New York State Hydrogen Assessment

Final Report | April 2025

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Our Mission:

Advance clean energy innovation and investments to combat climate change, improving the health, resiliency, and prosperity of New Yorkers and delivering benefits equitably to all.

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Final Report

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Abstract

New York State (NYS) recognizes hydrogen as a potential solution for decarbonizing its hard-to-electrify sectors, supporting the ambitious legislative goals outlined in the Climate Leadership and Community Protection Act (Climate Act). To evaluate hydrogen's feasibility, costs, and deployment opportunities across New York State's energy landscape, the New York State Energy and Research Development Authority (NYSERDA) collaborated with leading research institutions to conduct a comprehensive assessment, with a focus on hydrogen produced with electrolysis and water, using renewable and nuclear energy.

Hydrogen demand could reach 1.1 million metric tons (MT) annually by 2050, accounting for 11.4% of the State's total energy market. However, the high levelized cost of hydrogen presents a major barrier to widespread adoption. Among cost components, hydrogen production from renewable electricity represents the most significant part, contributing more than half of total hydrogen costs, outpacing storage and distribution expenses. The findings highlighted cost barriers across all examined sectors, including high-temperature industrial applications and fuel-cell electric vehicles (FCEVs). The technoeconomic landscape suggests addressing these challenges requires targeted innovation in electrolyzer efficiency, pipeline infrastructure, geologic storage solutions, and hydrogen-compatible end-use technologies.

This assessment provides a detailed framework for hydrogen development in New York State, identifying critical research priorities and deployment pathways that could position hydrogen as a complementary solution to electrification in achieving the State's ambitious climate objectives.

Keywords

hydrogen, decarbonization, electrolyzers, hard-to-electrify, industrial process heat, district heating, on-road transportation, nonroad applications

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Acronyms and Abbreviations

$/kW/yr	dollars per kilowatt per year
/kg	per kilogram
/kg-100miles	per kilogram per 100 miles
~	approximately
<	less than
>	greater than
≤	less than or equal to
≥	greater than or equal to
°C	degrees Celsius
AC-DC	alternating current to direct current
ACES	Advanced Clean Energy Storage
AEL	alkaline water electrolysis
ATAG	Air Transport Action Group
BEV	battery electric vehicle
BIL	Bipartisan Infrastructure Law of 2021
btu/lb	British thermal units per pound
CAC	Climate Action Council
CAPEX	capital expenditure
CCS	carbon capture and storage
CF	capacity factor
CHE	cargo handling equipment
CHP	combined heat and power
Climate Act	Climate Leadership and Community Protection Act
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
Con Edison	Consolidated Edison Company of New York, Inc.
DLE	dry low emisson
DLN	dry low NOx
DOE	U.S. Department of Energy
DRI	direct reduced iron
E3	Energy and Environmental Economics, Inc.
EAF	electric arc furnaces
EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute
EV	electric vehicle
FCEV	fuel cell electric vehicle
FCHEA	Fuel Cell and Hydrogen Energy Association

FRPs	fiber-reinforced polymers
gge/kg	gasoline gallon equivalents
GHG	greenhouse gas
GSE	ground support equipment
GW	gigawatts
H_2	hydrogen
H_2O	water
HDSAM	Hydrogen Delivery Scenario Analysis Model
HDV	heavy-duty vehicle
HHV	higher heating value
HTA	high technology availability
HYPSTAT	Hydrogen Production, Storage, and Transmission Analysis Tool
ICE	internal combustion engine
IRA	Inflation Reduction Act of 2022
IRS	Internal Revenue Service
ITC	investment tax credit
KBtu/kg	thousand British thermal units per kilogram
kg	kilograms
kg/min	kilograms per minute
kT	kilotonnes
kW	kilowatts
kW/yr	kilowatt per year
kWh/kg	kilowatt-hours per kilogram
kWth	kilowatt-thermal
LCOE	levelized cost of electricity
LCOH	levelized cost of hydrogen
LDES	long-duration energy storage
LDV	light-duty vehicles
LNE	limited nonenergy
LPG	liquid petroleum gas
MCH	methylcyclohexane
MDV	medium-duty vehicles
MHDV	medium and heavy-duty vehicles
MMBtu	million British thermal units
MMT CO2e	million metric tons of carbon dioxide equivalent
MMT	million metric tons
MMT/yr	million metric ton per year
mpgge	miles per gallons of gas equivalent
MT	metric tons

MTA	Metropolitan Transit Authority
MWh	megawatt hours
N_2	nitrogen oxides
NASA	National Aeronautics and Space Administration
NO	nitrogen oxide
NO_2	nitrogen dioxides
NOx	nitrogen oxides
NPV	net present value
NREL	National Renewable Energy Laboratory
NYISO	New York Independent System Operator
NYC	New York City
NYPA	New York Power Authority
NYS	New York State
NYSERDA	New York State Energy Research and Development Authority
O&M	operations and maintenance
OPEX	operating expenditure
OSW	offshore wind
PANYNJ	Port Authority of New York and New Jersey
PEC	photoelectrochemical
PEM	proton exchange membrane electrolysis
ppmv	parts per million by volume
PTC	production tax credit
PV	photovoltaic
R&D	research and development
RD&D	research, development, and demonstration
RTS	Regional Transit Service
SAF	sustainable aviation fuels
SCR	selective catalytic reduction
SMR	small modular reactor
SOEC	solid oxide electrolysis cell
Tbtu	trillion British Thermal Units
TCO	total cost of ownership
TPD	tonnes per day
VMT	vehicle miles traveled
VRE	variable renewable energy
ZEV	zero-emission vehicle

List of Definitions

City gate	The cost of hydrogen delivered to local distribution points before its final delivery to end users.
Cogeneration	The simultaneous production of electricity and useful heat from a single fuel source, capturing waste heat to improve overall energy efficiency.
Curtailment	The intentional reduction of renewable energy output below its potential production level, typically due to grid constraints or excess supply. This wasted energy presents an opportunity for hydrogen production.
Dedicated renewables	Renewable energy resources built specifically to power hydrogen production, rather than grid-tied electrolyzers that draw electricity from the general grid.
Embrittlement	The degradation of metal pipeline materials caused by hydrogen molecules infiltrating the metal, leading to blistering, reduced strength, and accelerated deterioration.
Firm capacity	Reliable, dispatchable power generation that can be activated to maintain grid stability.
Fuel cell	An electrochemical device that converts hydrogen and oxygen into electricity, producing only water and heat as byproducts.
Green hydrogen	Hydrogen produced through electrolysis powered by renewable energy sources, resulting in minimal or near-zero greenhouse gas (GHG) emissions.
Hard-to-electrify	Industries and applications where direct electrification faces significant technical, economic, or logistical limitations.
Hydrogen blending	The process of mixing hydrogen with natural gas within existing pipeline infrastructure.
Hydrogen combustion	The burning of hydrogen with oxygen to generate heat and water vapor.
HYPSTAT model	A linear optimization model developed by the National Renewable Energy Laboratory (NREL) that simulates hydrogen infrastructure and deployment cases. It optimizes production, storage, and transmission to minimize the statewide average cost of hydrogen.
Levelized cost of hydrogen (LCOH)	The average net present cost of hydrogen delivered over a facility's lifetime. It accounts for all costs, including initial investment, operation, maintenance, electricity, electrolyzers, transport, and storage, divided by the total hydrogen produced.
Process heat	Thermal energy directly used in industrial manufacturing processes.
Renewable overbuild	The construction of renewable energy capacity beyond immediate electricity demand to ensure long-term energy availability.

Seasonal storage Energy storage solutions designed to balance long-term, seasonal mismatches between energy production and demand.

Total cost of ownership (TCO) A financial estimate that accounts for the upfront purchase price of an asset along with its long-term costs, including operation, maintenance, and disposal. TCO analysis helps identify cost barriers to hydrogen adoption compared to traditional alternatives.

TCO gap The financial difference between the TCO for a hydrogen-based application and its conventional fossil fuel counterpart.

Variable renewable energy (VRE) Electricity generation sources that fluctuate due to weather conditions or time of day. This variability creates challenges for aligning supply with demand and influences how hydrogen production systems must be designed for efficiency.

Summary

As the U.S. energy landscape undergoes a historic transformation, New York State is committed to putting forward policies and programs that send a strong signal that public-private partnerships can catalyze economic growth and advance the State's energy transition.

New York State (NYS) has led in climate action. The NYS Climate Leadership and Community Protection Act (Climate Act) established some of the nation's most aggressive climate goals, including an 85% reduction in greenhouse gas (GHG) emissions from 1990 levels by 2050. This commitment has accelerated the growth of renewable energy and widespread electrification while ensuring innovation and technology are advancing along with manufacturing competitiveness and supply chain security. However, hard-to-electrify sectors—such as high-temperature industrial processes and heavy-duty transportation—require alternative decarbonization solutions, such as clean hydrogen to help the State transition toward a zero-emission economy. meet the State's climate objectives.

Built on years of research and modeling, the New York State Energy Research and Development Authority (NYSERDA) Hydrogen Assessment evaluates hydrogen's potential to decarbonize key sectors. Beyond sector-specific research, this study explores the infrastructure investments and research support needed to scale hydrogen production, storage, and distribution. It examines cost projections, supply chain constraints, and technology advancements that influence economic feasibility and can accelerate hydrogen deployment. This report focuses on hydrogen produced with electrolysis and water, using renewable energy and nuclear.

By integrating sector-specific insights with a comprehensive view of hydrogen's role in the State's energy transition, the 2025 Hydrogen Assessment serves as a guide for policymakers, industry stakeholders, and innovators. It provides key findings that inform the next steps for building a robust hydrogen economy aligned with New York State's ambitious climate goals. This Executive Summary highlights the study's key findings.

S.1 Projected Hydrogen Demand

Through a comprehensive literature review, the study projected potential hydrogen demand in New York State's hard-to-electrify sectors. It presents three demand scenarios—Low-, Mid-, and

High-demand—modeled for 2030, 2040, and 2050. These scenarios outline a range of potential market growth and technological development across sectors.

As shown in Table S-1, under the Mid scenario, hydrogen market demand is expressed as the percentage of energy derived from hydrogen relative to the total energy consumption in that sector.

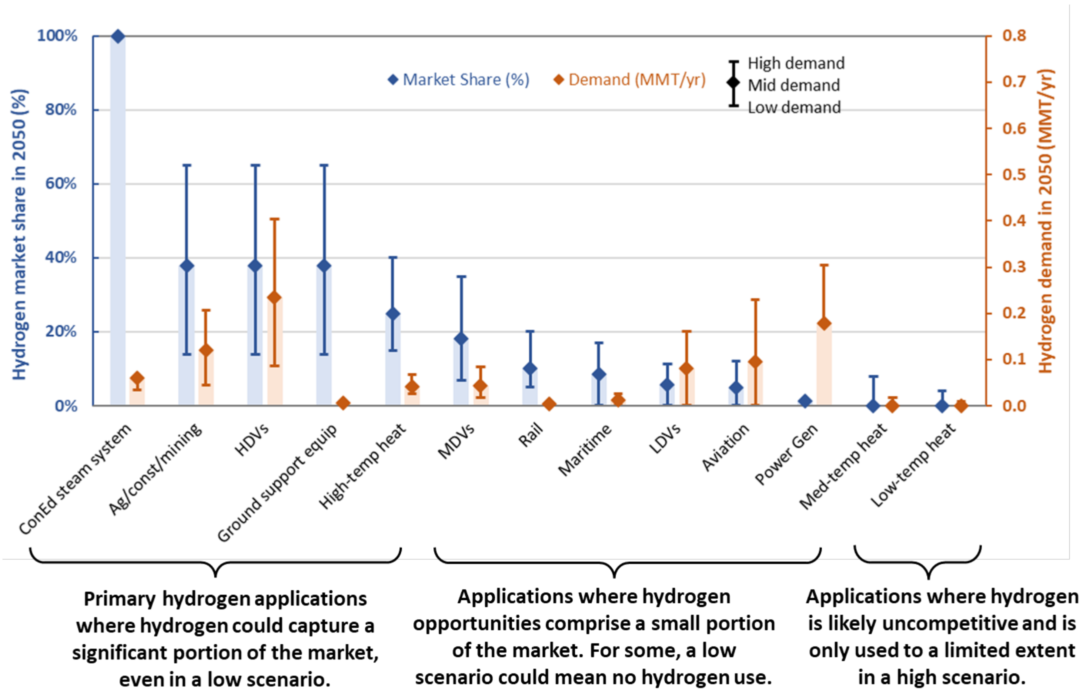
Table S-1. Projected Hydrogen Market Share in 2050 (Mid Scenario)

Sectors	Hydrogen Market Share[a]
District Heating	100%
Industrial Process	25%
Power Generation	1.3%
LDVs	6%
MDVs	18%
HDVs	38%
Other transportation (e.g., Aviation, Maritime, Rail, Ground Support Equipment)	2%–22%

[a] Market share is expressed as a percentage of the total energy consumption in each sector.

While market shares vary, hydrogen demand is expected to grow through 2050 across all Low-, Mid-, and High-demand scenarios.

Figure S-1. Projected Hydrogen Demand in 2050



In addition, the study considered seasonal and geographical demand across all three scenarios, reflecting the following results:

- **Seasonal demand:** By 2040, hydrogen demand peaks in winter months, driven by district heating needs and increased statewide electrification.
- **Geographical demand:** Hydrogen adoption concentrates around the New York Metropolitan area, a major hub for industrial, transportation, and heating needs.

These findings highlight that while hydrogen is a powerful decarbonization tool, seasonal and geographical factors must guide infrastructure investment.

S.2 Infrastructure Costs and Opportunities

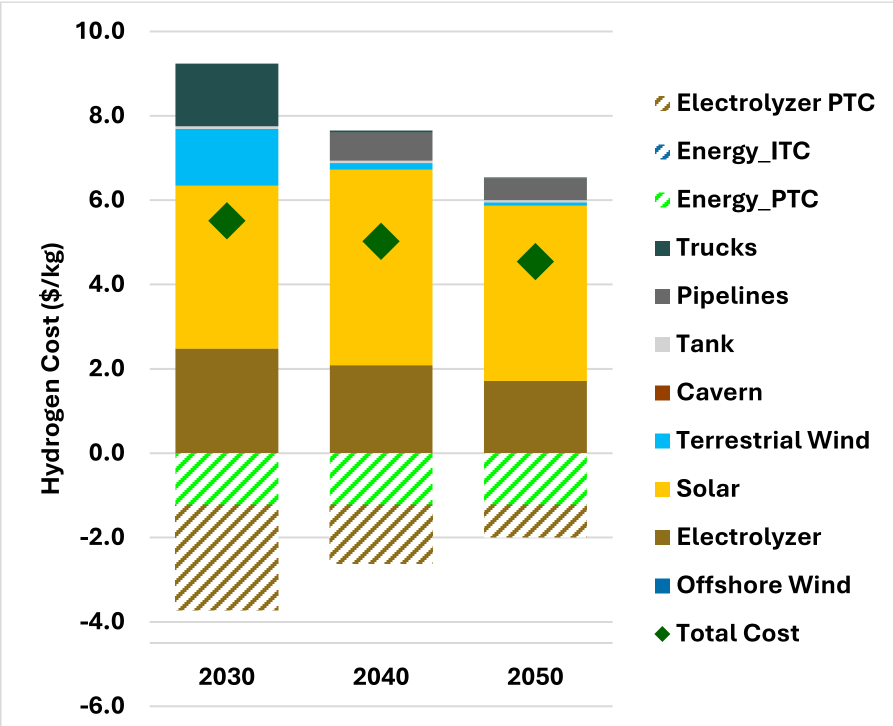
Using technoeconomic optimization modeling, the study examined renewable electricity production, storage, and transmission infrastructure needed to meet projected hydrogen demand at the lowest possible cost. The model incorporated real-world constraints, such as renewable resource availability, technology cost trajectories, hydrogen imports, and geologic storage resources.

In the base case, which reflects current market projections, the study found that by 2050, the levelized cost of hydrogen (net of all incentives) would reach \$4.50 per kilogram (kg).

Through 2050, the cost of renewable electricity will remain the primary driver of hydrogen production costs, accounting for more than half of total expenses. Electrolyzer costs also play a significant role in overall hydrogen pricing. Projected advancements in electrolyzer technology are expected to reduce the levelized cost of hydrogen by 22%—equivalent to a \$1.75 per kilogram (/kg) decrease—between 2030 and 2050. Additionally, as hydrogen demand grows, the transition from truck-based transport to pipelines in 2040 could lower transportation costs by 64%, or \$0.95/kg.

Figure S-2. Projected Hydrogen Costs in 2030, 2040, and 2050 Under Base Case

Key modeling parameters for the base case in the following chart can be found in section 3.2.



S.3 Pathways to Deploy Hydrogen Technology in Hard-to-Electrify Applications

To determine strategic deployment pathways, the study analyzed cost barriers preventing adoption of hydrogen technologies over fossil fuel applications. A total cost of ownership (TCO) analysis assessed costs for the following end uses:

- Light-duty vehicles (LDVs) requiring long-range and fast refueling
- Medium-duty vehicles (MDVs) and heavy-duty vehicles (HDVs)
- District heating
- High-temperature industry

Hydrogen use in power generation will be considered in future NYSERDA studies.

Even with existing incentives, such as the Inflation Reduction Act (IRA) tax credits and State incentives for zero-emissions vehicles, hydrogen technologies face significant cost barriers compared to fossil-fuel-based technologies. Table S-2 summarizes the additional lifetime costs of hydrogen adoption in key sectors.

Table S-2. Summary of Additional Total Cost of Ownership to Adopt Hydrogen Technology Compared to Existing Fossil Fuel Technologies

Use Case	TCO Gap Unit	Lifetime Cost Barrier to Adopt Hydrogen Technology	Key Cost Challenges and Uncertainties
LDVs	$/vehicle	$14,608	• Cost of delivered hydrogen and refueling stations • Availability of incentives
MDVs	$/vehicle	$84,553	
HDVs	$/vehicle	$512,595	
District Heating	$/MMBtu	$51	• Cost of delivered hydrogen • Delivery and storage costs
High-Temperature Industry	$/MMBtu	$38	

S.4 Innovation Focus Areas

The study assessed technological challenges across the hydrogen value chain, including:

- Renewable-energy-based hydrogen production
- Storage and transmission solutions
- Hydrogen adoption in hard-to-electrify sectors

Before identifying the research and development (R&D) needs, the study provides an overview of current technologies and the barriers preventing large-scale commercial adoption. Table S-3 summarizes the key areas.

Table S-3. Hydrogen Technology: Current Status, Challenges, and Needs

Category	Current State of the Art	Technical Challenges	Needs
Production	• AEL is the most mature electrolyzer technology in commercial operation, widely used globally and in NYS • PEM electrolyzers, although commercially available, are less common than AEL • SOEC electrolyzers are in the pilot stage	• PEM relies on high-cost rare earth materials but efficiently handles dynamic loads • AEL and SOEC have durability challenges and are difficult to integrate with variable renewables	• Scaling up manufacturing and developing new materials to improve durability • Advancing electrolyzer designs for better performance and cost reduction • Demonstrating hydrogen production integrated with renewables

Table S-3. (continued)

Category	Current State of the Art	Technical Challenges	Needs
Pipelines	• Hydrogen blending up to 20% demonstrated in existing natural gas networks (UK) • 1,600 miles of hydrogen-specific pipelines in the U.S., primarily for oil refining	• Steel embrittlement, leakage, low volumetric energy density of hydrogen	• Evaluating and piloting natural gas pipeline conversion for hydrogen in NYS • Developing new hydrogen compressor designs
Underground Storage	• Commercial-scale hydrogen storage in salt caverns, primarily for the chemical and refining industries (U.S. and UK) • Pilot projects integrating salt cavern storage with power generation and electrolysis	• NYS's bedded salt deposits differ from the salt domes typically used for hydrogen storage • Potential use of depleted oil and gas reservoirs for hydrogen storage	• Studying NYS geology for salt cavern storage suitability • Piloting geological hydrogen storage in salt caverns and depleted oil and gas reservoir
Emerging Storage Technologies	• Commercial ammonia production, storage, and distribution system • Metal hydride storage solutions at the pilot stage	• High cost and significant energy requirements for converting hydrogen from chemical and material-based storage	• Evaluating the safety, cost, and footprint of alternative hydrogen storage technologies • Improving ammonia reactors and crackers to reduce energy input and enhance flexibility • Enhancing hydrogen storage and extraction efficiency in metal hydrides
Building Applications	• Hydrogen heating through blended gas in pilot projects (UK) • Hydrogen fuel cells for combined heat and power in pilot projects (Japan)	• Compatibility of hydrogen with existing heating technologies • Availability of 100% hydrogen-based heating for district steam systems	• Identifying district steam systems suitable for hydrogen • Evaluating retrofitting vs. replacing heating systems for hydrogen use • Demonstrating 100% hydrogen in district steam systems
Industrial Process Heat	• Hydrogen used for high-temperature steel manufacturing in pilot projects (U.S. and Sweden)	• Compatibility with existing heating processes • Managing 100% hydrogen combustion for industrial heat	• Analyzing retrofits vs. new equipment for 100% hydrogen combustion • Studying hydrogen combustion behavior • Developing new hydrogen combustion-based heat technologies • Demonstrating 100% hydrogen for industrial heat

Table S-3. (continued)

Category	Current State of the Art	Technical Challenges	Needs
Power Generation	• Test gas turbines operating with up to 40% hydrogen (not commercially deployed) • Diffusion-type turbines reportedly capable of 100% hydrogen combusting • Commercial lean-premixed combustion (low NOx) in turbines supporting up to 50% hydrogen by volume • Studies of hydrogen's effect on the grid • PEM fuel cells commercially available for backup power	• Managing 100% hydrogen combustion with low NOx emissions • Hydrogen's impact on balance-of-plant applications • Adapting fuel cells for peaking power applications	• Conducting cost-benefit analysis of combustion vs. fuel cells for power • Demonstrating 100% hydrogen lean-premixed turbines and natural gas turbine retrofits • Developing NOx control strategies for hydrogen and ammonia combustion • Conducting RD&D on fuel cells for peaking power • Analyzing tradeoffs between electrical grid and hydrogen transmission capacity expansion • Piloting geological hydrogen storage with infrastructure for firm capacity generation • Conducting RD&D on multifuel microgrids and trigeneration systems (electricity, heat, and hydrogen)
Nonroad and Limited On-Road Applications	• Limited commercial deployment of FCEVs (light-, medium-, and heavy-duty) and refueling stations • Hydrogen-powered port and airport equipment in pilot projects (U.S. and China) • Commercial hydrogen-powered material-handling equipment • Hydrogen-powered trains in pilot projects (U.S. and Europe)	• Lack of widespread hydrogen refueling infrastructure • Refueling technology for medium- and heavy-duty FCEVs • Onboard hydrogen storage systems and fuel cell durability	• Demonstrating medium- and heavy-duty hydrogen refueling stations • Conducting RD&D on high-pressure, high-flow hydrogen refueling technology • Reducing fuel cell material costs by minimizing rare earth component usage
Aviation and Maritime Applications	• Hydrogen-powered aircraft and maritime vessels in pilot stage, limited to small size and short distance	• Need for high-energy-density, carbon-neutral fuels	• Planning studies on synfuels and biofuels for energy-intensive applications • Conducting RD&D for hydrogen-powered aircraft and marine vessels • Conducting RD&D for synfuel production

1 Introduction

1.1 New York State's Climate Leadership

In 2019, New York State enacted one of the most ambitious climate agendas in the U.S. through the Climate Leadership and Community Protection Act (Climate Act). This legislation aims to achieve a zero-emissions electricity system by 2040 and reduce gross greenhouse gas (GHG) emissions by 40% by 2030 and 85% by 2050. A defining element of the Climate Act is its commitment to equity, ensuring disadvantaged communities receive at least 35% of the benefits from clean energy investments.[1]

To support this agenda, the Climate Act established the Climate Action Council (CAC) to develop a strategic plan for meeting these targets. In December 2022, the CAC released its Final Scoping Plan, prioritizing electrification and renewable energy adoption as the foundation of New York State's decarbonization strategy. However, the plan recognizes that certain sectors—such as medium-duty vehicles (MDVs), heavy-duty vehicles (HDVs), district heating, and high-temperature industrial processes—are difficult to decarbonize via electrification alone.[2]

1.2 Hydrogen's Potential in Hard-to-Electrify Sectors

To address these challenges, clean hydrogen has emerged as a flexible, scalable solution to support New York State's decarbonization goals. In addition to providing a low-emissions alternative for hard-to-electrify sectors, hydrogen can enhance energy resilience by enabling long-duration energy storage (LDES) to manage and support seasonal demand fluctuations.[3]

Hydrogen's potential at the State level aligns with growing federal momentum. The Bipartisan Infrastructure Law of 2021 (BIL) and Inflation Reduction Act of 2022 (IRA) have created a national framework to accelerate the development of a robust clean hydrogen ecosystem. The BIL allocates:

- $1 billion to advance electrolyzer technology
- $500 million for clean hydrogen manufacturing and recycling research and development (R&D)
- $8 billion to develop regional hydrogen hubs[4]
- New clean hydrogen production standards to ensure sustainability

In addition, the IRA's Section 45V tax credit provides $3 per kilogram (/kg) in production cost offsets.[5] As federal and State policies converge, New York State has a unique opportunity to lead the nation's decarbonization efforts by overcoming the challenges of hydrogen deployment.

1.3 Barriers to Hydrogen Adoption

Despite its potential, several interconnected barriers hinder hydrogen adoption. To fully unlock its benefits, New York State must address market, regulatory, and technological challenges that could delay deployment:

1.3.1 Market Barriers

The hydrogen market encounters a cyclical dilemma: Producers hesitate to invest without guaranteed demand, while users remain reluctant due to limited availability and high costs. Infrastructure gaps, such as limited pipelines, storage facilities, and refueling stations, further compound this issue.

1.3.2 Regulatory Barriers

Federal legislation has accelerated hydrogen deployment by introducing funding, tax credits, and production standards, but regulatory uncertainty remains a major obstacle. The industry lacks standardized permitting processes, leading to administrative burdens and project delays.[6] Gaps in codes and regulations, particularly for transportation protocols and worker safety, add further hurdles. Additionally, regional restrictions, such as the Port Authority of New York and New Jersey's (PANYNJ) hazardous material regulations, further complicate hydrogen transport.[7]

1.3.3 Technological Barriers

Scaling hydrogen deployment requires R&D advancements across the industry. Electrolyzers need improvements to reduce material costs and integrate with variable renewables more effectively. Hydrogen's low volumetric energy density, roughly one-third that of natural gas, presents challenges for storage and transmission. Additionally, existing infrastructure, such as combustion turbines and natural gas pipelines, cannot directly use 100% hydrogen without modifications. To ensure hydrogen adoption in key sectors, New York State must assess existing technical barriers and identify solutions to overcome them.

1.4 Study Structure and Scope

This study evaluates hydrogen's role in New York State's clean energy transition and is organized as follows:

- **Section 2, Demand Assessment:** Analyzes projected hydrogen demand across key sectors, including industry, transportation, and power generation, considering Low-, Mid-, and High-demand scenarios.
- **Section 3, Infrastructure Costs and Opportunities:** Models the economic feasibility of hydrogen production, storage, and distribution, identifying key cost drivers and investment needs.
- **Section 4, Deployment Pathways:** Assesses sector-specific adoption strategies and evaluates how hydrogen technologies can integrate with existing decarbonization efforts.
- **Section 5, Innovation Focus Areas:** Identifies critical research and development priorities to accelerate hydrogen adoption.
- **Section 6, Societal and Environmental Benefits:** Evaluates hydrogen's potential impact on GHG emission reductions and broader environmental benefits.
- **Section 7, Conclusion:** Summarizes key findings to guide New York State's hydrogen economy development.

By providing actionable insights to support hydrogen integration into New York State's clean energy economy, this study aims to inform policymakers, industry stakeholders, and researchers as they navigate the challenges and opportunities of hydrogen deployment.

2 Hydrogen Demand Assessment

2.1 Market Analysis Introduction

Assessing energy demand dynamics in New York State is critical for realizing hydrogen's potential as a decarbonization tool. The market analysis provides a detailed outlook on future hydrogen demand through a comprehensive literature review from the last decade, building on existing studies such as the New York State Energy Research and Development Authority (NYSERDA) "Integration Analysis" and the CAC "Scoping Plan."

The analysis categorizes demand by end-use sector, identifying sectors where electrification faces significant technical, economic, and logistical challenges. These hard-to-electrify sectors underscore hydrogen's flexible value proposition:

- **District Heating:** Retrofitting existing systems to operate on clean hydrogen provides a low-carbon alternative to costly grid upgrades required for electrification.
- **Industrial Processes:** Many industrial applications rely on high-temperature combustion, which electricity struggles to achieve. Hydrogen combustion offers a potential solution for decarbonized operations.
- **Power Generation:** As renewable energy adoption expands, hydrogen can support decarbonization by storing energy during periods of surplus renewable electricity and converting the energy back to electricity to enhance grid reliability.
- **On-Road Transportation:** Hydrogen fuel cell electric vehicles (FCEVs) provide a zero-emission vehicle (ZEV) solution for medium- and heavy-duty applications where battery-electric options face limitations in weight, range, power, and charging times.
- **Nonroad Applications:** Aviation, maritime, and rail require energy-dense, low-downtime solutions, making hydrogen and hydrogen-derived fuels viable alternatives to fossil fuels.

2.2 Market Analysis Approach

To evaluate current and future demand, this analysis establishes sector-specific energy consumption across hard-to-electrify sectors. It then determines the proportion of this demand that hydrogen could meet in 2030, 2040, and 2050.

Three adoption scenarios outline potential hydrogen demand, each reflecting different levels of technological advancement, cost reductions, and policy support:

- **Low-Demand:** Adoption remains constrained due to high costs, minimal policy incentives, and strong competition from alternative technologies. Hydrogen use remains limited to niche applications where electrification is impractical.

