review of LCAs, which estimate the emissions associated with producing and consuming a fuel across a defined system boundary, the scope of which differs by study. The LCAs reviewed in this report generally use a cradle-to-gate boundary, accounting for emissions from raw material extraction through fuel production but excluding those from distribution and combustion, as well as embodied emissions in plants and equipment.[61]

Because RNG feedstocks are waste products not specifically produced for creating RNG, most life-cycle boundaries begin at anaerobic digestion and do not include upstream waste generation emissions. To account for this, RNG analyses commonly expand the life-cycle system boundary to include emissions avoided from conventional waste management practices (e.g., by using animal manure to produce RNG, one avoids fugitive methane emissions that might otherwise result from manure stored in lagoons or ponds).[62]

Maintaining the conditions necessary for anaerobic digestion requires heating energy that produces CO_2 emissions, depending on the energy source. While operators may supply this energy with renewable sources, most studies consider two pathways: parasitic heating using generated biogas or fossil natural gas input. This report focuses on the parasitic heating pathway. Beyond heating, fugitive emissions from methane leakage consistently contribute to the overall impact, although the quantity varies. Anaerobic digestion also yields digestate, an organic byproduct primarily composed of water, undigested solids, and nutrients that can be applied to land as fertilizer. When applied to land, digestate sequesters a portion of the carbon in the organic waste feedstock but emits additional methane and carbon dioxide.[63]

Once refined, RNG has a chemical composition very similar to that of conventional natural gas, both being primarily methane. As a result, RNG contributes similar emissions impacts during transportation due to compression requirements and leakage from aging infrastructure, as well as during combustion. Although RNG has similar combustion emissions to conventional natural gas, most GHG accounting frameworks consider it net-zero at the point of use because the feedstock is entirely biogenic and the carbon released during combustion equals the carbon uptake absorbed during feedstock growth. As mentioned in Section 1.3, however, this differs from DEC's treatment of biogenic emissions in its annual "Statewide Greenhouse Gas Emissions Report" for Climate Act compliance, which reports emissions in gross terms, including biogenic emissions from biofuels without crediting carbon removals from agriculture or land use.

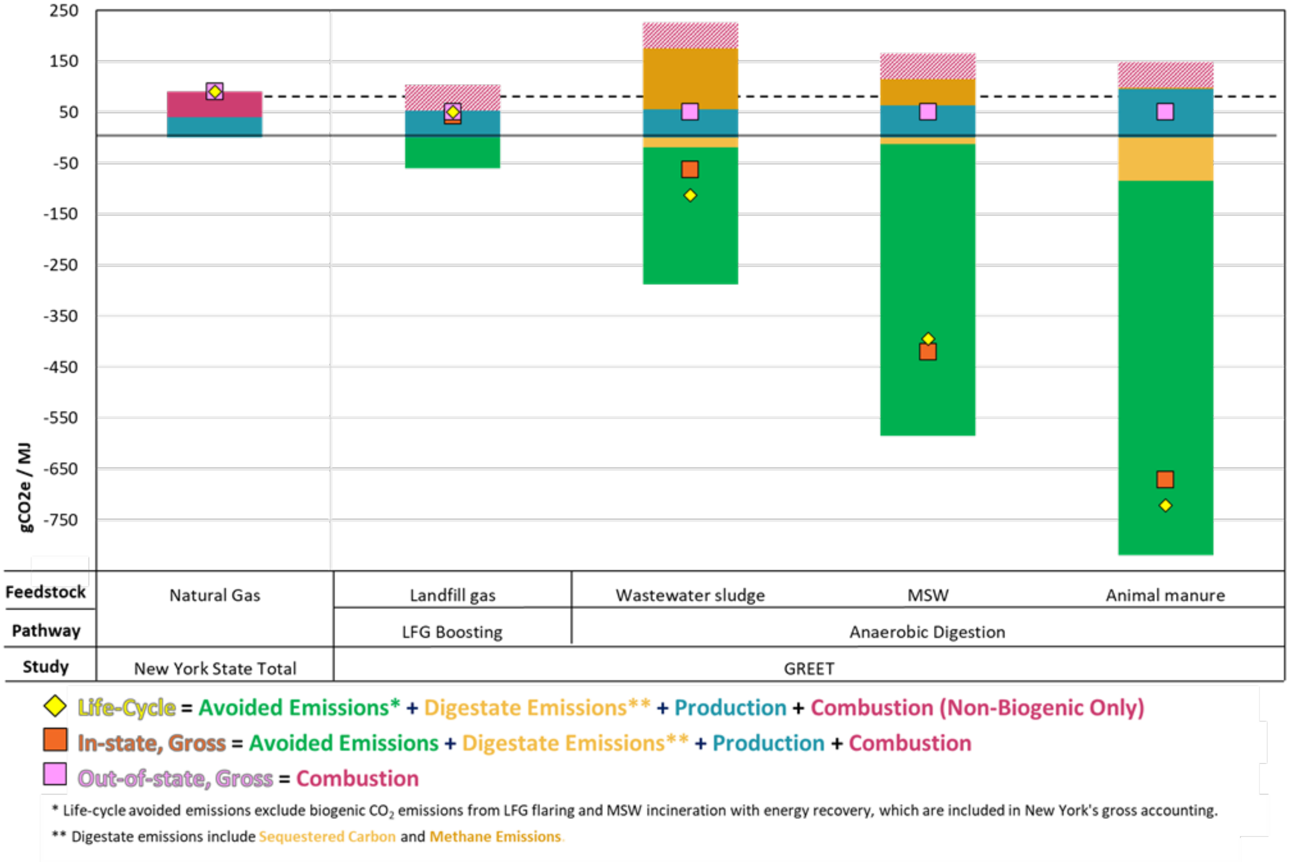
Figure 4 displays the results of an RNG LCA for four anaerobic digestion pathways conducted using Argonne National Laboratory's Greenhouse gases, Regulated Emissions, and Energy use in Technologies (GREET) model. The stacked bars represent the emissions intensity of each stage in fuel production, within the system boundary in terms of carbon dioxide equivalent per megajoule (CO_2e/MJ) of fuel produced, while the markers represent the total emissions by pathway under each relevant accounting standard: yellow rhombuses show the overall life-cycle total (sum of all displayed bars), while square markets indicate NYS gross accounting, pink for out-of-state RNG production and orange for in-state RNG production. The legend explains which components each total metric includes. RNG life-cycle estimates are compared against a fossil natural gas baseline derived from New York State's existing emissions coefficients for natural gas, which include in-state combustion and out-of-state upstream extraction and production.[64] The horizontal dashed black line in the figure represents the life-cycle emissions impact of fossil natural gas consumption in New York State. To facilitate comparison with fossil pathways, analysts add combustion emissions and biogenic credits for CO_2 uptake to the RNG cradle-to-gate estimates from GREET.

New York State's gross GHG emissions totals differ depending on whether the fuel was produced in-state or imported, as demonstrated by comparing the pink and orange markers. Currently, unlike fossil fuels, the Climate Act's inventory guidelines do not require accounting for upstream emissions of imported biofuels. As a result, imported RNG only accounts for combustion emissions. Transmission and distribution emissions are excluded from all presented totals due to a lack of reliable data and uncertainty in the associated distance traveled. However, given that RNG and natural gas are chemically similar, RNG is likely to be distributed using the same infrastructure and emit similar quantities of methane during transport, although ongoing investments in the natural gas system to minimize leaks are likely to reduce future emissions.

To remain consistent with the NYS GHG inventory, all totals use IPCC's AR5 GWP20 equivalency standard for non-CO_2 GHGs. The 20-year GWP factor for methane is considerably higher than the 100-year counterpart (84 compared to 28 times that of CO_2),[65] given methane's short-lived, high-impact atmospheric nature. This difference significantly impacts estimates of avoided emissions of conventional waste management, which mostly include fugitive methane emissions, although see discussion below regarding the relevance of these offsets.

Figure 4. Comparison of Life-Cycle Emissions Assessments for Renewable Natural Gas Pathways

CO_2 combustion emissions for RNG are considered biogenic and earn an equivalent biogenic uptake credit. CH_4 and N_2O emissions are nonbiogenic and have no offset. GREET LCA values are sourced from the R&D1 model assuming parasitic heating and AR5 GWP-20, with otherwise default inputs. Combustion emissions for fossil fuels are derived from New York State Energy Research and Development Agency's (NYSERDA), 2022, "Energy Sector Greenhouse Gas Emissions under the New York State Climate Act: 1990–2022, Final Report."



◇ Life-Cycle = Avoided Emissions* + Digestate Emissions** + Production + Combustion (Non-Biogenic Only)

■ In-state, Gross = Avoided Emissions + Digestate Emissions** + Production + Combustion

□ Out-of-state, Gross = Combustion

* Life-cycle avoided emissions exclude biogenic CO_2 emissions from LFG flaring and MSW incineration with energy recovery, which are included in New York's gross accounting.

** Digestate emissions include Sequestered Carbon and Methane Emissions.

As shown in Figure 4, estimates of overall emissions intensity for RNG vary considerably by pathway, driven largely by the inclusion of avoided emissions credits, which can lead dramatically reduce life-cycle carbon intensity. This credit has the greatest impact on the animal manure pathway, for which analysts assume conventional waste management practices are highly emissions-intensive. When imported from out-of-state, avoided emissions from conventional waste management would not be included under New York State's gross or net inventory. This exclusion reduces the fuel's advantage as a pathway toward meeting in-state decarbonization goals in-state (though it may be appropriate to consider them globally and from the perspective of climate change impact). In contrast, in-state RNG production captures the full benefit of RNG's abatement potential by reducing the State's existing waste management emissions in both gross and net terms.

However, waste management practices vary widely in their emissions implications, and the high-emissions assumptions used to estimate avoided emissions may not reasonably reflect existing processes in New York State, which could be less emission-intensive. Furthermore, if in-state waste management practices are independently reformed to reduce emissions as part of economywide decarbonization efforts, these actions would reduce the avoided emissions benefits of RNG production. Without credit for avoided emissions, some RNG pathways may emit more over the fuel cycle than the NYS benchmark for fossil natural gas. Operators may address some of these emissions by managing digestate more effectively, for example, by improving ventilation air handling from sludge facilities[66] or using nutrient recovery systems.[67]

Large avoided emissions estimates can give RNG disproportionate value in energy attribute certificate markets relative to its energy content, significantly impacting the fuel's economics and potentially creating perverse incentives in waste-generating industries (see Appendix C for further discussion).[68, 69] A thorough review of best practices for in-state waste management emissions and RNG production may be warranted to prevent distorted emissions reduction estimates and incentives and to update New York State's future GHG accounting approaches.

Other Environmental impacts

Beyond climate impacts, RNG production through anaerobic digestion raises other environmental considerations. Because anaerobic digestion facilities are typically collocated with existing waste management sites, such as landfills, wastewater recovery facilities (WWRFs), and manure lagoons and ponds, RNG production does not require significant amounts of new land or dedicated feedstock. Instead, it harnesses the biogas generation potential of the existing waste management system. As a result, most anaerobic digesters and biogas upgrading systems are retrofitted additions to existing facilities, requiring limited new infrastructure aside from pipelines additions and end-use sites.

Accordingly, RNG production has land and water use impacts that closely resemble those of existing waste management systems. The most common risk to human and ecological health stem from chemical runoff and nutrient leaching. However, collocating anaerobic digestion with waste management offers pathways for remediating some environmental impacts of conventional waste management. For instance, studies show that leachate from waste management sites can contaminate waterways, often affecting in EJ communities.[70] Anaerobic digestion of waste requires careful management, potentially reducing the incidence of leachate and producing a useful byproduct in digestate that can be used as fertilizer, supporting additional carbon uptake. When managed properly, anaerobic digestion can therefore reduce associated odors, mitigate water pollution, and displace chemical fertilizers. However, indiscriminate digestate application can still cause damage, particularly in the absence of mature and informed quality-assurance mechanisms, which are still largely underdeveloped.[71]

RNG is chemically nearly identical to natural gas and combusts similarly, and at least now, the two are blended in end-use applications. Thus, the local air quality impacts of RNG generally mirror those of natural gas.[72] While RNG use may offer limited air quality benefits when substituting for fossil natural gas, greater benefits may be realized when it displaces more polluting fuels like oil or coal. These substitutions may yield some near-term improvements in air quality benefits,[73] although over the long term, such fuels may no longer represent the appropriate comparison metric for evaluating RNG's performance.

2.2.2 Renewable Diesel and Biodiesel

Renewable diesel and biodiesel are other key low-carbon fuels under consideration as part of New York State's energy transition strategy. While RNG targets the gas system, renewable diesel and biodiesel are predominantly aimed at the transportation and heating sectors, offering drop-in alternatives to conventional liquid fossil fuels.

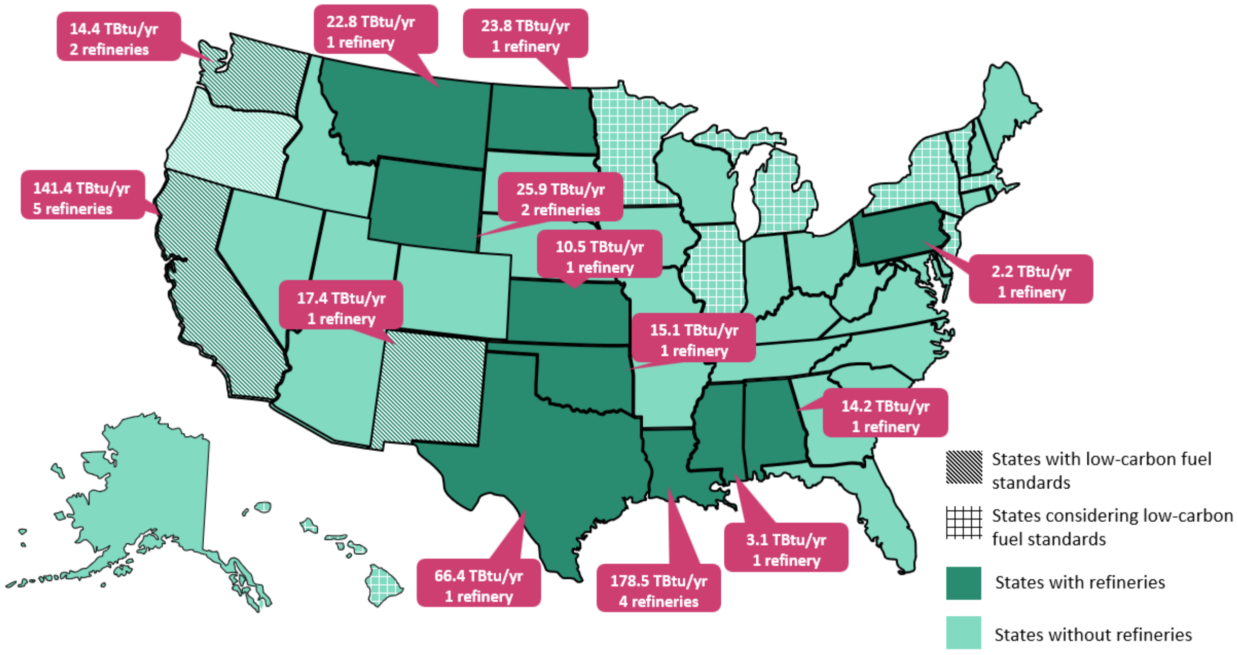
2.2.2.1 Supply and Demand Dynamics

Renewable diesel is processed to be chemically the same as fossil diesel and can therefore be used as a drop-in replacement fuel with unlimited blending opportunities. Most renewable diesel today is produced using hydrotreating, which reacts esters and lipids with hydrogen in a high-pressure and temperature environment with a catalyst.[74] Other potential production processes exist, such as biological sugar upgrading, gasification, and pyrolysis. The main end use for renewable diesel is in the transportation sector, with additional potential for heating.

National renewable diesel supply has increased substantially in recent years, growing from 25 million barrels in 2021 to 83 million barrels in 2024 (roughly 130 and 431 TBtu, respectively).[75] Much of this growth is situated on the West Coast, where low-carbon fuel programs have created favorable market conditions in the region. In 2024, the West Coast accounted for roughly 65 million barrels (338 TBtu) of renewable diesel supply, compared to just 1.3 million barrels (6.8 TBtu) on the East Coast. Given the regional disparity in existing demand, New York State currently has no renewable diesel refineries. According to the U.S. Energy Information Administration (EIA), as of August 2024, only one refinery in the Northeast produces renewable diesel (Figure 5).[76]

Figure 5. U.S. Renewable Diesel Production Capacity by State

Source: U.S. Energy Information Administration.[77]



Biodiesel and renewable diesel use similar feedstocks; however, biodiesel is not a full drop-in replacement for fossil diesel and must be blended in a limited fashion with fossil (or renewable) diesel. Users apply biodiesel in both heating and transportation and have typically favored it over renewable diesel for its simpler production process and lower cost. As of July 2023, all heating oil in New York State contains at least 5% biodiesel blend, with blending percentages set to increase to 10% in 2025 and 20% by 2030. New York State consumes more biodiesel in the residential and commercial sectors than any other state tracked by the EIA, largely due to these minimum blending standards.[78] Various State vehicle fleets have also used biodiesel blends for several years.

While renewable diesel demand in the Northeast is lower than in other regions of the U.S., the East Coast has begun importing more due to growing demand from suppliers and local governments in New York State, New Jersey, and Connecticut. Since April 2024, when new renewable diesel distribution infrastructure opened on the East Coast, imports have ranged from 5,000 to 7,000 barrels per day (or 0.03 to 0.04 TBtu/day), with approximately two-thirds destined for New Jersey. The East Coast now accounts for 10% of U.S. renewable diesel inventories and approximately 10% of U.S. renewable diesel imports.[79]

While blended biodiesel can help reduce emissions, it has limitations. Therefore, biodiesel could serve as a transitional fuel in New York State and eventually be supplanted by renewable diesel as supplies become available. Investments made to specifically support the distribution and storage equipment for biodiesel should be carefully considered; while some biodiesel infrastructure can be shared or repurposed for renewable diesel, policymakers should weigh investments in biodiesel against using those funds directly for renewable diesel and other fuels expected to play a longer-term role in the State's decarbonized strategy.

As the emphasis shifts toward renewable diesel production, New York State can apply lessons learned from biodiesel scale-up, including implementing minimum blending requirements and encouraging investment. New York City (NYC) has already begun converting its transportation fleet to renewable diesel by sourcing sufficient supplies for operations. In 2023, the Department of Citywide Administrative Services (DCAS) announced that the City's Department of Sanitation, Department of Parks and Recreation, Department of Transportation, Department of Corrections, and Department of Environmental Protections have fully transitioned to renewable diesel. The fire department, police department, and DCAS are in the process of converting.[80] These initiatives by State and local agencies can spur investments in renewable diesel fueling depots and end-use equipment. In addition, incentives such as NYS's Alternative Fuel Infrastructure Tax Credit can also encourage investment.

2.2.2.2 Infrastructure

This section outlines the infrastructure needed to support biodiesel and renewable diesel production, distribution, and use in New York State.

Renewable Diesel

Hydrotreating, the most mature production process for renewable diesel, closely resembles the process to desulfurize petroleum diesel. Therefore, petroleum refiners can retool their facilities to produce renewable diesel with relatively few infrastructure changes. First, refineries must install equipment to manage the additional heat generated when hydrotreating renewable diesel. Second, they must source more hydrogen because renewable diesel production requires high hydrogen input. [81] Over the past two years, several renewable diesel refiners have come online, with a combined production capacity of 2,856 million gallons (353.3 TBtu) per day. These refiners are primarily located in the western U.S., where they serve markets with clean fuel standards.[82] Today, East Coast renewable diesel markets rely on fuels imported from other U.S. regions or from abroad.[83] One renewable diesel refinery on the East Coast, located in Pennsylvania, produces renewable diesel at a capacity of 18 million gallons per year (2.2 TBtu).[84]

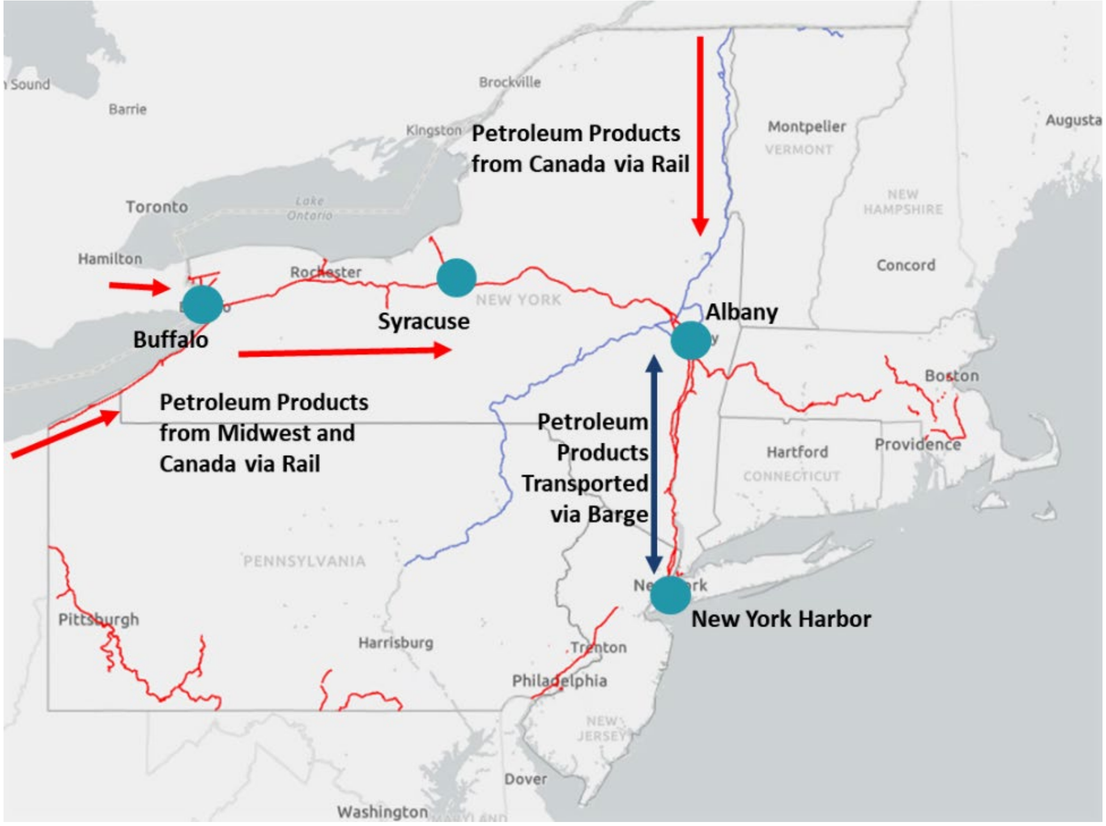
Given the limited production capacity on the East Coast, New York State should consider sending strong investment signals to encourage local and regional renewable diesel production. Western states have successfully driven such investment by implementing clean fuel standards. A similar policy in the Northeast could help catalyze deployment, alongside electrification and other decarbonization strategies. However, because renewable diesel production is hydrogen-intensive, new refineries will compete with other sectors for the State's limited hydrogen supplies. New York State should carefully evaluate how to balance the need for in-state renewable diesel production with the demand for hydrogen in other applications.

Renewable diesel is chemically identical to petroleum diesel, which allows it to be used as a drop-in fuel, transported through petroleum pipelines, and sold at fueling stations with or without blending. New York State has approximately 854 miles of refined product pipelines that transport gasoline, diesel, jet fuel, and other products from refineries located along the Gulf Coast, in the Midwest, and in Canada.[85] The two largest pipelines in the State are the Colonial Pipeline, serving Downstate New York, and the Buckeye Pipeline, serving Western and Central New York.

