



NARUC

National Association of Regulatory Utility Commissioners

Coal and Carbon Management Guidebook: Coal-to-Hydrogen Opportunities and Challenges



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Acronyms

ACAA	American Coal Ash Association
ACEEE	American Council for an Energy Efficient Economy
AEP	American Electric Power
AFC	Alkaline Fuel Cells
AML	Abandoned Mine Land
ARPA-E	Advanced Research Program Agency–Energy (DOE)
ARRA	American Recovery and Reinvestment Act
ATR	Autothermal Reforming
Bcf	Billion Cubic Feet
BECCS	Bioenergy with Carbon Capture and Sequestration
BH	Baghouse
BSCP	Big Sky Carbon Sequestration Partnership
Btu	British Thermal Unit
CarbonSAFE	Carbon Storage Assurance Facility Enterprise
CaSO ₃	Calcium Sulfite
CaSO ₄	Gypsum
CBA	Cost-Benefit Analysis
CCR	Coal Combustion Residuals
CCS	Carbon Capture and Storage
CCUS	Carbon Capture, Utilization and Storage
CDR	Carbon Dioxide Removal
CEQ	Council on Environmental Quality
CFP	Circulating Fluidized Bed
CH ₄	Methane
CM	Critical Minerals
CO	Carbon Monoxide
CO ₂	Carbon Dioxide
Coal FIRST	Coal Flexible, Innovative, Resilient, Small, Transformative
COP	Conference of the Parties
DAC	Direct Air Capture
DER	Distributed Energy Resources
DOE	U.S. Department of Energy
EERE	DOE Office of Energy Efficiency and Renewable Energy
EIA	U.S. Energy Information Administration
EOR	Enhanced Oil Recovery

EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute
ESP	Electrostatic Precipitator
FBC	Fluidized Bed Combustion
FCEV	Fuel Cell Electric Vehicle
FE	DOE Office of Fossil Energy
FECM	DOE Office of Fossil Energy and Carbon Management
FEED	Front-End Engineering Design
FEJA	Future Energy Jobs Act
FGD	Flue Gas Desulfurization
FR	Federal Register
GE	General Electric
GHG	Greenhouse Gas
GPSP	Great Plains Synfuels Plant
Gt	Gross Tonnage
GW	Gigawatts
H ₂	Hydrogen
H ₂ O	Water
H ₂ S	Hydrogen Sulfide
HDV	Heavy Duty Vehicle
HRSR	Heat Recovery Steam Generator
IEA	International Energy Agency
IEEE	Institute of Electrical and Electronic Engineers
IGCC	Integrated Gasification Combined Cycle
IMO	International Maritime Organization
IRP	Integrated Resource Planning
IRS	Internal Revenue Service
IURC	Indiana Utility Regulatory Commission
kg	Kilogram
kWh	Kilowatt Hour
lb	Pound
LACE	Levelized Avoided Cost of Electricity
LCOE	Levelized Cost of Electricity
LCOS	Levelized Cost of Storage
LDV	Light Duty Vehicle
M ³	Cubic Meters
MCFC	Molten Carbonate Fuel Cells

MDV	Midweight Vehicle
MGSC	Midwest Geological Sequestration Consortium
MMBtu	Metric Million British Thermal Unit
MRCSP	Midwest Regional Carbon Sequestration Partnership
MMT	Million Metric Tons
MSW	Municipal Solid Waste
MT	Metric Tons
MW	Megawatt
N ₂	Nitrogen
NACFE	North American Council for Freight Efficiency
NARUC	National Association of Regulatory Utility Commissioners
NE	DOE Office of Nuclear Energy
NEEP	Northeast Energy Efficiency Partnerships
NETL	National Energy Technology Laboratory
NERC	North American Electric Reliability Corporation
NGCC	Natural Gas Combined Cycle
NH ₃	Ammonia
NO _x	Nitrogen Oxides
NREL	National Renewable Energy Laboratory
NPC	National Petroleum Council
NSPS	New Source Performance Standards
O ₂	Oxygen
O&M	Operations and Maintenance
OMB	Office of Management and Budget
OE	DOE Office of Electricity
OEM	Original Equipment Manufacturer
PAFC	Phosphoric Acid Fuel Cells
PC	Pulverized Coal
PCOR	Plains CO ₂ Reduction Partnership
PCT	Participant Cost Test
PEM	Polymer Electrolyte Membrane
PF	Pulverized Fuel
PM	Particulate Matter
PSA	Pressure Swing Adsorption
PSC	Public Service Commission
PUC	Public Utility Commission
PV	Photovoltaic

R&D	Research and Development
RCRA	Resource Conservation and Recovery Act
RCSP	Regional Carbon Sequestration Partnerships
RD&D	Research, Development, and Demonstration
RDD&D	Research, Development, Demonstration, and Deployment
REE	Rare Earth Elements
RIM	Ratepayer Impact Measure
RPS	Renewable Portfolio Standards
R-SOFC	Reversible Solid Oxide Fuel Cells
Scf	Standard Cubic Feet
SCT	Societal Cost Test
SECARB	Southeast Regional Carbon Sequestration Partnership
SMR	Steam Methane Reforming
SNCR	Selective Non-Catalytic Reduction
SNG	Synthetic Natural Gas
SO ₂	Sulfur Dioxide
SO _x	Sulfur Oxides
SOFC	Solid Oxide Fuel Cells
SUV	Sports Utility Vehicle
SWP	Southwest Regional Partnership on Carbon Sequestration
Tcf	Trillion Cubic Feet
TDS	Total Dissolved Solids
TRC	Total Resource Cost
TRIG	Transport Integrated Gasification
TRL	Technology Readiness Level
TSA	Thermal-Swing Adsorption
UCT	Utility Cost Test
UIC	Underground Injection Control
USGS	U.S. Geological Survey
VSA	Vacuum-Swing Adsorption
WESTCARB	West Coast Regional Carbon Sequestration Partnership
WGS	Water-Gas Shift
WPC	Westinghouse Plasma Corporation

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Executive Summary

This report is prepared for use by State Utility Regulators in support of their efforts to ensure safe, reliable, resilient energy services for their states, as well as additional energy stakeholders, such as federal regulators, utilities, environmental advocates, state legislators and energy officials, and the public. Contents of the report and the information included are mostly derived from documents developed and published by a variety of public and private sector organizations and numerous other reference sources listed in the footnotes.

Key elements of this report include coal-to-hydrogen production in the context of the U.S. hydrogen market; the state of various hydrogen production technologies; present and forecasted demand for hydrogen in energy, transportation, and industrial sectors; an overview of environmental, economic, and infrastructure challenges to greater coal-to-hydrogen production; and information on the U.S. Department of Energy (DOE) programs and priorities for coal-to-hydrogen research and development.

The following are some of the highlights of the findings provided in this report. These and other focus areas of the report are discussed in more detail in the body of the report and the appendices. Chapter 1 provides an introduction, basic definitions, and context for the current policy and economic conditions faced by the coal industry.

Section A: Hydrogen Demand and Clean Energy (Chapters 2 - 3)

- Coal is as an abundant domestic resource with a long history as a reliable source of low-cost electricity generation. The U.S. has over 260 billion tons of recoverable coal reserves—28% of total global reserves. U.S. coal production and consumption has been on a decline since its peak of 1.17 billion tons of production in 2008 and 1.13 billion tons of consumption in 2007, accounting for a peak of 48% of the electricity generated. This percentage declined to 20% in 2020 and is expected to decline further as the trend to limit carbon dioxide (CO₂) emissions continues. The share of natural gas used to generate electricity has almost doubled to about 40% during the same period.
- As the demand for clean energy continues to rise in the U.S., alternative sources of energy such as hydrogen are being further explored, and advanced technologies and processes are continuously developed and improved to support various industries. Hydrogen can be produced from almost all energy resources, though today's use of hydrogen in oil refining and chemical production is mostly produced from fossil fuels. Hydrogen produced from fossil fuels with carbon capture, utilization, and storage (CCUS) can help meet demand, reduce emissions, improve air quality, and foster energy security through domestic production.
- Today's dedicated hydrogen production facilities around the world rely on fossil fuels (76% natural gas, 22% coal). In the U.S., 99% of U.S. hydrogen production is sourced from fossil fuels, with 95% from natural gas by steam methane reforming, and 4% by partial oxidation of natural gas via coal gasification. Only 1% of U.S. hydrogen is produced through electrolysis of water. Production of hydrogen from fossil fuels is currently the least-cost option using current technologies. In the long run, hydrogen could enable the power sector to transition to net-zero emissions and also bridge the gap between fossil fuels and renewable energy.

Section B: Building on Domestic Coal Resources and CCUS Research (Chapters 4 - 9)

- Declining coal production has left the U.S. with an enormous source of a domestic natural resource that can be an important element of energy security. Coal-to-hydrogen production gives the U.S. the opportunity and advantage to transition to hydrogen economy in the near term. High-efficiency, low-emission coal plants are an important pathway to reaching carbon-neutral or net-negative emissions. Despite the fact that current CCUS technologies to reduce CO₂ emissions in the production of hydrogen from fossil fuels add costs to the process, there are significant benefits associated with hydrogen.

- The U.S. has made significant strides in the development of CCUS technologies during the last two decades, which has been aided by public-private partnerships that have driven cost reductions and performance improvements. Some technologies are in use and available for commercial deployment today while others require commercial demonstration to prove their viability in a commercial setting. However significant research, development, and demonstration (RD&D) efforts are required to reduce the cost and technical risk of CCUS.
- The power sector is expected to play a key role in the widespread growth of hydrogen. State legislative requirements that expect utilities to decarbonize faster than other industrial sectors and other market incentives and subsidies may drive early adoption of hydrogen in power generation. The U.S. is well positioned to accelerate a transition to a hydrogen economy by developing technology solutions coupled with CCUS that enable the production of hydrogen with zero, or even net-negative, carbon emissions.

Section C: Deploying Innovation (Chapter 10)

- The development of new technologies requires investing significant capital and operating funds, which are subject to elevated levels of risk due to an uncertain return on investment. Capital investments will be required to modify and convert existing fossil fuel-based power plant to produce hydrogen while the recovery of associated costs will eventually have an impact on ratepayers or on the cost of electricity or hydrogen in the new marketplace. These risks are a disincentive for the market to invest the capital required to deploy new infrastructure associated with coal-to-hydrogen conversion; likewise, for corporate boards weighting the uncertainty of a return on investment for a large capital project and maximizing returns for shareholders. These risks can similarly result in a disincentive for state regulators to approve projects as they attempt to strike a balance between protecting ratepayers and facilitating the deployment of new technologies that could support state policy goals. The cost of hydrogen or electricity from a new coal-to-hydrogen facility may well be noncompetitive in the marketplace absent subsidies.
- Regulators can work with the private sector to ensure that sufficient incentives are in place that reward successful deployment of new technologies, yet at the same time protect ratepayers from cost overruns and other risks. Regulators must balance an increasingly wide range of economic, safety, reliability, policy, and societal goals in the oversight of the electricity system. These varied priorities can be competing and the decisions regulators make in response often reflect a measured consideration of multiple factors impacting the public interest.
- Public Utility Commissions have an obligation to ensure the establishment and maintenance of utility services and to ensure they are provided at rates and conditions that are fair, just, and reasonable for all consumers. For regulators, this means that the task of ensuring the affordability, safety, and reliability of energy systems, while also meeting emissions reductions and renewable policy goals, is becoming increasingly complex.
- Challenges and opportunities for coal-to-hydrogen can be addressed through continued cooperation and partnerships between the federal government, industry, and regulators. To succeed, the federal government will need to continue to fund the development of new technologies through the basic RD&D phases. Industry should allocate an appropriate percentage of their corporate budgets towards RD&D efforts.
- Incentives may be required to facilitate the use of hydrogen in the commercial, industrial, and transportation marketplaces. Regulators and legislators can work with the private sector to ensure that sufficient incentives are in place that reward successful deployment of new technologies, yet at the same time protect ratepayers from cost overruns and other risks.

Chapter 11 offers concluding remarks, remaining challenges, and areas for further research.

A forthcoming NARUC resource, *Regulators' Energy Transition Primer*, authored by BCS, LLC, provide information on other questions and challenges State Utility Regulators are likely to encounter as they consider investments in hydrogen production and transportation infrastructure. The issue brief details economic impacts, environmental justice, and energy workforce issues, highlighting federal initiatives to support fossil communities in the energy transition. Because of the relevance of coal-to-hydrogen production to these two subjects, a brief summary follows.

Economic Impacts of the Energy Transition on Energy Communities, Environmental Justice Considerations, and Implications on Clean Energy Jobs

- The shift away from coal as a primary source of electricity generation and closures of coal-fired power plants have accelerated over the last decade and resulted in job losses and economic downturns in fossil-dependent communities that are struggling to maintain services and businesses. Although workers and communities have suffered and are facing an uncertain future as the coal industry declines, federal, state, and local governments are looking for solutions and taking actions to help dislocated workers move to other industries, e.g., jobs in the clean energy sectors.
- In response to the emerging challenges created by this U.S. energy transition, the Biden Administration issued Executive Order (EO) 14008, "Tackling the Climate Crisis at Home and Abroad," on January 27, 2021, establishing two initiatives to lead and assist power plant communities through the nation's energy transition.
- The EO established the Interagency Working Group on Coal and Power Plant Communities and Economic Revitalization and directed the Working Group to prepare an initial report describing "mechanisms, consistent with applicable law, to prioritize grantmaking, federal loan programs, technical assistance, financing, procurement or other existing programs to support and revitalize the economies of coal and power plant communities."
- Environmental justice that requires the fair treatment and meaningful involvement of all people, regardless of race, color, national origin, or income, with respect to the development, implementation and enforcement of environmental laws, regulations and policies, is an important factor in decisions regarding the choice, location, and environmental impacts of new technologies.

1. Introduction

Coal is as an abundant domestic resource with a long history as a reliable source of low-cost electricity generation. According to the U.S. Energy Information Administration (EIA), as of January 1, 2020, demonstrated reserve base¹ of the U.S. was estimated to contain 473 billion tons and the U.S. leads the world with over 260 billion tons of recoverable coal reserves—28% of total global reserves. At current mining levels, coal reserves would last more than 200 years.^{2,3} However, over the past decade, coal-based power plants have faced rising operating costs, pressures to decarbonize, stagnant electricity demand exacerbated by COVID-19 pandemic-induced economic recession, and price competition from natural gas and renewables. Large coal plants, designed to supply steady baseload power, must also cope with the rapid cycling now required to offset the grid's increased use of intermittent renewable energy.

The role of coal in U.S. power generation mix has declined. Coal plant capacity peaked at 318 gigawatts (GW) in 2011 and has fallen since then as plants retire or switch to other fuels (Figure 1⁴). By the end of 2019, capacity dropped to 229 GW, and utilization rates declined from 67% in 2010 to 48% in 2019.⁵ Many of the plants closed were aging and more than 60 years old, but some utilities have begun closing newer coal plants as well. It is anticipated that growing environmental, social, and governance pressures are likely to cause more closures or bankruptcies in the near term. Some utilities plan to sustain operations by co-firing with biomass or operating only during peak seasons. EIA projects that coal will provide only 13% of U.S. power in 2050, down from 24% in 2019.⁶

In 2020, about 4 trillion kWh of electricity was generated at utility-scale generation facilities in the U.S. About 60% of this electricity was from fossil fuels—natural gas (40%), coal (19%), and petroleum and other gases (0.7%). The rest, 40% was from nuclear and renewable energy sources, about 20% each. ([U.S. Energy Information Administration](#))

Construction of new coal power plants virtually stopped over the past two decades due to competition from other fuels and permitting/regulatory requirements, resulting in an older, less efficient operating fleet. Most older U.S. coal plants operate at subcritical conditions, as opposed to more efficient supercritical and ultra-supercritical plants. Supercritical and ultra-supercritical plants that operate at higher temperatures and pressures are more efficient, resulting in less fuel per unit output and proportionally lower emissions.

Fossil Energy Trends and the Future of Fossil Fuel Based Power Plants

The fossil energy sector of the U.S. is becoming more agile and innovative in response to recent past and ongoing economic and environmental challenges. One of the driving forces behind energy transition is the need to address climate change concerns and reduce the carbon footprint of energy production. In 2021, the Biden Administration proposed ambitious carbon reduction goals to achieve carbon-free power generation by 2035 and a net-zero carbon economy by 2050. Domestic coal markets are expected to continue declining as a result of reduced demand and the industry will likely continue to face significant hurdles without low-cost, proven technologies to generate power with carbon neutral or net-negative emissions. In response to stakeholder concerns, many states, tribes, companies, cities, and utilities plan to achieve carbon neutrality by 2050 or sooner. In order to survive, coal-fired power plants will need to invest in and adopt a range of new operating methods, equipment, and strategies.

1 A collective term for the sum of coal in both measured and indicated resource categories of reliability, representing 100% of the in-place coal in those categories as of a certain date that meet specific minability criteria.

2 U.S. Energy Information Administration, "U.S. Coal Reserves," November 5, 2020, <https://www.eia.gov/coal/reserves/>

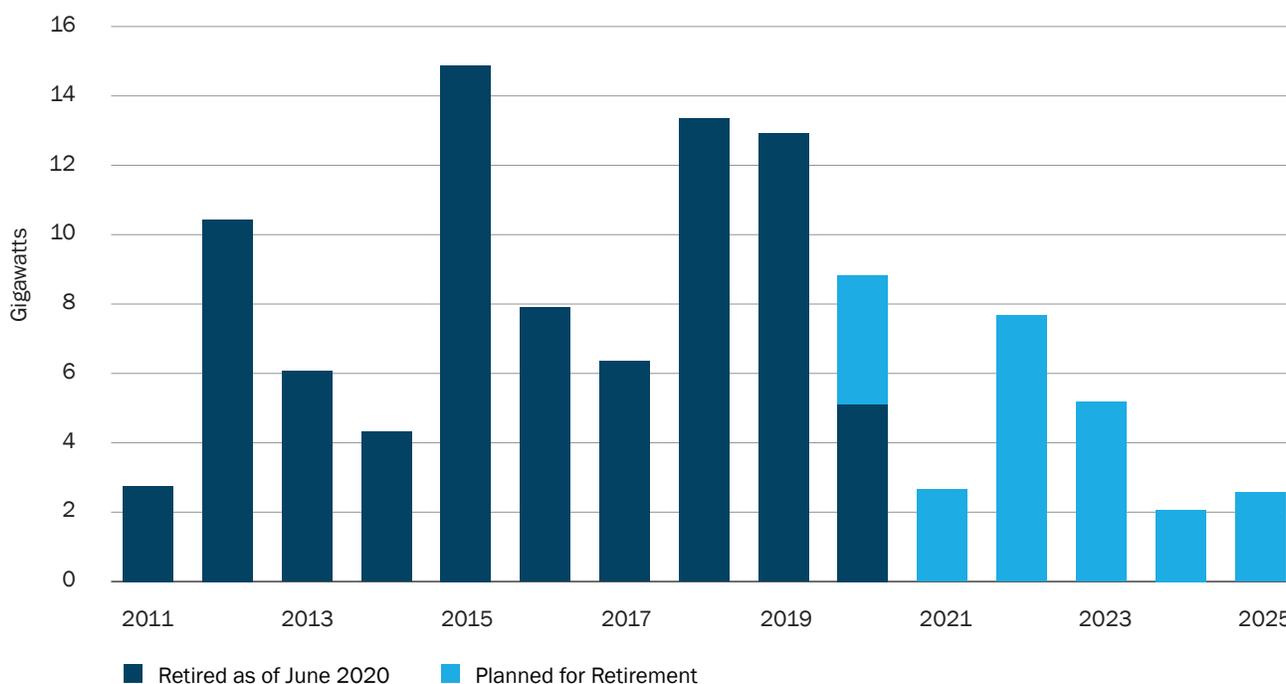
3 U.S. Energy Information Administration, "United States Leads the World in Coal Reserves," *Today in Energy*, September 5, 2011, <https://www.eia.gov/todayinenergy/detail.php?id=2930>

4 U.S. Energy Information Administration, "More than 100 Coal-fired Plants Have Been Replaced or Converted to Natural Gas Since 2011," *Today in Energy*, August 5, 2020, <https://www.eia.gov/todayinenergy/detail.php?id=44636>

5 U.S. Energy Information Administration, "U.S. Coal-Fired Electricity in 2019 Falls to 42-year Low," *Today in Energy*, May 11, 2020, <https://www.eia.gov/todayinenergy/detail.php?id=43675>

6 U.S. Energy Information Administration, "EIA Projects Generation from Coal and Nuclear Power Plants Will Plateau After 2025 - *Today in Energy*," February 7, 2020, <https://www.eia.gov/todayinenergy/detail.php?id=42755>

Figure 1 – U.S. Annual Coal-Fired Electricity Generation Capacity Retirements



Environmental concerns about global climate change caused by the carbon dioxide (CO₂) formed during the combustion of fossil fuels has provided motivation to reduce the use of coal for power generation and to develop technologies to capture and utilize or store the CO₂ from the combustion of fossil fuels. The advanced fossil energy power plants of the future will need to be flexible, reliable, highly efficient, environmentally sound, and avoid producing greenhouse gas (GHG) emissions. While the average efficiency of the most recently constructed U.S. coal plants is about 38%, the efficiencies of older coal power plants can be much lower. Most coal plants in the U.S. were built between 1950 and 1990 and the average efficiency of U.S. plants was 32% in 2007. Coal plants will increasingly need fast cycling and rapid ramp-up capabilities to integrate seamlessly with a modern, resilient, and highly connected energy grid that uses intermittent or distributed power sources. High-efficiency, low-emission coal plants are an important pathway to reaching carbon-neutral or net-negative emissions. These types of coal plants have been built in the U.S. to demonstrate technologies, such as an advanced supercritical boiler and high-efficiency turbine generator. Technology advances under development in the U.S. have significant potential to improve efficiency while providing co-benefits in reliability, flexibility, carbon management, and environmental performance.^{7, 8}

Opportunities with Hydrogen

Hydrogen (H₂) is the most abundant element in the universe. It only occurs naturally on Earth when combined with other elements. Hydrogen, like electricity, is an energy carrier that must be produced from another substance and can be used to store, move, and deliver energy. It has the highest energy content of any common fuel per unit of weight, but is less dense than other fuels, which hinders its wide-scale deployment. While hydrogen fuel consumption is not widespread, there has been growing interest in its use as a potential fuel source across the economy.

⁷ U.S. Department of Energy, “Coal FIRST,” Office of Fossil Energy and Carbon Management, <https://www.energy.gov/fe/coal-first>

⁸ U.S. Energy Information Administration, “Most Coal Plants in the United States Were Built Before 1990,” Today in Energy, <https://www.eia.gov/todayinenergy/detail.php?id=30812>

Hydrogen can be produced using diverse, domestic resources. Fossil fuels, such as natural gas and coal, can be converted to produce hydrogen, and the use of carbon capture, utilization, and storage can reduce the carbon footprint of these processes. Hydrogen can also be produced from low-carbon and renewable resources, including biomass grown from non-food crops and splitting water using electricity from wind, solar, geothermal, nuclear, and hydropower. This diversity of potential supply sources is an important reason why hydrogen is such a promising energy carrier.⁹

Hydrogen from fossil fuels, including coal, when combined with carbon capture, utilization, and storage (CCUS), is expected to play a key role in the U.S. transition to clean, low-carbon energy systems. EIA predicts the U.S. and other advanced countries that develop a successful hydrogen economy will rely primarily on fossil fuels along with CCUS. Industrial hydrogen is a major global market and demand is expected to rise, which would enable wide-scale decarbonization and global emissions reduction. Today, hydrogen is used primarily in oil refining, ammonia and methanol production, and steel making. Hydrogen consumed by large volume users is typically generated onsite (captive hydrogen), while for industries such as glass manufacture, food, and electronics, it is supplied by trailers (merchant hydrogen).

Currently, dedicated hydrogen production facilities around the world rely primarily on fossil fuels (76% natural gas, 22% coal), generating about 830 million metric tons (MMT) of CO₂ annually. Currently, 99% of U.S. hydrogen production is sourced from fossil fuels, with 95% from natural gas by steam methane reforming (SMR) and 4% by partial oxidation of natural gas via coal gasification. Only 1% of U.S. hydrogen is produced through electrolysis of water, which does not produce CO₂ but the cost production is higher than other options. In electrolysis, water (H₂O) is separated into hydrogen and oxygen by electrically breaking the molecular bond, hence without producing any CO₂. Annually, the U.S. produces more than 10 MMT of hydrogen.¹⁰ Utilizing existing natural gas infrastructure including pipelines, railcar, or ship transport may potentially expand the adaptation of hydrogen by consumers. Conventional truck transportation can provide economical movement of hydrogen for small quantities over short distances. Transportation of large quantities of hydrogen by pipelines, railcar, or ship would not be as constrained to weight restrictions encountered on roadways and will reduce hydrogen transportation costs over larger distances. Blending hydrogen into natural gas pipeline networks and using separation and purification technologies downstream to extract hydrogen from the natural gas blend near the point of end use may be an affordable alternative for delivering pure hydrogen to markets.¹¹

Hydrogen from coal-based, integrated gasification combined cycle (IGCC) also has a potentially important role in the future economy. In gasification, coal is reacted with oxygen and steam under high pressures and temperatures to form synthesis gas (syngas), comprising mostly hydrogen and carbon monoxide. IGCC, combined with CCUS, represents a low-carbon alternative with potentially higher thermal efficiencies, lower costs, fewer emissions, and reduced water use. Co-firing coal with biomass, petroleum, or waste products (e.g., plastics) using CCUS can produce low-carbon hydrogen for use in energy storage, transportation, or power generation.

Coal gasification, when combined with CCUS, is a proven technology for hydrogen production. Syngas produced from IGCC with CCUS provides not just power and hydrogen fuels but enables production of higher-value chemical products with a lower carbon footprint than traditional processes and without petroleum feedstocks. Hydrogen in coal-derived syngas can be converted into transport fuels as well as valuable chemical products, such as methanol and ammonia. Carbon monoxide (CO) from gasification can also be converted to hydrogen

9 U.S. Department of Energy, "Hydrogen Production," Fuel Cell Technologies Office, https://www.energy.gov/sites/prod/files/2016/07/f33/fcto_hydrogen_production_fs.pdf

10 U.S. Department of Energy, "Hydrogen Strategy: Enabling A Low Carbon Economy," Office of Fossil Energy, July 2020, https://www.energy.gov/sites/prod/files/2020/07/f76/USDOE_FE_Hydrogen_Strategy_July2020.pdf

11 Ibid.

via the water-gas shift reaction, and to acetic acid and other chemicals. While coal gasification can be combined with CCUS, there are technical challenges. For example, few technologies exist that produce both high-purity hydrogen and CO₂ that is pure enough for other uses or storage, because gas separation technologies focus on either hydrogen removal or CO₂ removal. The choice and design of the capture technology therefore depends on what the hydrogen is going to be used for, as well as on production costs.

This report covers a wide range of topics on hydrogen production and its applications, power generation, retrofitting of existing fossil-based plants, CCUS, new technology evaluation and regulatory decision making by public utility commissions (PUCs), as well as a discussion on environmental justice considerations and impact of declining coal use and plant closures on communities that have traditionally relied on coal mining and its use for power generation.

Section A: Hydrogen Demand and Clean Energy

2. Overview and Definitions

2.1 Relevance to Power Sector Changes and Public Utility Regulators

The development of new technologies requires the investment of significant capital and operating funds subject to elevated levels of risk due to an uncertain return on investment. These risks are a disincentive for the market to invest the significant capital required to deploy new infrastructure associated with coal-to-hydrogen conversion. This also results in a quandary for state regulators who must strike a balance between protecting the ratepayers whom they represent while facilitating research, development, demonstration, and deployment (RDD&D) of new technologies that could support state policy goals. It also results in uncertainty for investors in plants outside the traditional regulatory structure. New technologies have inherent risks, and investors may be averse to lending capital to a multi-million-dollar facility using unproven technologies, or charge a premium for the financing cost for such a facility. Therefore, the cost of hydrogen or electricity from such a facility may well not be competitive in the marketplace absent subsidies. Capital investments will be required to modify and convert existing fossil fuel-based power plants to produce hydrogen. The recovery of associated costs will eventually have an impact on ratepayers or on the cost of the electricity or hydrogen in the marketplace.

Hydrogen can be used in a broad range of stationary power generation applications—including large scale power generation, distributed power, combined heat and power, and backup power. It can provide power through combustion of hydrogen using turbines in simple- or combined-cycle generation or through electrochemical conversion using fuel cells. A decarbonized power grid would likely rely on a very high share of variable renewable energy sources. The future electric power system will require a variety of technology options to balance these variables and the intermittency of those renewable energy sources.

Hydrogen can also play an important role as a low-carbon fuel for establishing a low-carbon power grid. It provides the benefits of long-term storage capability and ready dispatchability during extended periods of insufficient energy generation from variable renewable sources due to weather conditions. Dispatchable power is installed to serve energy demand when wind and solar photovoltaic (PV) power generation is insufficient. In a 100% zero-carbon scenario, with large shares of wind and solar power, grid operators need a dispatchable, low-carbon energy source to provide electricity during extended periods of low renewable supply.¹²

Hybrid energy systems integrating natural gas or coal conversion with hydrogen technologies can provide significant value for industrial applications. Pilot-scale plants that integrate systems for steam methane reforming of natural gas with vacuum-swing adsorption to co-produce hydrogen for petroleum refining along with concentrated carbon dioxide for use in enhanced oil recovery have been deployed. Large-scale gasification facilities that co-fire coal, biomass, and waste plastics can be integrated with thermal storage, hydrogen production and utilization technologies, and carbon capture to achieve low-emissions power generation. The use of optimized CCUS along with the co-firing of biomass in these facilities offers a potential pathway to carbon net-negative power generation.¹³

12 "Roadmap to a U.S. Hydrogen Economy," Fuel Cell and Hydrogen Energy Association, January 27 2021, <https://www.fchea.org/us-hydrogen-study>.

13 U.S. Department of Energy, "Hydrogen Strategy: Enabling A Low Carbon Economy," Office of Fossil Energy, July 2020, https://www.energy.gov/sites/prod/files/2020/07/f76/USDOE_FE_Hydrogen_Strategy_July2020.pdf

State legislative requirements to rapidly decarbonize may also drive early adoption of hydrogen in power generation for both electricity generated by integrated utilities and for electricity purchased in the open marketplace. Another reason for the power sector to move toward hydrogen is flexibility it provides. Hydrogen can be blended at low concentrations into existing natural gas infrastructure with minimal impact.

As the availability of hydrogen fuel increases, new infrastructure will need to be built when the switch to hydrogen is feasible and economic. While the conversion to a 100% hydrogen-fueled energy will require new capital investment, such as modifications to a gas turbine and/or installation of new gas combustors, these changes should not disrupt electricity service from existing natural gas-based power plants.

While blending low levels of hydrogen with current natural gas infrastructure is feasible, U.S. utilities face a lack of regulatory clarity around blending standards, safety protocols, cost recovery options, and uncertainties about how to store and transmit hydrogen. In the long run, hydrogen could enable the power sector to transition to net-zero emissions and also bridge the gap between fossil fuels and renewable energy. Currently, hydrogen production from natural gas and coal, with CCUS, is the lowest-cost path to low-carbon hydrogen.¹⁴ As production costs continue to fall, storage and transportation remain key barriers to the widespread adoption of hydrogen. This could be eliminated by generating green hydrogen on site.¹⁵

2.2 Colors of Hydrogen

Hydrogen can be produced using diverse, domestic resources—including fossil fuels, such as natural gas and coal; nuclear energy; and renewable energy sources, such as biomass, wind, solar, geothermal, and hydro-electric power—using a wide range of processes.¹⁶ Various end-use applications of hydrogen consumption may dictate the hydrogen production processes. Hydrogen can be produced at or near the site end used in distributed production, at central production facilities and delivered to point of use, or at intermediate scale facilities located near point of use in semi-central production.

Color coding of hydrogen by the resource and production process is a common industry practice. Hydrogen is predominately color-coded as brown, grey, blue, green, pink, or additional variations as shown in Figure 2 and discussed below in order of present market share.¹⁷

Advanced production pathways provide a range of options across regional resources and infrastructure for carbon-neutral hydrogen production. Fossil resources, such as coal and natural gas, without CCUS, produce most of today's hydrogen. Combining fossil-based processes with CCUS offers a promising near-term option for carbon-neutral hydrogen production. Using CCUS when co-firing fossil-based feedstocks with biomass offers the potential for carbon-negative hydrogen as an additional environmental benefit.¹⁸

14 Sonal Patel, "GE Will Pilot F-Class Dual-Fuel Gas and Hydrogen Plant in Australia," *Power Magazine*, June 16, 2021, <https://www.powermag.com/ge-will-pilot-f-class-dual-fuel-gas-and-hydrogen-plant-in-australia/>

15 Emma Penrod, "Hydrogen is Having a Moment, and Power Generation is Leading the Way," *Utility Dive*, November 2, 2020, <https://www.utilitydive.com/news/hydrogen-is-having-a-moment-and-power-generation-is-leading-the-way/587958/>

16 U.S. Department of Energy, "Hydrogen Production," Fuel Cell Technologies Office, https://www.energy.gov/sites/prod/files/2016/07/f33/fcto_hydrogen_production_fs.pdf

17 "Hydrogen Color Spectrum," Adapted from the North American Council for Freight Efficiency (NACFE), <https://nacfe.org/wp-content/uploads/2020/12/Hydrogen-Color-Spectrum-HiRes-2.png>

18 U.S. Department of Energy, "Department of Energy Hydrogen Program Plan," 2020, <https://www.hydrogen.energy.gov/pdfs/hydrogen-program-plan-2020.pdf>

Black/Brown Hydrogen: Brown hydrogen is produced by transforming coal into syngas, through a gasification process. Gasification is achieved at very high temperatures with controlled amounts of oxygen and steam converting fossil-based materials into hydrogen, CO, and CO₂.¹⁹ Hydrogen separated from the syngas is considered “brown” hydrogen when derived from coal. As compared with other hydrogen production options, emissions from this process are higher due to release of carbon dioxide into the atmosphere.

Grey Hydrogen: Natural gas (CH₄) can produce hydrogen with thermal processes, such as SMR, that separate the carbon from the hydrogen. In the U.S., 95% of hydrogen is produced through natural gas reforming in large central plants, via SMR.²⁰ In this pathway, methane reacts with steam under high pressure to produce hydrogen, CO, and CO₂. Once CO₂ and other impurities are removed from the gas stream, the resulting hydrogen is considered “grey” hydrogen when the CO₂ is not captured through means such as industrial CCUS, and is, instead, released to the atmosphere. Grey hydrogen accounts for most of the production today.

Figure 2 – Hydrogen Color Spectrum



¹⁹ Sara Giovannini, “50 Shades of (Grey and Blue and Green) Hydrogen,” Energy Cities, Nov. 13, 2020, <https://energy-cities.eu/50-shades-of-grey-and-blue-and-green-hydrogen/>

²⁰ U.S. Department of Energy, “Hydrogen Production: Natural Gas Reforming,” <https://www.energy.gov/eere/fuelcells/hydrogen-production-natural-gas-reforming>

Blue Hydrogen: Hydrogen produced from natural gas or coal with CCUS is considered “blue” hydrogen and it accounts for 3% to 4% of current hydrogen production in the U.S.²¹ Blue hydrogen uses the same process as grey hydrogen. However, CCUS eliminates the emissions of grey hydrogen, improving the hydrogen’s environmental impact. Blue hydrogen is considered low-carbon; however, not all CO₂ generated during the production process can be captured.

Green Hydrogen: Hydrogen generated from renewable electricity, such as solar PV or wind, by electrolysis of water, from biogas by steam reforming, or from biomass through thermal conversion is considered “green” hydrogen.²² Electrolyzers use an electrochemical reaction to split water into its components of hydrogen and oxygen, emitting zero-carbon in the process. Due to high production costs, green hydrogen currently makes up only 1% of the overall production via electrolysis in the United States.²³

Pink Hydrogen: Hydrogen produced from electrolysis through nuclear energy is considered “pink” hydrogen. The technical and economic feasibility of pink hydrogen production is being evaluated by utilities. Ongoing research from the U.S. Department of Energy (DOE) is focused on developing industrial-scale production of hydrogen using the heat and electricity from nuclear energy systems, as well as investigating hybrid nuclear-renewable energy systems for providing clean hydrogen.²⁴

Turquoise Hydrogen: Low-carbon hydrogen extracted from natural gas via methane pyrolysis is considered “turquoise” hydrogen. Extracting hydrogen via methane pyrolysis is currently experimental only and not in commercial operation.²⁵ Solid carbon is an extraction process byproduct.

Yellow Hydrogen: Hydrogen produced via the electrolysis process from grid power is considered “yellow” hydrogen. Yellow hydrogen produced from electricity may come from mixed sources based on availability from renewables to fossil fuels or a mixture of multiple resources.^{26, 27}

White Hydrogen: Hydrogen produced as a byproduct of other industrial processes is often considered “white” hydrogen. Additionally, naturally occurring hydrogen in deposits and released through hydraulic fracturing (fracking) may also be considered white hydrogen.

21 U.S. Department of Energy, Office of Fossil Energy and Carbon Management, “USEA Hydrogen Workshop,” July 23, 2020, <https://www.energy.gov/fe/articles/usea-hydrogen-workshop>

22 Green Hydrogen Coalition, “Green Hydrogen,” <https://www.ghcoalition.org/green-hydrogen>

23 U.S. Department of Energy, “Hydrogen Strategy: Enabling A Low Carbon Economy,” Office of Fossil Energy, July 2020, https://www.energy.gov/sites/prod/files/2020/07/f76/USDOE_FE_Hydrogen_Strategy_July2020.pdf

24 U.S. Department of Energy, “Hydrogen Production,” <https://www.hydrogen.energy.gov/production.html>

25 Sara Giovannini, “50 Shades of (Grey and Blue and Green) Hydrogen,” *Energy Cities*, November 13, 2020, <https://energy-cities.eu/50-shades-of-grey-and-blue-and-green-hydrogen/>

26 Ibid.

27 The CO₂ equivalent footprint of yellow hydrogen will likely be elevated relative to some other colors due to the current generation mix of today’s electricity grid.

2.3 Potential Benefits of Coal-to-Hydrogen Production

The U.S. has the largest recoverable reserves of coal in the world. As of 2020, U.S. proven reserves totaled about 249 billion tons, which accounted for 23.2% of global reserves.²⁸ Declining coal production has left the U.S. with an enormous source of a domestic natural resource that can be an important element of energy security. Since the early days of electric generation in the U.S., coal has provided a reliable and low-cost fuel for electric power plants. The use of coal has also resulted in emissions of particulate matter, sulfur dioxide, nitrogen oxides, mercury, and CO₂. Since the 1960s, the U.S. government has enacted laws that regulate these emissions.²⁹ These regulations have resulted in significant reduction in regulated emissions. On the other hand, as systems were retrofitted to older coal plants and installed on new coal plants, the capital cost and operating cost of coal plants has increased significantly.

Coal-to-hydrogen production also gives the U.S. the opportunity and advantage to transition to hydrogen economy in the near term, as the production of hydrogen from fossil fuels is currently the least-cost option using current technologies. Despite the fact that current CCUS technologies to reduce CO₂ emissions in the production of hydrogen from fossil fuels add costs to the process, there are significant benefits associated with hydrogen:³⁰

- It has the highest energy content by weight of all known fuels and is a critical feedstock for the entire chemicals industry, including for liquid fuels.
- It can be produced in large centralized production facilities or in smaller distributed production facilities, and can be transported via truck, pipeline, tanker, or other means.
- It can enable zero or near-zero emissions in transportation, stationary or remote power, and portable power applications, along with combustion-based technologies and with fuel cells.
- It can be used for gigawatt-hours of energy storage and as a “responsive load” on the grid to enable grid stability, increasing the utilization of intermittent renewable generation.
- It can be used in a variety of domestic industries, such as the manufacturing of steel, cement, ammonia, and other chemicals.