- **Mid-Demand:** Hydrogen gains traction in cost-effective applications. Moderate policy support and infrastructure development enable significant adoption in industrial processes, district heating, and medium- and heavy-duty transportation.
- **High-Demand:** Aggressive cost reductions, driven by robust policy frameworks and technological breakthroughs, position hydrogen as a competitive solution across multiple sectors, accelerating widespread adoption.

Sections 2.3–2.7 detail hydrogen demand projections for each sector, followed by an analysis of temporal and geographic variations in section 2.8 and a summary in section 2.9. Appendix A provides further methodological details on sector-specific demand evaluations.

2.3 District Heating

New York State's district heating sector presents a unique opportunity for hydrogen adoption, particularly in Manhattan's Consolidated Edison Company of New York, Inc., (Con Edison) steam system—the largest district heating network in North America. While most buildings are expected to decarbonize through electrification, such as grid-connected heat pumps, hydrogen offers a viable alternative for steam generation in areas where electrification is cost-prohibitive or technically challenging.

Currently, the Con Edison steam system serves more than 3 million New Yorkers through two primary technologies:

1. Natural gas-fired steam boilers: Conventional units burn natural gas to produce steam
2. Cogeneration plants: These facilities generate electricity using natural gas turbines while capturing and repurposing the exhaust heat for steam production

Transitioning this system to full electrification would require substantial transmission infrastructure investments. Additionally, aging and inefficient building stocks in parts of Manhattan pose structural challenges for electrification. However, leveraging clean hydrogen as a fuel could repurpose existing steam generation assets, avoid costly transmission upgrades, and provide firm, dispatchable heat.[8]

In 2019, cogeneration supplied 60% of the system's steam, while boilers accounted for the remaining 40%.[9] Considering factors such as a warming climate, shifting peak demand due to extreme weather, and increasing energy efficiency, total steam demand for the Con Edison system will decline.

Table 1. Projected Consolidated Edison Company of New York, Inc., District Heating Steam Demand

As a percentage of 2019 steam demand in the Low-, Mid-, and High-demand scenarios

Steam Demand Scenario	2030	2040	2050
Low (% of 2019 level)	75%	45%	20%
Mid (% of 2019 level)	77%	55%	35%
High (% of 2019 level)	77%	55%	35%

Given the projected decline, Table 2 estimates the share of steam demand expected to be met by hydrogen.

Table 2. Projected Consolidated Edison Company of New York, Inc., Hydrogen Market Share for District Heating

As percentages and physical hydrogen demand in the Con Edison district heating system**.**

Demand Scenario	2030		2040		2050	
	H_2 Market Share (%)	Physical H_2 Demand (MMT/yr)	H_2 Market Share (%)	Physical H_2 Demand (MMT/yr)	H_2 Market Share (%)	Physical H_2 Demand (MMT/yr)
Low	2%	0.003	30%	0.029	100%	0.043
Mid	3.5%	0.005	40%	0.047	100%	0.075
High	3.5%	0.005	40%	0.047	100%	0.075

In all scenarios, a gradual transition would enable hydrogen to meet 100% of Con Ed's steam demand by 2050.

2.4 Industrial Processes

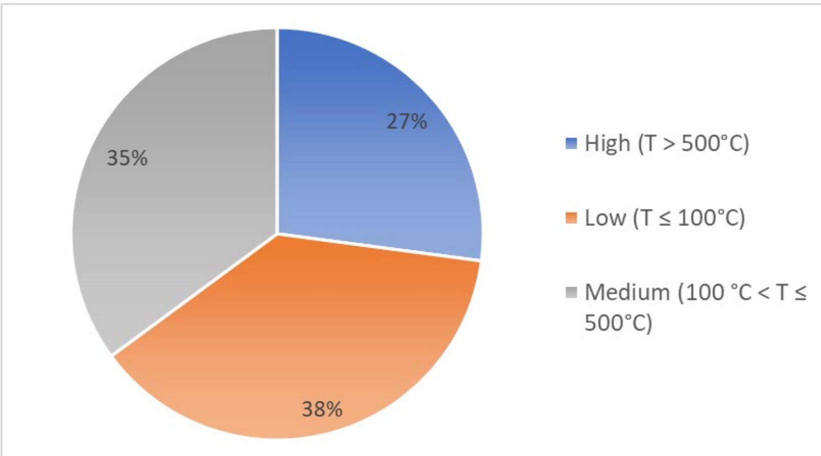
Industrial energy use plays a critical role in the U.S. economy, with approximately 50% allocated to industrial process heat[10, 11]—two-thirds of which relies on direct fossil fuel combustion.[12] In New York State, industrial activities account for 10% of total energy consumption and 9% of GHG emissions, creating a significant environmental footprint.[13, 14, 15]

Process heat is categorized by temperature (T):

- High (T > 500°C)
- Low (T ≤ 100°C)
- Medium (100°C < T ≤ 500°C)

Figure 1. Breakdown of Industrial Energy Use in New York State

Figures by heat grade.

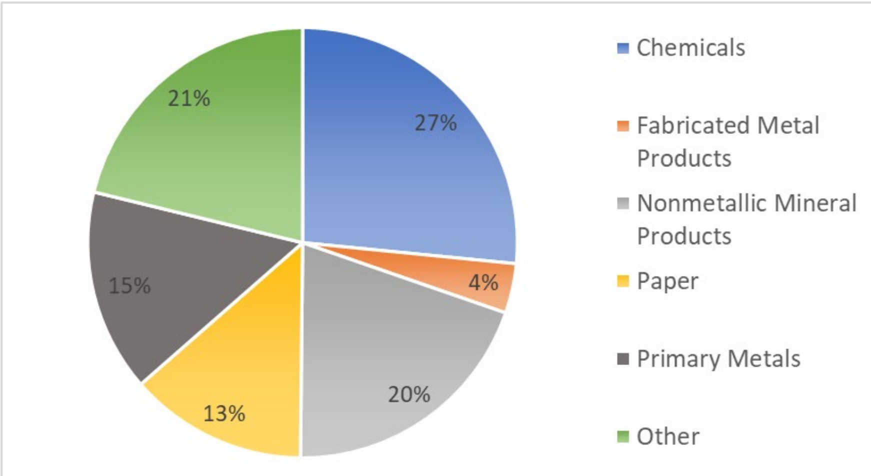


Electric boiler systems provide a mature, commercially available solution for low- and some medium-temperature processes, particularly those that use steam for heat. These systems achieve up to 99% efficiency and have capital costs 40% lower than fossil-fueled alternatives.[16] However, electrification struggles to generate the extreme temperatures required for high-temperature processes and certain medium-temperature applications that do not use steam.

In New York State, fossil fuels, such as natural gas and coal, supply 62% of the heat in medium- to high-temperature industrial processes. Of this total, 35% supports production of primary metals and nonmetallic minerals, including industries such as aluminum and glass. Another 44% powers sectors such as paper, chemicals, and fabricated metal parts manufacturing.[17]

Figure 2. Breakdown of High- and Mid-Temperature Industries in New York State

Figures by primary industry.



Hydrogen is a scalable alternative for high-temperature industrial processes, serving as a clean combustion fuel that replaces natural gas and coal. Analyzing historical energy use patterns alongside industry trends and anticipated technological advancements suggests that while overall demand may decline with efficiency improvements, the need for medium- to high-temperature heat will remain substantial.

Table 3. Projected Energy Demand for Industrial Process Heat in New York State

Temperature grade	2014	2030	2040	2050
Low (T ≤ 100°C)	50.6 Tbtu	45.4 Tbtu	42.5 Tbtu	39.2 Tbtu
Medium (100°C < T ≤ 500°C)	47.0 Tbtu	42.1 Tbtu	39.5 Tbtu	36.4 Tbtu
High (T > 500°C)	36.3 Tbtu	32.5 Tbtu	30.5 Tbtu	28.1 Tbtu
Economic-Driven Demand Growth	N/A	1.12	1.20	1.29
Efficiency Improvements	N/A	20%	30%	40%

Projections for hydrogen's share in industrial heat markets vary depending on adoption rates. In Low- and Mid-demand scenarios, hydrogen is used exclusively for high-temperature industrial processes. In the High-demand scenario, hydrogen also replaces fuel in low- and mid-temperature applications.

Table 4. Projected Hydrogen Market Share for Industrial Processes in New York State

Including the percentage of demand each year and the demand scenario for the industrial sector.

Demand Scenario		2030		2040		2050	
		H_2 Market Share (%)	Physical H_2 Demand (MMT/yr)	H_2 Market Share (%)	Physical H_2 Demand (MMT/yr)	H_2 Market Share (%)	Physical H_2 Demand (MMT/yr)
Low High-T heat only		0%	0	8%	0.018	15%	0.031
Mid High-T heat only		5%	0.012	12%	0.027	25%	0.052
High	Low-T heat	0%	0	1%	0.003	4%	0.012
	Mid-T heat	1%	0.003	4%	0.012	8%	0.022
	High-T heat	7%	0.017	20%	0.045	40%	0.083

In the high-adoption scenario, hydrogen could supply 40% of high-temperature industrial heat by 2050, supporting the State's decarbonization goals while maintaining industrial competitiveness.

2.5 Power Generation

As New York State transitions to a zero-emissions electricity system by 2040, maintaining grid reliability while integrating variable renewable energy (VRE) sources such as wind and solar presents several challenges, including the potential need for low-carbon, long-duration energy storage. Hydrogen offers a solution by storing energy when renewable electricity is abundant and converting it back to electricity when needed, helping to address multiday to multiweek shortfalls in VRE output. Additionally, as New York State retires fossil-fuel-based peaking power generation units and expands winter peaking capacity, hydrogen can provide dispatchable zero-emission resources.

NYSERDA will publish further exploration of hydrogen in the power sector separately.

2.6 On-Road Transportation

New York State's transportation sector is the largest source of GHG emissions, accounting for 28% of statewide emissions.[18] Decarbonizing this sector is essential to meeting the State's ZEV mandate, which requires all new passenger vehicles to be zero-emission by 2035 and all new medium- and heavy-duty vehicles (MHDVs) by 2045.[19]

While hydrogen FECVs for light-duty vehicles (LDVs) may excel in specific applications, battery electric vehicles (BEVs) are expected to dominate the market. However, hydrogen MHDVs offer distinct advantages. A recent National Renewable Energy Laboratory (NREL)study suggests that hydrogen MHDVs would have a lower total cost of ownership for applications requiring heavy-duty cargo hauling, long distances, or limited refueling times.[20] BEVs also require grid access and the power demand for charging MHDVs at plazas along key transportation corridors in the Northeast could exceed the capacity of the local grid distribution systems.[21]

Securing an interconnection to the high-voltage transmission network and meeting such capacity needs takes an average of five years.[22] In New York State, deploying a fleet of fuel cell buses could help reduce the need for electricity transmission expansion required to charge a fleet of electric buses.[23]

The cost-effectiveness of FCEVs compared to BEVs depends on end-use factors such as cost, range, battery size, refueling time, cargo weight, and volume needs. Successfully decarbonizing on-road transportation will require a combination of BEVs and FCEVs, aligning with projected vehicle miles traveled (VMT) in New York State through 2050.

Table 5. Summary and Projections for Vehicle Miles Traveled in New York State

Estimates in billions of VMT by vehicle class.

Vehicle Type	Projections of VMT (billions of VMT)			
	2019 (Baseline)	2030	2040	2050
LDV	109.5	120.5	132.1	144.9
MDV	6.1	7.1	8.2	9.6
HDV	8.9	9.6	10.3	11.1
Total	124.4	137.1	150.6	165.5

Hydrogen-powered FCEVs can help achieve the targets of New York State's ambitious ZEV mandate. To quantify their future market share, the study estimated the FCEV stock of LDVs, medium-duty vehicles (MDVs), and heavy-duty vehicles (HDVs) for the Mid-demand scenario in each decade.

Table 6. Projected Hydrogen Market Share for On-Road Transportation in New York State

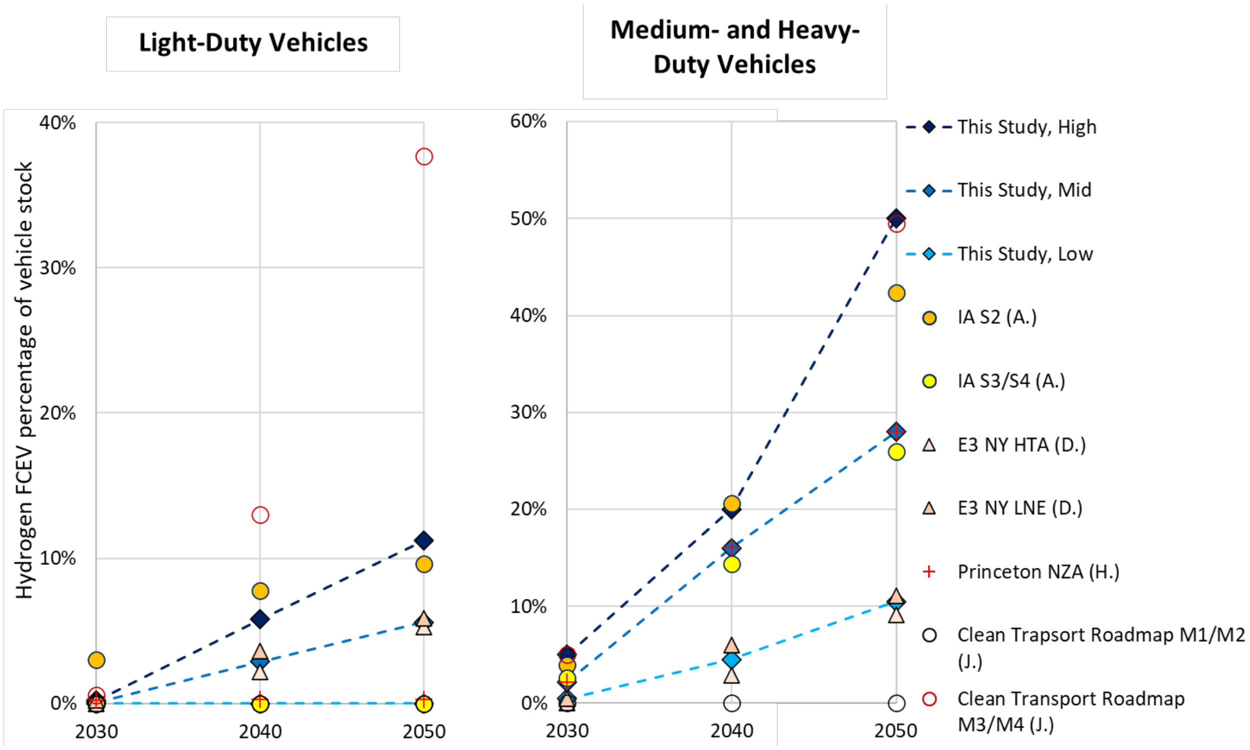
Including the percentage of demand each year and the demand scenario for the transportation sector.

Vehicle Type	Demand Scenario	2030		2040		2050	
		H_2 Market Share (%)	Physical H_2 Demand (MMT/yr)	H_2 Market Share (%)	Physical H_2 Demand (MMT/yr)	H_2 Market Share (%)	Physical H_2 Demand (MMT/yr)
LDV	Low	0%	0	0%	0	0%	0
	Mid	0%	0.002	3%	0.053	6%	0.101
	High	0.2%	0.004	6%	0.106	11%	0.202
MDV	Low	0.3%	0.001	3%	0.009	7%	0.021
	Mid	1%	0.003	10%	0.028	18%	0.054
	High	3%	0.008	14%	0.040	35%	0.105
HDV	Low	0.6%	0.005	6%	0.048	14%	0.109
	Mid	3%	0.025	22%	0.179	38%	0.294
	High	7%	0.057	26%	0.208	65%	0.505

By 2050, New York State's estimated hydrogen demand for transportation could range from 0 to 0.505 million metric tons per year (MMT/yr, depending on the market adoption of FCEVs. Notably, High-demand scenarios reflect heavy-duty trucks being the primary driver of growth.

Figure 3. Projected Hydrogen Market Share for Fuel Cell Electric Vehicles

Estimates from recent literature are compared to those in this study.



Given FCEVs' potential to meet New York State's ZEV mandate and the large carbon footprint of the State's on-road transportation, stakeholders should prioritize decreasing costs, expanding refueling infrastructure, and increasing consumer awareness of medium- and heavy-duty FECVs.

2.7 Nonroad Applications

Various industries rely on nonroad applications, although some face significant technical barriers to electrification. These applications often require energy-dense fuels, making them potential candidates for hydrogen and hydrogen-derived fuels. Nonroad applications include:

- **Aviation:** Hydrogen is both a direct fuel and a key component in producing sustainable aviation fuels (SAF). The Air Transport Action Group (ATAG) Waypoint study[24] notes that hydrogen is already feasible as a fuel for regional and short-range flights (aircraft with 9–100 seats). By 2035, advancements in fuel cells and hydrogen combustion are expected to support short-haul commercial flights (100–150 seats). However, large-scale adoption depends on improvements in hydrogen storage, fuel cell efficiency, and airport infrastructure.
- **Maritime:** Researchers are exploring hydrogen and hydrogen-based fuels (such as ammonia and methanol) for cargo ships, ferries, and auxiliary power systems, although estimates in literature set limitations on adoption[25]

- **Ground Support Equipment (GSE):** Baggage tugs, pushback tractors, and other GSE increasingly rely on hydrogen fuel cells for airport and seaport operations, following trends in hydrogen adoption seen in HDVs.
- **Rail Transport:** Freight rail, which often operates in remote and challenging terrains, is well-suited for hydrogen deployment. Unlike urban rail systems that can use direct electrification, hydrogen provides a flexible and efficient solution for less accessible routes.
- **Heavy Industrial Equipment:** Construction, agriculture, and mining industries depend on diesel-powered engines that are difficult to electrify. Hydrogen offers a low-carbon alternative for excavators, forklifts, and other heavy-duty machinery.

Envisioning a decarbonized future for these sectors involves estimating hydrogen's role in meeting their needs, sector by sector. These projections quantify the percentage of each sector's energy needs that hydrogen meets.

Table 7. Projected Energy Demand for Nonroad Applications in New York State

Sector	Energy Use and Metrics	Projections of Energy Use in Each Sector			
		Baseline	2030	2040	2050
Aviation	Energy use	287 Tbtu (2019)	318 Tbtu	335 Tbtu	322 Tbtu
	Scaling factor	N/A	1.23	1.57	1.87
	Efficiency improvements	N/A	10%	23%	40%
Maritime	Energy use	N/A	25.6 Tbtu	25.5 Tbtu	25.1 Tbtu
Rail	Energy use	6.7 Tbtu (2018)	7.6 Tbtu	8.4 Tbtu	9.6 Tbtu
	Scaling factor	N/A	1.20	1.43	1.72
	Efficiency improvements	N/A	5%	13%	17%
GSE and CHE	GSE energy use	1.7 Tbtu (2017)	2.1 Tbtu	2.6 Tbtu	3.2 Tbtu
	CHE energy use	0.9 Tbtu (2020)	0.9 Tbtu	0.9 Tbtu	0.9 Tbtu
	GSE scaling factor	N/A	1.23	1.57	1.87
	CHE scaling factor	N/A	1	1	1
	Efficiency improvements	N/A	0%	0%	0%

Table 7. (continued)

Sector	Energy Use and Metrics	Projections of Energy Use in Each Sector			
		Baseline	2030	2040	2050
Industrial Equipment	Agriculture energy use	12.5	11.1	10.4	9.5
	Construction energy use	41.8	37.9	36.2	34.0
	Mining energy use	13.4	11.7	10.9	9.9
	Agriculture scaling factor	N/A	1.10	1.18	1.27
	Construction scaling factor	N/A	1.13	1.24	1.36
	Mining scaling factor	N/A	1.09	1.15	1.23
	Efficiency improvements	N/A	20%	30%	40%

Hydrogen demand for nonroad applications is projected to range from 0.061 MMT/yr in conservative scenarios to 0.598 MMT/yr in more ambitious projections by 2050. Increasing adoption in aviation and industrial equipment sectors primarily drives the Mid- and High-demand scenarios, where even a modest market share could generate substantial hydrogen demand.

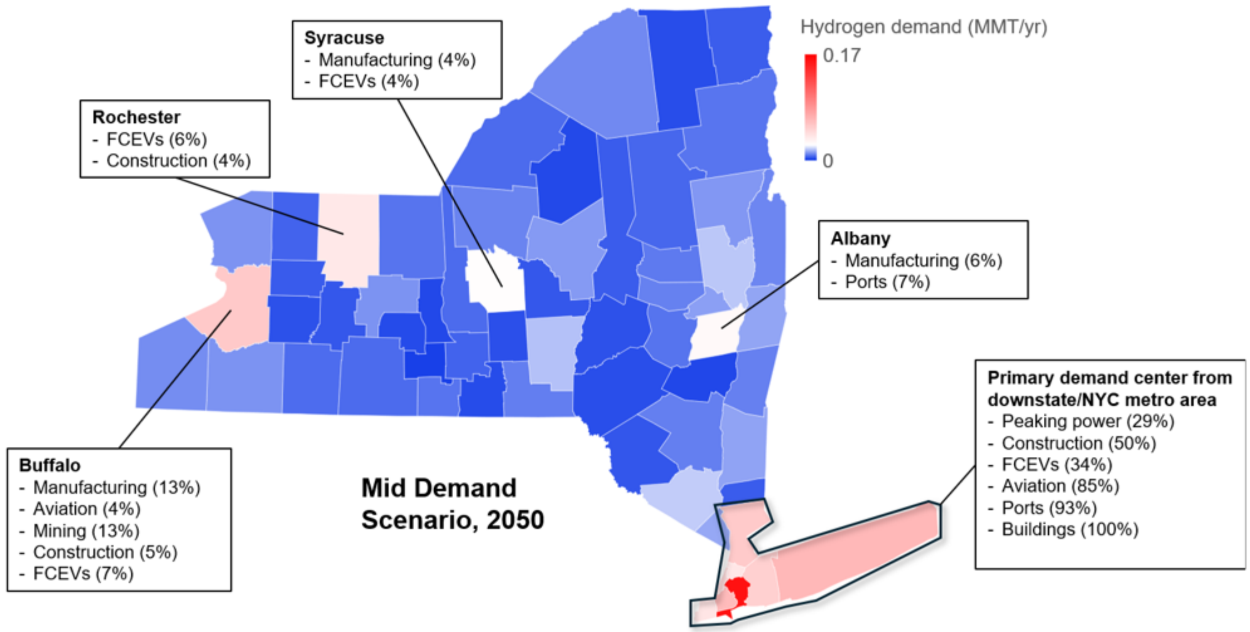
Because nonroad assets have long lifespans and fleets turn over slowly, investing early in hydrogen infrastructure and demonstration projects is crucial to accelerating adoption in hard-to-electrify sectors.[26]

2.8 Temporal and Geographic Disaggregation of Demand

Hydrogen demand in New York State will vary across the State and throughout the year. Key economic hubs will see the highest demand concentrations and seasonal fluctuations due to changes in energy use, industrial activity, and heating needs. While previous sections outlined sector-specific demand, this section explores the temporal and regional factors determining how, where, and when hydrogen can play a pivotal role.

Figure 4. Geographic Hydrogen Demand in New York State

Figures reflect the Mid-demand scenario in 2050. Percentages next to each application for a given demand center represent the proportion of total statewide demand at each demand center.

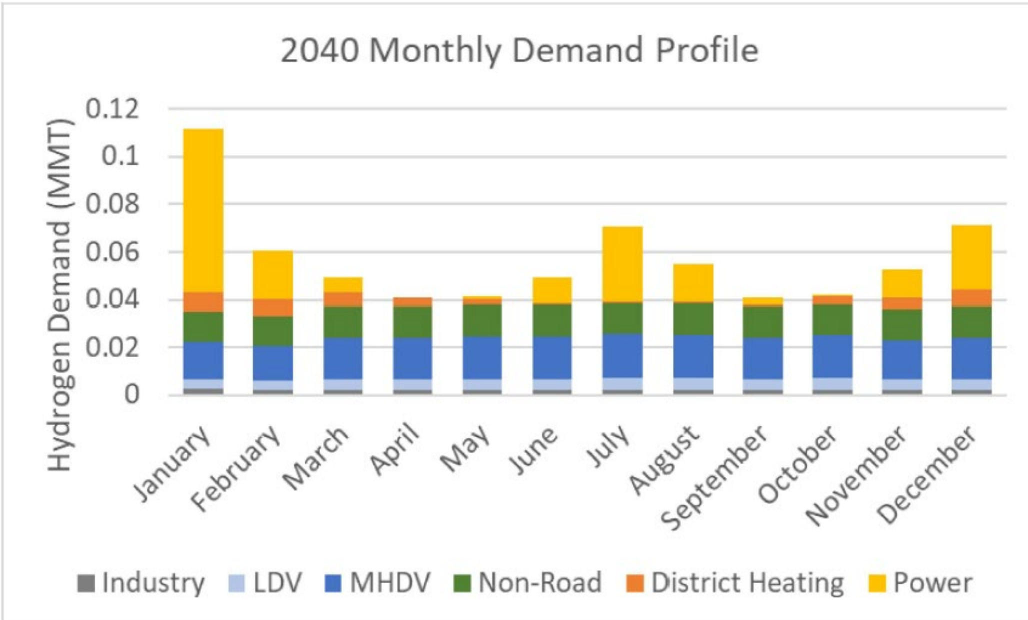


Regions with concentrated industrial, transportation, and energy infrastructure needs are expected to see the highest hydrogen adoption. Key demand centers include:

- **New York Metropolitan Area:** The region's dense transportation network, potential district heating infrastructure, and industrial hubs will drive significant hydrogen consumption. Hydrogen-powered buses, trucks, and port operations will require refueling infrastructure, while the Con Edison steam system could become a major hydrogen consumer for district heating.
- **Buffalo, Rochester, and Syracuse:** Upstate industrial centers will see demand from manufacturing facilities and heavy industry, particularly for high-temperature processes where electrification remains challenging.
- **Hudson Valley and Capital Region:** These regions will support hydrogen production and distribution hubs due to their proximity to renewable energy resources and transportation corridors.

Under these projections, demand will fluctuate throughout the year, driven by seasonal variations in power generation, transportation, and industrial activity.

Figure 5. Average New York State Hydrogen Demand by Month in the Mid-Demand Scenario in 2040



A winter-peaking electrical grid drives hydrogen demand for power generation, causing surges during colder months, with January as the peak. Smaller, less dramatic demand spikes also occur in the summer due to increased electricity use. These seasonal shifts highlight the need to design hydrogen systems with built-in flexibility to balance supply and demand.

2.9 Summary

Assessing hydrogen demand in New York State's hard-to-electrify sectors reveals opportunities to integrate hydrogen into the State's clean energy transition. Key takeaways include:

- **District heating** could transition to 100% hydrogen by 2050, with the Con Edison steam system serving as an early adopter.
- **Industrial processes** could rely on hydrogen for 25% to 40% of high-temperature process heat demand by 2050.
- **Energy storage** could use hydrogen for long-duration storage, ensuring grid reliability as renewable energy capacity increases.
- **On-road transportation** could drive significant hydrogen fuel demand, particularly for heavy-duty trucks and buses.
- **Nonroad applications** in aviation, maritime, and rail could adopt hydrogen-based fuels as decarbonization alternatives in specific use cases.

Even under conservative estimates, these scenarios demonstrate that hydrogen will play a role in sectors where electrification faces significant challenges.

Table 8. Projected Hydrogen Market Demand in New York State (Total)

Demand Scenario	2030		2040		2050	
	Estimated % of State Energy Demand	Annual H_2 Demand (MMT/yr)	Estimated % of State Energy Demand	Annual H_2 Demand (MMT/yr)	Estimated % of State Energy Demand	Annual H_2 Demand (MMT/yr)
Low	0.06%	0.012	2.71%	0.325	5.43%	0.488
Mid	0.38%	0.062	5.95%	0.684	11.44%	1.098
High	0.79%	0.129	8.59%	1.016	18.91%	1.981

3 Infrastructure Costs and Opportunities

3.1 Introduction

Hydrogen presents a transformative opportunity to decarbonize New York State's energy system. However, building a hydrogen ecosystem remains a significant challenge. This section examines the economics of hydrogen production, infrastructure, and deployment. Through system optimization modeling across multiple cases, the study identified the following key insights:

- Understanding tradeoffs among energy costs, energy production timing (e.g., stable sources such as nuclear vs. variable renewable energy), and supply-demand proximity is key to lowering production costs and seasonal storage needs.
- Developing pipeline infrastructure offers a more cost-effective approach than on-road trucking for cross-sector hydrogen transport, especially if demand exceeds thresholds such as low levels of targeted end use (e.g., industrial applications).
- Innovating in electrolyzer system design and manufacturing could further reduce costs.

This section begins by outlining the modeling framework, detailing the inputs, optimization processes, and outputs. It then presents modeled cases and their results, offering insights into the economic viability of hydrogen and key takeaways to inform future deployment.

3.2 Framework for Analysis: The Hydrogen Production, Storage, and Transmission Analysis Tool Model

The study developed cases based on the realities and limitations of deploying hydrogen in New York State. They then simulated these cases using the Hydrogen Production, Storage, and Transmission Analysis Tool (HYPSTAT), which NREL developed. HYPSTAT, a flexible linear optimization model, analyzes various hydrogen infrastructure and deployment cases.

