MEETING THE DUAL CHALLENGE

A Roadmap to At-Scale Deployment of CARBON CAPTURE, USE, AND STORAGE

VOLUME II • ANALYSIS OF CCUS DEPLOYMENT AT-SCALE

National Petroleum Council • 2019

NATIONAL PETROLEUM COUNCIL
An Oil and Natural Gas Advisory Committee to the Secretary of Energy

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December 12, 2019

The Honorable Dan R. Brouillette

Secretary of Energy
Washington, D.C. 20585

Dear Mr. Secretary,

By letter dated September 21, 2017, Secretary of Energy Rick Perry requested the National Petroleum Council's (NPC) advice on actions needed to deploy commercial carbon capture, use, and storage (CCUS) technologies at scale into the U.S. energy and industrial marketplace. Achieving this objective will pro-mote economic growth, create domestic jobs, protect the environment, and enhance energy security for the United States.

The response to the request required a study that considered technology options and readiness, market dynamics, cross-industry integration and infrastructure, legal and regulatory issues, policy mandates, economics and financing, environmental impact, and public acceptance. The effort involved over 300 participants from diverse backgrounds and organizations, 67% of whom are employed by organizations outside of the oil and natural gas industry.

Over the next two decades, global population and gross domestic product (GDP) are expected to grow significantly. Many outlooks anticipate a 25% to 30% increase in global energy demand by 2040 as well as a need to address rising greenhouse gas (GHG) emissions. The Council found in this "Roadmap to At-Scale Deployment of CCUS" that as global economies and populations continue to grow and prosper, the world faces the dual challenge of providing affordable, reliable energy while addressing the risks of climate change. Widespread CCUS deployment is essential to meeting this dual challenge at the lowest cost.

The United States is uniquely positioned as the world leader in CCUS and has substantial capability to drive widespread deployment. The United States currently deploys approximately 80% of the world's carbon dioxide (CO_2) capture capacity. However, the 25 million tonnes per annum (Mtpa) of CCUS capacity represents less than 1% of the U.S. CO_2 emissions from stationary sources. The study lays out a pathway through three phases of deployment – activation, expansion, and at-scale – that supports the growth of CCUS over the next 25 years, and details recommendations that enable each phase. In the first phase, clarifying existing tax policy and regulations could double existing U.S. capacity within the next 5 to 7 years. Extending and expanding current policies and developing a durable legal and regulatory framework could enable a second phase of CCUS projects (i.e., 75 to 85 Mtpa) within the next 15 years. Achieving CCUS deployment at scale (i.e., additional 350 to 400 Mtpa) within the next 25 years will require substantially increased support driven by national policies.

In addition, substantially increased government and private research, development, and demonstration (RD&D) is needed to improve CCUS performance, reduce costs, and advance alternatives beyond currently deployed technology. Increasing understanding and confidence in CCUS as a safe and reliable technology is essential for public and policy stakeholder support. The oil and natural gas industry is uniquely positioned to lead CCUS deployment due to its relevant expertise, capability, and resources.

The Council's policy, regulatory, and legal recommendations have been grouped into three phases:

Considering the activation phase, the NPC recommends the following:

- The IRS should clarify the Section 45Q requirements for credit transferability, options for demonstrating secure geologic storage, construction start definition, and credit recapture provisions.
- The Department of the Interior (DOI) and individual states should adopt regulations to authorize access to use pore space for geologic storage of CO_2 on federal and state lands.

Considering the expansion phase, the NPC recommends the following:

- Congress should amend Section 45Q to extend the construction start date, extend the duration of credits, lower the CO_2 volume threshold, and increase the value of the credit for storage and use applications.
- Congress should expand access to Section 48 tax credits and other existing financial incentives to all CCUS projects, effectively expanding current policies to a level of ~$90 per tonne to provide incentive for further economic investment.
- Congress should amend existing statutes to allow CO_2 storage in federal waters from all anthropogenic sources, and the Department of Energy (DOE) and DOI should establish processes to enable access to pore space and regulate CO_2 storage in federal waters.
- Concurrently with the activation phase, DOE should create a CO_2 pipeline working group to study the best way to harmonize the federal, state, and local permitting processes, establish tariffs, grant access,

administer eminent domain authority, and facilitate corridor planning. DOE should also convene an industry and stakeholder forum to develop a risk-based standard to address long-term liability.