2.4 Hydrogen Production Cost

Hydrogen production costs vary by technology and processes, with fossil fuels currently dominating the market. Hydrogen from fossil fuels with CCUS (blue hydrogen) could be an economically competitive, carbon-neutral alternative to traditional fuels used in the electricity, industrial, and transportation sectors. Currently, coal gasification without CCUS (brown hydrogen) on average is the most cost-effective conventional production process, according to DOE, as shown in Figure 3.³¹

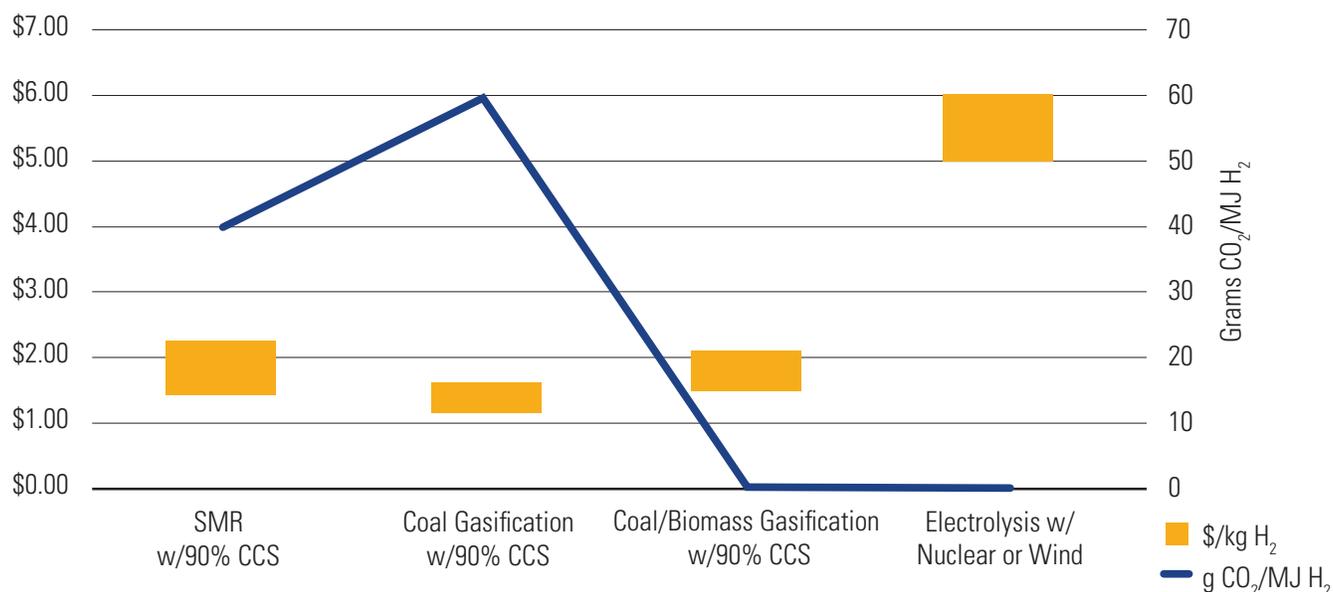
28 “Statistical Review of World Energy, 2021,” BP, <https://www.bp.com/content/dam/bp/business-sites/en/global/corporate/pdfs/energy-economics/statistical-review/bp-stats-review-2021-full-report.pdf>

29 U.S. Environmental Protection Agency, “Air Quality - National Summary,” <https://www.epa.gov/air-trends/air-quality-national-summary>

30 U.S. Department of Energy, “Hydrogen Program Plan,” November 2020, <https://www.hydrogen.energy.gov/pdfs/hydrogen-program-plan-2020.pdf>

31 U.S. Department of Energy, “Hydrogen Strategy: Enabling A Low Carbon Economy,” Office of Fossil Energy, July 2020, https://www.energy.gov/sites/prod/files/2020/07/f76/USDOE_FE_Hydrogen_Strategy_July2020.pdf

Figure 3 – Current Hydrogen Production Cost and CO₂ Intensity
 (Based on data from IEA Roadmap for Hydrogen and Fuel Cell and DOE Baseline Studies)



Steam reforming of natural gas for hydrogen production (grey hydrogen) costs vary from \$1.43/kg to \$2.27/kg with CO₂ capture and storage (blue hydrogen) and are highly dependent on the delivered natural gas price. Numerous studies report the cost of hydrogen from gasification varies between \$1.16/kg and \$1.63/kg for coal and between \$1.31/kg and \$2.06/kg for coal/biomass/waste plastic with CO₂ capture and storage. These processes are also highly dependent on the delivered feedstock price. Hydrogen production cost through electrolysis at a centralized station is estimated at \$5/kg to \$6/kg with electricity from nuclear or wind resources. Hydrogen from zero-carbon electricity, such as nuclear or wind, is 2.5–4 times more costly than hydrogen from carbon-neutral or net-negative carbon fossil resources.

2.5 Gasification, Syngas, and Synthetic Gas

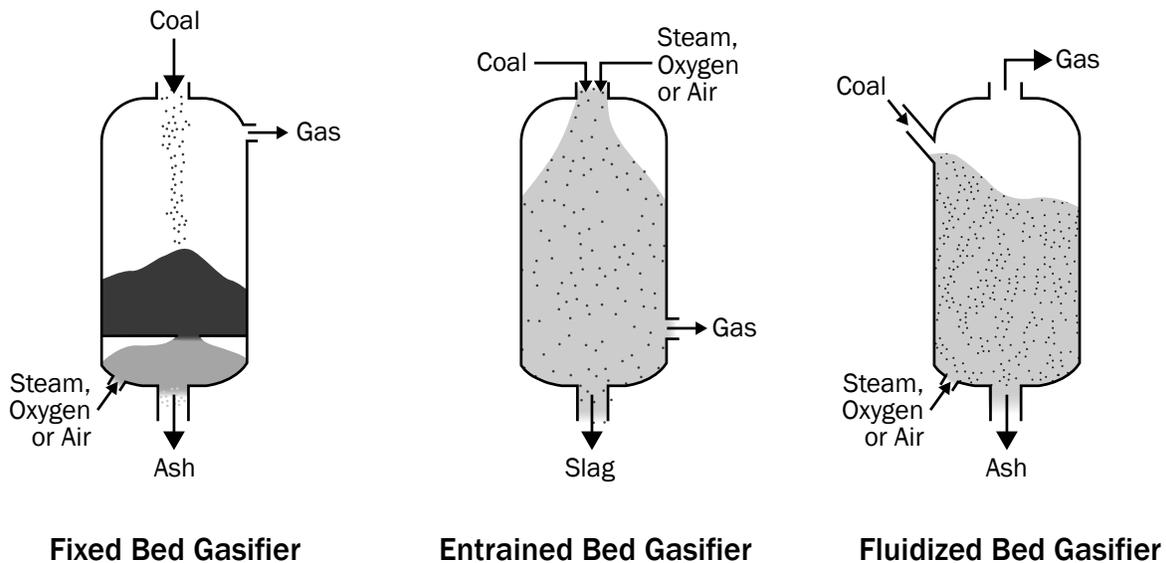
Coal gasification is viewed as the most likely approach to produce hydrogen from coal or other fossil fuels. The gasification process can convert any carbon-based raw material, such as coal, into fuel gas or syngas.³² Syngas is generally produced in a high temperature and high-pressure gasifier where air and steam are directly contacted with the raw material causing a series of chemical reactions that convert the coal to syngas and residues such as slag and ash. Material in a gasifier undergoes dehydration, pyrolysis, and finally partial combustion. Because gasification is a partial oxidation process, less oxygen is used in gasification than would be required for combustion (i.e., burning or complete oxidation) of the same amount of fuel. The major combustible products of gasification are CO and hydrogen, with only a minor amount of the carbon completely oxidized to CO₂ and water. The heat released by partial oxidation provides most of the energy needed to break up the chemical bonds in the feedstock, to drive the other endothermic gasification reactions, and to increase the temperature of the final gasification products.

Various types of gasifiers, including counter-current fixed bed known as an “up draft” gasifier, co-current fixed bed known as a “down draft” gasifier, and fluidized bed reactors and entrained flow gasifier are in commercial operation. Fixed-bed gasifiers tend to produce significant tar and methane at typical operating temperatures

³² National Energy Technology Laboratory, “Gasification Introduction,” *Gasifipedia*, Sec. 5.1, <https://www.netl.doe.gov/research/Coal/energy-systems/gasification/gasifipedia/intro-to-gasification>

requiring the resulting gas to be extensively cleaned before use. Co-current fixed bed gasifiers produce gas at higher temperatures with lower levels of tar resulting in a cleaner gas product. A fluidized bed reactor has higher fuel throughput than the fixed bed gasifiers and is mostly useful for fuels such as biomass that forms (or produces) highly corrosive ash that can damage slagging gasifiers. Entrained flow gasifiers have high operating temperatures suitable for most coals and requires significant oxygen production for gasification resulting in high energy consumption. Figure 4 shows gasifier types.³³

Figure 4 – Various Types of Gasifiers



Synthetic natural gas (SNG) is one of the commodities that can be produced from coal-derived syngas.³⁴ Any application that currently uses natural gas can use SNG.³⁵ Gasification can be used on-site for industrial applications to produce SNG and electricity, enabling continued operation of natural gas equipment but from a coal source. As a substitute for natural gas, SNG could be a viable option to increase the diversity of domestic fuels, and leverage existing natural gas infrastructure. In cogeneration plants with IGCC, syngas can be diverted from electrical generation to produce SNG or hydrogen. Power plants of the future may leverage SNG or hydrogen as fuel for electrical generation.

The economic viability of SNG production via coal gasification is heavily dependent on market prices of natural gas and coal as a feedstock material, as well as the fluctuating value of by-products. A representative illustration of the gasification process for coal is provided in Figure 5.³⁶ The Great Plains Synfuels Plant (GPSP) in Beulah, North Dakota, was the first commercial integrated coal-to-syngas plant. GPSP is discussed in more detail in Section 6.

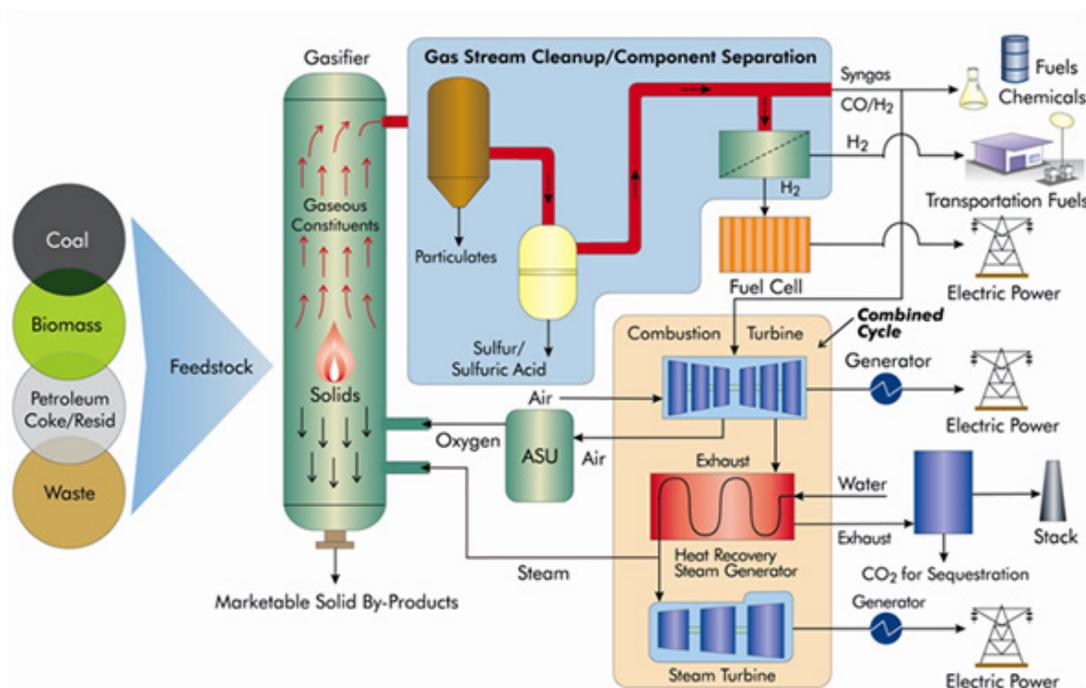
33 "Commercial Gasifiers," in *Gasifipedia*, Sec 5.2, NETL Website, <https://www.netl.doe.gov/research/Coal/energy-systems/gasification/gasifipedia/types-gasifiers>

34 National Energy Technology Laboratory, "Technology for SNG Production," *Gasifipedia*, Sec. 7.4, <https://www.netl.doe.gov/research/coal/energy-systems/gasification/gasifipedia/coal-to-sng>

35 National Energy Technology Laboratory, "Hydrogen Synthetic Natural Gas from Coal," *Gasifipedia*, Sec. 7.2, <https://www.netl.doe.gov/research/Coal/energy-systems/gasification/gasifipedia/hydrogen-commercial>

36 National Energy Technology Laboratory, Diagram of a Gasifier, <https://www.netl.doe.gov/sites/default/files/inline-images/intro-lg.jpg>

Figure 5 – Representative Gasification Process for Coal



2.6 “Remining” of Waste Coal as Feedstock for Hydrogen Production

Waste coal or coal refuse is the low-energy-value discards left over from coal mining, usually as coal tailings piles, waste material, or gob. Waste coal is called “culm” in the eastern Pennsylvania anthracite coal region and “gob” or “boney” in the bituminous coal mining regions (western Pennsylvania, West Virginia and elsewhere). For every ton of hard coal generated by mining, 400 kilograms (or 40%) of waste material remains, which includes some lost coal that is partially economically recoverable. Coal refuse is distinct from the byproducts of burning coal, such as fly ash. Waste coal piles accumulated mostly between 1900 and 1970 and the piles, in some areas, look like hills or small mountains that are dark and barren. The mine tailings typically contain additional carbon that could be used in properly-designed boilers or gasifiers.

Waste coal has an average of 60% of the British thermal unit (Btu) value of normal coals. It can take up to twice as much waste coal to produce the same amount of electricity, which means, in most places, waste coal burners can only be economically built where large volumes of waste coal exist near a centralized plant. Production technologies, combined with CCUS, can economically produce hydrogen from coal, biomass, and waste coals and also yield low-to-negative emissions of CO₂. According to EIA, over half of the 1,435 coal mines in the U.S. in 2008 have shut down. The resource that remains in the ground can be brought back to use if coal can be used to produce hydrogen in a safe and environmentally sound manner, a prospect which depends heavily on continued advances in production and CCUS technologies to bring costs down while capturing CO₂ emissions.

Waste coal can be reused and co-fired with biomass and other waste material through gasification for power generations, as well as hydrogen production. Some of the characteristics that are to be considered are the discards calorific value, ash content, sulfur content, fixed carbon content, and age of the discard. Waste coal can also be used to generate conventional coal products. While pulverized fuel (PF) combustion in a boiler for power generation is the most common approach for the utilization of low rank coals, circulating fluidized bed (CFB) boiler has been proven to be more efficient than the current PF combustion system. CFB technology is increasingly establishing itself as the technology of choice where fuel flexibility and limestone addition

as sorbent eliminates the capital cost of desulfurization unit used in PC technology.^{37, 38} Plasma gasification, which is used for converting municipal solid waste and other materials into synthesis gas (syngas) containing hydrogen and carbon monoxide that can be used to generate power, has been investigated for application to gasify coal and coal waste.

Additional information on this technology is provided below.^{39, 40, 41, 42, 43, 44}

Plasma Coal Gasification

Westinghouse Plasma Corporation (WPC) has been developing plasma gasification technology to treat industrial and municipal solid wastes (MSW) over the last decade, and recently has been investigating the application of their plasma technology to gasify coal. According to WPC, this technology can be demonstrated to gasify coal in an ambient pressure plasma-fired reactor that can be retrofitted into existing power plants and/or installed as a new facility. Its potential benefits over a pulverized coal power and/or conventional gasification plant include the following: greater feed flexibility enabling coal, coal fines, mining waste, lignite, and other opportunity fuels (e.g., biomass and municipal solid waste) to be used as fuel without the need for pulverizing; high conversion (>99%) organic matter to synthesis gas (syngas); higher thermal efficiency; lower CO₂ emissions; and low estimated capital and operations and maintenance (O&M) costs.

South Africa's national mineral research organization Mintek is also developing the concept of direct current arc plasma gasification to produce a synthesis gas that could be used for power generation, thereby creating an alternative viable use for low grade waste coal that is discarded as a byproduct of coal processing. The design concept centers on the use of a plasma arc furnace that is fed waste coal along with steam. The high temperatures in the furnace facilitate the decomposition and vaporization of the carbon in the coal, and the hydrogen and oxygen in the steam. These products are then removed and passed through a vertical column gasifier stage where they react in a controlled fashion to produce syngas, which might be used for hydrogen production or directly as a fuel to power turbines for electricity generation.

Plasma coal gasification is carried out using an external source of energy and can thus be carried out irrespective of the coal calorific value. Plasma assisted waste-to-energy processes have been developed and used for the processing of municipal solid wastes to generate electricity. DOE's National Energy Technology Laboratory (NETL) is also exploring utilization of low-temperature plasma technology for recovery of rare earth elements (REEs) from coal waste. NETL projects have achieved impressive results in laboratory and bench-scale experiments, indicating the highest REE concentration percentage achieved to date from coal and coal by-products, as well as the highest associated percentage of REE recovery.

37 Mohamed Belaid, Rosemary Falcon, Kamohelo V Patsa, and Pasi Vainikka, "Potential and Technical Basis for Utilizing Coal Beneficiation Discards in Power Generation by Applying Circulating Fluidized Bed Boilers," Second International Conference on Chemical, Ecology and Environmental Sciences, June 17-18, 2013, London (UK), https://ujcontent.uj.ac.za/vital/access/manager/Repository/uj:4977?site_name=GlobalView&view=null&f0=sm_creator%3A%22Belaid%2C+Rosemary%22&sort=null

38 "Pulverized Fuel – An Overview," ScienceDirect Topics, <https://www.sciencedirect.com/topics/engineering/pulverised-fuel>

39 "Plasma Gasification," NETL Website, <https://www.netl.doe.gov/research/Coal/energy-systems/gasification/gasifipedia/westinghouse>

40 "Coal and Biomass: Alternatives/Supplements to Coal: Feedstock Flexibility," in *Gasifipedia*, Sec. 1.3, NETL Website, <https://www.netl.doe.gov/research/Coal/energy-systems/gasification/gasifipedia/feedstock>

41 Nadine James, Waste Coal Gasification Could Offer Alternative Power Generation Source, Mining Weekly, (Sept. 16, 2016), <https://www.miningweekly.com/print-version/waste-coal-gasification-could-offer-alternate-power-generation-source-2016-09-16>

42 G. Akdogan, T.P. Kekana, and Q.G. Reynolds, "The Feasibility of Producing Syngas from Waste Coal Fines and Steam Using a DC Arc Gasifier," *International Mineral Processing Congress*, Cape Town, South Africa, October 18-22, 2020, <http://www.mintek.co.za/Pyromet/Files/2021Kekana.pdf>

43 "Low-Temperature Plasma Treatment for Enhanced Recovery of Highly Valued Critical Rees from Coal," Presentation at DOE 2019 Annual Project Review Meeting, Crosscutting Research, Rare Earth Elements, Gasification Systems, and Transformative Power Generation, April 9-11, 2019, https://netl.doe.gov/sites/default/files/2019-05/2019_Annual_Reports/Wednesday/REE/2%20-%202019_Crosscutting_UK_DE-FE0031525.pdf

44 U.S. Department of Energy, "NETL-Supported REE Extraction Project Exceeds Expectations," Office of Fossil Energy and Carbon Management, May 7, 2020, <https://www.energy.gov/fe/articles/netl-supported-ree-extraction-project-exceeds-expectations>

3. Hydrogen Demand, and Decarbonization Potential in the United States

As the demand for clean energy continues to rise in the U.S., alternative sources of energy such as hydrogen are being further explored, and advanced technologies and processes are continuously developed and improved to support various industries. Hydrogen can be produced from almost all energy resources, though today's use of hydrogen in oil refining and chemical production is mostly from hydrogen produced from fossil fuels. Hydrogen produced from fossil fuels with CCUS can help meet demand, reduce emissions, improve air quality, and foster energy security through domestic production.

Hydrogen can be stored as a liquid, gas, or chemical compound, and is converted to energy via traditional combustion methods in engines, furnaces, or gas turbines; through electrochemical processes in fuel cells; and through hybrid approaches such as integrated combined cycle gasification and fuel cell systems. It is also used as a feedstock or fuel in a number of industries, including petroleum refining, ammonia production, food and pharmaceutical production, and metals manufacturing. A wide range of current and future hydrogen applications and demand across industry sectors are shown in Table 1.⁴⁵

Table 1 – Existing and Emerging Demand for Hydrogen

	Transportation Applications	Chemical and Industrial Applications	Stationary and Power Generation Applications	Integrated/Hybrid Energy Systems
Existing Growing Demands	<ul style="list-style-type: none"> • Material-Handling Equipment • Buses • Light-Duty Vehicles 	<ul style="list-style-type: none"> • Oil Refining • Ammonia • Methanol 	<ul style="list-style-type: none"> • Distributed Generation: Primary and Backup Power 	<ul style="list-style-type: none"> • Renewable Grid Integration (with storage and other ancillary services)
Emerging Future Demands	<ul style="list-style-type: none"> • Medium-and Heavy-Duty Vehicles • Rail • Maritime • Aviation • Construction Equipment 	<ul style="list-style-type: none"> • Steel and Cement Manufacturing • Industrial Heat • Bio/Synthetic Fuels 	<ul style="list-style-type: none"> • Reversible Fuel Cells • Hydrogen Combustion • Long-Duration Energy Storage 	<ul style="list-style-type: none"> • Nuclear/Hydrogen Hybrids • Gas/Coal/Hydrogen Hybrids with CCUS • Hydrogen Blending

The increased use of hydrogen to decarbonize fuels provides opportunities across multiple industries and sectors as a cleaner alternative for conventional applications. Various government initiatives, such as DOE's H2@Scale, educate and provide an overarching vision for how hydrogen can enable energy pathways across applications and sectors in an increasingly interconnected energy system.⁴⁶ The H2@Scale concept is based on hydrogen's potential to meet existing and emerging market demands across multiple sectors. It envisions how innovations to produce, store, transport, and utilize hydrogen can help realize that potential and achieve scale to drive revenue opportunities while reducing costs as shown in Figure 6.⁴⁷

45 U.S. Department of Energy, "Hydrogen Program Plan," November 2020, <https://www.hydrogen.energy.gov/pdfs/hydrogen-program-plan-2020.pdf>

46 U.S. Department of Energy, "H2@Scale: Enabling Affordable, Reliable, Clean, and Secure Energy across Sectors," <https://www.energy.gov/sites/default/files/2020/07/f76/hfto-h2-at-scale-handout-2020.pdf>

47 U.S. Department of Energy, "H2@Scale," Hydrogen and Fuel Cell Technologies Office, <https://www.energy.gov/eere/fuelcells/h2scale>

According to the International Energy Agency (IEA), hydrogen is mainly used in the refining and chemical sectors and produced from fossil fuels, accounting for 6% of global natural gas use and 2% of coal consumption. It is responsible for 830 million metric tons (MMT) of CO₂ emissions annually.⁴⁸ Ammonia represented almost 43% of global hydrogen demand in 2018; refining represented almost 52%, and “other” demands (metals, food, electronics, and glass) accounted for 6%. By the year 2030, IEA forecasts a 31% increase in hydrogen demand under existing policies for ammonia and methanol due to economic and population growth.⁴⁹ Longer term demand for hydrogen is expected to grow as new ammonia and methanol demand arises for clean uses as hydrogen-based fuels for decarbonization. In 2020, over 171,738 million cubic feet of natural gas was used as feedstock for hydrogen production at refineries in the U.S. to produce 75,208 thousand barrels of hydrogen.^{50, 51}

In 2015, U.S. demand for hydrogen was about 13.8 MMT, while total on-purpose production⁵² was about 10 MMT.⁵³ Current production remains around 10 MMT per year.⁵⁴ According to the National Renewable Energy Laboratory (NREL) Resource Assessment for Hydrogen Production, the current technical resource availability of domestic energy resources is sufficient to meet an additional 10 MMT of hydrogen demand in 2040.⁵⁵ According to the NREL assessment, by 2050 the U.S. could see a two- to four-fold increase in hydrogen demand, as shown in Table 2. The projections are based on successful outcomes of research and development (R&D) efforts.^{56, 57}

48 International Energy Agency, “Hydrogen,” <https://www.iea.org/fuels-and-technologies/hydrogen>

49 International Energy Agency, “Future of Hydrogen,” June 2019, https://iea.blob.core.windows.net/assets/9e3a3493-b9a6-4b7d-b499-7ca48e357561/The_Future_of_Hydrogen.pdf

50 U.S. Energy Information Administration, “Petroleum and Other Liquids,” Released June 30, 2021, https://www.eia.gov/dnav/pet/pet_pnp_inpt_a_EPOOOH_yir_mbb1_a.htm

51 U.S. Energy Information Administration, “Natural Gas Used as Feedstock for Hydrogen Production at Refineries,” https://www.eia.gov/dnav/pet/pet_pnp_feedng_k_a.htm

52 One-third of global hydrogen supply is “by-product” hydrogen, meaning that it comes from facilities and processes designed to manufacture other products.

53 Daryl Brown, “Hydrogen Production – 2015,” CryoGas International,” July 2016, https://www.researchgate.net/publication/304628336_US_Hydrogen_Production_-_2015

54 U.S. Department of Energy, “Hydrogen Program Plan,” November 2020, <https://www.hydrogen.energy.gov/pdfs/hydrogen-program-plan-2020.pdf>

55 Connelly, Elizabeth, Michael Penev, Anelia Milbrandt, Billy Roberts, Nicholas Gilroy, and Marc Melaina. 2020, “Resource Assessment for Hydrogen Production,” Golden, CO, National Renewable Energy Laboratory, NREL/TP-5400-77198, <https://www.nrel.gov/docs/fy20osti/77198.pdf>

56 Ruth, Mark F., P. Jadun, N. Gilroy, E. Connelly, R. Boardman, A.J. Simon, A. Elgowainy, and J. Zuboy, 2020, “The Technical and Economic Potential of the H2@Scale Hydrogen Concept within the United States,” National Renewable Energy Laboratory, NREL/TP-6A20-77610, <https://www.nrel.gov/docs/fy21osti/77610.pdf>.

57 U.S. Department of Energy, “Hydrogen Program Plan,” November 2020, <https://www.hydrogen.energy.gov/pdfs/hydrogen-program-plan-2020.pdf>

Figure 6 – DOE Integration of Fossil Energy into the Hydrogen Economy

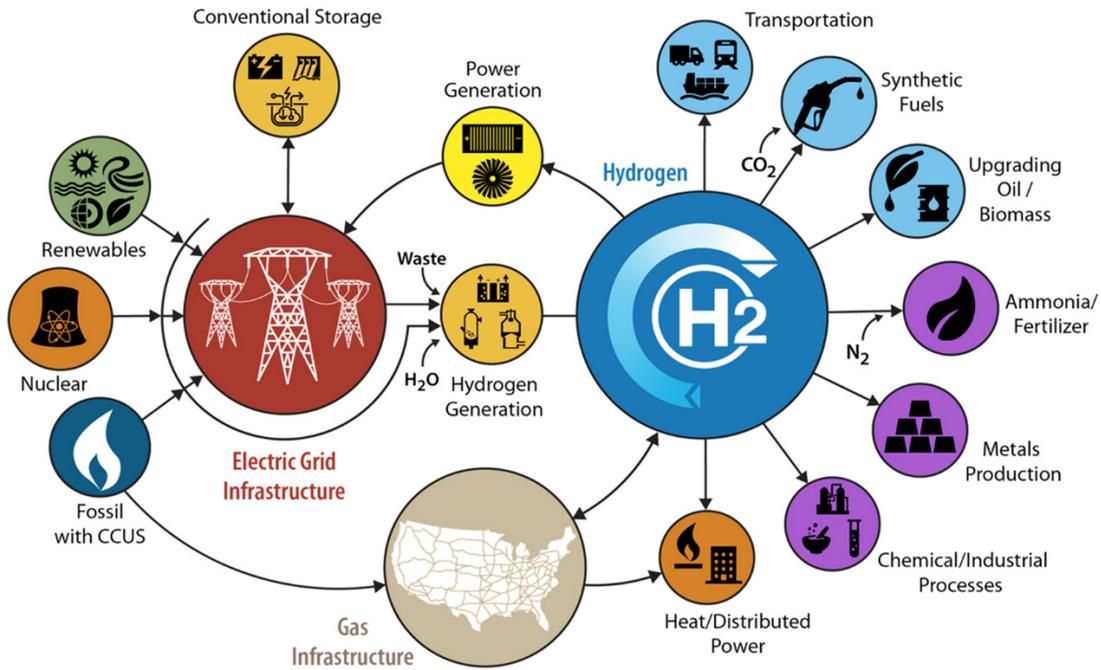


Table 2 – Current and Future Consumption Potential of Hydrogen in the U.S.

Demand Applications	Today	R&D Success Scenario
Oil Refining	6	7
Metal Refining	Negligible	4
Ammonia Production	3	4
Biofuels/Synfuels Production	1	9
Transportation FCEVs (LDVs, MDVs, HDVs)	Negligible	17
Total Hydrogen Market (MMT/Year)	10	41

The NREL assessment provides the amount of renewable and non-renewable resources required to produce 1 kg of hydrogen and associated production efficiencies in Table 3. The required resources to produce 10 MMT of hydrogen and the percentage of total technical potential of fossil pathways are shown in Table 4, concluding the required resources are achievable to meet demand.

Table 3 – Amount of Renewable and Non-Renewable Resources Required to Produce 1 kg of Hydrogen and Production Efficiencies

Resource	Conversion Pathway	Amount to Produce 1 kg Hydrogen	Production Efficiency (E_{out}/E_{in} , LHV)
Natural Gas	Steam methane reforming	167 standard cubic feet (scf)	73.0%
Coal (bituminous)	Coal gasification	8.6 kg	53.3%
Nuclear (uranium)	High-temperature electrolysis	4.62x10 ⁻⁵ kg U	50.2%
Biomethane	Steam methane reforming	3.29 kg Methane	73.0%
Wind, Solar, Water, and Geothermal Power	Low-temperature electrolysis	51.3 kWh	64.9%

Table 4 – Availability and Required Resources of Fossil Pathways

Resource Metric	Coal	Natural Gas
U.S. Resource Availability		
Technical Resource Potential	472 Billion Tons	2,829 Tcf
U.S. Required Resource for Hydrogen Production		
10 MMT of Hydrogen	78 Million Tons	1.7 Tcf
Percent of Technical Potential	0.02%	0.06%

Globally, hydrogen offers great potential in many sectors if production and transportation costs continue to be competitive to other fuels. According to the IEA report, *Future of Hydrogen*, current worldwide demand for pure hydrogen is around 70 MMT for specific applications that require hydrogen with only small levels of additives or contaminants tolerated. The main applications for this hydrogen are oil refining and ammonia production, primarily for fertilizers. A further 45 MMT of demand exists for hydrogen as part of a mixture of gases, such as synthesis gas, for fuel or feedstock.⁵⁸ Substantial potential for hydrogen is forecasted by the year 2050 across power generation, transportation, industrial energy, building heat and power, and industry feedstocks. Today's hydrogen industry is large, with many sources and uses. In energy terms, total annual hydrogen demand worldwide is around 330 MMT of oil equivalent, which is larger than the primary energy supply of Germany.

3.1 Heat Source for Industrial Processes

Industrial processes often require substantial energy consumption to generate significant heat sources for processing materials through thermal and chemical conversions. While the energy industry includes petroleum refining, gas processing and solid fuel manufacturing, the manufacturing industry includes steel, non-ferrous metals, chemicals, food processing, ceramics, cement, and pulp and paper. Hydrogen as an energy resource is a promising pathway in decarbonizing industrial processes for whom electrification may not be a viable option.⁵⁹ Hydrogen is being considered as an alternate fuel to natural gas for power generation and heating for industrial processes. With a high flame temperature, high flame speed, and low ignition energy, hydrogen has potential for widespread use in industrial sectors.

58 International Energy Agency, "Future of Hydrogen," June 2019, https://iea.blob.core.windows.net/assets/9e3a3493-b9a6-4b7d-b499-7ca48e357561/The_Future_of_Hydrogen.pdf

59 Jeffrey Rissman, "Hydrogen Could Become A \$130 Billion U.S. Industry By 2050. Could It Also Cut Emissions?" Forbes, October 7, 2019, <https://www.forbes.com/sites/energyinnovation/2019/10/07/how-hydrogen-could-become-a-130-billion-us-industry-and-cut-emissions-by-2050/?sh=20be74042849>

Several industrial and manufacturing processes typically require large volumes of hydrogen, including oil refining and ammonia production. According to the U.S. Environmental Protection Agency (EPA), in 2019, U.S. industrial processes and product uses generated 166.6 MMT of CO₂ or 3.2% of total emissions from the industrial sector.⁶⁰ Hydrogen presents an opportunity for emissions reduction across a number of sectors. Hydrogen can support supply of low-emissions electricity, be used as a clean fuel for heavy transport and machinery, provide clean industrial heat, and reduce emissions from industrial processes such as cement and steel production. However, additional RD&D is needed to assess the impacts of deviating from natural gas and coal fuel gases in favor of hydrogen. Efforts are underway to reduce emissions using hydrogen as a reduction agent for steel production in place of CO derived by fossil fuels.

Steelmaking, in particular, is receiving increasing attention as a source of demand for hydrogen. Steel is the most commonly used metal product worldwide, and the conventional way to produce it involves using coal in blast furnaces to reduce iron ore to iron. Steel manufacturing accounts for between 7% and 9% of global greenhouse gas emissions. Replacing coke with hydrogen in blast furnaces can drastically reduce those emissions.⁶¹ Cement production is responsible for another 8% of global carbon dioxide emissions, where the use of hydrogen in place of coal could reduce both CO₂ and NO_x emissions. Other potential industrial sectors include synfuel production, which involves reacting carbon dioxide with clean hydrogen, offering an option for versatile net-zero-carbon fuels, such as methanol or renewable natural gas. In addition, hydrogen can be used in glass manufacturing and industrial food processing.⁶²

Across different industrial end uses, the cost of hydrogen will depend on process-specific requirements for hydrogen purity, the pressure required for the process, and other factors that affect production, delivery, and storage costs. To ensure commercial viability, continued cost reductions will need to be achieved in all these areas. The use of hydrogen for heat generation would require a substantial volume of hydrogen. DOE's recently announced Hydrogen Shot initiative seeks to reduce the cost of clean hydrogen by 80% to \$1 per kilogram in a decade.^{63, 64} Currently, hydrogen from renewable energy costs about \$5 per kilogram (as opposed to \$1.63/kg from coal gasification with CCUS). Achieving the Hydrogen Shot's 80% cost reduction goal can unlock new markets for hydrogen, including steel manufacturing, clean ammonia, energy storage, and heavy-duty trucks.⁶⁵

Large industrial consumers are currently integrated into the existing natural gas infrastructure. Conversion to hydrogen for industry will require the adaptation of existing transmission and distribution infrastructure to safely accept blending of hydrogen into natural gas for industrial consumers and accommodate seasonal fluctuations in energy demand.

3.2 Ammonia Production

Ammonia is a highly sought inorganic chemical with numerous large-scale production plants worldwide. Conventional ammonia production plants convert natural gas or petroleum-based feedstocks to gaseous hydrogen predominantly through steam reforming and combine it with nitrogen to produce ammonia. For regions lacking access to inexpensive natural gas, coal gasification is an important pathway for ammonia

60 U.S. Environmental Protection Agency, "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2019," Updated May 5, 2021, <https://www.epa.gov/sites/default/files/2021-04/documents/us-ghg-inventory-2021-main-text.pdf>

61 World Steel Association, "Steel's Contribution to a Low Carbon Future and Climate Resilient Societies," 2020, https://www.worldsteel.org/en/dam/jcr:7ec64bc1-c51c-439b-84b8-94496686b8c6/Position_paper_climate_2020_vfinal.pdf

62 U.S. Department of Energy, "Hydrogen Program Plan," November 2020, <https://www.hydrogen.energy.gov/pdfs/hydrogen-program-plan-2020.pdf>

63 U.S. Department of Energy, "Hydrogen Shot," <https://www.energy.gov/eere/fuelcells/hydrogen-shot>

64 U.S. Department of Energy, "First Energy Earthshot Aims to Slash Cost of Clean Hydrogen by 80% in One Decade," <https://www.energy.gov/eere/fuelcells/hydrogen-and-fuel-cell-technologies-office>

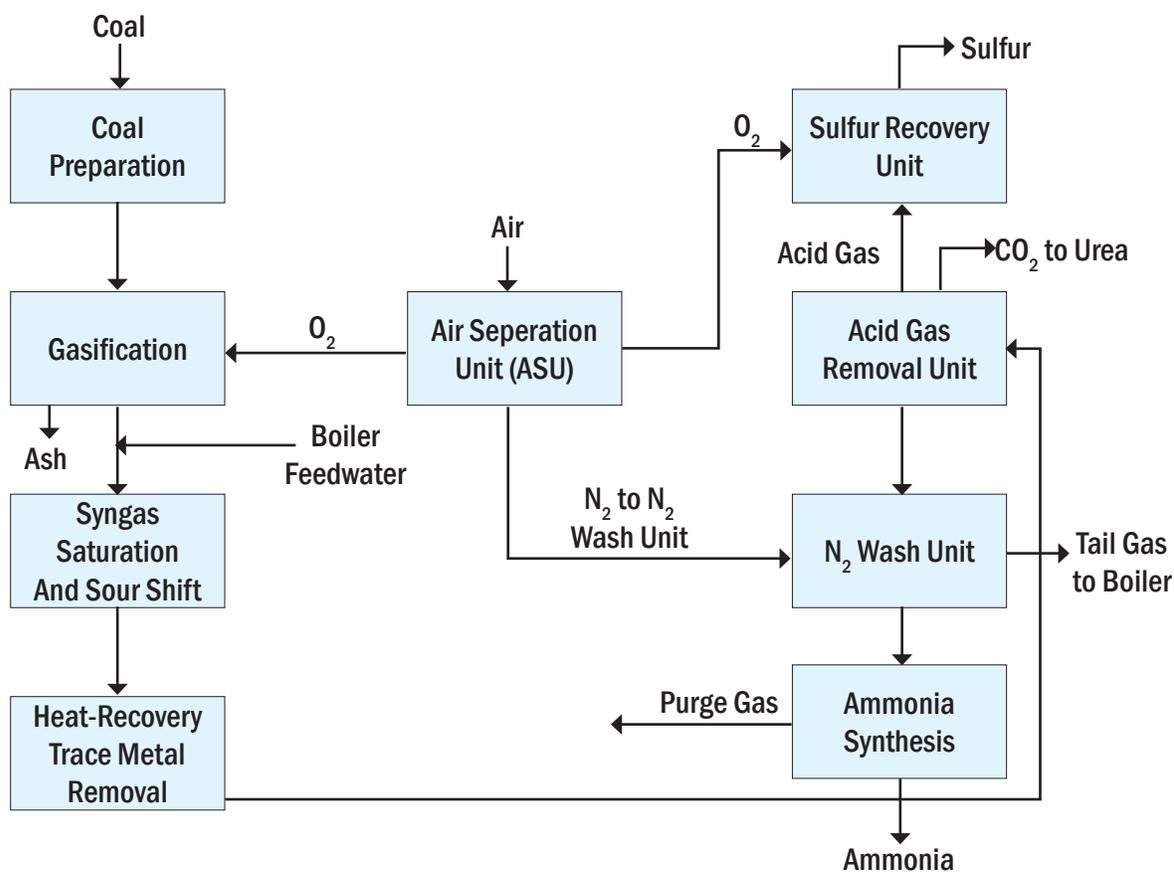
65 U.S. Department of Energy, "Hydrogen Shot," <https://www.energy.gov/eere/fuelcells/hydrogen-shot>

synthesis for fertilizer production. Fossil fuels are a cost-effective resource of hydrogen for ammonia production, as illustrated in Figure 7.⁶⁶

Approximately 80% of global ammonia produced is used in the manufacturing of fertilizers. The remaining is used in other industrial applications such as explosives, synthetic fibers, and other specialty materials.⁶⁷ The global production of ammonia as well as methanol combine for approximately 630 MMT of CO₂ emissions per year according to the IEA. Decarbonization is possible through CCUS to reduce fossil fuel emissions, electrolysis-derived hydrogen, or biomass feedstocks; however, absent fossil fuel CCUS, these options are currently more costly.

Ammonia production in the U.S. is a major consumer of hydrogen and is currently increasing due to the availability of low-cost natural gas and the resulting low-cost hydrogen produced. NREL projects that hydrogen demand from ammonia production will increase at a rate of about 1% annually from 2018 through 2050, resulting in 3.6 MMT per year.

Figure 7 – Ammonia Production from Coal



66 Jim Richardson and Venkat Pattabathula, "Introduction to Ammonia Production," American Institute of Chemical Engineers, Sept. 2016, <https://www.aiche.org/resources/publications/cep/2016/september/introduction-ammonia-production>

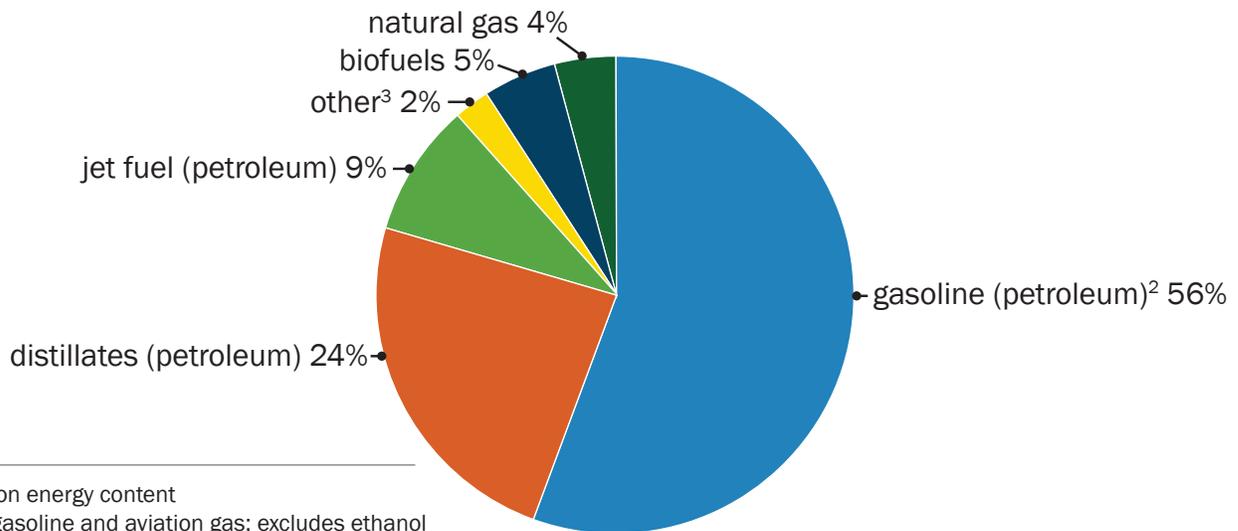
67 National Energy Technology Laboratory, "Commercial Technologies," *Gasifipedia*, Sec. 11,1, <https://www.netl.doe.gov/research/Coal/energy-systems/gasification/gasifipedia/fertilizer-commercial-technologies>

3.3 Transportation Fuel

According to the EIA, in 2020 petroleum products accounted for about 90% of the total U.S. transportation sector energy use while biofuels, such as ethanol and biomass-based diesel and distillates contributed about 5%; natural gas accounted for about 3%, and electricity provided less than 1% of total transportation sector energy use and nearly all of that in mass transit systems as shown in Figure 8.⁶⁸ In 2019, the transportation sector accounted for the largest portion at 29% of total U.S. GHG emissions.^{69, 70}

Hydrogen can be used directly as a fuel in fuel cell electric vehicles (FCEVs), which are twice as efficient as combustion engines vehicles and generated zero emissions at the tailpipe. Although light-duty FCEVs are currently available on the market, they are still produced at a relatively small scale. Availability of refueling infrastructure is another key challenge. The increased urgency to reduce emissions and energy related expenses provides a significant opportunity considering that, although, the medium and heavy-duty sectors account for 4% of the vehicle fleet, they account for 25% of annual vehicle fuel use.⁷¹

Figure 8 – U.S. Transportation Energy Sources / Fuels (2020)¹



¹ Based on energy content

² Motor gasoline and aviation gas; excludes ethanol

³ Includes residual fuel oil, lubricants, hydrocarbon gas liquids (mostly propane), and electricity (includes electrical system energy losses).