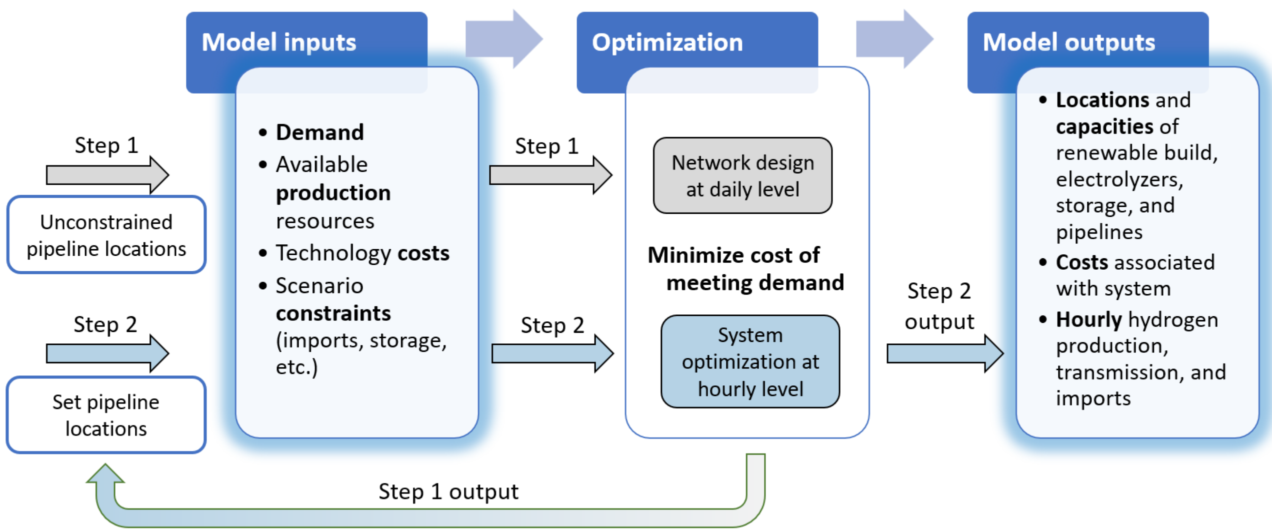
The study used the model to simulate single-year projections for 2030, 2040, and 2050,[27] focusing on minimizing the statewide cost of hydrogen production, storage, and transmission.

The model's outputs provide insights into New York State's hydrogen ecosystem, including:

- The levelized cost of hydrogen (LCOH) across the State
- Optimal locations and capacities for hydrogen production facilities
- Complementary infrastructure needs, such as dedicated renewables, pipelines, and storage systems
- Supply and demand balancing strategies under various conditions

Appendix B details the methodology's assumptions and inputs.

Figure 6. Hydrogen Production, Storage, and Transmission Analysis Tool Analysis Model Framework



The model minimizes the statewide average cost of hydrogen for a given set of cases and constraints through a two-step iterative process. The first iteration optimizes at the daily production and demand level to define optimal hydrogen corridors. The second iteration refines production, transmission, and storage costs at the hourly level, ensuring a more precise and cost-effective hydrogen infrastructure storage.

3.2.1 Model Inputs and Assumptions

HYPSTAT incorporates a robust set of inputs to ensure its outputs reflect realistic conditions. The following are the assumptions and applications of key inputs:

- **Energy Resources (Considered and Availability) for Hydrogen Production:** The model considers solar, land-based wind, offshore wind, and nuclear energy under various cases. It estimates renewable resource availability by subtracting the resources needed to meet the 2050 grid demand from the technical potential. The model sources technical potential and locations from the NYSERDA-published 2024 supply curve, organizing them by zone.[28] Insights from the coordinated grid planning effort[29] determine nuclear availability which is set to be available starting from 2040. The model permits nuclear build locations in the Hudson Valley, Capital Region, and Central New York. It's important to note that most land-based wind in NYS is assumed to meet grid demand, only 0.15GW land-based wind is allowed to use by the model for hydrogen production.

- **Tax Credits:** The model applies hydrogen production tax credits (PTCs), renewable energy production credits, and investment tax credits (ITCs). Appendix B details the assumed phase-out dates of these credits. The model assumes levelized credits across the asset's lifetime.
- **Imports:** The model assumes imported hydrogen is available on demand to meet 50% of the annual demand. It sets import costs equal to in-state hydrogen costs and does not explicitly model them.
- **Geologic Storage:** The model assumes only existing salt caverns in New York State are available for hydrogen storage (8 kilotonnes, or kT). The costs reflect the expense of retrofitting these caverns for hydrogen storage.
- **Hydrogen Transport:** The model optimizes between pipeline and truck transport. The model assumes new dedicated hydrogen pipelines follow existing natural gas rights-of-way. Cost estimates derive from Argonne National Laboratory's Hydrogen Delivery Scenario Analysis Model (HDSAM)[30] with NYS-specific adjustments. It models truck transport using tube-trailer trucks, applying median cost estimates from the HDSAM and literature research.

A set of constraints is applied to restrict the model to ensure that certain parameters will not exceed the specified range during its optimization process. These constraints are based on possibilities that are considered practical in New York State. Table 9 summarizes these constraints. Table 10 shows inputs provided to the model for simulation.

Table 9. Hydrogen Production, Storage, and Transmission Analysis Tool Model Constraints

Model Constraints	Value	Notes
On-Demand Imports	50% of supply/year	Based on a midpoint assumption
Maximum Limit for Renewable Build	Solar, 33GW Land-based wind, 0.15GW OSW, 11.7 GW (fixed bottom, 1.7 GW; floating, 10 GW)	Based on technical potential and grid needs in 2050
Maximum Limit for Nuclear Build	0.5 GW (Zones F and G) Unconstrained (Zone C)	Based on Coordinated grid planning effort
Electrolyzer Build Locations	Co-located with Energy Resource	Follows strictest interpretation of IRA 45V guidance
Maximum Limit for Storage Build	Salt Cavern, 8 kT (Zone CS), Aboveground Pressurized Gaseous Tank, not limited	Salt cavern limit based on existing available capacity in New York State.
Transportation Methods	New Build Pipelines, Flow rate depends on diameter built Gaseous Tube-trailer Truck, 700 kg per truck	Pipeline build follows existing right-of-way as Natural gas pipelines. Truck flow follows routes between fixed demand zones.

Table 10. Hydrogen Production, Storage, and Transmission Analysis Tool Model Key Inputs

Input	Value	Notes
Hydrogen Demand Profile	Use projected values from Mid-demand scenario	See details in section 2.
Renewable Resource Cost	Based on published '2024 NYSERDA Supply Curve'	Value varies by zone and modeling year (2030, 2040, 2050).
Nuclear Cost	\$8,700/kW (2040) \$6,600/kW (2050)	Represents CAPEX values.
Electrolyzer Cost	PEM Conservative: \$926/kW, \$736/kW, \$575/kW PEM Optimistic: \$665/kW, \$338/kW. \$218/kW PEM Offshore: \$1389/kW, \$1104/kW, \$863/kW SOEC Conservative: \$1100/kW, \$900/kW, \$700/kW	Cost is for 2030, 2040 and 2050, separately.
Storage CAPEX	Salt Cavern: \$16/kg (CAPEX to retrofit existing cavern) Above ground Pressurized Gaseous Tank: \$800/kg	Represents CAPEX value; Uses the same cost for all years.
Transportation Cost	Gaseous Tube-trailer Truck, \$1.25/kg-100-mile, Pipeline OPEX: \$0.06/kg Pipeline CAPEX: varies with diameter	Uses the same cost for all years. Offshore pipelines will include 1.7x cost adder.

These inputs enable case analysis that highlights cost drivers, infrastructure needs, and opportunities for strategic investment. The outputs are critical in assessing how different cases influence the LCOH and identifying barriers to establishing a hydrogen ecosystem in New York State.

3.3 Model Cases and Results

To address uncertainties in hydrogen deployment, the study modeled six distinct cases, each exploring two fundamental questions:

1. How do varying demand and resource availability levels influence hydrogen costs?
2. What strategies can reduce costs while meeting infrastructure and policy requirements?

The tables and figure below summarize the resulting net levelized cost of hydrogen (LCOH) estimates and the resource build for each scenario in 2030, 2040, and 2050.

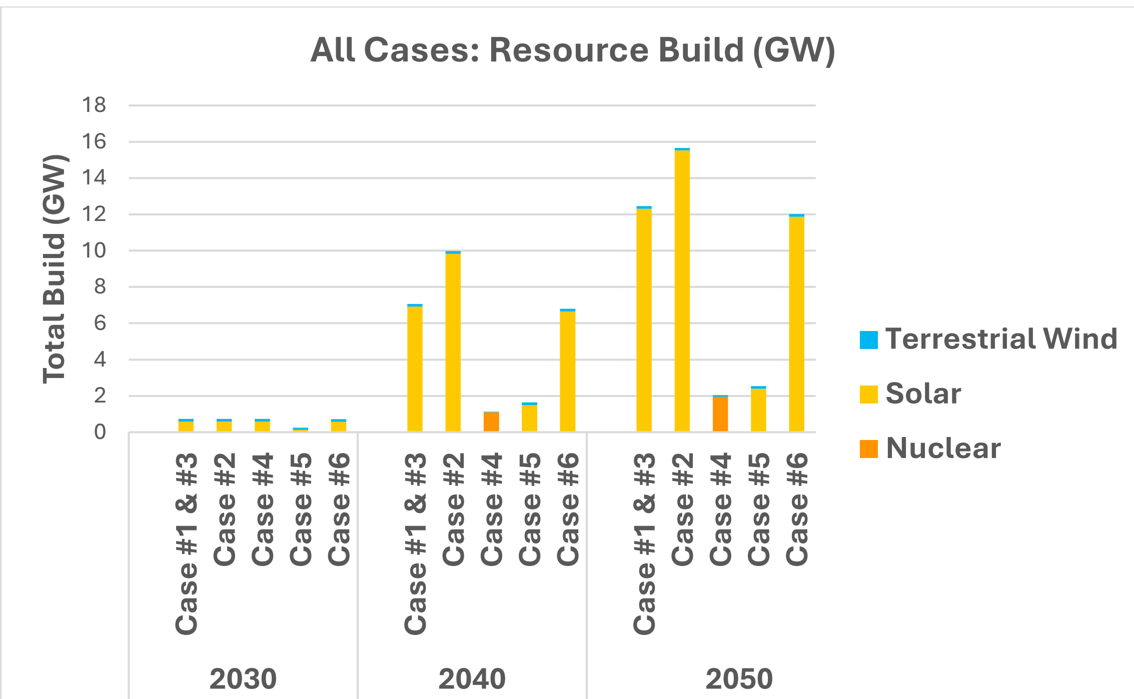
Table 11. Summary of Modeled Levelized Cost of Hydrogen Across Cases (2030, 2040, and 2050)

No.	Cases	2030 (\$/kg)	2040 (\$/kg)	2050 (\$/kg)
1	Limited renewable, no power (base case)	5.5	5.0	4.5
2	Limited renewable with power demand	5.5	5.1	4.5
3	Accelerated renewables, OSW	5.5	5.0	4.5
4	Accelerated clean energy, nuclear	5.5	2.9	2.4
5	No pipeline, industrial only	4.7	5.7	5.2
6	Low-cost electrolyzer	4.7	3.8	3.5

Table 12. Summary of Resource Build Across Cases (2040)

No	Cases	Solar (GW)	Land based wind (GW)	Offshore Wind (GW)	Nuclear (GW)	Total (GW)
1	Limited renewable, no power (base case)	6.9	0.15	—	—	7.05
2	Limited renewable with power demand	9.8	0.15	—	—	9.95
3	Accelerated renewables - OSW	6.9	0.15	—	—	7.05
4	Accelerated renewables - ruclear	—	0.03	—	1.1	1.13
5	No pipeline, industrial only	1.5	0.15	—	—	1.65
6	Accelerated tech: low-cost electrolyzer	6.7	0.15	—	—	6.85

Figure 7. Summary of Resource Build Across Cases (2030–2050)



The following sections describe each cases assumptions and results, offering insights into cost drivers and trade-offs in achieving a cost-effective hydrogen system.

3.3.1 Case 1: Base Case with Limited Renewables

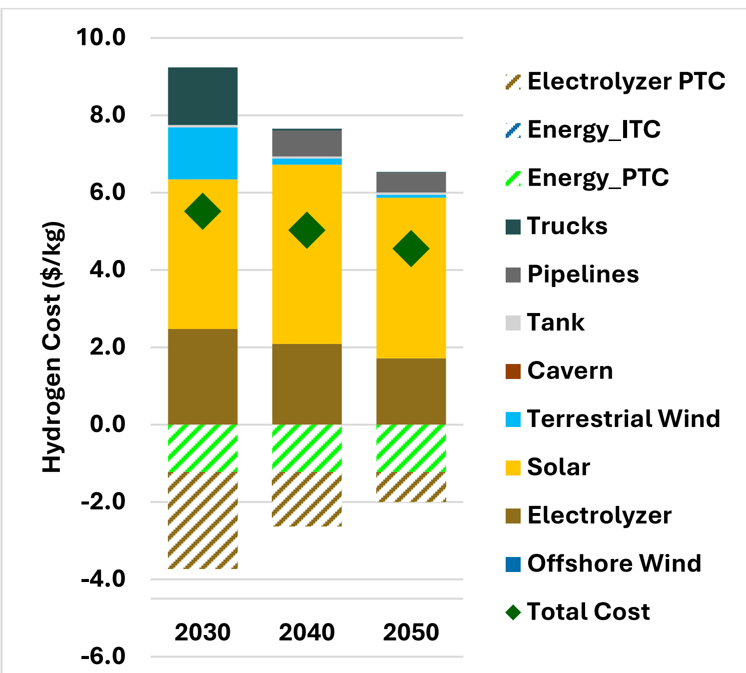
3.3.1.1 Base Case Description

The base case establishes a reference point for evaluating how hydrogen demand and infrastructure strategies impact costs. It assumes moderate hydrogen demand across all sectors but excludes power generation. The model limits renewable energy availability to solar and land-based wind, excluding offshore wind (OSW) and nuclear power. Storage relies on pressure tanks and up to 8 kT of salt cavern storage for short-term (sub-daily) and medium-term (longer than a day) supply-demand management. On-demand hydrogen imports address seasonal variations.

3.3.1.2 Base Case Results

In the base case, renewable electricity costs drive the LCOH, accounting for 56% to 65% of gross costs. Although land-based wind offers a cost-effective use case, its assumed availability remains extremely limited (0.15 GW available for hydrogen production). Therefore, the model relies heavily on solar energy to meet expected demand.

Figure 8. Case 1: Base Case Results



To increase electrolyzer use and decrease levelized cost impacts of its capital expenses, which accounts for 27% (2030) of the gross LCOH, the model identifies an optimal renewable overbuild (ratio of renewable capacity to electrolyzer capacity) of 1.5 to 1.7. As demand grows, the system will transition from truck-based delivery to pipelines starting from 2040, reducing transportation costs by 64% (2030-2050). Tank storage systems manage short-term supply-demand variations, while on-demand imports stabilize seasonal variations. These findings highlight the importance of reliable import infrastructure or alternative seasonal management solutions.

Projected reductions in the LCOE, advancements in electrolyzer technology, and optimized infrastructure, such as transitioning to pipeline transport, will drive the net LCOH down to $4.5/kg by 2050, an 18% reduction from 2030.

3.3.2 Case 2: Limited Renewables with Power Demand

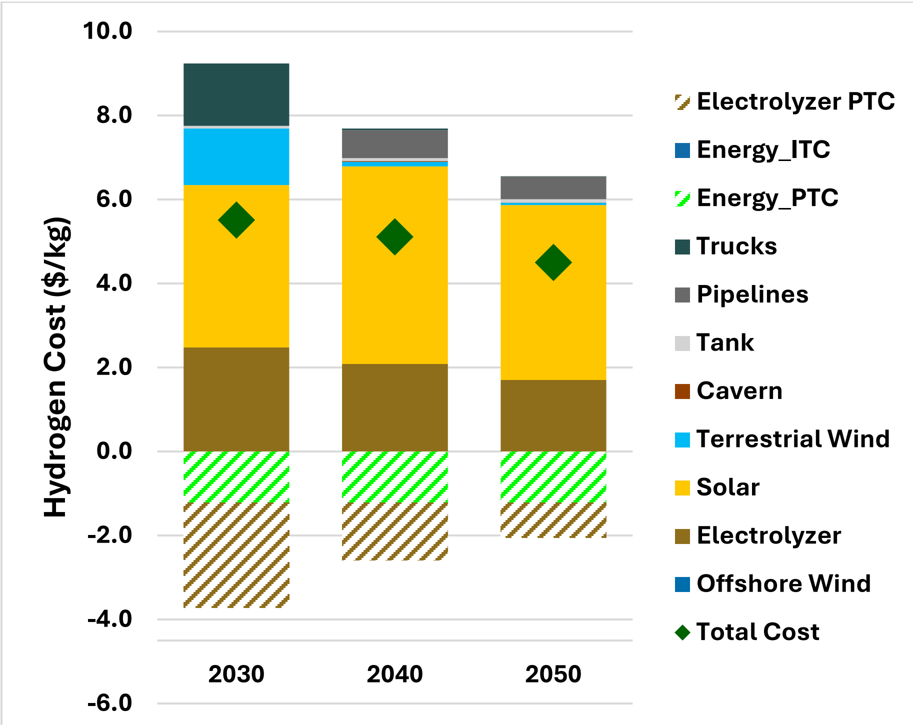
3.3.2.1 Power Demand Description

This case builds on the base case by introducing additional hydrogen demand from the power sector. Renewable energy availability, technology costs, and storage systems remain consistent with the base case, but power demand introduces greater seasonal variability, particularly during winter peaks. This case provides insights into how power sector integration affects hydrogen production, storage, and delivery and the associated infrastructure requirements and cost implications.

3.3.2.2 Power Demand Results

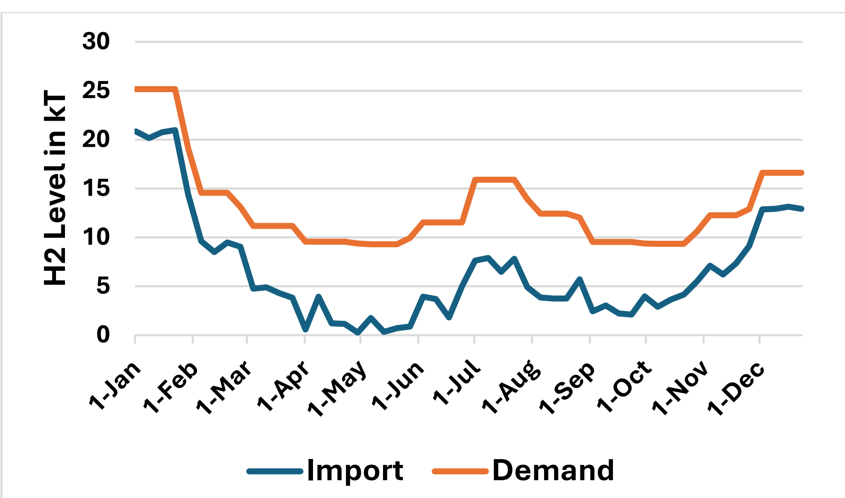
Despite a 40% increase in annual hydrogen demand due to power sector needs, the LCOH remains comparable to the base case, increasing by no more than 2% in 2040. However, power sector demand significantly increases reliance on imports, which supply around 80% of winter peak demand in 2040 (see Figure 10). Future supply security may pose a risk because potential hydrogen-exporting regions in New York State could experience similar seasonal demand patterns.

Figure 9. Case 2: Limited Renewables with Power Demand Results



Seasonal storage solutions mitigate risks associated with winter peaking behavior. Salt caverns are critical in balancing multiday supply-demand fluctuations, with peak construction occurring in 2040 (see Figure 14) when the power sector's relative winter peak demand is highest (see Figure 10). Tank storage provides short-term supply stability, while on-demand hydrogen imports remain essential for addressing winter shortages.

Figure 10. Case 2: Imports Versus Demand Profile



The availability and pricing of imports during periods of low solar output pose a key system risk. To ensure resilience, stakeholders must invest in additional seasonal storage infrastructure and coordinate a carefully managed supply chain.

3.3.3 Case 3: Accelerated Renewables, Offshore Wind

3.3.3.1 Offshore Wind Description

This case evaluates the potential benefits of lifting constraints on offshore wind (OSW) to expand renewable energy availability. OSW offers several advantages, including a higher capacity factor than solar or land-based wind, which reduces seasonal variability, enhances electrolyzer utilization, and lowers hydrogen production costs. However, this case examines whether these advantages outweigh the high capital expenditures (CAPEX) required for OSW infrastructure, co-located floating platform electrolyzers, and offshore hydrogen transport pipelines.

3.3.3.2 Offshore Wind Results

In practice, this case produces results similar to the base case because the model did not deploy any OSW. This outcome suggests that the high CAPEX for OSW infrastructure and offshore hydrogen production systems outweighs potential benefits, such as reduced seasonal variability and higher electrolyzer utilization. This analysis relies on the most recent CAPEX estimates for OSW in New York State from the published 2024 supply curve. Since CAPEX serves as a key decision metric, cost reductions in OSW infrastructure could shift this dynamic. At the modeled price points, achieving hydrogen production coupled with OSW requires further research and development to lower offshore hydrogen infrastructure costs. Alternatively, if sufficient OSW energy can be brought onshore through careful transmission planning with excess capacity available, hydrogen production could leverage this high-capacity factor resource while potentially reducing OSW power curtailment.

3.3.4 Case 4: Accelerated Clean Energy, Nuclear

3.3.4.1 Nuclear Description

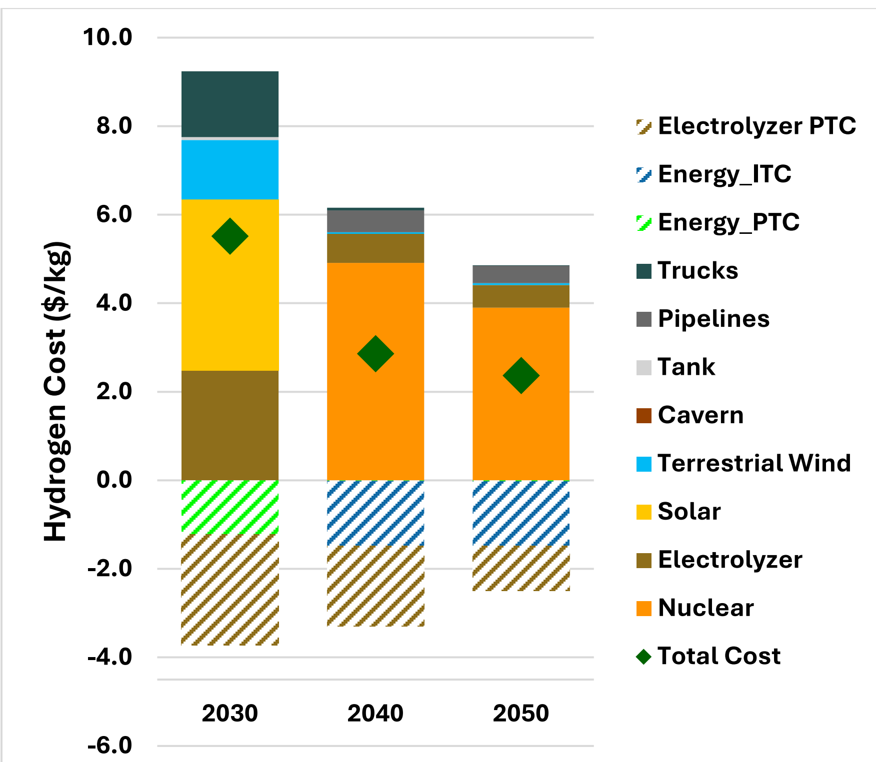
This case integrates hydrogen production with new advanced small modular reactor (SMR) construction from 2040 onward. Nuclear cost inputs are derived from Idaho National Laboratory’s analysis, adjusted for New York State construction costs. CAPEX is projected to decrease from $8,700/kW in 2040 to $6,600/kW by 2050, placing the LCOE from nuclear technology between $94 per megawatt hour (/MWh) and $66/MWh over that period.

When successfully integrated, dedicated nuclear power provides stable and continuous electricity, enabling higher electrolyzer use and lower hydrogen production costs. This minimizes the need to overbuild renewable generation resources. In modeling this case, hydrogen production from nuclear uses SOEC technology, assuming that nuclear power supplies the necessary heat for SOEC operation.

3.3.4.2 Nuclear Results

Including nuclear energy reduces the LCOH by more than 40% in 2040 compared to the base case. These cost reductions stem from the high utilization of SOECs due to nuclear's high-capacity factor (93%). Additionally, nuclear reduces total generation resource needs, renewable and nuclear capacity, by 5.9GW compared to the base case in 2040. The model still deploys a small amount of land-based wind after nuclear becomes available, suggesting that solar-based hydrogen is less economically viable than nuclear hydrogen, but land-based wind hydrogen remains cost-competitive. Seasonal storage requirements remain minimal because nuclear mitigates the variability challenges of a primarily solar-based hydrogen system.

Figure 11. Case 4: Nuclear Case Results



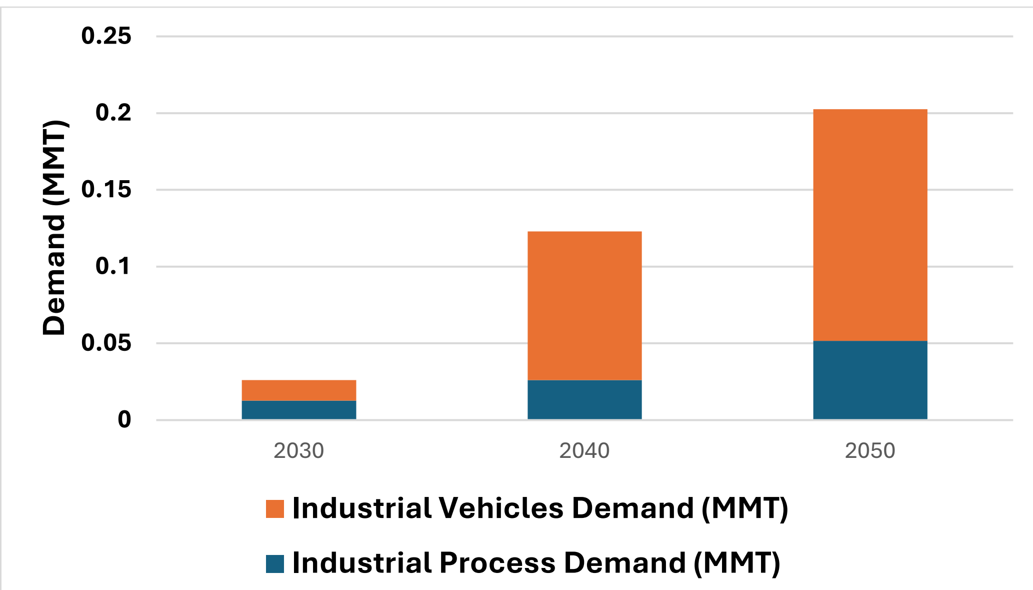
This case demonstrates nuclear energy's economic advantages for hydrogen production, offering a viable pathway to a cost-effective, stable hydrogen supply. However, the uncertainty associated with new nuclear projects, particularly cost and permits, remains a key consideration.

3.3.5 Case 5: Industrial Driven Demand

3.3.5.1 Industrial Driven Demand Description

This case evaluates hydrogen deployment for industrial processes and industrial vehicles while restricting pipeline infrastructure build-out, unlike other cases that optimize transport between truck and pipeline. In this case (shown in Figure 12), demand will reach approximately 23% of the base case level in 2050, representing likely demand with minimal alternative decarbonization solutions. The results offer insights into the effects of lower demand and the implications of a case without pipeline infrastructure development.

Figure 12. Case 5: Industrial Demand Inputs



3.3.5.2 Industrial Driven Results

In 2030, the industrial-only demand case results in an LCOH 15% lower than the base case. Lower total demand—0.026 million metric tons (MMT) compared to 0.062 MMT in the base case—allows a higher proportion of in-state hydrogen production from lower-cost land-based wind resources. Specifically, 66% of the hydrogen supply in this case originates from land-based wind, compared to a more diversified solar and wind mix in the base case. As a result, production costs are $6.70/kg in this case, compared to

$7.69/kg in the base case. Transportation costs remain comparable in 2030 because both cases rely solely on truck transport. Pipeline construction remains restricted in this case, and was not selected in the base case because it was not economic at this demand level.

By 2040 and 2050, LCOH in the base case becomes 11% and 13% lower, respectively, than in the industrial-only case. As demand increases to 0.20 MMT in 2050 in the industrial-only case, the percentage of hydrogen from land-based wind decreases due to availability limits, shifting the system toward higher-cost solar-based hydrogen production. In 2050, production costs reach $5.60/kg in the industrial-only case, comparable to $5.90/kg in the base case. However, transport costs differ significantly:

- As demand grows in the base case, pipeline infrastructure develops, achieving economies of scale and lowering levelized transport costs to $0.50/kg in 2050.
- In the industrial-only case, transport remains truck-based because pipeline construction is not permitted even if it would be more economical. As a result, levelized transport costs will reach $1.50/kg in 2050 and remain relatively unchanged across all three modeled years since all rely exclusively on truck transport

The analysis provides two key insights for hydrogen infrastructure development:

- Smaller hydrogen demand could benefit from better production economics:
    - Lower total hydrogen demand enables greater reliance on low-cost resources such as land-based wind.
    - Since the projected demand for industrial processes alone remains low (0.052 MMT in 2050, which is even lower than the 2030 base case demand of 0.062 MMT), targeted hydrogen deployment in this sector could mirror the economic trends observed in 2030.
- Truck transport remains the more cost-effective option for smaller demand:
    - In the base case, where the model can optimize transport modes, the pipeline is not built for demand levels at or below 0.062 MMT (2030 results).
    - If hydrogen demand remains limited to industrial processes without industrial vehicles (0.052 MMT in 2050, shown in Figure 12), truck transport will likely remain the most cost-effective option.
    - If both industrial process and vehicle demand materialize, pipeline infrastructure will be necessary to optimize hydrogen transport and improve overall economic viability (see Table 13).