Considering the at-scale phase, the NPC recommends the following:

- To achieve at-scale deployment of CCUS, concurrently with the expansion phase, congressional action should be taken to bring cumulative value of economic policies to about $110 per tonne.
- The oil and natural gas industry should continue to fund research and development at or above current levels in support of new and emerging CCUS technologies.

Concurrently with all three phases, and to achieve at-scale deployment of CCUS, Congress should increase the level of RD&D funding for CCUS technologies to $15 billion over the next 10 years, with a significant amount directed to less mature and emerging technologies that offer the greatest potential for a step change in performance and cost reduction.

Integral to success is adherence to the Council's following recommendations for engaging stakeholders:

- Government, industry, and associated coalitions should design policy and public engagement opportunities to facilitate open discussion, simplify terminology, and build confidence that CCUS is a safe and secure means of managing emissions.
- The oil and natural gas industry should remain committed to improving its environmental performance

and the continued development of environmental safeguards.

- Commensurate with the level of policy enactment being recommended, the oil and natural gas industry should continue its investment in CCUS.

The attached report provides additional details and recommendations. The Council looks forward to sharing this study with you, your colleagues, and broader government and public audiences.

Respectfully submitted,

Greg L. Armstrong

Chair

Attachment

MEETING THE
DUAL CHALLENGE

A Roadmap to At-Scale Deployment of
CARBON CAPTURE, USE, AND STORAGE

VOLUME II • ANALYSIS OF CCUS DEPLOYMENT AT-SCALE

A Report of the National Petroleum Council
December 2019

Committee on Carbon Capture, Use, and Storage
John C. Mingé, Chair

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The Report Summary, Chapters, Appendices, and other study materials may be downloaded at no charge from the NPC report website, dualchallenge.npc.org.

Print-on-demand versions of the Report Volumes may be purchased from Amazon.

Chapter One

THE ROLE OF CCUS IN THE FUTURE ENERGY MIX

I. CHAPTER SUMMARY

As global economies and populations continue to grow and prosper, the world faces the dual challenge to deliver affordable, reliable energy while addressing the risks of climate change. Energy fuels the engine of economic growth. For people in developed economies, reliable energy access—used for heat, cooling, light, and mobility—is the expectation. Reliable access is key to high standards of living. Yet for many people in emerging economies, the lack of reliable access to energy limits progress. At the same time, societal concern for the environment, and avoiding the risks of climate change, has led to demand for energy sources with lower emissions.

Lowering emissions will require many measures, such as energy efficiency and increased use of renewable sources of energy (renewables), and a shift to less carbon-intensive fuels. In addition, carbon capture, use, and storage (CCUS)[1] is a critical component of the portfolio of solutions needed to satisfy the dual challenge. Most long-term scenarios show that widespread deployment of CCUS is essential to meet energy delivery goals while reducing greenhouse gas (GHG) emissions[2]—of which carbon dioxide (CO_2) is the most significant—at the lowest cost.

CCUS combines processes and technologies to reduce or remove CO_2 from the atmosphere. It can play a crucial role in helping to reduce emissions from power and industry. Likewise, CCUS supports the deployment of renewables by reducing the emissions of fuels that can mitigate fluctuations in power generation from intermittent wind and solar. CCUS technologies are currently being applied in many industries, including power, steel, hydrogen, fertilizer, ethanol, chemical, and cement.

Many governments around the globe are enacting policies focused on emissions reduction. Stakeholders, including shareholders and nongovernmental organizations (NGOs), have taken decisive action to signal their commitment to greater sustainability with CO_2 reduction as a clear goal. And, as consumer awareness grows, people have become more environmentally conscious. Collectively, these movements create new market opportunities. The United States is well positioned to lead entry into these markets due to its experience with CCUS projects, established regulatory framework, world-leading policy support, cutting-edge research capability, and an innovative business climate.