Hydrogen and fuel cells are an important part of a portfolio of options to reduce transportation-related emissions, because they can be used in specific applications that are hard to decarbonize, such as long-haul heavy-duty trucks. Additional examples include other medium- and heavy-duty vehicles that require longer driving ranges, involve heavy loads, or demand faster refueling times than may be available with battery electric vehicles alone.⁷²

68 U.S. Energy Information Administration, "Use of Energy Explained: Energy use for Transportation," Updated on May 17, 2021, <https://www.eia.gov/energyexplained/use-of-energy/transportation.php>

69 U.S. Environmental Protection Agency, "Sources of Greenhouse Gas Emissions," <https://www.epa.gov/ghgemissions/sources-greenhouse-gas-emissions#transportation>

70 U.S. Environmental Protection Agency, "Fast Facts on Transportation Greenhouse Gas Emissions," June, 2021, <https://www.epa.gov/greenvehicles/fast-facts-transportation-greenhouse-gas-emissions>

71 U.S. Department of Energy, "Department of Energy Announces \$50 Million for Commercial Truck, Off road Vehicle, and Gaseous Fuels Research," July 29, 2019, <https://www.energy.gov/articles/departement-energy-announces-50-million-commercial-truck-road-vehicle-and-gaseous-fuels-0>

72 U.S. Department of Energy, "Hydrogen Program Plan," November 2020, <https://www.hydrogen.energy.gov/pdfs/hydrogen-program-plan-2020.pdf>

Hydrogen-powered transportation applications include fuel cell electric vehicles (FCEV) as an alternative to conventional gasoline-powered light duty vehicles (LDV), trucks and buses, as well as maritime, rail, and aviation. Most hydrogen-fueled vehicles have an electric motor powered by a hydrogen fuel cell. A few of these vehicles burn hydrogen directly. Several FCEV models are currently available for lease or purchase. During the past nine years, through 2020, approximately 9,000 new hydrogen fuel cell cars were sold in the U.S.⁷³ There are over 45 U.S. hydrogen fueling stations for LDVs, mostly concentrated in California.⁷⁴

The high cost of fuel cells and the limited availability of hydrogen fueling stations have limited the number of hydrogen-fueled vehicles produced and adopted by consumers.⁷⁵ The competitiveness of hydrogen with conventional fuels will be highly dependent on the development of refueling stations and infrastructure as well as government assistance and policy. However, recent advances in technology combined with marketplace developments are providing favorable conditions for the hydrogen fuel cell market for passenger cars and SUVs, light commercial vehicles, and heavy-duty trucks and buses. Developments in each of these segments are creating synergies driving down the costs of components and infrastructure. Globally, over 27,500 hydrogen fuel cell vehicles were sold by year-end 2020. Over 8,500 passenger fuel cell vehicles were sold in 2020, the highest annual sales compared to any of the previous years. The sales are being driven by the gradual emergence of a substantial hydrogen fueling infrastructure in several major global markets. It is projected that more than 19 million passenger hydrogen fuel cell vehicles will be sold or leased worldwide by 2035. This includes the fuel cell vehicles that have already been sold.⁷⁶ The global market is expected to increase as a result of surge in environmental concerns, government incentives for development of hydrogen fuel cell infrastructure and investments, and technological advancements.⁷⁷

There is also a rising interest in the use of hydrogen fuel cells for the rail transportation industry. Railway companies are focusing on adopting advanced technologies such as hydrogen fuel cell trains that are driven by self-propulsion modules. This trend is expected to have a strong influence on rail transportation companies, especially in North America, Europe, and Asia Pacific.⁷⁸

In addition to its use in fuel cells, hydrogen can also be combined with CO₂ to produce synthetic fuels, offering additional ways to meet the needs of various transportation modes including shipping and maritime applications.⁷⁹ Rail, marine and aviation applications are well suited to hydrogen because their energy intense duty cycles and long ranges make them particularly hard to electrify. There is increasing interest in hydrogen fuel cells for these applications, but to date activity has been primarily focused on European and Asian markets. For example, the world's first hydrogen-powered trains are operating in northern Germany on a 100 kilometer (km) (about 62 miles) stretch of track. The engines can run for 1,000 km (621 miles) on a tank of hydrogen and store excess energy produced by the fuel cell on board in ion-lithium batteries.⁸⁰

73 "US: Hydrogen Fuel Cell Car Sales Collapsed In 2020," *InsideEVs*, January 27, 2021, <https://insideevs.com/news/482386/us-hydrogen-fuel-cell-car-sales-2020/>

74 Sunita Satyapal, "Hydrogen and Fuel Cell Technology Growth Worldwide," Presentation at the DOE Hydrogen and Fuel Cell Technology Office H2@Airports Workshop, November 4, 2020, <https://www.energy.gov/sites/prod/files/2020/12/f81/hfto-h2-airports-workshop-2020-satyapal.pdf>

75 U.S. Energy Information Administration, "Hydrogen Explained: Use of Hydrogen," January 7, 2021, <https://www.eia.gov/energyexplained/hydrogen/use-of-hydrogen.php>

76 "Global Hydrogen Fueling Stations Market 2021: At Least a Dozen Automakers are Poised to Enter the Market Over the Coming Years," *Cision/PR Newswire*, June 25, 2021, <https://www.prnewswire.com/news-releases/global-hydrogen-fueling-stations-market-2021-at-least-a-dozen-automakers-are-poised-to-enter-the-market-over-the-coming-years-301320201.html>

77 "Hydrogen Fuel Cell Vehicle Market Size, Outlook, Trends by 2030," *Allied Market Research*, January 2020, <https://www.alliedmarketresearch.com/hydrogen-fuel-cell-vehicle-market>

78 "Hydrogen Fuel Cell Trains to Have Strong Impact on Rail Transportation Businesses," *Cision/PR Newswire*, June 25, 2021, <https://www.prnewswire.com/news-releases/hydrogen-fuel-cell-trains-to-have-strong-impact-on-rail-transportation-businesses--discover-company-insights-on-bizvibe-301319937.html>

79 U.S. Department of Energy, "Hydrogen Program Plan," November 2020, <https://www.hydrogen.energy.gov/pdfs/hydrogen-program-plan-2020.pdf>

80 "These Countries are Pioneering Hydrogen Power," *World Economic Forum*, January 15, 2019, <https://www.weforum.org/agenda/2019/01/these-countries-are-pioneering-hydrogen-power-d941536b-4206-4fa1-8932-8596d7b856bd/>

Current maritime applications are limited to demonstration projects. However, increased maritime freight demand with tightened pollution targets may gather further interest in hydrogen as an alternative fuel. Potential applications include hydrogen fuel cell propulsion systems as well as auxiliary power systems for ships. Early applications for hydrogen in marine include ferries, tugboats, and coastal and inland barges. Maritime applications can enable large scale use of hydrogen. Challenges for accelerating broader deployment of hydrogen and fuel cell technologies in maritime applications include improving the efficiency and durability of fuel cells at a lower cost, to compete with diesel engines; and establishing a hydrogen infrastructure for delivering hydrogen at a cost that is competitive with diesel.⁸¹ The International Maritime Organization (IMO) identified ammonia (made with renewable hydrogen) and hydrogen used directly as a fuel as potential fuels of the future in a decarbonized shipping industry.

3.4 Hydrogen Fuel Cells / Electricity Generation

Fuel cells use the chemical energy of hydrogen or other fuels to cleanly and efficiently produce electricity. If hydrogen is the fuel, the only byproducts are electricity, water, and heat. Fuel cells are unique in terms of the variety of their potential applications; they can use a wide range of fuels and feedstocks and can provide power for systems as large as a utility power station and as small as a hydrogen-fueled power pack that could replace batteries in portable gadgets.⁸² They also provide electricity and water to manned U.S. spacecraft. Fuel cells can efficiently convert hydrogen into power with low emissions, and the inherent modularity of fuel cell systems makes them ideally suited for a broad range of stationary-power applications ranging from less than a kilowatt up to the multi-megawatt scale.⁸³

According to EIA, at the end of October 2020, there were about 161 operating fuel cells at 108 facilities in the U.S. with a of 250 MW of electric generation capacity. The largest of these is stationed at the Red Lion Energy Center in Delaware with about 25 MW total electric generation capacity, which uses hydrogen produced from natural gas to operate the fuel cells.⁸⁴

Fuel cells have several benefits over conventional combustion-based technologies currently used in many power plants and vehicles. Fuel cells can operate at higher efficiencies than combustion engines and can convert the chemical energy in the fuel directly to electrical energy with efficiencies capable of exceeding 60%. Hydrogen fuel cells emit water, addressing critical climate challenges as there are no carbon dioxide emissions. There also are no air pollutants that create smog and cause health problems at the point of operation. Fuel cell power plants are sometimes used for backup power at small facilities such as hospitals. They can also be used to operate data centers for large private corporations that have committed to meeting 100% of their electricity needs with power produced from renewable sources.⁸⁵

Fuel cells are classified by their electrolyte, which determines the type of electro-chemical reaction that occurs in the fuel cell, the kind of catalysts required, the temperature range in which the cell operates, the fuel required, and other factors. Various fuel cell types are described below.⁸⁶

81 Argonne National Laboratory, "H2@Ports Workshop Summary Report," September 10-12, 2019, <https://publications.anl.gov/anlpubs/2020/03/158750.pdf>

82 Colin Barras, "World's Smallest Fuel Cell Promises Greener Gadgets," NewScientist, January 7, 2009, <https://www.newscientist.com/article/dn16370-worlds-smallest-fuel-cell-promises-greener-gadgets/>

83 U.S. Department of Energy, "Hydrogen Program Plan," November 2020, <https://www.hydrogen.energy.gov/pdfs/hydrogen-program-plan-2020.pdf>

84 U.S. Energy Information Administration, "Hydrogen Explained: Use of Hydrogen," <https://www.eia.gov/energyexplained/hydrogen/use-of-hydrogen.php>.

85 U.S. Energy Information Administration, "Fuel Cell Power Plants are Used in Diverse Ways Across the United States," <https://www.eia.gov/todayinenergy/detail.php?id=35872>

86 U.S. Department of Energy, "Types of Fuel Cells," Hydrogen and Fuel Cell Technologies Office, <https://www.energy.gov/eere/fuelcells/types-fuel-cells>

- *Polymer electrolyte membrane (PEM) fuel cells* deliver high power density, low weight, and are typically fueled with pure hydrogen supplied from storage tanks or reformers. PEM fuel cells are primarily used in transportation due to fast startup time and beneficial power-to-weight ratio but have limited use in stationary power applications due to their costly platinum catalyst. The design of fuel cells requires a high level of purity of the hydrogen (99.97%). Any contaminants, such as sulfur, will degrade fuel cell and significantly reduce the conversion efficiency.⁸⁷
- *Alkaline fuel cells (AFC)* use a solution of potassium hydroxide in water as an electrolyte and were limited to space applications due to its susceptible poisoning by carbon dioxide dramatically affecting cell performance and durability due to carbonate formation.
- *Phosphoric acid fuel cells (PAFC)* contain a liquid phosphoric acid as an electrolyte and is typically used for stationary power generation and some limited applications to power large vehicles such as city buses. PAFCs are more than 85% efficient when used for the co-generation of electricity and heat but they are less efficient at generating electricity alone (37%–42%); slightly more efficient than that of combustion-based power plants, which typically operate at around 33% efficiency. Because PAFCs have a lower power-to-weight ratio, they are often heavier and larger than other fuel cells typically resulting in higher costs.
- *Molten carbonate fuel cells (MCFC)* are currently being developed for natural gas and coal-based power plants for electrical utility, industrial, and military applications. Unlike AFC, PAFC, and PEM fuel cells, MCFCs do not require an external reformer to convert fuels such as natural gas and biogas to hydrogen. Since MCFCs operate at high temperatures, methane and other light hydrocarbons in these fuels are converted to hydrogen within the fuel cell itself by a process called internal reforming, which also reduces cost.
- *Solid oxide fuel cells (SOFC)* use a hard, non-porous ceramic compound as the electrolyte and are around 60% efficient at converting fuel to electricity. SOFCs can use natural gas, biogas, and gases derived from coal, but have a slow startup and require significant thermal shielding to retain heat and protect personnel which limits potential applications to utilities, but not for transportation.

Fuel cells can benefit the national grid in several ways. They are flexible, controllable, are typically co-located with demand (minimizing losses in transmission and distribution), and are likely to generate when demand for electricity is highest if used for combined heat and power to meet peak demand. Additionally, hydrogen feedstock may be produced onsite at a power plant, providing the large-scale long-term storage required to shift electricity from times of renewable surplus to those of shortfall.⁸⁸ Ongoing DOE RD&D focuses on the development of low-cost fuel cell stack and balance of plant components and advanced high-volume manufacturing approaches to reduce overall system cost; innovative materials and integration strategies to improve fuel cell efficiency and performance; and enhancing durability and system reliability under dynamic and harsh operating conditions. Currently, hydrogen use for power generation is limited; however, there remains vast potential through injection into existing natural gas pipeline infrastructure.

87 VSL, "Hydrogen Purity Analysis for Fuel Cell Vehicles," November 14, 2020, <https://www.vsl.nl/en/about-vsl/news/hydrogen-purity-analysis-fuel-cell-vehicles>

88 Iain Staffell, Daniel Scamman, Anthony Velazquez Abad, Paul Balcombe, Paul E. Dodds, Paul Ekins, Nilay Shah, Kate R. Ward, "The Role of Hydrogen and Fuel Cells in the Global Energy System," *Energy & Environmental Science Journal*, 2019, <https://pubs.rsc.org/en/content/articlelanding/2019/ee/c8ee01157e#divAbstract>

Section B: Building on Domestic Coal Resources and CCUS Research

4. Suitability of Various U.S. Coal Types for Hydrogen Production

4.1 Overview of Coal Types

Coal is derived from plant matter trapped underground, which has changed into a denser, drier, and harder material that is richer in carbon. The primary constituents of coal are carbon, hydrogen, oxygen, nitrogen, sulfur, and non-combustible material (ash). The energy content of coal is predominately measured in British Thermal Unit (Btu) per pound. Coal is typically distinguished by four major ranks. The major ranks of coal from highest to lowest carbon contents are anthracite, bituminous, sub-bituminous, and lignite. There are no clear-cut dividing lines between the different ranks. Each type has distinct characterizes as follows.⁸⁹

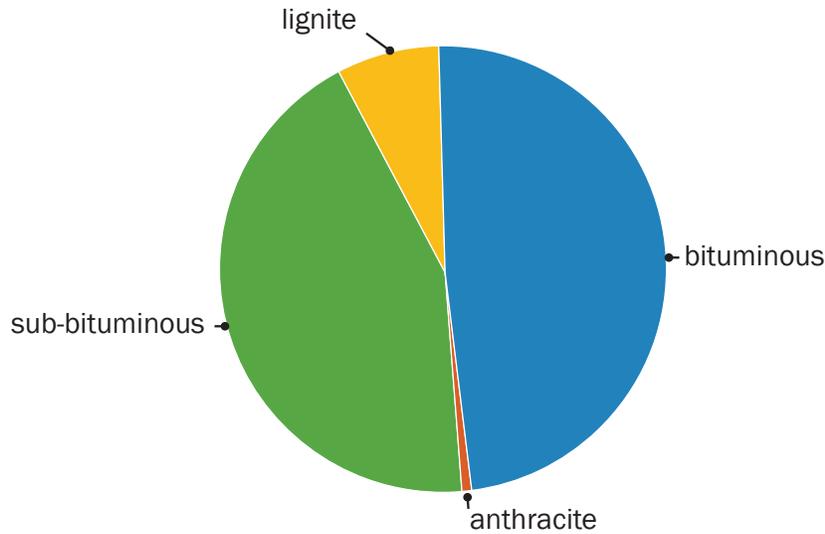
- **Anthracite coal** is typically shiny, black, hard and brittle, with a high percentage of fixed carbon, and a low percentage of sulfur content and volatile matter. It contains 86%–97% carbon and generally has the highest heating value of all ranks of coal. It is a slow burning coal due to the low volatile matter. Anthracite coal is predominantly mined in the eastern U.S. states, primarily in northeastern Pennsylvania. Anthracite accounted for less than 1% of the coal mined in the U.S. in 2019 and it is mainly used by the metals industry.
- **Bituminous coal**, often referred to as “steam coal,” is the most common coal used in electric generation. It contains 45%–86% carbon and is characterized by its high heating value, relatively low moisture and volatile content. Bituminous coal is the most abundant rank of coal found in the U.S., and it accounted for about 48% of total U.S. coal production in 2019. Bituminous coal is used to generate electricity and is an important fuel and raw material for making coking coal or use in the iron and steel industry. Bituminous coals are most prevalent in West Virginia, Illinois, Kentucky, and Indiana.
- **Subbituminous coal** has a lower heating value and higher moisture content and higher volatile content than the above coals, and is also used extensively in electric generation. Subbituminous coals typically contain 35%–45% carbon, and it has a lower heating value than bituminous coal and has low sulfur and ash content. About 44% of total U.S. coal production in 2019 was subbituminous and about 88% was produced in Wyoming. During the early days of the implementation of the Clean Air Act 1990 amendments, many utilities switched from bituminous coals with higher sulfur content to low-sulfur subbituminous coals as a means to delay the retrofit of flue gas desulfurization systems. A disadvantage of subbituminous coals is that they are subject to spontaneous combustion due to the high volatile content.
- **Lignite** is often referred to as “brown coal.” It contains 25%–35% carbon and has the lowest energy content of all coal ranks. It has a lower heating value and very high moisture content. Because of the younger age of lignite, it also has the highest volatile content of the coal ranks. Lignite coals are very susceptible to spontaneous combustion because of the high volatile and moisture content. Lignite accounted for 8% of total U.S. coal production in 2019; about 51% was mined in North Dakota and 41% was mined in Texas. The largest deposits of lignite in the U.S. are in Wyoming, Montana, Utah, Texas, and the Dakotas. Most power plants that use lignite are “mine-mouth” plants where the plants are built adjacent to the lignite mines. That is because it is not economical to transport lignite a long distance because of the low energy (Btu/lb) content, and the possibility of spontaneous combustion.

Figure 9 shows domestic coal production by type. Bituminous and sub-bituminous coals are generally preferred for gasification over anthracite coals. The main reason is that, because of the high oxygen content of this type of coal, it is less chemically stable and therefore easier to break apart during the gasification reaction. Further, there is a small boost from the hydrogen that is already present in the coal.⁹⁰

⁸⁹ U.S. Energy Information Administration, “Coal Explained,” Updated October 8, 2020, <https://www.eia.gov/energyexplained/coal/>

⁹⁰ Jessica Allen, “Explainer: How do we Make Hydrogen from Coal, and is it Really a Clean Fuel?” *The Conversation*, April 13, 2018, <https://theconversation.com/explainer-how-do-we-make-hydrogen-from-coal-and-is-it-really-a-clean-fuel-94911>

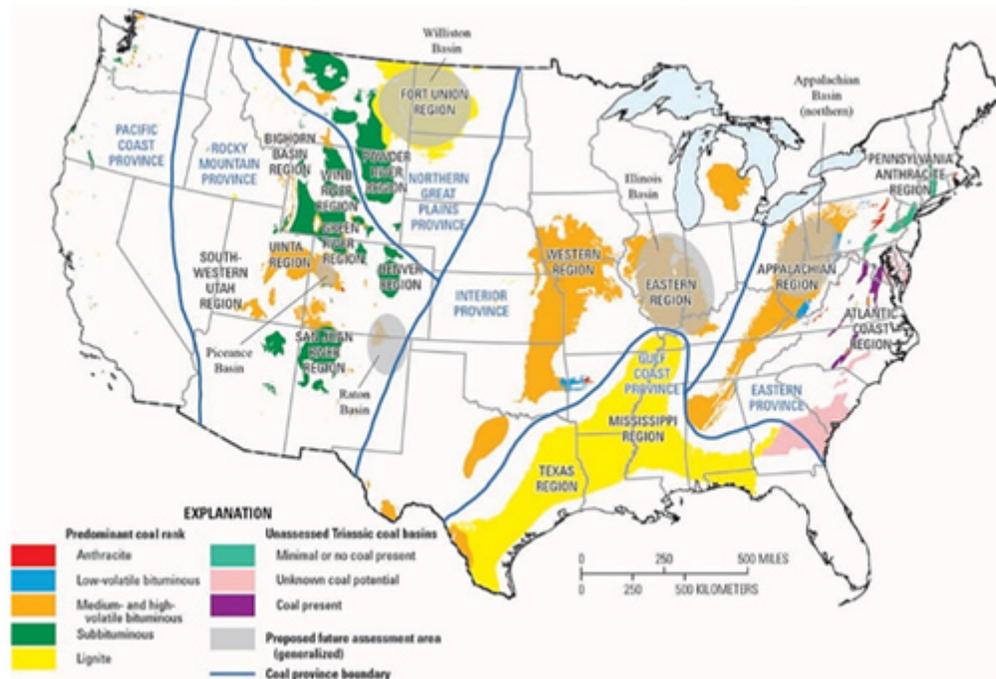
Figure 9 – U.S. Coal Production by Type, 2019⁹¹



4.2 Where Each Type of Coal is Found

The U.S. has the largest known recoverable reserve of coal in the world. Figure 10 provides a map showing the locations and types of the coal reserves in the United States.⁹² Coal is typically mined either in deep mines or surface mines. In deep mines, tunnels are dug down to a coal seam and the mined coal is removed by means of conveyors or trucks. In surface mines, earth (overburden) is removed from above the coal seam, the coal is removed, and then the overburden is placed over the area where the coal was removed. As coal is removed from the mine, typically the seam will vary in thickness to the point where the seam becomes too thin to economically mine.

Figure 10 – U.S. Coal Resources by Type and Location



⁹¹ U.S. Energy Information Administration, "Annual Coal Report 2019," <https://www.eia.gov/coal/annual/pdf/acr.pdf>

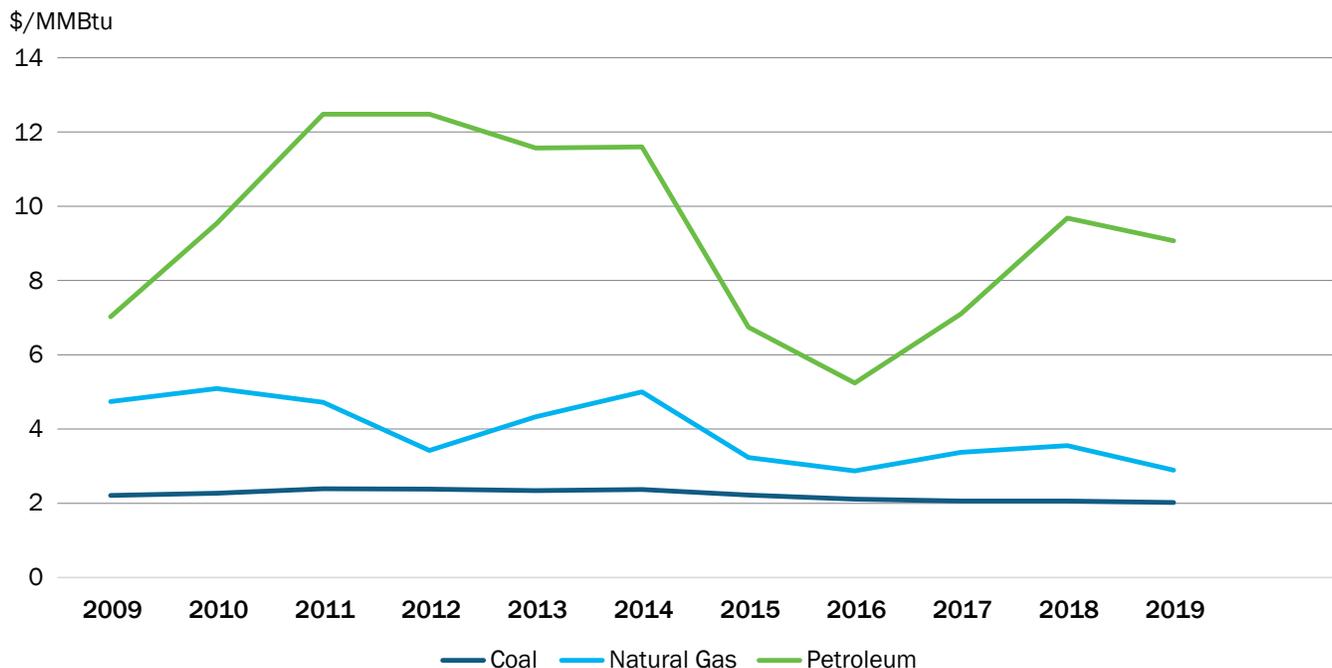
⁹² U.S. Geological Survey, "Coalfields of the Conterminous United States Map," <https://www.usgs.gov/media/images/usgs-coalfields-conterminous-united-states>

4.3 Coal Costs

Coal remains a relatively inexpensive fuel because of its high energy content, ease of transport, and ease of storage compared to other fossil fuels. Figure 11 shows the cost comparison for the major fossil fuels for the period of 2009–2019. Coal prices have been relatively stable, ranging from \$2.02–\$2.39 per MMBtu. Note that natural gas prices declined to \$2.89 per MMBtu in 2019. During the last week of June 2021, the average coal price was \$1.63 per MMBtu, whereas natural gas prices ranged from \$3.10–\$3.65 per MMBtu in June 2021.^{93,94}

While coal has traditionally been among the lowest cost fossil fuel on \$/MMBtu basis, when the externality costs due to the emissions are included in the end product, whether electricity, synfuel, hydrogen, or other byproducts, the cost advantage of coal becomes less clear. Coal emits more CO₂ than other fossil fuels because of its high carbon content. It also produces other byproducts of combustion including ash, SO₂, and NO_x.

Figure 11 – Average Cost of Various Fuels (\$/MMBtu)⁹⁵



4.4 Suitability of Coal Types for Hydrogen Production

Variations in coal quality can have an impact on the heating value of the syngas produced by the gasification process. The reactivity of coal, which has an impact on the suitability to gasify the coal, generally decreases with a rise in rank, i.e., going from subbituminous to bituminous. For medium- and low-rank coals, reactivity increases with an increase in pore volume and surface area, but for coals having a carbon content greater than 85%, these factors do not have an effect on reactivity. The volatile matter content of coal also varies for the coal types, depending on its ranking from high to low (anthracite with the lowest content and lignite with the highest content). Coals with higher volatile matter content are more reactive and can be more readily converted to gas while producing less char. While char is not a major concern for low-rank coals, their gasification results in high levels of tar in the syngas, which makes syngas cleanup more difficult. The ash content of the coal does not have much impact on the composition of the produced syngas. Oxygen supplied to the gasifiers must be increased with an increase in ash or moisture content in the coal.

⁹³ U.S. Energy Information Administration, “Coal Markets Data,” Updated July 26, 2021, <https://www.eia.gov/coal/markets/#tabs-prices-2>

⁹⁴ Natural Gas: 1990-2021 Data,” Trading Economics, <https://tradingeconomics.com/commodity/natural-gas>

⁹⁵ U.S. Energy Information Administration, “Table 7.1. Receipts, Average Cost, and Quality of Fossil Fuels for the Electric Power Industry, 2009 through 2019,” https://www.eia.gov/electricity/annual/html/epa_07_01.html

5. Prospect of Using Waste Coal-to-Hydrogen and Biomass with CCUS

In addition to coal resources, there is considerable waste coal in the U.S., as described in Section 2, above. Mixing waste coal with biomass has the potential to improve the handling and processing of the biomass in combustion and chemical conversion. Biomass material contains carbon and hydrogen that can be converted into energy or other forms of fuel. In biomass gasification, the carbonaceous material is converted into CO, hydrogen, and CO₂ at a high temperature with a controlled amount of steam and oxygen. The CO is converted into CO₂ and hydrogen using a water-gas shift (WGS) reaction.

While natural gas reforming, coal gasification, and electrolysis methods cover the current industry needs, numerous other pathways to hydrogen generation exist, including biomass as a feedstock for hydrogen production. Solid biomass, including specialty crops (e.g., switchgrass) and residues from agricultural or forest products, can be gasified like coal. Alternatively, biomass can be converted to liquid biofuels, such as ethanol, and subsequently reformed like natural gas. Biomass is a promising source for producing hydrogen and can play an important role in reducing carbon intensity of coal-based systems with application of advanced technologies integrating carbon capture. Whereas hydrogen made with renewable energy can be carbon neutral, hydrogen produced using biomass gasification and CCUS has the potential to be a negative emissions technology. While it is an area of debate, biomass is considered a net-neutral fuel for CO₂ emissions when it is replanted, as the new plants will absorb CO₂ in an approximately same amount as is generated during combustion. Carbon neutrality for biopower is calculated most accurately based on the carbon flux (i.e., GHG emission or sequestration) of several parameters over a specified time period. A life-cycle assessment (LCA) is a common technique to calculate the environmental footprint, including the carbon flux, of a particular biopower pathway.⁹⁶

Another option is blending of coal and biomass for hydrogen production. Interest in the concept of co-feeding biomass to coal-fueled plants including advanced gasification-based plants, such as IGCC power plants, emerged from the idea that coal-biomass systems could become part of an early compliance strategy for carbon reduction, particularly across the large existing installed base of coal-based power plants. Recognizing that the use of biomass for power is constrained by low biomass energy density, feedstock water content, feedstock collection and preparation, and seasonal/regional feedstock availability, coal-biomass systems could benefit from the stability of a primarily coal-based feed mix, adding tractable amounts of biomass as constrained by technical/performance requirements and biomass availability.

The major challenges of using biomass are high moisture content, materials handling, and transportation costs. Biomass is typically high in moisture content leading to a corresponding reduction in energy content per pound (Btu/lb). The high moisture content, combined with the cellulosic material leads to difficulty in material handling systems. Energy conversion processes typically are most efficient if the solid feedstock is reduced to a small size. The soft cellulosic material in biomass, along with the moisture is a challenge in the design of equipment to transport and process the biomass without extensive plugging. Because of the relatively low energy content of biomass, transportation costs in terms of \$/Btu-mile will limit the practical distance from a facility fueled with biomass from the fuel source.

The moisture content can be reduced by a process called torrefaction, through which the hemicelluloses in the wood are partially decomposed using a mild pyrolysis process at temperatures ranging from 225 to 300 °C. This process reduces the mass of the wood while conserving the lower heating value.

⁹⁶ Congressional Research Service, "Is Biopower Carbon Neutral?" February 4, 2016, <https://sgp.fas.org/crs/misc/R41603.pdf>

Co-gasification of coal and biomass matter has higher efficiency than gasification of coal alone because cellulose, hemicellulose, and lignin content of biomass help to ignite and enhance the rate of gasification.⁹⁷ Compared with pure biomass-fired power plants, coal-biomass co-firing technology has a higher power generation efficiency. This technology uses large-capacity and high-efficiency generating units of existing coal-fired power plants to generate electricity, which could make the power generation efficiency reach 40% to 46%.⁹⁸

Advanced gasification-based power plants, such as IGCC, using coal and biomass mixtures as feedstock for co-firing could become part of a carbon reduction strategy for existing coal-based power plants.⁹⁹ DOE's early-stage research for the Coal FIRST initiative supports the development of new generation of electricity and hydrogen energy plants that have net-zero carbon emissions and fueled by coal, natural gas, biomass, and waste plastics and incorporate CCUS technologies.¹⁰⁰

DOE RD&D in co-gasification is pursuing gasifier technology for higher efficiency gasification of coal and biomass blends and reduction of technology costs, which will enable negative greenhouse gas emissions technology in gasification systems.¹⁰¹ Areas of RD&D include bio-based technologies such as bioenergy with carbon capture and storage (BECCS); biomass co-firing with coal, CO₂ capture, and carbon-negative routes through the adoption of biomass gasification or combustion coupled with CCUS. In March 2021, DOE initiated RD&D projects aimed at finding different ways to produce hydrogen through co-gasification of blends waste from biomass, plastic, and coal feedstocks with oxygen and steam under high pressures and temperatures, which has the potential to produce cleaner hydrogen.¹⁰²

In addition, DOE's Clean *Hydrogen & Negative CO₂ Emissions* program focuses on designs and strategies for modular gasification-based systems enabling negative lifecycle emissions of greenhouse gases. For example, biomass can have an important role in reducing carbon intensity of coal-based systems, as can application of advanced technologies integrating carbon capture. Likely approaches to be considered include co-utilization of biomass with coal as gasification feedstocks, integrated or pre-combustion capture of CO₂ especially facilitated by gasification, and innovative technological approaches or combinations of technologies enabling extensive greenhouse gas reductions of modular gasification systems.¹⁰³

6. Maturity of Coal-to-Hydrogen Production Methods, Including CCUS

The conversion of solid fossil fuels to hydrogen is typically accomplished by gasification. In gasification, the solid fuel is partially combusted in a reducing atmosphere to convert the carbon in the coal to CO, and the hydrogen in the coal and water ultimately to hydrogen using the water-gas shift reaction. WGS reaction ($\text{CO} + \text{H}_2\text{O} \rightarrow \text{CO}_2 + \text{H}_2$) is a reversible, exothermic chemical reaction, usually assisted by a catalyst, and is the reaction of steam with CO to produce CO₂ and hydrogen gas. The mixture of CO and hydrogen is a combustible gas but combustion of the CO produces CO₂. Treating the mixture with water vapor over a catalyst converts the CO to CO₂ and produces more hydrogen.

97 Alka D. Kamble, Vinod Kumar Saxena, Prakash Dhondiram Chavan, Vinod Atmaram Mendhe, "Co-Gasification of Coal and Biomass an Emerging Clean Energy Technology: Status and Prospects of Development in Indian Context," Science Direct, <https://www.sciencedirect.com/science/article/pii/S2095268617306791>

98 Yan Xu, Kun Yang, Jiahui Zhou and Guohao Zhao, "Coal-Biomass Co-Firing Power Generation Technology: Current Status, Challenges and Policy Implications," May 2, 2020, <https://www.mdpi.com/2071-1050/12/9/3692>

99 National Energy Technology Laboratory, "Blue Hydrogen & Negative CO₂ Emissions," https://netl.doe.gov/coal/gasification/negative_ghg_emissions

100 U.S. Department of Energy, "Coal FIRST," Office of Fossil Energy and Carbon Management, <https://www.energy.gov/fe/coal-first>

101 National Energy Technology Laboratory, "Clean Hydrogen & Negative CO₂ Emissions," https://netl.doe.gov/coal/gasification/negative_ghg_emissions

102 "U.S. Department of Energy Awards \$2 Million To Develop Clean Hydrogen Technologies," <https://www.energy.gov/articles/us-department-energy-awards-2-million-develop-clean-hydrogen-technologies>

103 National Energy Technology Laboratory, "Clean Hydrogen & Negative CO₂ Emissions," https://netl.doe.gov/coal/gasification/negative_ghg_emissions

The type of gasifier used is highly dependent on the coal and feedstock properties. Entrained flow reactors typically operate better using low-ash, low-moisture bituminous coal. This is because the entrained flow reactors operate under high pressure and with relatively low residence time in the conversion to syngas. Fuel-feed systems, which are designed to pressurize the fuel in order to feed it into the gasifier, can be subject to clogging with fuels with high moisture content. Further, there is an energy loss associated with pressurizing any incombustibles in the fuels. Fixed bed reactors, which typically operate at a lower pressure and have a higher residence time in the reactor, are better suited for lower-rank fuels and biomass with high ash and moisture content.¹⁰⁴

6.1 Coal-to-Hydrogen Production Plants in Operation

The Dakota Gasification Company's Great Plains Synfuels Plant (GPSP) located near Beulah, North Dakota, was the first commercial integrated coal-to-synthetic natural gas gasification plant to capture CO₂ with the beneficial use of the CO₂ for Enhanced Oil Recovery. The plant produces approximately 160 million scf/day of syngas and about 8,000 metric tons of CO₂ daily. The plant, which was built with financial support of the DOE, has been in operation producing synthetic natural gas from lignite coal for 25 years and some changes have been made since its start to improve productivity, efficiency and the plant's effect on the environment. GPSP has been capturing CO₂ for underground storage since 2000 and has the ability to capture up to 3 million tons of CO₂ per year. In the years since, that plant has captured 40 MMT of CO₂—more CO₂ from coal conversion than any facility in the world.

The plant, which was built with financial support from the DOE, produces approximately 160 million cubic feet (MMcf) of syngas from 16,000 tons of lignite per day.¹⁰⁵ The GPSP has an overall higher heating value efficiency of about 65% and CCUS was added to the plant in 2000, capturing about 3 million tons of CO₂/year, representing around 50% of the CO₂ produced at the plant when running at full capacity. This is transported through a 205-mile pipeline to Saskatchewan, Canada, to be used for enhanced oil recovery.^{106, 107}

The total cost for the design and construction of the plant was around \$2 billion, which was designed with two product trains to improve plant availability, so that the plant can still operate at 50% capacity if one of the product trains is out of operation. The plant began operation in 1984, using 5 to 6 million tons of coal to produce around 53 billion cubic feet (Bcf) of SNG annually. The resulting production of hydrogen and syngas provides a source for chemicals and transportation fuels, as well as source fuels for combustion and preheating in combined cycles for electrical generation.

Captured CO₂ is transported via pipeline to Saskatchewan, Canada, where oil companies use it for enhanced oil recovery operations. This results in permanent CO₂ geologic sequestration. Hydrogen generated at the GPSP is used for ammonia production—approximately 400,000 tons per year. Most recently, in June 2021, it was announced that the plant may be acquired by Bakken Energy and Mitsubishi Power and converted into a large-scale producer of hydrogen as a hub for the production, storage, transportation and consumption of clean hydrogen.¹⁰⁸ If the acquisition goes through, the plant will produce clean hydrogen, with the carbon stored underground or injected back into oil wells.

104 National Energy Technology Laboratory, "Commercial Gasifiers," *Gasifipedia*, Section 5.2, <https://netl.doe.gov/research/Coal/energy-systems/gasification/gasifipedia/types-gasifiers>

105 Lignite Energy Council, "Great Plains Synfuels Plant," <https://lignite.com/mines-plants/poly-generation-plants/great-plains-synfuels-plant/>

106 National Energy Technology Laboratory, "SNG From Coal: Process & Commercialization," *Gasifipedia*, Section 7.5, <https://www.netl.doe.gov/research/coal/energy-systems/gasification/gasifipedia/coal-to-sng-process>

107 "Hydrogen from Coal," *Coal Age*, may 7, 2021, <https://www.coalage.com/features/hydrogen-from-coal/>

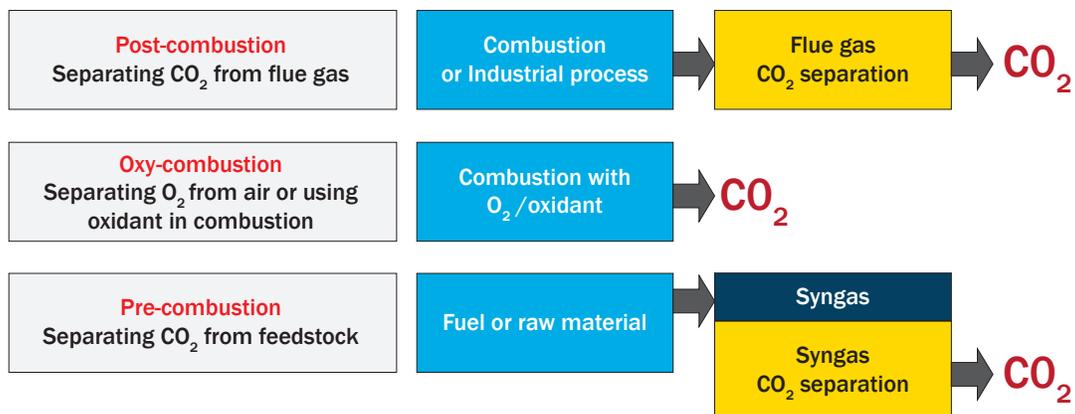
108 "Company Execs Boast Future 'Hydrogen Hub' in North Dakota," June 2, 2021, *The Dickenson Press*, <https://www.thedickinsonpress.com/business/energy-and-mining/7056537-Company-exec-boast-future-hydrogen-hub-in-north-dakota>

6.2 Carbon Capture, Utilization, and Storage

Carbon dioxide is produced from stationary sources in combination with other gases during industrial processes, including fossil fuel-based power generation, hydrogen production, steel and cement manufacture, and refined fuels production. CO₂ results from the combustion of fossil fuels for energy and heat during these operations as part of combustion emissions, as well as from the processes themselves as process emissions. Capture of CO₂ is the separation of CO₂ from these other gases from the exhaust stream of a power plant, or vented industrial flue gas emissions. The reduction of CO₂ emissions from the use of coal can be achieved before the fuel is burned, during the combustion process, or after the coal is burned. Pre-combustion removal entails removing carbon from the feedstock so that hydrogen combustion is the primary reaction. Removal or reduction of CO₂ during combustion can be achieved by combustion of the coal with oxygen enriched air and concentrating the CO₂ in the flue gas so that it is more easily used or sequestered. Post-combustion removal entails reacting the CO₂ with a solvent or adsorbent to physically or chemically remove the CO₂ from the exhaust. The principal challenge in post-combustion capture is separating the CO₂ generated during combustion from the large amounts of nitrogen found in the flue gas. After capture, CO₂ must be either utilized in a beneficial application or sequestered in permanent geologic storage. For the purposes of this paper, this section offers a short overview of carbon capture methods. See Appendix A, Carbon Capture, Utilization, and Storage, for additional detail on capture and an overview of utilization and sequestration.