Figure 13. Case 5: Industrial Driven Demand without Pipeline Results

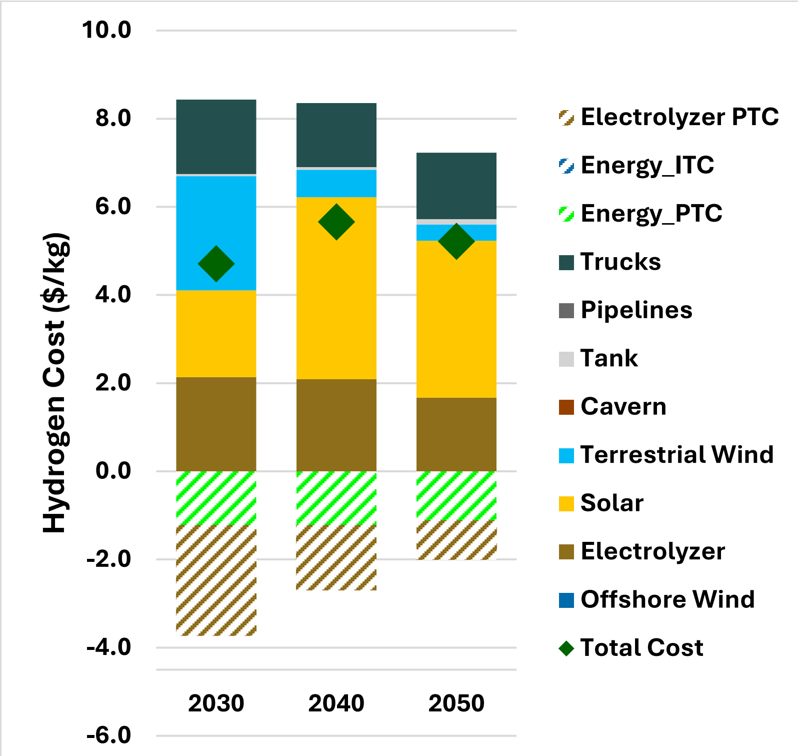


Table 13. Case 5 Comparison Results: Optimized Transport Versus Truck-Only Case

Year	LCOH with Optimized Transport Modes	LCOH with Truck Transport Only	Optimized Transport Benefit	Note
2030	$4.7/kg	$4.7/kg	0%	Demand below pipeline threshold
2040	$5.3/kg	$5.7/kg	7.5%	Model chooses to build out some pipeline, which lowers transport cost
2050	$4.9/kg	$5.2/kg	6.7%	

3.3.6 Case 6: Accelerated Technology, Low-Cost Electrolyzer

3.3.6.1 Low-Cost Electrolyzer Description

This case explores the potential impact of accelerating cost reductions in PEM electrolyzers. The modeling demonstrates how lower costs could significantly reduce hydrogen production expenses, making hydrogen a more competitive decarbonization solution across sectors.

3.3.6.2 Low-Cost Electrolyzer Results

A 54% reduction in electrolyzer costs leads to an LCOH of $3.82/kg, 24% lower than the base case in 2040. These savings accompany a 4% reduction in total renewable build requirements. The results highlight the importance of R&D in achieving cost reductions and positioning hydrogen as a major contributor in decarbonizing high-demand sectors.

Table 14. Comparison of Conservative Versus Optimistic Electrolyzer Cost Trajectory Result

Metric	Model	2030	2040	2050
Electrolyzer cost ($/kW)	Conservative	926	736	575
	Optimistic	665	338	218
LCOH ($/kg)	Conservative	5.51	5.03	4.55
	Optimistic	4.62	3.82	3.46

3.4 Opportunities for Cost Mitigation in Hydrogen Production and Delivery

Analyzing hydrogen deployment cases in New York State identifies key opportunities to mitigate costs and optimize hydrogen systems for scalability and efficiency. These opportunities involve renewable energy integration, infrastructure development, and advancements in electrolyzer technology, all essential for achieving cost-effective hydrogen production and delivery.

3.4.1 Strategic Planning for Resource Allocation and Hydrogen Generation

The cost of renewable energy to power electrolysis accounts for more than half of the hydrogen cost. To address this challenge, deploying low-cost renewable resources must be a priority. Since land-based wind capacity is expected to be limited and capital expenditures for OSW are projected to be high, based on recent supply curve data, solar power becomes the next viable and scalable resource for hydrogen production among the renewable resources considered in this analysis.

If SMR nuclear power becomes available, it could provide the cheapest clean hydrogen, based on the modeled cost inputs (levelized cost of electricity ~$94/MWh and a capacity factor of 93% in 2040) among the generation options considered. With a high-capacity factor and stable output, dedicated nuclear energy can provide consistent electricity for hydrogen production, reducing the need for seasonal storage. Integrating nuclear-based hydrogen systems could result in a 40% reduction in the LCOH, as demonstrated in the nuclear case.

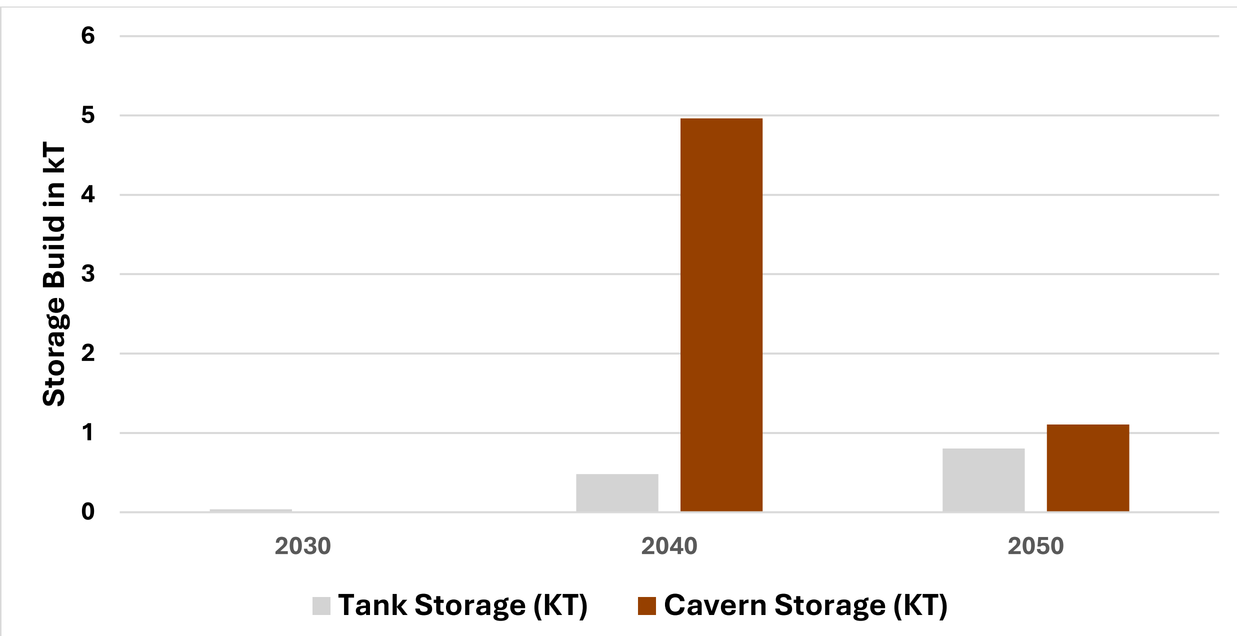
3.4.2 Developing Pipeline Transport Infrastructure

Infrastructure decisions are key in reducing costs and managing hydrogen supply-demand variability. While trucking may be sufficient for early-stage or low-demand hydrogen deployments, pipeline infrastructure is essential for scalability. Transitioning from truck-based delivery to pipelines can reduce transportation costs by up to 64% and support efficient hydrogen distribution as demand grows.

3.4.3 Managing Temporal Mismatches in Hydrogen Supply and Demand

On-demand hydrogen imports play a critical role in managing seasonal supply variations, particularly during winter when solar availability is low. However, this assumption that imports can be accessed on demand is a significant risk as it relates to availability and pricing.

Figure 14. Case 2: Storage Build Capacity Results



Seasonal storage solutions are critical to managing this risk, particularly for the scenarios involving power sector demand. Tank storage only remains a viable solution for short-term (few hours) supply management–for example to act as a buffer on site for end-users. Salt caverns, where available provide a cost-effective option for balancing multiday supply-demand fluctuations during winter. In the model, an assumed total of 8 kT of existing salt cavern capacity is considered available for hydrogen storage. In scenario 2, the model optimizes to build out only 5 kT, and of that, the maximum daily discharge observed is ~ 1 kT–a volume that is used to manage intra-day supply fluctuations only. This level of storage is therefore only sufficient to provide stop-gap supply for one to two days.

In effect, the modeled level of storage is adequate only because the system can rely on assumed on-demand imported hydrogen to fill shortfalls. This dynamic is seen in the 2040 modeling year in scenario 2, where imports supply approximately 81% of hydrogen demand in January – a month in which total demand is ~ 119 kT. This high dependance on imports highlights the importances of expanding the in-state, long-duration hydrogen storage options. To support the modeled level of demand, expanding geologic storage options, including evaluating new salt cavern sites and depleted oil and gas reservoirs, might be required.

Overall, an integrated strategy of focusing on in-state supply options, optimizing storage infrastructure, reducing peaks in demand will be necessary.

3.4.4 Accelerating Electrolyzer Cost Reductions

Electrolyzer capital costs account for approximately 30% of the LCOH in most cases. Accelerating cost reductions in electrolyzer technologies, particularly PEM electrolyzers, is a viable pathway to lowering hydrogen production costs. A 54% reduction in electrolyzer costs, as modeled in the low-cost electrolyzer case, could reduce the LCOH by 24% by 2040 and decrease total renewable build requirements by 4%.

Achieving these cost reductions will require prioritizing R&D to enhance manufacturing scalability through novel approaches, such as reducing precious metal loadings, which can help lower costs and drive economies of scale. Advancements in electrolyzer commercialization will position hydrogen as a more competitive alternative to fossil fuels across sectors.

4 Deployment Pathways

4.1 Introduction

Building on the modeling presented in section 3, which focuses on the economics of hydrogen infrastructure, the following section explores sector-specific strategies for deployment. Using the Total Cost of Ownership (TCO) Model, Energy and Environmental Economics, Inc., (E3) developed as the primary analytical tool, the study identifies the following insights:

- Scaling low-cost production technologies, improving delivery efficiency, and optimizing integration methods are essential for deploying hydrogen in hard-to-electrify sectors.
- High capital and maintenance costs for refueling stations and their utilization rates affect hydrogen's viability as a transportation fuel.
- Pilot and demonstration projects for promising technologies are critical investments to de-risk early adoption.

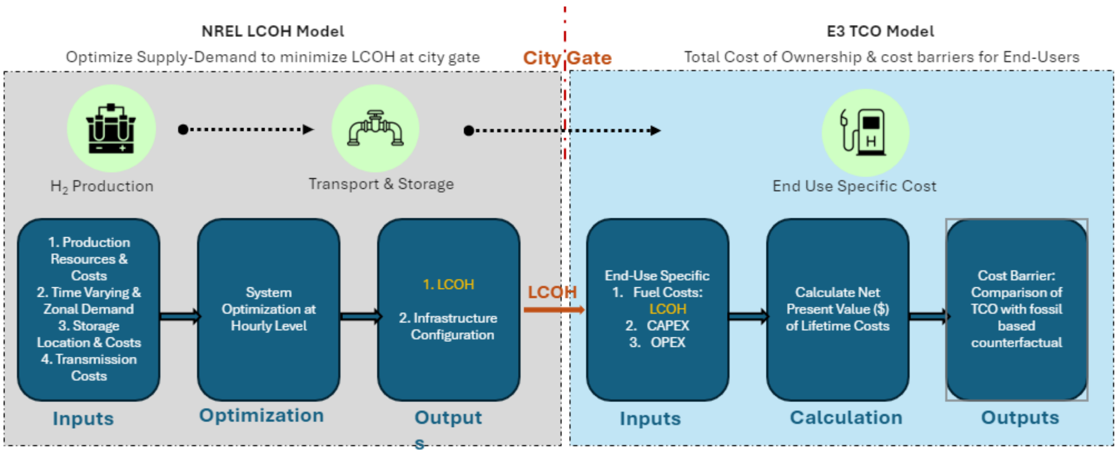
This section begins by outlining the methodology, inputs, and outputs of the E3 TCO Model. It then summarizes cost barriers and sector-specific challenges facing hydrogen adoption in LDVs, MDVs, HDVs, high-temperature industries, and district heat sectors. The section concludes with actionable recommendations to address these challenges and scale deployment in New York State.

4.2 Framework for Analysis: Energy and Environmental Economics, Inc.'s Total Cost of Ownership Model

The E3 TCO Model provides a comprehensive framework for assessing incremental costs and identifying key barriers to hydrogen adoption. It incorporates capital expenditures, operational costs, and policy incentives to calculate the TCO for end users, including industries and transportation systems. The analysis highlights the policy intervention and R&D required to make hydrogen cost-competitive in specific applications by comparing the projected TCO for hydrogen adoptions with that of traditional fossil-fuel-based counterparts.

The E3 TCO Model uses the LCOH at the city gate from the HYPSTAT model as the hydrogen fuel (explained in section 3). For all sectors except the high-temperature industry, the analysis uses LCOH values from the base case, which reflects a more conservative estimate. The analysis uses LCOH from case 3 (section 3.3.5, industrial only) for the high-temperature industry sector. In both cases, hydrogen fuel costs are interpolated linearly between 2030 and 2040 and held constant thereafter. While HYPSTAT optimizes production, storage, and transmission costs, the E3 TCO Model extends this analysis by examining ownership costs and sector-specific challenges at the end-user level. The analysis does not include the cost of transporting hydrogen from the city gate to specific end users, which could be an important cost consideration.

Figure 15. Total Cost of Ownership Analysis Model Framework



By inputting capital and operating expenditures to discover the lifetime costs associated with hydrogen implementation, the E3 TCO Model complements HYPSTAT in providing a cost comparison to fossil-fuel-based alternatives. Together, these models offer a comprehensive view of hydrogen's economic viability, from production to deployment in priority-use cases. Appendix C has additional information and details on the methodology for the model.

4.3 Model Results

The following results provide detailed insights into the cost drivers stifling hydrogen implementation and policies that help accelerate adoption.

4.3.1 On-Road Transportation Total Cost of Ownership

Hydrogen FCEVs are classified primarily by size, including LDVs, MDVs, and HDVs. While each vehicle class is unique, the challenges of increasing FCEV adoption are similar.

Across all vehicle types, refueling station costs are included in the operating cost in Figure 16 for hydrogen and counterfactual fuels, which vehicle users share. The refueling station costs include the capital cost of new hydrogen refueling stations and the operation and maintenance (O&M) costs of refueling stations for both hydrogen and counterfactual fuels. Utilization rates for refueling stations were assumed based on Chevron Corporation's demand profile for internal combustion engine (ICE) vehicles, varying over time to reflect evolving infrastructure use across conservative and advanced deployment cases. Appendix C has additional modeling details.

Under the IRA, LDVs receive a $7,500 investment tax credit (ITC),[31] significantly reducing the initial purchase cost of hydrogen vehicles and offsetting some of the higher upfront expenses. To evaluate the competitiveness of hydrogen LDVs against gasoline-powered alternatives, the analysis assumes equivalent annual mileage for both vehicle types.

MDVs and HDVs in New York State benefit from the Truck Voucher Incentive Program, which reduces the upfront cost of medium- and heavy-duty ZEVs, including BEV and FCEV options. Under this program, fleet operators are eligible for vouchers of up to $100,000 per MDV[32] and $185,000 per HDV, depending on the vehicle class. This analysis assumes that such incentives will remain available, and drivers will benefit from these subsidies in 2030.[33] To assess the competitiveness of MDVs and HDVs against their diesel alternatives, this analysis evaluates the lifetime ownership costs of hydrogen FCEVs, with detailed assumptions outlined in Appendix C.

4.3.1.1 Hydrogen Fuel Cell Electric Vehicles Results

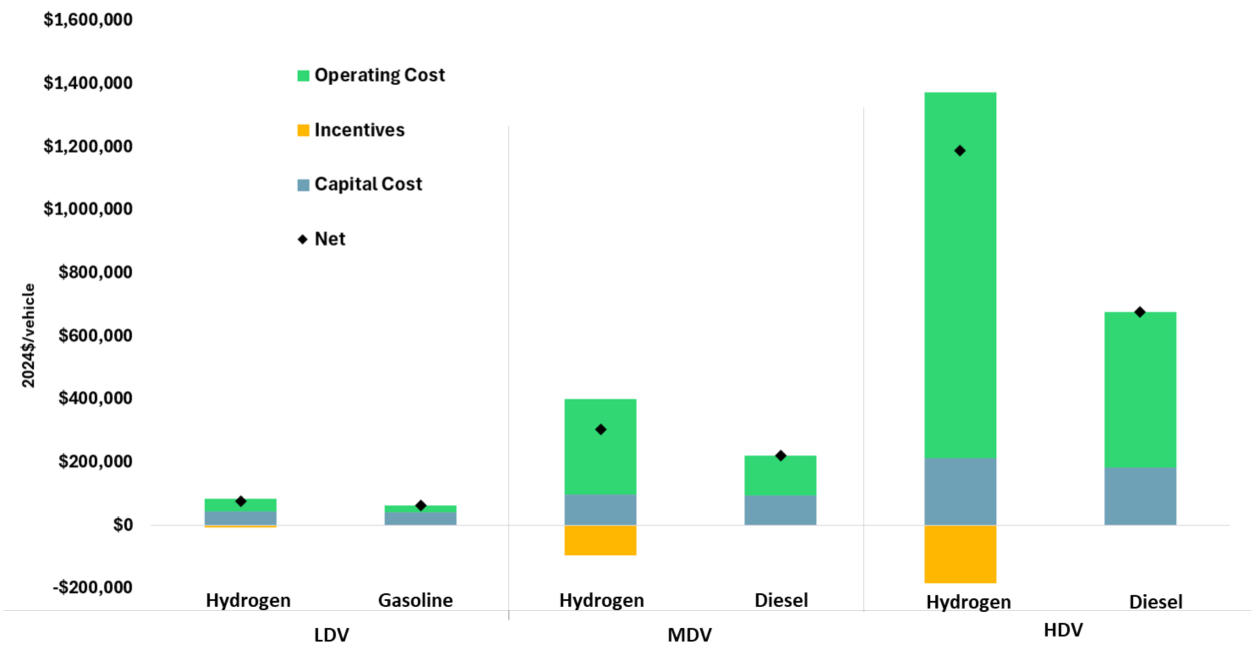
Operating costs are the dominant factor influencing the TCO for hydrogen FCEVs.[34] Hydrogen production and delivery expenses and refueling stations' capital and operational costs primarily drive these costs. The cost of delivered hydrogen fuel currently represents the most significant barrier to achieving cost parity with fossil-fuel-based internal combustion vehicles. While federal and State legislation helps address the higher upfront costs of hydrogen vehicles, infrastructure investments, and improved station utilization are necessary to close the gap.

For both MDV and HDV ownership, the absence of New York State's Truck Voucher Incentive Program would significantly increase the upfront cost of FCEVs, further raising their overall TCO.

The utilization rate of refueling stations also impacts costs. Hydrogen LDV drivers absorb some of these infrastructure costs through a premium charged at the pump.[35] Stations with lower utilization rates distribute fixed costs across fewer users, raising the per-unit cost of hydrogen fuel. While reducing hydrogen production costs remains essential, improving station efficiency and scaling infrastructure are critical levers for reducing costs.

Accelerating the adoption of hydrogen-powered vehicles in New York State and narrowing the TCO gap, will require sustained rebate programs, investment in refueling infrastructure, and efforts to increase vehicle utilization across all FCEV classes.

Figure 16. On-Road Transportation Results



4.3.2 High-Temperature Industry Total Cost of Ownership

4.3.2.1 High-Temperature Industry Description

The transition to hydrogen for industrial end uses faces significant cost and adoption barriers. Industrial facilities are capital-intensive, and owners may hesitate to invest in hydrogen-compatible technologies, which are still in the demonstration phase and carry elevated financial and operational risks. Additionally, the long lifetimes of industrial equipment and the high costs associated with hydrogen technology may slow equipment turnover, delaying a widespread transition in the industrial sector.

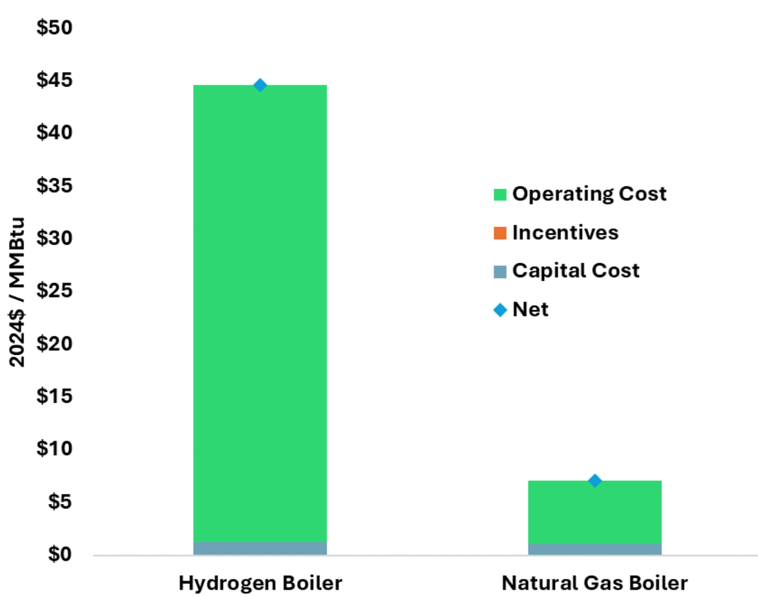
Lifetime costs for industrial facilities include hydrogen production and delivery (representing fuel costs), upfront capital investments, and O&M. This analysis models a representative high-temperature industrial boiler to evaluate potential transition costs under assumed hydrogen fuel prices.

In the model, O&M costs for hydrogen and natural gas heaters are assumed to be similar, although system integration challenges could lead to additional costs. As a result, differences in operating expenses are primarily driven by the assumed fuel price disparities. The capital cost for the hydrogen heater reflects the "high" CAPEX sensitivity case detailed in Appendix C. While these incremental capital costs are not substantial, their risk lies more in the lack of commercial deployment and operational uncertainty than in the magnitude of cost itself.

4.3.2.2 High-Temperature Industry Results

Similar to transportation, fuel costs emerge as the dominant factor in the TCO for industrial facilities transitioning to hydrogen. Under assumptions of a high load factor typical for high-temperature industrial operations,[36] lifetime fuel costs significantly exceed those for natural gas. Incremental capital costs for hydrogen-compatible equipment remain a barrier, although relatively small compared to fuel costs, particularly given the lack of widespread demonstrations of replacing natural gas with hydrogen in boilers or heaters.

Figure 17. High-Temperature Industry Versus Existing Fossil Fuel Technologies Total Cost of Ownership



In addition to these results, the incremental costs of a dedicated pipeline need to be considered. These costs will depend on the need for storage and the distance between the plant and the nearest pipeline or storage facility. These infrastructure considerations further represent hydrogen adoption's financial and logistical challenges in industrial applications.

While hydrogen presents a viable pathway for decarbonizing high-temperature industrial processes, achieving cost-competitive adoption requires reducing fuel costs, demonstrating the reliability of hydrogen-compatible technologies, and addressing infrastructure challenges.

4.3.3 District Heat Total Cost of Ownership

4.3.3.1 District Heat Description

The feasibility of converting New York City's district steam system to hydrogen has not yet been demonstrated, and no examples currently exist of hydrogen being tested at scale as the primary fuel source for a district steam system. In its *Long Range Steam Plan 2022–2031*, Con Ed identifies hydrogen conversion as a potential opportunity, but emphasizes the need for continued research to evaluate the associated costs, technical challenges, and feasibility of this approach.[37]

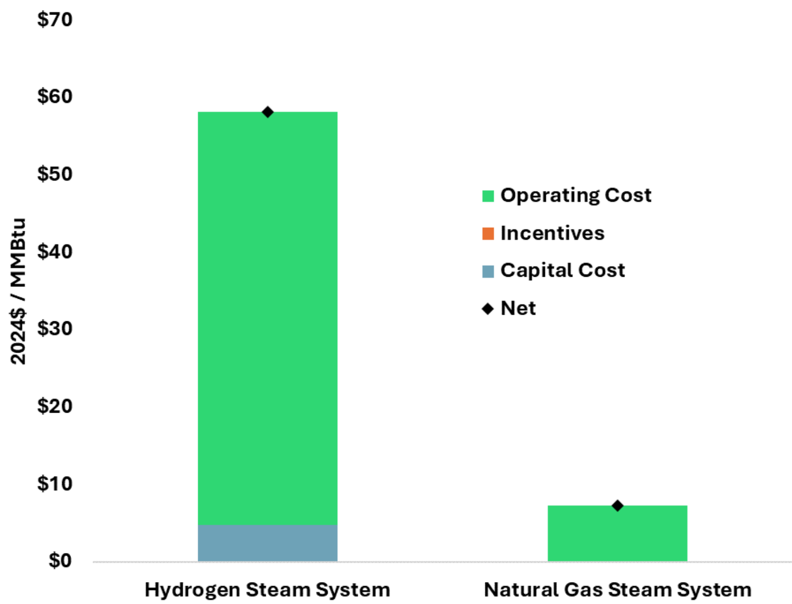
Using publicly available information and high-level assumptions, this analysis models the lifetime costs of converting one of Con Ed's existing steam boilers to hydrogen. Key cost components include the production and delivery of hydrogen (representing fuel costs) and the capital costs associated with converting a boiler to hydrogen.[38] The analysis focuses exclusively on converting an existing steam boiler and does not account for additional costs associated with broader cogeneration system upgrades. This analysis, therefore, represents a lower bound on the overall cost of hydrogen use in district steam systems. The scope of this analysis is limited to understanding the cost of producing steam. In reality, disaggregating the steam and electricity system would not be so straightforward.

4.3.3.2 District Heat Results

Although capital costs for converting an individual boiler are relatively modest in this analysis, they represent only a fraction of the total infrastructure investment required for a full-scale hydrogen transition. The cost disparity between hydrogen and natural gas highlights the importance of continued R&D to improve hydrogen production efficiency and reduce fuel costs. Additionally, the potential costs of pipeline infrastructure and systemwide upgrades must be carefully evaluated to determine the feasibility of this pathway.

Con Ed's exploration of hydrogen conversion represents an important step toward understanding the role hydrogen could play in decarbonizing urban heat systems. However, achieving cost parity with natural gas requires coordinated investment in hydrogen technology, infrastructure, and supportive policies to address the economic and technical barriers identified in this study.

Figure 18. District Heat Versus Existing Fossil Fuel Technologies Total Cost of Ownership



4.4 Opportunities for Cost Mitigation: Deployment

The analysis identifies several cost barriers that must be addressed to establish an economically viable hydrogen network in New York State. These barriers span production, infrastructure, and end-use applications, impacting across sectors to varying degrees. Strategic interventions can overcome these challenges and unlock hydrogen's potential as a critical decarbonization tool.

4.4.1 Hydrogen Production and Delivery Infrastructure

High production and delivery costs pose foundational challenges across all hydrogen applications. Although federal measures such as the IRA provide short-term relief through tax credits, producing and distributing hydrogen remains expensive. In the base case LCOH used in this analysis, the projected

2030 hydrogen cost of $5.51/kg exceeds the projected natural gas fuel costs by approximately seven to eight times (on a per-unit-of-energy-delivered basis). Since this TCO analysis focuses on using 100% green hydrogen, transitional strategies such as hydrogen blending with natural gas (where technically feasible) may help reduce near-term costs—especially for industrial end-use sectors and district heating.

Investing in scalable, low-cost hydrogen production technologies, optimizing renewable energy integration, and enhancing delivery efficiency are essential. Results from other cases in section 3 show that accelerating R&D in electrolyzer technologies and accessing high-capacity-factor resources such as nuclear can lower production costs by up to 40%, significantly improving hydrogen's cost competitiveness. Reducing these costs is pivotal to enabling hydrogen's competitiveness across multiple hard-to-electrify sectors.

4.4.2 Refueling Station Development

Building a robust hydrogen refueling network presents a substantial barrier to transportation use cases for LDVs, MDVs, and HDVs. Low utilization rates during early adoption phases exacerbate these costs, increasing the per-unit cost of hydrogen fuel. Overcoming this challenge requires a combination of State and federal funding, incentives for early infrastructure deployment, and coordinated efforts to drive station utilization through fleet adoption and strategic station placement.

4.4.3 Demonstration-Phase Applications

Hydrogen applications in high-temperature industrial processes and district heating face unique cost challenges. These include the additional CAPEX for early-stage technology deployment and infrastructure retrofitting. For example, converting industrial heaters or district steam boilers to hydrogen requires significant investment in hydrogen-compatible equipment, pipelines, or storage. Addressing these barriers necessitates targeted R&D investments, pilot projects to demonstrate technical and economic feasibility, and policies to de-risk early adoption.

5 Innovation Focus Areas

Achieving New York State's decarbonization goals requires technological advancements across the hydrogen value chain, from production to end-use applications. While federal and State policies have driven early hydrogen deployment, continued innovation is essential to reducing costs, improving efficiency, and ensuring hydrogen's long-term viability as a decarbonization tool.

This section highlights key R&D areas that can drive progress, address technical barriers, and unlock hydrogen's full potential in decarbonizing New York State's energy system. Appendix D has a library of sources with additional information regarding the referenced examples.

5.1 Hydrogen Production

Most industrial hydrogen today comes from steam methane reforming, which reacts methane with steam to produce hydrogen alongside carbon dioxide (CO_2) and monoxide. The steam methane reforming process emits approximately 9 kg of CO_2 per 1 kg of hydrogen,[39] making it inconsistent with New York State's decarbonization goals unless paired with carbon capture and storage (CCS). Despite its emissions, SMR remains a cost-effective method, with prices ranging between $0.9/kg and 1.2/kg (unabated) and $1.6/kg–$2/kg (low-carbon reformation) compared to $5/kg–$7/kg for green hydrogen electrolysis in 2024 (excluding tax credits).[40] Given these cost differences, this section focuses on the innovation needed to accelerate green hydrogen production technologies.

New York State's "Scoping Plan" prioritizes green hydrogen, produced through electrolysis, which splits water into hydrogen and oxygen using electricity. This process qualifies as "green" when powered by renewable energy. Several electrolysis technologies exist, each with distinct advantages and challenges. Although deployment is accelerating, widespread adoption requires rigorous innovation to optimize performance and integration with intermittent energy source and efficient low-carbon-electricity-to-hydrogen systems.