II. THE WORLD NEEDS MORE ENERGY TO SUPPORT AN INCREASE IN

POPULATION AND A GROWING GLOBAL ECONOMY

Over the next two decades, global population is expected to increase by about 1.5 billion people, reaching approximately 9.2 billion by 2040.[3] This increase is more than four times the population of the United States in 2019. At the same time, the world economy is expected to surge as gross domestic product (GDP) more than doubles. Such an expansion of global prosperity will lift billions in the developing world from low to middle incomes. This surge in global living standards is expected to increase energy consumption.

In its Energy Poverty Action Initiative, the World Economic Forum recognized that, “Access to energy is fundamental to improving quality of life and is a key imperative for economic development.” Figure 1-1 illustrates this relationship, comparing the United Nations Human Development Index—an assessment of life expectancy, education levels, and gross national income per capita—to energy use per capita. The data suggests that as energy use per capita rises, quality of life increases significantly, and the relationship flattens out at about 100 gigajoules (GJ) per capita per year.[4]

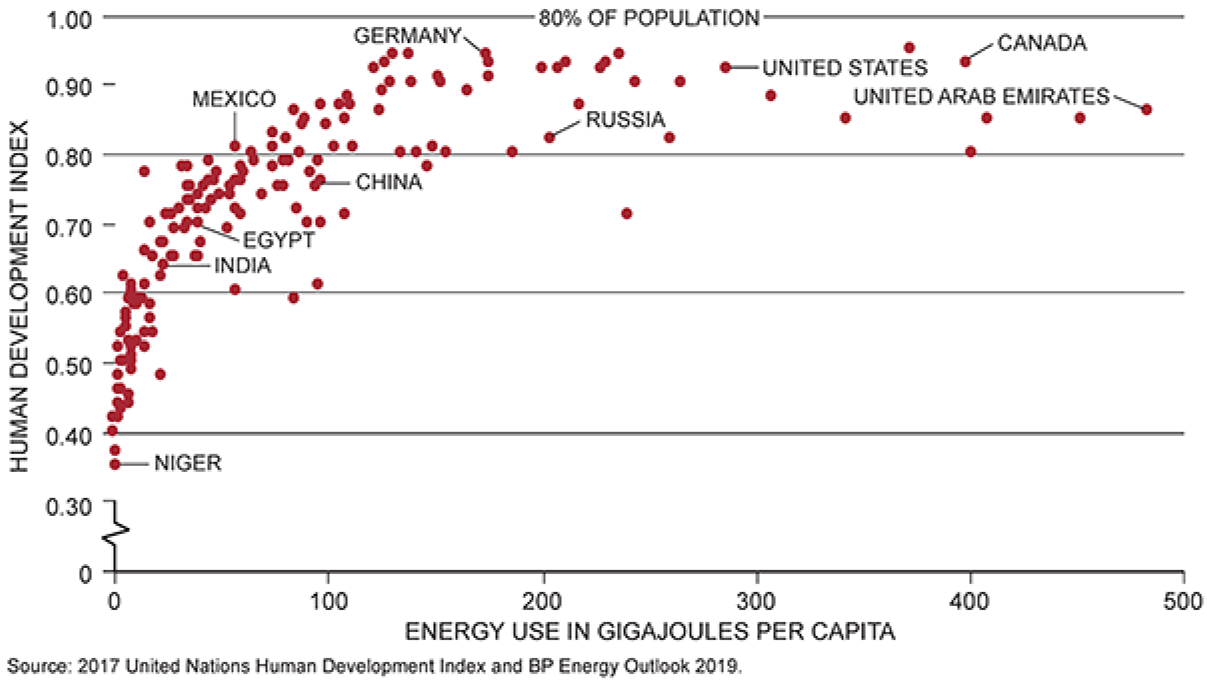
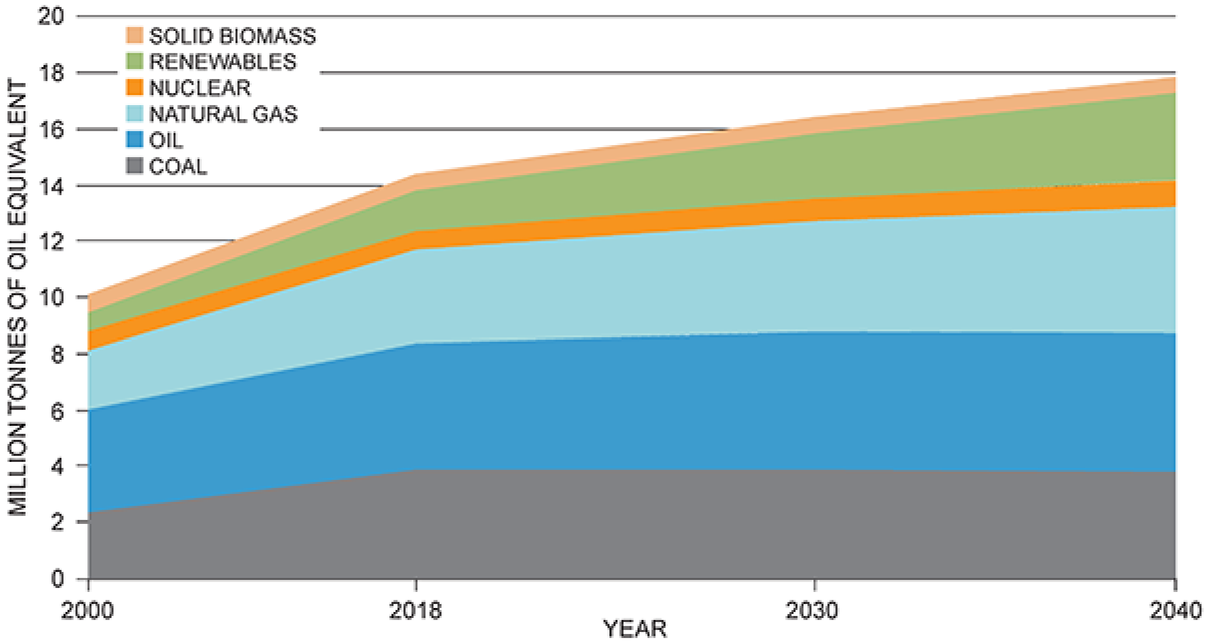