The appropriate carbon capture technology to apply in an industrial application depends on the size or volume of the source gas stream, concentration of CO₂ in the gas mixture, and percent of CO₂ to be captured. Combustion for electricity and power generation represents more than half of the nationwide stationary point-source emissions, with over 30% coming from coal-fired units. There are four main CO₂ capture technologies: absorption, adsorption, membranes, and cryogenic separation. Of these technologies, absorption has been the most widely deployed because it is the most mature technology. The four main applications of CO₂ capture technologies, predominantly associated with the electric power generation sector are pre-combustion, post-combustion, oxy-firing, and chemical looping. Post-combustion capture is widely deployed application currently. Simplified process flows for CO₂ capture are shown in Figure 12 and these are described below.

Figure 12 – Carbon Dioxide Capture Options¹⁰⁹



Post-combustion capture refers to separating CO₂ from a flue gas derived from combusting fossil fuel in air, the dominant method of making power. Depending on the type of fossil fuel, CO₂ concentration is 3% to 15% in a mix of nitrogen, water, oxygen, argon, and various impurities formed either during combustion or that were in the fossil fuel. Because nitrogen is the predominant component compared with other components, the key

109 U.S. Department of Energy, "Accelerating Breakthrough Innovation in Carbon Capture, Utilization, and Storage: Report of the Mission Innovation Carbon Capture, Utilization, and Storage Experts' Workshop," September 2017, https://www.energy.gov/sites/prod/files/2018/05/f51/AcceleratingBreakthroughInnovationinCarbonCaptureUtilizationandStorage_0.pdf

separation is between CO₂ and nitrogen (N₂). Therefore, post-combustion capture technologies target CO₂-N₂ separation while ensuring the other flue gas constituents have minimal impact on the capture process or are removed before the capture process. As previously described, examples of post-combustion technologies include solvents, adsorption, membranes, and cryogenic separation.

Oxy-combustion refers to combusting fossil fuels in oxygen (O₂) as opposed to air. The resulting flue gas from the combustor is mostly CO₂ and water. By substituting combustion air for oxygen, oxyfuel combustion produces a relatively pure stream of CO₂ for sequestration. Combustion in pure oxygen results in very high combustor temperatures and a portion of the CO₂-containing flue gas is recycled back and blended with the oxygen feed to limit the O₂ concentration in the combustor. This effectively reduces the temperature in the combustor while still producing a flue gas composed of predominantly CO₂ and water. For most oxy-firing processes, oxygen usually comes from air and the key separation is O₂-N₂, which is commonly referred to as air separation. A variation of oxy-combustion is chemical looping combustion, where oxygen is created in-situ, eliminating the need to separate oxygen from air, reducing energy demand and system costs. The combustion product from the fuel reactor is a highly concentrated CO₂ and water stream that can be purified, compressed, and sent for storage or beneficial use.

Pre-combustion capture refers to partially oxidizing fossil fuels using steam and O₂ or air under high temperature and pressure to generate a mixture of CO, CO₂, and H₂, commonly known as syngas. Through a WGS reaction, the CO within the syngas is further reacted with water to make CO₂ and H₂ at high temperature and pressure. The CO₂ is separated from H₂ typically using a pressure-swing adsorption process. Because the gas stream is at high pressure, the separation is easier than for gas streams at lower pressures, such as post- or oxy-combustion. The capital cost of equipment is higher than for post combustion capture systems.

CCUS combines processes and technologies that work together to capture CO₂ from stationary sources, compress it, and transport to a suitable location where the CO₂ is converted into useable products or injected deep underground for safe and permanent storage. CCUS has been deployed on large stationary source CO₂ emissions in several industries in the U.S. and globally, including applications in coal-fired power or electricity generation, natural gas processing, and hydrogen and fertilizer production. CCUS is critical to managing carbon emissions in a wide spectrum of industries, from fossil fueled power generation to manufacturing and heavy industry—including oil refineries and facilities that produce hydrogen, ethanol, cement, or steel. CCUS can enable advanced power systems to adapt to changing operational requirements, such as the growing need for fossil fueled power plants to be load-following, demand-responsive electricity generators. CCUS technologies constitute an important opportunity for coal and hydrogen is one of the most important products from coal. It offers the highest energy content by weight of any known fuel, and hydrogen fuel cells emit only heat and water.

CCUS technologies constitute an important opportunity for coal, as decades of RD&D have led to key breakthroughs in CCUS on coal-fired power plants. Although CCUS is confined to a handful of power plants and faces challenges to widespread adoption in the power sector, CCUS has shown promising results in industrial uses, and results from power sector applications have been encouraging. Increased deployment could enable coal to deliver the benefits of CCUS while improving environmental performance—making coal a more robust clean energy competitor.¹¹⁰ Reducing the cost of CCUS is essential to achieving at-scale deployment. Carbon capture can represent the largest cost component in the CCUS supply chain, accounting for as much as 75% of the project cost when applied to large-scale stationary emissions sources. Development of transport infrastructure to connect CO₂ sources and sinks, and identification and characterization of large-scale geologic storage formations, offer other means of reducing the cost of at-scale CCUS deployment.¹¹¹

110 National Association of Regulatory Utility Commissioners, “Carbon Capture, Utilization, and Sequestration: Technology and Policy Status and Opportunities,” November 5, 2018, <https://pubs.naruc.org/pub/8C07B393-A9A0-3F04-4832-D43790E10B91>

111 National Petroleum Council, “Meeting the Dual Challenge: A Roadmap to At-Scale Deployment of Carbon Capture, Use, and Storage,” Updated March 2021, <https://dualchallenge.npc.org/>

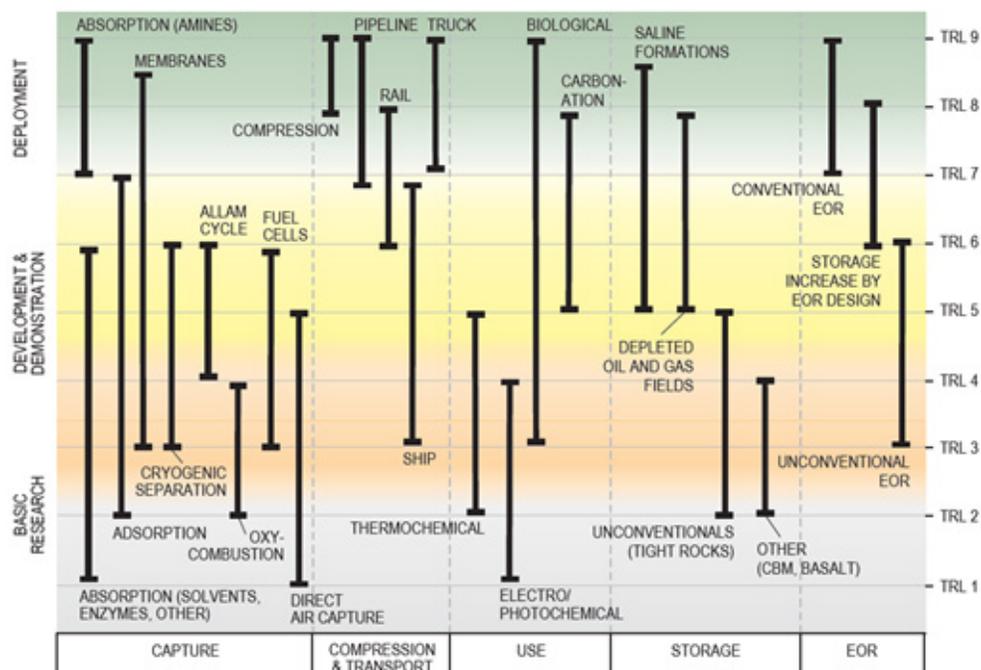
A 2018 report by NARUC provides a comprehensive discussion of CCUS, including a historical context, primer on CCUS technology, and policy approaches to expand CCUS.¹¹²

The U.S. has made significant strides in the development of CCUS technologies during the last two decades, which has been aided by public-private partnerships that have driven cost reductions and performance improvements. Some technologies are in use and available for commercial deployment today while others require demonstration to prove their viability in a commercial setting. Other technologies remain in earlier stages of development. A list of major U.S. CCUS projects is included in Appendix A.

6.3 CCUS Technology Maturity

A recent study by the National Petroleum Council (NPC), commissioned by DOE, assessed the Technology Readiness Level (TRL) ranges for CCUS technologies, as shown in Figure 13. Each technology is assigned a TRL range that represents its stage of technical development and maturity (vertical axis). The TRL scale ranges from 1 (basic principle observed) through 9 (operational at scale). The higher TRL level (i.e., ≥ 8) indicates a technology is closer to commercial readiness and deployment. There is a limited suite of high TRL (greater than TRL 7) technology options available to deliver at-scale CCUS projects. Typical projects consist of CO₂ capture via amine absorption, transport from source to sink by pipeline, and the CO₂ injected deep underground for storage in saline formations or used for conventional CO₂ EOR. In general, it is expected that there will be limited options for cost and efficiency improvements associated with high TRL technologies where transformational improvements are not anticipated. For these mature technologies, only incremental cost and performance gains are expected as a result of operational efficiency gains that come from “learning by doing” through the delivery of many examples of the same kinds of projects. Alternatively, less mature and emerging technologies (TRL 6 and below) highlight the need for steep changes in performance and cost reductions. Figure 13 highlights a number of these less mature technologies that should benefit from continued progress in RD&D activity.¹¹³

Figure 13 – Technology Readiness Level Ranges for CCUS Technologies



112 National Association of Regulatory Utility Commissioners, “Carbon Capture, Utilization, and Sequestration: Technology and Policy Status and Opportunities,” November 2018, <https://pubs.naruc.org/pub/09B7EAAA-0189-830A-04AA-A9430F3D1192>

113 Ibid.

6.4 Federal Incentives for CCUS

CO₂ capture and transport requires significant capital investment on equipment and infrastructure. These purchases of equipment, services, and labor have positive direct and indirect economic impacts in local communities and contribute to state tax revenues. It should be noted that federal government incentives play a role in investment in CCUS. For example, Section 45Q of the U.S. tax code provides a performance-based tax credit for carbon capture projects that can show the captured CO₂ in geologic formations is securely stored, or beneficially used captured CO₂ or its precursor carbon monoxide as a feedstock to produce fuels, chemicals, and products in a way that results in emissions reductions as defined by federal requirements.¹¹⁴

The availability of the newly expanded and reformed 45Q tax credit reduces the cost and risk to private capital of investing in the deployment of carbon capture technology across a range of industries, including electric power generation, ethanol and fertilizer production, natural gas processing, refining, chemicals production, and the manufacture of steel and cement.¹¹⁵ Section 45Q does not define carbon capture equipment, but the final Department of Treasury regulations under Section 45Q, issued in January 2021, define carbon capture equipment as including all components of property that are used to capture or process carbon oxide until the carbon oxide is transported for disposal, injection, or utilization.

Generally, projects are eligible for Section 45Q Credits for 12 years after the project is placed in service and the credits for such projects increase each year to a maximum of \$50 per metric ton of qualified CO₂ disposed; and a maximum of \$35 per metric ton of qualified CO₂ injected or used. Prior to 2021, the Section 45Q Credit was available only for qualifying projects for which construction began before January 1, 2024; the final regulation extended the start of construction deadline through the end of 2025.¹¹⁶

7. Environmental Impacts Including GHG Emissions and Other Pollutants Generated from Coal-to-Hydrogen Production

7.1 Power Plant Emissions

The stationary power sources in the U.S. emit nearly 2 billion metric tons of greenhouse gas emissions annually, while U.S. industrial facilities emit nearly 1 billion metric tons of greenhouse gas emissions. Combined emissions from these power and industrial facilities comprise roughly half of all U.S. greenhouse gas emissions.^{117, 118} Since the implementation of the Clean Air Act of 1970, there has been significant reduction in regulated pollutants released into the air and water.¹¹⁹ Table 5 shows the reduction in power-plant emissions from 2013 to 2019. The reduction in emissions have been a result of several factors including fuel switching to low-sulfur coal and natural gas, installation of FGD, use of low-NOx burners and SNCRs, and improvements in power-plant efficiencies as older plants were retired and replaced with more efficient coal-fired plants, natural gas plants, and renewable technologies.

114 "IRS Provides Welcome Guidance on Code Section 45Q Credits in Revenue Ruling 2021-13," *JDSupra*, <https://www.jdsupra.com/legalnews/irs-provides-welcome-guidance-on-code-4844787/>

115 Elizabeth Abramson, Dane McFarlane, Jeff Brown, "Transport Infrastructure for Carbon Capture and Storage: Whitepaper on Regional Infrastructure for Midcentury Decarbonization," Great Plains Institute, June 2020, https://www.betterenergy.org/wp-content/uploads/2020/06/GPI_RegionalCO2Whitepaper.pdf

116 Elizabeth McGinley, and Michael Recchia, "Treasury Releases Final Regulations on 45Q Carbon Capture Credits," *Bracewell*, January 19, 2021, <https://bracewell.com/insights/treasury-releases-final-regulations-45q-carbon-capture-credits>

117 Elizabeth Abramson, Dane McFarlane, Jeff Brown, "Transport Infrastructure for Carbon Capture and Storage: Whitepaper on Regional Infrastructure for Midcentury Decarbonization," Great Plains Institute, June 2020, https://www.betterenergy.org/wp-content/uploads/2020/06/GPI_RegionalCO2Whitepaper.pdf

118 U.S. Environmental Protection Agency, "Sources of Greenhouse Gas Emissions," <https://www.epa.gov/ghgemissions/sources-greenhouse-gas-emissions>

119 U.S. Environmental Protection Agency, "GHGRP Power Plants," Greenhouse Gas Reporting Program, <https://www.epa.gov/ghgreporting/ghgrp-power-plants>

Table 5 – Power Plant Emission Trends 2013 to 2019

	Carbon Dioxide (CO ₂) (Thousand Metric Tons)	Sulfur Dioxide (SO ₂) (Thousand Metric Tons)	Nitrogen Oxides (NO _x) (Thousand Metric Tons)	Generation (Thousand Megawatt Hours)
2013	2,173,806	3,609	2,164	4,065,964
2014	2,168,284	3,454	2,100	4,093,606
2015	2,031,452	2,548	1,824	4,077,601
2016	1,928,401	1,807	1,630	4,076,827
2017	1,849,750	1,657	1,506	4,034,268
2018	1,874,346	1,572	1,485	4,175,388
2019	1,724,396	1,267	1,342	4,126,882

Source: U.S. Energy Information Administration (EIA)

In conventional plants, sulfur emissions have been reduced by switching from high-sulfur coal to low-sulfur coal, coal cleaning at the mines, and flue gas desulfurization (FGD) systems. NO_x emissions have been reduced by burner modifications and selective non-catalytic reduction (SNCR) technology. Particulate emissions have been reduced by improvements in electrostatic precipitator (ESP) and baghouse technologies. Mercury emissions have been reduced by use of carbon adsorption systems. In addition, efficiency improvements in new power plants have reduced the amount of coal required to generate the same amount of electricity, hence less emissions per kilowatt of electricity produced. New technologies for using coal have also been developed including fluidized bed combustion (FBC) and IGCC technologies.

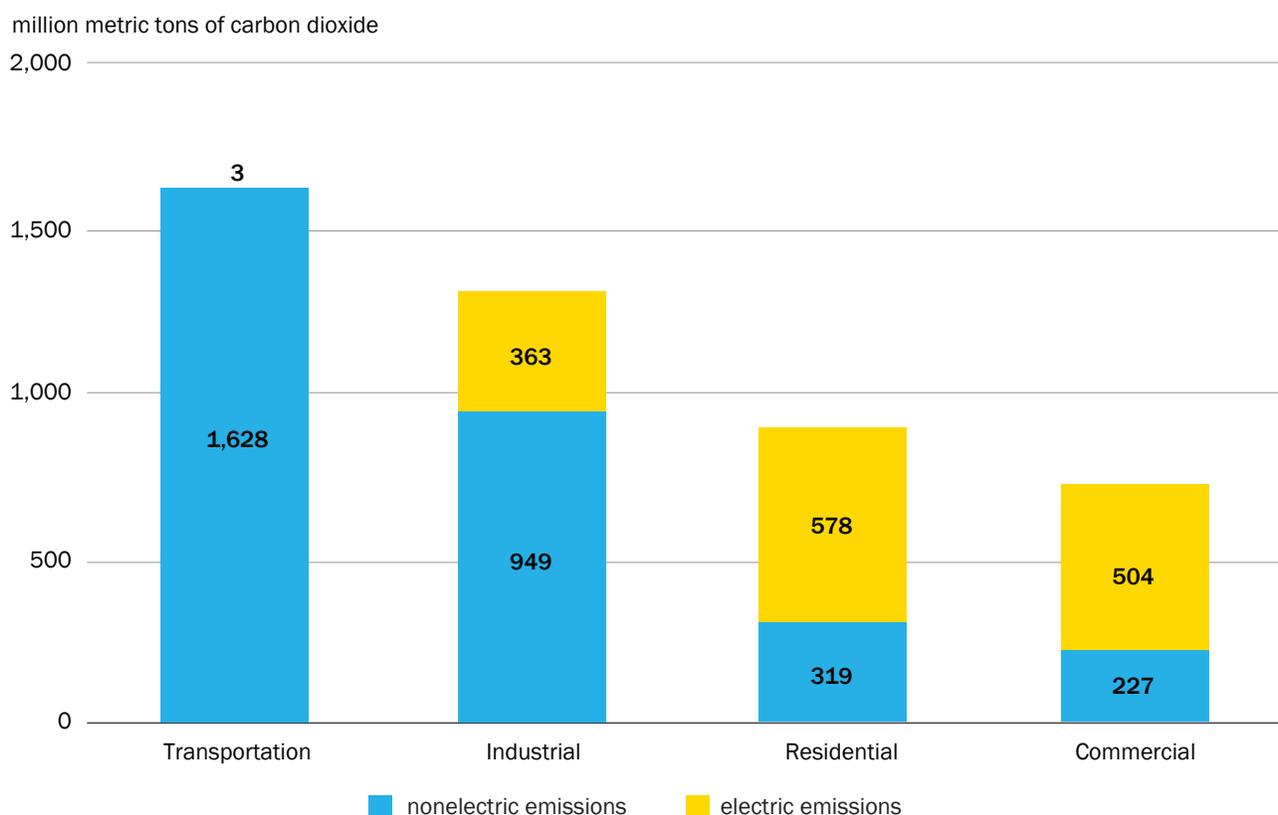
Reuse of the byproducts from these emission control systems has also reduced the amount of environmental damage from the byproducts (see Appendix B, Coal Combustion Residuals, for a more detailed discussion of coal combustion residuals). Beneficial use of coal ash includes structural fill, mine reclamation, and concrete. Beneficial use of FGD sludge includes making wall boards from the synthetic gypsum produced from the FGD.

Technologies to reduce CO₂ emissions are now at the forefront and the production of hydrogen from coal and CCUS go hand in hand. The use of IGCC for coal-to-hydrogen production results in *de-minimis* emissions of sulfur, particulates, and mercury because of the chemical systems used in associations with the gasification process. NO_x emissions are significantly reduced because of the advanced design of modern combustion turbines. Use of the WGS reaction to produce hydrogen and concentrated CO₂ provides a more economical approach to capture and remove CO₂ from the process so that it can be stored in geologic formations or used for beneficial purposes such as enhanced oil recovery. CO₂ emissions from the combustion turbine are reduced in direct proportion of the percentage of hydrogen is used in the syngas feed.

In addition to reduced emissions using advanced technologies to generate hydrogen from coal, the use of hydrogen has the potential to reduce emissions at the end use, especially in the transportation sector, which is the greatest source of CO₂ emissions as is shown in Figure 14.¹²⁰ The use of hydrogen as a fuel for transportation in fuel cell applications will result in a significant reduction in CO₂ emissions because the emissions from using hydrogen as a fuel are water vapor and NO_x. Therefore, installing IGCC systems to convert coal to hydrogen and electricity would yield significant improvements in all of the targeted emissions in both the generation and end use sectors of society.

120 U.S. Energy Information Administration, "U.S. Energy-Related CO₂ Emissions Declined by 11% in 2020," Today in Energy, <https://www.eia.gov/todayinenergy/detail.php?id=47496>

Figure 14 – CO₂ Emissions by End-Use Sectors (2020)



Source: U.S. Energy Information Administration. Nonelectric emissions are from primary energy consumption; electric emissions are from generation of electricity purchased from the electric power sector.

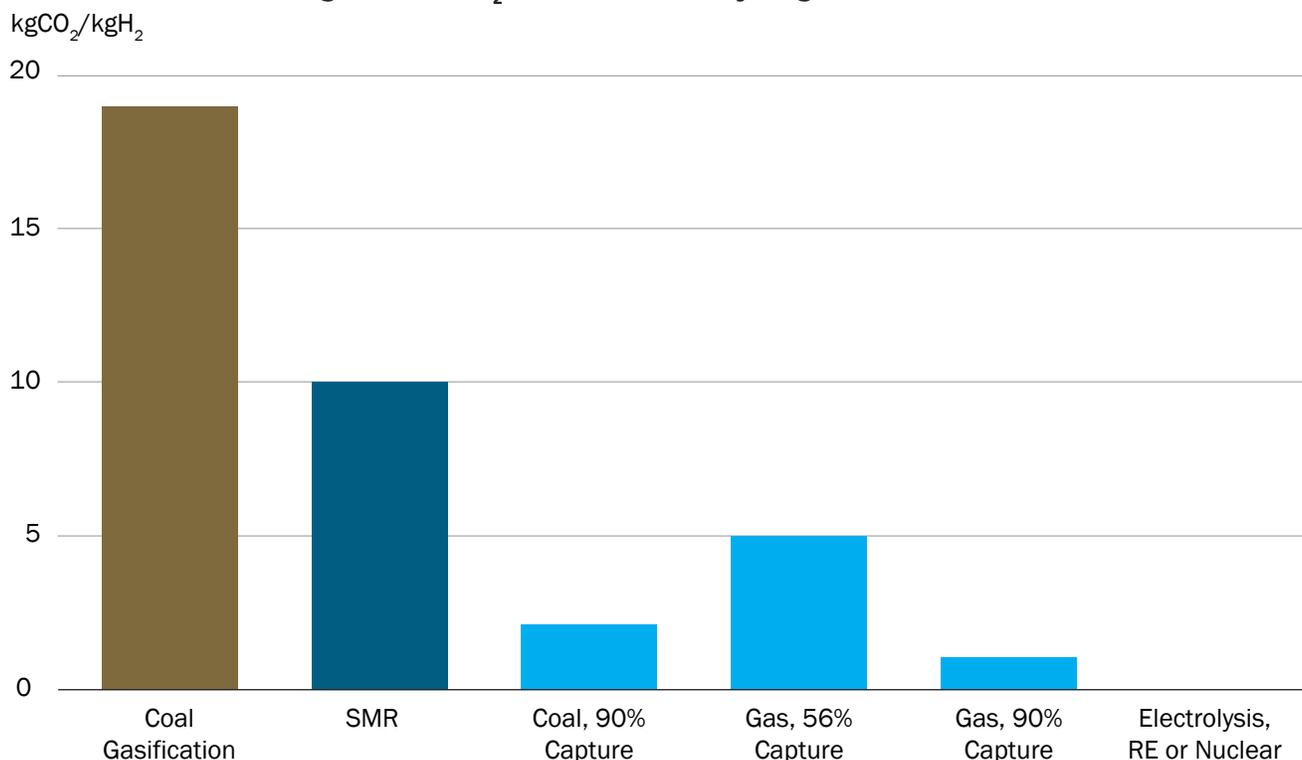
7.2 CO₂ Emissions from Coal-to-Hydrogen Production

The CO₂ impact of different hydrogen production technologies varies widely. The carbon intensity of hydrogen from natural gas without CCUS is roughly half that of coal without CCUS. The CO₂ intensity of electrolysis depends on the CO₂ intensity of the electricity input. The conversion losses during electricity generation mean that using electricity from natural gas or coal power plants would result in higher CO₂ intensities than directly using natural gas or coal for hydrogen production.

Whether hydrogen is produced from natural gas reforming or coal gasification and without CCUS, the generation of hydrogen is a source of CO₂ emissions. In 2017, globally, emissions from the dedicated production of hydrogen totaled 830 million tons, more than 2% of global fossil CO₂ emissions. Figure 15 shows CO₂ emissions by hydrogen production method with and without carbon capture (includes only CO₂ emissions from combustion and chemical conversion).¹²¹ Emissions range from 19 kgCO₂/kgH₂ for brown hydrogen to essentially zero for green hydrogen. Grey hydrogen has approximately half the emissions intensity of brown hydrogen, which in turn causes blue hydrogen from natural gas to have about half the emissions of blue hydrogen from coal at equivalent capture rates. Blue hydrogen is further split between capturing only the process CO₂ (50% to 60% capture) and capturing both process and combustion CO₂ (about 90% capture). In 2017, the U.S. electricity grid had an average carbon intensity between that of natural gas and coal-fired power. With the retirement of coal-fired power plants and the increase in wind and solar power, the carbon intensity of the U.S. power sector has been decreasing.

¹²¹ Jay Bartlett and Alan Krupnick, “Decarbonized Hydrogen in the US Power and Industrial Sectors: Identifying and Incentivizing Opportunities to Lower Emissions,” Resources for the Future, December 21, 2020, <https://www.rff.org/publications/reports/decarbonizing-hydrogen-us-power-and-industrial-sectors/>

Figure 15 – CO₂ Emissions from Hydrogen Production¹²²



The high CO₂ emissions intensity of coal-based hydrogen will require use of carbon capture technology if hydrogen from coal is to be a viable pathway in a low-carbon energy system. The use of CCUS brings some challenges, i.e., coal produces hydrogen with a relatively low hydrogen-to-carbon ratio and brings with it a high level of impurities in the feedstock, such as sulfur, nitrogen and minerals. The syngas obtained from the gasification of coal could be used to fuel a combined cycle power plant and, assuming the coal gasification plant is equipped with CCUS, the electricity it generates would be low-carbon (but not necessarily zero-carbon). If an additional water-gas shift unit could be added, the synthesis gas could also be used to produce more hydrogen, allowing the coal gasification plant to shift between the production of electricity and hydrogen according to which is more profitable. However, currently there are no large-scale commercial operations producing both hydrogen and electricity.¹²³

7.3 Environmental and Health Impacts of CCRs from Hydrogen Production

As discussed in Appendix B, coal contains non-combustible minerals that produce ash, or coal combustion residuals, when used in a combustion or gasification process. The coal combustion residuals (CCRs) include solids captured in the slurry streams produced during the quenching step in a gasifier plant. In a pulverized coal (PC) power plant, the ash contained in the coal is already being collected and disposed of. The majority of the ash in a PC power plant is fine dust and captured in ESPs or baghouses.¹²⁴ Some of it will deposit on the boiler tubes, and soot blowers move it from the economizer section tube surface to an ESP. In the past, the sulfur contained in coal was converted to sulfur oxides (SO_x) in the pulverized coal power plant, and was exhausted with the flue gases, causing acid rain. The WGS reactor recovers a significant part of the sulfur species as spent limestone or an equivalent form suitable for safe disposal. Coal can contain varying levels of heavy metals like lead, mercury, vanadium, nickel and, in a PC plant, these are vented with the flue gas using

¹²² Ibid.

¹²³ International Energy Agency, "Future of Hydrogen," June 2019, <https://www.iea.org/reports/the-future-of-hydrogen>

¹²⁴ ESP is used to filter dust particle in the flue gas in thermal power plant.

a stack. These pollutants and their environmental effects could be significant, as discussed in detail in several publications. The flue gas discharge temperature is maintained sufficiently high and the discharge point is elevated in order to ensure adequate dispersion of the contaminants to manage ground level concentrations within acceptable limits.

The CCR streams from a coal gasifier include sintered ash, and carbonaceous fines from the tailing ponds. The solids from the tailing ponds will need to be stored in a landfill, with liners to avoid contamination of subsurface water from potential leaching. Due to the sensitivity of the shift conversion catalysts to even trace amounts of sulfur species, nearly 100% removal of SO_x is necessary in a coal gasification plant. Metals like lead, mercury, vanadium, nickel, and byproduct chemicals (acids, ketones, alcohols), and particulates are captured in the quench/wet scrubbing process and in the waste water streams and discharged as aqueous streams. While the wash reduces the amount of toxic chemicals in coal from being released into the air, the compound that is left behind when coal is burned remains toxic. However, because the presence of toxic metals such as arsenic, selenium and cadmium depend on the composition of the coal source, one cannot determine if a sample is toxic without individual testing.

CCR Definitions

Fly ash is the powdery material that is captured by electrostatic precipitators or baghouses installed upstream of the stack. The primary use of fly ash is as a direct substitute for Portland cement during the production of concrete. The American Coal Ash Association (ACAA) estimates that there is a one-ton reduction of CO_2 emissions for every ton of fly ash used in the production of concrete. It is also used as material for structural fills, embankments, and mine reclamation.

Bottom ash is a heavier material, typically vitrified and larger than fly ash. It falls to the bottom of a boiler furnace. It is more chemically stable than fly ash and consists of denser particles. Therefore, the bottom ash can be mixed with water and sluiced to small ponds without the need for extensive treatment of the discharged water as was in the case of fly ash. The bottom ash is typically dredged from the ash pond and sold as an aggregate for concrete masonry and cinder blocks. It can be also used as a structural full for embankments and mine reclamation.

Scrubber sludge is the byproduct of flue-gas desulfurization. The sulfur in the flue gas reacts with lime-based reagent to form calcium sulfite (CaSO_3). Many systems oxidize the calcium sulfite to form gypsum (CaSO_4) which is much less reactive than CaSO_3 . The gypsum can be sold as a substitute for natural gypsum in the manufacturing of wall board. It also has applications in the agricultural industry for soil beneficiation and waste stabilization.

Slag is a glassy byproduct of certain wet-bottom boilers or gasifiers. The fly ash is vitrified at high temperatures to produce an inert and dense material that is easier to handle and dispose. Slag has many commercial uses including roofing material, sand-blasting grit, and road fill.

In the past, fly ash was released into the air through the smokestack, but environmental laws now require that most emissions of fly ash be captured by pollution control devices. In the U.S., fly ash and bottom ash are either stored near power plants or placed in landfills, or sold for beneficial uses. Pollution leaching from coal ash storage and landfills into groundwater is an environmental concern. The potential impacts of ash disposal on terrestrial ecosystems include leaching of potentially toxic substances into soils and groundwater; reductions in plant establishment and growth due primarily to adverse chemical characteristics of the ash; changes in the elemental composition of vegetation growing on the ash; and increased mobility and accumulation of potentially toxic elements in the food chain. Ash disposal in landfills and settling ponds can influence adjacent aquatic ecosystems directly, through inputs of ash basin effluent and surface runoff, and indirectly, through seepage and groundwater contamination.¹²⁵ Therefore, the permits for landfills require that an impermeable liner be installed beneath the landfill and that the run-off water be treated.

¹²⁵ D. Adriano and C. Carlson, "Environmental Impacts of Coal Combustion Residues," *Journal of Environmental Quality*, Volume: 22:2, April 1993, <https://www.osti.gov/biblio/6223223>

The toxic compositions of coal ash could have a range of health effects and can include potential increased risk of cancer and neurological and psychiatric disorders.¹²⁶ Heavy metals can contaminate the communities surrounding coal ash impoundments by leaching out of unlined ponds into local water supplies or blowing through the air in the form of fine particles and dust. Concerns exist for those consuming water from sources near coal ash impoundments. Storage of coal ash in poorly maintained impoundments also poses health risks to population in communities in the nearby or surrounding area.¹²⁷

Coal ash is currently not defined in statute or regulation as a toxic waste.¹²⁸ EPA's final rule on *Disposal of Coal Combustion Residuals from Electric Utilities* (December 2014) established technical requirements for CCR landfills and surface impoundments under Subtitle D of the Resource Conservation and Recovery Act (RCRA). The regulations address the risks from coal ash disposal, e.g., leaking of contaminants into ground water, blowing of contaminants into the air as dust, and the catastrophic failure of coal ash surface impoundments. Additionally, the rule sets out recordkeeping and reporting requirements as well as the requirement for each facility to establish and post specific information to a publicly-accessible website. The final rule also supports the responsible recycling of CCRs by distinguishing safe, beneficial use from disposal.¹²⁹

8. Challenges, Barriers, and Current Efforts

8.1 Emissions—Improving CCUS Technology for Low / Zero-Carbon Hydrogen from Various Types of Coal

The production of CO₂ from different fuels varies based on the energy content of the fuel and the carbon/hydrogen ratio of the fuel. Figure 16 provides an indication of the relative CO₂ emissions from various fuels, assuming similar cycle efficiencies, and without carbon capture.¹³⁰ It should be noted that the cost to remove the CO₂ from the emissions of various fuels is not necessarily directly proportional to the relative quantity of CO₂ produced. For example, while natural gas combustion produces significantly less CO₂ than coal combustion, the cost per ton to remove the CO₂ can be twice as expensive because the concentration of the CO₂ in the exhaust gas is significantly lower. Therefore, incorporating CCUS into a natural-gas fired plant may result in a higher cost of electricity compared to a coal plant with CCUS. The cost per ton to remove CO₂ from a gasification process is significantly lower compared to the cost per ton to remove CO₂ from the flue gas from a combustion-based system because the CO₂ is removed at high pressure and is more concentrated in the gas stream.

Transitioning to a hydrogen economy with *de minimis* CO₂ emissions hedges on the development of CCUS technologies. Advances in cycle efficiency of power generation systems through ultra-supercritical coal plants, high-efficiency combustion turbines have come a long way to reduce the CO₂ emissions from the use of coal. Advances in CCUS technologies provide further opportunity to reduce CO₂ emissions from coal.

126 Hyunyoung Kim, Won-Ho Kim, Young-Youl Kim, Hyun-Young Park, "Air Pollution and Central Nervous System Disease: A Review of the Impact of Fine Particulate Matter on Neurological Disorders," *Frontiers in Public Health*, December 16, 2020, <https://www.frontiersin.org/articles/10.3389/fpubh.2020.575330/full>

127 Deborah Payne and Elizabeth Walker, "Health Impact Assessment of Coal and Clean Energy Options in Kentucky," Kentucky Environmental Foundation, <https://www.pewtrusts.org/-/media/assets/2018/08/kef-coal-and-clean-energy-hia.pdf>

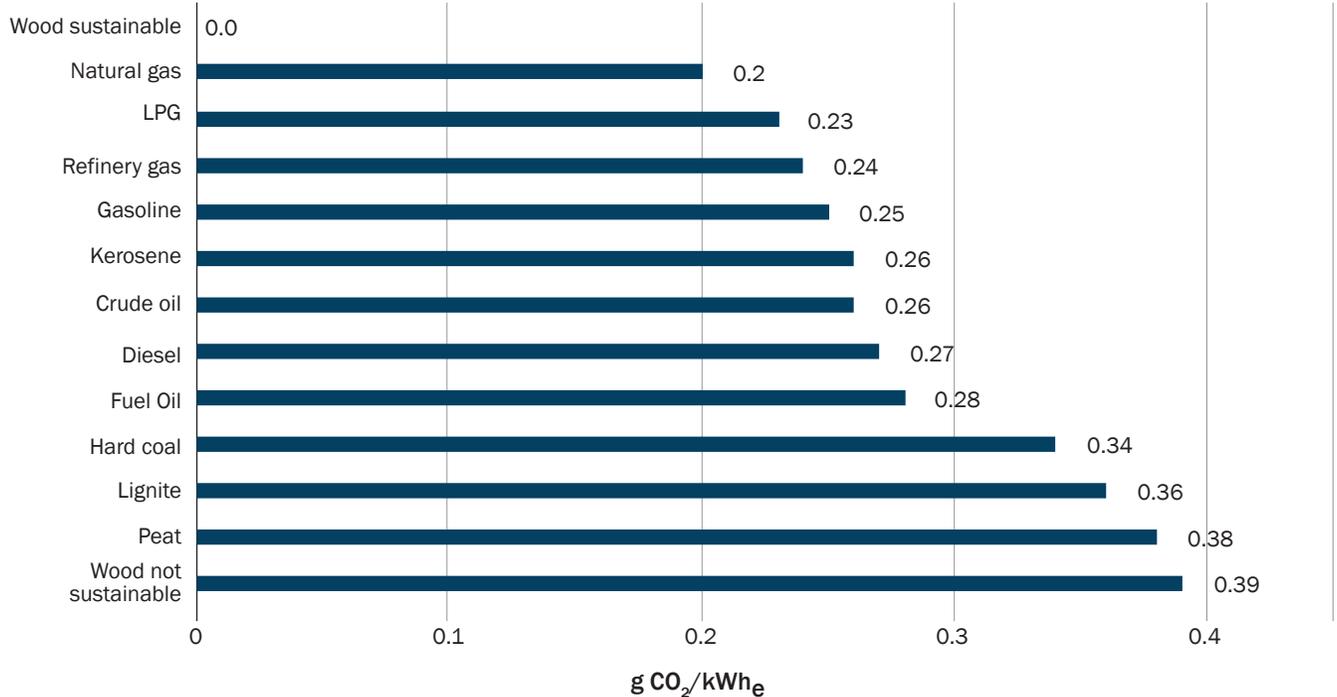
128 National Association of Regulatory Utility Commissioners, "A Comprehensive Survey of Coal Ash Law and Commercialization: Its Environmental Risks, Disposal Regulation, and Beneficial Use Markets," January 2020, <https://pubs.naruc.org/pub/A6923B2D-155D-0A36-31AA-045B741819EC>

129 U.S. Environmental Protection Agency, "Disposal of Coal Combustion Residuals from Electric Utilities Rulemakings," <https://www.epa.gov/coalash/coal-ash-rule>

130 "Specific Carbon Dioxide Emissions of Various Fuels," Volker Quaschnig, May 2021, http://www.volker-quaschnig.de/datserv/CO2-spez/index_e.php

As discussed previously, CCUS can play an important role in facilitating the production of low-carbon hydrogen for use across the energy system. Hydrogen is a low-carbon fuel or feedstock that can be used without direct emissions of air pollutants or greenhouse gas emissions. Hydrogen offers the opportunity to decarbonize a range of energy sectors. CCUS can help decarbonize hydrogen production by reducing emissions from existing hydrogen plants and by providing a least-cost pathway to scale up new hydrogen production.¹³¹

Figure 16 – Comparison of CO₂ Emissions from Different Fuels



An important approach in developing a zero to net-negative system for CO₂ emissions is the use of renewable combined with coal gasification. Use of biomass in combustion or gasification without CCUS creates CO₂. However, the same amount of CO₂ is recaptured in future biomass growth. Mixing biomass with coal in a combustion or gasification system that produces power and hydrogen provides the opportunity to continue to use coal with zero to negative CO₂ emissions when combined with carbon capture and storage.

While coal gasification can be combined with CCUS, there are technical challenges. For example, few technologies exist that produce both high-purity hydrogen and CO₂ that is pure enough for other uses or storage, because gas separation technologies focus on either hydrogen removal or CO₂ removal. The choice and design of the capture technology therefore depends on what the hydrogen is going to be used for, as well as on production costs. Natural gas and coal-based hydrogen production with CCUS is currently less expensive than using renewable energy for water electrolysis in most regions and will remain so where both CO₂ storage and low-cost fossil fuels are available. Producing low-carbon hydrogen from fossil fuels with CCUS will likely remain the lowest-cost option in regions with domestic coal and natural gas and available CO₂ storage.