5.1.1 Electrolysis Technology

5.1.1.1 Current State of the Art

Hydrogen electrolysis is expanding rapidly on a global scale. In 2024, planned electrolyzer capacity totaled 4.5 GW.[41] New York State is emerging as a key player, with about 200 MW of PEM electrolyzer capacity either planned, installed, or under construction.[42]

Federal incentives, such as tax credits and the U.S. Department of Energy's (DOE) Regional Hydrogen Hubs program, have helped scale deployment, but further innovation is needed to improve efficiency and durability across all electrolyzer types:

- **AEL: Reliable yet Inflexible**
  As the most mature and cost-effective option, AEL avoids needing precious metals and fluorine-based materials, making it relatively inexpensive. However, its high minimum energy load and fixed operations require large power outputs to operate effectively, limiting its compatibility with variable renewable energy sources like solar and wind.[43]
- **PEM Electrolysis: Flexible but Expensive**
  PEM electrolyzers offer rapid response times, low minimum load, and strong load-following capabilities, making them ideal for intermittent renewable energy.[44] However, their reliance on noble metals like platinum makes them expensive. To compete with SMR, PEM systems must reduce costs by 80%.[45]
- **SOEC: High Efficiency and High Heat**
  SOEC technology operates above 600°C[46] for electrolysis, leveraging high-temperature heat. This approach improves efficiency by reducing voltages and increasing current densities, enabling more efficient electricity use.[47] Pairing SOECs with advanced nuclear reactors, industrial processes, or geothermal systems could transform hydrogen production. Since SOECs use abundant materials, they present a promising alternative, although scaling and cost remain challenging.

5.1.1.2 Technical Challenges

Electrolyzers paired with renewable energy must handle frequent power fluctuations due to intermittency and variable energy demand. For PEM electrolyzers, this means managing membrane degradation, electrode corrosion, and catalyst deactivation under dynamic operating conditions. Engineers must design systems that balance durability with cost efficiency, especially those using high catalyst loadings, which improve longevity but increase production costs.

Researchers are also working to enhance AEL and SOEC systems, making them more resilient and adaptable to fluctuating power inputs. Advanced hydrogen production concepts are being explored in labs worldwide, but significant technical challenges remain:

- **Photoelectrochemical (PEC) Water Splitting**
  PEC systems combine photovoltaic and electrolysis processes into one unit, potentially enabling low-cost, clean solar hydrogen production. These systems use semiconductor materials submerged in a water-based electrolyte solution, where charge carriers split water molecules and store chemical energy as hydrogen.[48] As a lab-scale technology, PEC reactors have various proposed architectures, but if successfully developed, they could streamline hydrogen production while harnessing solar energy.

- **Microbial Hydrogen Production**
  Harnessing microorganisms to break down organic matter, such as refined sugars, corn stover, and even wastewater, to produce hydrogen opens new research opportunities.[49] Enhanced by light (photobiological) or electrical currents (microbial electrolysis), this process could create waste-to-energy solutions. Researchers continue to explore the most effective microbes and the system design.
- **Thermochemical Water Splitting**
  Using high temperatures (500°C–2,000°C) from concentrated solar energy or nuclear reactors, thermochemical reactions split water into hydrogen and oxygen. All chemicals are recycled except water, creating a closed-loop process with no waste. Researchers have investigated more than 300 thermochemical water-splitting cycles[50] and are now focused on developing and scaling the technology for commercial readiness.

5.1.1.3 Key Innovation Opportunities for New York State

To accelerate electrolyzer research and adoption, New York State must prioritize targeted research, development, and demonstration (RD&D) initiatives, including:

- **Electrolyzer Optimization:**
  - Reduce catalyst and membrane costs for PEM electrolyzers
  - Scale up high-throughput manufacturing to reduce costs for PEM electrolyzers
  - Develop ion-exchange membranes with high capacity and stability for advanced liquid alkaline or AEL electrolysis
  - Improve SOEC durability and cost-effectiveness through novel materials and industrial heat integration
  - Demonstrate SOEC performance using low-grade steam from nuclear reactors
  - Advance research to improve efficiency, cost, and durability across all electrolyzer types
- **Opportunities in Advanced Pathways:**
  - Reduce material costs, enhance conversion efficiencies, and extend cell lifetimes while advancing reactor design concepts for PEC hydrogen production
  - Explore novel microbes and reaction pathways to boost hydrogen yield and efficiency while optimizing microbial pathways for photobiological hydrogen production
  - Develop novel thermochemical processes or materials to lower reactor costs and improve process efficiencies

5.1.2 Integrating Electrolysis into Energy Generation

5.1.2.1 Current State of the Art

Effectively producing low-carbon hydrogen at scale requires integrating electrolyzer technologies into existing and developing energy generation systems. Co-locating compatible generation forms with hydrogen production facilities optimizes resource use by converting excess renewable electricity into hydrogen. This co-location simplifies grid power electronics, avoiding unnecessary alternating current to direct current (AC-DC) conversion when pairing DC-electrolyzers with DC-generating sources.

In New York State, OSW and nuclear energy present prime opportunities for demonstration. The State's commitment to deploying 9 GW of OSW energy by 2035[51] creates options for both onshore and offshore electrolysis. Two hydrogen demonstrations are underway at the Nine Mile Point Nuclear Station (Oswego, NY). The first project will use 1 MW of electricity to produce 500 kg of hydrogen daily for water treatment and corrosion protection. The second project will produce, store, and use hydrogen on-site to power a 10 MW fuel cell for peak demand management.[52] If successful, these projects can build momentum for similar demonstrations nationwide.

5.1.2.2 Technical Challenges

New York State's planned deployment of OSW technologies provides a clear opportunity for hydrogen production integration. Electrolysis powered by OSW can follow two configurations: onshore production with electricity transmitted from offshore facilities or offshore production with hydrogen transported via pipelines or marine vessels. Each approach comes with unique technical and logistical considerations.[53]

- **Onshore Electrolysis:**
  OSW projects constrained by interconnection limits can benefit from onshore electrolysis. For example, if an 800 MW wind installation is restricted to a 400 MW interconnect, the surplus electricity can be redirected to produce hydrogen at the interconnection point, avoiding curtailment and optimizing resource use.
- **Offshore Electrolysis:**
  Integrating electrolyzers with OSW turbine systems presents challenges, including durability concerns such as corrosion and storm resilience, as well as logistical hurdles for maintenance in harsh marine environments. Furthermore, transporting hydrogen from offshore platforms, whether via undersea pipelines or specialized vessels, requires thorough evaluation and validation. Demonstration projects are essential for assessing performance and economic feasibility under real-world conditions.

While integrating electrolysis with OSW presents scaling challenges, it offers a scalable and competitive green hydrogen source powered by one of the State's fastest-growing renewable resources.

New York State's nuclear energy infrastructure, which includes three plants and four reactors, presents another hydrogen production opportunity. The blueprint for advanced nuclear energy technology, published in January 2025, offers additional energy resource for hydrogen production in the state. High-temperature electrolysis technologies, like SOECs, are particularly well-suited for pairing with nuclear power. SOECs use nuclear-generated electricity and waste heat to achieve higher efficiencies than low-temperature processes such as PEM electrolysis.

Nevertheless, deploying SOECs in these settings introduces challenges. High-temperature operation requires advanced materials capable of withstanding dynamic conditions without degradation. Furthermore, integrating electrolysis with nuclear reactors in a grid with significant variable renewable energy necessitates sophisticated control systems to balance power supply, ensure grid stability, and optimize the dual use of nuclear resources for electricity and hydrogen production.

5.1.2.3 Key Innovation Opportunities for New York State

To accelerate the research and adoption of electrolyzer-generation integration technology in New York State, the State must prioritize targeted RD&D initiatives, including:

- **Opportunities for OSW and Electrolysis:**
  - Demonstrate OSW-electrolysis systems to assess performance and optimize designs
  - Analyze onshore versus offshore electrolysis, considering cost, logistics, and transmission requirements
  - Explore transportation methods for offshore-produced hydrogen, including pipelines and marine vessels
- **Opportunities for Nuclear and Electrolysis Integration:**
  - Develop advanced control systems to coordinate nuclear power generation, electrolysis, and grid operations
  - Optimize nuclear energy use for balancing between grid power and hydrogen production

5.2 Delivery and Storage Infrastructure

To expand hydrogen's footprint in New York State's energy system, innovation in delivery and storage infrastructure is essential. The State must evaluate whether to repurpose existing natural gas infrastructure for hydrogen transmission through retrofits or new construction. For storage, geologic formations such as salt caverns and depleted oil and gas reservoirs offer promising, cost-effective solutions for bulk storage.

The primary challenge lies in bridging spatial gaps between production sites and demand centers while managing temporal mismatches between periods of low-cost production and peak consumption. The following section explores three key areas: hydrogen pipelines, underground hydrogen storage, and alternative and emerging storage technologies.

5.2.1 Hydrogen Pipelines

5.2.1.1 Current State of the Art

The first hydrogen pipelines were constructed in 1938, with a pioneering 130-mile installation in Germany. Today, a global network of 2,800 miles of hydrogen-specific pipelines exists, with more than half (1,600 miles) located in the U.S. Air Products and Chemicals, Inc., owns the largest segment, 600 miles stretching from Houston to New Orleans, primarily serving the Gulf Coast's oil refining industry.[54]

While established networks demonstrate the viability of hydrogen pipelines, New York State faces unique challenges and opportunities—the State's existing natural gas infrastructure and liquid fuel rights-of-way complicated implementation. However, global projects facing similar challenges have demonstrated innovative solutions, including gas-hydrogen infrastructure conversion and hydrogen blends that use existing gas networks. Despite hydrogen's unique properties, the State has three pipeline implementation options:

- Build new hydrogen-specific pipelines using state-of-the-art materials to extend durability and reduce leakage
- Convert existing natural gas lines to hydrogen-specific pipelines, a viable but limited option due to infrastructure constraints
- Use hydrogen/natural gas blends in existing infrastructure as a cost-effective yet short-term solution

5.2.1.2 Technical Challenges

Hydrogen pipelines face a significant challenge: embrittlement. Hydrogen molecules infiltrate metal pipeline materials, causing blistering, reduced strength, and accelerated deterioration, particularly in the high-strength steel used in natural gas transmission. Hydrogen's small molecular size increases leakage risks, raising safety and economic concerns.

Global estimates suggest fugitive hydrogen emissions account for 2.7% of production[55] and 2% of storage and delivery infrastructure. These losses could decrease purpose-built infrastructure designed to minimize leaks.

5.2.1.3 New Hydrogen Pipelines

Materials science for hydrogen pipelines is well-established, with options ranging from various steels to aluminum, copper, titanium, and innovative composites such as fiber-reinforced polymers (FRPs).[56] While hydrogen-specific pipelines cost 10% to 68% more than natural gas pipelines, they offer proven reliability.[57, 58] In New York State, these costs may be even higher because construction costs in nearby New England typically exceed the national average by 50%–150%.[59]

Composite FRP lines offer a potential 20%–25% cost savings compared to steel installations. These lines can be delivered in half-mile spools or manufactured on-site in 2- to 3-mile sections, reducing installation labor and minimizing leak points.[60] Using existing natural gas pipeline rights-of-way, typically 50 feet to 100 feet wide and often already hosting multiple lines, could streamline permitting for new installations.

5.2.1.4 Conversion of Existing Infrastructure

New York State's pipeline network includes more than 50,000 miles of infrastructure, with 4,500 miles of natural gas transmission lines and 1,100 miles of hazardous liquid lines.[61, 62] Converting existing pipelines to hydrogen transmission could reduce costs by 20%–60%,[63] with retrofits costing as little as 10%–15% of new construction.[64]

However, the average U.S. transmission line is 50 years old,[65] necessitating line-by-line evaluations of materials, coatings, defects, and operating conditions. Hydrogen's tendency to aggravate cracks and weld defects means seemingly minor imperfections could become significant vulnerabilities.

Blending hydrogen into existing natural gas systems presents a middle-ground approach. Global pilot projects show that up to 15%–20% hydrogen by volume can be accommodated without major modifications.[66] However, hydrogen's lower energy density (roughly one-third that of natural gas)[67] means a 15% hydrogen blend reduces emissions by only 5%. Achieving a 50% emissions reduction would require a 75% hydrogen blend, far beyond current infrastructure capabilities without major modifications.

5.2.1.5 Key Innovation Opportunities for New York State

To identify the best methods for hydrogen pipeline infrastructure in New York State, the State must prioritize targeted RD&D initiatives, including:

- **Opportunities in Pipeline Technology:**
    - Collect, characterize, and analyze data on the status and integrity of existing natural gas transmission pipelines in New York State, including their potential for conversion to hydrogen
    - Develop advanced detection and monitoring technologies to address leakage through the generation, delivery, and end-use processes, such as solid-state sensors and chemichromic tapes
    - Develop lifetime or long-term risk assessment methodologies and integrity monitoring programs for evaluating converted and new pipelines
    - Address pipeline materials' compatibility issues to enable high-blend to 100% hydrogen in pipelines.
    - Pilot the conversion of an existing natural gas line to either 100% or high-blend hydrogen
    - Pilot new hydrogen-specific compressor designs
    - Conduct transition analysis for both the natural gas and hydrogen systems to identify potential candidate pipelines and timelines for conversion to hydrogen
- **Opportunities in Leakage Protection:**
    - Demonstrate advanced detection and monitoring systems that can enable accurate leak detection.
    - Design new infrastructure systems tailored to hydrogen's unique properties, such as its small molecular size, to reduce leakage risks.
    - Integrate hydrogen emission monitoring into broader decarbonization frameworks to ensure alignment with climate objectives.

5.2.2 Underground Hydrogen Storage

5.2.2.1 Current State of the Art

Geologic underground storage represents the most cost-effective solution for high-volume bulk storage of fuel gases and liquids, including natural gas and various hydrocarbon liquids. In New York State, depleted oil and gas reservoirs across 26 sites[68] account for 99% of underground natural gas storage capacity. In contrast, a single salt cavern storage site holds the remaining capacity. Additionally, two solution-mined salt cavern sites and one conventionally mined shale site store hydrocarbon gas liquids, including liquefied petroleum gas (LPG) and propane.[69]

Salt caverns are the most promising candidate for seasonal hydrogen storage among these underground options. Their high impermeability, minimal risk of contamination or leakage, impressive delivery rates, and operational flexibility collectively come at a fraction of the cost of other pure hydrogen storage solutions. Currently, operational hydrogen storage facilities exist in three Texas salt caverns and one in Teeside, UK,[70] with additional projects underway, including the Advanced Clean Energy Storage (ACES) project in Utah.[71]

5.2.2.2 Technical Challenges

New York State's potentially usable salt deposits lie in Central and Western New York, far from the anticipated Downstate New York demand centers. More critically, these deposits consist of bedded salts, which differ structurally from the salt domes typically used for hydrogen storage. While salt domes can accommodate large, stable caverns, bedded salt deposits are shallower and thinner, often requiring multiple smaller caverns to achieve equivalent storage capacity. However, demonstrations such as the HyPSTER Project in France prove that bedded salt storage remains feasible despite its challenges.[72]

Table 15. Hydrogen Storage Technologies Comparison

Cushion gas requirements refer to the additional volume of gas needed beyond the working gas capacity to provide pressure support and maintain cavern/reservoir integrity.[73, 74, 75, 76]

Storage Type	Cycling Type	Cushion Gas Required	Withdrawal Period	Injection Period	Potential for Hydrogen	New Upfront Costs for Hydrogen
Salt caverns	Peak (6–12 cycles/yr)	0%–30%	10–20 days	20–40 days	Proven 4 existing sites, several pilots	~$35/kg capacity for new caverns
Tank storage	Either	Minimal	N/A	N/A	Proven	$800/kg–$1,200/kg capacity (may decrease to $600 with manufacturing scale-up)
Buried pipe	Either	Minimal	N/A	N/A	Feasible	$500–$600/kg capacity
Liquid hydrogen	Either	Minimal	N/A	N/A	Proven	As low as $150/kg capacity but requires liquefaction (cost of $2–$3/kg stored)
Lined-hard rock caverns	Peak	Minimal	Similar to salt	Similar to salt	Conceptual but likely feasible	$50/kg–$70/kg capacity
Depleted oil and gas reservoirs	Seasonal (1–2 cycles/ year)	50%	100–150 days	200–250 days	1 pilot but concerned for 100% purity	~$15–$20/kg, but conversion costs uncertain
Aquifers	Either	50%–80%	100–150 days (or faster)	200–250 days	Conceptual no known 100% H_2 pilots	Expected similar to depleted oil & gas reservoirs, but costs are uncertain

Existing salt cavern storage sites could convert to hydrogen storage, requiring new infrastructure, including wellheads, liners, and compressors. Alternatively, The State could repurpose vacant caverns from previous salt mining operations or construct new ones.

Given the limitations of salt cavern storage in New York State, depleted natural gas reservoirs could serve applications that do not require pure hydrogen. Converting even a portion of these reservoirs could significantly increase in-state storage capacity. However, hydrogen's properties necessitate a reassessment of storage parameters due to possible geochemical reactions. Additionally, the low permeability of natural gas reservoirs typically allows for only one injection/withdrawal cycle per year, providing minimal support for New York State's fluctuating demand patterns.

5.2.2.3 Key Innovation Opportunities for New York State

To maximize New York State's underground storage capabilities, the State must prioritize targeted RD&D initiatives, including:

- Conducting an in-state pilot for hydrogen salt cavern storage at an existing site, a vacant cavern, or a newly constructed cavern
- Piloting hydrogen storage in depleted oil and gas reservoirs, coupled with applicable end-use application

5.2.3 Alternate and Emerging Storage Technologies

5.2.3.1 Current State of the Art

Beyond the underground caverns of Central and Western New York, New York State needs hydrogen storage solutions near its population centers to meet growing demand. The geographic mismatch between demand centers and potential storage locations, particularly along the Atlantic seaboard with its expanding OSW infrastructure, drives the need for innovative solutions. The current landscape of alternatives falls into two broad categories: physical storage and materials-based storage.[77]

Physical storage solutions have been successfully implemented under real-world conditions. The National Aeronautics and Space Administration's (NASA's) construction of a 1.25-million-gallon liquid hydrogen storage facility demonstrates the feasibility of large-scale storage.[78] Other solutions, such as buried pressurized pipes, are deployment-ready, but challenges such as embrittlement remain.

Material-based storage solutions vary in technological readiness. Metal hydride solutions are in pilot phases, while chemical carrier projects are already in industrial-scale production. Japan, for example, recently demonstrated the ability to bond hydrogen chemically to toluene to create methylcyclohexane (MCH), later extracting the MCH back to usable hydrogen gas while recycling the toluene.[79] However, these fossil-fuel-based production methods may require reimagining in a carbon-constrained future.

While not featured, underwater storage of pure hydrogen represents a conceptual technology that would use ocean-depth pressure to compress and store hydrogen in seafloor vessels.[80] This approach could prove valuable for storing hydrogen produced by offshore wind facilities, though significant research and development remain before this concept becomes reality.

5.2.3.2 Technical Challenges

Despite its technological readiness, the high cost of physical storage remains a primary challenge. Aboveground solutions require tanks with thick walls capable of withstanding extreme pressures; however, this technology currently costs 10–20 times more than salt cavern storage.[81] Cryogenic liquid hydrogen introduces additional challenges—it must be cooled to -423 degrees Celsius (°C), which is 180°F colder than liquified natural gas—a process that consumes 30% of the stored hydrogen's energy, adds $2/kg–$3/kg to costs, and raises concerns about resilience during power outages.[82, 83] While buried pipes offer some cost savings, they remain significantly more expensive than geologic storage.

Although promising, materials-based storage solutions will require continuous R&D. Metal hydrides exemplify this need because they currently require high, challenging temperatures to release hydrogen, prompting ongoing efforts to improve their performance under more feasible conditions. Researchers have proposed and evaluated various options for chemical carriers, including ammonia, hydrogen peroxide, methanol, and toluene/MCH, for materials-based storage and transportation. Ammonia presents a particularly compelling case: stored at 10 bar and 25°C, it achieves an energy density surpassing both compressed and liquid hydrogen. However, its release and purification processes consume 15%–30% of the stored energy, driving research into more efficient catalysts and alternative fuel cell technologies.[84]

5.2.3.3 Key Innovation Opportunities for New York State

To identify the most effective hydrogen storage infrastructure methods for New York State, the State must prioritize targeted RD&D initiatives, including:

- **Physical Storage Opportunities:**
  - Develop lower-cost, higher-strength tank storage materials, such as carbon-fiber composites
  - Develop strategies and technologies to mitigate boil-off from liquid hydrogen storage media
  - Develop novel ammonia cracking catalysts or reactor designs that reduce the energy required for cracking
  - Improve the efficiency and lower the cost of hydrogen liquefaction
  - Evaluate the safety, cost, and geographic footprint of alternative storage technologies for use in urban demand centers

- **Materials-Based Storage Opportunities:**
    - Explore ammonia/alkaline fuel cells or combustion technologies that can tolerate larger amounts of ammonia in the fuel stream to reduce the amount of ammonia that must be cracked
    - Pilot projects for carbon-neutral processes for chemical carrier production and decomposition, potentially using electrolytic hydrogen as a feedstock
    - Study materials-based storage technologies such as metal hybrids and metal-organic frameworks that allow for desorption of hydrogen closer to ambient temperatures

5.3 Hard-to-Electrify Applications

As described in section 2, hydrogen can serve hard-to-electrify sectors in New York State. However, scaling its use for these applications requires overcoming technical, cost, and infrastructure challenges. Hydrogen's combustion properties, material compatibility issues, and storage and distribution complexities must be addressed through targeted R&D. Additionally, strategic investments in pilot projects, policy incentives, and infrastructure expansion are necessary to facilitate sectorwide adoption.

The following section explores hydrogen's role in these applications, identifies current technological capabilities, and highlights key challenges and opportunities for innovation that can accelerate New York State's transition to a decarbonized future.

5.3.1 District Heating

5.3.1.1 Current State of the Art

Hydrogen offers a promising avenue to decarbonize district heating systems, such as the Con Edison district steam network in New York City, providing a cleaner alternative for urban energy infrastructure. However, demonstrations and deployments of hydrogen for district heating are limited to a few projects.[85]

Internationally, Japan's ENE-FARM program has deployed more than 300,000 fuel cell units for CHP in buildings.[86] Similarly, the UK's $H_2$1 Leeds City Gate project investigated the feasibility of converting an entire city's heating to 100% hydrogen, showing it is technically and financially viable.[87] In the U.S., Caterpillar Inc. is preparing to demonstrate of a 100% hydrogen-powered CHP system integrated into St. Paul, MN's district steam network.[88] This project reflects growing interest in transitioning district heating systems to cleaner hydrogen-based solutions.

5.3.1.2 Technical Challenges

A major obstacle to hydrogen's implementation into district heat systems is infrastructure. Conversion often requires connection to hydrogen pipelines, necessitating careful coordination between infrastructure development and system conversion planning. Furthermore, due to its material compatibility with natural gas, retrofitting or replacing existing district heating system equipment, such as furnaces and boilers, with hydrogen-compatible alternatives is almost certainly necessary.

5.3.1.3 Key Innovation Opportunities for New York State

To accelerate hydrogen technology for district heating in New York State, the State must prioritize targeted RD&D initiatives, including:

- Evaluating retrofitting versus replacing heating equipment, including standardizing the evaluation process
- Developing boilers and furnaces for 100% hydrogen use
- Demonstrating and deploying hydrogen as a fuel for Con Ed's steam system

5.3.2 Industrial Process Heat

5.3.2.1 Current State of the Art

Industrial facilities require high-temperature heat above 500ºC, which relies almost entirely on fossil fuels, presenting a major challenge for decarbonization. Hydrogen offers a promising alternative due to its combustion properties, energy density, and ability to generate extreme heat levels. As a result, hydrogen's role in industry is growing, although still limited. A notable application is decarbonizing steelmaking, particularly through direct reduced iron (DRI) production. In this process, hydrogen replaces carbon from coke or natural gas as the reducing agent to refine iron ore.[89, 90] The subsequent steelmaking step uses electric arc furnaces (EAF),[91] which can be powered by renewable electricity, achieving near-zero carbon emissions.

Emerging projects are demonstrating these technologies on a larger scale. Sweden's HyBrit[92] initiative is pioneering hydrogen use in steelmaking, while in the U.S., Cleveland-Cliffs Steel Corporation is installing a DOE-funded DRI system at its Ohio facility.[93] Similar applications of clean hydrogen as a carbon-neutral input in other material manufacturing sectors, such as primary metals and nonmetallic mineral products, hold significant potential.

5.3.2.2 Technical Challenges

Hydrogen combustion is not a simple drop-in replacement for natural gas in industrial settings. It has unique physical and chemical properties challenges, including lower volumetric energy density, a wider flammability range, higher flame speed, and different radiative heat transfer characteristics. These factors require redesigned kilns and furnaces to manage hydrogen combustion safely and efficiently.[94]

Another challenge is that hydrogen molecules are extremely small and highly diffusive, which can cause embrittlement and cracking of porous materials and metals, as mentioned in section 5.2. Although hydrogen does not directly trap heat in the atmosphere, it can indirectly influence global warming by prolonging the atmospheric lifetime of other GHGs. Investments in advanced sensors, monitoring protocols, and pipeline materials could ensure that hydrogen leakage remains minimal as its use scales up.

Additionally, hydrogen combustion produces no PM2.5 emissions, improving overall air quality, but the high-temperature process can still generate nitrogen oxides (NO_x) emissions, raising air-quality concerns.[95] These challenges highlight the need for innovative combustion technologies, such as lean-burn techniques or advanced burner designs, to keep NO_x emissions at or below the levels associated with natural gas.

To enable hydrogen adoption, industries such as primary metals and mineral products, which rely heavily on high-temperature heat, must assess whether retrofitting existing equipment or transitioning to hydrogen-compatible systems is more practical. Adoption also depends on infrastructure for hydrogen delivery, storage, and use in manufacturing facilities, drawing on lessons from sectors such as refining and ammonia production. Finally, demonstrations of hydrogen technologies' functionality and long-term reliability are essential for gaining industry confidence.

5.3.2.3 Key Innovation Opportunities for New York State

To accelerate hydrogen's adoption in hard-to-electrify industrial processes across New York State, the State must prioritize targeted RD&D initiatives, including:

- **Opportunities for Industrial Process Heat:**
  - Analyze retrofitting existing equipment versus replacing it entirely
  - Study the kinetics of chemical reactions that use hydrogen as a direct input to optimize final product quality in processes that would otherwise require high-temperature heat
  - Study the kinetics of high-temperature hydrogen reduction of metal oxides for metal manufacturing

- Study hydrogen combustion behavior and gas flow to optimize system design
    - Develop safety-related technologies, such as hydrogen sensors for industrial use
    - Develop heat-provision technologies, such as boilers, kilns, and furnaces compatible with hydrogen-specific properties such as flammability window, flame speed, and radiative heat transfer
    - Demonstrate hydrogen for high-temperature heat provision in New York State manufacturing activities
- **Opportunities for Safety Standards in Industrial Process Applications:**
    - Develop lean combustion practices that operate under excess air conditions to lower flame temperatures, significantly reducing NO_x formation.
    - Develop enhanced control technologies that leverage hydrogen's low-ignition energy and faster flame speeds to allow for precise temperature regulation, minimizing NO_x production.

5.3.3 Ground Vehicles and Nonroad Applications

5.3.3.1 Current State of the Art

Ground Vehicles

Hydrogen FCEVs are among the most advanced hydrogen applications today, offering an alternative to conventional electric vehicles (EVs) for long-range and quick-refueling needs. As of mid-2022, approximately 60,000 FCEVs were on roads worldwide, with nearly one-fourth of them in the U.S., primarily in California.[96] Adoption is gaining momentum, with global FCEV stock increasing by 55% from 2020 to 2021. Most FCEVs on the road today are LDVs, with slightly less than 5,000 each of fuel cell buses and heavy-duty trucks deployed at the end of 2021, primarily in China. Of the 59 hydrogen refueling stations in the U.S., 58 are concentrated in California, supporting more than 15,700 FCEVs.[97] By the end of 2024, Regional Transit Service (RTS) deployed two hydrogen fuel cell buses in Rochester, NY, the first in the State, supported by a NYSERDA grant.[98] In addition, the Metropolitan Transit Authority (MTA) is piloting hydrogen fuel cell buses in the Bronx, NY, also supported by NYSERDA. These buses are expected to be in operation by the end of 2025.[99]

Expanding MHDV adoption requires significant advancements in refueling infrastructure. Unlike LDVs, MHDVs require dedicated fueling stations capable of handling higher hydrogen demands. Examples such as NREL's research refueling station highlight the challenges of high costs and a lack of standardized station designs.[100] Addressing these challenges is a priority for DOE, which supports research into advanced components and standardized refueling solutions.

Nonroad Applications

Hydrogen's potential extends beyond road vehicles to nonroad applications, including material handling, rail, agriculture, and port operations.

- **Material Handling:** Forklifts and other material-handling equipment are among the most established hydrogen applications. More than 50,000 hydrogen-powered material handling units operate in the U.S. Plug Power, a company headquartered near Albany, NY, manufactured many of these units.
- **Rail:** Trials of hydrogen-powered passenger train trials have occurred in countries such as Germany, France, and Japan, proving hydrogen's feasibility as a clean alternative to diesel-powered trains. Freight train retrofits are also under exploration, particularly in Europe and Australia.
- **Agriculture, Construction, and Mining:** Several demonstrations of hydrogen-powered equipment have occurred, with more expected in the near term. For instance, Anglo American PLC is retrofitting 400 mining haul trucks with hybrid battery and fuel cell systems.
- **Ports and Airports:** Ports and airports increasingly adopt hydrogen technologies to reduce emissions. Notable examples include a fuel-cell-powered mobile crane at the Port of Shanghai, hydrogen-powered cargo tow tractors tested at Albany, NY, and Hamburg, Germany, airports, and a fuel-cell rubber-tired gantry crane demonstration scheduled for the Port of Los Angeles in 2024.