In addition to pipelines, New York State has an extensive freight rail, trucking, and maritime network to transport petroleum products to and from terminals across the State (Figure 6). New York Harbor is the largest petroleum products hub in the Northeast, with a combined capacity of more than 75 million barrels along the New York and New Jersey shoreline.[86] Petroleum products arrive by ship (or pipeline) and are then redistributed to smaller terminals on Long Island or Upstate New York by barge, truck, or rail. The Port of Albany also plays a significant role in the State's petroleum distribution network, receiving products from Midwest refineries via rail lines that serve terminals in Western and Central New York and from Canadian refineries via rail from Quebec. Petroleum products are transported to and from New York Harbor via barge.[87] This existing distribution infrastructure can support renewable diesel transportation across the State. Terminal storage capacity will also remain vital for balancing supply and demand in the renewable diesel market.

Figure 6. New York State's Transportation Corridors for Petroleum Products

Source: Office of the New York State Comptroller.[88]



Renewable diesel, like other petroleum products, will travel from terminals to distribution centers or fueling depots across the State by truck or rail. Tankers can haul up to 8,000 gallons of fuel over relatively short or medium distances, typically the last mile in the distribution channel.[89] Railcars can transport up to 2.4 million gallons to more distant markets but are limited to facilities with nearby tracks and offloading facilities.

Because renewable diesel is a drop-in replacement for petroleum-based diesel, fueling stations can distribute it without significant modifications. Likewise, end-use equipment does not require alterations because renewable diesel meets ASTM International (ASTM) D975, the U.S. standard for diesel fuel.[90]

Case Study
Renewable Diesel Retail Stations in Downstate New York

In January 2024, Sprague Energy opened the first retail fueling station east of the Mississippi River to offer renewable diesel, located in Lawrence, NY.[1] The station is supplied by Sprague's renewable diesel terminal in the Bronx, which began operations in June 2023. More recently, in June 2024. Sprague expanded its offerings by supplying renewable diesel from its fuel terminal in Rensselaer, NY.[2] The terminal serves fleet operators and wholesalers throughout the region.

[1] Biodiesel Magazine, 2024, "Sprague Opens Renewable Diesel Retail Station in NYC" (January 12), https://biodieselmagazine.com/articles/sprague-operating-resources-makes-supplies-renewable-diesel-retail-station-in-nyc

[2] Sprague Energy, n.d., "Cleaner Air Ahead for Upstate New York," https://www.spragueenergy.com/renewable-diesel-at-sprague/

Biodiesel

Unlike renewable diesel, biodiesel is not a drop-in replacement for traditional transportation fuels. It must be blended into petroleum-based diesel to avoid technical and environmental limitations with its use. Blends up to 5% by volume, known as B5, are considered regular diesel fuel and are compatible with existing diesel infrastructure. Higher blends of 20% (B20) to 100% (B100) by volume are also produced.

Biodiesel presents some known limitations in transport and use. Pure biodiesel is incompatible with certain diesel vehicle fuel system materials, including specific elastomers, metals, and plastics.[91] B20 and lower blends typically pose fewer material compatibility issues.[92] Pure biodiesel also gels at temperatures between -3 degrees Celsius (ºC) to 15ºC, stressing fuel equipment and requiring heated fuel lines and storage tanks.[93] Using B5 and B20 blends or adding fuel additives can improve cold-weather performance.[94] Biodiesel is also more biodegradable than traditional petroleum fuels, making it more susceptible to microbial contamination. This biodegradation can lead to corrosion of metallic components in storage tanks and fuel equipment.[95] Due to these characteristics, biodiesel is not transported via pipeline. Instead, it must be transported via rail, barge, or truck, constructed with materials that are compatible with the given biodiesel blend and have appropriate equipment, if needed, to transport it during cold weather.[96]

Environmental challenges also accompany biodiesel production and use. As discussed elsewhere in this report, biodiesel relies on feedstocks that compete with other agricultural products, such as food crops. This competition can strain land and resource availability and create unintended consequences.

Given these technical and environmental challenges, biodiesel is expected to play a limited, transitional role in decarbonizing New York State's transportation sector. The State should collaborate with fuel distributors, fleet operators, and other industry players to assess appropriate levels of production and distribution infrastructure investment. Infrastructure investments should prioritize long-term, low-carbon alternative fuels with fewer technical constraints and stronger GHG emissions-reduction potential. New York State should also coordinate with neighboring states to align on a regional framework for low-carbon transportation fuels, ensuring infrastructure investments in distribution and fueling infrastructure across the region are focused on the most effective long-term alternative fuels, especially given the region's highly interconnected economy and fuel ecosystems.

2.2.2.1 Emissions and Environmental Impacts

Biodiesel and renewable diesel share feedstocks and target markets but differ in production methods and chemical compositions. Both can be produced from vegetable oils (soy, canola, and corn oil as a byproduct of ethanol production) and waste fats, oils, and greases (FOGs). Evaluating life-cycle emissions intensity requires distinguishing between agricultural, byproduct, and waste products for feedstocks and assigning appropriate upstream emissions.

Agricultural products, like soy and rapeseed (canola), have associated emissions during cultivation, primarily from fertilizer application and machinery use; once harvested, soy and rapeseed must be crushed into oils and refined before processing into fuel, further contributing to overall process emissions (emissions from heating or chemical conversion in the primary production phase of the fuel of interest.) Additionally, many studies that consider agricultural product feedstocks assign an ILUC emissions coefficient to the resulting alternative diesel products. ILUC debits the net emissions resulting from conversion to cropland.[97, 98]

Byproduct inputs, such as corn oil from ethanol production, receive a proportional share of process emissions based on mass or energy content relative to the main product. Waste products of other processes, such as cooking oil, are not produced for biodiesel and renewable diesel, so upstream production emissions are typically excluded from the LCA boundary.[99]

All feedstock types require some refinement before processing. Transesterification, the core process for producing biodiesel, is sensitive to water and free fatty acids, requiring high feedstock quality, especially for waste FOG pathways.[100] Hydroprocessing, the respective process for renewable diesel production, tolerates higher degrees of feedstock impurity due to the energy-intensive nature of the technology.[101]

Transesterification operates at significantly lower temperatures and pressures than hydroprocessing, resulting in overall lower process emissions. However, it requires methanol (often a fossil-derived alcohol product) and produces glycerol as a byproduct, both of which can expand the associated emissions of production. Hydroprocessing, by contrast, involves the hydrogenation of FOG feedstock under high temperature and pressure, requiring greater energy input and resulting in higher process emissions. Hydrogen, another necessary input to the hydroprocessing step, can also increase the overall emissions of the technology, depending on the source.[102, 103] New York State should consider requiring emissions-free hydrogen (e.g., electrolytic hydrogen produced entirely using renewable electricity) for renewable diesel production.

Figures 7 and 8 display life-cycle emissions estimates for five feedstock pathways common to renewable diesel and biodiesel production. Like Figure 4, LCA estimates are broken into stacked bars corresponding to different life-cycle stages, with colored markers representing total emissions according to the relevant accounting standards (life-cycle baseline from GREET and gross totals as defined by the DEC's annual inventory), differentiating between in-state (pink square) and out-of-state production (orange square). All pathways are compared to a fossil diesel baseline, the LCA coefficient of which is derived from the DEC inventory, which provides in-state combustion emissions and upstream out-of-state emissions associated with imported fossil fuels.[104] Stage-by-stage emissions estimates for renewable diesel and biodiesel are calculated using the GREET model, with combustion emissions (both biogenic and nonbiogenic) and biogenic uptake credits added in based on the New York State reported coefficients for fossil natural gas combustion.

Under the life-cycle framework, biogenic CO_2 emissions from biofuel combustion are considered fully offset by the carbon uptake of the organic feedstock. However, New York State's gross emissions inventory, used for Climate Act compliance, does not reflect this assumption, which is indicated in the figures.

As shown in the figures, life-cycle emissions estimates for renewable diesel and biodiesel are broadly comparable, though renewable diesel typically has slightly higher totals due to its more energy-intensive production process. For each fuel, differences in feedstock system boundaries and treatment of ILUC estimates cause life-cycle emissions to diverge between pathways, while production emissions remain generally consistent. As assessed, the pathways with the lowest emissions intensity are waste feedstock and byproduct pathways (tallow, used cooking oil, and corn oil), owing to less intensive feedstock production and processing emissions. While leveraging waste feedstocks can yield significant per-unit emissions reductions compared to other pathways, these pathways are not broadly scalable, primarily due to the limited availability of suitable feedstocks (see Section 2.2.2.1).

Figure 7. Comparison of Life-Cycle Emissions Assessments for Renewable Diesel Pathways

The Integration Analysis provides combustion estimates for renewable diesel. It classifies carbon dioxide combustion emissions from renewable diesel as biogenic, granting them an equivalent biogenic uptake credit. In contrast, methane and nitrous oxide emissions are nonbiogenic and do not receive any offset. The R&D1 model supplies GREET LCA values, using default assumptions and GWP20 equivalency coefficients. Combustion emissions for fossil fuels are derived from NYSERDA's “Energy Sector Greenhouse Gas Emissions under the New York State Climate Act: 1990–2022, Final Report.”

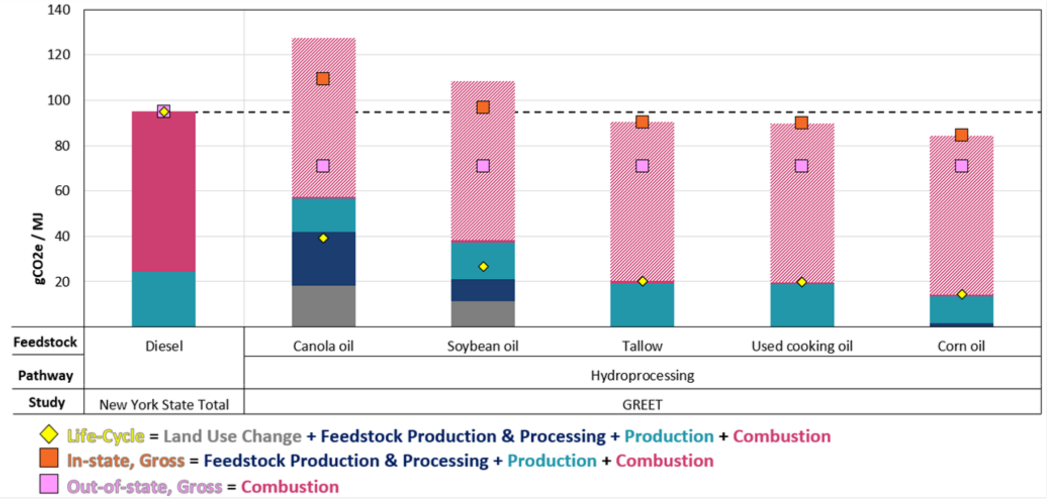
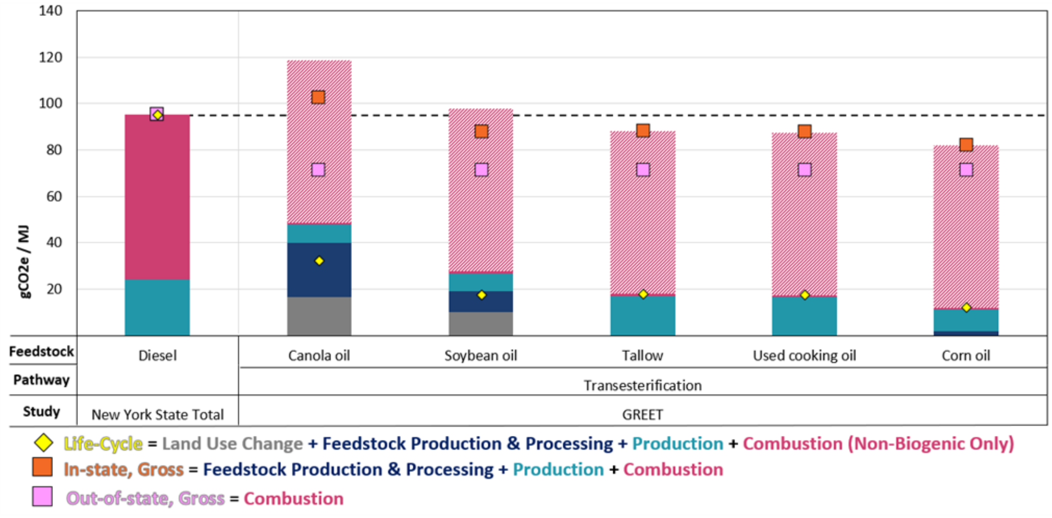


Figure 8. Comparison of Life-Cycle Emissions Assessments for Biodiesel Pathways

Assumptions for the renewable diesel figure carry over for biodiesel.



Land use change (LUC) emissions play a significant role in the soy and canola pathways for both renewable diesel and biodiesel. GREET assumes that increased demand for energy crops drives net ILUC-related emissions. The model includes two ILUC cases: domestic changes within the U.S. and expanded changes accounting for international and indirect effects. In the present analysis, GREET's default ILUC assumptions, which include both, are used. In NYS's GHG inventory, in-state LUC emissions are reported under the agriculture, forestry, and land use sector and are included only in net totals. If renewable diesel and biodiesel were produced entirely within New York State, accurately accounting for ILUC emissions from soy and corn would be critical to capturing their full climate impact.

Interpreting the emissions reduction potential of biodiesel is complicated by blending limitations. Due to operational and storage challenges, such as cold-weather sensitivity and lower-energy density, pure biodiesel is rarely employed as a stand-alone transportation fuel.[105, 106] Instead, it is typically blended with fossil diesel, with B5 and B20 blends being the most common, effectively discounting any emissions reduction to the same level.

However, California presents an exception, where producers have blended biodiesel into renewable diesel to create a 100% biofuel in response to state regulatory requirements. This approach offers an attractive opportunity to combine the cost advantages of biodiesel with the drop-in qualities of renewable diesel.[107] While the emissions reductions from biodiesel depend on the blend ratio, renewable diesel can fully replace fossil diesel.[108, 109]

Currently, under Climate Act inventory guidelines, upstream emissions from imported biofuels are not tracked. This gives imported renewable diesel and biodiesel an apparent emissions advantage. However, from a life-cycle and global climate perspective, upstream emissions are significant. Additionally, relying on out-of-state production reduces NYS's ability to direct investment and development towards chosen fuel pathways.

Other Environmental Impacts

Beyond GHG emissions, both the renewable and biodiesel supply chain requires careful environmental oversight. Two of the most developed existing feedstock pathways, soy and corn oils, present significant ecological and environmental justice concerns for LCU, biodiversity loss, water quality, and air pollution.[110] While New York State is less directly affected, wetland and grassland conversion to soy and corn farming has contributed to significant ecological disruption across the Midwest, principally due to fertilizer and pesticide runoff, water use, and soil erosion.[111]

Downstream of agriculture, both biodiesel and renewable diesel production pose additional environmental risks. Transesterification, the primary method for biodiesel production, generates alkaline wastewater that contains methanol residues, glycerin, and soap byproducts, which require treatment before discharge.[112] Renewable diesel hydroprocessing produces wastewater that can contain toxic organic compounds, which pose risks if not properly managed.[113] For context, about 98% of the life-cycle water used for soy biodiesel comes from irrigation for feedstock. Water use in biorefineries makes up a small and declining share, which has fallen by more than half between 1998 and 2017.[114]

Additional research is needed to determine the upstream sources and characteristics of air pollutant emissions from hydroprocessing and transesterification. The LCA studies reviewed provide GHG estimates, but omit non-GHG air pollutants. One study compiled information from the U.S. Environmental Protection Agency's (EPA) 2022 Toxics Release Inventory and found that biodiesel production releases significant quantities of acetaldehyde, formaldehyde, and hexane, which are volatile organic compounds believed to have carcinogenic and other adverse health effects.[115] The report cites data from a sample of reporting biodiesel facilities and may underestimate actual emissions. It also presents data from 135 reporting petroleum refineries and indicates that they release acetaldehyde and formaldehyde in greater quantities than biodiesel refineries on a per plant basis, though the reverse is true for acetaldehyde. However, this comparison does not account for differences in plant characteristics, and more research is needed before drawing a definitive conclusion about their relative copollutant intensity. Renewable diesel facilities were not tracked in this inventory. Without appropriate mitigation measures, communities near refining facilities may face exposure to these pollutants, which could increase risks of respiratory and cardiovascular health problems.[116]

2.2.3 Sustainable Aviation Fuel

SAF is one of the most viable near-term options to cut GHG emissions from the aviation sector. SAF can be blended into existing jet fuel systems with limited infrastructure changes and is currently the only scalable alternative for long-haul flights. As demand grows, especially in major hubs such as the New York Metropolitan Area, SAF presents both challenges and opportunities for targeted policy support.

2.2.3.1 Supply and Demand Dynamics

SAFs are low-carbon jet fuel alternatives, commonly produced using FOGs and other biological feedstocks. Several production processes exist, but hydrotreating fats and oils is the most technically mature.[117] As the aviation industry looks to decarbonize operations, demand for SAF is expected to rise.

The aviation industry is distinct from many other sectors in that alternatives to SAF are currently limited. Electrification may work for smaller aircraft on shorter routes, but is not viable for most flights. Similarly, hydrogen-powered aircraft would require major technological and infrastructure changes and may only be feasible for niche applications.

Although New York State has limited regulatory authority over airline operations, except for flights that originate and terminate within the State, it remains a major hub for international and domestic air travel, which positions it as a prime demand center for SAFs. For example, in 2024, Jet Blue signed an agreement to take delivery of roughly 3.3 million gallons of blended SAF at John F. Kennedy International Airport (JFK), with the option to purchase an additional 13 million blended gallons (0.4 and 1.2 TBtu).[118] In late 2023, the first commercial transatlantic flight using 100% SAF flew from London to JFK, further underscoring the State's importance in SAF deployment.[119] Nationally, the U.S. also has a "2030 SAF grand challenge," with a target of domestically producing 3 billion gallons of SAFs annually (360 TBtu), which is roughly 10% of anticipated jet fuel demand.[120] While New York State's direct authority is limited, it can still play a meaningful role in accelerating SAF adoption through policy, incentives, and voluntary decarbonization in aviation.

Despite growing demand for SAFs, the U.S. Department of Energy (DOE) and World Economic Forum (WEF) report that production capacity lags behind projected needs. WEF's February 2025 report estimates that SAF global demand will reach 17 million tonnes (64 TBtu) by 2030, while current and planned capacity totals only 11 million tonnes (43 TBtu). This leaves a gap of 5.8 million tonnes (22 TBtu) in SAF production capacity needed to meet 2030 demand.[121] The DOE estimates that the U.S. consumed 26 million gallons (3 TBtu) of SAF in 2023, and while 2024 consumption grew substantially, it still falls far short of the 2030 target.[122] The DOE also notes that announced production capacity could meet the 2030 target, but most projects will likely face delays or cancellations. Boston Consulting Group finds that SAF project announcements fell 50%–70% from 2022 to 2023, and fewer than 30% of projects reached final investment decision.[123] While New York State can support supply growth, the SAF market will operate at a national and likely international scale.

SAF costs are substantially higher than traditional jet fuel, between 2 to 10 times more expensive according to the DOE.[124] A critical mechanism supporting SAF procurement is the use of off takers who purchase the environmental attributes. Airlines pay a premium for SAFs and sell the attributes to corporations to offset the added costs. While this approach supports near-term development, concerns remain about the long-term availability of these contracts, which are needed to sustain continued growth. Federal and State incentives also help by giving airlines more certainty around financial support, which is important in an industry that often operates on thin margins.

Beyond costs, supply availability presents another challenge New York State should monitor. Federal agencies have flagged concerns regarding national production capacity, and in-state demand may outpace existing supply. Current production processes rely heavily on fats and oils, which are difficult to scale without centralized collection infrastructure. Any disruption to production expansion could hinder the State's capabilities to meet anticipated consumption targets.

2.2.3.2 Infrastructure

Due to its favorable energy content-to-weight ratios and compatibility with existing fuel infrastructure, SAF has been identified as the primary technology to decarbonize air transport, particularly for medium- and long-distance flights where electrification is not feasible. Producers can make SAF in retooled petroleum refiners or stand-alone biorefineries[125] using one of eight production pathways approved by ASTM and the Federal Aviation Administration (FAA).[126]

Today, airplanes consume Jet A fuel produced at petroleum refiners and shipped to airports via petroleum product pipelines, barges, and rail. Current federal regulations do not allow 100% SAF to be transported via pipeline; however, pipeline transport of SAF blended with Jet A is permitted.[127] For example, in 2022, operators commissioned a demonstration shipment to transport blended SAF from a refinery near Houston, TX, through two pipeline systems to LaGuardia Airport for use by Delta Air Lines.[128] To enable pipeline transport of blended SAF, FERC requires pipelines to publish relevant rules in their tariff or shipper's manual.

Until regulations change to allow pipeline transport of pure SAF, stand-alone biorefineries that do not blend with Jet A must rely on truck, rail, or barge transport. Industry best practices recommend using dedicated railcars,[129] each capable of holding approximately 30,000 gallons.[130] Inland barges can carry 400,000 to 1.2 million gallons, while oceangoing barges can hold up to 14 million gallons. Although barge transportation is generally more expensive than pipelines, it is less costly than rail or truck.[131] Trucks can move up to 10,000 gallons of SAF over short distances from terminals to airport tank farms, where a pipeline system is unavailable.[132] Today, tankers that transport Jet A are dedicated vessels, which reduces contamination risks.[133] SAF (blended or pure) is expected to use the same trucks as Jet A today.

The majority of infrastructure costs associated with distributing SAF will likely be incurred at terminals, where SAF and Jet A blending typically occurs. Terminal blending requires dedicated lines, pumps, and other equipment for offloading SAF.[128] SAF and Jet A are usually stored in separate tanks at terminals, where operators test both fuels for compliance with the applicable ASTM fuel standards. They then transport the fuels to a third tank to blend at the desired ratio and then retest the blended for ASTM compliance.[134] Terminals may need to invest in additional storage capacity for blending or repurpose existing tanks. Stand-alone biorefineries using rail or barge will also need transmodal facilities and fuel transfer equipment.

Among terminals indirectly connected to airports in the New York Metropolitan Area or New Jersey, Buckeye's Perth Amboy and Shell's Sewaren terminals handle jet fuel and accept delivery by all modes of transport. These facilities are well-situated to blend SAF. They would send blended SAF to Buckeye's Linden fuel terminal, where it would be transported to JFK, Long Island McArthur Airport, Newark Liberty International Airport, or LaGuardia Airport via pipeline, and Teterboro Airport via truck. Some of these airports already receive SAF. As previously discussed, SAF was first delivered to LaGuardia in 2022 through the Colonial and Buckeye pipeline systems for Delta Air Lines.[135]

Table 2. Terminal Fuel Receipt Modes

Source: National Renewable Energy Laboratory[136]

Terminals	Barge	Pipeline	Rail	Ship	Truck
Buckeye Linden	X	✓	X	X	X
Buckeye Perth Amboy	✓	✓	✓	✓	✓
Buckeye Port Reading	✓	✓	✓	✓	✓
Citgo Linden	✓	✓	✓	✓	X
Kinder Morgan Carteret	✓	✓	✓	✓	X
Kinder Morgan Perth Amboy	✓	✓	X	✓	X
NuStar Linden	✓	✓	X	✓	✓
Philips 66 Tremley	✓	✓	X	X	✓
Shell Sewaren	✓	✓	✓	✓	✓

A final consideration involves New York State's jurisdiction over aviation fuel use within the State. The federal government regulates international and interstate air travel, whereas New York State has jurisdiction over intrastate flights. While New York State has an intrastate air travel market, it is small relative to interstate and international travel. New York State should collaborate with the federal government and the airline industry to develop SAF infrastructure at airports within the State and secure sufficient supply to meet anticipated demand. The State can also explore the authority it holds over intrastate flights to determine how best to incentivize adoption of SAF in these markets. Influencing SAF use beyond New York State's borders may require mechanisms such as feed-in tariffs, a clean fuel standard with aviation opt-in, and other similar policy tools.