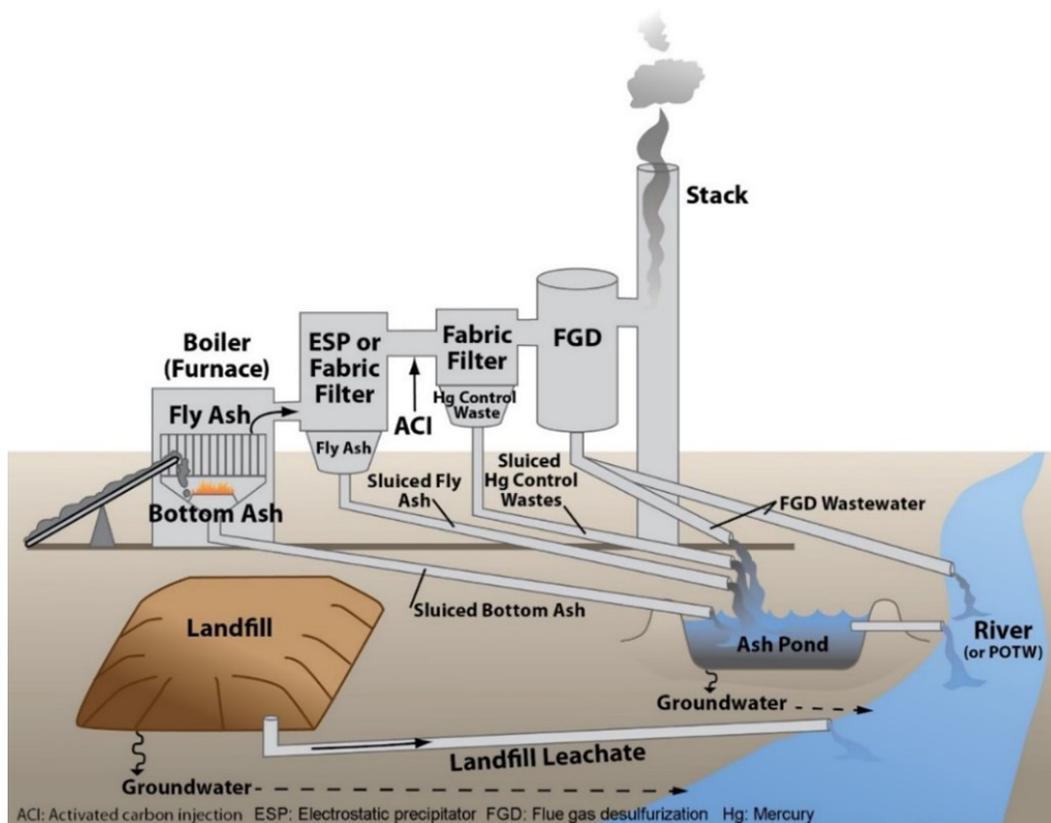
131 International Energy Agency, “Energy Technology Perspectives 2020,” September 2020, <https://www.iea.org/reports/energy-technology-perspectives-2020>

8.2 Pollution Management: CCR Disposal Practices, Beneficial Reuse Pathways

According to EPA, CCRs, commonly referred to as coal ash, are one of the largest industrial waste streams generated in the U.S. Coal-fired electric generation is the source of virtually all CCR generation, approximately 110 million tons per year. Most coal plants built prior to the Clean Water Act of 1977 mixed the fly ash with water to fill a valley with the ash. Since then, many of those plants converted their systems to a dry system and new plants used dry systems where the fly ash was sent to silos and then trucked to lined landfills. Figure 17 shows how coal ash is typically generated in coal-fired power plants. The bottom ash or slag produced in power plants are typically sluiced with water and piped to a settling pond. This heavier CCR quickly settles in the pond and is typically reclaimed for beneficial uses.¹³²

A recent NARUC report provides detailed information on coal ash and its legacy, federal framework for regulating coal ash disposal, state environmental regulatory role in coal ash management, coal ash products and beneficial uses, and PUC challenges with utility cost recovery applications.¹³³

Figure 17 – Typical Process for Generation of CCRs¹³⁴



¹³² Coal Ash Management: Understanding Your Options," *Power Engineering*, February 14, 2014, <https://www.power-eng.com/emissions/policy-regulations/coal-ash-management-understanding-your-options/#gref>

¹³³ National Association of Regulatory Utility Commissioners, "A Comprehensive Survey of Coal Ash Law and Commercialization: Its Environmental Risks, Disposal Regulation, and Beneficial Use Markets," January 2020, <https://pubs.naruc.org/pub/A6923B2D-155D-0A36-31AA-045B741819EC>

¹³⁴ U.S. Environmental Protection Agency, "Steam Electric Power Generating Effluent Guidelines - 2015 Final Rule," <https://www.epa.gov/eg/steam-electric-power-generating-effluent-guidelines-2015-final-rule>

8.3 Beneficial Uses of CCRs and Future R&D

CCRs are designated by the EPA as solid waste rather than hazardous waste. While there are strict regulations for the design, operation, and monitoring of CCR disposal sites, this designation allows for the opportunity for finding beneficial uses of CCRs. According to ACAA data, approximately 50% of CCRs are beneficially used.

Ongoing research is leading to new and innovative beneficial uses of CCRs.¹³⁵ CCRs can also contain useable rare earth metals. DOE is working with several research organizations to develop means to separate the rare earth metals from CCRs using technologies, such as new sorbent media and acid digestion processes. The introduction of low-NO_x burners in pulverized coal-fired plants has resulted in a higher amount of unburned carbon in the CCRs. Studies are underway to reclaim the unburned carbon from CCRs for beneficial uses, such as capture of toxic trace elements (e.g., mercury) from gaseous streams. The development of nanomaterials is leading to investigations for using fly ash as a source for the nanomaterials. Combustion of western coals, which are typically higher in calcium content in pulverized-coal fired boilers, can result in hollow fly ash particles called cenospheres. The cenospheres have numerous applications ranging from materials used for ballast to strong and light-weight materials that can be used in place of steel and aluminum.

8.4 Retrofitting Existing Power Plants with a Gasifier to Produce Hydrogen

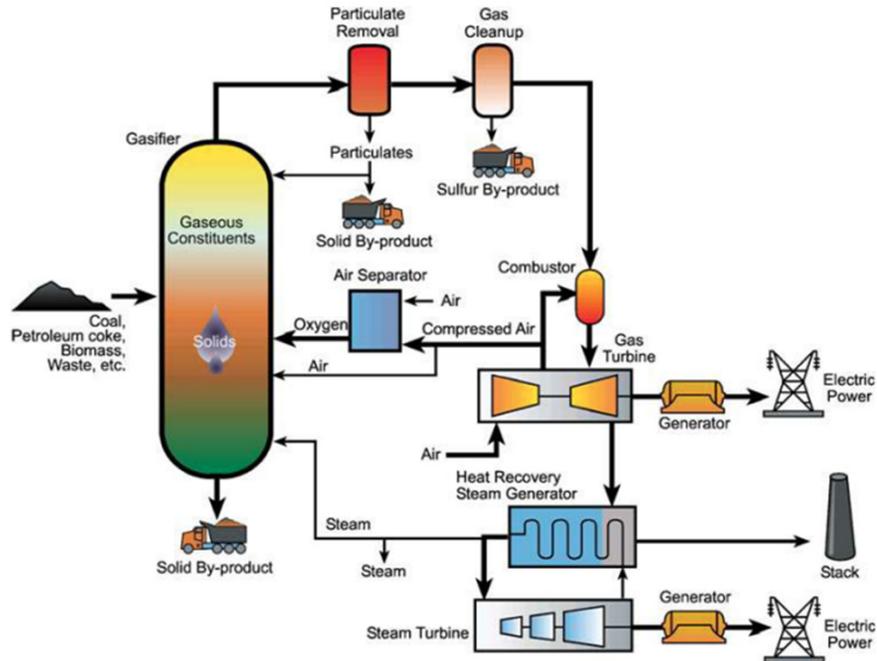
In order to use coal as a feedstock to produce hydrogen, the coal must first be gasified. If a gasifier is used to retrofit an existing plant, the plant would be converted into an integrated gasification combined cycle (IGCC) plant to reduce emissions and generate electricity more efficiently. To date, IGCC plants do not include full CCUS. However, IGCC plants are conducive to retrofitting them with a CCUS system if CO₂ emissions become regulated. Following are descriptions of IGCC Power Plant, which would be the backbone of the retrofits, Pulverized Coal-Fired Plant and Natural Gas Combined Cycle Plants that would be considered for retrofit.

Integrated Gasification Combined Cycle (IGCC) Power Plant: An IGCC power plant uses a coal gasification system to convert coal into a synthetic gas, which is then used as fuel in a combined cycle electric generation process. Coal is gasified by a process in which coal or a coal/water slurry is reacted at high temperature and pressure with oxygen (or air) and steam in a vessel referred to as a “gasifier” to produce syngas. Gasification processes have been developed using a variety of designs including moving bed, fluidized bed, entrained flow, and transport gasifiers. Figure 18 shows a simplified schematic of an IGCC power plant, which gasifies coal by partially combusting the carbon. The gasifier effluent consists of nitrogen, carbon monoxide, hydrogen, water vapor, and hydrogen sulfide (H₂S). The CO, when reacted with water, is converted to CO₂ and hydrogen through a WGS reaction, and the CO₂ and H₂S are removed before the CO and hydrogen are combusted in a gas turbine. The turbine exhaust is sent to a heat recovery steam generator (HRSG) for generating high-pressure steam, which is sent to a condensing steam turbine for additional power generation.

IGCC plants in operation today do not include carbon capture. Retrofitting an IGCC plant with carbon capture involves installing the equipment to accomplish a water-gas shift reaction to convert the syngas to CO₂ and hydrogen. The CO₂ is then captured under pressure using a Thermal Swing Adsorption (TSA) process or a Pressure Swing Adsorption (PSA) process. The removed CO₂ will be further pressurized for geologic storage or beneficial use such as Enhanced Oil recovery. The hydrogen will fuel the combustion turbine. Due to the differences between the combustion characteristics between syngas and hydrogen, significant modifications will be required to the combustion turbine.

¹³⁵ Grant Bromhal (NETL), “Extracting Rare Earth Elements and Critical Minerals from Coal,” presented at the NARUC Summer Policy Summit, July 18-21, 2021, <https://www.naruc.org/meetings-and-events/naruc-summer-policy-summits/2021-summer-policy-summit/agenda/>

Figure 18 – Simplified Schematic of an IGCC Power Plant¹³⁶



Some of the advantages of IGCC technology include: (1) higher efficiencies than PC Plants due to the combined-cycle design, (2) lower emissions of SO_2 , mercury, particulates, and NO_x ; and (3) reduced water consumption when compared to a PC-fired plant.

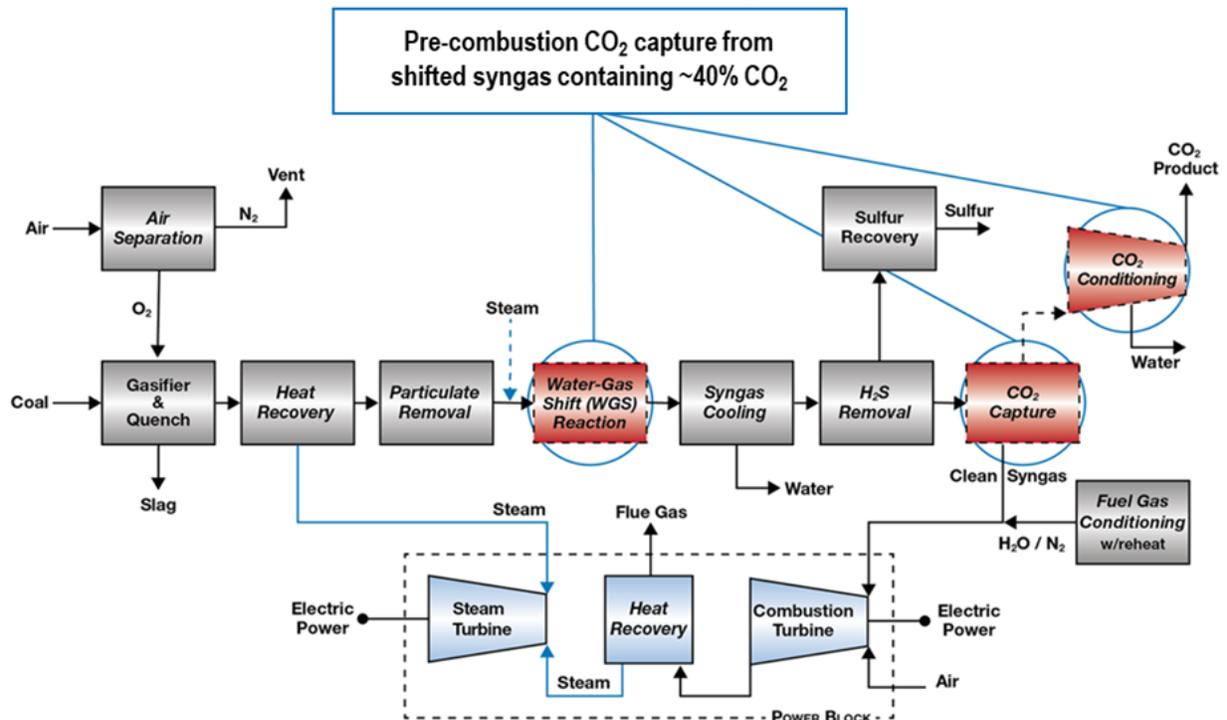
IGCC power plants offer the potential to remove up to 99% of the CO_2 emissions because the CO_2 in the syngas can be removed prior to combustion. Further, IGCC provides the most likely path to produce hydrogen from coal. However, deployment of IGCC involves additional plant complexity, higher construction costs, and poorer performance at high altitude locations when compared to a PC-fired power plant using a supercritical boiler. Finally, IGCC may lead to considerable cost uncertainty as it is not a mature technology.

Syngas produced by coal gasification can be used as a fuel to generate electricity or steam as well as for a large number of petrochemical and refining products. Because of these multiple uses, IGCC projects may include facilities that integrate electricity generation with the production of other industrial outputs such as chemical feedstocks for manufacturing operations or hydrogen fuel for vehicles and other uses. Figure 19 show a block flow diagram of an IGCC plant with CCUS.

The power block of an IGCC plant uses the same steam cycle and systems as conventional PC-fired plants, which is the most common technology applied to produce power from coal or biomass. IGCC uses the same steam and turbine cycles as conventional natural gas combined cycle (NGCC), which is the most common technology to produce power from natural gas. Retrofitting existing plants with a gasifier to enable removal of CO_2 and the production of hydrogen has the potential to reduce the plant costs compared to building a greenfield plant, provided there is a good thermodynamic match between the existing plant and the gasifier system.

¹³⁶ U.S. Environmental Protection Agency, "Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Coal-Fired Electric Generating Units," October 2010, <https://www.epa.gov/sites/default/files/2015-12/documents/electricgeneration.pdf>

Figure 19 – IGCC Plant with CO₂ Capture¹³⁷



Pulverized Coal-Fired Plants

Figure 20 shows a typical pulverized coal (PC)-fired plant with CCUS.¹³⁸ A PC power plant utilizes coal as the feedstock to generate power using a thermal cycle. Pulverizing coal into a very fine powder allows the coal to be burned more easily and efficiently. For a PC power plant, the coal must first be pulverized in a mill to the consistency of talcum powder. The pulverized coal is generally entrained in primary combustion air before being blown through the burners into the combustion chamber where it is fired in suspension. The plant combusts coal in a boiler to generate high-pressure steam, which is fed to a condensing steam-turbine to generate electricity. The flue gases are sent through a selective catalytic reactor (SCR) to reduce the nitrogen oxides (NO_x), and then to an electrostatic precipitator (ESP) or baghouse (BH) for removal of particulates and soot, and then to a flue gas desulfurization (FGD) scrubber for removal of sulfur oxides (SO_x). The advantages of PC plants are that the technology is mature, proven, and reliable. The disadvantage is that the technology is more expensive than natural gas combined cycle plants and the efficiency is limited because of the thermodynamics of the steam cycle. PC-fired boilers are classified by the firing position of the burners either as wall-fired or tangential-fired.

Retrofit of a PC plant with a gasifier involves replacing the boiler house, flue-gas train, and stack with a gasifier system to convert the coal into syngas and hydrogen, a gas turbine, and a heat recovery steam generator to provide steam to supply the existing steam cycle, as is shown in Figure 21.¹³⁹ The combustion turbine exhaust is cooled in the boiler to generate high-pressure steam, which is then sent to a steam turbine cycle. The syngas is quenched with water to reduce the temperature, processed for removal of sulfur compounds, then heated and sent to a WGS reactor to convert the CO to hydrogen and CO₂. The recovered CO₂ is dehydrated and compressed for sequestration. The pure hydrogen can then be fired in a gas turbine or for other applications as appropriate. Much of the existing infrastructure of the PC plant would also be retained including the coal receiving, storage, and handling systems, cooling water systems.

137 National Energy Technology Laboratory, "Pre-Combustion CO₂ Capture," <https://netl.doe.gov/coal/carbon-capture/pre-combustion>

138 "IPCC Special Report on Carbon Dioxide Capture and Storage," Prepared by Working Group III of the Intergovernmental Panel on Climate Change, 2005, https://www.ipcc.ch/site/assets/uploads/2018/03/srccs_wholereport-1.pdf

139 James Katzer, "The Future of Coal-Based Power Generation with CCUS, MIT Energy Initiative, MIT Future of Coal, UN CCS Summit, https://sustainabledevelopment.un.org/content/documents/3290katzer_presentation.pdf

Figure 20 – Simplified Schematic of a Pulverized Coal-Fired Plant with CCUS

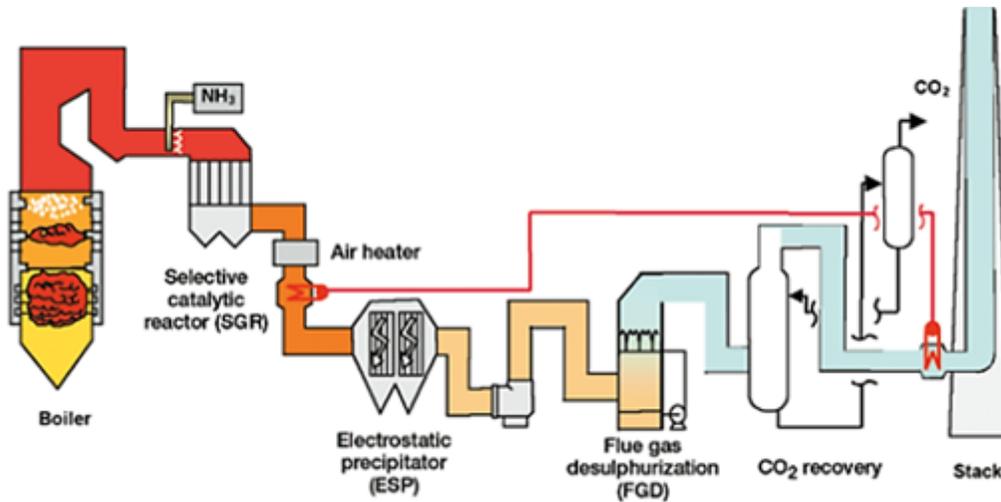
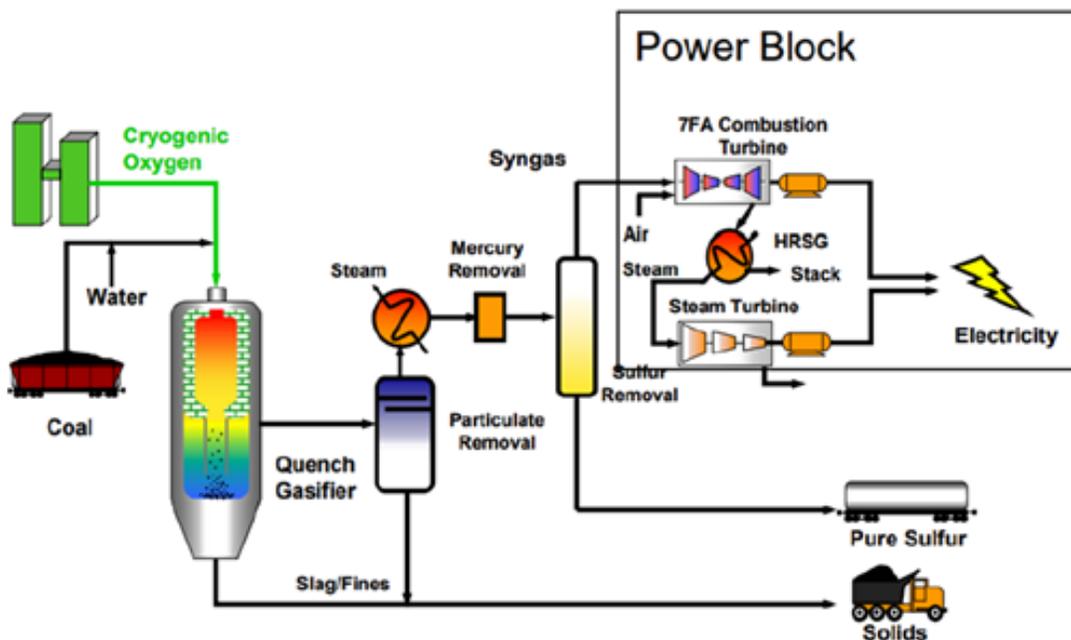


Figure 21 – Retrofit of a PC Plant with IGCC



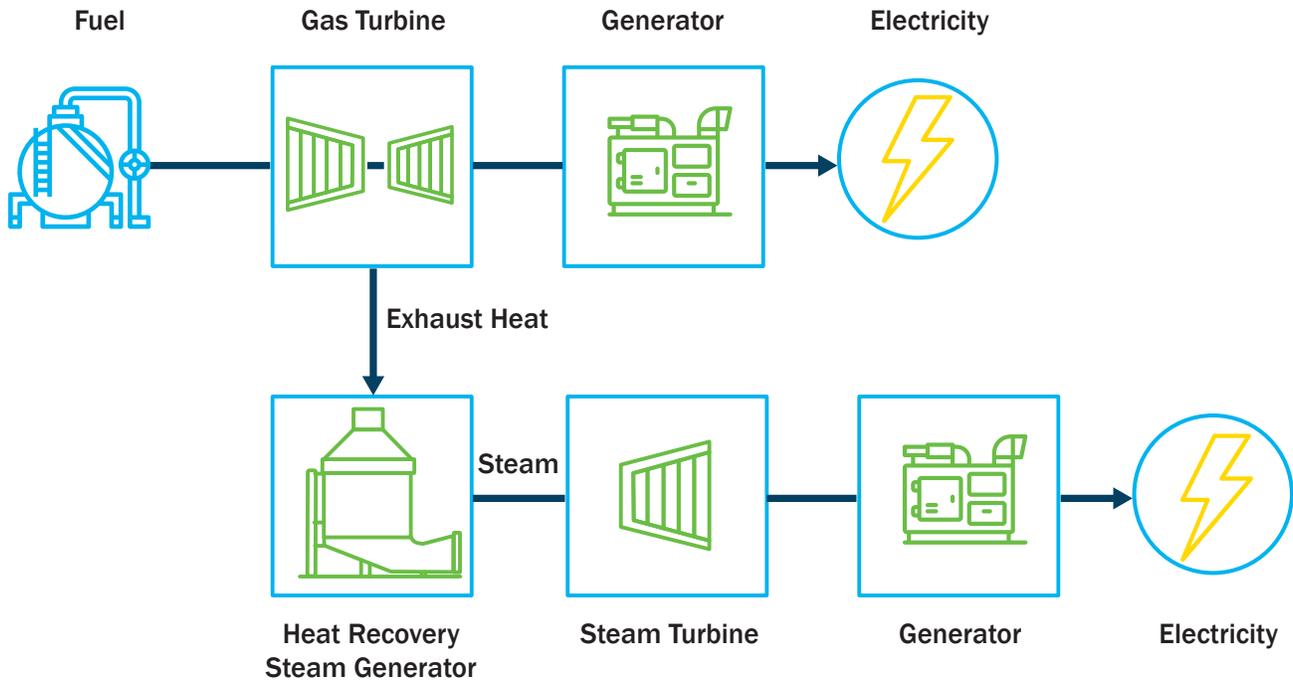
Natural Gas Combined Cycle Plants (NGCC)

Natural gas combined cycle (NGCC) plants have dominated the marketplace for new generation and retrofit of older coal plants, considering the lower capital cost, shorter construction time required, superior heat rate, and lower emissions compared to a coal-based power plant, coupled with the relatively low cost for natural gas. The amount of generating capacity from NGCC plants has grown steadily over time. As of January 2019, NGCC-based generating capacity in the U.S. totaled 264 GW, surpassing 243 GW of coal-fired power plants.¹⁴⁰ Using natural gas to generate electricity, particularly in higher efficiency combined cycle power systems and the higher efficiency and cleaner burning nature of natural gas results in fewer SO_x and NO_x emissions, lower resource consumption and solid waste generation.

¹⁴⁰ U.S. Energy Information Administration, "U.S. Natural Gas-fired Combined-cycle Capacity Surpasses Coal-fired Capacity," *Today in Energy*, April 10, 2019, <https://www.eia.gov/todayinenergy/detail.php?id=39012>

Figure 22 is a simplified schematic of a NGCC plant.^{141, 142} Natural gas supplies a combustion turbine to drive a generator to produce power. The gas turbine exhaust is cooled in an HRSG to produce high-pressure steam, which supplies a steam cycle using a condensing steam turbine to produce additional power. The efficiency of a modern NGCC plant is as much as 20% higher than a PC-fired plant because it combines the steam cycle with a gas cycle to extract more energy from the feed. Retrofit of a natural gas combined cycle plant involves installing a coal gasifier system upstream of the plant to produce synthetic gas as a replacement for natural gas from a pipeline. The economics of retrofitting a NGCC plant with a gasifier is depends on the capital cost of the gasification system, the cost of natural gas, and the price (if any) of carbon emissions.

Figure 22 – Simplified Schematic of an NGCC Plant



8.4.1 Costs

The cost estimates to construct a new power plant with CCUS and hydrogen production are based on numerous economic studies that have been conducted by engineering firms. Actual construction cost data for new plants is not available. Therefore, there is considerable uncertainty with respect to what the true cost of a new plant with CCUS and hydrogen production will actually be. Not only are there cost uncertainties with respect to the cost to design and construct the complex systems involved, but it could take several years between the start of design and approval and the start of construction. Escalation in costs due to inflation in materials and labor costs have been difficult to predict over such a large time frame. As a result, many capital projects in all sectors, including power generation have come in higher than originally forecast. Information on past IGCC projects provide some insight to the cost overruns of new plants without CCUS and hydrogen production that have been built in a regulated environment. Table 6 provides a comparison of the carbon capture technologies

141 "Gas Turbine Combined Cycle (GTCC) Power Plants," Mitsubishi Power, <https://power.mhi.com/products/gtcc>

142 Robert Irons, Colin Snape, Cheng-Gong Sun, and Wenbin Zhang, "Process Simulations of Post-combustion CO₂ Capture for Coal and Natural Gas-Fired Power Plants Using a Polyethyleneimine/Silica Adsorbent," *International Journal of Greenhouse Control*, December 2016, https://www.researchgate.net/publication/311690952_Process_simulations_of_post-combustion_CO2_capture_for_coal_and_natural_gas-fired_power_plants_using_a_polyethyleneiminesilica_adsorbent

assessed by National Energy Technology Laboratory (NETL)¹⁴³ as well as biomass power generation plants sponsored by the Electric Power Research Institute in 2018.¹⁴⁴ The costs to retrofit an existing plant with a gasifier are site specific and would require an engineering study and cost estimate for the specific site.

Table 6 – Cost of Power Generation Technology Comparison

Technology	Nominal Plant Capacity (MW)	Net HHV Heat Rate (Btu/kWh)	Total Plant Cost* (\$/kW)
Pulverized Coal with Carbon Capture	650	10,834 – 11,393	3,756 – 3,800
IGCC with Carbon Capture	519 – 557	10,101 – 10,497	5,177 – 6,209
NGCC with Carbon Capture	646	7,159	1,984
Biomass	50-100	12,900 - 14,000	4,266 – 6,035**

* Cost in Constant December 2018 Dollars **Cost escalated from 2016 to 2018 Dollars

8.4.2 Considerations and Issues

Significant considerations and issues with retrofitting existing IGCC plants with CCS and hydrogen production are discussed briefly below.

Capacity Mismatch: There is potential for a mismatch between the nameplate rating of an existing PC plant and the gasifier. Gasifier capacities are typically not variable, but fixed sizes are typically based on the combustion turbine used, so the challenge lies in identifying an existing plant that is a thermal match to a given gasifier size. Mismatching may lead to inefficiencies.

Cost of Downtime: There is also the economic consideration of time out of service. If an existing PC plant is in good working condition, it will need to be taken out of service during the retrofit tie-in. The lost revenue during that outage is an economic penalty in a pro-forma evaluation of the project. If an old plant is shut down, the refurbishment cost of bringing the old plant up to good condition may make that project uneconomical.

Gas Turbine Modifications: The challenge of firing a natural gas turbine with hydrogen is a potential issue due to the difference in combustion properties which leads to different flame speeds and unstable combustion and the difference in mass flow leading to a compressor and turbine mismatch, which can lead to an unstable turbine. The difference in mass flow will also impact the HRSG. Several original equipment manufacturers (OEMs) are on the forefront of researching this issue, and are expected to find a simple solution. Absent a “patch solution,” the entire gas turbine may need to be replaced.

Plot Space: Available space for the new system can also be a challenge for retrofitting an existing plant. This applies to coal delivery, storage, crushing, grinding, ponds for raw water and grey and black waters, and large wastewater treatment facilities.

Permitting: Retrofitting an older plant will usually trigger New Source Performance Standards (NSPS) compliance for all aspects of the plant, from the water-cooling system, to air emissions, and all other possible sources of pollution. Conceivably, the larger goal of decarbonization may encourage the regulatory authorities to relax the regulatory requirements.

143 National Energy Technology Laboratory, “Cost and Performance Baseline for Fossil Energy Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity,” September 2019, https://www.netl.doe.gov/projects/files/CostAndPerformanceBaselineForFossilEnergyPlantsVol1BitumCoalAndNGtoElectBRRRev4-1_092419.pdf

144 Electric Power Research Institute, “Program on Technology Innovation: Integrated Generation Technology Options 2017,” March 13, 2018, <https://www.epri.com/research/products/000000003002011806>

Brownfield vs Greenfield Considerations: It is worth mentioning that “recycling” a brownfield site rather than using a “greenfield” site may be more economical than developing a greenfield site. An old plant that is beyond its useful life could be demolished to make room for a new coal-to-hydrogen plant with hydrogen production. The advantage of recycling an existing site is that some of the existing infrastructure could be used, including the coal receiving, storage, and handling system, the condenser cooling water system, the water intake system, and the transmission interconnect. A greenfield site would need additional infrastructure and may be difficult to get permitted. On the other hand, the use of a brownfield site may compel remediation of existing hazards on the brownfield site.

Transmission Interconnect Study: If a PC plant is retrofitted, a new transmission interconnect study will be required to accommodate the new generator associated with the combustion turbine. This could result in additional project costs for transmission system upgrades.

Ratio of Natural Gas to Coal Prices: The ratio of the cost of natural gas to coal would be an important economic factor in a decision on whether to repower a NGCC plant with IGCC. Natural gas prices have been low due to the abundance of domestic natural gas supplies, which was not the case 20 years ago when there was a natural gas shortage. That could change due to pipeline infrastructure limitations with natural gas and the construction of natural gas terminals to export natural gas, which will increase domestic prices. With those factors and the decline of the coal market, there could be a threshold where a conversion to gasifying coal would make sense. On the other hand, as long as natural gas prices remain low, it will continue to be the preferred fuel.

8.5 Infrastructure: Production, Transportation, and Storage Infrastructure Needs; Leveraging Existing Infrastructure and Facilitating Increased Capacity

The infrastructure required to support implementation of coal-to-hydrogen involves the production, transport, and use of hydrogen and CO₂. The technology required for the production of hydrogen, as discussed above, is generally available. The major infrastructure issue is the storage and use of the CO₂ generated during the production of hydrogen. Issues associated with the sequestration of CO₂ are focused on well characterization and modeling, permitting, liability, and public acceptance. DOE’s ongoing efforts in this area continue to address these important issues.

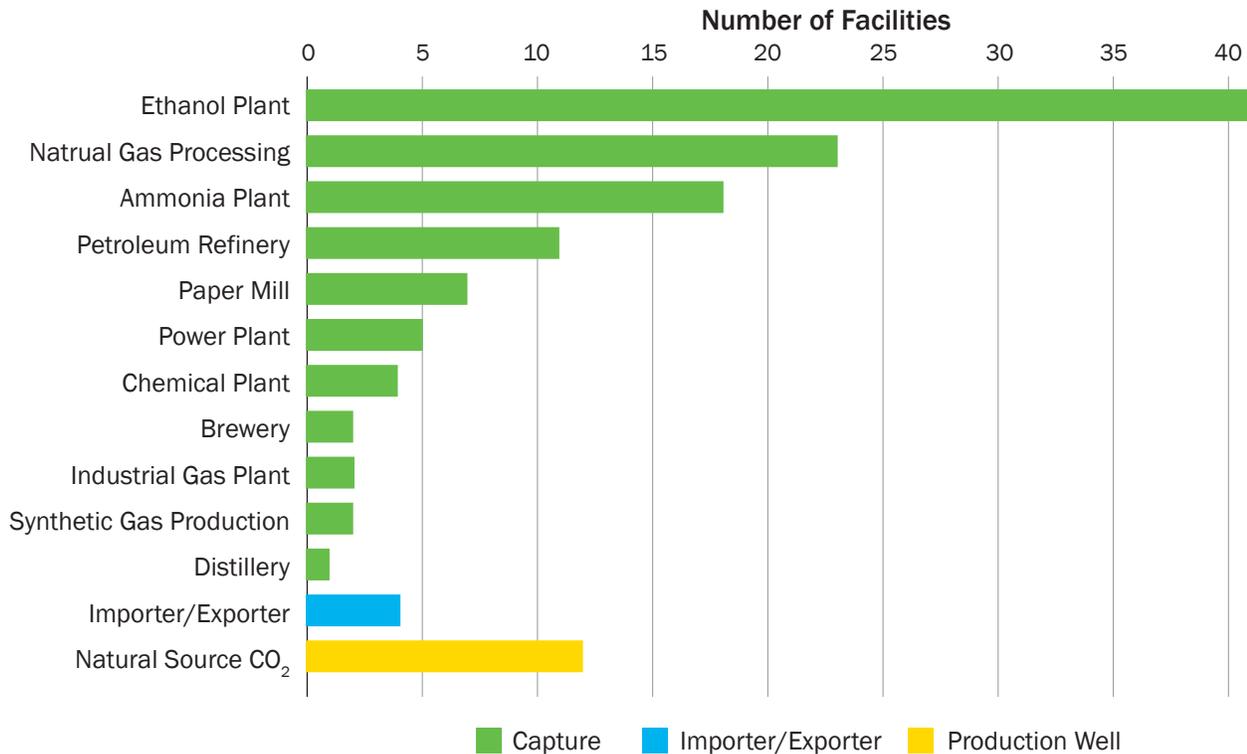
Researchers from the Great Plains Institute looked into the most feasible near- and medium-term opportunities for deployment of regional CCUS projects that can unlock the economic potential for the industrial and power sectors to capture carbon and safely store it. It is estimated that more than 350 million tons of CO₂ can potentially be captured and stored annually by scaling up and optimizing regional carbon transport and storage infrastructure. This is more than a fifteen-fold increase of the current carbon capture rate in the United States. According to EPA, as shown in Table 7, 22.3 million metric tons of CO₂ were captured from industrial sources in 2020. Figure 23 shows the types of facilities that capture and supply CO₂. Ethanol, natural gas, and ammonia production are among the top three industrial facility types that capture CO₂ for supply into the economy.

Table 7 – CO₂ Capture and Injection in the United States

	Amount (MMT)	Reporting Facilities
Capture and Supply of CO₂ *		
Total CO ₂ captured and produced	61.3	122
CO ₂ captured (industrial sources)	22.3	110
CO ₂ produced (natural sources)	39.0	12
Underground Injection of CO₂		
Total CO ₂ received for underground injection	49.3	93
CO ₂ received for enhanced oil and gas recovery	48.7	64
CO ₂ received for acid gas injection/disposal, carbon storage R&D, and other purposes	0.6	29

*As of 9/26/2020

Figure 23 – Facilities that Capture and Supply CO₂



About 66% of the CO₂ captured from industrial processes and 96% of the CO₂ produced from natural sources was used for enhanced oil and gas recovery (Figure 24). Food and beverage manufacturing is the second most common end use, followed by other end uses such as pulp and paper manufacturing, fire-fighting equipment, and metal fabrication.

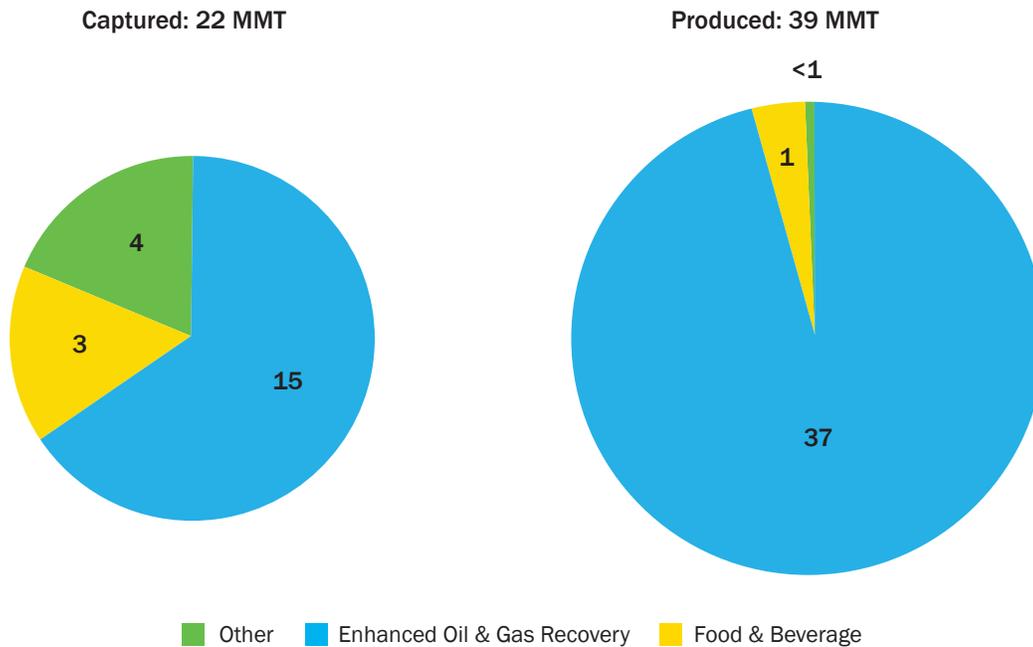
Investing in large trunk pipelines can substantially reduce the overall cost by transporting huge volumes of carbon dioxide from different emitting facilities to the designated geologic storage sites.¹⁴⁵ A window of opportunity has opened for CCUS in the U.S. as the Energy Act of 2020 includes authorization for new CCUS

¹⁴⁵ "Transport Infrastructure for Carbon Capture and Storage: Whitepaper on Regional Infrastructure for Midcentury Decarbonization," Great Plains Institute, https://www.betterenergy.org/wp-content/uploads/2020/06/GPI_RegionalCO2Whitepaper.pdf

demonstration projects and an extension of the 45Q tax credit¹⁴⁶ eligibility period for CO₂ sequestration. However, the 45Q tax credit for carbon sequestration is unlikely by itself to be sufficient to drive large-scale deployment of CCUS.

Figure 24 – Primary End Uses for CO₂ Captured and Produced

Millions Metric Tons (MMT)



In order to achieve decarbonization, especially in the industrial and power sectors, significant infrastructure upgrades are required. These upgrades are not limited to facility-level retrofits. They must also include regional carbon transport infrastructure to deliver the captured carbon dioxide to utilization or storage sites. One of the main challenges for the industrial and power facilities in the U.S. is they not all are located in regions with significant geologic formations suitable for permanent storage. Hence, a shared regional carbon dioxide transport infrastructure is necessary for reducing investment requirements and costs.

8.5.1 Pipelines

In terms of coal-to-hydrogen production, one way to rapidly expand the transportation of hydrogen is to use the existing natural gas pipeline infrastructure. In order to accomplish this, compatible pipeline infrastructure assessments should be undertaken to further characterize and quantify those portions of the U.S. natural gas pipeline system suitable for handling blended hydrogen and natural gas mixtures. Advanced materials need to be identified for many infrastructure components, like compressors, to ensure integrity of hydrogen infrastructure.

Introduction of hydrogen into natural gas pipelines can have a major effect on the U.S. electric power industry by proportionately reducing the emissions of carbon dioxide. Approaches to retrofitting existing assets for the utilization of hydrogen and natural gas mixtures should be fully explored, as hydrogen can be used in gas turbines, fuel cells, and other heat engines. The use of abundant low-cost natural gas to produce hydrogen with CO₂ capture for power generation could be a key component of a hydrogen economy strategy.

¹⁴⁶ Federal Section [45Q tax credits](#) are available for companies that capture and sequester carbon emissions in geologic formations or use CO₂ enhanced oil recovery to extract oil from existing wells. The tax credit is computed per metric ton of qualified carbon oxide captured and sequestered.

Approximately 1,600 miles of dedicated hydrogen pipelines are currently operating in the United States. These pipelines, owned by merchant hydrogen¹⁴⁷ producers, are located where large hydrogen users, such as petroleum refineries, steel mills, and chemical plants—mostly concentrated in the Gulf Coast region. Existing hydrogen pipeline infrastructure is small compared to the natural gas and oil pipeline infrastructure in the U.S., which is a highly integrated network that moves natural gas across about 3 million miles of mainline to end user markets. The hydrogen pipeline network required to support a hydrogen-based U.S. energy strategy would need to be much larger and with much broader geographic reach than what is in place for hydrogen currently. Hydrogen has a very low energy density (energy content per unit volume), lower than any other commonly used feedstock, so it needs to be compressed for economical transportation and storage. The gas compression process uses considerable energy, and like any pressurized gas, compressed hydrogen will have leakage, reducing the process' total energy output.¹⁴⁸

Blending of Hydrogen with Natural Gas

One possibility for rapidly expanding the hydrogen delivery infrastructure is to adapt part of the natural gas delivery infrastructure to accommodate hydrogen. Converting natural gas pipelines to carry a blend of natural gas and hydrogen (up to about 15% hydrogen) may require only modest modifications to the pipeline. Most of the current natural gas pipeline infrastructure would be unsuitable to transport hydrogen in higher amounts, as hydrogen causes embrittlement of pipeline steel and welds, and thus would require upgrades to transport hydrogen. R&D efforts are underway address the technical barriers to blending hydrogen in natural gas pipelines. For example, DOE's National Renewable Energy Laboratory (NREL) will lead a new collaborative R&D project, HyBlend, to investigate the potential for increasing natural gas and hydrogen blending.

Blending hydrogen into the existing natural gas infrastructure has national and regional benefits for energy storage, resiliency, and emissions reductions. Hydrogen produced from renewable, nuclear, or other resources can be injected into natural gas pipelines, and the blend can then be used by conventional end users of natural gas to generate power and heat. Several projects worldwide are demonstrating blends with hydrogen concentrations as high as 20%, but the long-term impact of hydrogen on materials and equipment is not well understood, which makes it challenging for utilities and industry to plan around blending at a large scale.¹⁴⁹

Converting existing natural gas pipelines to deliver pure hydrogen may require more substantial modifications. Due to their high capacity and economies of scale, pipelines are the most economic transportation mode for shipping most gaseous and liquid commodities—including hydrogen—over long distances in large quantities. However, establishing a national network of dedicated hydrogen pipeline infrastructure, or reconfiguring existing natural gas systems to carry hydrogen, poses numerous challenges related to technology, regulation, siting, and economics.