Figure 1-1. *2017 Human Development Index and Energy Consumption per Capita*

Eighty percent of the world's population lives in countries where per capita energy consumption is less than 100 GJ per year, and the global average in 2017 was only 82 GJ. In comparison, the average annual energy consumption for members of the Organization for Economic Co-operation (OECD) is about 169 GJ.[5] This pronounced difference in consumption—more than double the global average—highlights the gap between most OECD countries and developing economies.

To help define the nature of the energy system, many institutions have projected pathways for the evolution of energy demand and supply. These assessments rely on a range of assumptions, which can vary widely between scenarios and organizations. Many outlooks expect global demand for energy to grow by 25% to 30% by 2040.[6]

This is true for the International Energy Agency's (IEA) Stated Policies Scenario (STEPS[7,8]), which aims "to provide a detailed sense of the direction in which existing policy frameworks and today's policy ambitions would take the energy sector out to 2040."[9,10] Figure 1-2 shows that the STEPS estimates global energy demand will rise more than 25% by 2040. Most of this growth will come from India and China, as well as other emerging economies, as prosperity and populations rise. Conversely, as energy efficiency improves, demand in many developed economies, like the United States, is expected to remain flat or decline. (See also text box titled "Three Views on U.S. Energy Consumption.")



Source: Based on data from International Energy Agency, World Energy Outlook 2019.