2.2.3.3 Emissions and Environmental Impacts

The DOE's Alternative Fuels Data Center currently tracks nine pathways for producing SAF.[137] Only one, hydroprocessed ester and fatty acid (HEFA), has reached commercialization in the U.S. In addition to HEFA, two other processes show promise for near-term commercialization: alcohol-to-jet (ATJ) using isobutanol (ATJ-isobutanol) and ethanol-to-jet (ATJ-ethanol). Both of these convert lignocellulosic or sugar-based feedstock into carbon-dense alcohols, which undergo additional refinement before ultimate hydroprocessing.[138]

The range of feedstocks for the HEFA process essentially mirrors those of renewable diesel because both require the hydroprocessing of FOGs. The distinction between HEFA SAF and renewable diesel from an emissions perspective lies in the additional refining steps needed to upgrade hydroprocessed fuel to aviation grade. These include hydrocracking and isomerization, which require additional energy input and contribute to greater life-cycle emissions.[139]

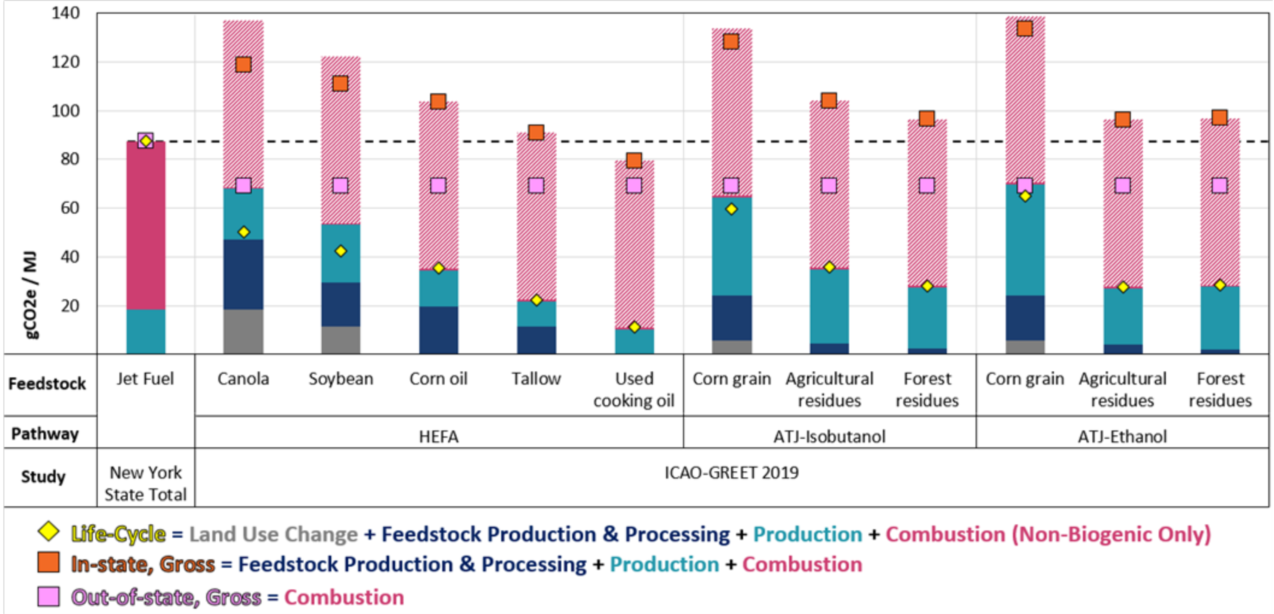
The two ATJ pathways have essentially identical system boundaries, with their respective processes diverging primarily in the choice of base alcohol—ethanol or isobutanol—and the associated steps required before hydroprocessing can occur. Ethanol is a mature product that can be produced relatively efficiently. Easier to ferment than isobutanol, ethanol also has a higher feedstock-to-alcohol ratio. However, isobutanol, being significantly more carbon-dense and pure, results in less carbon loss when refining prior to hydroprocessing. As a result, a smaller quantity of isobutanol is required to produce an equivalent output of SAF, offsetting ethanol's advantage in alcohol yield per unit feedstock.[140]

Figure 9 presents life-cycle emissions estimates for a sample of prominent SAF feedstock-technology combinations, following the same structure as earlier figures. These estimates are based on GREET's collaborative life-cycle model with the International Civil Aviation Organization (ICAO), released in 2019.

As Figure 9, illustrates, fuel production emissions vary significantly by feedstock. For example, the ATJ-Isobutanol pathway can use both corn grain and forest residues. Forest residues, due to their reduced land use impact and less carbon-intensive fermentation emissions, generate lower cradle-to-gate life-cycle emissions than corn grain.

Figure 9. Comparison of Life-Cycle Emissions Assessments for Sustainable Aviation Fuel

The analysis classifies carbon dioxide combustion emissions from SAF as biogenic, granting them an equivalent biogenic uptake credit. In contrast, methane and nitrous oxide emissions are nonbiogenic and do not receive any offset. The ICAO-GREET LCA values follow the AR5 GWP20 convention. Combustion emissions for fossil fuels are derived from NYSERDA's "Energy Sector Greenhouse Gas Emissions under the New York State Climate Act: 1990–2022, Final Report."



The life-cycle emissions from the HEFA pathway mirror the pattern displayed for renewable diesel, with waste and byproduct pathways offering the highest degree of abatement. These pathways often face scalability challenges due to limited feedstock availability. For the ATJ pathways, agriculture and forest residue options eliminate associated LCUs because they involve collected wastes that do not require new agricultural land, and have lower associated feedstock processing emissions, contributing to greater reductions than the corn grain pathway. Similar to renewable diesel and biodiesel, under current standards where upstream biofuel emissions are not counted in imported fuels, gross emissions of imported SAF produced using used cooking oil would be lowest.

Other Environmental Impacts

SAF produced through the HEFA pathway has environmental impacts similar to those of renewable diesel, although the additional refining stages require more energy and water. The ATJ pathways, however, differ in their environmental profile, particularly during fermentation and the refining processes prior to hydrotreatment. Fermentation of both ethanol and isobutanol is water-intensive, requiring significant input for microbial growth, substrate dilution, and cooling. It also generates wastewater contaminated with organic materials, which must be treated to avoid eutrophication and environmental harm. According to EPA estimates, producing a gallon of corn ethanol requires 76 gallons of water on average, compared to 5.7 gallons for petroleum gasoline, although this varies considerably based on local irrigation practices.[141] In the ATJ pathways, water use may exceed that of its fossil fuel alternative, although additional research is needed to draw definitive conclusions.

2.3 Considerations across Biofuels

The deployment of low-carbon alternative fuels involves interconnected challenges across supply, demand, infrastructure, technology readiness, and environmental impacts. While each fuel pathway has unique characteristics, they also share common feedstocks, infrastructure, and end-use considerations. Understanding these cross-cutting dynamics is critical to developing policies that balance emissions reductions, cost-effectiveness, and energy system reliability.

2.3.1 Supply and Demand Dynamics

The markets for the alternative fuels described earlier are not mutually exclusive and will have synergies between feedstocks, production processes, and end uses. Recognizing these interdependencies early in market development can help optimize the use of these fuels. Feedstock availability is perhaps the most critical component because many of these fuels (RNG, renewable diesel, SAF) often share common feedstocks. If regional feedstock supply is limited, then end uses with higher willingness to pay or subject to targeted policy mandates, such as aviation, may outcompete others.

In the Pathways Analysis, available feedstocks were converted to eligible fuels, including RNG, renewable diesel, and SAF, using an optimization tool. This tool converted feedstock to final fuels based on quantity, price, and final energy demand, selecting the production pathways that provide the greatest emissions reductions at the lowest cost. Feedstock quantities were drawn from the DOE's *2016 Billion-Ton Report* and the NYSERDA's "Potential of Renewable Natural Gas" report.[142] Based on this data, in-state renewable fuel potential was estimated between 127 and 179 TBtu. However, as markets evolve, actual allocation may differ from this cost- and emissions-optimized scenario. While achieving emissions reductions at the lowest cost will certainly be a favorable outcome for New York State, the scale of these markets will expand beyond State boundaries, meaning that access to feedstocks may be limited to a few end users who are willing to pay the most, rather than being evenly distributed across in-state fuel needs.

Feedstock competition may also be exacerbated by commercial deployment timelines. Purpose-grown energy crops, projected to supply roughly 20% of the total potential supply in most outlooks, are not yet widely adopted. Whether and how quickly energy crops and other feedstocks are deployed will significantly impact total supply. Relatedly, the timing of feedstock availability and demand is another factor that may create discrepancies between supply and demand, thereby creating short-term supply shortages.

Some scenarios project the highest alternative fuel use in the medium-term (2030–2040). The State may face challenges in developing and scaling feedstock production quickly enough to meet demand over the next 5–15 years, which could result in total supply aligning more closely with near-term estimates rather than the mature market projections.

Furthermore, while these estimates include the use of energy crops, policymakers should apply the precautionary principle and avoid those feedstocks where possible, given uncertainties around land use, emissions, and other impacts. Policies that drive long-term growth in RNG use could increase land use impacts due to feedstock demand. Therefore, as discussed above, policymakers should prioritize RNG use for buildings or other sources that can be electrified for targeted use cases, including supporting supplemental heating and difficult-to-electrify settings, and design policies to prioritize waste-based feedstocks.

In addition to feedstocks, the pace of technology development will also influence the viability of alternative fuels. Drop-in fuels like RNG and renewable diesel integrate most easily into existing infrastructure, but other low-carbon alternative fuels like biodiesel require investment in transportation and end-use equipment designed to address the fuel’s technical and environmental limitations. For example, investment in RNG from waste resources could lead to systems optimized for methane production rather than liquid fuels such as renewable diesel. Without policies guiding priorities, investments in infrastructure and technology could create economic incentives that turn short-term solutions into long-term dependencies or stranded assets. The pace at which these developments occur will affect the dynamic of predominant fuel use in the future.

2.3.2 Infrastructure

Leveraging low-carbon alternative fuels to help meet NYS's energy and climate policy goals will require a network of production, transmission, storage, and distribution infrastructure that can safely and reliably serve end users of low-carbon alternative fuels. Many factors will shape this development: the relative location of supply and demand; the extent to which existing infrastructure can be repurposed to transport these fuels; the relative cost of transporting fuels using different modes; the anticipated level of future demand; and the environmental and community impacts of constructing and using the infrastructure.

RNG, renewable diesel, biodiesel, and SAF rely on biological feedstocks for production. These feedstocks come from agricultural lands, largely concentrated in Western and Central New York, as well as wastewater treatment facilities near population centers and landfills across the State. Fully leveraging agricultural feedstocks in New York State will require investments in feedstock processing, first-mile infrastructure, and centralized treatment and processing facilities. First-mile infrastructure collects feedstocks from farms and other facilities and transports them to centralized locations. This model limits the land use and capital investments burden on individual feedstock producers, shifting investments to third parties who build centralized treatment and processing facilities across New York State. SAF and renewable diesel are already produced at refineries using this approach,[143] which is common in Europe and other parts of the U.S. Centralized treatment and processing facilities also enable better oversight and quality control of low-carbon alternative fuel production.

Some low-carbon alternative fuels, like renewable diesel, SAF, and RNG, are drop-in replacements for their fossil fuel equivalents and can use existing infrastructure for transportation, storage, and distribution. For example, fuel terminals in Rensselaer and the Bronx already store renewable diesel, which is sold at a retail fueling station in Nassau County. Blended SAF is also delivered to airports in the New York Metropolitan Area. As a result, dedicated distribution and storage infrastructure investments for renewable diesel and SAF are limited, relative to other low-carbon alternative fuels. The State does not anticipate needing to support such development. RNG is chemically similar to natural gas and can flow through the existing natural gas infrastructure.

While the Scoping Plan expresses a preference for using biogas (the precursor to RNG) on-site for heating, industrial processes, power generation, or as a nonroad transportation fuel,[144] this approach will likely not meet the scale envisioned in the State Energy Plan's Pathways Analysis. Sources of biogas, whether agricultural or waste-based, are not generally collocated with demand centers, such as industrial facilities or the range of households and businesses that may use it supplemental heating. While some on-site biogas uses may be feasible in isolated situations, New York State should use existing infrastructure to distribute RNG and other alternative fuels consistent with the use envisioned in these scenarios.

New York State must also configure wastewater treatment facilities and landfills to provide feedstocks for high-value alternative fuel production like SAF and renewable diesel, especially as the State transitions away from the gas system. Other low-carbon alternative fuels like biodiesel present known technical challenges when used in existing infrastructure, particularly at higher concentrations. Although the industry has developed solutions to address these challenges, the ability to deploy them depends on the material composition and current conditions of New York State's infrastructure. Therefore, these fuels are more likely to require new infrastructure that is designed to transport and store these fuels.

Demand for low-carbon fuels will be significantly smaller than the current demand for their fossil fuel counterparts. As a result, infrastructure needs for transport, storage, and distribution will also be smaller. This presents opportunities to strategically retire existing fossil fuel infrastructure no needed to transport low-carbon alternative fuels like RNG, renewable diesel, and SAF. Where existing infrastructure cannot be reused, or where demand and supply locations differ from legacy fossil counterparts, developers will need to build new infrastructure. New York State should work closely with developers to ensure this new infrastructure is appropriately sized to meet anticipated demand for low-carbon alternative fuels, consistent with New York State's clean energy and climate goals.

New York State should also carefully consider the environmental and community impacts of repurposing existing infrastructure or building new infrastructure. Repurposing can reduce environmental harm and limit disruption to nearby communities. Strategic retirement of unneeded fossil fuel infrastructure can yield additional benefits during the transition. When new infrastructure is required, the State should collaborate with developers, stakeholders, and local governments to mitigate potential community impacts.

Figure 10 shows the topology of existing gaseous fuel infrastructure in New York State and neighboring states, including RNG supply sources and potential end uses. Wastewater treatment facilities (light blue dots) and landfills (dark blue dots) are spread across the State, generally near population centers. Their proximity to natural gas pipelines (tan lines) or gas utility distribution systems suggests they could easily interconnect. The State currently hosts at least 39 livestock anaerobic digesters (pink cross),[145] mostly concentrated in the agricultural centers in Western New York, the Finger Lakes, and the Southern Tier. These regions are well served by existing gas pipelines with connections to major population centers, like Buffalo, Rochester, and Syracuse. Soybeans (green dots) and corn (yellow dots) feedstocks are similarly concentrated in Western New York and the Finger Lakes. New York State could also access RNG supplies from feedstocks located in northern Vermont, western Massachusetts, and southern Pennsylvania, although they are farther from major downstate population centers and would entail higher transportation costs. In addition, both Vermont and Massachusetts (and other regional states) are considering RNG to meet their own decarbonization goals, which could increase regional competition for the limited supply.

Figure 10. Map of Existing Energy Infrastructure for Gaseous Fuels

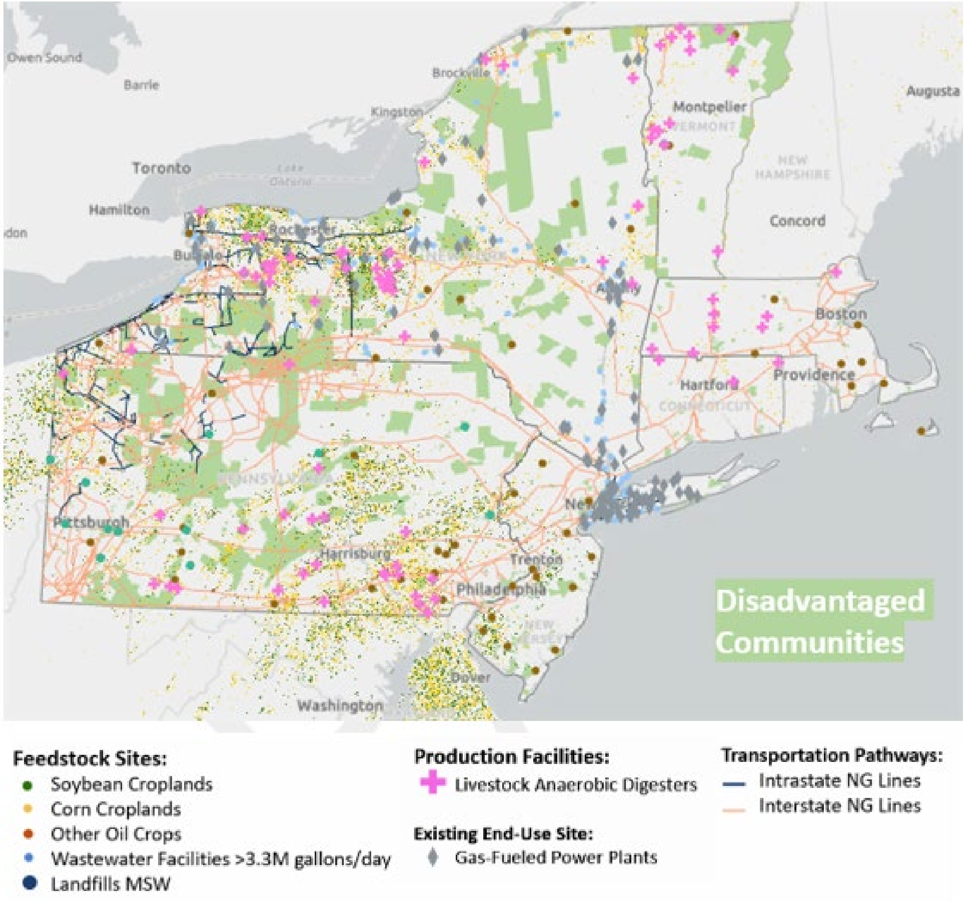
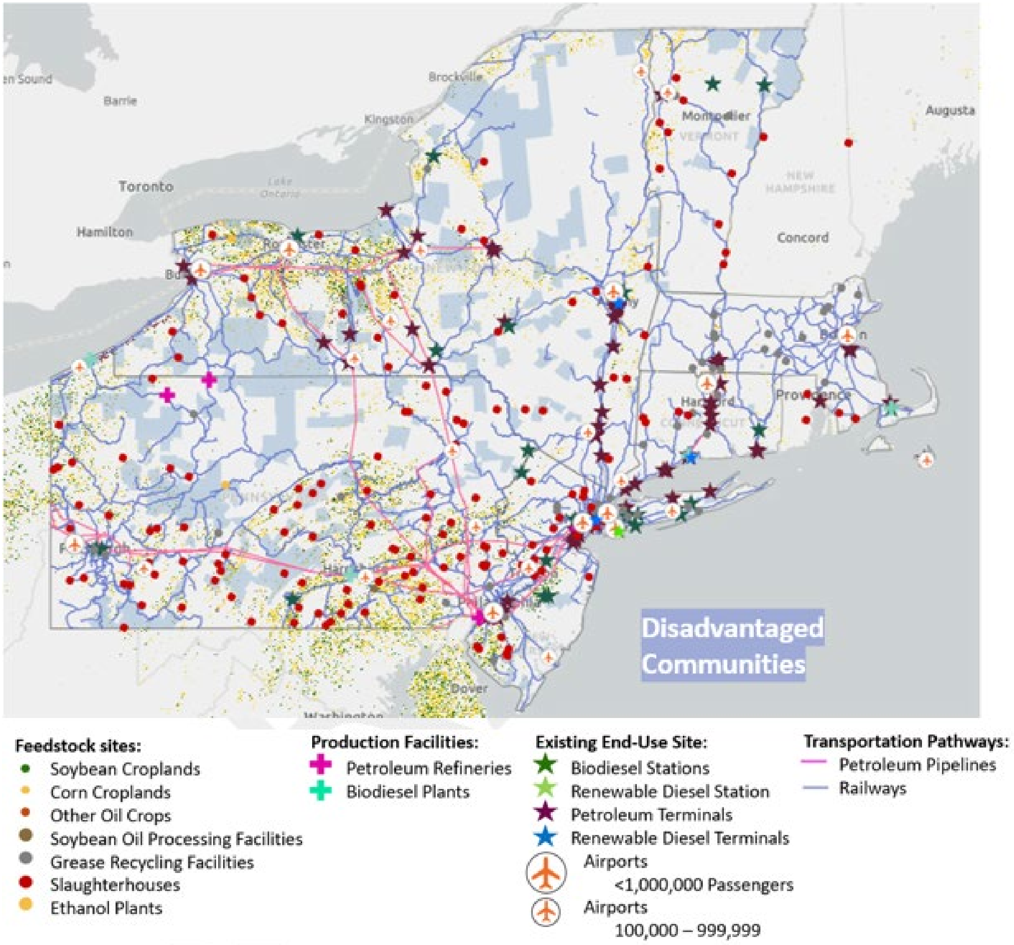


Figure 11 shows the topology of existing liquid fuel infrastructure in New York State and neighboring states, including production facilities and certain end uses for biofuels and SAF. New York State does not have any petroleum refineries (bright pink cross) or biodiesel plants (green cross). Most petroleum refineries and biodiesel plants operate primarily in Pennsylvania and New Jersey. These facilities connect to petroleum pipelines (pink lines) that serve major population centers in Western New York, such as Buffalo, Rochester, Syracuse, and Utica, as well as the New York Metropolitan Area. In addition, these petroleum refiners and biodiesel plants are located near freight railways (light purple lines) that traverse New York State and the region.

Figure 11. Map of Existing Energy Infrastructure for Liquid Fuels



Biodiesel stations (dark green star) and petroleum terminals (dark purple star) serve as proxies for transportation demand. These terminals and stations are well dispersed across Western New York, the Finger Lakes, and the Southern Tier. Several petroleum terminals are located along major NYS waterways, including the Lake Ontario, Lake Erie, the Hudson River, New York Harbor, and the waters surrounding Long Island. Existing marine transportation infrastructure can support the import of low-carbon alternative transportation fuels to markets along these waterways.

Crop feedstocks (small green, yellow, and red clusters) appear sparsely across New York State, but most crop feedstocks will need to be sourced from and made into liquid biofuels in the Midwest, where oil croplands and petroleum refineries are more concentrated. Existing petroleum pipelines can deliver SAF and renewable diesel to New York State, while biodiesel must be shipped by road or rail. In-state liquid biofuel feedstocks will primarily come from New York State's grease and used cooking oil recycling facilities and slaughterhouses, which are scattered across lower New York State. As of 2023, New York State had nine registered used cooking oil and yellow grease processing facilities, some of which already send the processed waste to out-of-state biofuel refineries. Facility capacities vary, only three facilities process more than 10,000 tons of waste per year (or more than 27 tons/day).[146]

Finally, airports in New York State (orange airplane icons) connect to petroleum pipelines, such as those (Buffalo, Rochester Syracuse, Binghamton, Elmira, the New York Metropolitan Area), which could be used to deliver blended SAF and, potentially in the future, 100% SAF. Airports in Albany, White Plains, Stewart, and Plattsburgh do not have pipeline connections and mut rely on existing maritime and rail connections to receive SAF.

2.3.3 Emissions and Environmental Impacts

Given the range of available pathways for each fuel type and the early stage of commercialization, the State should actively and knowledgeably guide the alternative fuel market toward a low-cost, high-abatement future with minimal environmental impact.

New York State currently produces little alternative fuel. However, as the industry responds to market and policy signals, more of the supply chain may concentrate within the State. A holistic understanding of alternative fuels, based in comprehensive life-cycle analysis (including any upstream impacts), and awareness of estimation assumptions and limitations, will enable the State to identify the most suitable pathways for its unique conditions and encourage investment in those sectors.

Under IPCC guidelines for jurisdictional inventories, upstream emissions from imported energy are excluded. New York State diverges from this standard by incorporating upstream estimates for imported fossil fuels and electricity. However, in New York State's existing GHG accounting studies, upstream emissions of alternative fuels have been omitted, with the only contribution towards economywide totals being in-state combustion emissions. For biofuels like renewable diesel, biodiesel, and SAF, importing from out-of-state, therefore, offers (from a Climate Act emissions inventory perspective) greater abatement potential than producing the fuels within New York State because upstream emissions do not contribute to the inventoried emissions. For imported RNG, however, this implies that avoided emissions from diverting feedstock away from conventional waste management are not included in the State's inventory, in this case reducing the overall benefit of the fuel within the inventory and making in-state sourcing preferable for maximizing inventoried emissions reductions.