Retrofitting natural gas pipelines to accept a blended mixture of natural gas and hydrogen will potentially require alterations to dedicated pipeline infrastructure and end-use systems such as household appliances and industrial burners. The maximum volume of hydrogen that can be safely blended into the natural gas pipeline system without negative impact to end users is determined by the composition of the natural gas, the type of consumption mechanism (e.g., engine, boiler, appliance) and the age of the consumption mechanism. Therefore, determining the maximum volume of hydrogen that can be blended with natural gas in any existing pipeline sub-system must be done on a case-by-case basis. Construction of new pipelines—either natural gas pipelines that will be used for a blended gas or hydrogen dedicated lines—should consider the challenges

147 Hydrogen generated on site or in a central production facility and sold to a consumer by pipeline, bulk tank, or cylinder truck delivery.

148 Alan Alexander, Mostafa Al Khonaizi, Eamon Nolan, and Hailey Phillips, "Hydrogen Applications and Usage," Vinson and Elkins, December 8, 2020, <https://www.velaw.com/insights/hydrogen-applications-and-usage/>

149 National Renewable Energy Laboratory, "HyBlend Project to Accelerate Potential for Blending Hydrogen in Natural Gas Pipelines," November 18, 2020, <https://www.nrel.gov/news/program/2020/hyblend-project-to-accelerate-potential-for-blending-hydrogen-in-natural-gas-pipelines.html>

that hydrogen poses during pipeline transportation, including components that may degrade due to hydrogen permeation, end-system use, and potential increases in leakage throughout the system. Specific areas of concern regarding leakage of hydrogen include physical distribution and transmission pipeline connections (joints/welds), gathering and compressor stations (seals), storage systems (underground formations or tanks), and monitoring equipment.

Some pipeline operators have initiated projects to evaluate blending significant hydrogen volumes in natural gas pipelines and demonstration projects in Europe have been blending up to 20% by volume of hydrogen. Most recently in the U.S., Southern California Gas Company and San Diego Gas & Electric Company filed a joint application with state regulators to initiate a similar hydrogen blending demonstration project in their respective gas distribution systems in California.¹⁵⁰ Several other U.S. utilities have proposed or initiated early efforts to test hydrogen blending in natural gas pipeline systems. However, 20% hydrogen blending by volume may be the maximum allowable before significant pipeline upgrade costs are required due to potential impacts on pipeline materials. In addition, the end-use equipment in power plants and industrial facilities served by natural gas transmission pipelines may not tolerate higher hydrogen concentrations without modification.

9. How DOE's Hydrogen Program Strategy and Research Portfolio is Addressing Challenges; Gaps Remaining

DOE, the private sector, and other government and nongovernment organizations understand the key benefits to a hydrogen economy. This may include a reduction in emissions, accessible production from diverse domestic resources across multiple sectors, and high energy content amongst other benefits. Various key technical challenges to mass adoption of hydrogen and associated technologies are mainly cost, durability, reliability, and performance as well as a lack of a dedicated hydrogen infrastructure.

DOE's Hydrogen Program Plan, released in November 2020, provides a strategic framework that incorporates the research, development, and demonstration efforts of the Offices of Energy Efficiency and Renewable Energy (EERE), Fossil Energy and Carbon Management (FECM), Nuclear Energy (NE), Electricity (OE), Science, and Advanced Research Program Agency—Energy (ARPA-E) to advance the production, transport, storage, and use of hydrogen across different sectors of the economy. FECM and NE are primarily focused on large-scale power generation using fossil fuels or nuclear resources, while EERE focuses on renewables as well as end uses for hydrogen and fuel cells in multiple applications in the transportation sector, for stationary distributed power in buildings, and in industrial applications. Chemical and fuel production using hydrogen is an area of coordination between EERE and FECM, with FECM focusing on large-scale co-gasification and polygeneration, and EERE focusing on smaller scale production such as synfuels for the transportation sector or trigeneration for hydrogen fueling stations. FECM also leads DOE's CCUS efforts and collaborates with EERE on opportunities to co-locate hydrogen production with CCUS sites and large-scale hydrogen storage sites to enable the use of hydrogen and carbon dioxide to produce synthetic chemicals and fuels.

150 Joint Application of Southern California Gas Company, San Diego Gas and Electric Company, Pacific Gas and Electric Company, and Southwest Gas Corporation Regarding Hydrogen-Related Additions or Revisions to the Standard Renewable Gas Interconnection Tariff, before the California Public Utilities Commission, November 20, 2020, https://www.socalgas.com/sites/default/files/2020-11/Utilities_Joint_Application_Prelim_H2_Injection_Standard_11-20-20.pdf

9.1 RD&D Thrusts and Needs and Challenges

The key technical challenges for hydrogen and related technologies include cost, durability, reliability, and performance, as well as the lack of hydrogen infrastructure. DOE’s Hydrogen Program Plan has identified needs and challenges in key areas of hydrogen energy systems and provided a strategic pathway to address and overcome these challenges and achieve widespread commercialization. The Plan also defined targets for hydrogen and related technologies based on the technical advances that are needed to be competitive in the marketplace with incumbent and other emerging technologies. These are summarized in Table 8.¹⁵¹

Table 8 – Hydrogen Energy System, Common RD&D Thrusts, and Needs and Challenges

Key Aspects of the Hydrogen Energy System, Common R&D Thrusts and Needs and Challenges	
<p>PRODUCTION: Hydrogen can be produced from diverse domestic resources—including fossil fuels, nuclear energy, and renewables (wind, solar, geothermal, biomass, and waste, including plastics). The primary pathways for producing hydrogen are through thermochemical processes such as reforming, gasification, pyrolysis and through electrolysis via water splitting. Hydrogen also offers the options of large-scale centralized production or distributed production at small facilities, close to or at the point of use.</p>	
Common R&D Thrusts	Needs and Challenges
<ul style="list-style-type: none"> • New catalysts and electrocatalysts with reduced platinum group metals • Modular gasification and electrolysis systems for distributed and bulk power systems • Low-cost and durable membranes and separations materials • Novel, durable, and low-cost thermochemical and photoelectrochemical materials • Accelerated stress tests and understanding of degradation mechanisms to improve durability • Reduced capital costs for reforming technologies, including autothermal reforming (ATR) • Improved balance-of-plant components and subsystems, such as power electronics, purification, and warm-gas cleanup • Component design and materials integration for scale-up and manufacturability at high volumes • Reversible fuel cell systems including for polygeneration of electricity and hydrogen • System design, hybridization, and optimization, including process intensification 	<ul style="list-style-type: none"> • Lower-cost, more-efficient, and more-durable electrolyzers • Advanced designs for reforming, gasification, and pyrolysis • Advanced and innovative hydrogen production techniques from renewable, fossil, and nuclear energy resources, including hybrid and fuel-flexible approaches • Lower-cost and more-efficient technologies for producing hydrogen from water, fossil fuels, biomass, and waste • Low-cost and environmentally sound carbon capture, utilization, and storage technologies
<p>DELIVERY: Hydrogen can be transported and dispensed as either pure hydrogen or as part of a chemical carrier via several different pathways: distributed in pipelines, transported in high-pressure tanks, or carried as a liquid via tanker truck. Large volumes of hydrogen can also be transported by rail or ships. End-use applications will have varying needs for flow rates, purity, and cost, imposing different requirements on the refueling infrastructure.</p>	

151 U.S. Department of Energy, “Hydrogen Program Plan,” November 2020, <https://www.hydrogen.energy.gov/pdfs/hydrogen-program-plan-2020.pdf>

Key Aspects of the Hydrogen Energy System, Common R&D Thrusts and Needs and Challenges

Common R&D Thrusts	Needs and Challenges
<ul style="list-style-type: none"> • Materials compatibility with hydrogen at high pressures and/or low temperatures • Innovations in hydrogen liquefaction • Carrier materials and catalysts for hydrogen storage, transport, and release • Innovative components for low-cost distribution and dispensing (e.g., compressors, storage vessels, dispensers, nozzles) 	<ul style="list-style-type: none"> • Lower-cost and more-reliable systems for distributing and dispensing hydrogen • Advanced technologies and concepts for hydrogen distribution including liquefaction and material-based chemical carriers • Rights-of-way, permitting, and reduced investment risk of deploying delivery infrastructure
<p>STORAGE: Hydrogen may need to be stored prior to use—either in bulk, at the site of production, during the delivery process, or at the point of use, and this can be accomplished via: (i) physical storage, which includes high-pressure tanks and liquid hydrogen; or (ii) and material-based processes that incorporate hydrogen in chemical compounds, with the potential for higher capacities at ambient temperature and pressure. Additional approaches—such as geologic storage—may be needed for large-scale, long-term hydrogen storage.</p>	
Common R&D Thrusts	Needs and Challenges
<ul style="list-style-type: none"> • Reduced costs, at the material-based, component-, and system-level • Low-cost, high-strength carbon-fiber for high-pressure tanks • Materials compatible with hydrogen for durability and safety • Cryogenic RD&D for liquid hydrogen and cold/cryo-compressed storage • Discovery and optimization of hydrogen storage materials to meet weight, volume, kinetics, and other performance requirements • Optimization for round-trip efficiency using chemical hydrogen carriers • Storage of hydrogen in the form of a chemical energy carrier that can be used in hydrogen turbines • Identification, assessment, and demonstration of geologic storage of hydrogen • Systems analysis for the export of hydrogen and hydrogen carriers • Analysis to refine targets for a broad range of storage options and end uses • Sensors and other technologies needed to ensure storage of hydrogen is safe, efficient, and secure 	<ul style="list-style-type: none"> • Lower-cost hydrogen storage systems • Higher storage capacity, with reduced weight and volume • Large-scale storage, including onsite bulk emergency supply and in geologic formations • Optimized storage strategies for co-locating stored hydrogen with end-use applications to meet throughput and dynamic response requirements and reduce investment cost
<p>CONVERSION: To be useful, the energy carried by hydrogen must be converted into a different form, such as electricity or heat, and this can be accomplished through electrochemical conversion using fuel cells, or via combustion using turbines or reciprocating engines. Hybrid systems, such as natural gas/other fuel combined cycle fuel cell systems offer high efficiencies and reduced emissions compared with conventional technologies.</p>	

Key Aspects of the Hydrogen Energy System, Common R&D Thrusts and Needs and Challenges

Common R&D Thrusts	Needs and Challenges
<ul style="list-style-type: none"> • Enable wider range of acceptable hydrogen concentrations (up to 100%) in simple and combined cycles • Improve understanding of combustion behavior and optimization of component designs for low NO_x combustion • Apply and develop advanced computational fluid dynamics with reacting flows 	<ul style="list-style-type: none"> • Lower-cost, more-durable, and more-reliable fuel cells that can be mass-produced • Turbines that can operate on high concentrations of hydrogen or pure hydrogen • Development and demonstration of large-scale hybrid systems
<ul style="list-style-type: none"> • Develop advanced manufacturing techniques for combustors • Develop new materials, coatings, and cooling schemes • Optimize conversion efficiency • Improve durability and lifetime and lower costs, including for operations and maintenance • Develop system-level optimization and control schemes • Assess and mitigate moisture content effects on heat transfer and ceramic recession • Develop and test hydrogen combustion retrofit packages • Enable combustion of carbon neutral fuels (i.e., NH₃, ethanol vapor) 	
<p>END-USE APPLICATIONS AND INTEGRATED ENERGY SYSTEMS: Hydrogen can be used in diverse applications across multiple sectors. It can provide value directly to end-use applications (heavy-duty transportation, stationary power, industrial and chemical applications, etc.) and as an enabler of integrated energy systems, where it can improve the economics and performance of existing and emerging electric power generators.</p>	
Common R&D Thrusts	Needs and Challenges
<ul style="list-style-type: none"> • Development of rigorous application-specific targets for hydrogen utilization • Materials compatibility issues in diverse end uses • Reduced cost and improved durability and efficiency in industrial-scale electrolyzers, fuel cell systems, combustion turbines and engines, as well as in hybrid systems • Component- and system-level integration and optimization, including balance of plant components and systems • Optimized controls of integrated systems, including cybersecurity • Manufacturing and scale-up, including process intensification • Harmonized codes and standards, including refueling protocols • Capacity expansion models to identify value propositions for use of hydrogen in new applications 	<ul style="list-style-type: none"> • Systems integration, testing, and validation to identify and address the challenges unique to each application • Demonstration of end-use applications, including steel manufacturing, ammonia production, and techniques for producing synthetic fuels from hydrogen and carbon dioxide • Demonstration of grid-integration to validate hydrogen energy storage and grid services

Key Aspects of the Hydrogen Energy System, Common R&D Thrusts and Needs and Challenges

SAFETY, CODES AND STANDARDS: Technically sound codes and standards will provide an essential basis for the safe and consistent deployment and commercialization of hydrogen and related technologies. Along with widely shared safety information and best practices, they will also improve confidence in the commercial viability of the technologies among all stakeholders, which can further accelerate adoption and encourage investment.

Needs and Challenges

- Appropriate, uniform codes and standards to address all end-use applications, including for combustion applications (such as in turbines) as well as for fuel cells (such as in high throughput fueling for heavy-duty applications, including trucks, marine, and rail)
- Improved safety information and sharing of best practices and lessons learned

EDUCATION AND WORKFORCE: A highly skilled workforce can effectively respond to growth in hydrogen-related industries and can support and sustain a national competitive advantage in this advanced energy technology field. Broader understanding of hydrogen and related technologies can build confidence in the safe use of hydrogen as an energy carrier among key constituencies, including investors, policymakers, and the general public.

Needs and Challenges

- Educational resources and training programs for diverse stakeholders including first responders, code officials, and technicians (e.g., on operations, maintenance, and handling of hydrogen and related technologies)
- Access to accurate, objective information about hydrogen and related technologies

9.2 Office of Fossil Energy and Carbon Management RD&D Program

DOE’s CCUS and fossil energy related hydrogen research is conducted by the Office of Fossil Energy and Carbon Management. The office name was recently changed from Office of Fossil Energy to FECM to reflect the new program direction, i.e., minimize the climate and environmental impacts of fossil energy and advance carbon management, point source carbon capture, CO₂ removal and reliable storage, CO₂ conversion into products, “blue hydrogen” production, and critical mineral production from industrial and coal mining waste. There is also increased emphasis on recovery of critical minerals and rare earth elements from coal waste—coal and its waste byproducts can help supply critical minerals for the solar panels, wind turbines, and electric vehicles that are all essential to the clean energy transition.

FECM recognizes low-carbon hydrogen will be critical to produce fuels and chemicals with CO₂ as a feedstock and there is a potential for applying carbon capture to help advance a low-cost and low-carbon hydrogen economy. FECM will focus on reaching net-zero goals in a just and sustainable way and is also committed to improving the conditions of communities impacted by the legacy and continued use of fossil fuels. FECM’s RDD&D is will be a key contributor to developing and deploying low-carbon supply chains like cement and concrete, steel, paper, fuel, and other products. High-level CCUS-related FECM goals include expanding net negative technologies such as direct air capture (DAC) and bio-energy with CCS (BECCS); simultaneously bring new carbon capture technologies to market, continuing to fund carbon capture RD&D; retrofitting existing power plants; and decarbonizing industry, especially in hard-to-abate sectors. For hydrogen, the goals include driving down cost of green hydrogen, and focus on “carbon-free” hydrogen. Refocused FECM priorities and goals as related to above areas are described below in more detail.

Transition to Net-Zero Carbon Economy: Invest in technologies and approaches and deploy regional initiative help in the transition to a net-zero carbon economy in coal and fossil-based power plant communities. These approaches, such as co-firing fossil fuels with waste biomass, coupled to carbon capture, in addition to mineral and carbon extraction from coal, using safe and sustainable technologies, will leverage both regional resources and existing labor forces to achieve a clean energy economy.

Carbon Capture: Point source carbon capture utilizing both new technologies and the demonstration of more proven approaches. Efforts will focus on:

- *Post-Combustion Capture:* Novel CO₂ capture technologies, such as non-aqueous solvents, membranes and advanced sorbents, for both power and industrial sectors.
- *Pre-Combustion Capture:* Pursuing transformational goals that require capture greater than 95%; new fundamental knowledge for hydrogen production and other industrial processes.
- *Emissions Control:* Reducing the costs and emissions of non-CO₂ pollutants associated with the use and combustion of carbon-containing fuels.

Carbon Utilization: Development of technologies to recycle CO₂ into value-added products; catalytic conversion to higher value products such as fuels, chemicals, polymers and nutraceuticals; catalysts made from low-cost materials and improved reactor designs; mineralization to building products; generation of solid carbon products; and algal systems designed to integrate CO₂.

Carbon Storage: Development of technologies for the safe and secure geologic storage of captured CO₂; and improving storage and operational efficiency and understanding of overall cost and de-risking strategies to reduce these costs. Specific efforts will focus on:

- *Storage Infrastructure:* Broadening the availability of certified resources for geologic storage of CO₂, deploying field projects that advance characterization and certification of storage complexes in prospective regions, promoting the integration of capture and storage projects.
- *Advanced Storage:* Developing and validating CO₂ storage technologies that improve capabilities in plume detection, storage efficiency, secure storage verification, subsurface stress assessments and wellbore integrity monitoring and mitigation.

Carbon Dioxide Removal (CDR): Research, develop, and demonstrate CDR technologies and approaches by investing in direct air capture coupled with reliable storage, bioenergy with carbon capture and storage and mineral carbonation projects. This effort will leverage CCUS activities, such as past work on DAC, enhanced mineralization, co-firing of biomass and capture technology development.

Carbon-Neutral Hydrogen: Develop technologies that leverage the natural gas infrastructure for hydrogen production, transportation, storage, and use coupled to carbon management. Hydrogen offers an emissions-free fuel for power generation, industrial applications, and the transportation sector.

Low-Carbon Supply Chains for Industries: Develop novel approaches to recycle carbon oxide emissions, principally CO₂, into value-added products such as cement, concrete, steel, chemicals, and fuels using systems-based carbon management approaches.

Advanced Energy and Hydrogen Systems: Improve overall system efficiency, reduce capital and operating costs, increase hydrogen production and enabling affordable carbon capture; increase the availability, efficiency and reliability of carbon neutral power derived from fossil fuels and other feedstock such as waste biomass and plastics. Specific efforts will focus on:

- *Gasification Systems*: Modularization and intensification, solutions for process issues to support hydrogen production at \$1 per kilogram by 2030, improving the efficiency and cost of small-scale gasification-based plants and systems to make them more attractive in the marketplace.
- *Advanced Turbines*: Improve flexible operations of combined and simple cycle gas turbines for power generation, support the requirements of an electric grid with increasing levels of variable renewable generation; use hydrogen and hydrogen-natural gas blends as a fuel, and design for optimized capture and geological storage of CO₂.
- *Reversible Solid Oxide Fuel Cells (R-SOFC)*: Shift focus on areas to achieve greater impact toward establishing a net-zero carbon economy by mid-century—R-SOFCs can use natural gas to produce electricity, water, and CO₂ when operating in a fuel cell mode and configured to operate in reverse as an electrolyzer using power, water and CO₂ as inputs to produce hydrogen.
- *Advanced Energy Materials*: Fossil power generation applications with an objective of improving the flexibility and reliability of those applications while enabling high efficiency, enhance the nation's supply chain for high-temperature materials.
- *Crosscutting Research*: Innovative early-stage RD&D for improving reliability, availability, efficiency and environmental performance; technologies that aid in minimizing the environmental impact of dependence on fossil fuels, which includes both power and industrial sectors, bridge basic and applied research by targeting concepts with the greatest potential for transformational breakthroughs.

Natural Gas Hydrogen Research: Focus on technologies for carbon-neutral hydrogen production, as well as hydrogen (and ammonia) transportation and geologic storage technologies that leverage existing natural gas infrastructure; improve natural gas steam methane reforming, blending hydrogen with natural gas, and leveraging existing transportation and storage infrastructure.

Critical Minerals (CM), Rare Earth Elements (REE), Coal Waste to Products, and Mine Remediation: Develop technologies that enable the sustainable recovery of CM, including REE from multiple feedstocks, throughout the upstream, midstream, and downstream supply chain from carbon and other ores, mining by-products, abandoned mines and wells and other valuable sources.

In addition, FECM typically focuses on early-stage research in natural gas infrastructure and leverages insight and expertise in oil and natural gas production, transport, storage, and distribution and supports efforts to enable the use of natural gas supply and storage infrastructure and the large-scale delivery and storage (e.g., geological storage) of hydrogen. Focus areas include RD&D to enable the transmission and storage of hydrogen and hydrogen blends in the existing national network of natural gas pipelines and underground reservoirs; hydrogen-based approaches for mitigating mid-stream emissions from natural gas infrastructure; technologies to convert flared or vented gas to hydrogen products; and technologies to convert natural gas to solid carbon products, hydrogen, and other value-added products.

Section C: Deploying Innovation

10. Regulatory Oversight of New Technologies

Utility regulation is viewed as primarily economic in nature. In practice, however, regulators must balance an increasingly wide range of economic, safety, reliability, policy, and social goals in the oversight of the electricity system. These varied priorities can be competing and the decisions regulators make in response often reflect a measured consideration of multiple factors impacting the public interest. Public Utility Commissions (PUCs) have an obligation to ensure the establishment and maintenance of utility services and to ensure they are provided at rates and conditions that are fair, just, and reasonable for all consumers.

PUCs typically oversee utility services (e.g., electricity, natural gas, telecommunications, water) by adjudicating utility rate setting, determinations around construction and siting for service-related infrastructure, and resources used to meet customer needs across a utility's territory. Commissions universally regulate investor-owned utilities, although a few also oversee rural electric cooperatives and municipal electric utilities to varying degrees. Depending on the state, PUCs may also engage in statutorily defined rulemaking or regulation-writing processes, quasi-judicial proceedings, and/or non-contested investigatory matters.¹⁵²

In 2020, the U.S. generated roughly 20% of all electricity from renewable resources, while some states generated close to 50% of electricity sales from intermittent renewable resources in 2019.¹⁵³ As the share of low-cost, intermittent resources increases on the grid, carbon-emitting, inefficient, or higher cost fossil fuel baseload generation is often being pushed out. Against this backdrop, utilities are also confronting weather and climate related disruptions that are acknowledged to be increasing in both frequency and severity, creating a national debate around grid reliability and resource adequacy to address system disturbances.¹⁵⁴ For regulators, this means that the task of ensuring the affordability, safety, and reliability of energy systems, while also meeting emissions reductions and renewable policy goals, is becoming increasingly complex.

10.1 Coal-Based Generation

The economic, environmental, and social pressures on the coal industry have been well-documented in recent years. In 2019, the U.S. saw the second highest number of coal-fired plant closures, representing some 15 gigawatts (GW).¹⁵⁵ According to EIA, at the end of 2010, 316.8 GW of coal-fired capacity existed in the U.S., but by the end of 2019, 49.2 GW of that amount was retired, 14.3 GW had the boiler converted to burn natural gas, and 15.3 GW was replaced with natural gas combined cycle.¹⁵⁶

152 Danielle Byrnett and Daniel Shea, "Engagement between Public Utility Commissions and State Legislatures," National Council on Electricity Policy, https://www.ncsl.org/Portals/1/Documents/energy/NCSE_NARUC_Engage_Leg_PUCs_34251.pdf

153 U.S. Energy Information Administration, "What is U.S. Electricity Generation by Energy Source?" *Frequently Asked Questions*, <https://www.eia.gov/tools/faqs/faq.php?id=427&t=3>

154 North America Electric Reliability Corporation, "2020 Long Term Reliability Assessment," December 2020, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2020.pdf

155 Scott Davino, "U.S. Coal-fired Power Plants Closing Fast Despite Trump's Pledge of Support for Industry," Reuters, (January 13, 2020), <https://www.reuters.com/article/us-usa-coal-decline-graphic/u-s-coal-fired-power-plants-closing-fast-despite-trumps-pledge-of-support-for-industry-idUSKBN1ZC15A>

156 U.S. Energy Information Administration, "More than 100 Coal-fired Plants Have Been Replaced or Converted to Natural Gas Since 2011," *Today in Energy*, August 5, 2020, <https://www.eia.gov/todayinenergy/detail.php?id=44636#>

As coal continues to lose energy resource portfolio share, the economic impacts on communities have been significant. The U.S. coal industry employed just over 40,000 people in the third quarter of 2020, down from almost 53,000 people in 2019.¹⁵⁷ The COVID-19 crisis appears to have accelerated these trends, as lower electricity demand in 2020 led to a smaller number of coal-fired plants running and increased buildups at utility coal stockpiles that drive down coal production—over 6,000 coal mining jobs were lost in March and April 2020.¹⁵⁸

The social issues arising from job losses and economic impacts on coal communities are of growing concern as plants and mines continue to close across the country. The Biden Administration has prioritized energy justice initiatives and programs to ensure that energy system transitions will not disproportionately impact vulnerable communities and will be fair and equitable to all. This includes regions where access to renewable resources may be limited, or where fossil fuel fired plants have been prematurely retired.

In conversations with regulators in jurisdictions, especially burdened by the transition away from coal, there is great concern about how to help impacted communities. Regulators feel they have few options to assist, lack expertise to bring about any lasting change, and do not believe it their responsibility to solve this problem, as one regulator put it, “We do power plants, we don’t do economic development.” Commissions that want to get involved feel that they can direct utilities to engage with communities, set pathways, and make funds available; however, they are not able to lead workforce transition and job creation efforts, as discussed in a 2021 NARUC publication.¹⁵⁹

While economic, workforce, and social issues within coal communities may not be within every regulator’s purview, commission decisions can have clear impacts on coal host communities. Commissions have broad oversight of regulated utility planning processes and resource investment decisions, as well as oversight of system reliability and resource adequacy. It is here that the emergence of zero-emission coal-to-hydrogen technologies have presented tools to simultaneously leverage existing coal resources, while potentially addressing broad policy and system reliability goals. Regulators, however, cannot base resource policy decisions on workforce issues alone.

The following is an assessment of where or under what circumstances a regulatory commission may review or consider a potential coal-to-hydrogen project.

10.2 Resource Planning

Regulators oversee utility planning processes that ultimately affect a utility’s resource portfolio. This resource planning process, or integrated resource planning (IRP), at a basic level, is a process of selecting long-term supply and demand side resources. IRPs typically compare total lifecycle costs of various resources and technologies and select the most economical, long-term portfolio that meets certain system, environmental, or policy goals. Each jurisdiction has their own flavor of IRP and a tailored criteria of system planning goals and objectives that need to be met, and characteristics that are valued. Some of these may include reliability or resource adequacy standards, diversity of generation supply, renewable portfolio standards (RPS), and greenhouse gas reduction. Within this context, coal-to-hydrogen projects can conceivably contribute to several common regulatory and utility planning criteria.

157 Taylor Kuykendall, “U.S. Coal Jobs Down 24% from the Start of Trump Administration to Latest Quarter,” *S&P Global*, November 11, 2020, <https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/us-coal-jobs-down-24-from-the-start-of-trump-administration-to-latest-quarter-61386963>

158 Can Coal Survive the Coronavirus? *E&E News*, April 8, 2020, <https://www.scientificamerican.com/article/can-coal-survive-the-coronavirus/>; <https://data.bls.gov/timeseries/CES1021210001>

159 Kiera Zitelman and Jasmine McAdams, “The Role of State Utility Regulators in a Just and Reasonable Energy Transition: Examining Regulatory Approaches to the Economic Impacts of Coal Retirements,” National Association of Regulatory Utility Commissioners, 2021.

10.3 RPS/Clean Energy Standards and Carbon Reduction

State renewable portfolio standards (RPS) vary widely in terms of targets, timing, and qualifying resources. Most states have implemented portfolio standards that explicitly incentivize electricity generation from renewable resources.¹⁶⁰ Some RPS policies even establish carve-outs and resource multipliers to promote diverse energy mixes and encourage deployment of new technologies.¹⁶¹ Michigan, Colorado, and Pennsylvania have included nonrenewable, low-, or zero-carbon emitting technologies within portfolio standards.¹⁶²

In most cases, however, RPS policies do not necessarily value reduction in carbon emissions. To address this, several states have additional clean energy standards that typically target 100% carbon- or emission-free electricity by a certain date.¹⁶³ Adding to this mix, an increasing number of utilities have independent carbon reduction or elimination targets and goals, with several pledging drastic carbon reductions by 2030.¹⁶⁴ In contrast with most RPS policies, clean energy standards and carbon reduction goals are more technologically neutral, as a wider range of resources can meet necessary carbon reduction goals.¹⁶⁵

Coal-to-hydrogen projects, paired with CCUS, can potentially fit into existing RPS frameworks in jurisdictions with expansive definitions of qualifying renewable resources. However, these projects may more appropriately contribute towards clean energy standards and utility decarbonization goals, especially in states that explicitly tie resource planning to greenhouse reduction targets,¹⁶⁶ or those that assign a dollar value to resource carbon emissions.¹⁶⁷

10.4 System Reliability and Resource Diversity

Ensuring the grid is supplied with reliable power is a central responsibility for PUCs. While there is ongoing debate around the nature of system reliability, and how it should be addressed, evolving resource mixes (e.g., the additions of inverter-based resources) along with retirements of conventional thermal generation, are modifying how the bulk power system is planned and operated and potentially impacting system reliability.¹⁶⁸ In its 2020 Long-Term Reliability Assessment, the North American Electric Reliability Corporation (NERC) observed that “planning for long-term resource adequacy is becoming increasingly complex with a resource mix that is more unpredictable and less energy-assured,” and offered the following recommendations for regulators, policymakers, and industry.¹⁶⁹

160 “State Renewable Portfolio Standards and Goals,” National Conference of State Legislatures, August 13, 2021, <https://www.ncsl.org/research/energy/renewable-portfolio-standards.aspx>

161 Ibid.

162 “Electricity Market Design and Carbon Capture Technology: The Opportunities and the Challenges,” State CO₂-EOR Deployment Work Group, June 2017, https://www.betterenergy.org/wp-content/uploads/2018/01/Electric_Markets_and_CCS_White_Paper.pdf

163 “100% Clean Energy Collaborative, Table of 100% Clean Energy States,” Clean Energy States Alliance, November 2019, <https://www.cesa.org/projects/100-clean-energy-collaborative/table-of-100-clean-energy-states/>

164 Cara Bottorff, John Romankiewicz, Leah Stokes, “The Dirty Truth: About Utility Climate Pledges,” Sierra Club, January 2021, https://www.sierraclub.org/sites/www.sierraclub.org/files/blog/Final%20Greenwashing%20Report%20%281.22.2021%29.pdf?_ga=2.163547839.288002361.1611578929-2075657276.1610633741

165 Electricity Market Design and Carbon Capture Technology: The Opportunities and the Challenges, White Paper prepared by the State CO₂-EOR Deployment Work Group, June 2017, https://www.betterenergy.org/wp-content/uploads/2018/01/Electric_Markets_and_CCS_White_Paper.pdf

166 Peter Maloney, “CPUC Adopts IRP Process Tied to GHG Reduction Targets,” American Public Power Association Blog, February 9, 2018, <https://www.publicpower.org/periodical/article/cpuc-adopts-irp-process-tied-ghg-reduction-targets>

167 “Emissions Reporting Requirements for Utility IRP, Michigan Public Service Commission Staff Report,” Michigan Power Grid: Integration of Resource/Distribution/Transmission Planning, Filed to the docket for Case No. U-20633, December 15, 2020, https://www.michigan.gov/documents/mpsc/Report_only_MPG_Integration_of_GDT_Planning_Emissions_Update_710800_7.pdf

168 “2020 Long-Term Reliability Assessment,” North American Electric Reliability Corporation, December 2020, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2020.pdf

169 Ibid.

- Regulators and policymakers in high-risk areas should coordinate with electric industry planning and operating entities to develop policies that prioritize reliability, such as promoting the development and use of additional flexible resources, energy-assured generation, and resource diversity.
- Regulators and policy makers should consider revising their resource adequacy requirements to consider new risks that emerge during nonpeak hours, limitations from neighboring systems during system-wide events, and the reduced resource diversity and/or increased reliance on a single fuel source or delivery mode.
- Industry should identify and commit flexible resources to meet increasing ramping and load-following requirements that result from increased variable energy resources and not solely to meet peak load capacity requirements.

Some jurisdictions have resource or technology diversity considerations or criteria in their formalized IRP processes.¹⁷⁰ Others, like Michigan, are currently exploring how to value resource diversity and what system-wide goals should be set around it.¹⁷¹ As highlighted earlier, coal-to-hydrogen projects can provide system reliability benefits and the flexibility of resource diversity to an energy system and may be particularly attractive to regulators if a widespread resource diversity value is adopted.

10.5 Review of Regulatory Challenges Associated with Technology Deployment

To facilitate an equitable, safe, and reliable energy system transition, the utility industry must invest in and deploy an array of new and innovative technologies. Regulators play a critical role in overseeing responsible investments. For utilities, poor performance of a new technology, construction delays, or cost overruns can all lead to reduced financial recovery from regulators. In the non-regulated marketplace, these issues can lead to contractual damages, lost profits, and impaired investments. If a technology fails to provide the level of benefit to customers as initially projected, the project can fail to be considered “used and useful” and may be deemed an “imprudent” investment when scrutinized in a rate proceeding.¹⁷² Furthermore, even if regulators approve of a new technology, regulatory depreciation policies may leave utilities with stranded costs. For example, if a technology becomes obsolete, and the economic life of the asset is shorter than the book life, utilities, shareholders, and ratepayers may be responsible for the ensuing cost.¹⁷³

Ratepayers and the public are similarly exposed to risks stemming from a utility’s investment strategy. If proper risk management and cost allocation strategies fail to be considered when regulators approve of an investment, ratepayers can end up subsidizing a utility mistake, or overpaying for the level of benefit received from an investment. Conversely, if a utility fails to sufficiently innovate and explore all available technologies at its disposal, system affordability, customer choice, and policy and societal goals may be jeopardized.

Reducing investment risk for utilities can encourage innovation, but if customers assume a large share of that risk it can create a “moral hazard.” Therefore, regulators must strive to strike a balance between insulating customers from excessive risk and providing adequate incentives for a utility to innovate.¹⁷⁴ In doing so, there are several challenges a commission may face when considering a new technology investment, as described below.

170 Bruce Biewald and Rachel Wilson, “Best Practices in Electric Utility Integrated Resource Planning: Examples of State Regulations and Recent Utility Plans,” Synapse Energy Economics, June 2013, <https://www.raponline.org/wp-content/uploads/2016/05/rapsynapse-wilsonbiewald-bestpracticesinirp-2013-jun-21.pdf>

171 Comments of the Association of Businesses Advocating Tariff Equity, State of Michigan before the Michigan Public Service Commission, Case No. U-20633, Filed on February 19, 2021, https://www.michigan.gov/documents/mpsc/Integration_of_Resource_Distribution_and_Transmission_comments_from_February_9_meeting_717029_7.pdf

172 Ken Costello, “New Technologies: Challenges for State Utility Regulators and What They Should Ask,” National Regulatory Research Institute, January 2012, <https://pubs.naruc.org/pub/FA8662AC-F265-3C52-7B79-B159C1FBB512>

173 Ibid.

174 Ibid.

10.6 Regulatory Challenges

Information Asymmetry: In conversations with regulators, the information asymmetry that exists between a utility and a regulatory commission was consistently identified as one of the biggest challenges facing regulators. The funding, resources, and capabilities of commissions can be considerably less than many regulated utilities. Additionally, some commissions have noted the difficulties in recruiting, training, and maintaining a qualified staff, given the unique skillset utility regulation requires and the often-limited access to funding. As a result, utilities are better informed about the costs, risks, and benefits of new technologies. Regulators frequently must make decisions based solely on information that the utility submits to support a technology or project investment. It is critical that a regulator is sufficiently knowledgeable about new technologies to be able to determine the accuracy of information received. Furthermore, regulators have noted that there are often disagreements between utilities, stakeholders, and within a commission about the validity and appropriateness of the supporting information a utility provides.

Risk Allocation: Building on the issue of information disparities, regulators must be keenly aware of the risks associated with a technology. These risks must be identified, calculated, and appropriately allocated between the utility and ratepayer. Furthermore, risk may need to be appropriately divided between customer types, in the event a technology only benefits a specific section of a utility's customers.

Facilitating Innovation: Commissions can play a significant role in a utility's decision to invest and deploy new or innovative technologies, and there may be differing regulatory philosophies as to how to best achieve appropriate levels of utility innovation. For example, one regulator believes that it is not a commission's job to explicitly encourage innovation, but rather to foster a stable regulatory environment, ensuring that the utility is not constrained and is comfortable making decisions within that environment. This more passive approach may help to facilitate innovation.

On the other hand, some PUCs have more actively fostered innovation by implementing performance incentive mechanisms that better align utility rewards with risks and provide extra financial compensation for utilities to invest in new, beneficial technologies.¹⁷⁵ Regardless of the approach, a utility's appetite for innovation is directly linked to the regulatory structure and incentive mechanisms in place and regulators should seek to avoid utility under- or over-investment in new technologies—both can have negative consequences.

Utilities may underinvest when perceived risks are greater than benefits or new technologies erode utility profit margins. For example, a utility may be hesitant to invest in control software to facilitate the growth of distributed energy resources (DER) in areas where utility revenues are coupled to sales.¹⁷⁶ On the other hand, utilities may attempt to overinvest in capital-intensive technologies in order to inflate rate base and generate greater returns, or in instances where utilities bear little risk and pass through all costs to customers—often through a cost “tracker” or “rider” mechanism.¹⁷⁷

Accountability: Regulators must ensure that when approving technology investments, expected cost-benefit and performance goals, criteria, and metrics are clearly articulated. Regulators must ensure that cost recovery is contingent on a satisfactory level of achievement of these standards and is not guaranteed.¹⁷⁸ Regulators can undertake prudence reviews of technology investments during rate proceedings before deciding to allow an investment to be included in rate base and receive cost recovery.

175 Guy Burdick, “Performance Incentive Mechanisms Can Support Broad Policy Goals, RMI Finds,” *Utility Dive*, August 18, 2020, <https://www.utilitydive.com/news/performance-incentive-mechanisms-can-support-broad-policy-goals-rmi-finds/583662/>

176 Herman Trabish, “Colorado Decoupling Proposal Unites Xcel, Distributed Energy Advocates,” *Utility Dive*, June 7, 2017, <https://www.utilitydive.com/news/colorado-decoupling-proposal-unites-xcel-distributed-energy-advocates/444165/>

177 Ken Costello, “New Technologies: Challenges for State Utility Regulators and What They Should Ask,” The National Regulatory Research Institute, January 2012, <https://pubs.naruc.org/pub/FA8662AC-F265-3C52-7B79-B159C1FBB512>

178 Ibid.

10.7 Review of Case Studies: Lessons Learned

This section provides an overview of recent and notable coal-based IGCC and CCUS facilities in the United States. The difficulties, risks, and lessons captured from these innovative projects can potentially mirror those that can be experienced when coal-to-hydrogen projects are deployed, and these projects may warrant further study when a PUC is considering the approval of a coal-to-hydrogen facility.

NRG Petra Nova

The Petra Nova Project was a commercial-scale carbon capture project at NRG's Parish Plant near Houston Texas—a coal-based project which represented the world's largest installation of CO₂ capture on a power plant.¹⁷⁹ It was the only commercial-scale facility operating in the U.S. designed to capture 92.4% CO₂ in a slip stream from an existing coal-based power plant, up to 1.6MMT of CO₂ per year. The captured CO₂ was to be transported under pressure to the West Ranch Oilfield through an 80-mile pipeline where it would be used for enhanced oil recovery. The \$1 billion project received \$190 million from DOE, a \$250 million loan from the Japan Bank for International Cooperation, and approximately \$300 million in equity from NRG and JX Nippon, the technology provider.

Lessons learned:

- The project was the first demonstration of post-combustion CCUS technology at commercial scale in the United States, and the three-year demonstration proved that the technology can be successfully built and operated. The experiences gained, and challenges overcome can help others to better understand and improve the development of CCUS technology, as well as reduce capital and operating costs.¹⁸⁰
- Economics of large-scale CCUS facilities are challenging. DOE notes in its final Petra Nova project report the complexities of unlocking value chains from captured CO₂, even with access to nearby EOR field interests and pipelines.¹⁸¹
- Petra Nova was conceived primarily as a technology demonstration, in which any technical issues associated with dramatically scaling up a carbon capture process could be identified and resolved for the benefit of future projects. Technical issues encountered were mostly related to leaking heat exchangers and equipment scaling with calcium deposits.
- DOE describes the task of assembling risk-sharing project sponsors to innovative, capital-intensive projects as "extremely difficult." However, the project did demonstrate that with a strong plan and committed sponsors and stakeholders, the technology can be financeable.
- The pioneering facility had served its primary purpose in progressing the technology to its next stage. Future CCS infrastructure is much more likely to rely on two-party "take or pay" arrangements, with some of the new projects focused mainly on producing pipeline-ready CO₂ at the plant fence.
- Petra Nova relied on using CO₂ for enhanced oil recovery and was impacted by plummeting oil prices in the wake of the COVID-19-induced slump in demand. Enhanced oil recovery becomes uneconomical when the oil price falls below \$60/barrel. Due to the lower oil prices, the project became uneconomical for Petra Nova to capture and sell CO₂ for EOR. The project needed oil at \$60 a barrel to break even and linking economics of project to another volatile fossil fuel may have created greater risks. Due to the resulting crash in oil prices, it became uneconomical for Petra Nova to capture carbon, and the CCUS facility has been postponed since May of 2020.