Figure 1-2. *IEA Stated Policies Scenario Shows More Than a 25% Increase in Global Primary Energy Demand by 2040*

THREE VIEWS ON U.S. ENERGY CONSUMPTION

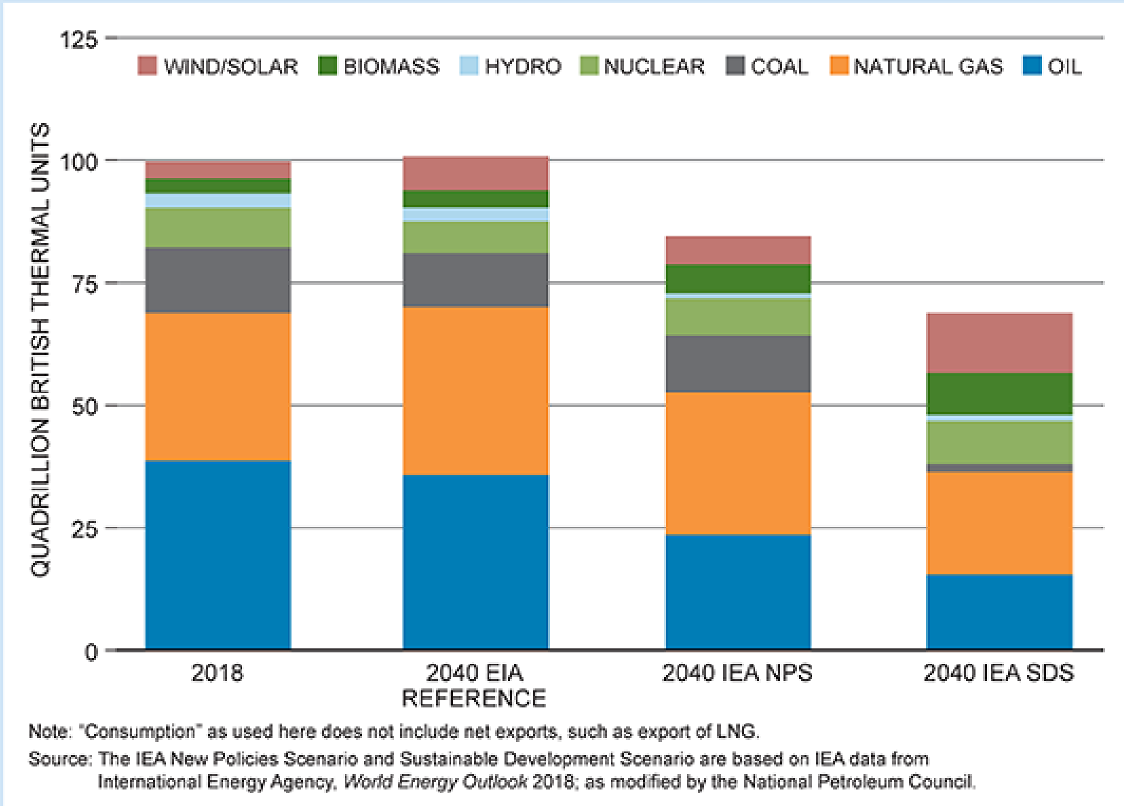
In contrast to global demand, U.S. energy demand is expected to remain flat or decline in the next two decades. The figure below shows three projections for U.S. energy demand in 2040.

The U.S. Energy Information Administration's reference case—which does not include new greenhouse gas reduction policies—projects that energy demand in 2040 will be flat with the level in 2018.*

The International Energy Agency's Stated Policies Scenario (STEPS), previously known as the New Policies Scenario (NPS), which includes energy policies that stem from governments' announced intentions, shows U.S. primary energy demand decreasing about 16% by 2040.

Finally, the IEA Sustainable Development Scenario (SDS), which makes assumptions to hold the average global temperature increase to well below 2°C, shows U.S. primary energy demand in 2040 shrinking by about 31% compared with 2018 levels.

To meet these scenario demands at the lowest cost, the STEPS and SDS include policies and emissions constraints that lead to deployment of efficiency measures and zeroemissions technologies, including wind, solar, nuclear, and CCUS.