5.3.3.2 Technical Challenges

On-Road Transportation

R&D for hydrogen on-road transportation can focus on improving fuel cell technology to reduce cost and improve durability, enhancing onboard hydrogen storage to extend FECV ranges, and refining refueling station designs to increase fueling rates and reduce costs. For MHDVs, the DOE targets a refueling rate of 10 kg of hydrogen per minute, with peak flows of 18 kilograms per minute (kg/min).[101] While these rates were demonstrated at NREL in June 2022,[102] commercial adoption requires developing high-flow refueling components such as pumps, flow meters, and sealing materials. Standardizing station design, including liquid hydrogen refueling capabilities, can improve rates, cost-efficiency, and scalability.

Nonroad Applications

Many fundamental R&D needs for nonroad applications align with those for on-road heavy-duty fuel cell EVs, such as improving fuel cell durability for high-power and dynamic operation, enhancing hydrogen storage systems to enable greater fuel storage and ranges, and developing and demonstrating rapid hydrogen fueling technology. Small hydrogen ecosystems could integrate hydrogen demonstrations for cargo-handling equipment in ports and airports with marine or aviation demonstrations, hydrogen refueling, and even hydrogen production.

5.3.3.3 Key Innovation Opportunities for New York State

To accelerate hydrogen-fueled vehicles in New York State, the State must prioritize targeted RD&D initiatives that:

- Couple demonstrations and deployments of hydrogen refueling stations and FCEVs to ensure demand for the stations and supply for the vehicles
- Demonstrate and deploy hydrogen-powered trains, agriculture, construction, and mining equipment, and cargo handling, which can drive the development of hydrogen ecosystems at high-use locations such as ports and airports
- Research and develop high-pressure (>700 bar) and high-throughput hydrogen refueling equipment to meet heavy-duty fueling requirements
- Reduce or replace platinum group metal used in fuel cells and increase resistance to trace impurities
- Develop high-performance, durable platinum-group-metal-free catalysts for fuel cells in MHDVs

5.3.4 Aviation and Marine Vessels

5.3.4.1 Current State of the Art

As noted in section 2.6, stakeholders typically consider direct hydrogen use for aviation and maritime applications in short- and medium-haul flights and shipping. ZeroAvia, an aviation company, is testing hydrogen's potential as a propulsion fuel by designing aircraft powered by hydrogen fuel cell electric drivetrains. The company is currently developing two prototype models: one with a 20-passenger capacity and another with a 40- to 80-passenger capacity.[103]

In maritime applications, stakeholders have already demonstrated hydrogen use. For example, startup Switch Maritime developed and deployed a hydrogen-powered ferry in San Francisco.[104] Engineers continue to explore the fundamental design and engineering of hydrogen-powered aviation and marine vessels, especially about hydrogen storage needs and constraints

5.3.4.2 Technical Challenges

Researchers must conduct R&D to improve the feasibility of direct hydrogen use in aviation and maritime applications, particularly focusing on onboard storage systems and refueling infrastructure (including cryogenic hydrogen). Enhancing the energy density of storage systems may support hydrogen use in larger ships and long-range aircraft. Developing hydrogen storage and fueling infrastructure at ports and airports is critical to enabling hydrogen adoption. With further research, this infrastructure could serve multiple vehicle types (e.g., ships and port cargo handling equipment).

5.3.4.3 Key Innovation Opportunities for New York State

To accelerate hydrogen's use in New York State's aviation and maritime infrastructure, RD&D initiatives can:

- Focus on the fundamental design and engineering of hydrogen-powered aviation and marine vessels, prioritizing hydrogen storage needs and constraints
- Support the research, design, and demonstration of hydrogen fueling infrastructure

5.3.5 Power Generation

5.3.5.1 Current State of the Art

Across the globe, various projects are demonstrating hydrogen's potential in power generation. In Orange County, Texas, engineers are constructing a 1.2 MW combustion turbine that can burn hydrogen.[105] In Utah, an Advanced Clean Energy Storage project integrates hydrogen production, salt cavern storage, and a hydrogen-capable gas turbine power plant aiming for 100% hydrogen by 2045.[106]

In New York State, the New York Power Authority (NYPA) successfully retrofitted a natural gas turbine at the Brentwood Power Station to operate on hydrogen blends ranging from 5% to 40%, marking the first such demonstration for U.S. natural gas facilities.[107]

Although blending hydrogen with natural gas offers a transitional solution, it provides limited decarbonization potential. Achieving full decarbonization requires advancing R&D to enable 100% green hydrogen as a standalone fuel. Stakeholders are also pursuing parallel strategies, such as ammonia combustion, due to ammonia's superior storage and energy transport properties. Japan's IHI Corporation,[108] in partnership with the General Electric Company (GE) and Mitsubishi Power, is developing turbines capable of combusting 100% ammonia by 2030,[109] signaling an alternative fuel pathway in the early development stages.

5.3.5.2 Long-Duration Energy Storage

Experts categorize LDES systems as part of the power generation sector. According to the DOE, LDES systems can deliver electricity for 10 hours or more. As VRE expands alongside growing demand, seasonal mismatches between energy production and consumption will likely require LDES systems capable of providing electricity for 100 hours or longer.

Operators can leverage surplus renewable energy to produce hydrogen and convert it back to electricity using fuel cells or gas turbines during peak demand. Hydrogen thus serves as a viable LDES solution to replace fossil-fuel-based backup power and support the development of microgrids that bolster grid resilience, especially for communities with critical facilities such as hospitals and emergency shelters.

5.3.5.3 Technical Challenges

Systems can combust hydrogen in turbines or convert it electrochemically into fuel cells to generate electricity. Combusting hydrogen poses several challenges due to its lower heating value per unit volume, higher flame speed, and small size of the hydrogen molecule. When retrofitting gas turbine systems for hydrogen integration, engineers must consider the following key factors:

- **Fuel Accessory Systems**
  - Engineers may need to implement blending systems for mixed fuels.Near-100% hydrogen fuels require systems that address higher NO_x emissions.
  - Hydrogen's lower volumetric energy density than natural gas requires larger or modified pipes, valves, and fuel delivery systems.
- **Safety Protocols**
  - Engineers must install enhanced gas leak detectors calibrated for hydrogen and upgraded flame detection systems.
  - Safety protocols must address hydrogen's broader flammability range (4%–75% in volume, compared to natural gas's 5%–15%) and near-invisible flame.
- **Combustion Systems**
  - Dry low emission (DLE) combustors, commonly used to limit NO_x emissions, can typically handle only moderate hydrogen blends (e.g., 35%–50% by volume).[110]
  - Advanced diffusion combustors capable of handling 100% hydrogen face increased NO_x emissions and require costly mitigation measures such as water, steam, or nitrogen dilution.
  - Hydrogen's high flame speed increases risks of combustion instability, including flashback or flame holding, which can damage equipment.

- **Material Compatibility**
    - Engineers must install upgraded seals, welded connections, and hydrogen-compatible alloys across turbine systems.
    - On-site hydrogen storage solutions must meet safety standards and integrate seamlessly into plant configurations.

Fuel cells offer an alternative to combustion turbines, generating electricity with only water vapor as emissions. Their higher efficiency than simple-cycle turbines makes them attractive for stationary power generation. However, deploying fuel cells at the scale necessary for New York State's firm capacity and LDES poses challenges.

Stationary fuel cells typically operate continuously, but grid firm capacity requires dynamic, intermittent operation. This shift can accelerate degradation and reduce efficiency. While retrofitting turbines often proves more cost-effective, utility-scale fuel cell deployment demands significant upfront investment in new infrastructure.

The three leading fuel cell technologies are:

1. **PEM Fuel Cells**
   These rely on platinum group metal catalysts and offer higher power density, making them ideal for FCEVs. Engineers can leverage automotive PEM fuel cell development expertise to advance dynamic operations for peak power applications.[111]
2. **AFCs**
   Historically used in space missions, AFCs offer lower material costs and greater tolerance to impurities. However, they require CO_2 removal from air intake because CO_2 can degrade the electrolyte.
3. **SOFCs**
   Operating at high temperatures, SOFCs tolerate fuel and air impurities and use no precious metal catalysts. However, their heat requirements limit their responsiveness to fluctuating grid demands.

Table 16. Hydrogen Fuel Cell Technology Comparisons

Fuel Cell Type	Electrolyte (Ion Conductor)	Operating Temperature (ºC)	Electrical Efficiency (LHV)	Advantages	Challenges
PEM	Perfluorosulfonic acid	20ºC–100ºC	60%	• Power density • Solid electrolyte • Low temperature • Quick startup and load following	• Expensive catalysts • Sensitivity to fuel impurities
AFC	Aqueous potassium hydroxide or alkaline polymer membrane	20ºC–100ºC	60%	• Less expensive materials • Low temperature • Quick startup	• Sensitive to CO_2 in air • Liquid electrolyte management • Polymer electrolyte conductivity
SOFC	Yttria stabilized zirconia	500ºC–1,000ºC	60%	• Fuel flexibility • Solid electrolyte suitable for CHP • Hybrid gas turbine cycle	• High-temperature corrosion and breakdown of cell components • Long startup time

Ammonia, derived from green hydrogen, presents advantages for power generation due to its storage, transport, and combustion. While power plants already widely use ammonia in selective catalytic reduction (SCR) systems, adopting it as a primary fuel faces multiple obstacles. Its lower reactivity complicates ignition and sustained combustion, and its nitrogen content generates significant NO_x emissions when burned. Engineers are working on advanced combustion designs to address these issues.

Surrounding infrastructure requires substantial capital investment, such as dedicated hydrogen pipelines, compression or liquefaction systems, and end-use technologies (e.g., hydrogen turbines or fuel cells). Integrating hydrogen production into the existing grid also calls for sophisticated control systems to synchronize electrolysis loads with fluctuating renewable output, allowing hydrogen production to align with real-time demand patterns.

5.3.5.4 Key Innovation Opportunities for New York State

To accelerate hydrogen-fueled power generation in New York State, the State must prioritize RD&D efforts that:

- Demonstrate hydrogen-fueled combustion turbines, including 100% hydrogen demonstration
- Evaluate hydrogen storage for peaking power and compare hydrogen's competitiveness with other long-duration energy storage solution technologies

- Conduce technoeconomic analysis on retrofitting a standard gas turbine peaking plant in New York State
- Develop and demonstrate DLE and dry low NO_x (DLN) combustion turbines capable of operating on fuels near 100% hydrogen or 100% ammonia
- Develop and demonstrate technologies to reduce NO_x emissions through innovative combustion design or postcombustion treatment
- Advance the research, demonstration, and deployment of fuel cells designed for peaking power operation
- Advance the research, demonstration, and deployment of hydrogen power generation technologies that use advanced combustion or electrochemical means, such as linear generators
- Demonstrate end-to-end, co-located hydrogen LDES, including renewable production, electrolysis, storage, and reconversion, at scales suitable for both urban microgrids and bulk power generation
- Develop and demonstrate control systems that enable hydrogen use for demand response and peak shaving

6 Societal and Environmental Impact

New York State's commitment to an equitable energy transition requires a comprehensive understanding of hydrogen's potential to reduce GHG emissions and improve air quality. This section highlights hydrogen's dual role: displacing fossil fuels to curb GHG emissions while addressing the air quality and health impacts associated with its adoption.

6.1 Greenhouse Gas Emissions

Replacing diesel, gasoline, and natural gas with green hydrogen offers significant opportunities for emissions reduction. This section analyzes GHG emissions across several priority end-use sectors,[112] including LDVs, MDVs, HDVs, nonroad applications,[113] district heating, industry, and power generation.

6.1.1 Use Case Methodology and Results

This analysis focuses exclusively on green hydrogen, assuming that green hydrogen—produced from renewable energy—has a zero-emission factor. The study calculated emission reductions based on displacing fossil fuels with green hydrogen in each sector, accounting for emissions at the point of consumption and upstream sources. The emission factors used in this study come from a NYSERDA publication[114] and include fossil fuel extraction, production, and transportation. The study is based on total hydrogen demand for each sector in New York State on the Mid-demand scenario outlined in section 2. To calculate the total emissions avoided, the study multiplied the total hydrogen demand in each sector by the emission factor of the fossil fuel expected to be replaced by hydrogen.

- **LDVs:** Hydrogen FCEVs complement BEVs in applications requiring extended range or rapid refueling, contributing to 1.4 MMT in CO_2 emissions abatement by 2050.
- **Additional Transportation:** MHDVs offer the highest potential for emissions reductions in transportation, contributing a cumulative 4.71 MMT in CO_2 emissions abatement by 2050. Nonroad applications, including aviation, could abate an additional 3.88 MMT CO_2e by 2050.
- **Industry and District Heating:** High-temperature industrial processes and New York City's district steam heating system could eliminate 0.66 MMT and 0.96 MMT CO_2e, respectively, by 2050.
- **Power Generation:** Using hydrogen as a peaking power source could avoid 2.86 MMT CO_2e annually by 2050. [115]

In aggregate, these projections suggest a potential reduction of 14.48 MMT of CO_2 by 2050, the equivalent of that absorbed by 17 million acres of forest in a year.

Table 17. Potential for Avoided Emissions End-Use Sector, Mid-Demand Scenario

Figures in million metric tons of carbon dioxide equivalent per year (MMT CO_2e/year).

End-Use Sector	Avoided Emissions In		
	2030	2040	2050
LDV	0.03	0.73	1.40
MDV	0.05	0.37	0.73
HDV	0.34	2.42	3.98
Nonroad Aviation	0	0.62	1.48
Nonroad, Maritime	0.00	0.08	0.22
Nonroad, Rail	0.00	0.02	0.06
Nonroad, Mining	0.04	0.24	0.38
Nonroad, Construction	0.12	0.81	1.29
Nonroad, Agriculture	0.03	0.24	0.37
Nonroad, CHE	0.00	0.01	0.02
Nonroad, GSE	0.00	0.04	0.07
District Heating	0.06	0.60	0.96
Industry	0.15	0.35	0.66
Power Generation	0.00	2.48	2.86

[a] "Nonroad" includes aviation, maritime, rail, ground support equipment, cargo-handling equipment, and industrial vehicles. For the percent of market share of hydrogen in each of these sectors, see section 2.

[b] "District heating" includes hydrogen demand for only the Con Edison District Steam System in New York City.

[c] "Power generation" here refers to firm capacity generation.

6.2 Nitrogen Oxides Emissions

Combusting hydrogen in turbines for power generation or industrial applications creates high-temperature hydrogen-air mixtures that produce No_x, a class of pollutants that includes nitrogen oxide (NO) and nitrogen dioxide (NO_2). While higher-temperature combustion improves efficiency, it also produces more NO_x.[116, 117]

We can control NO_x emissions through improved combustion design or by SCR, which converts the NO_x into nitrogen gas (N_2) and water (H_2O) in the presence of a catalyst and a reducing agent, typically ammonia. Because hydrogen's flame temperature exceeds that of natural gas, the NO_x emissions of hydrogen-fired turbines may be higher than that of natural gas-fired turbines. However, further research is needed to characterize hydrogen combustion performance in DLE turbines fully. SCR is a mature technology, and systems exist that can ramp up as quickly as aeroderivative turbines to keep NO_x below permitted levels during all phases of operation, including startup.

Although researchers have not yet fully characterized the amount of NO_x created by a hydrogen turbine, we can estimate the cost of SCR retrofits across potential NO_x scenarios. Drawing from an Electric Power Research Institute (EPRI) publication,[118] the study evaluated an aeroderivative gas turbine with a baseline SCR inlet NO_x level of 25 parts per million by volume (ppmv) and an outlet NO_x level of 2.5 ppmv (a typical NO_x permit limit for an aeroderivative turbine firing natural gas in New York State). The study assessed two scenarios where SCR inlet NO_x levels rose by 50% and 100% while keeping the SCR outlet NO_x constant. The evaluation showed lifetime costs for the additional catalyst volume and ammonia usage amounted to approximately $175,000 for the 50% increase and $240,000 for the 100% increase. These costs are not prohibitively high in retrofitting a gas turbine, indicating that NO_x should not present a significant roadblock to retrofitting existing turbines to use hydrogen.

7 Conclusion

Hydrogen can play a critical role in helping New York State achieve its climate goal by decarbonizing hard-to-electrify sectors such as industrial processes, on-road and nonroad vehicles, district heating systems, peaking power generation, and long-duration energy storage. Under the Mid-demand scenario, total hydrogen demand in New York State will reach 11% by 2050.

However, adopting hydrogen presents significant total cost of ownership challenges across all sectors. The study calculated the cost of hydrogen delivery at each zone in New York State, incorporating the cost of hydrogen production from renewable energy and its distribution and storage. Even considering tax credits such as 45V, hydrogen remains a major contributor to end-user operational costs. Temporal and geographic variations in hydrogen demand, along with the dynamics of hydrogen production and consumption, significantly influence overall hydrogen costs and the development of hydrogen infrastructure in the State.

This assessment identifies the technology landscape and R&D focus areas across hydrogen production, storage, distribution, and end-use applications. New York State can leverage federal funding and strengthen private–public partnerships to prioritize innovation investments.

Opportunities to further reduce costs and support hydrogen development in New York State are to:

- Combine gas system transition with hydrogen planning: As electrification advances across multiple sectors, New York State can explore how to repurpose its existing gas network to support hydrogen usage.
- Blend hydrogen into existing natural gas pipelines: Low-percentage hydrogen blending for industrial processes, district heating, or peaking power generation can serve as a transition solution, requiring fewer equipment upgrades than a full hydrogen switch. While statewide implementation remains unlikely in the near term due to the compatibility of end-use equipment and pipeline materials, targeted adoption in specific areas could be possible if combined with gas system transition plans.
- Leverage new modalized nuclear plants: As New York State explores new modalized nuclear plants, the State can produce low-cost hydrogen while balancing nuclear power generation loads. As shown in section 3, hydrogen produced from nuclear sources could cost up to 40% less than the base case.
- Develop hub hydrogen: New York State can build dedicated hydrogen hubs at selected sites to reduce costs by sharing infrastructure.

In conclusion, New York State can collaborate with federal agencies, other states, industry, and academic entities to overcome cost barriers, address infrastructure gaps, and tackle technical challenges. As the State decarbonizes its energy system, it can build a resilient, innovative, and economically viable hydrogen economy through focused R&D, strategic planning, and strong policy support.

Appendix A. Supplementary Material for Demand Analysis

A.1 District Heating Methodologies to Evaluate Demand

This section outlines the approach used to estimate hydrogen demand for district heating applications in New York State, with a primary focus on the Con Edison steam system—the largest district energy system in the state. The methodology combines published demand projections, planning documents, and technical studies to estimate how steam demand may evolve through 2050, and what share of that demand could be met with hydrogen. A two-step approach is used: first, total district heating demand is projected across Low-, Mid-, and High-demand scenarios; second, hydrogen's potential market share is applied to estimate total hydrogen demand. Table A-1 lists key data sources used in this analysis.

A.1.1 District Heating Research Methodology

The analysis begins by using sources from IDEA (2013), NYC Mayor's Office of Sustainability (2021), Con Edison (2022), and NYSERDA (2022) to project Low, Mid, and High levels of future Con Edison steam demand. Total steam demand for the Con Edison system is expected to decline over the following decades due to increased energy efficiency, electrification, a generally warmer climate, and changes in peak demand from extreme temperature events.[119] The 2019 Con Edison steam demand baseline is calculated as 28.8 trillion British thermal units (Tbtu) based on estimates from the (NYC Mayor's office (2021).

Steam demand projections for 2050 are developed using the following sources and assumptions. Estimates for 2030 and 2040 are obtained through interpolation:

- Mid- and High-demand scenarios use the 2050 estimate informed by the lower range of projections from the "Pathways to a Carbon Neutral NYC" (NYC Mayor's Office of Sustainability 2021) report and steam demand projections from the "Integration Analysis" (NYSERDA 2022), which indicates steam demand declines to 35% of 2019 levels.
- Low-demand scenario limits 2050 steam demand to the portion attributed to cogeneration in the Mid- and High-demand scenarios. This is calculated by assessing what portion of steam demand is attributable to Con Ed's cogeneration units, as reported in the *2013 IDEA Global District Energy Climate Awards* (IDEA 2013). Steam demand falls to 20% of the baseline value.

Table A-1 summarizes these steam demand projections in the report.

The next step estimates the share of steam demand met by hydrogen in each scenario from 2030 to 2050. The assumptions include:

- All demand scenarios assume hydrogen meets 100% of Con Edison steam demand by 2050.
- Across scenarios, a gradual transition to hydrogen occurs: hydrogen meets 2.5%–3.5% of steam demand in 2030 and 30%–40% in 2024.

A.1.2 District Heating Demand Methodology

This step estimates hydrogen demand based on the district heating system's energy use (reported on a higher heating value [HHV] basis), hydrogen market share, and hydrogen heating value. The analysis assumes hydrogen is used via combustion, resulting in efficiencies similar to fossil fuels. Thus, the only conversion required is from energy to hydrogen mass using hydrogen's HHV of 134.4 thousand British thermal units per kilogram (kBtu/kg). The equation used is:

$$\mathrm{H_2}\ \textit{demand} = \textit{2019 energy use} * \textit{fraction of 2019 energy use} * \mathrm{H_2}\ \textit{market share} \div \textit{HHV of}\ \mathrm{H_2}\ \textit{demand}$$

A.2 Industrial Processes Methodologies to Evaluate Demand

This section presents the methodology used to estimate future hydrogen demand for industrial process heat in New York State. The analysis focuses on the role hydrogen may play in decarbonizing thermal energy use in the manufacturing sector, particularly in high-temperature applications that are difficult to electrify. The demand estimation process considers three scenarios—Low-, Mid-, and High-demand—based on the extent to which hydrogen is adopted for high-, mid-, and low-temperature heat processes. It begins with a baseline estimate of industrial heat demand in 2014, derived from a detailed national dataset, and scales that demand forward using projections of industrial growth and energy efficiency improvements. Hydrogen market shares are then applied based on decarbonization pathways found in a range of literature sources. Table A-2 summarizes the references used in the analysis.

A.2.1 Industrial Processes Research Methodology

The study assumes the Low- and Mid-demand scenarios use hydrogen only for high-temperature industrial processes due to its difficulty to electrify. The High-demand scenario also considers hydrogen used in some low- and mid-temperature industrial heat processes.

The first step in analyzing hydrogen potential for industrial heat begins with estimating sector energy demand based on NREL's "Manufacturing Thermal Energy Use in 2014" (McMillan 2014) dataset. The dataset includes estimates of thermal energy use across the country sorted by type (process heating, boilers, combined heat, and power), fuel, temperature, county, and size for all U.S. manufacturing industries in 2014. The dataset was filtered for facilities in New York State and sorted by temperature grade. This results in baseline 2014 estimates for low-, mid-, and high-grade heat, respectively. Projections of future demand in 2030, 2040, and 2050 are made by using the following sources and assumptions:

- Multiplicative scaling factors for projecting demand increases from 2014 levels in 2030, 2040, and 2050 are obtained by averaging increases in heat demand from *Hydrogen: Scaling Up* (Hydrogen Council 2017) and the *Annual Energy Outlook* (EIA 2023).
- Energy efficiency improvements for 2030 and 2050 are sourced from the "Integration Analysis" (NYSERDA 2022), using the estimated increase in manufacturing efficiency used in scenarios 2 through 4. Values for 2040 are obtained through interpolation.
- Energy demand for all heat grades in 2030, 2040, and 2050 is estimated by multiplying by the corresponding scaling factor and then energy efficiency improvements.

Hydrogen market shares for 2050 are then estimated with different references for Low-, Mid-, and High-demand scenarios. Estimates of market share in 2030 and 2040 are obtained through interpolation between 2014 (0%) and the estimated market share in 2050.[120] The following sources and assumptions for hydrogen market share in 2050 include:

- For the Low-demand scenario, the estimate for hydrogen market share of 15% of high-T heat is taken from Larson et al.'s *Net Zero America* (2021) study.
- For the Mid-demand scenario, the estimate of high-T heat demand met by hydrogen is 25%, and it was taken from the *Road Map to a U.S. Hydrogen Economy* (FCHEA 2019).
- For the High-demand scenario assumes more aggressive hydrogen adoption than the 25% cited in the Mid-demand scenario, increasing it to 40%. The 2050 market share estimates for low- and mid-temperature heat—4% and 8%, respectively—are based on FCHEA (2019).

Results reflect hydrogen demand ranges from 0.031 MMT/yr to 0.117 MMT/yr, primarily driven by hydrogen demand for high-grade industrial heat. Even in the High scenario in 2050, where hydrogen meets modest amounts of low- and mid-temperature heat, 71% of total demand supports high-temperature heat applications.

A.2.2. Industrial Processes Demand Methodology

Hydrogen demands are estimated using the estimated energy use for industrial heat (reported on an HHV basis), hydrogen market share, and hydrogen heating value. The assumption considers hydrogen providing heat via combustion, similar to fossil fuels, resulting in comparable efficiency. As a result, no efficiency conversion is needed beyond converting energy to hydrogen mass using hydrogen's HHV of 134.4 kBtu/kg. The equation used is:

*Demand = 2014 energy use * scaling factor * (1 − efficiency improvements) **
H_2 *market shareHHV of* H_2 *Demand = 2014 energy use * scaling factor * (1−efficiency improvements) **
H_2 *market share HHV of* H_2

A.3 Power Generation Methodologies to Evaluate Demand

This section details the methodology used to calculate the physical hydrogen demand required for power generation applications, specifically focusing on providing zero-carbon firm capacity. It outlines the formula used to convert estimated hydrogen fuel consumption and market share projections into hydrogen mass.

A.3.1 Power Generation Demand Methodology

The estimation of physical hydrogen demands uses hydrogen fuel consumption for firm capacity and hydrogen market share estimates, converting the result to hydrogen mass based on hydrogen's HHV of 134.4 kBtu/kg, as shown in the following formula:

*Demand = Hydrogen fuel consumption **
zero−carbon firm generation H_2 *market shareHHV of* H_2*Demand = Hydrogen fuel consumption **
zero−carbon firm generation H_2 *market shareHHV of* H_2

A.4 On-Road Transportation

This section describes the methods employed to estimate potential hydrogen demand in the on-road transportation sector, covering LDVs, MDVs, and HDVs. It details the research methodology used to establish baseline and projected Vehicle Miles Traveled (VMT) and to estimate Fuel Cell Electric Vehicle (FCEV) market shares under different scenarios, followed by the calculation methodology converting these projections into physical hydrogen demand using fuel economy assumptions.

A.4.1 On-Road Transportation Research Methodology

The analysis begins by establishing baseline estimates of 2019 vehicle miles traveled (VMT) in New York State, segmented by LDV, MDV, HDV, and then projecting VMT in 2030, 2040, and 2050.

- Averaged 2019 New York State values from three sources—the "Bureau of Transportation Statistics for State Highway Travel" (DOT BTS 2019)[121], "New York State Clean Transportation Roadmap, Final Report" (NYSERDA 2021)[122], and "Integration Analysis–Appendix G" (NYSERDA 2022)—to derive the total VMT (124.4 billion miles) across all segments (LDV, MDV, and HDV).
- Calculated the LDV segment by averaging the percentage of VMT attributable to LDVs from the "New York State Clean Transportation Roadmap" (NYSERDA 2021) and the "Bureau of Transportation Statistics for State Highway Travel" (DOT BTS 2029), then applied this average to the total estimated VMT to determine the LDV segment baseline.
- Attributed the remaining VMT percentage to MHDVs and further divided it into MDV and HDV segments. Estimated the MDV share by applying the 40.7% figure for medium-duty domestic freight from the *Annual Energy Outlook* (EIA 2023) to the MHDV portion of VMT, Assigned the remaining VMT share to HDVs.
- Projected VMT growth for LDVs, MDVs, and HDVs at approximately 0.9%, 1.5%, and 0.7% per year, respectively, based on averages of VMT growth estimates from the "New York State Clean Transportation Roadmap" (NYSERDA 2021) and the *Annual Energy Outlook* (EIA 2022).

Table A-1. Estimated Fuel Cell Electric Vehicle Stock for Mid-Demand Scenario

Sector	Application	2030	2040	2050
On-road transportation vehicles	HDVs and MDVs	4,600 FCEVs	37,000 FCEVs	65,000 FCEVs
	LDVs	10,000 FCEVs	300,000 FCEVs	600,000 FCEVs

Literature sources project a wide range of FCEV market share—from no hydrogen adoption to 50% of vehicles. The following sources and assumptions define the Low-, Mid-, and High-hydrogen demand across each vehicle class:

- For LDVs, the Mid-demand scenario estimates in all years align with an average value in the high technology availability (HTA) and limited nonenergy (LNE) scenarios from *Pathways to Deep Decarbonization in New York State* (E3 2014). The Low-demand scenario assumes not hydrogen market share because battery electric vehicles (BEVs) are expected to dominate this market. The High-demand scenario assumes twice the hydrogen market share of the Mid case.
- For MHDVs, the Mid case aligns with the *Net-Zero America* (Larson et al. 2021) study, resulting in 2050 shares of 18% for MDVs and 38% for HDVs. The High scenario follows the M3/M4 cases in the "New York State Clean Transportation Roadmap" (NYSERDA 2021), and the Low case aligns with an average of the HTA and LNE scenarios from the *Pathways to Deep Decarbonization in New York State* (E3 2014) report.

Total hydrogen demand in 2050 ranges from 0.130/MMT/yr to 0.812 MMT/yr, depending on the market adoption of FCEVs. Although LDV FCEV stock exceeds MHDV stock in the Mid-demand scenario, a larger share of the more energy-intensive MHDV stock consists of FCEVs.