179 "Learning from Petra Nova: What are the Lessons for Carbon Capture Technology?" *NS Energy, Originally in Modern Power Systems Magazine*, November 13, 2020, <https://www.nsenerybusiness.com/features/petra-nova-carbon-capture-project/#>

180 Greg Kennedy, W.A. Parish, "Post-Combustion CO₂ Capture and Sequestration Demonstration Project Final Technical Report," DOE-PNPH-03311, DOE/NETL, March 31, 2020, <https://www.osti.gov/servlets/purl/1608572>

181 Ibid.

Kemper IGCC Project

The Kemper IGCC project, built in Kemper County, Mississippi, led by Southern Company and its subsidiary Mississippi Power, consisted of two gasifiers based on the transport integrated gasification (TRIG™) technology generating syngas from mine-mouth lignite coal. The syngas was combusted in two gas turbines. The project planned to capture 65% of the CO₂ and had a peak generation capacity of 582 MW. The project was designed to produce 3.8 million tons of CO₂ for enhanced oil recovery, 0.15 million tons of sulfuric acid (H₂S), and 19,000 tons of ammonia as byproducts annually—these would be captured after the syngas cooling and ammonia removal step using a Selexol® solvent. Carbon dioxide was to be transported 60 miles for enhanced oil recovery.

The Mississippi Public Service Commission (PSC) approved the project in 2010, at an estimated cost of around \$2.9 billion. By 2014, the facility was producing electricity only as a conventional NGCC facility and, by 2017, the total facility costs had increased to \$7.5 billion. By this point, the PSC ordered Southern Company to end construction and the plant is operating as a NGCC facility to date.¹⁸² In 2018, the PSC reached a settlement agreement with Mississippi Power that will see the utility's shareholders absorb \$6.4 billion in total losses from the project.

Lessons learned:

- This was a mammoth project that was attempting to deploy first of its kind technology on a scale that had never been done before. As DOE's final report on the project recognized; "Kemper was the largest IGCC project in the world, the first to use lignite as fuel, the first to capture and sell CO₂, and each of the two Kemper gasifiers were the largest in the world in IGCC application by a factor of nearly two.¹⁸³ " Innovative deployment of technologies, at a record-breaking scale should have invited more scrutiny as to the overall project risks, and highlights the imperative for regulators to properly understand and characterize risks before moving forward with a new technology.
- Technical challenges experienced included chronic coal dust suppression issues; tube leaks in the synthetic gas cooler; insufficient process water capacity; and a too-small nitrogen plant, which required trucks to haul gas to the plant. The plant also had a complex supply chain around the plant—water supply from the City of Meridian, natural gas from Tennessee Gas Pipeline, CO₂ sales to Denbury Resources, nitrogen supply from Air Liquide, and sulfuric acid and ammonia sales to Martin Product Sales. In addition, "unknown startup, operation and technology risks" and other operational issues, which included equipment reliability issues associated with sustained integrated operation of both gasifiers at design capacity, sustained electrical production on both combustion turbines at rated capacity, sustained production of byproducts at design rates and quality, and overall plant process control integration. The project also raised questions about its economic viability that contributed to the suspension of the project.¹⁸⁴
- Kemper again demonstrates the challenging economics of CCUS projects at this point in commercialization. The current large capital, operating, and construction costs necessitate a well devised business model. Mississippi Power stated in 2017, after completing a PSC-ordered update to its CBA, that "projected long-term natural gas prices, and to a lesser extent an increase in operating costs of the project, negatively impact the economic viability of Kemper."¹⁸⁵

182 U.S. Department of Energy, "Southern Company - Kemper County, Mississippi," Office of Fossil Energy and Carbon Management, <https://www.energy.gov/fe/southern-company-kemper-county-mississippi>

183 Eamon Hogg, and P. Vimalchand, "Kemper County IGCC Final Project Report," Project No. DE-FC26-06NT42391, DOE/NETL, May 17, 2019, <https://www.osti.gov/servlets/purl/1513228>

184 David Wagman, "The Three Factors That Doomed Kemper County IGCC," *IEEE Spectrum*, Jun. 30, 2017, <https://spectrum.ieee.org/energywise/energy/fossil-fuels/the-three-factors-that-doomed-kemper-county-igcc>

185 Sonia Patel, "Billions Over Budget, Kemper Facility Gasification Portion Is Suspended," *Power Magazine*, June 28, 2017, <https://www.powermag.com/billions-over-budget-kemper-facility-gasification-portion-is-suspended/>

Edwardsport Power Station

Edwardsport is a 618-megawatt IGCC facility, located in Knox County, near Edwardsport, Indiana, converts coal into a synthetic gas. Remaining NO_x, SO₂, and mercury emissions are removed from the gas before it is burned to generate electricity. The new facility replaced a 160-megawatt station at Edwardsport that had been in operation since the 1940s.

In 2006, Duke Energy requested permission from the Indiana Utility Regulatory Commission (IURC) to commit nearly \$2 billion to build Edwardsport Power Station and recover those costs through rates. These costs estimates were revised upwards in 2008 and 2009, to \$2.35 and \$2.88 billion, respectively. In 2012, the IURC approved a settlement agreement that permanently capped project costs amid concerns of spiraling cost overruns, and in June 2013, the plant was declared operational at a price tag of \$3.4 billion.¹⁸⁶ In 2018, Duke Energy forfeited an additional \$32 million because of cost overruns of the plant's annual operating expenses.

Lessons learned:

- Active interveners and stakeholders have held Duke Energy accountable and returned over \$100 million in value to ratepayers in litigated proceedings by challenging the project's "in service date," and seeking recovery of testing, start up, and operating costs.
- Even without the addition of CCUS technology, the project faced rather significant cost overruns and delays to operations. The IURC imposed overall cost caps, as well as caps on annual operating expenses to reduce ratepayer risk as the facility was being constructed and continuing into normal operations.
- Duke Energy proposed to add CCUS technology to the project to capture and store 15% to 20% of CO₂ emissions. Regulators, unsure of the prospects of new CCUS technology, ordered Duke to conduct a preliminary engineering and design study to better understand the technological risks for a CCUS addition. In 2013, regulators rejected the utility's request for \$42 million to move onto the next phase of its CCUS study, citing the many "uncertainties related to the long-term management of CO₂" and the fact that potential EPA regulations concerning existing power plants are "speculative in terms of both timing and result."
- Duke Energy reached settlement agreements in 2016 and 2018 laying out how much ratepayers should be charged for the more than \$3 billion project, given delays and technical difficulties during its startup. The commission approved a cost cap of \$2.651 billion in 2016 to be recovered through retail rates. In June 2020, the Indiana Utility Regulatory Commission approved a two-step, \$146 million increase into base rates for Duke Energy for the IGCC power plant. Under a rate case approved by the IURC, cost recovery for the coal gasification power plant moves into base rates and will no longer be tracked through a rider.^{187, 188}

10.8 Decision Support Tools, Including Economic Models, To Aid Regulators in Technology Evaluation

Technological advancements are creating transformation in many front fronts, including regulatory decision making based on science and factual data and information. In today's environment, this is posing significant challenges for regulators who strive to maintain a balance between fostering innovation and protecting consumers. The following is a discussion on tools used for technology evaluation and regulatory decision making to help regulators meet these challenges in the context of coal-to-hydrogen facilities.

186 "Duke Hit Hard by Exorbitant O&M Costs at Edwardsport IGCC Facility," *Power Magazine*, September 27, 2018, <https://www.powermag.com/duke-hit-hard-by-exorbitant-om-costs-at-edwardsport-igcc-facility/>

187 Darren Sweeney, "Group Issues Report Blasting Duke Energy for Nearly \$12B in 'Failed' Projects," *S&P Global Market Intelligence*, August 31, 2020, <https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/group-issues-report-blasting-duke-energy-for-nearly-12b-in-failed-projects-60155422>

188 "Updated: Indiana OKs \$146M Rate Increase for Duke Energy," *Tribune-Star*, June 29, 2020, https://www.tribstar.com/news/indiana-news/updated-indiana-oks-146m-rate-increase-for-duke-energy/article_168b9002-29ae-5316-a194-fcce8d8e88a3.html

Cost-Benefit Analysis

A common evaluation of the reasonableness of a technology investment, energy efficiency and other innovative utility programs, or energy resource additions is the cost-benefit analysis (CBA). A CBA is a lifecycle comparison of a project's benefits to its costs: In many cases, a project or investment will be deemed "cost effective" if the projected benefits to the utility, ratepayer, or society are greater than the estimated costs. There are several variations of commonly accepted CBAs, with the primary difference being the perspective of where benefits or costs accrue. A summary of five regularly accepted CBA models is provided in Table 9.

Table 9 – Generally Accepted Cost-Benefit Analysis Models

Test	Key Question Answered
Participant Cost Test (PCT)	Will the participants benefit over the measure's life?
Utility Cost Test (UCT)	Will utility bills increase?
Ratepayer Impact Measure (RIM)	Will utility rates increase?
Total Resource Cost Test (TRC)	Will the total costs of energy in the utility service territory decrease?
Societal Cost Test (SCT)	Is the utility, state, or nation better off as a whole?

Source: Adapted from National Action Plan for Energy Efficiency (2008). Understanding Cost-Effectiveness of Energy Efficiency Programs: Best Practices, Technical Methods, and Emerging Issues for Policymakers.

Of these five tests, three (UCT, PCT, RIM) focus on costs from either the utility, participant, or ratepayer in a singular perspective. Two tests (TRC, SCT) broaden the perspectives and impacts, as TRC is a combination of utility and customer costs, and SCT builds on TRC by considering the same impacts with the addition of larger societal effects.¹⁸⁹ Recent efforts have expanded on these CBA tests and have advocated for the adoption of a regulatory/jurisdictional test. This localized CBA reflects both the impacts and perspectives of local utilities, as well as the broader impacts to state or jurisdictional policy goals.¹⁹⁰

Additional metrics including levelized cost of electricity (LCOE), levelized avoided cost of electricity (LACE), and levelized cost of storage (LCOS) are often considered when determining the economic competitiveness of various power generation technologies. The LCOE of a technology refers to the cost estimate of the revenue required to build and operate a generator over a specific cost recovery period, LACE refers to the revenue available to that generator during the same period, and LCOS quantifies the discounted cost per discharged electricity. Actual investment decisions in generating plants may involve additional factors such as projected utilization rate which may indicate the extent of consuming demand for a particular load profile. Combining LACE with LCOE and LCOS further defines the economic competitiveness when several available technologies can meet the load demand. EIA calculates LACE-to-LCOE and LACE-to-LCOS ratios to derive which technologies provide the most value. Technologies with a ratio greater than one are more economically attractive as new builds than those with a value-cost ratio less than one.¹⁹¹

There is no widespread agreement on what tests best apply to specific types of technologies or programs, and the numerous options reflect the competing considerations and tradeoffs that regulators must balance when reviewing utility investments. In some cases, specific classes of ratepayer savings may be prioritized above total system costs, and this may detract from broader societal or jurisdictional goals. It is not uncommon for there to be disagreement between utilities, stakeholders, and regulators about which CBA is most appropriate, and often more than one test is submitted to regulators to review.

189 "NEEP Implementation Guide: Establishing a Jurisdiction-Specific Cost-Benefit Test," Northeast Energy Efficiency Partnerships, https://neep.org/sites/default/files/media-files/cbt_implementation_guide.pdf

190 "National Standard Practice Manual: For Benefit Cost Analysis of Distributed Energy Resources," National Energy Screening Project, August 2020, https://www.nationalenergyscreeningproject.org/wp-content/uploads/2020/08/NSPM-DErs_08-24-2020.pdf

191 U.S. Energy Information Administration, "Levelized Costs of New Generation Resources in the Annual Energy Outlook 2021," February 2021, https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf

While CBA can be a powerful tool to assist regulators in the evaluation of investments, there are risks associated with relying too heavily on them, particularly when applied to capital intensive technologies. It can be difficult for a utility to accurately forecast specific costs and measurable benefits, and perhaps even more difficult for a commission to effectively scrutinize the data being supplied. If a project suffers from cost overruns, even modest changes can significantly alter the cost effectiveness of a project. This is especially applicable within the context of coal-to-hydrogen facilities that rely on carbon capture technologies that have, at least to date, been susceptible to large cost overruns. Therefore, CBA should be a tool to assist in project evaluation, but it should not be the singular decision-making tool for a regulator.

Regulatory Processes

In conversations with regulators, many stressed the importance of leveraging existing regulatory processes to reduce information asymmetry issues, protect ratepayers, and better evaluate new technologies. Process can be a very effective tool at a regulator's disposal. Many new technologies are investigated and vetted by utilities, stakeholders and interveners, and regulators within the context of IRP proceedings. These open proceedings can draw experienced interveners that are able to supplement a commission's capabilities and resources.

Similarly, there are benefits to be gained from requiring pre-approval for a utility to commit funds for a project. Pre-approvals of utility investments and projects can provide greater flexibility and time for regulators and experienced interveners to scrutinize utility investments instead of waiting until project completion and litigating concerns within a rate proceeding. However, while there are benefits associated with additional time and resources to vet projects, once approved and within certain bounds, the utility is essentially entitled to cost recovery for the project. This can represent a major shift in risk from the utility to customers, and regulators should proceed carefully.

Regulators can also take a more proactive approach and directly engage utilities and stakeholders in the investigation of new technologies long before they are proposed as a utility investment. One regulator interviewed believes that it is important to maintain an active relationship with utilities with regular meetings to ensure continued alignment with any commission approved long-term resource plans. Regulators can then better anticipate utility actions and prepare for a potential new technology investment. Regulators may also open investigatory proceedings or working groups and direct utilities and any interested stakeholder to assess the feasibility of a specific technology before any investment decision is considered—outside of the context of an adjudicated proceeding. In sum, active interveners, engaged stakeholders, and a well-developed record are additional resources and can be key supplemental decision-making tools for a regulator.¹⁹²

Cost Caps/Reduced Rate of Return

As mentioned, regulatory pre-approval of investments can mark a significant risk shift from the utility to customer. However, regulators have tools to blunt this risk transfer, especially for particularly risky projects or large capital costs. The first measure is to impose a cost cap on total project capital costs to limit any ratepayer exposure to potential cost overruns. A cost cap can be either a percentage of total costs, a fixed dollar amount, or a cost floor, whereby the utility must present justification that anything over the set cost level was a prudently incurred expense.¹⁹³ Similarly, a reduction in a utility's authorized rate of return, reflecting the reduced risk to a utility when projects have received preapproval, can alleviate some risk to ratepayers.¹⁹⁴

192 Jasmine McAdams, "Public Utility Commission Stakeholder Engagement: A Decision-Making Framework," National Association of Regulatory Commissioners, January 2021, <https://pubs.naruc.org/pub/7A519871-155D-0A36-3117-96A8D0ECB5DA>

193 Scott Hempling, Scott Strauss, "Pre-Approval Commitments: When and Under What Conditions Should Regulators Commit Ratepayer Dollars to Utility-Proposed Capital Projects?" National Regulatory Research Institute, November 2008, <https://pubs.naruc.org/pub/5F3D50FA-1866-DAAC-99FB-55C8EF422EC8>

194 Ibid.

Pilot Program/Demonstrations

Regulators can also encourage utilities to pursue pilot or demonstration projects when investigating a new technology. A pilot program or project allows for the testing of technology and business models in a dynamic environment.¹⁹⁵ Pilots can dramatically scale down the complexities, risks, and costs associated with new technology deployment, allowing commission staff and utilities to more easily vet new technologies.

Although pilots can have lower overall costs than full-scale technology roll outs, utilities may expect ratepayers to cover costs of trial and error, where ratepayer benefits may be nonexistent or years away from realization. Utilities can often benefit from partnering with technology vendors, or public research agencies to subsidize pilot costs and lessen any ratepayer burden.

Furthermore, regulators should ensure that pilots or demonstration projects are closely aligned with regulatory goals, or a utility's strategic vision. Pilots may often result in a situation where the program fails or does not provide the data or insights necessary to validate a potential solution. Often, the solution to this can be another round of pilots, resulting in "pilot fatigue."¹⁹⁶

11. Concluding Remarks

Hydrogen is a compelling clean fuel option for reducing carbon emissions. Hydrogen is not an energy source or primary energy existing freely in nature. It is an energy carrier and has a strategic importance in the pursuit of a more sustainable energy system. Combustion of hydrogen consists of water and a small amount of nitrogen oxides (NO_x). In the near future, production options for hydrogen will be based on distributed hydrogen production from electrolysis of water and reforming of natural gas and coal.¹⁹⁷

Hydrogen is a versatile fuel that offers a path to sustainable long-term economic growth. It can add value to multiple sectors in the economy. It can serve as a sustainable fuel for transportation and as input to produce electricity and heat. As part of a comprehensive energy portfolio, it can provide economic value and environmental benefits for diverse applications across multiple sectors. As mentioned previously, hydrogen can be derived from a variety of domestically available resources; stored as a liquid, gas, or chemical compound; and converted to energy via traditional combustion methods, through electrochemical processes and hybrid approaches such as integrated combined cycle gasification and fuel cell systems. It is also used as a feedstock or fuel in a number of industries, including petroleum refining, ammonia production, food and pharmaceutical production, and metals manufacturing.

There has been a renewed and emerging interest in the "Hydrogen Economy," which refers to the vision of using hydrogen as a clean, low-carbon energy resource to meet the world's energy needs, replacing traditional fossil fuels and forming a substantial part of a clean energy portfolio. There are several reasons hydrogen is again receiving serious consideration as an alternative energy source. In addition to a global desire for more environmentally friendly fuel sources, improvements in hydrogen technologies, increasing government support for climate-friendly fuel diversification and changes in global energy policy, in emission standards and in the global technology landscape—such as the rapid deployment of intermittent renewables that require grid-scale storage for system stability—these all help to support the argument for developing the hydrogen economy.

195 "Pilot Projects – Guidelines for a Successful Grid Modernization Pilot Project Program," Smart Electric Power Alliance, 2019, <https://seppower.org/resource/pilot-projects-guidelines-for-a-successful-grid-modernization-pilot-project-program/>

196 Ibid.

197 Mustafa Balat, "Potential Importance of Hydrogen as a Future Solution to Environmental and Transportation Problems," *International Journal of Hydrogen Energy*, Volume 33, Issue 2, via *Science Direct*, August 2008, <https://www.sciencedirect.com/science/article/abs/pii/S0360319908005272>

Hydrogen is emerging as a low-carbon fuel option for transportation, electricity generation, and manufacturing applications. Hydrogen has the potential to decarbonize a range of industries where electrification has limited applicability. For example, as a heating fuel, hydrogen is a cleaner-burning molecule that can be a substitute for combustion of fossil fuels in applications where high-grade heat is needed and where electric heating is not the best option. The industrial sector uses natural gas as a source of process heat, and as a fuel for the generation of steam. When natural gas is combusted to generate heat, carbon emissions are released. It is challenging to capture CO₂ emissions at the point of use outside of large industrial plants. Hydrogen can be burned directly or blended with natural gas to reduce emissions.

The U.S. is well-positioned to accelerate the transition to a hydrogen economy by developing technology solutions that enable the production of hydrogen from fossil fuels with zero, or even net-negative, carbon emissions when combined with CCUS. Research efforts have been underway on technologies that can produce hydrogen from coal-derived synthesis gas and build and operate a zero-emissions, high-efficiency co-production power plant that produces hydrogen and electricity from coal. While hydrogen's economic potential is substantial, the power sector is expected to play a key role in the widespread growth of hydrogen. State legislative requirements that expect utilities to decarbonize faster than other industrial sectors may drive early adoption of hydrogen in power generation.¹⁹⁸

Current modelling efforts for deep decarbonization of the electricity sector have suggested that hydrogen generation can complement and provide value to renewable and storage pairings. In one study, hydrogen demonstrated an ability to meet up to 14% of total U.S. energy generation in 2050.¹⁹⁹

As described in previous sections, hydrogen's use in power generation, including coal-to-hydrogen generating facilities, can provide several benefits to the electricity system that can be of potential interest to regulators. The gasification of coal with integrated CCUS technology can produce hydrogen, and subsequent power generation, with net-negative carbon emissions.²⁰⁰ As grids become more variable, with increasing additions of intermittent generating resources, a low-carbon flexible resource such as this can provide bulk generation when wind or solar resources are low and can complement grid-scale battery storage to stabilize the grid.²⁰¹ Additionally, coal-to-hydrogen facilities can be operated as baseload, in times when electricity demand is low, and hydrogen can be produced for storage or other commercial and industrial uses.²⁰² This option, however, comes with significant challenges around cost recovery and plant economics that would need to be carefully examined.

However, the infrastructure needs for CCUS are significant. Carbon sequestration requires the development of suited reservoirs that can store CO₂. Those reservoirs require characterization, modeling, permitting, installation of injection wells, and installation of monitoring wells. A system must be designed and installed to pressurize and transport the CO₂ to the injection site. The injection site would preferably be adjacent to the plant site. If the site is not adjacent to the plant, a pipeline must be designed, permitted, and installed between the source of CO₂ and the injection site. A typical rule of thumb is that a pipeline for transporting CO₂ costs approximately \$1 million per mile. Long pipelines to transport the CO₂ must obtain a constant and reliable source of CO₂ in order to keep the line full and pressurized, and so that the CO₂ is always available on demand. Therefore, a robust infrastructure should have multiple sources of CO₂ supplying it. DOE has been involved in studies, designs, and implementation for several pipeline projects.

198 Emma Penrod, "Hydrogen is Having a Moment, and Power Generation is Leading the Way," *Utility Dive*, November 2, 2020, <https://www.utilitydive.com/news/hydrogen-is-having-a-moment-and-power-generation-is-leading-the-way/587958/>

199 Larry Pearl, "NextEra Sees Hydrogen as Key to Deep Decarbonization, Takes Small Steps for Now," *Utility Dive*, April 22, 2021, <https://www.utilitydive.com/news/nextera-sees-hydrogen-as-key-to-deep-decarbonization-takes-small-steps-for/598855/>

200 "Roadmap to a U.S. Hydrogen Economy: Reducing Emissions and Driving Growth Across the Nation," The Fuel Cell and Hydrogen Energy Association, 2020, <https://cafcp.org/sites/default/files/Road+Map+to+a+US+Hydrogen+Economy+Full+Report.pdf>

201 International Energy Agency, "Future of Hydrogen," June 2019, <https://www.iea.org/reports/the-future-of-hydrogen>

202 U.S. Department of Energy, "Hydrogen Strategy: Enabling A Low-Carbon Economy," Office of Fossil Energy, July 2020, https://www.energy.gov/sites/prod/files/2020/07/f76/USDOE_FE_Hydrogen_Strategy_July2020.pdf

Coal-to-hydrogen facilities can leverage existing coal facility infrastructure to potentially reap system and societal benefits. Jurisdictions with abundant coal supplies and existing infrastructure may benefit from decreased input costs in the conversion to hydrogen and retrofits of existing coal-fired or gasification facilities have the additional potential to improve the economics of coal-to-hydrogen projects. Moreover, even if a facility is not retrofitted, there may be project benefits and cost reductions associated with building on a brownfield site of a prior coal facility. These sites may be further beneficial to coal-to-hydrogen projects if there is an existing transmission interconnect, potentially saving project costs as well as avoiding competition for transmission capacity in transmission constrained areas.

It is difficult to ignore the benefits that this technology can potentially provide for existing coal host communities, especially when projects are sited on existing infrastructure. While all levels of government are working towards a policy option to assist these communities, coal-to-hydrogen technology can provide an additional, complimentary tool to ensure a just and equitable energy transition for all.

Industry stakeholders advocate for a staged approach to developing the hydrogen economy, beginning with developing CCUS to enable blue hydrogen production. Resources companies believe there are significant synergies with hydrogen to be explored before a full transition to green hydrogen, given their reserves of gas, evolving CCUS capabilities, and opportunities to repurpose existing technology and facilities to accommodate blue hydrogen. Due to the significant costs involved in sufficiently scaling up hydrogen infrastructure, governments have an important role to play in considering investment proposals and creating a supportive regulatory framework.²⁰³

Challenges and opportunities for coal-to-hydrogen include the following:

- CCUS technologies are capital-intensive. Installing a carbon capture system on a conventional coal plant can add up to 40% to the capital cost. Installation on an IGCC plant, which could produce hydrogen, can add up to 25% to the capital cost. Many studies have been completed to project paths towards reducing the capital cost of CCS systems, however major first-of-a-kind demonstration plants must be built and operated to drive new technologies towards lower costs for CCS systems.
- CCUS technologies entail high operating costs. Adding a system to remove the CO₂ from the system requires significant steam for a temperature-swing system and significant energy for a pressure-swing system. Continued R&D is needed to develop advanced chemicals that will allow capture and release of the CO₂ at lower temperature or pressure swings. In addition, continued R&D is required to improve the life cycles of the sorbents to reduce attrition and loss of porosity. Further, the cost to pressurize the CO₂ to feed into geologic sinks or pipelines consumes a significant amount of parasitic energy.
- Scale up of new technologies involves risks. Not all new technologies will be successful when scaled up to full size, even with carefully engineering. Scaling up, integrating, and designing first-of-a-kind systems entails challenges to system designers, which typically requires redesigns of systems as a new system is started up.
- Cost estimates require large contingencies. Duplicating existing designs has the luxury of using cost data from past plants for reliable equipment costs. It is often difficult to obtain reliable cost estimates from suppliers for the components and systems that go into a first-of-a-kind facility. Even with high contingencies, cost overruns are not infrequent in first-of-a-kind facilities.

203 Henry Carlson and Alexander Woody, "Hydrogen's New Dawn," White and Case, November 12, 2020, <https://www.whitecase.com/publications/alert/hydrogens-new-dawn>

- The risk/reward model is a challenge for new technologies. The marketplace typically does not embrace higher prices for the commodities of electricity or hydrogen from new technologies when lower cost alternatives exist. There is a natural tension between the regulators and producers of a commodity from a new plant with respect to whether the higher costs and risk of failure should be borne by the producer or end user.
- Liability of potential CO₂ leaks or intrusion outside of the injector's mineral rights must be addressed.

These challenges can be addressed through continued cooperation and partnerships between the federal government, industry, and regulators. The federal government should continue to fund the development of new technologies through the basic research, development, and demonstration phases. Industry should allocate an appropriate percentage of their corporate budgets towards RD&D efforts. Incentives may be required to facilitate the use of hydrogen in the commercial, industrial, and transportation marketplaces. Regulators and legislators can work with the private sector to ensure that sufficient incentives are in place that reward successful deployment of new technologies, yet at the same time protect ratepayers from cost overruns and other risks.

Appendix A – Carbon Capture, Utilization, and Storage

In coal-based power generation, carbon dioxide (CO₂) is a byproduct of coal combustion and gasification. The amount of CO₂ produced is directly proportional to the carbon content of the feedstock and the efficiency of the power plant. Converting coal into usable energy is primarily dependent on the amount of carbon and hydrogen content of the coal. In conventional combustion, oxygen reacts with the carbon to produce CO₂ and heat, and with hydrogen (H₂) to produce heat and water (H₂O). The carbon/hydrogen ratio of a fossil fuel determines the amount of CO₂ vs. H₂O. Natural gas is primarily methane (CH₄), which has a higher energy content relative to other fuels, and thus, it has a relatively lower CO₂-to-energy content. In gasification, the carbon and hydrogen are converted to carbon monoxide (CO) and hydrogen. The CO is converted to CO₂ and H₂ through a water-gas shift (WGS) reaction. WGS is commonly used to adjust H₂ to CO ratios in syngas for many end products or purposes of coal gasification. However, in the production of hydrogen, it is an essential post-gasification operation and used to convert all CO present in the syngas to CO₂, yielding the maximum possible amount of hydrogen.

Removing CO₂ from the stream of gasification or combustion entails the concept of pressure-swing adsorption (PSA), vacuum-swing adsorption (VSA), thermal-swing adsorption (TSA), or membrane separation. In PSA, the CO₂ is absorbed by a permeable material at high pressure and the concentrated CO₂ is released at a low pressure. TSA is a variation of PSA and the CO₂ is absorbed at a low temperature by a solvent, and the concentrated CO₂ is released at a high temperature. In membrane technology, the CO₂ is removed from the gas by permeating the gas through membranes, which separate the CO₂ from the gas stream due to differences in the rate of permeation for different gases or through a chemical reaction between the gas being removed and the membrane.

PSA process use has seen a significant growth due to its simplicity and low operating costs and is the most common method used today for hydrogen separation. It is based on an adsorbent bed that captures the impurities in the syngas stream at higher pressure and then releases the impurities in low pressure. Multiple beds are utilized simultaneously so that a stream of hydrogen at up to 99.9% may be produced. PSA is used for removal of CO₂ as the final step in large scale commercial synthesis of hydrogen and it can also remove methane, CO, nitrogen, moisture, and as well as argon from hydrogen. On the other hand, TSA is not widely used because of the relatively long time it takes to heat and cool sorbents. The disadvantage of the PSA and TSA technologies is that they entail significant capital cost and consume a significant of parasitic load during their operation.

In VSA, also a variation of PSA, the process stream containing CO₂ is not pressurized and CO₂ is removed from the sorbent by establishing a vacuum on the regenerating sorbent bed which draws off the CO₂. The mechanism is the same in either case; CO₂ adsorbs at higher pressure and desorbs at lower pressure, and the pressure differential can range above or below ambient pressure. VSA's disadvantages include large sorbent beds required for high-throughput applications, such as flue gas treatment, and high capital cost for sorbent and associated process equipment.

Membrane-based CO₂ separation has many advantages compared to other capture approaches. Membrane module systems have simple operation with no chemical reactions, no moving parts, and no temperature or pressure swings. The disadvantage of membrane technology is the cost and durability of the membrane as well as the possibility of pluggage of the membrane pores. Several significant challenges for membrane CO₂ capture technologies result in a less favorable cost compared to other technologies. Because membranes are competing against the more established, less costly CO₂ capture processes, the use of membranes for large CO₂ gas separation has been limited to small scale natural gas purification.

Carbon Utilization

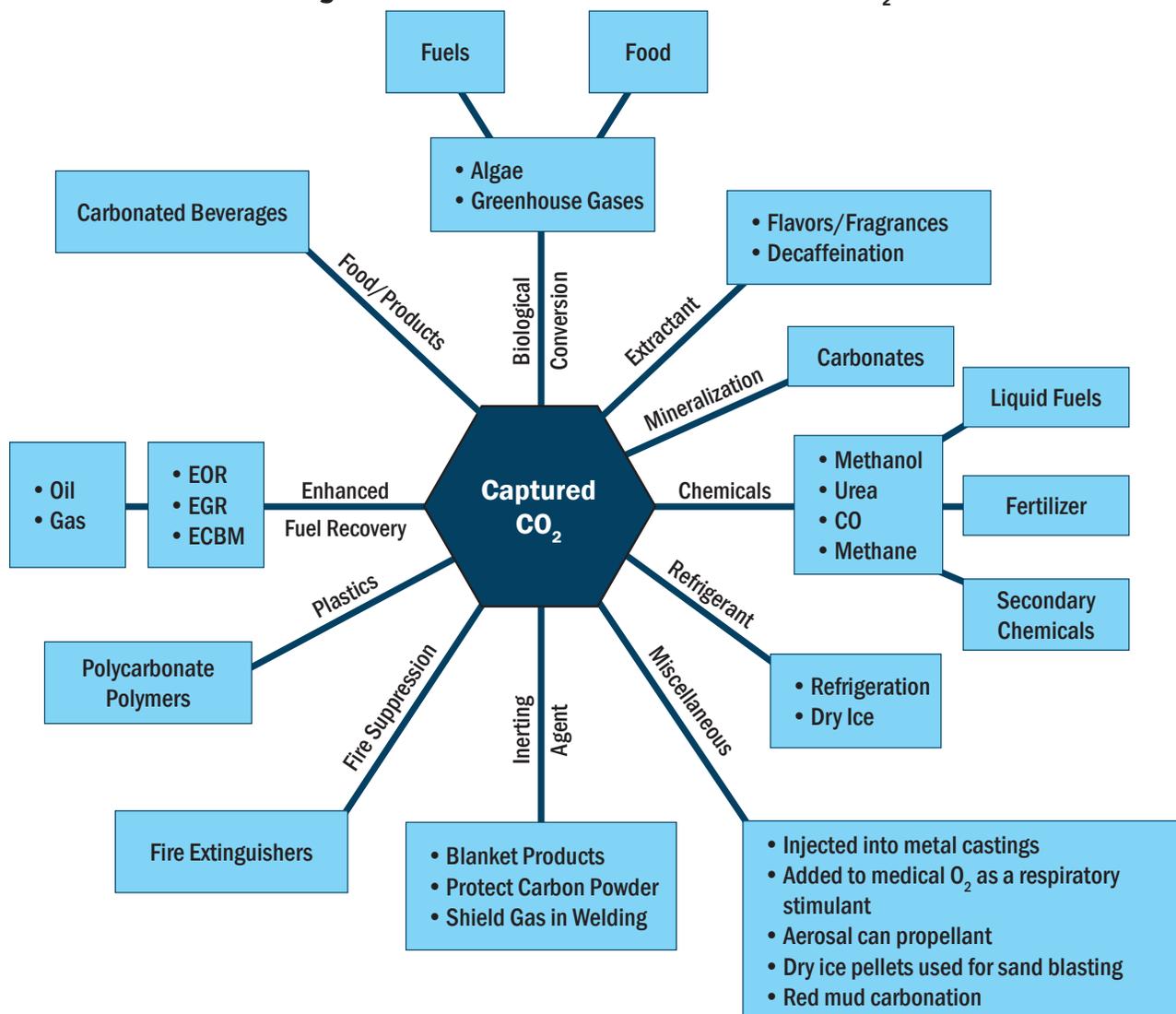
Once the carbon is captured, it must be either used in a beneficial manner or stored, i.e., sequestered. Although technologies for carbon capture, utilization, and storage (CCUS) have advanced in recent years, today's technologies are still costly and energy-intensive, and further advances are needed before more viable CCUS technologies are realized. In developing various carbon storage options. One particularly important need is the development of new processes to convert the captured CO₂ into useful commodity materials and chemicals, which are currently produced from fossil fuels. Effective means of producing commercial products—from liquid fuels to myriad materials used in consumer products (e.g., polymers)—could help drive the economics of CCUS processes and provide pathways to decarbonize sectors beyond power generation such as chemicals and materials sectors.

Carbon dioxide use converts CO₂ into valuable products through chemical reactions or biological conversions. Carbon is used to produce fuels, polymers, industrial chemicals, carbon nanotubes, and building products such as carbonates and cement. It is also used in the production of steel, electronics, and consumable goods. Some CO₂-derived products, such as construction materials, could significantly expand their use of CO₂. The four main types of CO₂ use technologies are thermochemical, electrochemical and photochemical, carbonation, and biological conversion. These processes lead to potential use pathways in which CO₂ is converted into useful products. Some of these product pathways reduce the carbon intensity of products made with fossil fuels and have a large CO₂ storage potential in the products, chemicals, or fuels that are produced.

Figure A-1 illustrates potential utilization streams for captured CO₂.²⁰⁴ Each carbon utilization pathway has specific characteristics in terms of technical maturity, market potential, economics, and CO₂ reduction impact. Enhanced oil recovery (EOR) using CO₂ is the most widely practiced form of carbon utilization today.

204 U.S. Department of Energy, "Accelerating Breakthrough Innovation in Carbon Capture, Utilization and Storage, Report of the Mission Innovation Carbon, Capture Utilization," Storage Experts Workshop, September 2017, https://www.energy.gov/sites/prod/files/2018/05/f51/Accelerating%20Breakthrough%20Innovation%20in%20Carbon%20Capture%2C%20Utilization%2C%20and%20Storage%20_0.pdf

Figure A-1 – Potential Utilization Streams for CO₂



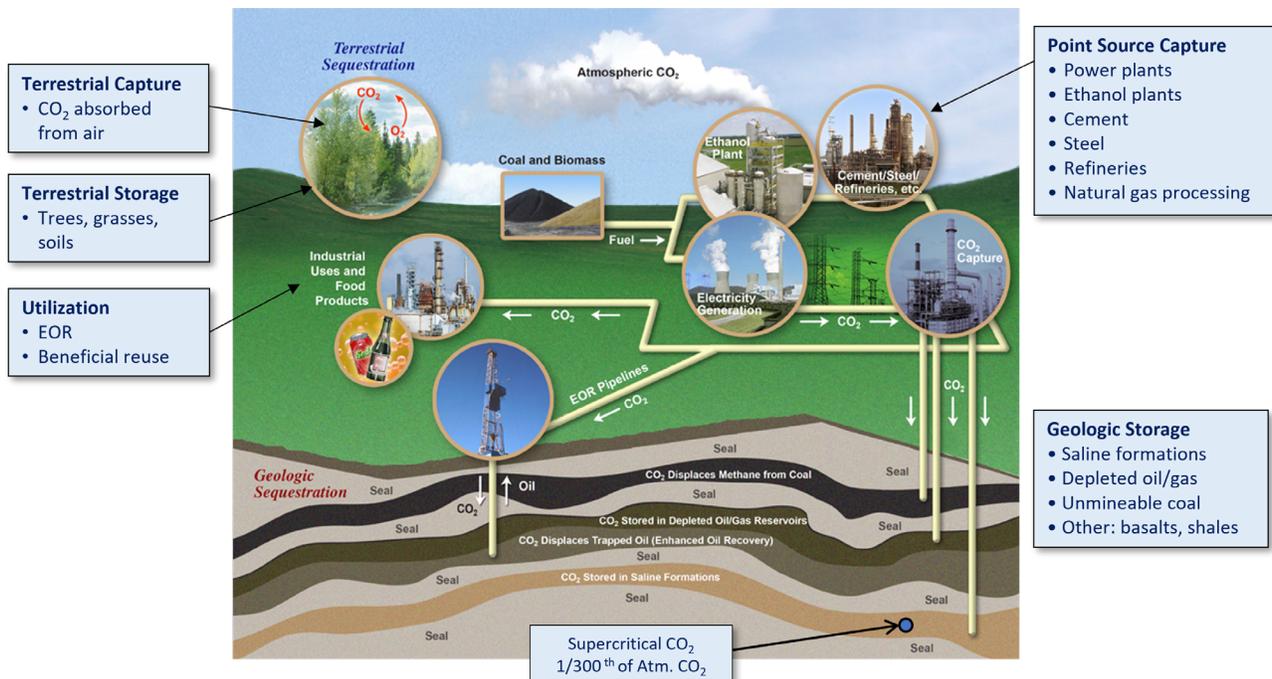
Approximately 17 million metric tons (MMT) per year of anthropogenic CO₂ are currently used in the U.S. for EOR, along with much higher quantities of CO₂ from naturally-occurring sources. Construction materials represent a large, near-term opportunity for carbon utilization, principally through cement and aggregate—the gravel, sand, or crushed stone used with cement to form concrete. Fuels, chemicals and plastics represent a significant opportunity for utilization technologies. Conversion of CO₂ to fuels and chemicals often entails adding hydrogen to the carbon in CO₂. Advancing these processes to operate at a commercial scale represents a significant technical challenge. Algae-based carbon utilization holds near-term opportunity in some product categories, including biofertilizers, aquaculture, livestock feed, and feed additives. It also offers a number of economic and environmental benefits and the most attractive feature of algae-based utilization is the wide range of potential products that can be generated. A potentially significant long-term product pathway associated with algal uptake of CO₂ is the production of fuels.²⁰⁵

205 Fatima Ahmad, Jeffrey Bobeck, Ron Munson, and Janet Peace, "Carbon Utilization: A Vital and Effective Pathway for Decarbonization," Center for Climate and Energy Solutions, Aug. 2019, <https://www.c2es.org/site/assets/uploads/2019/09/carbon-utilization-a-vital-and-effective-pathway-for-decarbonization.pdf>

Carbon Sequestration

Carbon capture, utilization and storage (CCUS) refers to a suite of technologies. Figure A-2 shows several of these technology combinations.²⁰⁶ CCUS involves the capture of CO₂ from large point sources, including power generation or industrial facilities that use either fossil fuels or biomass for fuel. The CO₂ can also be captured directly from the atmosphere. If not being used on-site, the captured CO₂ is compressed and transported by pipeline, ship, rail or truck to be used in a range of applications, or injected into deep geological formations, which trap the CO₂ for permanent storage.²⁰⁷

Figure A-2 – Capture and Storage of CO₂ that would Otherwise be Emitted to the Atmosphere



Once carbon is captured, it must be stored or used in a beneficial manner. Carbon sequestration, also termed carbon storage, is the permanent storage of CO₂, usually in deep geologic formations. For example, CO₂ resulting from fossil fuel combustion, gasification, and other industrial processes is injected as a supercritical fluid into geologic reservoirs, where it is held in place by natural traps and seals.

Geologic storage refers to the process by which CO₂ is pumped underground through injection wells into rocks below the surface, such that it is permanently trapped and cannot return to the atmosphere. The key to achieving this is identifying geologic formations that have specific properties. The wells require a special geological structure of porous rock such as limestone that is capped by an impermeable structure such as shale or slate.