As shown throughout this section, pathways leveraging waste materials and byproducts (such as renewable diesel from used cooking oil) tend to offer the highest degree of GHG emissions abatement relative to fossil baselines while avoiding competition with existing industries. Given New York State's large, dense urban population, waste-derived pathways (e.g., RNG from municipal solid waste or used cooking oil) present strong opportunities to redirect emitting waste management processes to productive uses. Still, the depth of available feedstock and sourcing logistics may limit the scale of these waste-based pathways as a primary decarbonization strategy (see Section 2.3.4). Moreover, if avoided emissions are to be priced into the market, credits must be based on independent assessments of NYS-specific waste management practices and associated emissions to avoid overevaluation.

While waste- and byproduct-based pathways shorten the life cycle and avoid negative impacts associated with feedstock cultivation, agricultural pathways have seen the most commercialization and now serve as mainstays of the alternative fuel sector. Most agricultural pathways use energy crops (primarily soy and corn), which are highly concentrated in the Midwest. In 2023, for example, New York State produced just 0.41% and 0.56% of total U.S. soy and corn, respectively.[147, 148] As a result, in-state production for these pathways would likely require large crop imports from the Midwest or cause additional LCU emissions if demand prompts expansion of energy cropland within the State.

Thorough emissions accounting is essential for adopting biofuel New York State. However, the State should also consider broader environmental impacts across the full supply chain, such as water use, air quality, ecological integrity, and uncertainties tied to land-use change. Feedstocks like corn, soy, and rapeseed, which are commonly used in biodiesel, renewable diesel, and SAF, require substantial pesticide and water use. Converting forests or low-intensity croplands to cultivate these energy crops often results in significant LCUs, harming water, soil, and air quality and reducing native species habitats.

Furthermore, biofuels production processes, including transesterification, hydroprocessing, and alcohol production for ATJ SAF, generate considerable quantities of wastewater, which must be meticulously managed to prevent eutrophication and other ecological harm. Several stages in biofuel production, as well as feedstock processing, also emits hazardous air pollutants that may affect nearby communities. The State must monitor and mitigate these effects to prevent disproportionate harm to marginalized groups.

In contrast, RNG generally does not necessitate significant incremental land use because anaerobic digestion often takes place at collocated waste management facilities from which they source feedstocks. Still, managing the byproducts of anaerobic digestion, wastewater and digestate, is crucial to limit fugitive methane emissions and runoff into water systems. Properly managed digestate can serve as an effective fertilizer, potentially reducing the reliance on synthetic alternatives and enhancing RNG's overall ecological benefits.

3 Hydrogen

This section discusses the potential markets, infrastructure needs, and emissions and environmental impacts of electrolytic hydrogen in New York State's energy transition. The analysis focuses on the current outlook and market potential for hydrogen end uses. It then explores the several important supply and demand considerations as well as the infrastructure requirements necessary to support the deployment of hydrogen in the State. Finally, the section reviews the emissions and environmental impacts of electrolytic hydrogen.

3.1 Markets, Infrastructure, and Greenhouse Gases

Hydrogen's use as a clean energy carrier has growing relevance in the context of decarbonization. This section explores its market outlook, key infrastructure challenges, and GHG implications, especially with regard to hydrogen produced via electrolysis.

3.1.1 Current Outlook and Future End Uses

Hydrogen is an energy carrier produced mainly through steam methane reforming (SMR), electrolysis, or other means. SMR uses high-temperature steam to strip hydrogen from natural gas, releasing carbon to the atmosphere as CO_2. Electrolysis, by contrast, uses electricity to strip hydrogen from water. Hydrogen produced through electrolysis is often referred to as "clean" because it does not release carbon and can be produced using clean electricity. Hydrogen produced using SMR can be done with carbon capture, which is either permanently sequestered or utilized. [149] Currently, most hydrogen is produced through SMR without carbon capture. It is critical to account for the emissions associated with the natural gas consumed during SMR hydrogen production.

To align New York State's energy transition targets, future hydrogen production and consumption must use clean hydrogen, likely requiring policy support. While other low-emissions production pathways exist, this report focuses on electrolysis; other methods of production should be explored in subsequent work.

Hydrogen is primarily used in chemical processes to refine petroleum, produce chemicals and fertilizer, and for other industrial processes, with production concentrated near the industrial centers where it is used rather than distributing it widely. In a decarbonized energy future, hydrogen could serve as an alternative, potentially GHG-free fuel to power hard-to-electrify applications, including the power sector, industrial processes, buildings, and transportation. These technologies are still in early stages and are not yet deployed at scale.

Hydrogen's very low energy density presents major transportation and storage challenges. It must be compressed or chilled into liquid hydrogen (at -253ºC, close to absolute zero), but this requires considerable additional energy input and infrastructure. It can also be bound into chemical compounds for easier handling, for example, as ammonia (NH_3), which can be used directly as a fuel, or converted back to hydrogen.

3.1.2 Supply and Demand Dynamics

Clean hydrogen is distinct from other alternative fuels because it uses water and electricity as feedstocks. This creates unique benefits and drawbacks. Unlike biofuels, hydrogen does not rely on biological feedstocks, which will face high demand. Constraints on the supply of hydrogen will instead be imposed by the availability of clean power to run electrolyzers. Similarly, its cost competitiveness with other alternatives will be significantly influenced by the price of power. Aside from power costs, transportation and storage costs will also impact the delivered costs of hydrogen. These delivery costs depend partly on how close electrolyzers are sited to demand centers.

The power sector is expected to experience significant load growth from the electrification of space heating, transportation, as well as the addition of new, large loads like data centers. While electrolyzers are relatively flexible and can run during periods of excess generation, any additional demand that they impose on the power grid will only further strain the system. Regional transmission buildout and storage resources are additional factors that will influence how much clean power is available to run electrolyzers. Some producers are exploring producing hydrogen through SMR with carbon capture. This approach would not be limited by the availability of clean power but would rather depend on the rate of adoption of carbon capture technology and will face its own carbon transportation and storage constraints (e.g., development timelines for carbon dioxide pipelines and Class IV injection wells), which will be highly influenced by location.

Currently, two potential sources of clean hydrogen located near New York State are the Mid-Atlantic Hydrogen Hub (MACH2) and the Appalachian Regional Clean Hydrogen Hub (ARCH2). These facilities anticipate that they will produce 270 and 1,500 metric tons of hydrogen per day (roughly 62 TBtu per year), yet neither of the hubs are sited within New York State.[150, 151] The DOE hydrogen hubs will produce hydrogen using a variety of production methodologies (e.g., electrolysis, SMR with carbon capture) and feedstocks (e.g., renewable power, nuclear, natural gas, RNG). New York State should consider mechanisms to ensure that hydrogen transported into the State comes from technologies and feedstocks consistent with New York State's policy objectives. New York State is also investing in expanding in-state hydrogen production capabilities. In early 2025, New York State awarded $1.2 million to four hydrogen R&D projects aimed at improving electrolyzer technology. This is in addition to the $27 million hydrogen innovation budget approved in 2023.[152]

Federal production and tax incentives for hydrogen may reduce costs but are highly uncertain in the long term. New York State can also implement state-specific incentives to stimulate a regional market and focus on hydrogen production in locations where renewable power would otherwise be curtailed and be of beneficial use.

Some applications in these sectors are difficult to electrify and can benefit from the flexibility of hydrogen. Moreover, given the lack of viable alternatives in many of these uses, these end users are willing to pay the premium for limited supply. The industrial sector already consumes a significant amount of hydrogen for ammonia and chemical production, and the DOE recognizes the industrial sector as a prime candidate for the initial uptake of clean hydrogen. Importantly, most of the existing hydrogen use in the industrial sector occurs outside of New York State in states like Texas and Louisiana; in-state hydrogen demand may not develop as quickly. The DOE also recognizes the potential for clean hydrogen to power some of the medium- and heavy-duty transportation sectors, although the hydrogen fuel cell vehicle market is more nascent than the rapidly expanding electric vehicle market.[153]

Hydrogen's ability to meet New York State's needs will largely be dependent on the future of the State's power sector and the pace of technological advancement and development in the region. In recent years, New York State has faced challenges in renewable energy development due to supply chain obstacles and inflationary pressures. The State Energy Plan projects load growth that could make procuring enough clean power to meet demand and significantly increase production costs. As the number of intermittent resources grows, the State's bulk transmission system may become constrained. Ensuring that clean power can be delivered to electrolyzers is equally as important as producing it. Though hydrogen can increase demand for clean electricity, it can also act as a storage technology.

The advancement of clean hydrogen technology is another variable that needs to be followed closely. Most of the current hydrogen production uses SMR, not electrolyzers. Electrolyzer development and deployment will need to accelerate over the next 10 to 15 years to meet the projected levels of demand. Similarly, hydrogen is not widely used in the transportation sector today, but it is anticipated to contribute in the future. The usefulness of hydrogen in decarbonizing transportation will closely follow the continuing development and deployment of fuel cell vehicles.

Hydrogen has the potential to take on a more significant role in New York State's energy future, depending on how quickly the market matures. For example, if enough battery capacity is built, storage resources can be used to flexibly run electrolyzers. In addition, ongoing research and development could lead to more flexible and lower-cost hydrogen production, which could result in more cost-effective production than currently anticipated and wider dispersion of production sites.[154] Hydrogen can also be transformed into ammonia, methane, and e-fuels, each of which has its own particular use cases.

3.1.3 Infrastructure and Production

Infrastructure is a key component in the successful deployment of electrolytic hydrogen. This section explores the requirements for hydrogen production, including siting, renewable power access, and transportation infrastructure.

Electrolytic hydrogen is produced by using renewable energy to split water molecules into hydrogen and oxygen using electrolysis.[155] Unlike traditional fuels, hydrogen production is not restricted to a specific location (e.g., underground natural gas deposits), but producers must consider important siting conditions.

First, the site must have sufficient land to site the electrolyzer(s) and ancillary equipment. Typically, hydrogen is produced at centralized facilities with one or multiple electrolyzers operating in parallel, each of which is approximately the size of a shipping container[156] and have a capacity of approximately 5–10 MW per electrolyzer today.[157] In addition to the electrolyzer(s), hydrogen production sites may include piping, storage facilities, wastewater ponds, renewable generation assets, utility corridors, and/or access roads, depending on the facility. Colocating large electrolyzers near end users can add further siting complications, particularly in high-density areas or areas with specific environmental, safety, or community-impact considerations. For example, more than 2,800 MW (nameplate capacity) of gas-fired generation is located in Astoria, Queens. If these units were converted to burn hydrogen produced on-site, electrolyzers, storage, and other associated equipment would need to be colocated with the facilities in a dense urban environment.[158] For certain applications, commercially available small-scale electrolyzers can be installed within the existing footprint of an end-use facility. These electrolyzers range in size from utility cabinets to small appliances.

Second, electrolyzers must have access to renewable power, either through a direct connection to a dedicated renewable resource or an interconnection with the electric grid. Dedicated renewables provide greater assurance that hydrogen is produced using clean electricity (and access to clean hydrogen production tax credits or other incentives), but they significantly increase costs and land-use requirements, especially for high-capacity hydrogen production facilities. Producers can offset these cost increases by selling excess renewable power into the market. On the other hand, grid-connected electrolyzers can offer a stable power source at a potentially lower cost. Before New York State achieves its 100% clean electricity goal, the State should ensure grid-connected electrolyzers are powered by renewable electricity, which would reduce emissions compared to conventional fuel. In both instances, New York State should carefully balance renewable power priorities to ensure its available for high-value end uses, such as building electrification and electric vehicles, without unnecessarily driving up prices through competing demands.

Lastly, the hydrogen production facility must have access to infrastructure for transporting the product to end users. Transporting hydrogen can be expensive due to technical challenges and the limited existing infrastructure, as discussed in the next section. Some studies estimate that transportation can account for up to 40% of the delivered price of hydrogen.[159] However, costs can be reduced through economies of scale by building fewer pipelines to gather and transport large volumes of hydrogen from various producers along the route (similar to natural gas gathering lines). A recent study commissioned by the European Parliament found that producing hydrogen in low-cost areas and then using repurposed natural gas pipelines to transport it to demand centers is more cost-effective than colocation (see accompanying case study). Alternatively, electrolyzers can be located near demand centers, reducing transportation costs or simply requiring yard piping to serve end users. The siting of hydrogen production facilities must balance land access, renewable power availability, water resources, and transportation costs. Because New York State's hydrogen industry is still in its early stages, the State has the opportunity to analyze and influence the extent to which hydrogen production is collocated with demand.

Case Study
European Hydrogen Backbone: Taking Advantage of Regional Supply and Demand Differences

Due to limited midstream hydrogen infrastructure in Europe, most hydrogen developers have focused on projects where production is collocated with offtakers.[1] However, Europe plans to build an extensive hydrogen pipeline system. In 2022, the European Hydrogen Backbone presented a hydrogen pipeline infrastructure plan that includes five hydrogen corridors, designed to exploit regional differences. These corridors will connect areas with low-cost supply potential to industrial demand centers in central Europe.[2] The South Central and Iberian corridors will transport electrolytic hydrogen imports from North Africa through Italy and Spain; the North Sea, Nordic, and Baltic corridors carry hydrogen produced via offshore wind farms and hydroelectric dams. The eastern and southeastern corridors will connect with neighboring countries in Asia. Initially, these corridors will connect local supply and demand within Europe, but they are set to expand to connect regions outside of Europe as well.[3]

[1] Monika Dulian and Gregor Erbach, 2025, “Renewable and Low-carbon Hydrogen: State of Play and Outlook,” European Parliament Research Service, Renewable and low-carbon hydrogen

[2] European Hydrogen Backbone, 2022, “Five Hydrogen Supply Corridors for Europe in 2030: Executive Summary” (May), https://ehb.eu/files/downloads/EHB-Supply-corridors-presentation-ExecSum.pdf

[3] Central European Hydrogen Corridor, n.d., “Hydrogen Vision for Europe,” https://www.cehc.eu/h2-for-europe/

Transportation and Storage

Hydrogen can be transported from the electrolyzer to the end user in various ways. Today, hydrogen gas is transported through pipelines, similar to natural gas, or trucked in tube trailers. Alternatively, hydrogen can be chilled into a liquid and trucked in cryogenic tankers. In addition, hydrogen can undergo further chemical processing to turn into other energy carriers, such as liquid ammonia, for transportation or storage. The method used to transport hydrogen depends on the required volumes, distances, and associated costs.

Pipelines

Pipelines offer a low-cost option to deliver large volumes of gaseous hydrogen to the end user. Approximately 1,600 miles of hydrogen pipelines currently operate in the U.S., primarily connecting hydrogen production to various chemical and refinery plants along the Texas and Louisiana Gulf Coast.[160] In New York State, one hydrogen pipeline in Niagara County transports hydrogen 1 mile from a producer to a purification and liquefaction facility.[161, 162] The liquified hydrogen is then transported by truck to industrial customers throughout the Northeast, who use it in steel processing and e-fuel production (e.g., gasoline, diesel).[163] While pipelines offer an efficient and low-cost way to transport hydrogen, the lack of existing hydrogen pipelines means that significant upfront capital investments and permit approvals will be required to leverage this transportation method.

Alternatively, small volumes of hydrogen can be blended into the existing natural gas transmission or distribution pipeline network (discussed in detail in Section 2.2.1.2), but several known technical and safety challenges, particularly at the distribution level, limit the feasibility of this approach. Studies have found that hydrogen can only be blended into existing natural gas pipelines at limited concentrations, with an upper limit of 20% by volume often quoted. At higher concentrations, hydrogen can interact with the steel, causing fatigue and embrittlement of the pipe. [164] A 2022 University of Riverside study, commissioned by the California Public Utilities Commission, found that embrittlement can occur at concentrations as low as 5% in transmission networks.[165] Additionally, hydrogen has a very low energy density by volume—approximately one-third that of natural gas. To deliver the same amount of energy, hydrogen pipelines must operate at higher pressures. This creates technical and safety challenges for blending larger concentrations of hydrogen and/or repurposing existing natural gas pipelines because natural gas pipelines are rated for lower maximum allowable operating pressures. Hydrogen is also the smallest element and has a higher propensity to leak than natural gas.[166] Leakage can pose safety risks because hydrogen combusts at a wider flammability range than natural gas (4%–75% versus 5%–15% gas-to-air volume ratio, respectively) and burns with a nearly invisible flame.[167] As discussed earlier, New York State has the second-highest amount of leak-prone pipe in the U.S. according to the Pipeline and Hazardous Materials Safety Administration (PHMSA). New York State should replace its cast and wrought iron pipes before allowing blending to occur. Lastly, blending is limited by the tolerance of the most sensitive equipment in the gas distribution system. As a result, many countries limit hydrogen blending to 2% by volume. [168]

If technical and safety challenges can be overcome, repurposing existing gas pipelines to transport pure hydrogen and/or hydrogen blended with RNG could create substantial cost savings and mitigate potential environmental and land-use impacts from building new infrastructure. In Europe, capital expenditures for repurposing pipelines to transport pure hydrogen are 10%–35% of the cost for new hydrogen pipelines.[169]

The cost to repurpose an existing pipeline system to transport high concentrations of or pure hydrogen stems from several technical differences between hydrogen and natural gas. Due to hydrogen's lower energy density, hydrogen transportation requires approximately three times more compression power than natural gas to achieve the same amount of delivered energy.[170] Repurposing existing natural gas infrastructure will likely require investments in new compression facilities, depending on the existing compressor technology. Technical studies from Europe have found that retrofitting gas turbo-compressors, which are typically used on large diameter pipelines, to handle gas containing more than 40% hydrogen by volume is not currently feasible due to material compatibility issues.[171] However, reciprocating compressors can handle pure hydrogen, although they are typically not efficient for large diameter pipelines. The additional compression requirements will also increase the pipeline's operating cost.[172]

Moreover, upgrades to the existing pipeline may be necessary. Existing natural gas pipelines are rated to operate at a certain maximum pressure based on their material composition and dimensions. Repurposing the pipeline to transport hydrogen at a higher pressure will require recertification to operate at a higher maximum operating pressure and possibly the replacement of some pipe segments. If the existing pipeline is not made with hydrogen-compatible materials, liners or coatings can be used.[173] Alternatively, a new hydrogen-compatible pipeline can be pulled through an existing steel pipe, reducing construction costs and environmental impacts compared to full replacement. This technology, however, is only applicable to small diameter pipes.[174] Other components of the pipeline system, including meters, regulators, valves, and fittings, may also need to be replaced with hydrogen-compatible equipment.[175]

While these requirements may pose feasibility challenges for repurposing existing pipelines, studies show that the costs are lower than constructing new hydrogen pipelines. The European Hydrogen Backbone study found that the capital costs per kilometer of repurposed pipe are one-third of the cost of constructing new hydrogen pipelines (Table 3).[176] The German Association of Gas Transmission Operators estimated the cost of building new hydrogen pipelines to be nine times higher than repurposing existing pipelines. The European Commission conducted a study that estimated capital costs of repurposed pipelines at €0.37 million per kilometer (approximately $0.43 million 2025 USD) versus €0.93 to €3.28 million per kilometer (approximately $1.08 million 2025 USD to $3.8 million 2025 USD) for new pipelines (depending on the diameter).[177] While these studies show consistent results, the potential costs of repurposing versus building new hydrogen pipelines have not been rigorously studied in the U.S., let alone in New York State. Such studies will be crucial as New York State evaluates the benefits and challenges of repurposing existing infrastructure to transport hydrogen.

Table 3: European Hydrogen Backbone Study Estimates of New versus Repurposed Pipelines

Source: European Hydrogen Backbone.[178]

Diameter	Type	Pipeline Capex	Compression Capex	Capex Unit
Small (20-inch)	New	1.5	0.09	€/kg H_2/200 km
	Repurposed	0.3	0.09	
Medium (36-inch)	New	2.2	0.32	€/kg H_2/1,000 km
	Repurposed	0.4	0.14	
Large (48-inch)	New	2.8	0.62	
	Repurposed	0.5	0.62	

Several natural gas distribution utilities in New York State are considering hydrogen blending as a way to reduce GHG emissions in support of the State's or their own corporate environmental goals. In the NYS Public Service Commission's (PSC) ongoing Gas System Long Term Plan, utilities such as National Grid and Central Hudson Gas and Electric Company (Central Hudson) relied on hydrogen and RNG blending as part of their technology pathway analyses. In its plan, National Grid states:

> *[T]he use of green hydrogen produced locally or regionally is a key element of National Grid's Clean Energy Vision to decarbonize the gas network . . . blending hydrogen into the gas network allows customer to use their current infrastructure and devices, making the transition to cleaner energy more accessible and affordable.*[179]

As part of its plan, Central Hudson completed a study that performed hydraulic modeling simulations and found it could technically blend up to 20% hydrogen into its distribution.[180] At this time, no significant volumes of hydrogen are being blended into the New York State gas utilities' distribution systems.

Case Study
Repurposing Existing Natural Gas Pipelines to Build the European Hydrogen Backbone System

The European Union Agency for the Cooperation of Energy Regulators (ACER) studied the potential for repurposing natural gas transmission pipelines in Europe for hydrogen versus building new hydrogen pipelines. Although repurposing is the less expensive and more feasible option, it faces technical issues such as embrittlement, leakage, and requirements for higher compression power.[1] However, some solutions are available: embrittlement can be remedied by applying an inner coating to prevent steel degradation, using intelligent pigging, managing operational pressure, and adding degradation inhibitors. Based on these learnings, the European Hydrogen Backbone Initiative expects to build an approximately 33,000-mile system, using 60% repurposed natural gas pipelines and 40% new pipelines, at a total cost of €80 billion–€143 billion (approximately $93 billion to $167 billion 2025 USD).[2]

[1] European Union Agency for the Cooperation of Energy Regulators, 2021, "Transporting Pure Hydrogen by Repurposing Existing Gas Infrastructure: Overview of Existing Studies and Reflections on the Conditions for Repurposing" (July 16): 7, https://acer.europa.eu/sites/default/files/documents/Publications/Transporting%20Pure%20Hydrogen%20by%20Repurposing%20Existing%20Gas%20Infrastructure_Overview%20of%20studies.pdf

[2] European Hydrogen Backbone, n.d., "European Hydrogen Backbone Grows to Meet REPowerEU's 2030 Hydrogen Targets," https://ehb.eu/newsitem/european-hydrogen-backbone-grows-to-meet-repowereu-s-2030-hydrogen-targets

Dedicated hydrogen pipelines are a mature technology designed to address many of the technical and safety challenges discussed above. Hydrogen pipelines use midstrength steels, including American Petroleum Institute (API) steels 5L X42, X46, and X52. These grades are less susceptible to embrittlement than steels used in natural gas pipelines. In addition, these midstrength steels can operate at higher pressures, up to 1,900 pounds per square inch gauge (psig), than natural gas pipelines.[181] Recent indications from Europe suggest that new hydrogen pipelines could cost approximately 110%–150% of corresponding new natural gas pipelines.[182] A 2024 study by the National Petroleum Council similarly estimated that new hydrogen pipelines will cost 110% of a similar-diameter natural gas pipeline.[183] However, both estimates rely on an assumed multiplier because actual project data for new purpose-built hydrogen pipelines is limited.[184] The multiplier accounts for additional costs for enhanced pipeline welding procedures and hydrogen-compatible sealing materials, which are more expensive than those for natural gas.[185] The Natural Petroleum Council study estimated that the average cost for a new hydrogen pipeline in the U.S. is $11 million per mile for a 36-inch pipeline, with costs in the Northeast 2.6 times higher at $19.8 million per mile.[186]

Permitting and constructing new hydrogen pipelines could prove more challenging than the current challenges of permitting new natural gas pipelines. At the federal level, no clear framework regulates hydrogen pipelines. The Surface Transportation Board (STB) currently provides limited economic regulation, but ongoing discussions question whether jurisdiction should transfer to FERC and whether hydrogen pipelines should be regulated like natural gas pipelines under the Natural Gas Act or like oil pipelines under the Interstate Commerce Act.[187] PHMSA has federal oversight of hydrogen pipeline safety.[188] Regulations at the State level primarily focus on air and water quality, waste management, land use, and, in some cases, permitting for hydrogen pipelines. Recently, Pennsylvania, Louisiana, South Dakota, and other states have passed legislation providing broader economic, siting, and safety regulatory oversight for hydrogen facilities.[189] New York State should evaluate its regulatory framework for hydrogen pipelines and determine if modifications are necessary.