U.S. Energy Consumption by Type

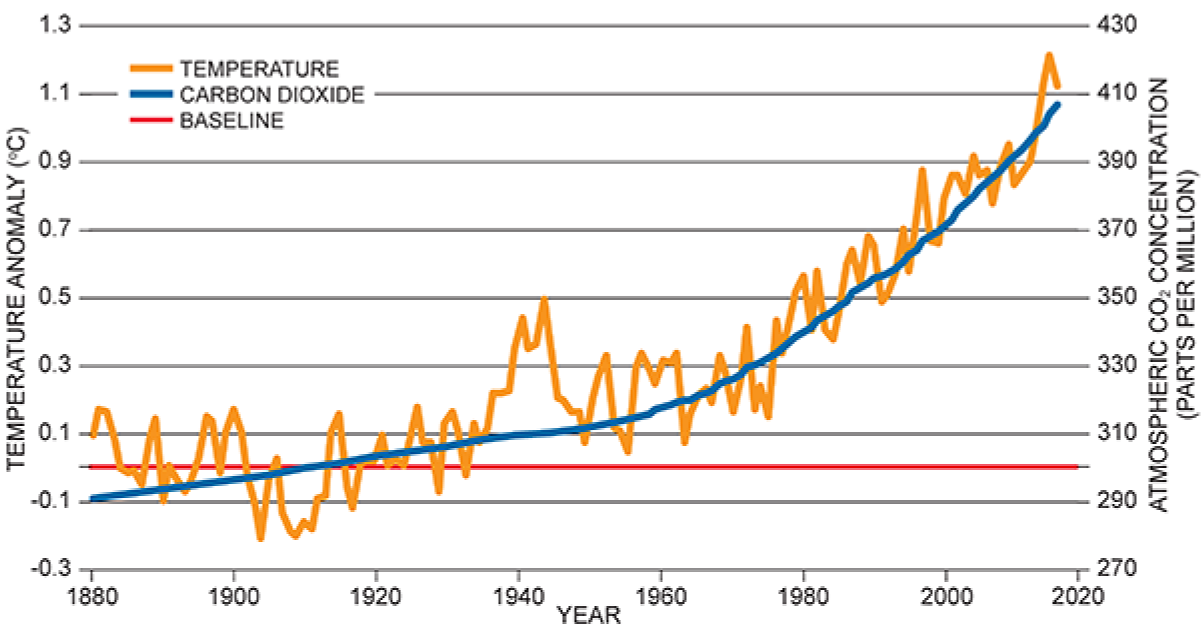
* EIA, *Annual Energy Outlook 2019 with Projections to 2050.* Washington, D.C.: U.S. Energy Information Administration, 2019. www.eia.gov/aeo, accessed December 2, 2019.

III. THE WORLD WILL NEED TO ADDRESS THE RISKS OF CLIMATE CHANGE

In addition to providing more affordable, reliable energy to support growing economies and populations, the world will need to address rising GHG emissions and the risks of climate change. In 2019, atmospheric concentrations of CO_2

climbed to over 400 parts per million (ppm) from a pre-Industrial Revolution level of 280 ppm.[11]

According to the Intergovernmental Panel on Climate Change (IPCC), “It is extremely likely that more than half of the observed increase in global average surface temperature from 1951 to 2010 was caused by an anthropogenic[12] increase in greenhouse gas concentrations,”[13] and “continued emission of greenhouse gases will cause further warming and long-lasting changes in all components of the climate system.”[14] Figure 1-3 shows the relationship between CO_2 concentration and global temperature. (See also text box titled “CO_2 and the Greenhouse Effect.”)



Note: Global temperature anomalies averaged and adjusted to early industrial baseline (1881-1910).
Source: Climate Central, “Rising Global Temperatures and CO_2,” November 20, 2018.