The CO₂ storage reservoirs are either conventional or unconventional formations. Typical conventional formations include sandstone, limestone, dolomite, or a mixture of these rock types that enable gas and fluid to easily flow to or from wellbores drilled into the formation. Unconventional formations include a collection of rock types such as shale, low-permeability or tight sandstones, and some carbonates. Other possible subsurface CO₂ storage options include oil and natural gas reservoirs, unmineable coal seams, basalt formations, and organic-rich shales. Oil and natural gas reservoirs are ideal geologic storage sites and have

²⁰⁶ Modified image, courtesy of the Rocky Mountain Coal Mining Institute

²⁰⁷ International Energy Agency, "About CCUS," April 2021, <https://www.iea.org/reports/about-ccus>

conditions suitable for CO₂ storage. Once the oil and natural gas is extracted from an underground formation, it leaves a permeable and porous volume that can be readily filled with CO₂. Injecting CO₂ can also enhance oil production by pushing fluids towards producing wells through a process called enhanced oil recovery. Coal that is considered unmineable because of geologic, technological, and economic factors (e.g., too deep, too thin, or lacking the internal continuity to be economically mined) could also serve as locations to store CO₂. Coal seams may also contain methane, which can be produced in conjunction with CO₂ injection in a process called enhanced coal bed methane recovery.²⁰⁸

In order to be considered for CO₂ storage, the formation rock must have sufficient pore space in which CO₂ can be contained for storage and pathways connecting the pore space so the CO₂ can be injected into and move within the formation. The storage formations must be deep enough so that the natural pressure and temperature can maintain the CO₂ as a dense fluid, also called a supercritical fluid or state. Typically, the minimum depth required for this temperature and pressure are greater than or equal to about 3,000 feet. To protect underground drinking water aquifers, CO₂ storage is only permitted in saline formations that are saltier than 10,000 ppm Total Dissolved Solids (TDS), per EPA Class VI UIC regulations.

In addition, a prospective storage reservoir must have a geologic seal above it and the sedimentary rock of a geologic seal must have a very low permeability that prevents CO₂ from leaving the storage formation. Seals are often made up of shale, salt, or carbonate rocks with pores that are too small to enable the CO₂ to enter or pass through them. When CO₂ is injected into the formation rock, it displaces some of the saline water—also called brine—in the formation, causing the reservoir’s fluid pressure to increase. The pressure buildup increases the density of the brine and pore volume of the rock, making space in the reservoir to accommodate the incoming volume of CO₂. Sandstone reservoirs with alternating layers of porous and permeable rock, sitting below a low-permeability geologic seals, are ideal for storing large volumes of CO₂ because of their layered geology.

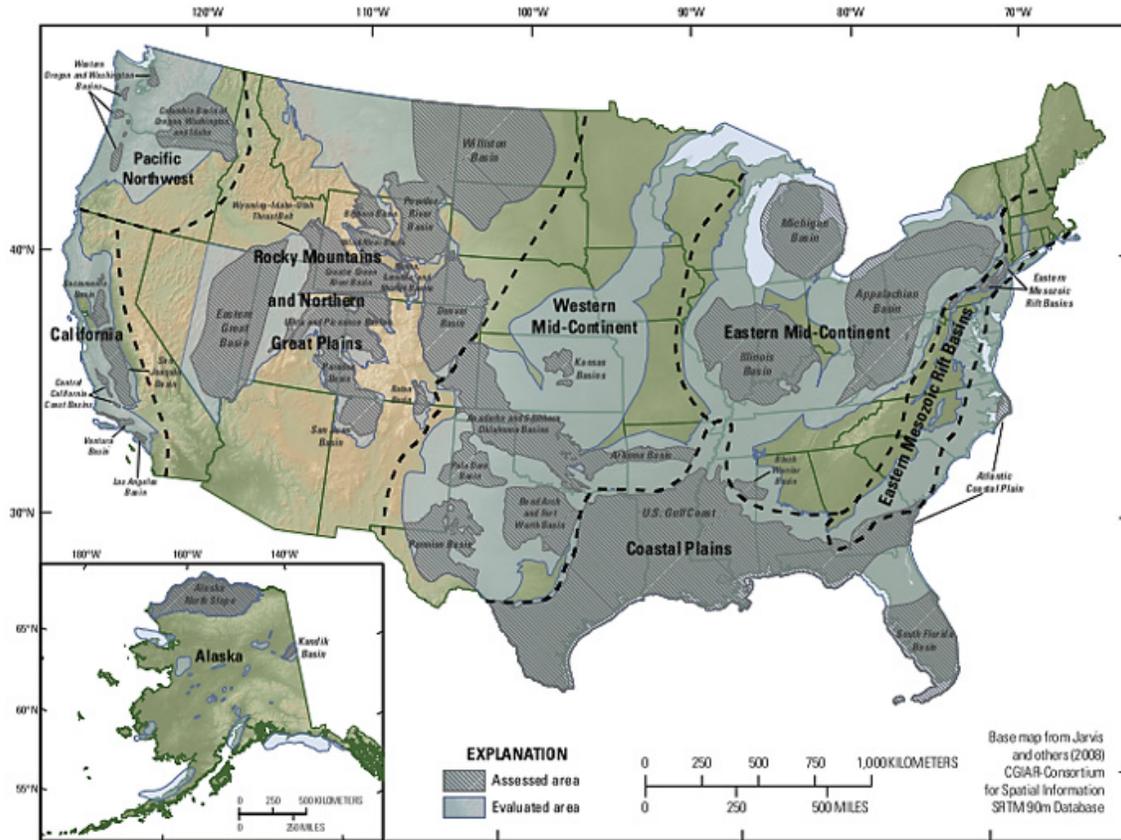
The subsurface storage capacity in the U.S. is assessed to be enough to sustain a large-scale CO₂ storage industry. Different types of formations have varying technical and practical storage capacity estimates due to differing reservoir properties. It is estimated that, currently in the U.S., approximately 500 billion metric tons (Gt) of storage capacity is available within reasonable proximity to CO₂ emissions sources or transport infrastructure.²⁰⁹ Figure A-3 shows the geologic CO₂ storage capacity assessment areas conducted by U.S. Geological Survey (USGS).²¹⁰

208 National Energy Technology Laboratory, “What is Carbon Capture and Storage,” Carbon Storage FAQs, <https://www.netl.doe.gov/coal/carbon-storage/faqs/carbon-storage-faqs>

209 Ganeswara Dasari, Eric Drueppel, Kenneth Hood, Jeffrey Palmer, Gregory Shipman, Michael Sullivan, and Gary Teletzke, “Evaluation of Practicable Subsurface CO₂ Storage Capacity and Potential CO₂ Transportation Networks, Onshore North America,” Presented at 14th Greenhouse Gas Control Technologies Conference, Melbourne, Oct. 2018, Revised October 27, 2020, https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3366176

210 U.S. Geological Survey, “National Assessment of Geologic Carbon Dioxide Storage Resources—Results,” USGS Circular 1386, Version 1.1, September 2013, https://pubs.usgs.gov/circ/1386/pdf/circular1386_508.pdf

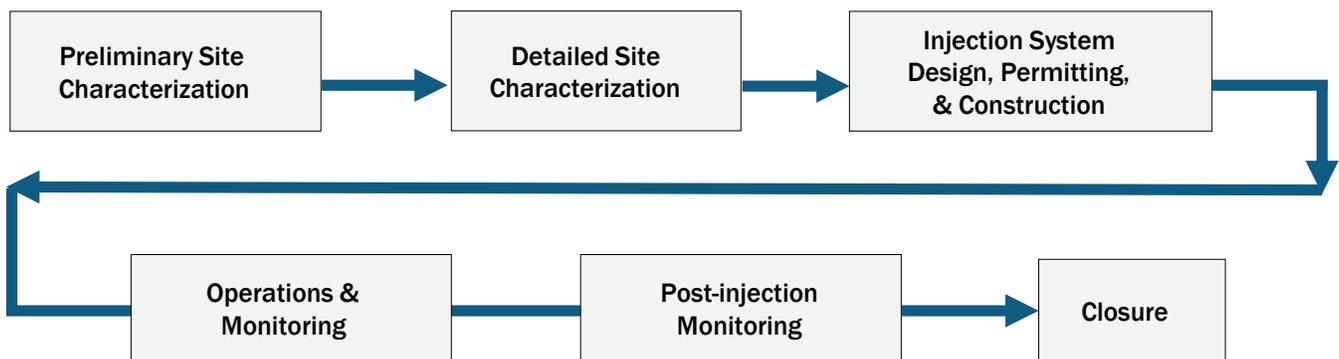
Figure A-3 – Potential Sites for Geologic Storage of CO₂



Map of the conterminous U.S. and Alaska showing 8 onshore regions, evaluated areas (bluish gray) that were not assessed, and 36 the areas assessed by USGS (pattern) for CO₂ storage. Onshore only and excludes Hawaii.

Extensive site characterization, modeling, with a monitoring and closure plans are required before a permit can be issued as a pre-requisite for the drilling of a well for carbon storage. Figure A-4 shows the steps required for developing an injection well. Locating a station adjacent to the sequestration site reduces the cost of transporting the CO₂ via a pipeline to a distant site, however it has been proposed to build a network of pipelines to collect the CO₂ to transport the gas to a common storage field.

Figure A-4 – Stages of a Carbon Sequestration Project



Regional Carbon Sequestration Initiatives

According to a recent International Energy Agency (IEA) report, the U.S. accounts for more than 60% of global CO₂ capture capacity and half of all planned capacity.²¹¹ The majority of stationary emission sources in the U.S. are located close to potential geological storage sites and 85% of emissions come from plants located within about 60 miles of a site and 80% within 30 miles. In light of the ambitious targets set by the Biden Administration, i.e., carbon-free power generation by 2035 and a net-zero carbon economy by 2050, clean-energy technologies have received renewed policy support, as well as an increased interest in technologies to capture CO₂ from industrial and power plants, and transport and storing it underground.

The U.S. has been a leader in technology innovations and is in an advantageous position to commercialize these technologies worldwide to accelerate global decarbonization efforts. Continued and increased level of research and development (R&D) is critical to validating and increasing confidence in the safety, affordability, and permanence of CO₂ injection and storage. Further advances in CO₂ storage technology will provide industry the verifiable information needed to economically and safely assess and monitor long-term storage of CO₂. Carbon capture and geologic storage need to be demonstrated as an effective and reliable solution before being widely implemented.

To support the development of regional infrastructure for carbon capture and storage, National Energy Technology Laboratory (NETL) of the U.S. Department of Energy (DOE), as part of its Carbon Capture Program, created a network of seven Regional Carbon Sequestration Partnerships (RCSP), which began in 2003 to be implemented over several phases. Characterization activities started as Phase I of the RCSP Initiative and included cataloging regional CO₂ sources, characterizing CCUS prospects, and prioritizing opportunities for future CO₂ injection field projects. The Regional Partnerships and the lead organization for each are shown Table A-1.²¹²

In 2005, validation of the most promising regional storage opportunities was initiated through a series of small-scale field laboratory projects during the *Validation Phase*. This phase led to the successful completion of 19 small-scale field projects in a variety of storage complexes, providing information on reservoir and seal properties of regionally significant formations, testing, and initial validation of modeling and monitoring technologies. In 2008, the RCSP focus turned to large-scale field laboratories in saline formations and oil and gas fields with a target of injecting at least 1 MMT per project in the *Development Phase* of the RCSPs. Through the RCSPs, small-scale field projects in oil and gas fields, unmineable coal seams, saline formations, and basalt formations were completed, leading to large-scale formations in saline formations and oil-and-gas fields.

211 International Energy Agency, "Energy Technology Perspectives 2020, Special Report on Carbon Capture Utilization and Storage: CCUS in Clean Energy Transition," 2020, https://iea.blob.core.windows.net/assets/181b48b4-323f-454d-96fb-0bb1889d96a9/CCUS_in_clean_energy_transitions.pdf

212 National Energy Technology Laboratory, "Regional Carbon Sequestration Partnerships (RCSP) Initiative," <https://www.netl.doe.gov/coal/carbon-storage/storage-infrastructure/regional-carbon-sequestration-partnerships-initiative>

Table A-1 – Regional Partnerships and Lead Organizations

Regional Partnership	Lead Organization
Big Sky Carbon Sequestration Partnership (BSCP)	Montana State University - Bozeman
Midwest Geological Sequestration Consortium (MGSC)	Illinois State Geological Survey
Midwest Regional Carbon Sequestration Partnership (MRCSP)	Battelle Memorial Institute
Plains CO ₂ Reduction Partnership (PCOR)	University of North Dakota Energy and Environmental Research Center
Southeast Regional Carbon Sequestration Partnership (SECARB)	Southern States Energy Board
Southwest Regional Partnership on Carbon Sequestration (SWP)	New Mexico Institute of Mining and Technology
West Coast Regional Carbon Sequestration Partnership (WESTCARB)	California Energy Commission

The large-scale field laboratories support and validate the industry’s ability to ensure storage permanence in storage complex in different geologic settings. They address practical issues, such as sustainable injectivity, well design for integrity, storage resource utilization (utilization of pore space and oil and gas recovery), and reservoir behavior—with respect to prolonged injection.²¹³

Numerous applied research technologies have been integrated into these projects and the results have been essential in further technology development of CCUS. The RCSP accomplishments include the following:

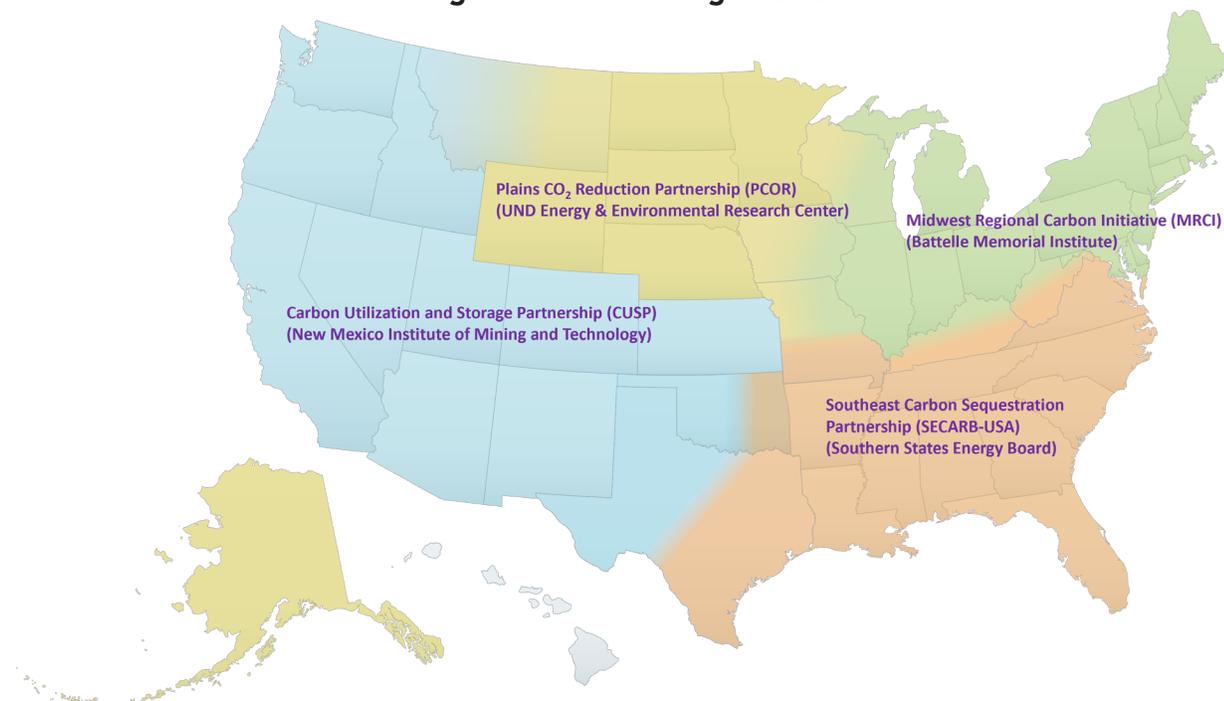
- Injected more than 12 MMT of CO₂, demonstrating capacity to permanently, economically, and safely store CO₂;
- Supported the development and verification of carbon storage related technologies including characterization, modeling and simulation, mitigation, and risk assessment;
- Developed the [National Carbon Storage Atlases](#) and a Geographic Information System to store CCUS related data;
- Contributed to a series of [Best Practices Manuals](#) for geologic storage projects to establish effective methods, reliable approaches, and consistent standards; and
- Midwest Geological Sequestration Consortium obtained an EPA Region 5 Underground Injection Control (UIC) Class VI permit.

In 2020, DOE consolidated the seven RCSPs into four regional initiatives under a new Regional Initiative to Accelerate CCUS Deployment.²¹⁴ These regions are shown in Figure A-5 and listed in Table A-2 with the lead organizations. The regional initiatives will facilitate integrating information for the regions, include working with existing and future demonstration projects within that region, and coordinate efforts related to past and current field projects.

213 National Energy Technology Laboratory, “RCSP Development Phase,” <https://www.netl.doe.gov/node/5908>

214 U.S. Department of Energy, “FOA 2000: Regional Initiative to Accelerate CCUS Deployment,” Office of Fossil Energy and Carbon Management, <https://www.energy.gov/foa-2000-regional-initiative-accelerate-ccus-deployment>

Figure A-5 – CCUS Regional Initiatives



According to DOE, by leveraging the strengths of this new initiative, it will be possible to identify and promote potential infrastructure and/or carbon utilization/storage projects that will help enable low emission coal-based facilities of the future. The regions will help coordinate the capabilities and experience of industry, academia, and government to accelerate CCUS deployment; address key technical challenges; assess transportation and distribution infrastructure; facilitate data collection, sharing, and analysis; and promote regional technology transfer and dissemination of knowledge.

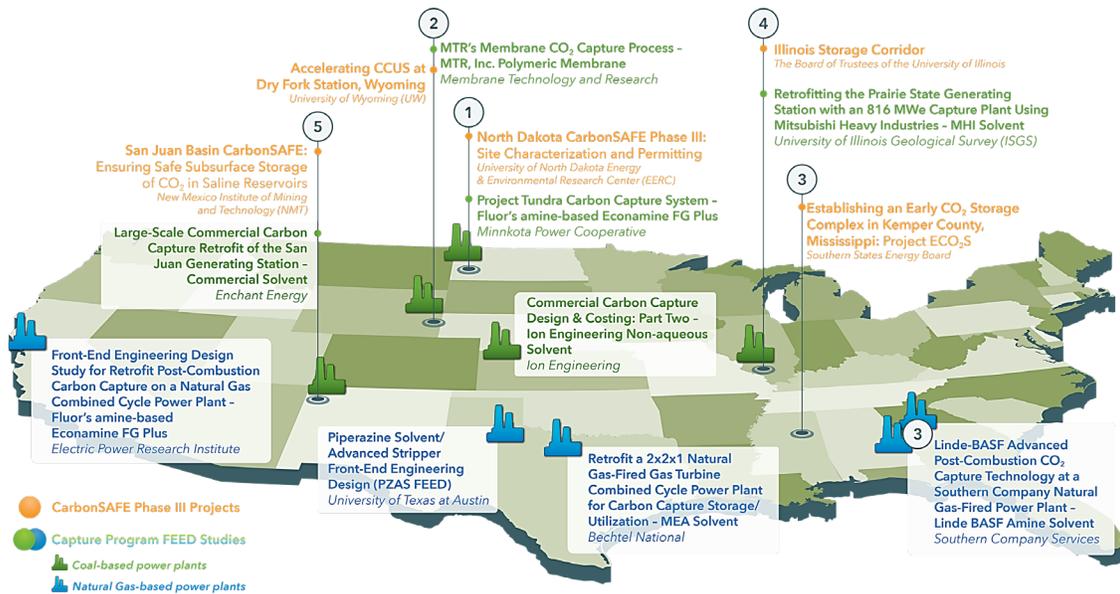
Table A-2 – Regional Initiatives and Lead Organizations

Regional Initiative	Lead Organization
Regional Initiative to Accelerate CCUS Deployment in the Midwest and Northeastern USA	Battelle Memorial Institute
Carbon Utilization and Storage Partnership of the Western United States	New Mexico Institute of Mining and Technology
Southeast Regional Carbon Utilization & Storage Partnership (SECARB-USA)	Southern States Energy Board
Plains Carbon Dioxide Reduction (PCOR) Partnership Initiative to Accelerate CCUS Deployment	University of North Dakota

Other DOE programs, the Front-End Engineering Design (FEED) and Carbon Storage Assurance Facility Enterprise (CarbonSAFE), together provide foundational research in CCUS infrastructure and capabilities to support carbon capture at commercial coal and natural gas projects. The essential engineering studies conducted by these programs closely intersect with private-sector interests, fostering and spurring investment in future CCUS projects. DOE’s Carbon Storage Program also engages in international collaborations and supports integrated domestic and international activities to ensure carbon capture and storage (CCS) technologies are cost-effective and commercially available. Current studies and project locations are shown

in Figure A-6.²¹⁵ Further, DOE is directly engaged in several large-scale CCUS demonstration projects around the world and partnering with several international organizations, such as IEA's Greenhouse Gas R&D Program and the Carbon Sequestration Leadership Forum. NETL's CCUS database includes active, proposed, and terminated CCUS projects worldwide.

Figure A-6 – CarbonSAFE Phase III and Capture Funded FEED Studies Locations



Infrastructure Needs Associated with Increased Sequestration

Enhanced Oil Recovery

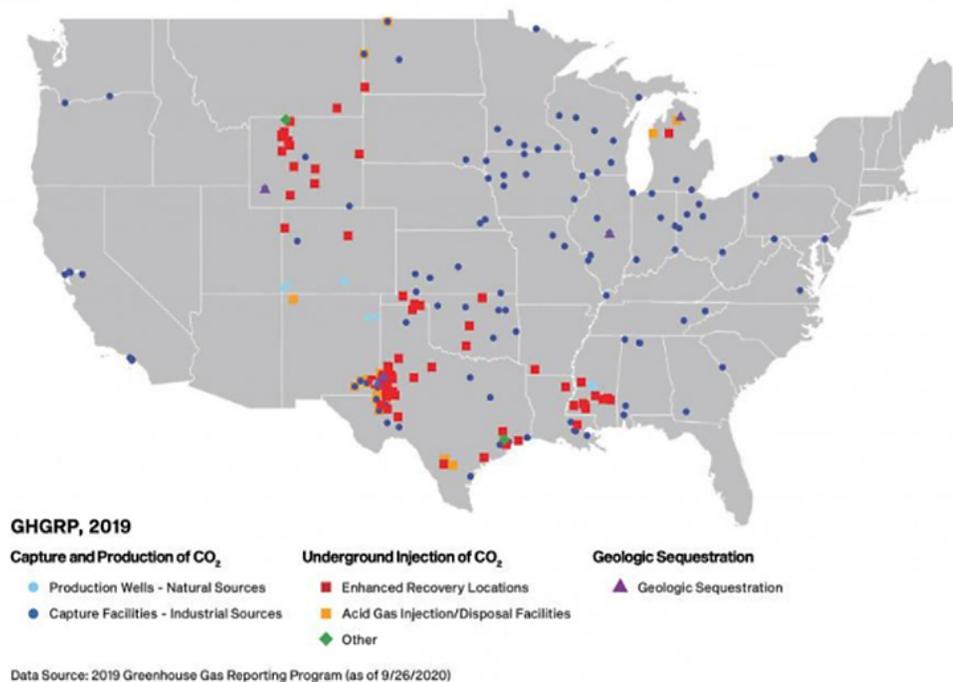
As oil wells become depleted, extraction of the remaining oil can become difficult. Injection of a chemical into a well to lower its viscosity combined with CO₂ to force the oil into the oil well increases the extraction of 30% to 60% more oil from the well. The injected CO₂ trades places with oil that is released from minute pore spaces within the reservoir rock. This exchange results in the CO₂ becoming trapped by capillary pressure within this same pore space, dissolving in the residual fluids present in the pore space, or eventually becoming mineralized. CO₂-EOR is a mature technology that has been applied for more than 40 years, during which, CO₂-EOR operations in the U.S. have injected more than 1 billion tons of CO₂. The experience has shown that more than 99% of the CO₂ remains safely trapped underground after CO₂ injection is completed. The process benefits the environment when CO₂ from industrial sources, such as power generation, is captured, injected, and stored underground, thereby reducing greenhouse gas emissions by providing large-scale CO₂ storage. Enhanced oil recovery from existing fields requires fewer resources than installing infrastructure and equipment to develop new oil field locations.

While most CO₂ captured or produced is supplied to facilities that conduct EOR, a smaller portion is injected underground for other purposes. Figure A-7 shows the locations of capture and production of CO₂, underground injection of CO₂, and geologic sequestration of CO₂.²¹⁶

215 National Energy Technology Laboratory, "Carbon Storage Program," <https://www.netl.doe.gov/sites/default/files/2021-04/Program-116.pdf>

216 U.S. Environmental Protection Agency, "Capture, Supply, and Underground Injection of Carbon Dioxide," Greenhouse Gas Reporting Program (GHGRP), <https://www.epa.gov/ghgreporting/capture-supply-and-underground-injection-carbon-dioxide>

Figure A-7 – Locations of CO₂ Capture and Sequestration



CO₂-EOR projects can be conducted under miscible or immiscible conditions, but miscible projects are more common and commercially viable. The advantage of a miscible CO₂ process is that the oil's volume is increased through swelling and its viscosity is lowered, causing more oil to become mobile and travel to the producing wells. Commercial scale CO₂-EOR projects in the U.S. have been largely limited to the prolific oil reservoirs of the Permian Basin of Texas and New Mexico that are especially amenable to this EOR process. Approximately half of the world's CO₂-EOR are in the Permian basin, not far from some of the biggest natural sources of CO₂ in the United States. Use of CO₂ for enhanced oil recovery can provide a positive revenue stream for the CO₂ as compared to the cost of geological sequestration. The value of the CO₂ sold for EOR is strongly influenced by the price per barrel of oil.

The estimated onshore and offshore U.S. remaining oil in place is approximately 414 billion barrels of oil that would not be recovered without application of tertiary recovery operations such as CO₂-EOR. Of this volume, 177 billion barrels of oil is estimated to be technically recoverable through CO₂-EOR technology application. This would require injecting 51 billion tons of CO₂, however, and only a portion of this would be economically feasible.²¹⁷

CO₂ Transportation

In most cases, captured CO₂ will need to be transported from the capture location to a location where it can be stored or utilized. Typical modes of transportation include pipelines, railcars, trucks, and ship and barge. Pipelines are generally the most cost-effective method of transporting large volumes of any fluid, including CO₂. For pipeline transport, CO₂ is compressed into a dense supercritical fluid phase before entering a pipeline system and it can be pumped like other liquids. Use of CO₂ for EOR requires the installation of a pipeline from the source of CO₂ to the well. Ideally, a series of pipelines could be installed to transport the CO₂ from multiple sources to the oil fields. Railcars may be cost effective for small to medium volumes of CO₂ over longer distances if there are existing rail routes from near the source to the vicinity of the storage. Rail transport may require construction of a liquefaction facility at the point of origin. Trucks may be cost effective

²¹⁷ National Petroleum Council, "Meeting the Dual Challenge: A Roadmap to At-Scale Deployment of Carbon Capture, Use, and Storage," March 2021, <https://dualchallenge.npc.org/>

for very small volumes of CO₂ traveling short distances. Similar to rail, trucking can take advantage of existing infrastructure, but also, like rail, liquefaction facilities may be needed at the point of origin. Transport with ship and barge is technically feasible but it has only been demonstrated at a small scale.

The energy industry in the U.S. has constructed more than 5,000 miles of CO₂ pipelines, representing approximately 85% of the total CO₂ pipeline mileage in the world. The CO₂ transported through this pipeline network is a mix of anthropogenic and natural CO₂ and is primarily used for EOR. Figure A-8 provides a map of current pipelines for EOR in the United States.²¹⁸ Use of CO₂ for EOR provides the benefit of a positive revenue stream for the CO₂. As shown in this figure, pipelines already are in operation for the transport of CO₂ to oilfields. While a pipeline system for using EOR for major oil fields important, it should be noted that there are a large amount of small independent owners and operators of oil fields, especially in the Midwest. A distribution system will need to be developed to serve these small oil wells so that they can benefit from EOR.

CO₂-EOR projects require infrastructure to handle the injection, production, separation, and recycling of CO₂ in a closed-loop system. This infrastructure includes equipment within the oil field and outside the field. Infrastructure outside the field is commonly shared among several CO₂-EOR projects, creating economies of scale. The availability of affordable CO₂ from anthropogenic sources, combined with advances in the technologies used in CO₂-EOR, would significantly increase the associated CO₂ storage potential in the U.S. to a range between 274 to 479 billion tons. The economics for CO₂-EOR is reservoir- and site-specific, and the pace of development is constrained by the amount of CO₂ that can be sourced affordably in close proximity to oil fields that are amenable to CO₂-EOR.

CCUS projects have been deployed both in the U.S. and globally. As of end of 2019, there were 19 large-scale CCUS projects operating around the world, with a total capacity of about 32 MMT of CO₂ captured per year. Large-scale projects are defined as those integrated projects that store at least 80,000 tons of CO₂ per year from a coal-based facility, or at least 400,000 tons of CO₂ per year from other sources. Ten of these projects are in the U.S., with a total storage capacity of about 25 MMT per year. The 10 large-scale CCUS projects in the U.S. are shown in Table 6. Note that, of these, Petra Nova is the only plant for coal-fired power generation; however, the facility suspended its carbon capture operations in 2020 due to economic challenges.

218 Advanced Resources International, "A Survey of U.S. CO₂ Enhanced Oil Recovery Projects," April 2021, <https://www.adv-res.com/pdf/2019-US-CO2-EOR-Survey-ARI-4272021.pdf>

Figure A-8 – Current CO₂-EOR Operations and Infrastructure

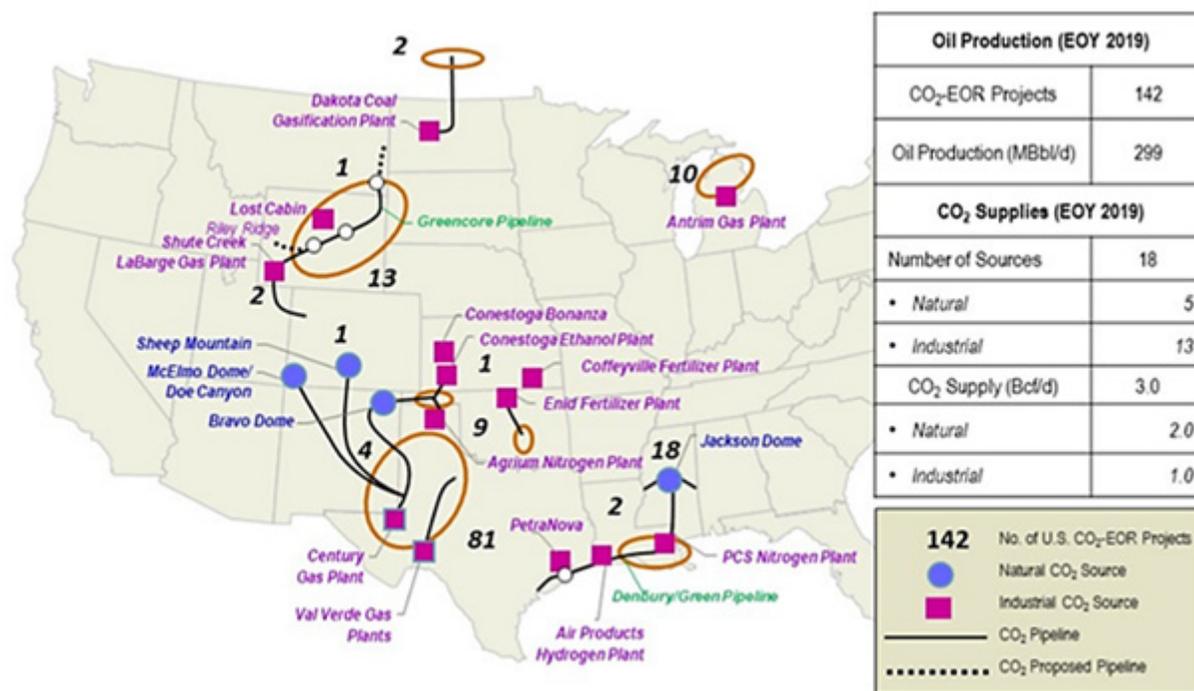


Table A-3 – Ten Large Scale CCUS Projects in the U.S.

Name	Location	Operator	Start Date	Size (MMT/Year)
Terrell Natural Gas Processing	Fort Stockton, Texas	Occidental Petroleum	1972	0.5
Enid Fertilizer	Enid, Oklahoma	Koch Nitrogen Company	1982	0.7
Shute Creek Gas Plant	La Barge, Wyoming	ExxonMobil	1986	7.0
Great Plains Synfuels Plant	Beulah, North Dakota	Dakota Gasification Company	2000	3.0
Century Plant	Pecos County, Texas	Occidental Petroleum	2010	8.4
Air Products SMR	Port Arthur, Texas	Air Products	2013	1.0
Coffeyville Gasification	Coffeyville, Kansas	Coffeyville Resources	2013	1.0
Lost Cabin Gas Plant	Freemont County, Wyoming	ConocoPhillips	2013	0.9
Illinois Industrial CCS	Decatur, Illinois	Archer Daniels Midland	2017	1.1
Petra Nova	Houston, Texas	NRG Energy	2017	1.4

These projects represent approximately 80% of global capacity and span a range of CCUS supply chains from multiple industries, including natural gas processing and production of synthetic natural gas, fertilizer, coal-fired power generation, hydrogen, and ethanol. The U.S. projects have captured and stored approximately 160 MMT of CO₂.²¹⁹

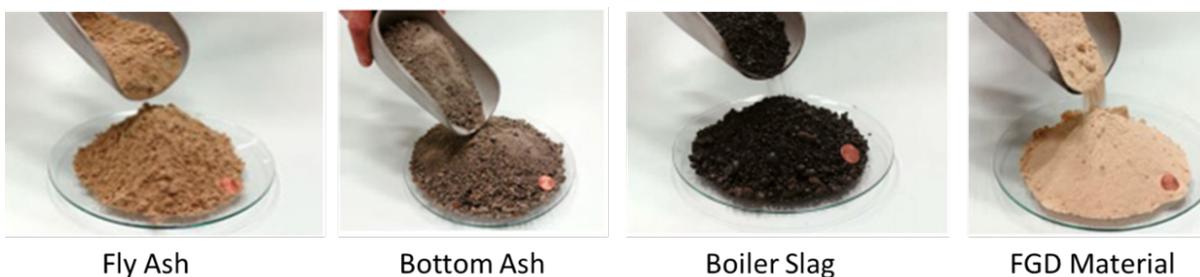
219 National Petroleum Council, "Meeting the Dual Challenge: A Roadmap to At-Scale Deployment of Carbon Capture, Use, and Storage," Updated March 2021, <https://dualchallenge.npc.org/>

Appendix B – Coal Combustion Residuals

Coal combustion residuals (CCR) is a broad term used to refer to the byproducts that are generated either directly by coal combustion or as a result of applying certain pollution control devices to emissions from coal-fired combustion units, with the resulting wastes destined for disposal. Figure B-1 shows these different coal combustion residuals.²²⁰ Coal ash is produced primarily from the burning of coal in coal-fired power plants. Coal ash includes a number of by-products produced from burning coal, including:²²¹

- **Fly Ash:** A very fine, powdery material composed mostly of silica made from the burning of finely ground coal in a boiler.
- **Bottom Ash:** A coarse, angular ash particle that is too large to be carried up into the smoke stacks so it forms in the bottom of the coal furnace.
- **Boiler Slag:** Molten bottom ash from slag tap and cyclone type furnaces that turns into pellets that have a smooth glassy appearance after it is cooled with water.
- **Flue Gas Desulfurization Material:** A material leftover from the process of reducing sulfur dioxide emissions from a coal-fired boiler that can be a wet sludge consisting of calcium sulfite or calcium sulfate or a dry powdered material that is a mixture of sulfites and sulfates.

Figure B-1 – Coal Combustion Residuals



Other types of by-products are fluidized bed combustion ash, cenospheres,²²² and scrubber residues. According to the American Coal Ash Association's (ACAA) *Coal Combustion Product Production & Use Survey Report*, nearly 130 million tons of coal ash was generated in 2014 and has been on the decline since then. In 2019, approximately 78.7 million tons of coal ash was generated. Coal ash is disposed of or used in different ways depending on the type of by-product, the processes at the plant, and the regulations the power plant has to follow. Some power plants may dispose of it in surface impoundments or in landfills. Others may discharge it into a nearby waterway under the plant's water discharge permit. Coal ash may also be recycled into products, such as concrete or wallboard. ACAA reported that 52% or 41 million tons of CCR generated in 2019 was recycled and utilized.²²³ Figure B-2 shows the coal combustion product volumes and beneficial use percentages.

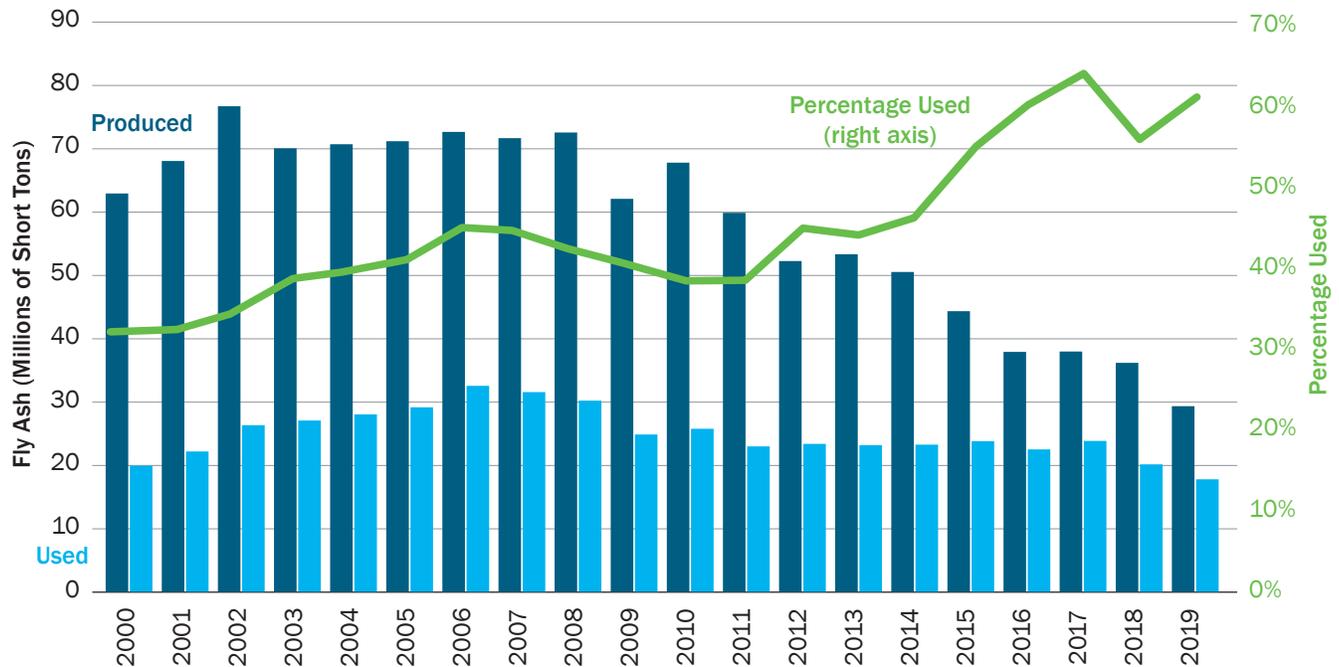
220 National Association of Regulatory Utility Commissioners, "A Comprehensive Survey of Coal Ash Law and Commercialization: Its Environmental Risks, Disposal Regulation, and Beneficial Use Markets," January 2020, <https://pubs.naruc.org/pub/A6923B2D-155D-0A36-31AA-045B741819EC>

221 U.S. Environmental Protection Agency, "Coal Ash Basics," <https://www.epa.gov/coalash/coal-ash-basics>

222 Lightweight, inert, hollow sphere made largely of silica and alumina and filled with air or inert gas, typically produced as a coal combustion byproduct at thermal power plants

223 American Coal Ash Association (ACAA), "Fly Ash Use in Concrete Increases Slightly as Overall Coal Ash Recycling Rate Declines," ACAA Press Release, December 15, 2020, <https://acaa-usa.org/wp-content/uploads/coal-combustion-products-use/Coal-Ash-Production-and-Use.pdf>

Figure B-2 – CCRs Production and Use with Percent Used



Source: ACCA Production and Use Survey²²⁴

According to ACAA, there are many good reasons to view coal ash as a resource, rather than waste. Using it conserves natural resources and saves energy. In many cases, products made with coal ash perform better than products made without it. While the volume of fly ash used in concrete increased slightly in 2019, most other uses saw significant declines, leading to an overall decrease in recycling activity of 31%. Concrete producers and consumers have indicated a desire to use more fly ash, but several regional markets were affected by shifting supply dynamics associated with closures of coal-fueled power plants.

Recycling and reusing coal ash can create environmental, economic, and product benefits, including:

- **Environmental benefits**, such as reduced greenhouse gas emissions, reduced need for disposing in landfills, and reduced use of other materials.
- **Economic benefits**, such as reduced costs associated with coal ash disposal, increased revenue from the sale of coal ash, and savings from using coal ash in place of other, more costly materials.
- **Product benefits**, such as improved strength, durability, and workability of materials.

Coal ash contains contaminants like mercury, cadmium and arsenic. Without proper management, these contaminants can pollute waterways, ground water, drinking water, and the air. To address the risks from improper disposal and discharge of coal ash, EPA has established federal rules for coal ash disposal and is strengthening existing controls on water discharges. EPA’s Disposal of Coal Combustion Residuals from Electric Utilities final rule went into effect in April 2015.²²⁵ The rule established corrective action, closure and post closure, technical standards, and inspection, monitoring, recordkeeping and reporting requirements.²²⁶

²²⁴ American Coal Ash Association (ACAA), “Beneficial Use of Coal Combustion Products: An American Success Story,” ACAA Brochure, <https://aca-ausa.org/wp-content/uploads/coal-combustion-products-use/ACAA-Brochure-Web.pdf>

²²⁵ U.S. Environmental Protection Agency, “Disposal of Coal Combustion Residuals from Electric Utilities Rulemakings,” <https://www.epa.gov/coalash/coal-ash-rule>

²²⁶ U.S. Environmental Protection Agency, “Revisions to the Coal Combustion Residuals (CCR) Closure Regulations,” Office of Land & Emergency Management, July 2020, https://www.epa.gov/sites/default/files/2020-07/documents/factsheet_ccr_part_a_final_rule.pdf



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