Trucking

In areas where hydrogen pipelines are difficult to build, trucks can transport hydrogen from the production site to end users. Trucks can haul gaseous hydrogen in tube trailers, which contain stacks of long, pressurized cylinders.[190] The weight of the steel tubes limits the capacity of tube trailers to approximately 380 kilograms (kg) of hydrogen per truck. This weight and capacity limitation makes tube trailers better suited for short-distance transportation.

Today, hydrogen most commonly travels by truck as a liquid.[191] The liquification process cools hydrogen to below −253ºC before loading it into a cryogenic liquid tanker. These tankers allow for higher-volume on-road transport of hydrogen (4,000 kg of hydrogen per truck) and are better suited for longer distances. However, the liquefaction process is expensive and can consume about 35% of hydrogen's energy content.[192]Additional hydrogen volumes can be lost during transport as boil-off.[193] One further consideration is whether the end user will require equipment to vaporize the liquid hydrogen after delivery.

Trucking could play a significant role in transporting hydrogen, particularly in the early stages of the transition when other hydrogen distribution systems in New York State are not mature. However, New York State faces challenges. The cost to truck hydrogen is 2 to 6.5 times more expensive than pipelines on a volumetric basis, but may be worthwhile if the need for a pipeline cannot be justified or is too challenging to construct.[194] In addition, tube trucks and cryogenic liquid tankers have limited capacities (relative to pipelines), potentially requiring frequent and high-volume deliveries to provide reliable services to end users. The environmental and community impacts of trucked hydrogen will need careful consideration against those of other hydrogen transportation methods. New York State should work closely with State and local agencies to ensure the safe transportation of hydrogen, particularly near critical infrastructure.

Storage

Hydrogen can be stored in systems connected to pipelines, colocated near end users, or alternative energy carriers (see the next section) to manage timing differences between supply and demand. Today, hydrogen is primarily stored in aboveground steel storage tanks either as compressed gas or in liquid form at end-use locations.[195] Gaseous hydrogen storage tanks have lower storage capacity but are cheaper to construct and operate. Liquid storage tanks are more common because they store larger volumes of hydrogen but incur significant energy penalties and costs to liquify the product.

Larger volumes of gaseous hydrogen can be stored in underground geological facilities, although the feasibility depends on the type of formation. Depleted reservoirs are the most common type of underground storage facility, including in New York State. However, hydrogen's properties make storing it in these types of formations difficult. Hydrogen can seep deep into the formation, particularly after interacting with brine solutions, making it extremely challenging to withdraw and causing permanent loss.[196] Hydrogen can also interact with microbes in the formation, which use the hydrogen for metabolic processes, introducing contaminants into the gas stream, such as methane and other gases.[197] This can create gas quality issues for pipelines and/or end users.[198] Pilot studies are underway in Europe to evaluate potential solutions to these challenges.

Case Study
Pilot Project to Demonstrate Hydrogen Storage in Depleted Gas Reservoirs

In 2024, the European Commission officially launched the European Underground Hydrogen Storage Reference System (EUH2STARS) project. The project aims to demonstrate underground hydrogen storage in depleted porous natural gas reservoirs by 2029. It seeks to address some of hydrogen storage challenges mentioned earlier, such as developing a hydrogen purification system and integration into the hydrogen withdrawal process at its demonstration facility to achieve Grade A (or 99.8%) pure hydrogen or better. Additionally, the project plans to operate four seasonal storage cycles at an underground hydrogen demonstration facility and two storage cycles at a different site. Each cycle will test different market-driven operational characteristics. The facility also aims to develop guidelines related to environmental, safety, legal, and future regulatory, societal, and market-related aspects of operating an underground hydrogen storage facility in Europe.[1] EUH2STARS's second work package includes an analysis of hydrogen leakage risks and prevention measures.[2]

[1] European Underground Hydrogen Storage Reference System (EUH2STARS), n.d., "EUH2STARS: European Underground Hydrogen Storage Reference System," https://www.euh2stars.eu/en/project/project-description.html

[2] European Underground Hydrogen Storage Reference System (EUH2STARS), n.d., "Work Package 2," https://www.euh2stars.eu/en/project/work-packages/work-package-2.html

Salt dome formations hold the most significant promise for storing large volumes of gaseous hydrogen. These artificial structures are created by dissolving salt formations and pumping out the resulting brine. Unlike depleted reservoirs, salt dome formations are sealed caverns, which greatly reduce the risk of loss or leakage. In addition, the formation can be treated to minimize the risk of bacteria or other contaminants. Hydrogen storage in salt dome formations has been proven, and several projects in the U.S. are pursuing this technology, such as the Advanced Clean Energy Site (ACES) in Delta, Utah.[199] While salt dome storage fields are promising, they are rare in the U.S.; most are concentrated in the Gulf Coast region. However, some smaller salt dome facilities exist in the Finger Lakes region, which are currently used for natural gas.

Storage will play a critical role in balancing hydrogen supply and demand in New York State. For example, the Scoping Plan envisions using hydrogen as a fuel for dispatchable power generation, which will require large volumes of hydrogen to be available when the grid needs firm power. The State has limited geological resources that can store larger hydrogen volumes, and the existing salt dome facilities in New York State serve interstate natural gas pipeline shippers. Aboveground storage tanks will therefore likely play a larger role in meeting anticipated end-use demands. New York State should collaborate closely with State and local officials, as well as communities, on siting these facilities.

Alternative Energy Carriers and Storage Media

As mentioned earlier, transporting gaseous hydrogen presents technical, safety, or cost challenges. These issues can be addressed by transporting hydrogen in an alternative energy form. For instance, wind and solar energy can be transmitted as electricity to electrolyzers near end users. The electricity could also be stored in a battery energy storage system (BESS) and discharged later to power an electrolyzer. This configuration might include grid-connected electrolyzers, as discussed earlier. If the electrolyzer must collocate with the demand center to avoid developing hydrogen pipelines, dedicated high-voltage transmission lines could instead connect renewable resources elsewhere in the State to the hydrogen production facility. While permitting electric transmission lines can be challenging, in some cases, they may offer easier and more cost-effective solutions than constructing a new hydrogen pipeline.[200, 201]

Gaseous hydrogen can also be converted into liquid ammonia, an effective energy carrier with a high energy density of 3.83 megawatt-hours per cubic meter (MWh/m^3) or 3.66 million British thermal units per cubic meter ($MMBtu/m^3$) for ammonia, compared to 2.64 MWh/m^3 or 2.52 $MMBtu/m^3$ for liquid hydrogen.[202] Ammonia is suitable for long-distance transportation and storage. It can be produced by combining clean hydrogen with nitrogen from the air through the Haber-Bosch process. The process occurs at high temperatures (approximately 400ºC) and high pressures (approximately 150 bar).[203] Afterward, the ammonia is liquified at −33ºC, which is warmer than hydrogen liquification and thus provides an energy cost savings relative to cryogenic hydrogen transport.[204] The ammonia production process is energy-intensive, with current technology achieving only 50% efficiency.[205] However, new ammonia synthesis processes are under development. For example, electrochemical ammonia production uses the nitrogen reduction reaction, running a current through an electrochemical cell containing hydrogen and nitrogen. This process operates at lower pressures and can be scaled for smaller applications, although it still requires significant energy and is not yet commercialized.[206]

Ammonia is an established global commodity, primarily used in fertilizer production, with a mature multimodal transportation network already in place to be leveraged. Most ammonia is transported as a pressurized liquid in railway tanker cars, tanker trucks, ammonia pipelines, and barges.[207] Ammonia also has a lower boil-off rate than liquid hydrogen, resulting in better energy retention during transport.[208]

Once ammonia reaches its destination, it can be consumed directly as a fuel. However, one challenge of combusting ammonia is its potential to generate significant nitrogen oxide emissions. Recent demonstration projects in Japan have used two-stage combustion processes with limited oxygen supplies to lower nitrogen oxide emissions.[209] Alternatively, ammonia can be cracked back into hydrogen and nitrogen, but this process is energy-intensive, requiring temperatures exceeding 900ºC. This cracking process results in a minimum energy loss of 5%–6%, with an additional 4%–7% lost as thermal energy.[210]

Case Study
Cofiring Ammonia in Power Generation

In 2024, Japanese companies Jera Co., Inc., and IHI Corporation launched a demonstration project to cofire 20% ammonia with coal in a 1 GW unit at the Hekinan power plant. The goal of the project is to study nitrogen oxide emissions and assess the operability and impact on boilers and other ancillary equipment. Jera plans to begin cofiring ammonia in power plants starting in March 2025, with a goal of achieving 50% ammonia cofiring by the 2030s and eventually reaching 100% ammonia combustion.[1] Japan aims to import 2 million tons per year of ammonia by 2030 to meet the anticipate demand.

[1] Motoko Hasegawa, 2024, “Japan’s Jera, IHI Start Ammonia-Coal Co-firing Trial” (January 4), Argus, https://www.argusmedia.com/en/news-and-insights/latest-market-news/2553431-japan-s-jera-ihi-start-ammonia-coal-co-firing-trial

End-Use Equipment

Most existing equipment used in end-use applications will likely require retrofits or replacements, and New York State will design new end-use equipment to be hydrogen compatible. Currently, markets for hydrogen-compatible equipment are not mature for many applications.[211] For example, the Scoping Plan recommends initially using alternative fuels to “manufacture lower-carbon building materials, such as cement, steel, and aluminum.”[212] However, replacing up to 30% of natural gas with hydrogen for direct reduced iron-electric arc furnace (DRI-EAF) steel production can only occur with minimal retrofits. DRI-EAF steelmaking also requires a reliable, high-volume hydrogen supply, which could incur substantial upfront costs and coordination challenges.[213]

Other high-heat industrial processes, such as glass and cement manufacturing, can also utilize hydrogen, but must address challenges like burner design and managing nitrous oxide emissions.[214] Ongoing research aims to develop turbines for power generation that can combust high concentrations of hydrogen or pure hydrogen.[215] By partnering with industry partners and other governments, New York State should invest in research and development efforts and offer rebates and incentives to ease the transition to hydrogen.

In addition, end-use equipment can have varying degrees of sensitivity to the purity of the hydrogen in the gas stream. For example, hydrogen fuel cells require 99.97% pure hydrogen to achieve optimal performance.[216] New York State and the industry should collaborate to ensure that all end users accessing common carrier transportation methods (e.g., pipelines) receive hydrogen that meets or can be treated to meet the quality specifications for their specific applications. Overcoming barriers to hydrogen adoption in hard-to-electrify industries will be essential for New York State to meet its climate and energy goals.

Other potential end-uses of hydrogen, like heating and cooking, also face significant challenges. Behind-the-meter equipment will need to be hydrogen-compatible for both blended and pure hydrogen. Many buildings will need to replace existing gas pipes with those made from hydrogen-compatible materials. In addition, hydrogen-compatible appliances can accommodate hydrogen blends up to approximately 20%; higher blends will require retrofits or full appliance replacements due to hydrogen's chemical properties and combustion (see accompanying case study).

Effectuating this transition at scale will be extremely challenging. Customers will face conversion costs and building upgrades, codes will need to be updated, and skilled laborers must be trained and certified to handle hydrogen safely. However, the investment may not be as valuable in helping New York State meet its climate and energy goals, particularly when electrification alternatives are available.

Case Study
Initiative to Develop Hydrogen-Compatible End-Use Equipment

The United Kingdom's Hy4Heat government program examined hydrogen usage for heating certain commercial and industrial sector end uses. The program also studied tentative acceptable levels of hydrogen impurities for different applications, specifically the effects of carbon monoxide, water, carbon dioxide, methane, inert gases, oxygen, and sulfur compounds on pipes, boilers, cookers, stationary polymer electrolyte membrane (PEM) fuel cells, and vehicle PEM fuel cells. For example, carbon monoxide was found to be a catalyst poison for fuel cells and is limited to 0.2 parts/million (ppm), whereas carbon monoxide in pipes, boilers, and cookers can reach up to 100 ppm before workplace exposure limit of 15 minutes is imposed.[1]

In addition, the United Kingdom's Heating and Hotwater Industry Council developed standards and labels to identify hydrogen-compatible appliances: (1) "hydrogen blend appliances" can accommodate blends up to 20% without modification; (2) "hydrogen ready appliances" can handle higher blends of hydrogen with additional modifications; and (3) :hydrogen 100% appliances" can burn pure hydrogen.[2] These hydrogen-compatible appliances are designed to handle key characteristic differences between hydrogen and natural gas:

- Hydrogen molecules are smaller, so the supply system to stoves will need to be more leak-proof.
- Hydrogen has a wider and lower flammability range than natural gas (4%–75% for hydrogen versus 5%–15% for natural gas), making combustion control more difficult.
- Hydrogen's quick flame speed requires changes in combustion design to prevent backfiring (flames tend to move upstream).
- Hydrogen combusts at higher temperatures, which may require higher-quality materials to withstand the heat (e.g., upgrading steel burner connections).
- Hydrogen combustion produces 60% more water vapor per unit of energy, which can impact ovens and boilers.[3]

[1] Hy4Heat, 2019, "Hydrogen Purity—Final Report" (October 31), https://static1.squarespace.com/static/5b8eae345cfd799896a803f4/t/5e58ebfc9df53f4eb31f7cf8/1582885917781/WP2+Report+final.pdf

[2] Heating and Hotwater Industry Council, 2022, "Hydrogen Appliances" (June), https://www.hhic.org.uk/uploads/62CFE776309E6.pdf

[3] Power Engineers, 2025, "6 Things to Remember about Hydrogen vs Natural Gas" (February 25), https://www.powereng.com/library/6-things-to-remember-about-hydrogen-vs-natural-gas; John Guarco, Bob Langstine, and Michael Turner, n.d., "Practical Considerations for Firing Hydrogen versus Natural Gas," https://cea.org.uk/wp-content/uploads/2021/06/Zeeco-Hydrogen-Article.pdf; and Steve Livermore, 2018, "Exploring the potential for domestic hydrogen appliances" (May 1), The Engineer, https://www.theengineer.co.uk/content/news/exploring-the-potential-for-domestic-hydrogen-appliances/

New York State's Hydrogen Infrastructure Topology

Currently, three hydrogen electrolyzers are operating or under construction in New York State.[217] As mentioned earlier, potential end uses for hydrogen include hard-to-electrify industries such as heavy-duty transport and power generation. However, New York State currently has no public hydrogen fueling stations,[218] nor do power plants run partially or fully on hydrogen.[219]

The location of natural gas-fired power plants, however, offers a clue as to where this demand may emerge. These plants are primarily located in Western and Central New York, as well as the Capital Region, Hudson Valley, New York City, and Long Island. They are located near interstate gas pipelines that pass through areas rich in biological feedstocks. The power plants are also located close to population centers with nearby wastewater treatment facilities and/or municipal solid waste facilities. This colocation creates a strong opportunity to repurpose existing gas infrastructure to serve power generation demand, provided the technical and safety challenges mentioned earlier can be addressed. Alternatively, new hydrogen pipelines could be routed to these power plants using already disturbed rights-of-way.

3.1.4 Emissions and Environmental Impacts

Electrolytic hydrogen is produced by splitting water into hydrogen and oxygen molecules through electrolysis powered by renewable electricity. With renewable energy input, electrolytic hydrogen production generates no process emissions because the only byproducts are oxygen and hydrogen. Some emissions may occur during water treatment and compression, but they are fairly minimal and could be avoided if powered entirely by renewables.[220]

Hydrogen itself is an "indirect" GHG that can negatively impact the climate by reacting with atmospheric chemicals to produce other GHGs.[221] As discussed in Section 3.1.3, due to its small atomic structure and unique properties, hydrogen infrastructure faces challenges related to high-pressure requirements and the element's ability to permeate (i.e., leak) and weaken materials over time. To mitigate these impacts, ensuring that systems designed for transporting, storing, or using hydrogen are adequately reinforced to prevent leakage is crucial. This reinforcement will help minimize potential climate consequences from fugitive hydrogen emissions.

3.1.4.1 Other Environmental Impacts

While electrolytic hydrogen produced from renewable electricity offers a carbon-neutral fuel pathway, the process requires significant water consumption, estimated between 17 to 24 liters per kilogram of hydrogen produced.[222] Green hydrogen facilities located in water-stressed areas will face competition for local water resources or may need to rely on desalination for water supply, complicating the supply chain, expanding the life-cycle boundary, and impacting economic viability. A promising focus of modern hydrogen research and development is seawater electrolysis, which would alleviate concerns regarding freshwater consumption and expensive water treatment, though significant technical and economic challenges remain before the technology can be commercialized.[223, 224]

Even given freshwater concerns, the water requirements of green hydrogen production are much lower than those for existing thermal power generation. For instance, a 1-gigawatt (GW) coal-fired or combined-cycle gas power plant typically withdraws about 18.2 and 14.8 million cubic meters per year, respectively. In contrast, a 237 kilotonnes of hydrogen per year (ktH_2/yr) green hydrogen facility (equivalent in energy content) would consume around 7.6 million cubic meters.[225] Because hydrogen producers will likely source water locally to avoid the costs of transporting it to the facility, New York State and local governments will need to carefully study and develop strategies to avoid any potential environmental impacts or impacts to local communities that rely on the water sources before granting permits for hydrogen facilities.

4 Tracking Environmental Attributes of Low-Carbon Alternative Fuels

The EPA defines "an energy attribute certificate (EAC) [as] a contractual instrument that conveys information (attributes) about a unit of energy, including the resource used to create the energy and the emissions associated with its production and use."[226] EAC markets rely on chain of custody frameworks designed to track the flow of materials at each step of the supply chain, providing verifiable information about a product's origin (i.e., energy), composition, process, and transport. Four common chain of custody frameworks to verify claims that are useful in developing EAC markets: (1) identity preservation model; (2) segregation chain of custody model; (3) mass-balance model; and (4) book-and-claim model.[227] The following discusses each model, which has its advantages and disadvantages.

The book-and-claim framework is the most common type of EAC market in North America, especially in the case of renewable energy certificates (RECs). This secondary market reflects the environmental value of 1 megawatt-hour (MWh) of electricity generated from renewable resources. Mature markets for trading RECs provide renewable power producers with diversified revenue streams and allow private entities to meet decarbonization goals where direct power substitution is not feasible. A similar opportunity exists for EAC markets to promote the adoption of alternative fuels, creating new compliance pathways for hard-to-abate sectors such as industry and heavy transportation.

Currently, the U.S. has two major EAC markets for alternative fuels: the EPA's Renewable Fuel Standard (RFS) and California's Low Carbon Fuel Standard (LCFS). Both systems generate credits for alternative fuels based on their life-cycle abatement potential compared to fossil alternatives. Regulated entities must meet obligations through direct fuel purchases of alternative fuels or by acquiring credits disconnected from the physical fuel product. In both cases, trade in generated EACs occurs exclusively between private entities, generating no direct government revenue. These systems stimulate the adoption of alternative fuels by requiring a designated proportion of fuel consumption to be met through alternative fuels.

Though similar, the RFS and LCFS differ considerably in their design, scope, and targets. This section reviews both systems and discusses lessons that can guide the development of an alternative fuel EAC market in New York State.

4.1 Chain of Custody Frameworks

Chain of custody models provide a framework to trace a product (i.e., energy) through all stages of the supply chain, feedstock sourcing, production, processing, transportation, and end-use, to verify claims about the product. For example, in consumer products or retail, a chain of custody model can verify a product's claim of being sustainably or ethically produced. These frameworks are being adapted for energy products, including renewable electricity and biofuels. New York State should consider these four chain of custody frameworks as it develops its own chain of custody framework for low-carbon alternative fuels.

4.1.1 Identity Preservation Framework

The first chain of custody framework is the identity preservation model, which aims to ensure that a verified product, produced at a verification location, is not mixed with other certified and noncertified products. This model traces the verified product as it moves through the supply chain, allowing the end-user to confirm that 100% of the product received comes from certified materials.[228]

Implementing this framework requires several steps: documentation must accompany the certified product at all times; facilities typically must be certified to handle certified products; a central authority generally audits, certifies, and registers these facilities; and, where necessary, equipment must be cleaned between processing certified and noncertified products.[229]

The identity preservation model can be used, for example, to track hydrogen molecules produced using renewable energy and delivered to an end user using trucks dedicated solely to transporting electrolytic hydrogen. In this case, the truck operator ensures physical separation between the electrolytic hydrogen and SMR-derived hydrogen it transports.

This framework offers several advantages. It ensures that the unique characteristics of an energy product are traced and preserved through the supply chain. These preserved attributes can add value and allow the energy product to command a premium price. Additionally, transparently verifying the product's low-carbon fuel characteristics and preserving through tracing reduces the need for additional testing as the alternative fuel moves through the supply chain.

However, the model also presents several disadvantages. Ensuring physical separation from other fuelscan be logically intensive. Operators may need to use dedicated infrastructure or deploy technologies such as molecular sieves to separate these fuels from traditional fuels. These requirements introduce strict operational requirements and limitations on how low-carbon alternative fuels are handled and processed. The framework requires a more complex system of standards, recordkeeping, and auditing to track a verified product. Collectively, these factors can also make the identity preservation model more expensive than other chain of custody frameworks.[230]

4.1.2 Segregation Chain of Custody Framework

The second model is the segregation chain of custody framework, which requires that verified products, produced at a verification location, are not mixed with other noncertified products. Unlike the identity preservation model, this framework allows mixing of certified products from different sources, as long as they meet the same defined standard.

The same implementation requirements apply: documentation, certified facilities, regular audits, and (where applicable) equipment cleaning to prevent cross-contamination.[231] For example, RNG produced from agricultural waste and landfill gas can be mixed and transported together if both share and meet a state's RNG standards. However, the RNG from these two producers cannot be injected into a pipeline and blended with fossil natural gas because the fossil natural gas does not meet the same standard.

Like the identity preservation framework, the segregation chain of custody ensures that the unique characteristics of the energy product are traced and preserved, enabling a premium price for verified qualities, even when mixed with other certified products. It also limits the amount of testifying required to substantiate the claim of the product throughout the supply chain by providing a transparent and verifiable way to preserve the product's claim.

This framework shares similar disadvantages to the identity preservation framework: logistical complexity; a need for rigorous standards, recordkeeping, and auditing; and higher costs compared to other, less stringent, chain of custody frameworks.[232]

4.1.3 Mass-Balance Framework

The third chain of custody approach, the mass-balance framework, tracks the amount of sustainable content added during the production process and measures its relative contribution to the finished product. This framework, using established standards and auditable tracking systems, allows mixing of certified and noncertified products. [233] For each unit of sustainable certificate product, producers must match the quantity of sustainable content in the finished product.

At the site and tank levels, the framework requires pairing certificates coupled with the certified product up to the blending stage. Facilities handling certified products must undergo audits, obtain certification, and register with a central authority.[234] This approach works particularly well in scenarios where maintaining physical separation of products is challenging or cost prohibitive.

For example, under this framework, RNG produced from agricultural waste and landfill gas could be injected into a natural gas pipeline and blended with fossil natural gas. The end user drawing gas from the natural gas pipeline could then claim emission reduction credits based on the relative mass-balance of each RNG pathway to fossil natural gas.

The mass-balance framework offers notable advantages. It provides greater flexibility in sourcing feedstocks for low-carbon alternative fuels and allows blending of these fuels with traditional fossil equivalents. It is also relatively easier and less expensive to implement because it does not require a dedicated infrastructure for the physical separation of energy products. However, because the framework does not require physical traceability of the feedstocks or finished energy products, it may be more susceptible to abuse or false claims. Third-party verification and audits can help mitigate these risks.

While this framework can scale with increasing production of low-carbon fuels, maintaining and enforcing the framework’s certification, recordkeeping, and auditing processes becomes more complex and time-consuming over time.[235]

4.1.4 Book-and-Claim Framework

In the book-and-claim framework, companies obtain attribute certificates based on the volume of certified materials they produce. Certified and noncertified products are allowed to flow through the supply chain, without separation and without a traceable connection between the certified supplies and the end product.[236] Instead, an independent authority administers the certificate marketplace. Producers with excess attribute certificates can sell them to those who lack sufficient certificates to meet compliance obligations. This system is commonly used for RECs and carbon trading. Other applications include the EPA's RFS and LCFS in California, Oregon, Washington, and British Columbia.