A.4.2 On the Road Demand Methodology

Physical hydrogen demand is estimated from VMT using FCEV fuel economy estimates in miles per gallon of gas equivalent (mpgge), from the *Technical and Economic Potential of the H_2@Scale Concept* (NREL 2020) for 2030 and 2050 for LDVs and for 2050 for MDVs and HDVs. Values for 2030 for MDVs and HDVs are estimated by matching LDV trends, and 2040 values are interpolated. Hydrogen demand is estimated using a conversion of 1.019 gge per kg of hydrogen, based on NREL's *2020 Annual Technology Baseline*.[123]

Table A-2. Summary of Fuel Cell Electric Vehicles Fuel Economy Assumptions

Vehicle Type	FCEV Fuel Economy Assumptions (mpgge)		
	2030	2040	2050
LDV	67.5	74	82
MDV	26.8	29.4	32.6
HDV	11.9	13.1	14.5

The equation used is:

*Demand = 2019 VMT * scaling factor * H_2 *market sharefuel economy * 1.019 kg/ggeDemand = 2019 VMT * scaling factor * H_2 *market sharefuel economy * 1.019 kg/gge*

A.5 Nonroad Applications Methodologies to Evaluate Demand

This section presents the methodologies used to evaluate potential hydrogen demand across diverse non-road applications, including aviation, maritime, rail, ground support and cargo handling equipment, and industrial equipment. It covers the research approach for establishing baseline energy use and projecting future demand, incorporating scaling factors and efficiency improvements, as well as estimating hydrogen market shares. It concludes by outlining the calculation methodology used to determine physical hydrogen demand, including the application of specific efficiency correction factors where relevant.

A.5.1 Nonroad Applications Research Methodology

The analysis establishes a baseline estimate for current energy use and projects future energy demand in 2030, 2040, and 2050 across each nonroad application examined in this section. Specific sources and assumptions used include:

- **Aviation:** The analysis takes baseline energy consumption in 2019 from the "Bureau of Transportation Statistics for State Highway Travel" (DOT BTS 2019), scales it for each analysis year using a 2.1% annual growth in aviation fuel use from *Annual Energy Outlook* (EIA 2022), and adjusts it with efficiency improvements from the *Pathways to Deep Decarbonization* (E3 2014) report.
- **Maritime:** The analysis obtains U.S. national shipping energy use projections (including domestic and international freight shipping) for 2030, 2040, and 2050 from the *Annual Energy Outlook* (EIA 2022) and scales them to New York State using 2019 shipping tons at New York and New Jersey ports in 2019 from the Bureau of Transportation Statistics for *State Highway Trave*l (DOT BTS 2019). The analysis attributes only half of the total shipping tons in New York State from the Port Authority of New York and New Jersey Multi-Facility Emissions Inventory (PANYNJ 2020).[124]
- **Rail:** The analysis uses baseline energy consumption in 2018 from the "Integration Analysis" (NYSERDA 2022) and scales it to future years using an average of growth rates from EIA (2023) and NYSERDA (2021), approximately 1.6% per year. It applies efficiency improvements estimated from rail ton-mile per thousand British thermal units (BTU) efficiency values from EIA (2022).
- **Ground Support Equipment (GSE):** No New York State–specific energy use data available, so total emissions estimates for 2017 at Port Authority of New York and New Jersey (PANYNJ) airports in New York City, derived from PANYNJ's "Greenhouse Gas and Criteria Air Pollutant Emissions Inventory" (2020), are used. These estimates are converted to energy using emissions factors from the EIA and U.S. Environmental Protection Agency (EPA). The data is then scaled for future years, assuming the same growth and scaling factors as for aviation. No efficiency improvements are assumed for future years due to lack of data.
- **Cargo-Handling Equipment (CHE):** Baseline energy estimates for New York State in 2020 come from half the value in PANYNJ's *Multi-Facility Emissions Inventory* (2021). These estimates are scaled to the entire State using the same shipping tons metric as the maritime sector. Energy demand remains constant because carbon emissions from CHE in PANYNJ (2020) have been reported to stay the same. No efficiency improvements are assumed for future years due to lack of data.
- **Industrial Equipment:** Total energy demand for these applications in 2014 was estimated using NREL's *United States County-Level Industrial Energy Use* (2014b) dataset, then scaled to future years based on annual growth rates from the *Annual Energy Outlook* (EIA 2023) and estimated industrial efficiency improvements from the "Integration Analysis" (NYSERDA 2022). Estimated growth rates are 0.7%, 0.9%, and 0.6% per year for agriculture, construction, and mining, respectively.

The next step in the process involves estimating demand projections captured by hydrogen, application by application. Estimates for hydrogen market share are made for 2030 and 2050, with values for 2040 are interpolated based on increasing growth, unless otherwise indicated. These hydrogen market shares represent the percentage of energy needs met by hydrogen in each application. The specific sources and assumptions used include:

- **Aviation:** The High-demand estimate in 2050 is benchmarked to scenario 4 in the "Integration Analysis" (NYSERDA 2022). For the Mid case for 2050 estimates the market share percentage on the Hydrogen Council's *Hydrogen Scaling Up* (2017) and *Hydrogen Insights* (2022) reports. The Low-demand case assumes no hydrogen market capture. All scenarios assume no market capture in 2030.
- **Maritime:** The High-demand estimate for market share in 2050 comes from the IEA's "Net Zero by 2050" (2021) and the 2030 value from the IEA's "Global Hydrogen Review 2022" (IEA 2022). The Low case assumes no hydrogen adoption, while the Mid case is set to intermediate values between the low and high estimates.
- **Rail:** The High-demand estimate for market share in 2050 comes from *Hydrogen Scaling Up* (Hydrogen Council 2019) and in 2030 from the "Global Hydrogen Review 2022" (IEA 2022). Estimates for Mid-demand market share for 2050 come from the "Integration Analysis" (NYSERDA 2022) and for 2030 from the "Global Hydrogen Review 2022". The Low-demand market share estimate for 2050 comes from "Net Zero by 2050" (IEA 2021), with no adoption assumed in 2030.
- **GSE, CHE, and Industrial Equipment:** Market shares for HDVs from the on-road transportation analysis (see section 2.5) are used.

Table A-3 summarizes the hydrogen demand analysis for this section, showing hydrogen market shares in each application and their equivalent in physical hydrogen demand (MMT/yr). Total demand in 2050 under "nonroad applications" ranges from 0.061 MMT/yr to 0.598 MMT/yr. Increasing adoption for direct use in the aviation and industrial equipment sectors drives substantial physical hydrogen demand in the Mid and High scenarios, even when hydrogen captures only a modest amount of market share.

Table A-3. Projected Hydrogen Market Share for Nonroad Applications

Application	Demand Scenario	2030		2040		2050	
		H_2 Market Share (%)	Physical Hydrogen Demand (MMT/yr)	H_2 Market Share (%)	Physical Hydrogen Demand (MMT/yr)	H_2 Market Share (%)	Physical Hydrogen Demand (MMT/yr)
Aviation	Low	0%	0	0%	0	0%	0
	Mid	0%	0	2%	0.050	5%	0.120
	High	0%	0	6%	0.150	12%	0.287
Maritime	Low	0%	0	0%	0	0%	0
	Mid	0%	0	3%	0.006	9%	0.016
	High	1%	0.002	6%	0.011	17%	0.032
Rail	Low	0%	0	2%	0.0007	5%	0.002
	Mid	0.7%	0.0002	4%	0.0015	10%	0.004
	High	2%	0.0007	8%	0.0030	20%	0.009
GSE and CHE	Low	0.6%	0.0001	6%	0.0009	14%	0.003
	Mid	3%	0.0004	22%	0.0035	38%	0.007
	High	7%	0.0009	26%	0.0041	65%	0.012
Industrial Vehicles	Low	0.6%	0.003	6%	0.026	14%	0.056
	Mid	3%	0.014	22%	0.096	38%	0.151
	High	7%	0.032	26%	0.111	65%	0.258

A.5.2 Nonroad Applications Demand Methodology

To estimate physical hydrogen demand, energy use estimates are converted using the HHV of hydrogen (134.4 kBtu/kg) because the above energy use is reported on a HHV fossil fuel basis. For rail, GSE, and CHE, hydrogen equipment operates more efficiently than traditional diesel engines, applying a use efficiency correction factor of 0.6. This factor is based on approximate efficiency values for hydrogen fuel cells (50%) and diesel engines (30%), as reported by Hunter et al. (2021) and Nunno (2018).

For aviation, maritime, and industrial equipment, similar efficiency for hydrogen use as fossil fuels is assumed, with no efficiency conversions beyond the HHV of hydrogen. In maritime applications and heavy industrial equipment, hydrogen shows no significant efficiency gains over fossil fuels because the large diesel engines used today already achieve high efficiencies similar to fuel cells. For aviation, no efficiency improvements over fossil fuels are assumed due to the nascent and uncertain nature of hydrogen aviation technology. The equation used to calculate physical hydrogen demand is:

Demand=energy use ×H_2 market shareH_2 HHV×use efficiency correctionDemand=energy use ×H_2 mark et shareH_2 HHV×use efficiency correction

For all subsectors except for maritime, the energy use must be calculated from:

energy use=baseline energy use ×scaling factor ×(1−efficiency improvements)energy use=baseline ener gy use ×scaling factor ×(1−efficiency improvements)

Table A-4 summarizes the use efficiency correction factors.

Table A-4. Summary and Justifications of Efficiency Correction Factors

Application	Use efficiency correction factor	Justification[125, 126]
Aviation	1	Hydrogen aviation technology is nascent and uncertain; no additional efficiency gains are assumed for a conservative estimate.
Maritime	1	Slow-speed diesel engines used in maritime applications already achieve high efficiencies similar to those of hydrogen fuel cells (~50%).
Rail	0.6	Based on high-level estimates for diesel fuel efficiency of 30% (Nunno 2018) and a fuel cell efficiency of 50% (Hunter et al. 2021).
GSE and CHE	0.6	Based on high-level estimates for a diesel fuel efficiency of 30% (Nunno 2018) and a fuel cell efficiency of 50% (Hunter et al. 2021).
Industrial Vehicles	1	No additional efficiency gains are assumed for a conservative estimate. Additionally, large industrial vehicles may use slow-speed diesel engines similar to maritime applications, which already have higher efficiencies.

A.6 Temporal and Geographic Disaggregation Methodologies to Evaluate Demand

Hydrogen demands disaggregate to the county level using proxy metrics for each end-use sector relevant to geographic distribution. Table A-5 summarizes the proxy metrics, along with their sources. Demand in each county is assumed to be proportional to the corresponding proxy metric, meaning the fraction of total demand for a given county matches the fraction of the statewide value of the proxy metric for that county.

Table A-5. Summary of County-Level Proxy Metrics Used in Geographic Disaggregation

Sector	Subsector	Geographic Proxy Metrics	Sources[127, 128, 129, 130, 131, 132]
District Heating		N/A demand is all attributed to the Con Edison steam system in New York County)	N/A
Industry		County-level manufacturing thermal energy use inputs	"Manufacturing Thermal Energy Use in 2014" (McMillan 2014)
Power Generation		2040 and 2050 projected zero-carbon firm power generation by NYISO load control zone.	"Integration Analysis" (NYSERDA 2022)
On-Road Transportation		2018 vehicle registrations by county consider Standard, Taxi, and Rental categories as LDVs and Commercial, Bus, Ambulance, and Farm categories as MHDVs; MDVs and HDVs are assumed to have the same geographic distribution for this modeling	"NYS Vehicle Registrations of File-End of Year 2018" (Pandora Group 2018)
Nonroad Applications	**Aviation**	2019 enplanements at NYS airports	Passenger Boarding Enplanement and All-Cargo Data for U.S. Airports—Previous Years (FAA)
	Maritime	2019 shipping tons at NYS ports	2019 Trade Statistics (PANYNJ 2019)
	Rail	Assumed constant across all counties due to lack of data	N/A
	GSE and CHE	Assumed the same as aviation and maritime, respectively	See sources for aviation and maritime in this table
	Industrial Equipment	County-level industrial energy use inputs	United States County-Level Industrial Energy Use (Narwade 2014)

Hydrogen demands disaggregate by month using proxy metrics for each end-use sector relevant to temporal distribution. Table A-6 summarizes the proxy metrics and their sources. Demand in each month is proportional to the noted proxy metric, meaning the fraction of annual demand for a given month matches the fraction of the annual value of the proxy metric for that month.

Table A-6. Summary of Monthly Proxy Metrics Used in Geographic Disaggregation

Sector	Subsector	Monthly Proxy Metrics	Sources[133, 134, 135]
District Heating		Heating degree days (30-year average, 1981–2010); 85% of heat provided by H_2 goes toward space heating, which varies month-to-month, proportional to heating degree days, and 15% goes to water heating, which remains constant each month.	Patterns and Trends: New York State Energy Profiles, 2007-2021 (NYSERDA 2024) *Pathways to Deep Decarbonization in New York State* (E3 2020) for estimation of 85% space heating, 15% water heating based on heating device energy demands
Industry		Monthly fossil fuel use by U.S. industry (2010–2019 average)	EIA Monthly Energy Review February 2022
Power Generation		Number of hours per month over a 32.6 GW load threshold in 2040 load modeling from the "Integration Analysis" (load threshold set to match annual hydrogen demands)	"Integration Analysis" (NYSERDA 2022)
On-Road Transportation		U.S. monthly VMT as reported by DOE (2010-2019 average) and DOT (2019 data)	Monthly Fluctuation in U.S. Vehicle Miles Traveled (DOE 2023) Traffic Volume Trends (DOT 2019)
Nonroad Applications	**Aviation**	2019 monthly aircraft movements at PANYNJ airports	(PANYNJ 2019)
	Maritime	Loaded monthly throughput (by container volumes) at Port of New York and New Jersey (2000–2015 average)	NY State Loaded Containers Monthly Imports and Exports Through Port Authority of NY NJ Maritime Terminals (PANYNJ 2019)
	Rail	Assumed constant across all months due to lack of data	N/A
	GSE and CHE	Assumed the same as aviation and maritime, respectively	See aviation and maritime
	Industrial Equipment	Assumed constant across all months due to lack of data	N/A

Table A-7 includes projected market share, by percentage, for each respective sector, based on the findings and research methodology outlined above.

Table A-7. Summary of Hydrogen Demand in Each Sector

Figures are in MMT/yr.

Sector	Application	Demand Scenario		Physical Hydrogen Demand (MMT/yr)		
				2030	2040	2050
District Heating		Low		0.003	0.029	0.043
		Mid		0.005	0.047	0.075
		High		0.005	0.047	0.075
Industry		Low		0	0.018	0.031
		Mid		0.012	0.027	0.052
		High	Low-T heat	0	0.003	0.012
			Mid-T heat	0.003	0.012	0.022
			High-T heat	0.017	0.045	0.083
On-Road Transportation	**LDV**	Low		0	0	0
		Mid		0.002	0.053	0.101
		High		0.004	0.106	0.202
	MDV	Low		0.001	0.009	0.021
		Mid		0.003	0.028	0.054
		High		0.008	0.040	0.105
	HDV	Low		0.005	0.048	0.109
		Mid		0.025	0.179	0.294
		High		0.057	0.208	0.505
Nonroad Applications	**Aviation**	Low		0	0	0
		Mid		0	0.050	0.120
		High		0	0.150	0.287
	Maritime	Low		0	0	0
		Mid		0	0.006	0.016
		High		0.002	0.011	0.032
	Rail	Low		0	0.0007	0.002
		Mid		0.0002	0.0015	0.004
		High		0.0007	0.0030	0.009
	GSE and CHE	Low		0.0001	0.0009	0.003
		Mid		0.0004	0.0035	0.007
		High		0.0009	0.0041	0.012
	Industrial Vehicles	Low		0.003	0.026	0.056
		Mid		0.014	0.096	0.151
		High		0.032	0.111	0.258

Table A-8 summarizes the hydrogen market share by sector, presenting the percentage of energy needs met by hydrogen across different sectors.

Table A-8. Summary of Hydrogen Percent Market Share Per Sector

Sector	Application	Demand Scenario		H_2 Market Share (%) 2030	2040	2050
District Heating		Low		2%	30%	100%
		Mid		3.5%	40%	100%
		High		3.5%	40%	100%
Industry		Low		0%	8%	15%
		Mid		5%	12%	25%
		High	Low-T heat	0%	1%	4%
			Mid-T heat	1%	4%	8%
			High-T heat	7%	20%	40%
On-Road Transportation	LDV	Low		0%	0%	0%
		Mid		0%	3%	6%
		High		0.2%	6%	11%
	MDV	Low		0.3%	3%	7%
		Mid		1%	10%	18%
		High		3%	14%	35%
	HDV	Low		0.6%	6%	14%
		Mid		3%	22%	38%
		High		7%	26%	65%
Nonroad Applications	Aviation	Low		0%	0%	0%
		Mid		0%	2%	5%
		High		0%	6%	12%
	Maritime	Low		0%	0%	0%
		Mid		0%	3%	9%
		High		1%	6%	17%
	Rail	Low		0%	2%	5%
		Mid		0.7%	4%	10%
		High		2%	8%	20%
	GSE and CHE	Low		0.6%	6%	14%
		Mid		3%	22%	38%
		High		7%	26%	65%
	Industrial Equipment	Low		0.6%	6%	14%
		Mid		3%	22%	38%
		High		7%	26%	65%

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Appendix B. Supplementary Material for Hydrogen Cost and Infrastructure Modeling

The National Renewable Energy Laboratory's (NREL's) Hydrogen Production, Storage, and Transmission (HYPSTAT) model served as the primary analytical tool for projecting hydrogen infrastructure costs in New York State. The model operates in two stages. First, it analyzes daily production and demand to identify optimal locations for hydrogen pipelines. Second, it runs hourly simulations to refine production, transmission, and storage costs. This two-step process ensures the model captures the complexities of hydrogen ecosystem dynamics.

This appendix details the key assumptions in the modeling framework and presents technical information about the case results.

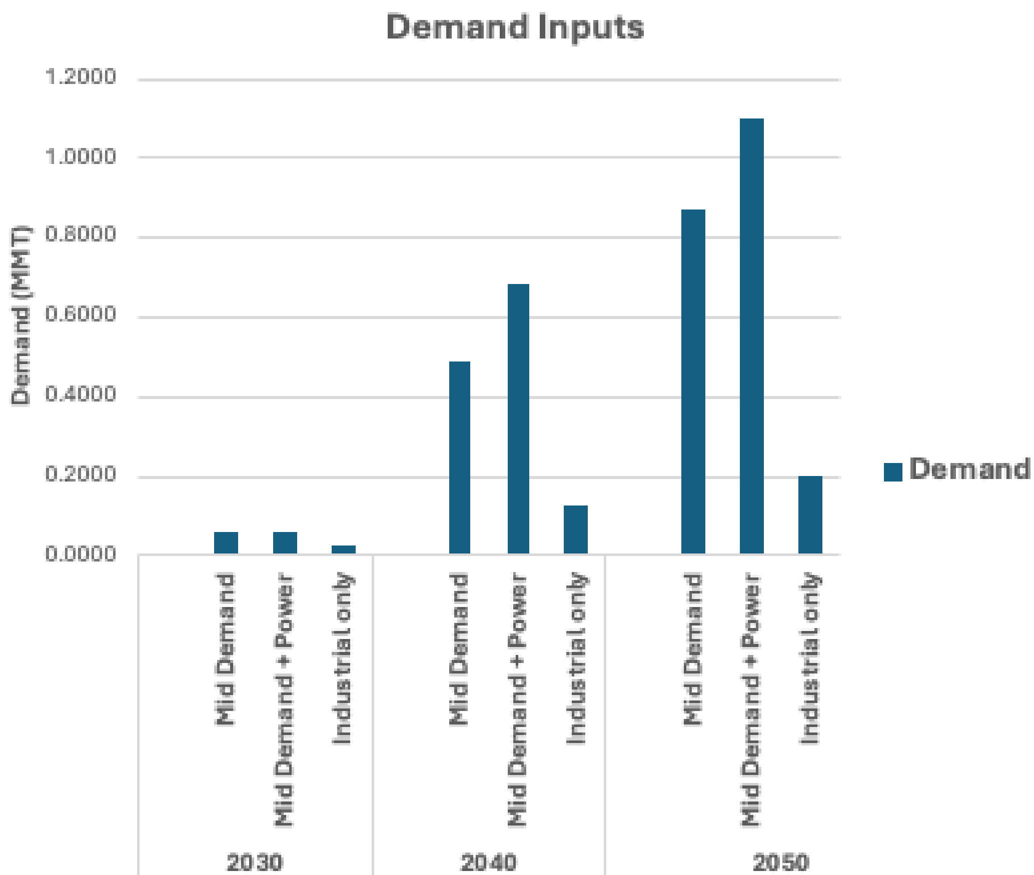
B.1 Key Inputs of Hydrogen Production, Storage, and Transmission Analysis Tool Model

B.1.1 Demand Assumptions

The base case aligns with the Mid-demand case projections that exclude power sector demand.
Case 1B examined the impact of including power sector demand, while the industrial-only case evaluates a hydrogen use case for a targeted end use. Figure B-1 shows the total demand inputs for each case across the modeling years.

Figure B-1. Demand Modeling Inputs

Figures in MMT.

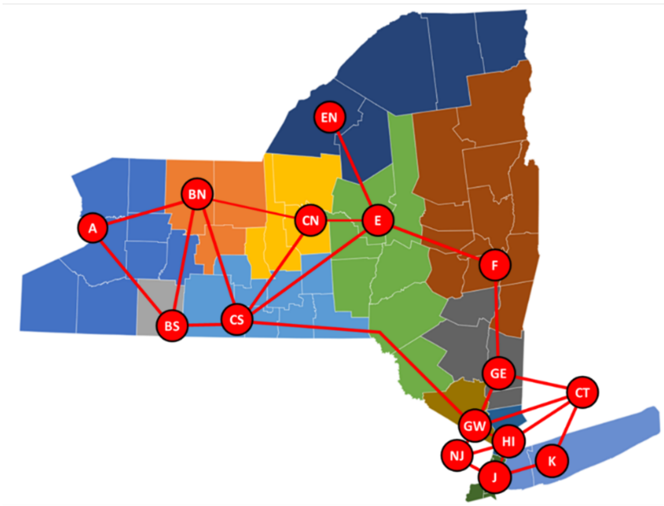


B.1.2 Spatial Load Zones Assumptions

The model divides hydrogen demand and production resources across several spatial zones based on New York Independent System Operator (NYISO) load control zones.[136]

For each zone, the model defines a central representing the major population and hydrogen demand center or, if more suburban/rural, the intersection of existing natural gas transmission pipelines. The model then defines potential transmission linkages and distances between nodes by following existing natural gas pipeline corridors.[137]

Figure B-2. Spatial Network Inputs for Hydrogen Production, Storage, and Transmission Analysis Tool Model



Zone	Node
A	Buffalo
BN	Rochester
BS	Whitesville
CN	Syracuse
CS	Steuben County
E	Utica (Central)
EN	Waterton
F	Albany
GE	Poughkeepsie
GW	Rockland
HI	Scarsdale
J	Queens
K	Commack
CT	Shelton, CT
NJ	Bergen County, NJ
OSW	Offshore Node

Zone OSW (Offshore Node) is not illustrated in the network diagram but is located on Long Island, where the offshore wind (OSW) and associated OSW electrolyzers would be situated.

B.1.3 Generation Resource Assumptions

The model considers only hydrogen production from electrolysis co-located with zero-emission electricity production resources. It evaluates hydrogen production as separate from electrical grid needs—treating renewable resources for hydrogen production as incremental and additional to those required to meet electrical grid demand. This assumption also means electrolyzers are not necessarily connected to the larger electrical grid. The resource assessment more closely reflects the dedicated renewables cases from Appendix G of the "Integration Analysis,"[138] although it uses a different methodologically from the grid-tied cases.

To determine renewable resources available for dedicated hydrogen production, the model subtracts grid resource needs from each resource's total technical potential in New York State in 2050, assigning the cheapest resources to the grid and the remaining resources available for hydrogen. The 2024 NYSERDA supply curve informed total technical potential, while the "Integration Analysis" informed grid needs.[139] The model limits solar build (and thus electrolyzer build) on Long Island (Zone K) to 0.5 gigawatts (GW).

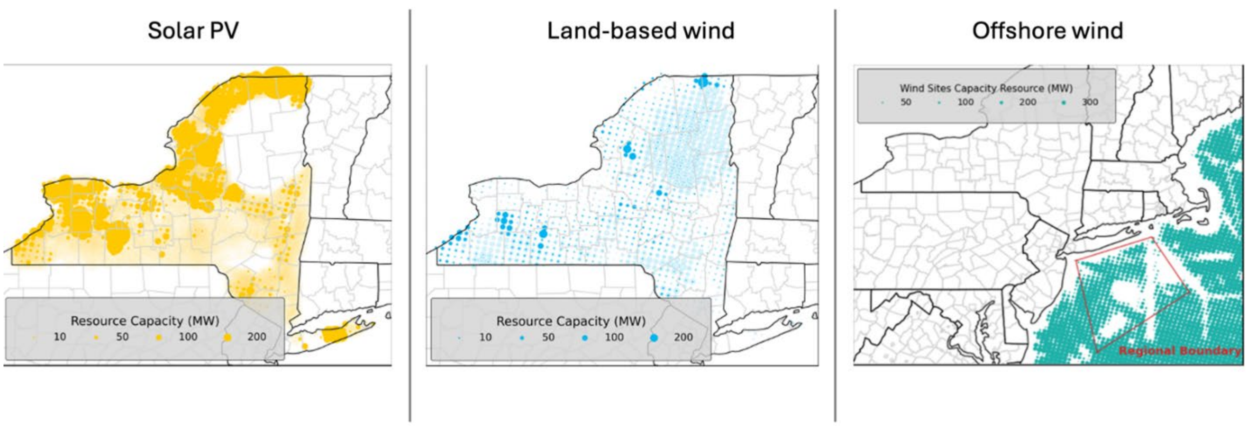
The potential for nuclear build presents a much more uncertain future and is not easily defined by technical potential such as renewables. However, assumptions were made to model a nuclear-based hydrogen network that limits nuclear build to 0.5 GW in Zones F (Capital Region) and G (Hudson Valley), leaving the build unconstrained in Zone C. This base assumption aligns with other efforts, including the coordinated grid planning process.

Table B-1. Resource Inputs for Hydrogen Production

Resource	Assumed Available Build Capacity (GW)	Average Electric CF (%)
Land-based wind	0.145 GW	~40%
Solar PV	33 GW	~20%
OSW	1.7 GW (fixed bottom) 10 GW (floating bottom)	~50%
Nuclear	0.5 GW (Zones F and G) Unconstrained (Zone C)	~93%

Research reflects the regional variation in land-based wind and solar photovoltaic (PV) availability for hydrogen production. These differences will likely influence where hydrogen can be produced at the lowest cost and the hydrogen transmission and storage infrastructure needed for a statewide hydrogen network.

Figure B-2. Resource Potential by Region Source



Based on this resource assessment, the Hydrogen Production, Storage, and Transmission Analysis Tool (HYPSTAT) model[140] uses these resource availabilities by zone as input parameters.

B.1.4.1 Renewable Resource Costs

The model sources each renewable resource's capital and annual operating costs from NYSERDA's February 2024 energy supply curve.[141] Within each zone, resources of the same technology share identical capital and operating costs, calculated by averaging county-level values. However, capacity factor profiles vary by resource tranche[142] and zone.

The model bases nuclear resource costs on the Idaho National Laboratory's lab meta-analysis of advanced nuclear reactors.[143] It selects a small modular reactor (SMR) design and applies New York State–specific adjustments to some inputs, such as cost of labor. Table B-2 shows the final cost inputs for nuclear.

Table B-2. Small Modular Reactor Nuclear Cost Inputs

Parameter	2040 Costs	2050 Costs
Overnight Capital Costs ($/kW)	8,700	6,600
Fixed O&M ($/kW/yr)	147	147
Variable O&M ($/MWh)	2.92	2.92
Heat rate (MMBtu/MWh)	10.34	10.34

B.1.5.2 Electrolyzer Costs

The HYPSTAT model[144] includes conservative and optimistic cost trajectories for proton exchange membrane (PEM) electrolyzers. The conservative trajectory aligns with the "Integration Analysis"[145] and assumes that 2050 costs are approximately half those in 2020. The optimistic trajectory follows the NREL H_2A model's low-temperature, central-based case, with 2050 costs at roughly 10% of current levels.

The model uses NREL H_2A projections for solid oxide electrolysis cell (SOEC) costs for 2030 and 2040 and extends the projections to 2050 using a combination of sources, including the H_2A model and IEA databases.

Table B-3. Electrolyzer Cost Assumptions

<table>
<tr><th rowspan="2">Technology/ Trajectory</th><th colspan="3">2030</th><th colspan="3">2040</th><th colspan="3">2050</th></tr>
<tr><th>CAPEX ($/kW)</th><th>OPX ($/kW/yr)</th><th>Efficiency (kWh/kg H_2)</th><th>CAPEX ($/kW)</th><th>OPEX ($/kW/yr)</th><th>Efficiency (kWh/kg H_2)</th><th>CAPEX ($/kW)</th><th>OPEX ($/kW/yr)</th><th>Efficiency (kWh/kg H_2)</th></tr>
<tr><td>Conservative Trajectory (PEM)</td><td>926</td><td>64</td><td rowspan="2">51</td><td>736</td><td>54</td><td rowspan="2">51</td><td>575</td><td>44</td><td rowspan="2">51</td></tr>
<tr><td>Optimistic Trajectory (PEM)</td><td>665</td><td>37</td><td>338</td><td>24</td><td>218</td><td>19</td></tr>
<tr><td>SOEC</td><td>1100</td><td>103</td><td>45</td><td>900</td><td>61.5</td><td>45</td><td>700</td><td>47.83</td><td>45</td></tr>
</table>

B.1.4 Inflation Reduction Act Tax Credit Assumptions

The Inflation Reduction Act of 2022 (IRA) introduces multiple tax credits to reduce net hydrogen production costs through 2050.

The IRA offers direct tax credits to hydrogen production facilities based on lifecycle emissions, contingent on the three criteria: regional clean energy sourcing, hourly matching starting in 2028, and new clean power generation. Although final requirements are pending when developing this report, the HYPSTAT model satisfies these conditions by co-locating renewables and performing hourly matching, aligning with the strictest possible interpretation of the Internal Revenue Service (IRS) guidance.[146]

The IRA also grants tax credits to zero-emission electricity generation resources, including renewables. These electricity generation tax credits become technology-neutral after 2025, so any facility meeting the emissions requirements can qualify. Hydrogen production facilities co-located with clean electricity can qualify for both credits.[147]

The IRA credits take the form of a 10-year production tax credit (PTC, in dollars per megawatt hours [$/MWh] electricity or per kilogram of hydrogen) or a one-time investment tax credit (ITC, as a percentage of upfront capital investment). Qualifying projects choose which credit to take, although the benefit of each credit generally depends on technology type, relative upfront capital expenditure, and sometimes project-specific factors. For electricity production credits, projects with relatively high capital costs and/or low capacity factors generally benefit more from the ITC. Because OSW and nuclear projects incur high capital costs, they will likely use the ITC, while land-based wind projects will likely choose the PTC. The decision to use the PTC or ITC for utility-scale solar PV projects depends on resource quality and the project's expected capacity factors.

Both hydrogen and electricity generation tax credits include phase-out schedules and safe-harbor periods. Safe harbor periods provide projects with additional construction time after the phase-out date if the project achieves key milestones before that date, for example, starting significant physical construction work or incurring at least 5% of the total facility cost. If a project reaches a milestone by the phase-out date and begins operation by the end of the safe-harbor period, it qualifies for the relevant IRA tax credits, including the full 10-year PTCs when applicable. Table B-4 summarizes the IRA tax credit provisions for hydrogen production and electricity generation.

Table B-4. Inflation Reduction Act Tax Credit Provisions for Hydrogen

IRA Credit	Tax Code Section	Full PTC Value*	Full ITC Value	Phase-Out Date	Safe-Harbor Period
Hydrogen Production	§ 45V	$3/kg H_2	N/A	2032	3 years
Electricity Generation	§ 45Y (PTC) § 48E (ITC)	$26/MWh, with bonus credits available	30%, with bonus credits available	Later of (1) 2032, or (2) when U.S. electricity emissions fall to 25% of 2022 levels	4 years 10 years for OSW

Table B-5 details key assumptions about the IRA tax credits related to the HYPSTAT model. The phase-out date for renewable generation credits was assumed to begin in 2045, allowing all land-based wind and solar PV capacity built in the HYPSTAT model to receive the full value of the credits. Additionally, all credits were levelized over each technology's assumed 30-year cost recovery period. This results in the net levelized credit value seen in Table B-5, which was applied across the project's entire lifespan.

Table B-5. Inflation Reduction Act Tax Credit Inputs for Hydrogen Production, Storage, and Transmission Analysis Tool Model

IRA Credit	Credit Type	Technologies	Levelized Credit Value[a]	Phase-out Date Begins	Safe-Harbor Period	Online By (End-of-Year)
Renewable generation	PTC	Land-based wind, solar PV	$24/MWh	2045	4 years	2049
	ITC	OSW, nuclear	~$40/MWh		10 years	2055
Hydrogen	PTC	Hydrogen	$2.5/kg	2032	3 years	2035

a Assuming full credit value with labor requirements met, the model allocated renewable generation credits to capture half of the available bonus credits and assumes 90% monetization of hydrogen credits. For simplicity, the ITC credit was converted to an equivalent $/MWh value using moderate cost assumptions from the NREL model.

B.1.5 Import Assumptions

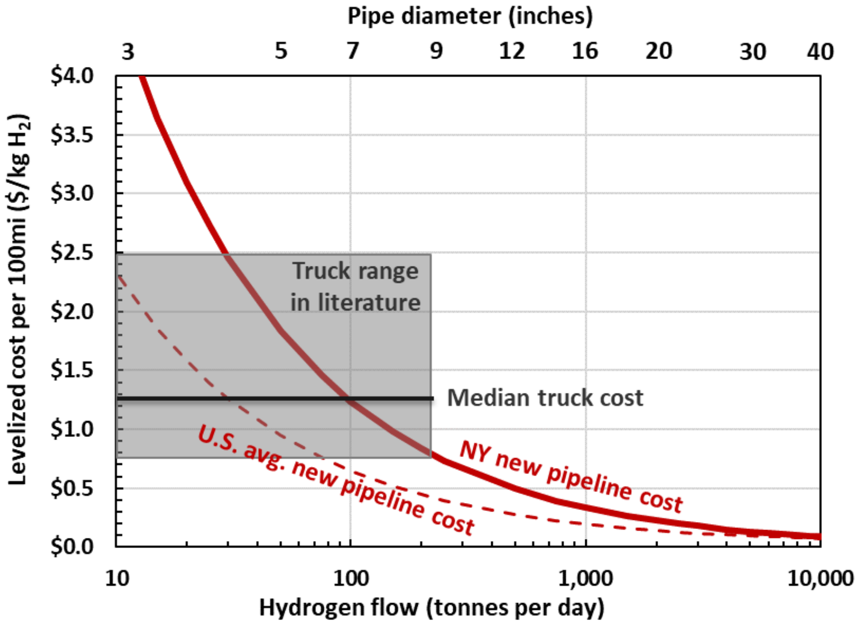
This study specified hydrogen imports on a volumetric basis, consistently allocating them to meet 50% of annual demand. Imported hydrogen was priced as the average in-state production cost and treated as available on demand without restrictions, even during periods of peak hydrogen demand. Imports were limited to entry to New York State through Zone CS on the Pennsylvania border.

B.1.6 Transport Assumptions

As with the natural gas system, pipelines are assumed to represent the most economical option for high-volume, long-distance hydrogen transmission. Smaller volumes and distribution are assumed to rely on the on-road truck, marine, or rail transport of gaseous or liquid hydrogen. In the HYPSTAT model, hydrogen transmission occurs via new builds, 100% hydrogen pipelines, or tube-trailer trucks, with the selected option based on volume and resulting cost. Pipelines are estimated to become more cost-effective than trucks for volumes exceeding 100 tonnes per day (TPD)–250 TPD, corresponding to pipeline diameters of approximately 7 inches–9 inches. The following outlines the cost assumptions for each transport option:

- **Pipelines:** New hydrogen pipelines are assumed to follow only existing natural gas pipeline rights-of-way. Capital costs for new hydrogen pipelines were estimated using the Argonne National Laboratory Hydrogen Delivery Scenario Analysis Model (HDSAM),[148] applying a best-fit curve on model outputs across a range of hydrogen flows shown in Figure B-3. Costs in New York State are assumed to be twice the U.S. average cost (modeled by HDSAM), based on similar cost premiums reported for new natural gas pipelines in the Northeast U.S.[149] A levelized operating cost for compression—$0.06 per kilogram per 100 miles (/kg-100 miles)—was also included from HDSAM.
- **Trucks:** Trucks are likely more cost-effective than small-diameter pipelines below this volume threshold, including during early stages of hydrogen supply and demand development. Current tube-trailer trucks for gaseous hydrogen have capacities of up to 300 kg–400 kg hydrogen, while larger-capacity trucks holding 1,000 kg (1 tonne) are in development. Typical costs for truck transmission vary widely in literature and recent models, ranging from $0.6/kg-100 miles–$2.5/kg-100 miles.[150] The HYPSTAT model uses a single median value of $1.25/kg-100 miles from this range and selects the more cost-effective transmission option(s) for each potential transmission corridor or linkage as part of the cost optimization.

Figure B-3. Transmission Costs Inputs for Best-Fit Curve Model



B.1.7 Storage Assumptions

The study included two technologies for hydrogen storage in the HYPSTAT model: pressurized tanks for aboveground storage and existing salt caverns in New York State. Depleted oil and gas reservoirs for high-volume geologic storage are also technically feasible but not modeled here given uncertainties in costs and availability. For each technology, the hydrogen compression cost for storage was assumed to be $0.06/kg (based on levelized compression costs from HDSAM).

- **Salt cavern/geologic storage:** The analysis assumed availability of the four existing salt cavern storage sites in New York State, all located in Zone CS, for conversion to hydrogen storage, with a total working capacity of 8 kilotonnes (kT).[151] The capital cost for retrofitting these existing caverns was estimated at $19/kg of working capacity, based on the negligible geological site preparation costs and a 50% reduction in costs for cushion gas, pipelines, and wells compared to new construction, while all other costs remained unchanged.[152, 153]
- **Aboveground tank storage:** Tank costs are significantly higher than those for geologic storage—estimated capital costs range from $800/kg–$1200/kg working capacity, with potential reductions to $600/kg through manufacturing scale-up.[154] The HYPSTAT model used the midpoint of this range ($800/kg). Tank storage was allowed in all zones except Zone J (New York City) due to current regulatory restrictions on siting and permitting hydrogen storage.

Appendix C. Supplementary Material for Total Cost of Ownership Analysis

C.1 Introduction

Energy and Environmental Economics, Inc. (E3) generated a quantitative analysis of the priority hydrogen use cases to provide additional economic context around the total cost of ownership (TCO) gap of hydrogen applications. The exercise applied a comprehensive, unified metric to:

- Realize the magnitude of the economic efficiency of each use case
- Compare TCO gaps across use cases, as much as possible, to assess relative economics

Together with qualitative insights, this would form a comprehensive picture of which options could best support NYSERDA's hydrogen goals—both in the current and future landscape—and provide an indication of the potential order of magnitude of incentives needed to enable successful deployment of hydrogen across various use cases.

C.2 Methodology

The agreed upon metric for determining financial comparability was the TCO gap of each use case, evaluated under a variety of sensitivities. The TCO gap represents the make-whole payment required to close the cost gap between a hydrogen project and its counterfactual for a given use case. This metric indicates the level of subsidy needed for a hydrogen application to reach financial parity with an incumbent technology and fuel.

The TCO gap metric includes both capital and operating cost gaps, serving as a "total cost of ownership" analysis. Capital costs are treated as upfront payments on an asset—including any loans or debt—such as the cost of a vehicle or an industrial boiler. Operating costs are paid throughout the asset's lifetime and include expenses such as gasoline or fuel used for heat. Modeled operating costs are comprehensive, covering fuel, maintenance, infrastructure, carbon payments, and any other applicable costs.

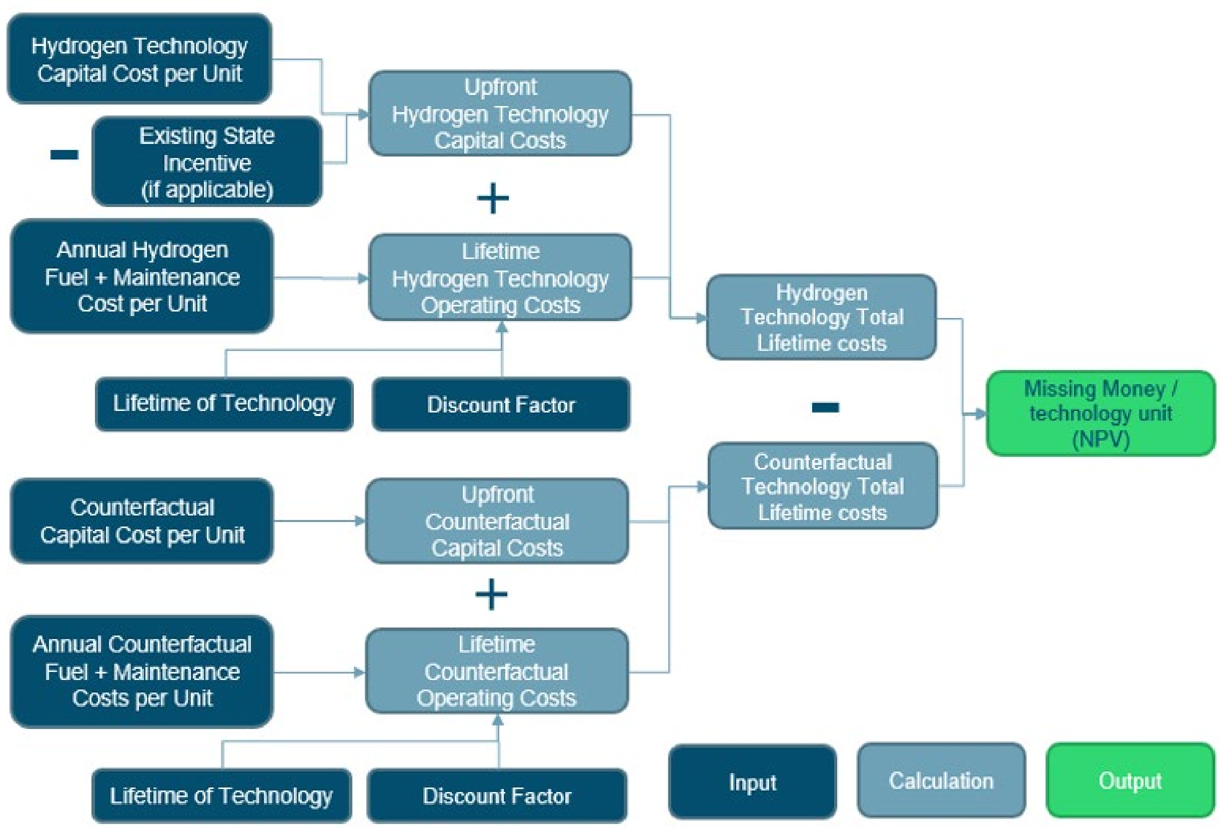
Both capital and operating costs are discounted to calculate the net present value (NPV) of an asset deployed in a given year. E3 assumes a baseline inflation rate of 2% per year, with real discount rates and discount periods (asset lifetimes) varying by use case. This annualized value is referred to as the lifetime cost.

Table C-1. Assumed Discount Factors and Lifetimes by Applications

Use Case	Discount Factor	Lifetime (Years)
LDVs	7.0%	16
MDVs	7.0%	19
HDVs	7.0%	16
High-Temperature Industry	5.1%	25
District Heating	7.5%	20

Figure C-1 presents a flowchart illustrating the logic used to calculate capital and operating lifetime cost inputs.

Figure C-1. Total Cost of Ownership Gap Methodology Framework



The study sourced the inputs for the analysis across the use cases from existing E3 and New York State Energy Research and Development Authority (NYSERDA) analyses, along with the latest publicly available industry information. Key inputs were reviewed and refined with support from various NYSERDA working groups.

C.3 Refueling Station Costs

Two cases were used to generate input parameters for refueling station capital costs in the assessment of hydrogen fuel costs for LDVs and MHDVs. The first case represents an advanced refueling station with higher station production and correspondingly lower station costs. The second case reflects a conservative refueling station with lower station production and correspondingly high station costs. Four total capital cost cases were applied: conservative and advance cases for both LDV and MHDV station cases.

To capture the potential effects of changing utilization and fuel supply on refueling costs, E3 varied assumptions from 2020 to 2050 in five-year increments. Utilization was modeled to increase over time in both cases, with the advanced case reaching higher total utilization. In addition, the advanced case included the introduction of new hydrogen fuel pipeline infrastructure after 2030, with pipeline-based fuel supply assumed to fully replace other sources after 2035.

E3 used the inputs in to model conservative and advanced refueling station costs for LDVs and MHDVs within the Department of Energy (DOE) and Argonne National Laboratory Heavy-Duty Refueling Station Analysis Model (HDRSAM). In all cases, HDRSAM modeled station utilization hours based on Chevron Corporation’s demand profile for internal combustion engine (ICE) vehicles at gasoline and diesel refueling stations.

Table C-2. Refueling Station Parameters

LDVs	Conservative Case						
Year	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Fuel Supply	Liquid	Liquid	Liquid	Liquid	Liquid	Liquid	Liquid
Pressure (bar)	700	700	700	700	700	700	700
Tank Type	IV	IV	IV	IV	IV	IV	IV
Avg Station Capacity (kg H_2 dispensed/day) (State Success)	130	420	710	1,000	1,180	1,360	1,540
Vehicle Fill Time (min)	2.8	2.8	2.8	2.8	2.8	2.8	2.8
Station Tech Learning Rate	Low	Low	Low	Low	Low	Low	Low
Station Utilization	20%	30%	40%	40%	40%	40%	40%
LDVs	**Advanced Case**						
Year	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Fuel Supply	Liquid	Liquid	Liquid	20-bar pipeline	20-bar pipeline	20-bar pipeline	20-bar pipeline

Table C-2. (continued

LDVs	Conservative Case						
Year	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Pressure (bar)	700	700	700	700	700	700	700
Tank Type	IV	IV	IV	IV	IV	IV	IV
Avg Station Capacity (kg H_2 dispensed/day) (State Success)	130	420	710	1,000	1,180	1,360	1,540
Vehicle Fill Time (min)	2.8	2.8	2.8	2.8	2.8	2.8	2.8
Station Tech Learning Rate	Medium	Medium	Medium	Medium	Medium	Medium	Medium
Station Utilization	20%	30%	40%	50%	59%	69%	78%
MDVs and HDVs	**Conservative Case**						
Year	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Fuel Supply	Liquid	Liquid	Liquid	Liquid	Liquid	Liquid	Liquid
Pressure (bar)	350	350	350	350	350	350	350
Tank Type	III	III	III	III	III	III	III
Avg Station Capacity (kg H_2 dispensed/day) (State Success)	130	420	710	1,000	1,180	1,360	1,540
Vehicle Fill Time (min)	4.9	4.9	4.9	4.9	4.9	4.9	4.9
Station Tech Learning Rate	Low	Low	Low	Low	Low	Low	Low
Station Utilization	20%	30%	40%	40%	40%	40%	40%
MDVs and HDVs	**Advanced Case**						
Year	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Fuel Supply	Liquid	Liquid	Liquid	20-bar pipeline	20-bar pipeline	20-bar pipeline	20-bar pipeline
Pressure (bar)	350	350	350	350	350	350	350
Tank Type	III	III	III	III	III	III	III
Avg Station Capacity (kg H_2 dispensed/day) (State Success)	130	**420**	710	**1,000**	1,180	1,360	**1,540**
Vehicle Fill Time (min)	4.9	4.9	4.9	4.9	4.9	4.9	4.9
Station Tech Learning Rate	Medium	Medium	Medium	Medium	Medium	Medium	Medium
Station Utilization	20%	30.00%	40.00%	49.50%	59.00%	68.50%	**78%**

Table C-3. Hydrogen Refueling Station Costs

Hydrogen Refueling Station Costs, Updated (in $2020)							
Years	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
LDV Conservative Production Station Cost ($2020/kg)	26.5	10.6	9.5	5.0	4.7	4.3	4.2
LDV Advanced Production Station Cost ($2020/kg)	40.8	14.7	13.4	11.8	11.3	10.7	10.5
MDV/HDV Conservative Production Station Cost ($2020/kg)	19.3	9.7	7.4	3.4	2.9	3.2	3.0
MDV/HDV Advanced Production Station Cost ($2020/kg)	28.0	11.2	9.7	9.2	8.3	8.8	8.3
MDV/HDV Conservative Production Station Cost ($2020/kg)	19.3	9.7	7.6	3.4	2.9	3.2	3.0
MDV/HDV Advanced Production Station Cost ($2020/kg)	28.1	11.2	9.7	9.2	8.3	8.8	8.3

C-4 Detailed Assumptions by Use Case

The TCO gap calculations for the six priority use cases include detailed assumptions. Relevant sources are provided for reference.

Table C-4. Detailed Input Assumptions by Use Case

LDVs	Market	Source	Unit	2025	2030
Fuel economy	ICE	**Integration Analysis – Appendix G (NYSERDA 2022)**	miles per gallon	35.3	41.0
Fuel economy	H2	**Integration Analysis – Appendix G (NYSERDA 2022)**	miles per gallon	54.8	58.4
VMT	ICE, H2	**Integration Analysis – Appendix G (NYSERDA 2022)**	VMT/vehicle	11647	11235
Gasoline costs	ICE	**Integration Analysis – Appendix G (NYSERDA 2022)**	$2020/gallon	2.93	2.72
Capital costs	ICE	**Integration Analysis – Appendix G (NYSERDA 2022)**	$2020/vehicle	31665	32756
Capital costs	H2	**Integration Analysis – Appendix G (NYSERDA 2022)**	$2020/vehicle	58391	35476
Maintenance costs	H2	**AFLEET Tool (Argonne, 2020)**	$2020/mile	0.06	0.06
Maintenance costs	ICE	**AFLEET Tool (Argonne, 2020)**	$2020/mile	0.10	0.10

Table C-4. (continued)

MDVs	Market	Source	Unit	2025	2030
Fuel economy	ICE	**New York State Clean Transportation Roadmap (NYSERDA 2021)**	mpg	9.14	9.82
Fuel economy	H2	**New York State Clean Transportation Roadmap (NYSERDA 2021)**	mpg	10.88	11.69
VMT	ICE	**Integration Analysis – Appendix G (NYSERDA 2022)**	miles/vehicle	19960.50	20942.33
VMT	H2	**Integration Analysis – Appendix G (NYSERDA 2022)**	miles/vehicle	19960.50	20942.33
Diesel costs	ICE	**Integration Analysis – Appendix G (NYSERDA 2022)**	$2020/gallon	3.14	3.25
Capital costs	ICE	**New York State Clean Transportation Roadmap (NYSERDA 2021)**	$2020/vehicle	72565.43	78848.67
Capital costs	H2	**New York State Clean Transportation Roadmap (NYSERDA 2021)**	$2020/vehicle	174064.06	80819.92
State voucher	H2	**NYSERDA Truck Voucher Incentive Program (NYSERA 2022)**	$2020/vehicle	100000.00	100000.00
Maintenance costs	ICE	**NREL Total Cost of Ownership (Trucks) Report (Hunter, 2021)**	$2020/mile	0.12	0.12
HDVs	Market	**Source**	**Unit**	**2025**	**2030**
Fuel economy	ICE	**New York State Clean Transportation Roadmap (NYSERDA 2021)**	mpg	5.1	5.5
Fuel economy	H2	**New York State Clean Transportation Roadmap (NYSERDA 2021)**	mpg	6.5	7.0
VMT	ICE	**Integration Analysis – Appendix G (NYSERDA 2022)**	miles/vehicle	51011.1	53651.6
Diesel costs	ICE	**Integration Analysis – Appendix G (NYSERDA 2022)**	$2020/gallon	3.1	3.3
Capital costs	ICE	**Integration Analysis – Appendix G (NYSERDA 2022)**	$2020/vehicle	143122.5	153585.9

Table C-4. (continued)

HDVs	Market	Source	Unit	2025	2030
Capital costs	H2	**New York State Clean Transportation Roadmap (NYSERDA 2021)**	$2020/vehicle	355099.4	178105.1
State voucher	H2	**NYSERDA Truck Voucher Incentive Program (NYSERA 2022)**	$2020/vehicle	185000.0	185000.0
Maintenance costs	ICE	**NREL Total Cost of Ownership (Trucks) Report (Hunter, 2021)**	$/mile	0.15	0.15
Maintenance costs	H2	**NREL Total Cost of Ownership (Trucks) Report (Hunter, 2021)**	$/mile	0.15	0.15
High Temperature Industry	**Market**	**Source**	**Unit**	**2025**	**2030**
Industrial delivered costs	NG	**Integration Analysis – Appendix G (NYSERDA 2022)**	$2020/MMBtu	5.44	4.86
Capital cost hydrogen heater, high	H2	**Industrial Fuel Switching Market Potential Study (Element Energy, 2018)**	$2020/kWth	322.2	322.2
Capital cost hydrogen heater, low	H2	**Assumed equal to counterfactual cost**	$2020/kWth	268.0	268.0
Capital cost counterfactual	NG	**Industrial Fuel Switching Market Potential Study (Element Energy, 2018)**	$2020/kWth	268.0	268.0
O&M fixed costs	H2	**Industrial Fuel Switching Market Potential Study (Element Energy, 2018)**	$2020/kW/yr	3.19	3.19
O&M fixed costs	NG	**Industrial Fuel Switching Market Potential Study (Element Energy, 2018)**	$2020/kW/yr	4.31	4.31
Efficiency	H2/NG	**Industrial Fuel Switching Market Potential Study (Element Energy, 2018)**	%	0.92	0.92

Table C-4. (continued)

High Temperature Industry	Market	Source	Unit	2025	2030
Load factor	H2/NG	**Industrial Fuel Switching Market Potential Study (Element Energy, 2018)**	%	0.80	0.80
District Heating	**Market**	**Source**	**Unit**	**2025**	**2030**
Hydrogen conversion costs	H2	**Industrial Fuel Switching Market Potential Study (Element Energy, 2018)**	$2020/kW	69.4	69.4
Implied gas usage	NG	**Con Edison 2021 Annual Adjustment Filing (ConEd 2021)**	MMBtu	477437.6	477437.6
Efficiency	H2/NG	**Derived from Heat Rate of 1480 btu/lb (2021 Annual Report)**	%	0.81	0.81
Load factor	H2/NG	**ConEd 10k Annual Report, (ConEd 2021)**	%	0.05	0.05

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Appendix D. Supplementary Material for Demand Analysis Innovation Focus Areas

Table D-1. Source Library for Innovation Focus

Project	Category	Description
Plug Power Hydrogen Production Facility	Production	**Plug Power** is building a 120 MW hydrogen production facility that will take advantage of clean hydropower from Niagara, NY. The facility is expected to produce 45 MT of liquid hydrogen per day.
Topsoe SOEC Manufacturing Facility	Production	**Topsoe** is constructing an electrolyzer manufacturing plant in Cheterfield County, VA, with a production capacity of 500 MW per year, with plans to expand to 5 GW per year.
Nine Mile Point Hydrogen Pilot	Production, Power Generation	**Constellation Energy Group**, operator of Nine Mile Point Nuclear Station near Oswego, NY, has a 1 MW PEM electrolyzer that uses nuclear generated electricity to produce hydrogen. The plant is also developing 10 MW of fuel cells to generate electricity from hydrogen produced on-site for peak demand management.
Air Products Gulf Coast Hydrogen Network	Delivery and Storage	**Air Products and Chemicals** manages a 600-mile network of dedicated 18-inch hydrogen pipelines stretching from Houston, TX, to New Orleans, LA.
Air Liquide Hydrogen Network	Delivery and Storage	**Air Liquide** operates a hydrogen pipeline network along the Gulf Coast, which includes two segments converted from crude oil to hydrogen in the 1990s.
H_2HoWi Project	Delivery and Storage	**E.ON** plans to convert an existing natural gas line in Germany to carry pure hydrogen.
HyDeploy	Delivery and Storage	The **HyDeploy** project, on the campus of Keele University in the UK, has safely tested blends up to 20% in the existing gas distribution network.
mosaHYc	Delivery and Storage	The **mosaHYc** project aims to convert around 70 km of gas pipelines along the French-German border to carry 100% hydrogen.
Teeside Salt Cavern	Delivery and Storage	**Sabic Petrochemicals** has maintained a salt cavern for hydrogen storage in Teeside, UK, since 1972, which stores up to 25 GWh of energy.
ACES Utah	Delivery and Storage, Power Generation	The **ACES Delta** project in Utah will deploy 220 MW of renewable electricity to produce 100 MT per day of hydrogen and store up to 300GWh of hydrogen in salt caverns.
HyPSTER	Delivery and Storage	The **HyPSTER** project, supported by the EU in France, aims to store hydrogen in bedded salt deposits for later industrial and power generation uses.
NASA H_2 Storage Tanks	Delivery and Storage	**NASA** recently completed the construction of new liquid hydrogen storage tanks in Florida, holding approximately 4,200 MT, the largest in the world.
AHEAD Methylcyclohexane Dehydrogenation	Delivery and Storage	The **AHEAD** consortium in Japan successfully demonstrated the dehydrogenation of methylcyclohexane from a transocean shipment to power gas turbines for power generation.
ENE-Farm	Buildings	The **ENE-FARM** project in Japan includes over 300,000 fuel cell units generating combined heat and power for buildings.
$H_2$1 Leeds City Gate	Buildings	The **Leeds City Gate** study investigated converting the city of Leeds (within the city of West Yorkshire, England) to 100% hydrogen for building heating and found it to be technically, economically, and financially feasible.

Table D-1. (continued)

Project	Category	Description
Caterpillar CHP Demo	Buildings	Caterpillar plan to demonstrate a 100% hydrogen-powered CHP system integrated into the district steam system in St. Paul, MN.
HyBrit	Industry	Sweden's **HyBrit** project demonstrates DRI production using clean hydrogen as the reducing agent to decarbonize steelmaking. The project will produce 1.2 MT of crude steel annually, representing 25% of Sweden's overall production.
Cleveland Cliffs DRI	Industry	**Cleveland-Cliffs Steel Corporation** is installing a hydrogen-based DRI system at its facility in Ohio, with $500 M of support from the DOE.
Entergy Texas	Power Generation	**Entergy Texas** has contracted with an EPC consortium led by Mitsubishi Power to develop a 1.2 GW hydrogen-capable combined cycle power plant in Orange County, TX.
NYPA Brentwood Plant	Power Generation	**NYPA**, together with **EPRI** and **GE,** demonstrated the combustion of natural gas/hydrogen blends ranging from 5% to 40% hydrogen by volume in GE combustion turbines at the NYPA Brentwood plant in Suffolk County, NY.
40 MW Ammonia Turbine	Power Generation	**Mitsubishi Power** is developing a 40 MW turbine that can burn 100% ammonia.
MTA FCEV Bus Pilot	Ground Vehicles	The **MTA** in Downstate New York is developing a pilot of hydrogen bus FCEVs with $8 M in support from NYSERDA.
Hydrogen-powered Mine Haul Truck	Ground Vehicles	**Anglo American** unveiled a prototype battery/fuel cell hybrid mine haul truck.
Hydrogen-powered Mobile Crane	Ground Vehicles	The **Port of Shanghai** tested a hydrogen fuel-cell powered mobile crane.
Hydrogen Crane Deployment	Ground Vehicles	The **Port of Los Angeles** (CA) deployed the world's first hydrogen fuel cell–powered rubber-tired gantry crane.
Ammonia-powered Tugboat	Maritime	**Amogy**, a startup based in Brooklyn, NY, demonstrated an ammonia-powered tugboat with a 1 MW fuel cell system.

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