Especially with fuels and energy sources that become indistinguishable once injected into the broader transmission and distribution system, like electricity and RNG, where electrons and molecules cannot be traced from source to sink, these systems reflect the broader displacement of fossil fuels that the EAC represents, even if the purchaser is outside the specific jurisdiction requiring alternative fuels use.

Book-and-claim frameworks are flexible and offer the lowest barrier to entry, incurring no additional transportation costs because the framework does not require physical traceability or production location verification. In addition, the attribute certificate market can provide a highly visible and transparent market signal to increase production of more low-carbon alternative fuels when attribute certificate demand exceeds available supplies. However, this framework is susceptible to fraud and manipulation because participants can make claims even when the fuel consumed contains no renewable feedstocks, simply by purchasing attribute certificates for that product.[237]

Entities have imposed additional requirements on participants in book-and-claim systems to ensure compliance with the program objective. In the energy sector, these requirements often relate to deliverability, additionality, and temporal matching of renewable energy or feedstocks used to produce EACs:

- Deliverability requires that renewable energy be sourced from producers located in the same region (i.e., balancing authority, market, or state) as the end-user of that energy. This ensures that the renewable energy (or feedstocks) resource can physically deliver the energy to the end-user.
- Additionality requires that renewable energy is sourced from new resources, rather than redirected from existing end uses. This ensures that the emission reduction benefits associated with the end use would not have occurred without the latest generation.
- Temporal matching requires that renewable energy is produced within a similar time period as its consumption (i.e., the same hour, month, or year). This supports the claim that renewable energy meets the end user's demand. Temporal matching is especially important when the marginal emission rate associated with the production of the energy changes over time.

Several clean electricity and low-carbon alternative fuel programs incorporate these requirements across sectors. For example, under New York State's Clean Energy Standard (CES), electricity must meet the following criteria to qualify for Tier 1 RECs:

1. It must come from a facility that began operating after January 1, 2015 (additionality)
2. It must be:
    - Scheduled into a market administered by New York Independent System Operator (NYISO) for end use in New York State
    - Delivered through a wholesale meter for use in New York State
    - Delivered to an end-user through a dedicated generation meter (deliverability)
    - If an out-of-state renewable source injects electricity into the New York State grid, it cannot be counted in more than one state, and it must demonstrate that an equal amount of energy is transmitted out of the affected spot market for end use during the same hour as the injection (deliverability and temporal matching).[238]

California's LCFS program was recently amended to include deliverability requirements for alternative fuels, requirements that already applied to low-carbon intensity electricity pathways.[239, 240] The changes place more stringent requirements on hydrogen and biomethane projects that come online in 2030 or later, requiring that at least 50% of the fuel must be delivered and consumed in California to count toward the fuel's overall carbon intensity score.[241] Previously, LCFS allowed projects to use indirect accounting, enabling them to claim benefits as long as the gas was injected into the North American natural gas pipelines without needing to demonstrate physical delivery to California.

Another example is the clean hydrogen production tax credits under Section 45V of the Internal Revenue Code. To claim the emissions reduction benefit and receive the applicable level of tax credit, producers must purchase an EAC. Specifically, the clean hydrogen must be produced using power that meets the following conditions:

- The power must come from a renewable resource located within the same region, as defined by the National Transmission Needs Study (deliverability).
- The renewable resource must have entered commercial operations within 36 months prior to the electrolyzer being placed into service (additionality).
- The renewable electricity must be generated in the same year the hydrogen is produced, both before and after 2030 (temporal matching).[242]

Today, both major U.S. low-carbon fuel attributes markets, the RFS and LCFS, require book-and-claim accounting to validate the chain of custody.[243] The following sections discuss other key aspects of these programs, as well as guidelines issued by ICAO, the U.S. Department of Agriculture (USDA), and the European Union.

4.2 Examples of Chain of Custody Frameworks Used to Track Environmental Attributes of Low-Carbon Alternative Fuels

Policymakers have implemented several chain of custody frameworks to verify the environmental attributes of low-carbon fuels and ensure compliance with renewable energy mandates. These systems, most commonly structured around the book-and-claim framework, allow producers, refiners, and fuel suppliers to track environmental benefits, reduce emissions, and meet regulatory obligations. The RFS and LCFS are two of the most prominent examples in the U.S.

4.2.1 Renewable Fuel Standard

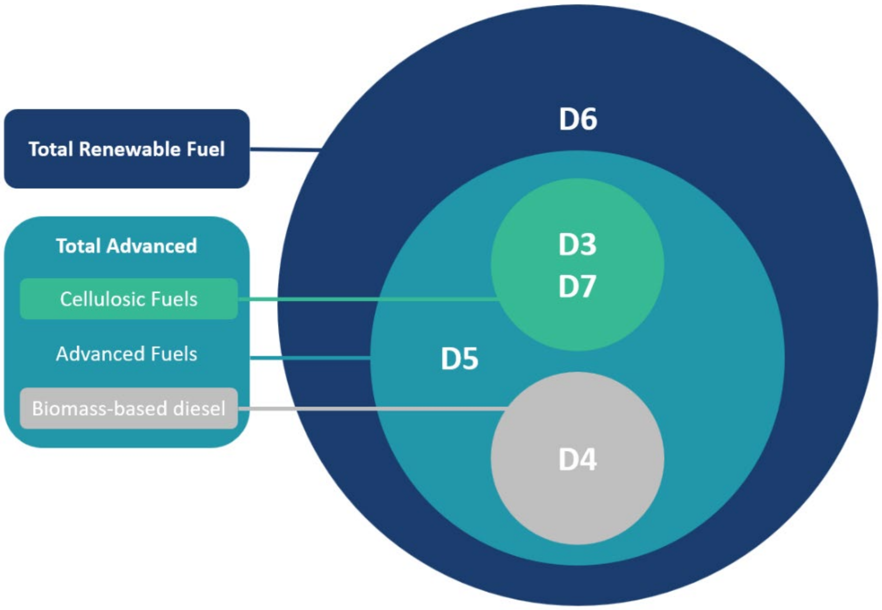
First established in the Energy Policy Act of 2005, and later expanded in the Energy Independence and Security Act of 2007, the RFS program promotes the domestic production of low-carbon biofuels through a national EAC market. The RFS relies on the book-and-claim chain of custody framework. Under this program, the EPA sets renewable volume obligations (RVOs), which require that a designated proportion of alternative fuels be blended into the U.S. surface vehicle fuel supply.[244]

As Figure 12 illustrates, RVOs apply to four nested categories of alternative fuels:

1. Conventional (D6)
2. Advanced (D5)
3. Cellulosic (D3 and D7)
4. Biomass-based diesel (D4)

These categories differ based on the life-cycle carbon dioxide reduction each class of alternative fuel offers compared to its fossil fuel counterpart. Producers can use excess cellulosic fuels (primarily RNG) or biomass-based diesel (renewable diesel and biodiesel) and apply the excess toward meeting the total advanced RVO. Once advanced RVO is met, any additional contributions may count toward the conventional alternative fuels (primarily met by ethanol). However, the reverse is not allowed; these nested contributions cannot flow from traditional to advanced or cellulosic categories.

Figure 12. Renewable Fuel Standard Renewable Identification Number Categories

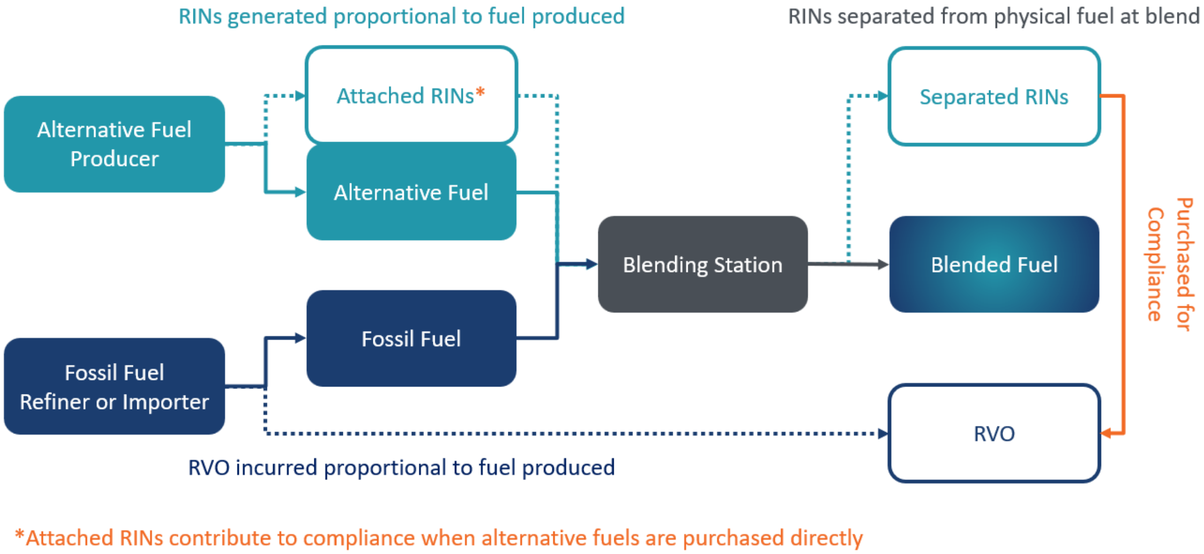


Congress originally established aggressive volumetric RVO targets (measured in gallons) for 2010–2022, projecting year-over-year growth in alternative fuel production and consumption. These statutory volumes were based on fuel demand forecasts at the time the legislation was passed. Using actual transportation fuel consumption data, the EPA converts statutory volumetric obligations into percentage-based standards. These standards require that a designated proportion of alternative fuel be blended with each unit of fossil fuel consumed. Although statutory guidance for volumetric RVOs ended after 2022, the RFS remains in effect unless Congress repeals it. As a result, the EPA now has significant flexibility to set and adjust RVO targets.[245]

4.2.1.1 Compliance Tracking

Obligated parties comply with RVOs by trading renewable identification numbers (RINs), which are 38-character codes assigned to each physical gallon of renewable fuel produced or imported.

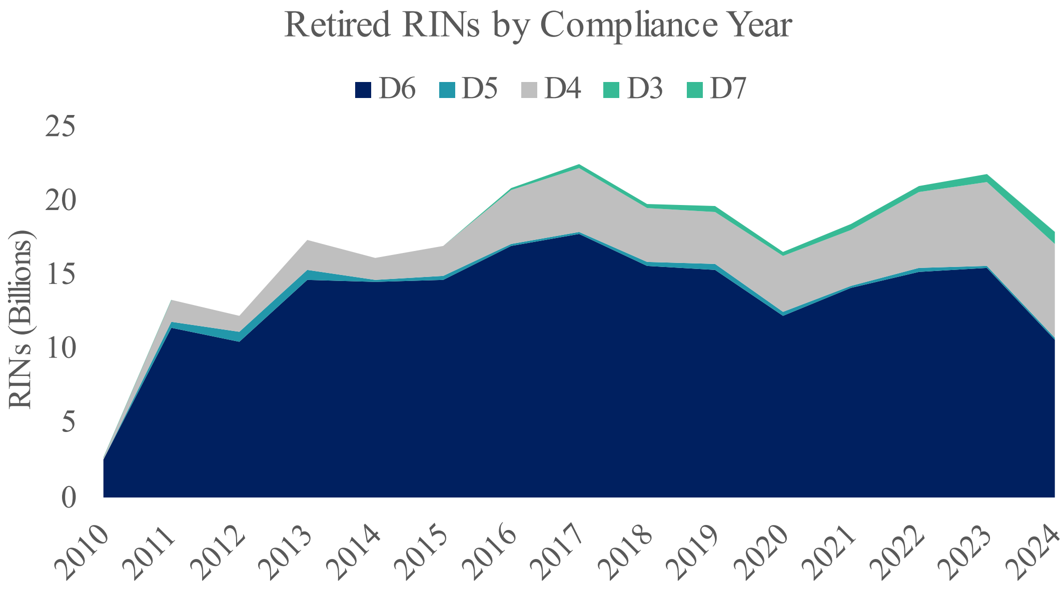
Figure 13. Renewable Fuel Standard Renewable Identification Number Process Diagram



As Figure 13 illustrates, when producers or importers generate a qualifying alternative fuel and blend it into the vehicle fuel system, they also generate a corresponding number of RINs. The number of RINs reflects both the fuel's energy content and its abatement potential. Obligated entities, refiners and importers of petroleum transportation fuels exceeding 75,000 barrels or 0.4 TBtu/day of average aggregate daily crude oil throughput,[246] can then trade RINs electronically, apply them toward their current RVO balance, or bank them for future use. Once an RIN is used to demonstrate compliance, it is retired.[247]

As Figure 14 illustrates, most transacted RINs are D6, which corresponds to ethanol. D4 RINs, which represent biodiesel and renewable diesel, have grown significantly since 2010 and now make up the second largest share of retired RINs.[248]

Figure 14. Retired Renewable Identification Numbers by Compliance Year, 2010–2024



The detailed RIN identifier generated during the production of biofuels includes information such as the year of production or import, company and facility identifier, batch number, renewable fuel category, and equivalence value. The EPA registers all RINs in its tracking system, the EPA Moderated Transaction System (EMTS), which enables transfers of ownership, typically through over-the-counter transactions between parties. When RINs are attached to the biofuel, the system also requires a formal product transfer document (PTD) to be included when the transaction is reported.[249] To help prevent fraud, the EPA has established a voluntary quality assurance program that relies on third-party auditors to verify RINs.

4.2.2 Low Carbon Fuel Standard

While the RFS applies nationally to all major oil importers and refiners, California has developed a secondary alternative fuel EAC market through its LCFS, though names vary, to incentivize the production of alternative fuels and decrease dependence on petroleum.[250] This program operates under a book-and-claim chain of custody framework, similar to RFS. Since 2013, California's LCFS program has issued more than $22 billion in credits and has helped renewable diesel become the dominant source of distillate fuel consumption for transportation in the state in recent years.[251, 252]

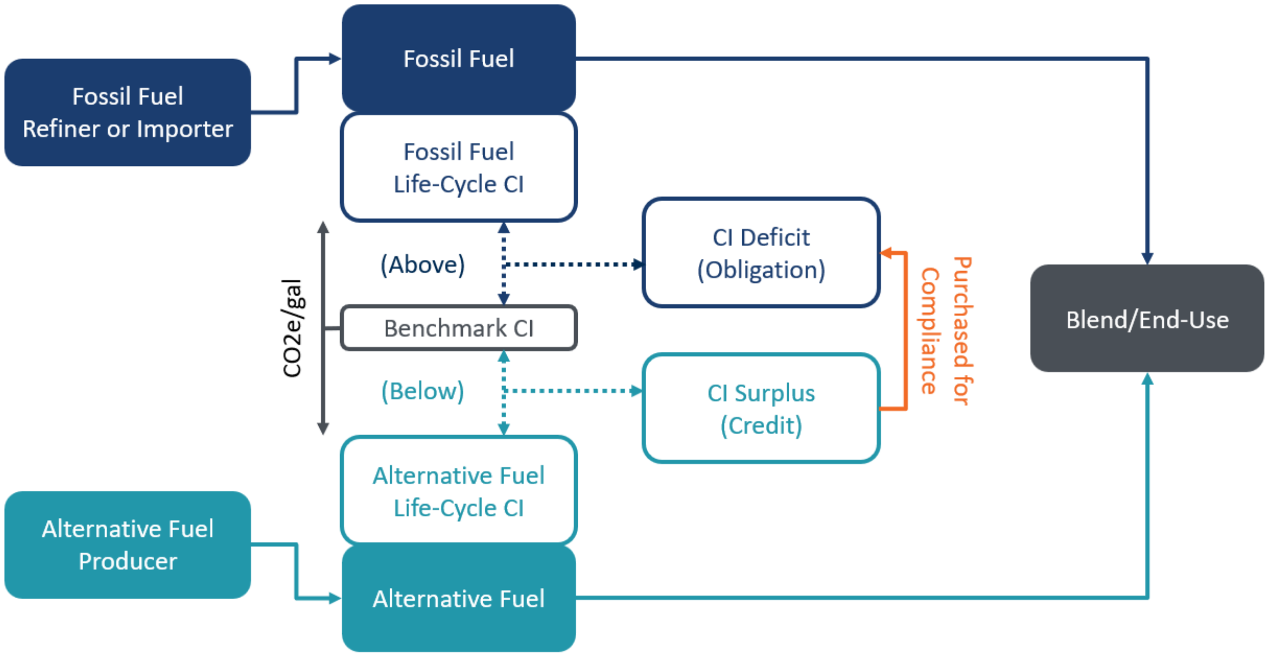
4.2.2.1 Compliance Tracking

Under the LCFS, obligated parties must demonstrate GHG reductions related to their fuel usage by obtaining and retiring credits that are measured using carbon intensity values.

The program allows emission reduction credit generation in three ways: fuel pathways, projects, and capacity-based crediting. Under the fuel pathway method, fuel producers generate credits when their product's life-cycle carbon intensity (CI) falls below the applicable state-determined benchmark. Each year, the California Air Resources Board (CARB) establishes a target CI benchmark for a given fuel type (e.g., gasoline, diesel), which is lowered over time to promote further GHG emission reductions. As Figure 15 illustrates that if an entity produces or imports fuels with a lower CI than the relevant benchmark, it generates credits. Whereas if an entity produces a fuel with a higher CI than the benchmark, the regulated entity incurs a CI deficit, which must be matched through the purchase of credits to make up the difference.[253] For example, if an oil refiner produces gasoline with an estimated LCA of 85 CO_2e/gal, and the target CI is 70 CO_2e/gal, the refiner must purchase an equivalent quantity of LCFS credits to offset the difference. Effectively, the LCFS system functions as an intensity-based cap-and-trade program for transportation fuels.[254] However, like RINs, LCFS credits are traded between private entities and generate no government revenue.

In addition to pathway-based crediting, the LCFS also allows two other mechanisms: project-based crediting, which awards credits for life-cycle emissions reductions achieved through actions at refineries, crude oil production sites, and transportation facilities or through carbon capture and sequestration; and capacity-based crediting, which incentivizes investment in zero-emission vehicle infrastructure.

Figure 15. Low-Carbon Fuel Standard Carbon Intensity Pathways-Credit Trading System



The Alternative Fuels Portal (AFP) and the LCFS Credit Banking and Transfer System (LRT-CBTS) support the implementation of the LCFS program. Applicants use the AFP to submit their CI calculator and supplemental documentation to obtain a certified CI score. CARD determines these CI scores CARB using industry-average inputs in two models: California Greenhouse gases, Regulated Emissions, and Energy Use in Technologies (CA-GREET) and the Oil Production Greenhouse Gas Emissions Estimator (OPGEE). Applicants proposing innovative, new pathways may customize the CA-GREET model to calculate site-specific CI.

Once CARD certifies a CI score, the system calculates LCFS credits based on that score, the vehicle's energy and economy ratio, and the quantity of fuel reported. CARD issues these credits quarterly. Entities use the LRT-CBTS to report credit banking and transfers. Because LCFS credits carry financial value, CARB requires entities to work with an approved third-party verifier to ensure the accuracy and regulatory compliance of reported data.[255]

4.2.3 Carbon Offsetting and Reduction Scheme for International Aviation

The ICAO administers the Carbon Offsetting and Reduction Scheme for International Aviation (CORSIA), which requires economic operators to track and transmit information demonstrating compliance with CORSIA's suitability criteria throughout the SAF supply chain.[256] These criteria include information about the raw material's country of origin, its life-cycle emissions, and supporting documentation verifying its sustainability.[257]

CORSIA permits two chain of custody models: physical segregation and mass-balance.[258] Operators using physical segregation must keep sustainable and nonsustainable materials separate so they do not mix. They may also choose whether to segregate sustainable materials with different characteristics (e.g., origin, life-cycle emissions), separating sustainable and nonsustainable materials, but the mix of sustainable materials with different characteristics is allowed. Alternatively, under the mass-balance approach, operators track the sustainability characteristics of a fuel based on the amounts of sustainable and nonsustainable materials added as they move through the supply chain.[259] The choice of physical segregation versus mass balance is at the discretion of the operator and the strength of the sustainability claim it wants to make.[260] CORSIA prohibits book-and-claim frameworks due to their inability to trace sustainable elements directly to final use. CORSIA compliance is enforced through strict certification, documentation, and reporting requirements.

Environmental claims under CORSIA are transmitted through the supply chain using a Sustainability Declaration, which records information about the sustainable materials incorporated into the fuel, based on a mass-balance framework.[261] All certified entities must periodically report their incoming volumes, storage levels, and outgoing volumes of sustainable and nonsustainable products. Entities must also immediately report any discrepancies related to documentation, reporting, and material flow.[262]

Before handling sustainable materials or issuing Sustainability Declarations, CORSIA requires that each entity in the supply chain be certified. This includes verifying that upstream suppliers are also certified at the time of delivery. To become certified, CORSIA requires each entity in the supply chain to develop procedures, reporting mechanisms, and documentation that meet sustainability requirements, and to provide employee training on the scheme's requirements.[263] Each entity must also undergo annual internal audits and periodic external audits.

4.2.4 U.S. Department of Agriculture Guidelines for Agricultural Crops Used as Biofuel Feedstocks

In January 2025, the USDA issued technical guidance allowing farmers to quantify GHG emissions associated with corn, soybeans, and sorghum grown as a feedstock for biofuels using climate-smart agriculture practices. The draft rules require each entity in the supply chain to maintain records using the mass-balance method, which tracks product weight or volume without requiring product segregation. Farmers must retain five years of records documenting the implementation of climate-smart agriculture practices, sales of reduced carbon-intensity feedstocks, and USDA-approved CI calculations. Each party along the supply chain must verify its data and pass supporting documentation to the next party. For example, farmers must complete a Biofuel Feedstock Report for every crop sold under a reduced-CI designation and provide it to the crop buyer. This report includes the farmer's attestation and supporting documentation for the crop-specific CI value.[264] The rules also require annual third-party audits to verify estimated emission reductions.

4.2.5 European Renewable Natural Gas Tracking Systems and Certificates

Under the European Renewable Energy Directive (RED), two systems are used to verify the sustainability and origin of RNG:

1. The Guarantees of Origin (GO) scheme, used in voluntary markets and based on a book-and-claim framework
2. The proof of sustainability (PoS), used to demonstrate compliance with RED criteria for sustainability and emissions reduction, based on a mass-balance framework.

The GO certification serves as a consumer disclosure tool that enables title-tracking of RNG blends. Producers generate GO certificates for every megawatt-hour of RNG produced and register them in a national registry. These certificates are tracked through the supply chain and may be traded separately from the physical gas, as allowed under the book-and-claim accounting framework.

In contrast, the PoS certification demonstrates legal compliance with RED sustainability and emissions reduction criteria. PoS covers the entire value chain but, unlike the GO scheme, does not allow the certificate to be separated from the physical product, helping to prevent any risk of double counting. RNG with PoS certification is traded under mass-balance chain of custody rules.[265]

4.3 Considerations across Frameworks

Each of the four chain of custody frameworks has distinct strengths and weaknesses, particularly about the policy objectives discussed earlier. The identity preservation and segregation frameworks offer the highest level of assurance regarding the traceability and composition of low-carbon alternative fuels. Still, they can be expensive and time-intensive to implement due to the need to separate certified and noncertified products throughout the supply chain.

Mass balance offers more flexibility by tracking the composition of renewable material within the final energy product. This flexibility may be particularly beneficial as New York State transitions away from fossil fuels. Still, as alternative fuel use increases, the cost and complexity of compliance under a mass-balance system are also likely to rise. Importantly, mass-balance does not require physical traceability. Without proper oversight and enforcement, this can lead to system abuse and false environmental claims.

Finally, book-and-claim offers the most flexibility and provides a highly visible and transparent market signal through attribute certificate trading. However, it is also susceptible to false claims and, thus, requires stringent oversight and enforcement mechanisms. New York State should carefully weigh and balance the pros and cons of each framework when developing an EAC market.

Lessons learned from existing programs, including the RFS, LCFS, and ICAO's CORSIA, offer valuable insights:[266]

- The RFS model has faced challenges meeting volumetric targets, especially due to the slow pace of cellulosic biomass production capacity relative to RVOs. Technical limitations in fuel blending also restrict the broader adoption of many biofuel pathways. Biodiesel, for example, cannot be used as a drop-in replacement for fossil diesel and must be blended up to approved limits, usually of 20%. The maximum theoretical blend of biodiesel, therefore, is constrained to 20% of total diesel consumption. If the statutory RVO assumes higher total diesel consumption than actual, then full compliance becomes impossible, driving up RIN prices.[267] Additionally, the expanded demand for energy crops has raised concerns about LCUs that may be both ecologically damaging and carbon positive.
- The LCFS model, which uses CI as its compliance target, allows regulators to account for the impact of these induced LUCs in LCAs, although these estimates remain uncertain. Critics argue that avoided emissions credits for RNG pathways may artificially inflate the abatement value and market price of LCFS credits. This could unintentionally incentivize larger herd sizes and other perverse outcomes.[268] The impact on consumer fuel prices remains unclear, but is expected to grow as CI reduction targets continue to expand aggressively. A study by the University of Pennsylvania's Center for Energy Policy projected LCFS-related price increases ranging from $0.60 to $0.70/gallon in the near-term, rising to $0.85/gallon by 2030, and $1.34/gallon by 2035. However, other studies dispute any direct correlation between LCFS implementation and retail fuel prices.[269, 270]
- The ICAO's CORSIA program has faced criticism for its voluntary nature, although it becomes mandatory for all ICAO member states starting in 2027. CORSIA also excludes domestic flights, which account for one-third of global aviation emissions because they fall outside ICAO's jurisdiction.[271] The program has failed to promote SAF production because it allows participants to meet carbon emissions reduction targets using CORSIA-compliant carbon offsets, which are less expensive than producing SAF that meets CORSIA standards. In addition, frictions between CORSIA certifications and national standards, such as those in the U.S. and the European Union, complicate compliance. A batch of SAF can only hold one certification at a time, so SAF certified under CORSIA cannot be simultaneously certified under standards in other jurisdictions. These issues have led market participants to urge ICAO to streamline administrative requirements (and thereby costs) of complying with CORSIA and to develop a standardized certification process across jurisdictions.[272]

New York State should weigh the pros and cons of the chain of custody frameworks and determine the attribute that would best serve the State's climate and clean energy goals, while being feasible to uniformly quantify, track, and monitor the environmental attributes of low-carbon alternative fuels.

5 Guidelines and Recommendations

New York State has enacted some of the most ambitious climate and energy policies in the country to combat climate change. Meeting these goals will necessitate a significant shift in how the State produces, transmits, and uses energy over the coming decades.

This report reviewed two categories of low-carbon alternative fuels—biofuels (RNG, biodiesel, renewable diesel, and SAF) and hydrogen—which were the primary focus in the State Energy Plan. The report explored the costs, risks, benefits, uncertainties, and market potential of these low-carbon alternatives across multiple dimensions: supply and demand, infrastructure requirements, and environmental impacts, including GHG emissions and air quality.

Based on this analysis, the report provides the following guidelines and recommendations to help New York State prioritize the deployment of alternative fuels in a way that maximizes decarbonization benefits, particularly in hard-to-decarbonize applications. It also identifies areas where additional analysis and data are needed to support policy and program design.

5.1 Policy Considerations for New York State

The following policy considerations are intended to guide New York State in deploying low-carbon alternative fuels strategically, prioritizing applications where they offer the greatest climate benefit and ensuring alignment with the State's long-term energy and environmental goals.

- **Prioritize electrification where feasible.** Given that low-carbon alternative fuels will remain in limited supply, electrification or other zero-emissions solutions should continue to serve as the primary decarbonization pathway. Where electrification is difficult due to technical, safety, or reliability considerations, the use of low-carbon alternative fuels should be optimized and directed toward end uses in such a way that maximizes GHG and co-pollutant emissions reductions while minimizing cost, environmental, and health impacts associated with alternative fuels.
- **Optimize use of limited feedstocks.** New York State should direct scarce feedstocks to produce the types and quantities of low-carbon alternative fuels that (1) meet near-term need, (2) build capacity for long-term climate goals (i.e., 2040 and beyond), and (3) help achieve the targets of the Climate Act while ensuring reliability and affordability. Specifically:
    - Direct organic feedstocks to high-priority uses, such as SAF, where no electrification alternative exists.
    - Prioritize in-state agricultural and organic waste feedstocks as well as feedstocks with the lowest GHG emissions for low-carbon alternative fuel production.

  - Ensure that clean electricity used for alternative fuel production, such as hydrogen, does not divert from easy-to-electrify applications in buildings and transportation.

- **Plan and invest in fuel infrastructure strategically.** As demand for low-carbon alternative fuels grows, the State should ensure that it has sufficient delivery infrastructure to move alternative fuels from production locations to demand areas. To reduce costs and minimize impacts:
  - Leverage existing infrastructure where possible, accounting for technological, economic, and safety considerations.
  - Where existing infrastructure cannot be repurposed, develop limited new alternative fuel infrastructure to connect supply and demand for alternative fuels.
  - Recognizing that energy infrastructure is regional, coordinate with neighboring states and provinces to align investments and develop a regional infrastructure strategy for low-carbon alternatives.

- **Establish robust life-cycle GHG emissions accounting standards** for biofuels that fully reflect all life-cycle emissions, including LUCs and upstream inputs. These standards should:
  - Develop GHG emissions accounting standards for biofuels that appropriately take into account all relevant stages of their life cycle when determining emission reduction benefits.
  - Ensure that policies, programs, and regulations appropriately reflect the requirements for alternative fuels and prioritize GHG emissions reductions while minimizing co-pollutant emissions.
  - Avoid increases in local GHG and copollutant emissions from the use of low-carbon alternative fuels, even when total life cycle GHG reductions are achieved.
  - Prioritize electrification unless specific technological, safety, or reliability challenges justify the use of low-carbon alternative fuels.

5.2 Supply and Demand

New York State can actively incentivize the use of low-carbon fuels through levers, including developing a regional low-carbon fuels market, providing incentives to optimize the production of key fuels, creating a centralized entity to offer market guidance, and supporting the deployment of end-use equipment.

Regional low-carbon fuel markets play a key role in supporting early market development. By implementing these markets on a regional scale, states can improve efficiency, facilitate price formation, and enable the sharing of regional feedstocks. As discussed earlier, the LCFS in California, Oregon, Washington, and British Columbia have already driven a shift from fossil to low-carbon alternative fuels in those jurisdictions. As a result, the West Coast has become the leading consumer of renewable diesel. New York State can consider adopting similar fuel standards along with neighboring states to grow demand in the Northeast and stimulate the development of local markets. This approach will help ensure that the production capacity aligns with anticipated demand. Regional market formation can support a smooth transition by integrating alternative fuels markets into existing fossil fuel markets.

Regional markets can further assist by implementing gradual blending standards, which incentivize early development of nascent fuel markets. These blending standards offer predictability and can target specific sectors or end uses. Once markets and infrastructure for the fuels mature, the State can redirect blends of low-carbon alternative fuels to other end uses as needed.

State policy also plays a critical role in ensuring that market development aligns with long-term strategic goals. Natural market forces may steer the use of alternative fuels in directions that conflict with New York State's energy vision. As discussed, limited biological feedstocks may flow toward lower-cost, but less strategic, applications that outcompete more targeted applications, especially during the early stages of market development. Wastewater, for instance, may be able to produce RNG at a lower cost than SAF or renewable diesel; however, injecting RNG into the gas distribution system does not directly advance the State's long-term goals, whereas using it to produce SAF or renewable diesel does. By prioritizing electrification and other zero-carbon solutions (e.g., hydrogen) in easy-to-electrify end uses, the State can preserve scarce low-carbon alternative fuels for hard-to-electrify end uses. To support this, New York State should establish regulations and enforcement mechanisms that prevent the use of unverified or unverifiable feedstocks in the production of low-carbon alternative fuels.

The creation and development of these markets will involve multiple interconnected components, from producing fuels and connecting supply with end users, to verifying emissions reductions and scaling end-use technologies. New York State can take the lead by establishing a central authority responsible for coordinating these efforts and ensuring that market development aligns with State goals and standards. This organization can provide technical guidance, track emissions reductions, administer incentives for market participants, provide relevant market data (such as available supply and pricing), and provide education materials for the public.

5.3 Infrastructure

The demand for low-carbon alternative fuels in New York State is anticipated to be lower than the current demand for fossil fuels because a significant share of today's fossil fuel end uses will be electrified. As a result, the scale and capacity of infrastructure required to produce, store, and distribute alternative fuels will be less than that of the current fossil fuel infrastructure. New York State should consider steps to ensure that sufficient delivery infrastructure is available to safely and reliably move alternative fuels from production locations to areas of demand. Scaling end-use equipment will also be vital to ensuring the success of some alternative fuels, particularly hydrogen. Statewide incentives, along with federal support, will be necessary to support the early-stage deployment of these technologies within the State.

New York State should identify opportunities to optimize the use of existing infrastructure to the extent possible—accounting for technological, economic, and safety considerations—to minimize costs and infrastructure development impacts. Where utilizing existing infrastructure is not a feasible solution, New York State can develop limited new alternative fuel infrastructure. This may be required, for example, where technical, economic, or safety challenges cannot be overcome or where the supply or demand of alternative fuels is located in different geographies than existing infrastructure. Developing an alternative fuels infrastructure plan for the State could guide the development and permitting of required infrastructure, identifying desirable locations and rights-of-way, evaluating land use impacts, potential impacts on DACs, and strategies to distribute alternative fuels to areas in the State with limited or no infrastructure suitable for alt fuels.

New York State should work with neighboring states and provinces to develop regional infrastructure plans, recognizing that much of the existing infrastructure and the markets for the alternative fuels themselves extend well beyond the State. Coordinated infrastructure planning can allow for efficient redeployment of existing infrastructure and development of new infrastructure that can lower costs and mitigate environmental impacts. It can also facilitate the development of low-carbon alternative fuel markets at scale. An additional benefit of regional infrastructure planning is that it will allow New York State to work with a broader group of stakeholders to develop a uniform set of standards and requirements for alternative fuel infrastructure and fuel quality standards. For hydrogen, New York State can coordinate with neighboring DOE Hydrogen Hubs in Pennsylvania and New Jersey. This infrastructure coordinate will ensure that feedstocks or supplies can readily move across the region to demand centers.

Alternative fuel infrastructure build-out also requires a review of local, state, and federal codes, regulations, and safety standards to evaluate if alternative fuels are permitted to be produced, transported, stored, and consumed under existing frameworks. If required, existing frameworks should be revised or put in place to allow the use of alternative fuels, at the scale and scope envisioned by New York State. Similarly, New York State should consider if low-carbon alternative fuels will be state-regulated (like natural gas is today) and, if so, how and by which agency.

Finally, New York State should coordinate with the federal government, states, industry organizations, and other stakeholders that are undertaking research and development and pilot programs of low-carbon alternative fuels. Doing so allows New York State to leverage its research funding and incentive dollars to take advantage of economies of scale to access research across a broader footprint. For example, funding pilot projects for alternative fuel infrastructure at airports, marine terminals, or fueling stations across the region contemporaneously can incentives a broader set of market participants to invest in and utilize alternative fuels.

5.4 Environmental Attribute Credit Considerations for New York State

As New York State scales up the adoption of alternative fuels to meet its decarbonization targets, developing an EAC market presents an opportunity to accelerate the commercial deployment of low-cost, high-abatement fuel pathways. While California's LCFS offers a useful case study, any EAC market in New York State must be tailored to the State's unique conditions, energy and climate policy goals, and regional context. Given the high degree of economic integration in the Northeastern U.S., New York State can leverage regional network benefits to lower costs and enhance the effectiveness of an interstate approach to alternative fuel adoption.

In pursuing a regional EAC market, New York State should collaborate closely with neighboring states to align fuel definitions, LCA standards (such as ISO 14044: 2006) and GHG accounting practices. Standardizing these assumptions will simplify transactions and create a consistent regional framework. Once this foundation is established, tradeable credits can be designed to prioritize the abatement potential of competing pathways, incorporating penalties for alternative fuels that are not fully GHG-free. This regional approach will also reduce the risk of accounting errors, such as double-counting, and improve consumer transparency through well-documented assumptions.

In pursuing an EAC market approach, New York State should establish price mechanisms for GHG emissions, while also incorporating standards for copollutants and siting requirements as prerequisites for credit generation. New York State should also consider establishing and standardizing emissions accounting rules for biofuels to enable the development of these markets and inform the State's procurement strategies.

As low-carbon fuels production expands in New York State, the State should implement an EAC framework that verifies and tracks the origins and emission reduction attributes of these fuels. The framework should align with the State's energy and climate goals and encourage the cost-effective, efficient, and verifiable production of low-carbon alternative fuels.

The framework should work within the existing or anticipated supply chains for low-carbon fuels without unduly disrupting system operations. Requiring strict physical segregation of low-carbon fuels from traditional fossil fuels, for example, would necessitate significant investment in dedicated infrastructure, increase land and community impacts, and potentially delay the market development of supply and demand for these fuels, increasing emissions over time. It also runs counter to the State's objective of leveraging existing infrastructure where possible. However, imposing requirements for the strict handling of sustainable feedstocks may be warranted in certain high-stakes applications, such as the production of SAF.

New York State should set clear standards and guidelines for verifying low-carbon alternative fuel claims. It should also design documentation, certification, and audit requirements for market participants that strike a balance between ensuring compliance and minimizing administrative and cost burdens. To achieve scalability and interoperability, the State should collaborate with federal and other state EAC program administrators to implement the same or similar requirements, such as certificate issuance, verification protocols, and registry systems. This coordination will support the development of larger regional, national, or international markets and reduce friction in importing or exporting certified low-carbon alternative fuels.

Programs like California's LCFS and the federal RFS both use book-and-claim frameworks, while the ICAO's CORSIA permits only physical segregation or mass-balance methods for sustainability claims. The USDA's draft guidelines also propose using a mass-balance approach for tracking biofuel feedstocks. However, a state-specific approach that offers flexibility to promote the development of low-carbon alternative fuels must balance those benefits with consistency with the State's climate and energy policy objectives.

Finally, the framework must systematically audit \ emissions claims of low-carbon alternative fuels across the supply chain. A designated New York State authority or an independent auditor could administer the system. The administrator should also have the authority to certify market participants and their processes, and to enforce compliance. The ICAO and the USDA both deployed strict certification, documentation, audit requirements, and reporting frameworks to maintain the integrity of their respective programs.

Appendix A. Overview of Low-Carbon Alternative Fuels

This Appendix provides a technical overview of the processes to produce and transport low-carbon alternative fuels. Each alternative fuel discussed in this section has multiple feedstocks and production pathways. This section focuses on the most common or typical pathways. It does not address more nascent pathways, although they may play a larger role in the future as research and development efforts advance.

As a further complication, some alternative fuels, such as hydrogen, can be used as inputs to produce other low-carbon alternative fuels, which this section briefly discusses. However, the primary focus of this section and the broader report is to clarify the most common production pathways currently in use or under consideration. This section also briefly describes the primary end-use applications of each fuel as currently contemplated. However, the future use of alternative fuels in New York State is not limited to the fuels discussed here. Instead, the focus is on the low-carbon alternative fuels that are primarily addressed in the State Energy Plan.

A.1 Renewable Natural Gas

RNG is a gaseous biofuel derived from the breakdown of biological matter, such as agricultural and forest residues, animal waste, the organic portion of municipal solid waste, and wastewater sludge. This decomposition of organic materials produces biogas, which is a combination of methane, carbon dioxide, and other gases created by bacteria in an oxygen-free environment. Biogas typically contains approximately 45% to 75% methane by volume, with the remainder composed of carbon dioxide and other impurities, depending on the production pathway. This composition results in a lower heating value (LHV) of 16 to 28 megajoules per cubic meter (MJ/m^3).[273]

The following are three well-established pathways for producing biogas, each in use for years.

1. **Landfill Gas**
   The first pathway involves breaking down the organic portion of municipal solid waste in an anaerobic environment at landfill facilities. Known as landfill gas, this method accounts for approximately 90% of current biogas production in the U.S.[274] For example, since 1982, the Fresh Kills Landfill on Staten Island has collected landfill gas and injected it into National Grid's natural gas distribution system. As of 2018, Fresh Kills produced approximately 3 million cubic feet of landfill gas per day, which is enough to heat approximately 22,000 homes. [275]The volume of landfill gas depends on the amount of municipal solid waste at the landfill and decreases over time after the landfill is capped and sealed.
2. **Anaerobic Digestion**
   The second pathway, anaerobic digestion, is a process in which operators dilute organic material with water and seal it inside an anaerobic digester (biodigester). This facilitates and accelerates the breakdown of organic materials by bacteria in an anaerobic environment and processes sewage sludge, effectively reducing organic pollutants and producing biogas.[276] In recent years, the use of anaerobic digesters has expanded to include other organic waste streams such as livestock manure and food waste, which are now common feedstocks.[277] For example, the Newtown Creek Wastewater Treatment Facility in Brooklyn uses digester eggs to convert organic materials into biogas, producing 500 million cubic feet of biogas per year. Previously, the facility used approximately 40% of the gas to power its on-site boilers, but since 2013, it has injected 100% of its biogas into National Grid's gas distribution system. [278]
3. **Thermal Gasification**
   The third pathway involves thermal gasification, in which biomass, such as agricultural residues, forestry and forest product residues, energy crops, and biogenic and non-biogenic municipal solid waste, is broken down at high temperatures (700ºC–800ºC) and high pressures in a low-oxygen environment.[279] Under these conditions, the organic material converts to syngas (a mixture of carbon monoxide, hydrogen, and methane) and other gases. Operators then treat the syngas to remove undesired compounds, especially acidic and corrosive elements. A final catalytic reaction between the hydrogen and carbon monoxide in the syngas produces methane (biogas). Although thermal gasification is technically viable, high costs and technical challenges due to the production of residual tar during the process, have limited its commercialization to date.[280]

After production, biogas undergoes several rounds of treatment. The primary treatment removes moisture and particulate matter from the gas stream. The second stage treatment then removes siloxanes and sulfur compounds, and then compresses the gas to higher pressures. At this stage, biogas is ready on-site combustion for applications such as heating, power generation, transportation fuels, and industrial processes.

Instead of being consumed directly, biogas can be upgraded by removing carbon dioxide and other impurities to create RNG. RNG is a short-chain hydrocarbon chemically equivalent to methane, making it a drop-in substitute for natural gas. The upgrading process varies by feedstock and production pathway (Table A-1), but typically aims to remove contaminants such as carbon dioxide, oxygen, nitrogen, and volatile organic compounds and increase the methane content of the gas stream in order to meet established gas quality standards.[281]

Table A-1. Renewable Natural Gas Constituents of Concern by Feedstock

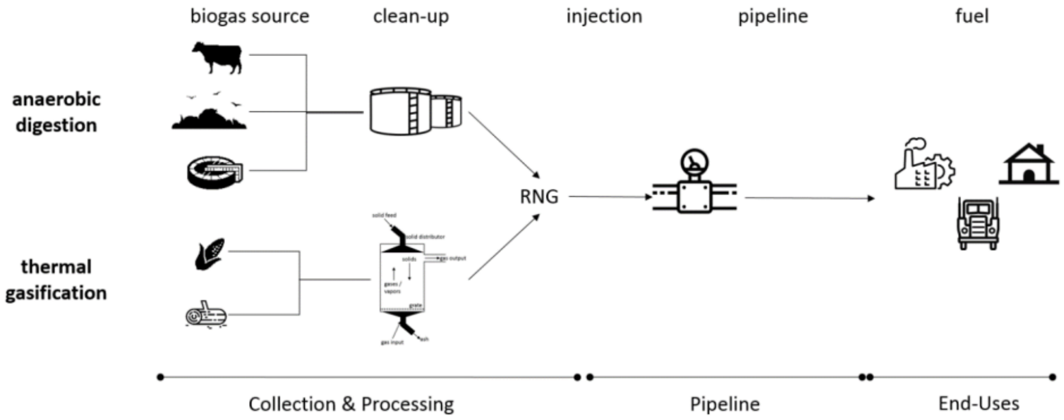
Source: Northeast Gas Association.[282]

Parameter	Landfill	AD of Agricultural and Clean Organics	WTTP AD	AD of Source/ Facility Separated Organics	Gasifier Syngas
Water Content	✓	✓	✓	✓	✓
Sulfur, including Hydrogen Sulfide	✓	✓	✓	✓	✓
Hydrogen	✓	✓	✓	✓	✓
Carbon Dioxide	✓	✓	✓	✓	✓
Nitrogen	✓	✓	✓	✓	✓
Oxygen	✓	✓	✓	✓	✓
Ammonia	✓	✓	✓	✓	✓
Biologicals	✓	✓	✓	✓	X
Mercury	✓	X	✓	X	✓
Volatile Metals	✓	X	X	X	✓
Siloxanes	✓	X	✓	✓	X
Volatile Organic Compounds	✓	X	✓	X	✓
Semi-Volatile Organic Compounds	✓	X	X	X	✓
Halocarbons	✓	X	✓	X	✓
Aldehydes and Ketones	✓	✓	✓	✓	✓
Polychlorinated Biphenyls	X	X	X	X	X
Pesticides	X	X	X	X	X

As a drop-in substitute for natural gas, RNG can be injected into the existing natural gas pipeline system for transport, storage, and distribution to end users. Existing natural gas equipment can combust RNG without modification. RNG produced in New York State will likely serve end uses that currently rely on natural gas and cannot be easily electrified. According to the Scoping Plan and Integration Analyses, these uses include, but are not limited to, firm, dispatchable power generation and backup heating fuel for heat pumps in the buildings sector.[283]

Figure A-1. Renewable Natural Gas Production via Anaerobic Digestion and Thermal Gasification

Potential of RNG in New York State.[284]



A.2 Hydrogen

Hydrogen, the first element in the periodic table and the most abundant in the universe, is a highly flammable gas that, under ideal conditions, reacts with oxygen during combustion, releasing only water vapor. Today, industry widely uses hydrogen in petroleum refining, metal processing, food production, and fertilizer refining, it is also attracting growing interest as a low-carbon fuel for transportation, hard-to-decarbonize industrial processes, and energy storage for electricity generation. Although abundant in hydrocarbons, water, and other organic matter, hydrogen must be isolated through energy-intensive processes. Its small molecular size also creates challenges for transportation and storage.[285]

Numerous hydrogen production methods exist, which use varying combinations of feedstocks, energy inputs, and technologies. Some production processes include some CI pathways, with other processes offering lower-carbon alternatives. As of 2022, about 95% of hydrogen produced in the U.S. comes from steam-methane reformation (SMR), a CI process that converts high-temperature steam and methane into carbon dioxide and hydrogen.[286]

Globally, hydrogen production leveraging brown coal (lignite) and black coal has achieved significant commercialization, particularly in coal-intensive industrial economies like China. These processes convert coal into syngas and isolate hydrogen from it.[287] Though efficient and commercially mature, these methods consume large amounts of energy and generate substantial GHG emissions, prompting further diversification in hydrogen production technology.

Some updated natural gas pathways aim to reduce emissions. For example, one method colocates carbon capture and sequestration, while another uses a novel methane pyrolysis approach that decomposes methane into hydrogen and solid carbon, thereby eliminating the GHG effect. However, both technologies face significant economic barriers to adoption.

An alternative, emergent class of hydrogen production technology gaining widespread attention for its low-carbon potential is electrolysis. The process uses an electric current to split water into hydrogen and oxygen, facilitated by an electrolyte such as alkaline, PEM, or solid oxide electrolyzers. The associated emissions from electrolysis depend on the carbon footprint of the electricity source.

Once generated, hydrogen must be compressed, liquified, or chemically converted to enable storage and transportation to its end-use site. Applications include:

- Blending with natural gas in existing pipeline infrastructure
- Fuel-cell vehicles for mobile use
- Industrial heat
- Electricity generation via hydrogen fuel cells

A hydrogen fuel cell rebonds separated hydrogen and oxygen molecules to form water, converting the bonding chemical energy into electricity in the process.

A.3 Renewable Diesel

Renewable diesel is a drop-in replacement for petroleum diesel, produced primarily through hydrotreatment of fats, oils, and greases, such as soybean and vegetable oils, corn oil byproducts of ethanol production, used cooking oils, and animal fats. Unlike biodiesel, the hydrotreatment process yields a chemically equivalent diesel product that works in existing diesel engines without requiring blending.

Production of renewable diesel is concentrated almost entirely in California, propelled by the state's Low Carbon Fuel Standard (LCFS), but it is rapidly spreading. In recent years, renewable diesel production has expanded substantially, matching or exceeding that of biodiesel in the U.S. However, 2024 saw a notable decline in production capacity due to slower-than-anticipated demand growth, resulting in excess refining capacity.[288] Renewable diesel offers several advantages over biodiesel: its identical chemical structure enables compatibility with existing diesel infrastructure and end-user equipment, avoiding issues associated with biodiesel such as higher freezing points and cold-temperatures gelling.

Hydrotreatment, the primary pathway for producing renewable diesel, uses high temperature and pressure to hydrogenate input fats, oils, and greases. This process can tolerate more impurities in its input feedstocks and requires fewer purification steps than biodiesel production. However, its energy-intensive nature and hydrogen input contribute significantly to the fuel's carbon footprint.

Carbon dioxide emissions from renewable diesel combustion are generally considered neutral given the carbon uptake of its feedstocks, though life-cycle emissions depend heavily on feedstock sourcing, land use, and energy management. Though combustion still yields other air pollutants, the purity of the fuel achieved through hydrotreatment results in cleaner combustion than both petroleum and biodiesel.[289]

A.4 Biodiesel

Similar to renewable diesel, biodiesel is a naturally derived petroleum diesel alternative designed for use in mobile applications. Producers generate biodiesel using the same feedstocks as renewable diesel, but through a distinct transesterification process, a chemical process that converts fats or oils into biodiesel and glycerin by reacting them with an alcohol, typically methanol or ethanol, in the presence of a catalyst. This breaks down large fat or oil molecules (triglycerides) into smaller molecules called esters, which form biodiesel, while separating glycerin as a byproduct.

Unlike renewable diesel, the methyl esters yielded through transesterification are chemically distinct from petroleum diesel and present distinct limitations in end-use applications. Notably, biodiesel has a higher freezing point and a tendency to freeze at low temperatures, constraining its transportation and use as a stand-alone fuel. Operators typically blend biodiesel with petroleum diesel in ratios ranging from 1% to 20% to reduce diesel's overall carbon intensity. Additionally, biodiesel provides mechanical advantages to the operation of diesel-powered machinery when blended with petroleum or renewable diesel, with particular advantages in lubrication.

A.5 Sustainable Aviation Fuels

Sustainable Aviation Fuels (SAF) refers to a range of low-carbon alternative feedstock-to-fuel pathways that are beginning to reach commercial adoption in aviation. Producers can derive SAF from a variety of renewable feedstocks, including vegetable oils and byproducts; fats, oils, and greases; organic waste; biogas; and lignocellulosic biomass (woody biomass and crop residues).[290] These feedstocks undergo one of eight technology pathways currently approved by the Federal Aviation Administration (FAA).[291]

The FAA certifies jet engine and aircraft fuels that meet strict standards set by ASTM International (ASTM). In addition to conventional aviation fuel standards, ASTM developed ASTM D4054 (Standard Practice for Evaluation of New Aviation Turbine Fuels and Fuel Additives), which establishes specific standards for developing and testing alternative fuels to ensure the safe and reliable operation of aircraft.[292]

ASTM D4054 is a four-tiered process for evaluating new aviation fuels, including submitting information about the fuel to aircraft and turbine original equipment manufacturers (Ds) for review and approval.[293] After completing the ASTM D4054 screening, the new fuel proceeds through the approval process specified by ASTM D7566 (Standard Specifications for Aviation Turbine Fuel Containing Synthesized Hydrocarbons).[294]

During evaluation, SAF properties are compared to conventional fossil fuel-based alternatives. If the SAF is chemically equivalent to its traditional counterpart, it receives “drop-in” designation and its production pathway is listed in ASTM D7566, allowing for the SAF to be integrated into the existing fuel delivery infrastructure without separate regulatory oversight.[295] SAF certification typically takes 3 to 5 years and can cost millions of dollars to complete.[296]

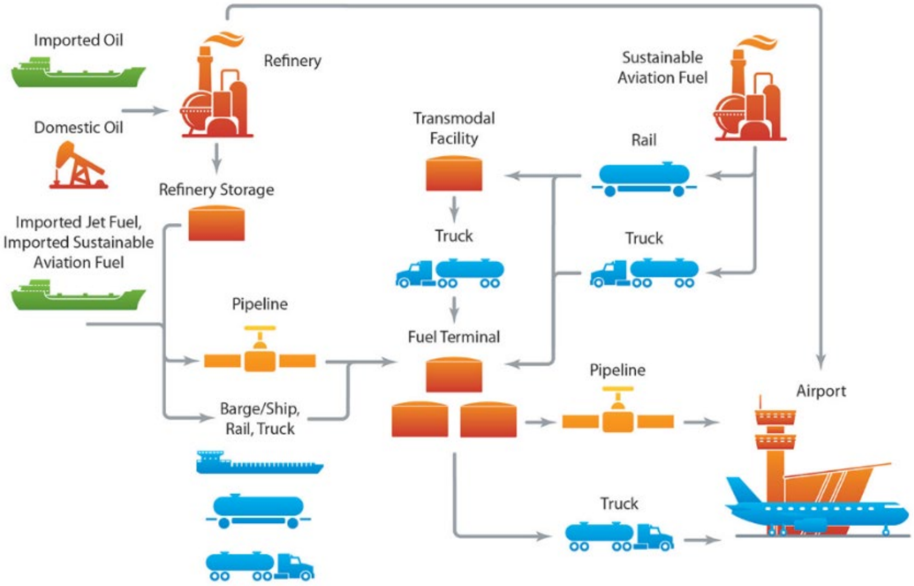
As of 2024, the eight ASTM-approved processes are:

1. **Fischer-Tropsch Synthetic Paraffinic Kerosene (FT-SPK)**
   Convert biomass (municipal solid waste, agricultural and forest wastes, wood, and energy crops) to syngas using thermal gasification (see Section A.1). The syngas is then converted into liquid jet fuel using metal catalysts at 150ºC–300ºC and high pressures, known as the Fischer-Tropsch (FT) process. ASTM approved FT-SPK in 2009 as ASTM D7566 Annex A1 for up to a 50% blend with petroleum-derived jet fuel.
2. **Hydroprocessed Esters and Fatty Acids from Plant and Animal Oils (HEFA-SPK)**
   Take fatty acids from fats, oils, and greases (oilseed crops, waste oils, or algae) and covert them to SAF using hydroprocessing (a chemical reaction that uses hydrogen to remove impurities from the feedstock and build complex hydrocarbons). Petroleum refiners use hydroprocessing as a mature technology used to produce transportation fuels. ASTM approved HEFA-SPK in July 2011 as ASTM D7566 Annex A2 for up to a 50% blend with petroleum-derived jet fuel. Military and commercial flights have demonstrated HEFA-SPK fuels.
3. **Hydroprocessed Fermented Sugars to Synthetic Isoparaffins (HFS-SIP)**
   Hydroprocess waste fat, oils, and greases as a feedstock to produce SAF. Ferment sugars to produce fuel molecules that are chemically different from HEFA-SPK. ASTM approved HFS-SIP in June 2014 as ASTM D7566 Annex A3 for up to a 10% blend with petroleum-derived jet fuel. Several commercial flights, including a Boeing 737, have flown with blended HFS-SIP.

4. **Fischer-Tropsch with aromatics (FT-SPK/A)**
   Apply the Fischer-Tropsch process similarly to FT-SPK, converting syngas to SAF, but add aromatic components during the process. ASTM approved FT-SPK/A in June 2014 as ASTM D7566 Annex A4 for up to a 50% blend with petroleum-derived jet fuel.
5. **Alcohol-to-Jet Synthetic Paraffinic Kerosene (ATJ-SPK)**[297]
   Convert cellulosic biomass-derived isobutanol to paraffinic kerosene using thermochemical processes. ASTM approved ATJ-SPK in June 2014 as ASTM D7566 Annex 5 for up to a 10% blend with petroleum-derived jet fuels. In April 2018, ASTM expanded ATJ-SPK approval to include production from ethanol feedstocks for fuel blends up to 50%.[298]
6. **Catalytic Hydrothermolysis Synthesized Kerosene (CH-SK or CHJ)**
   Combine clean free fatty acid oil from the processing of waste oils or energy oils with water and place it in a catalytic hydrothermolysis reaction, which creates a high-temperature and high-pressure environment. Subject the feedstocks to hydrothermal liquefaction to produce SAF. ASTM approved CH-SK or CHJ in February 2020 as ASTM D7566 Annex A6 for fuel blends up to 50% with petroleum-derived jet fuels.
7. **Hydrocarbon-Hydroprocessed Esters and Fatty Acids (HC-HEFA-SPK)**[299]
   Take oil from algae (*Botryococcus braunii*) as a feedstock and convert it to SAF using hydroprocessing. ASTM approve HC-HEFA-SPK in 2020 as ASTM D7566 Annex A7 for fuel blends up to 10% blend with petroleum-derived jet fuels.
8. **Alcohol-to-Jet Synthetic Paraffinic Kerosene with Aromatics (ATJ-SKA)**[300]
   Convert biomass to C2 to C5 alcohols using thermochemical processes to produce SAF. Unlike other approved pathways, ATJ-SKA accepts multiple feedstocks. ASTM approved ATJ-SKA in 2023 as ASTM D7566 Annex 8 for a blend up to 50% with petroleum-derived jet fuels.

Transporters move SAF to airports using a variety of transportation methods, such as barge, ship, pipeline, rail, and truck, depending on the location of the production facility, fuel type, and volume. If producers coproduced SAF with Jet A at a refinery, then the refiner issues a Refinery Certificate of Quality for the SAF, which can be blended with Jet A and transported to an airport or nearby fuel terminal via pipeline. Current federal regulations prohibit transporters from moving unblended SAF via pipeline. Producers at stand-alone facilities more commonly transport SAF to airports or fuel terminals via rail, truck, or barge. In this situation, fuel terminal operators blend the SAF near the airport. Airports use their existing fuel infrastructure to accommodate blended SAF/Jet A fuel, given the chemical similarities between the two as mandated by the ASTM approval processes.

Figure A-2. Sustainable Aviation Fuel Production, Distribution, and End Uses



Endnotes

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[2] U.S. Department of Energy (DOE), 2024. “Renewable Diesel Production and Consumption” (October), https://afdc.energy.gov/data/10965

[3] U.S. Energy Information Administration (EIA), 2025. “Petroleum and Other Liquids” (June 30), https://www.eia.gov/dnav/pet/pet_sum_snd_d_nus_mbbl_a_cur-1.htm.

[4] N.Y. Tax Law § 187-b.

[5] New York State Energy Research and Development Agency (NYSERDA), n.d., “Truck Voucher Incentive Program,” https://www.nyserda.ny.gov/All-Programs/Truck-Voucher-Program

[6] Columbia University, Center on Global Energy Policy, 2025, “National Hydrogen Strategies and Roadmap Tracker” (July 15), https://www.energypolicy.columbia.edu/publications/national-hydrogen-strategies-and-roadmap-tracker/

[7] E-fuels, also known as synthetic fuels, are produced using renewable power to produce hydrogen via electrolysis. The hydrogen is then combined with captured carbon dioxide to produce synthetic hydrocarbon fuels that can serve as a drop-in replacement for fossil fuels. Examples include e-methane, e-diesel, and e-SAF.

[8] Massachusetts Executive Office of Energy and Environmental Affairs, 2022, Massachusetts Clean Energy and Climate Plan for 2050 (December 21), 102, https://www.mass.gov/info-details/massachusetts-clean-energy-and-climate-plan-for-2050

[9] Énergir, 2023, “Climate Resiliency Report,” 33, https://energir.com/files/energir_common/Climate-Report-2023-VF.pdf

[10] U.S. Energy Information Administration (EIA), 2024, “Small Volumes of Renewable Diesel Are Now Consumed on the U.S. East Coast” (December 3), https://www.eia.gov/todayinenergy/detail.php?id=63884.

[11] N.Y. Envtl Conserv. § 75-0107(1).

[12] N.Y. Envtl Conserv. § 75-0101(13).

[13] N.Y. Envtl Conserv. § 75-0103(11).

[14] N.Y. Envtl Conserv. § 75-0109; PSL §§ 66-p(1)(b), 66-p(2), 66-p(5).

[15] N.Y. Envtl Conserv. § 75-0117.

[16] N.Y. Envtl Conserv. § 75-0115.

[17] N.Y. Envtl Conserv. §§ 75-0103(11)-(14).

[18] New York Climate Action Council, 2022, *New York State Climate Action Council Scoping Plan.* https://climate.ny.gov/resources/scoping-plan.

[19] *New York State Climate Action Council Scoping Plan, p. 2.*

[20] *New York State Climate Action Council Scoping Plan, p. 3.*

[21] *New York State Climate Action Council Scoping Plan*, pp. 119–120, and Scoping Plan Appendix G (Integration Analysis), pp. 13-14.

[22] Integration Analysis, p. 25.

[23] Integration Analysis, p. 22.

[24] Integration Analysis, p. 21.

[25] New York State Energy Planning Board, 2025, *Draft State Energy Plan* (July), https://energyplan.ny.gov/

[26] New York State Department of Environmental Conservation (DEC), 2024, *Energy: 2024 NYS Greenhouse Gas Emissions Report, Sectoral Report #1*, Table SR1.1, https://dec.ny.gov/sites/default/files/2024-12/sr1energynysghgemissionsreport.pdf

[27] New York Department of Environmental Conservation (DEC), 2024*. 2024 Statewide GHG Emissions Report*, 13, https://dec.ny.gov/sites/default/files/2024-12/summaryreportnysghgemissionsreport.pdf

[28] Although the state tracks these carbon removals and biogenic emissions, and reports net totals, gross emissions form the basis for measurement and compliance.

[29] F. Taheripour, S. Mueller, I. Emery, O. Karami, E. Sajedinia, Q. Zhuang, and M. Wang, 2024, "Biofuels Induced Land Use Change Emissions: The Role of Implemented Land Use Emission Factors," *Sustainability 16*, (March 26): 2729, https://www.eaps.purdue.edu/ebdl/pdfs/SUS2024.pdf

[30] Appendix A details the production processes.

[31] New York State Energy Research and Development Agency (NYSERDA), 2022, “Patterns and Trends—New York State Energy Profile,” https://www.nyserda.ny.gov/About/Publications/Energy-Analysis-Reports-and-Studies/Patterns-and-Trends

[32] New York State Energy Planning Board, 2025, Draft State Energy Plan (July), https://energyplan.ny.gov/

[33] American Gas Foundation, 2019, “Renewable Sources of Natural Gas” (December), https://gasfoundation.org/wp-content/uploads/2019/12/AGF-2019-RNG-Study-Full-Report-FINAL-12-18-19.pdf

[34] New York State Energy Research and Development Agency (NYSERDA), “Potential of Renewable Natural Gas in New York State,” April 2022, https://www.nyserda.ny.gov/-/media/Project/Nyserda/Files/EDPPP/Energy-Prices/Energy-Statistics/RNGPotentialStudyforCAC10421.pdf

[35] Appendix A.1 includes a detailed description of both production processes.

[36] See Appendix A.1 for a further discussion on the production and treatment of biogas and renewable natural gas.

[37] Biogas Go Global, 2020, “Biogas Production: Insights and Experiences from the Danish Biogas Sector” (June), 36, https://biogasclean.com/wp-content/uploads/2021/02/biogas-in-denmark-june-2020.pdf

[38] See, e.g., Gas Technology Institute, 2012, “Guidance Document for the Introduction of Landfill-Derived Renewable Gas into Natural Gas pipelines,” GTI-12/0007 (May 2), https://www.gti.energy/wp-content/uploads/2018/09/120007_Landfill_Guidance_Document_FINALREPORT-05-9-2012.pdf

[39] New York State Energy Planning Board, 2025, Draft State Energy Plan (July), https://energyplan.ny.gov/

[40] New York State Energy Planning Board, 2025, Draft State Energy Plan (July), https://energyplan.ny.gov/

[41] Public Service Commission of Wisconsin, 2022, “Biogas & Renewable Natural Gas (RNG)” (December 15), 11, https://primis-meetings.phmsa.dot.gov/archive/Day_3_AM_1000_Renewable_Natural_Gas__Biogas_(Kirschling).pdf

[42] American Gas Foundation, 2023, “Regulatory Pathways for Advancing Low-Carbon Gas Resources for Gas Distribution Companies” (February), 34, https://gasfoundation.org/wp-content/uploads/2023/02/AGF-LCR-Study-Full-Report-Final-Final-2.6.23.pdf

[43] Granite Fuel Engineering, 2024, “The Essential Role of Biogas Pretreatment in RNG Production” (January 23), https://granitefuel.com/the-essential-role-of-biogas-pretreatment-in-rng-production/

[44] Northeast Gas Association and GTI, 2019, “Interconnection Guide for Renewable Natural Gas (RNG) in New York State” (August), 6, https://americanbiogascouncil.org/wp-content/uploads/2019/09/RNG-Interconnect-Guide-for-NY-State-2019.pdf

[45] That is, RNG produced in another state can be transported on an interstate pipeline and combusted by an end user in New York State. This contrasts with notional RNG supplies that are produced and injected into a gas pipeline within one state, then combusted by an in-state end user, but the environmental attributes are claimed by an end user in another state who never physically received the RNG.

[46] See Table A-1 in Appendix A.

[47] Akin Gump, 2023, “Renewable Natural Gas: Pipelines, FERC and Tariffs” (June 20), https://www.akingump.com/en/insights/alerts/renewable-natural-gas-pipelines-ferc-and-tariffs

[48] Federal Energy Regulatory Commission (FERC), 2006,"Policy Statement on Provisions Governing Natural Gas Quality and Interchangeability in Interstate Natural Gas Pipeline Company Tariffs," Docket No. PL04-03-000 (June 15). https://www.ferc.gov/sites/default/files/2020-04/G-1_29.pdf. Note that the 2006 policy statement was developed to address disputes related to the quality of imported liquified natural gas. It established a framework for gas quality based on the following five principles: (1) only natural gas quality and interchangeability specifications published in FERC-approved tariffs may be enforced; (2) such tariff provisions must be flexible; (3) pipelines should develop these specifications in collaboration with their customers; (4) specification development should be guided by certain FERC-endorsed scientific references; and (5) disputes regarding gas quality and interchangeability that cannot be resolved otherwise, FERC will address on a case-by-case basis through a fact-based and technical review (pp. 29–33).

[49] Akin Gump, 2023, "Renewable Natural Gas: Pipelines, FERC and Tariffs" (June 20), https://www.akingump.com/en/insights/alerts/renewable-natural-gas-pipelines-ferc-and-tariffs

[50] Federal Energy Regulatory Commission (FERC), 2024, Order Approving Contested Settlement, 189 FERC ¶ 61,202, Docket No. RP23-466-002 (December 19), 2, https://www.ferc.gov/media/g-1-rp23-466-002

[51] Federal Energy Regulatory Commission (FERC), 2024, Order Approving Contested Settlement pp. 2-3. Note that FERC also ruled that Florida Gas Transmission failed to demonstrate that the constituent tolerance levels it proposed would resolve any identified technical problems, and that the pipeline could pursue no lower-impact solution to address its gas quality concerns.

[52] Federal Energy Regulatory Commission (FERC), 2024, Order Approving Contested Settlement pp. 15–16.

[53] Eastern Gas Transmission and Storage did submit a tariff change, which they claimed promoted RNG use. However, FERC ultimately rejected the proposed tariff records. See also Akin Gump Strauss Hauer & Feld LLP, 2023, "Renewable Natural Gas Tariff Provisions in FERC Regulated Pipelines," Allhttps://www.akingump.com/a/web/t8guJY8FtWGwZdfzZ82i46/rng-developments-at-ferc-614.pdf.

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[55] Federal Energy Regulatory Commission (FERC), 2024, Order Approving Contested Settlement pp. 2–3. Note that FERC also ruled that Florida Gas Transmission failed to demonstrate that the constituent tolerance levels it proposed would resolve any identified technical problems, and that the pipeline could pursue no lower-impact solution to address its gas quality concerns.

[56] U.S. Department of Transportation DOT), n.d., "Domestic Shipping," https://www.maritime.dot.gov/ports/domestic-shipping/domestic-shipping

[57] U.S. Energy Information Agency (EIA), 2025, "Underground Natural Gas Storage Capacity" (June30), https://www.eia.gov/dnav/ng/ng_stor_cap_a_EPG0_SACW0_Mmcf_a.htm

[58] REEthink, 2022 "INGAA Key Initiative: Transportation and Storage of Renewable Natural Gas" (May 27), 29, https://ingaa.org/imci-2-0-ingaa-key-initiative-transportation-and-storage-of-renewable-natural-gas-rng/

[59] New York State Energy Research and Development Agency (NYSERDA), 2023, "New York State Oil and Gas Sector: Methane Emissions Inventory," Report Number 23–38 (December), https://www.nyserda.ny.gov/-/media/Project/Nyserda/Files/Publications/Energy-Analysis/3-28-2021-Inventory-New-York-State-Oil-and-Gas-Sector-Methane-Report.pdf

[60] This is also a concern for RNG leaked during the production, transportation, and storage process.

[61] While embodied emissions from physical equipment and plants are normally considered in a comprehensive life-cycle analysis, they are often excluded from quantitative assessments because they do not contribute enough to the total emissions of the selected functional unit.

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[64] New York State Energy and Research Development Authority (NYSERDA), 2024, "Energy Sector Greenhouse Gas Emissions under the New York State Climate Act: 1990–2022, Final Report," NYSERDA Report Number 25-02, prepared by Eastern Research Group Inc., Concord, MA, https://www.nyserda.ny.gov/About/Publications/Energy-Analysis-Reports-and-Studies/Greenhouse-Gas-Emissions

[65] New York State Department of Environmental Conservation (DEC), 2023, “2023 Statewide GHG Emissions Report,” Table 2, 6, https://dec.ny.gov/sites/default/files/2023-12/summaryreportnysghgemissionsreport2023.pdf

[66] M.R.J. Daelman, E.M. van Voorthuizen, U.G.J.M. van Dongen, E.I.P. Volcke, M.C.M. van Loosdrecht, 2012, “Methane Emission during Municipal Wastewater Treatment,” Water Research 46 11(July), https://www.sciencedirect.com/science/article/abs/pii/S0043135412002795

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[68] Lambert Schneider, 2011, “Perverse Incentives under the CDM: An Evaluation of HFC-23 Destruction Projects,” Climate Policy 11 (2): 851–64, https://doi.org/10.3763/cpol.2010.0096

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[71] B. Lamolinara, A. Pérez-Martínez, E. Guardado-Yordi, C.G. Fiallos, K. Diéguez-Santana, G.J. Ruiz-Mercado, 2022, “Anaerobic Digestate Management, Environmental Impacts, and Techno-Economic Challenges,” *Waste Management 140* (March): 14–30, https://www.sciencedirect.com/science/article/abs/pii/S0956053X21006887

[72] RNG’s controlled production typically produces a marginally purer final product and may have somewhat less associated copollutant emissions than natural gas. U.S. Environmental Protection Agency (EPA), n.d., “Renewable Natural Gas,” https://www.epa.gov/lmop/renewable-natural-gas

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