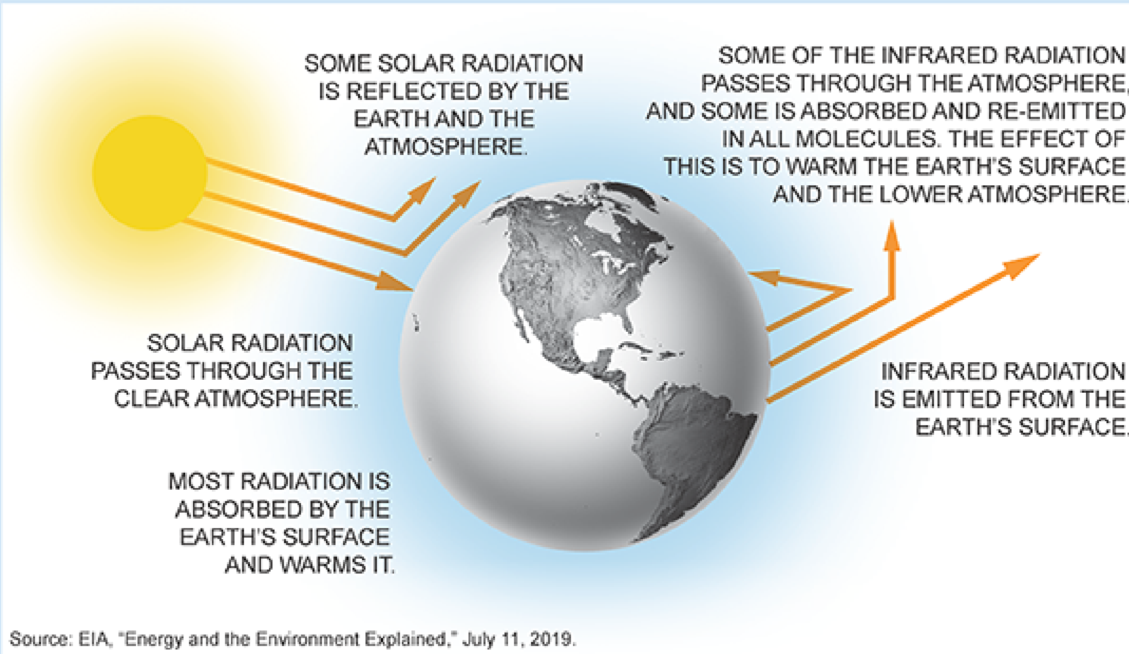
Figure 1-3. *The Relationship between CO_2 Concentration and Global Temperature*

CO_2 AND THE GREENHOUSE EFFECT

CO_2 is a colorless, odorless, incombustible gas that is primarily produced through human activities—the combustion of hydrocarbon products (coal, oil, natural gas) and from certain industrial processes (productionof cement, steel, chemicals). It also occurs through natural processes, like the respiration of animals and humans, and is absorbed by plants through photosynthesis. CO_2 is the largest contributor to climate change from human activities, and once generated, remains in the environment until it is proactively removed.

The greenhouse effect is an atmospheric process that warms the Earth's surface. As solar energy enters the atmosphere, it is either reflected back to space (often by clouds or ice) or absorbed by the Earth's surface. The Earth also emits energy as infrared radiation that travels directly to space or is absorbed by atmospheric gases and remains as heat. Greenhouse gases (GHGs) include CO_2, methane, nitrous oxide (N_2O), ozone, and chlorofluorocarbons; they permit sunlight to enter the atmosphere but trap heat before it escapes (see figure below). Without the greenhouse effect, Earth's temperature would fall to −18°C.

Over time, economic development has increased the amount of GHGs in the atmosphere and intensified the natural greenhouse effect, resulting in an increased global average temperature. Reducing CO_2 emissions and removing CO_2 from the atmosphere are two methods that can help lower the increase in global temperature. CCUS technologies can support both pathways.



The Greenhouse Effect

IV. WHAT IS CCUS?

CCUS combines several technologies to reduce the level of CO_2 emitted to the atmosphere. The CCUS process, as shown in Figure 1-4, involves the capture (separation and purification) of CO_2 from stationary sources so that it can be transported to a suitable location where it is converted into useable products or injected deep underground for safe, secure, and permanent storage.

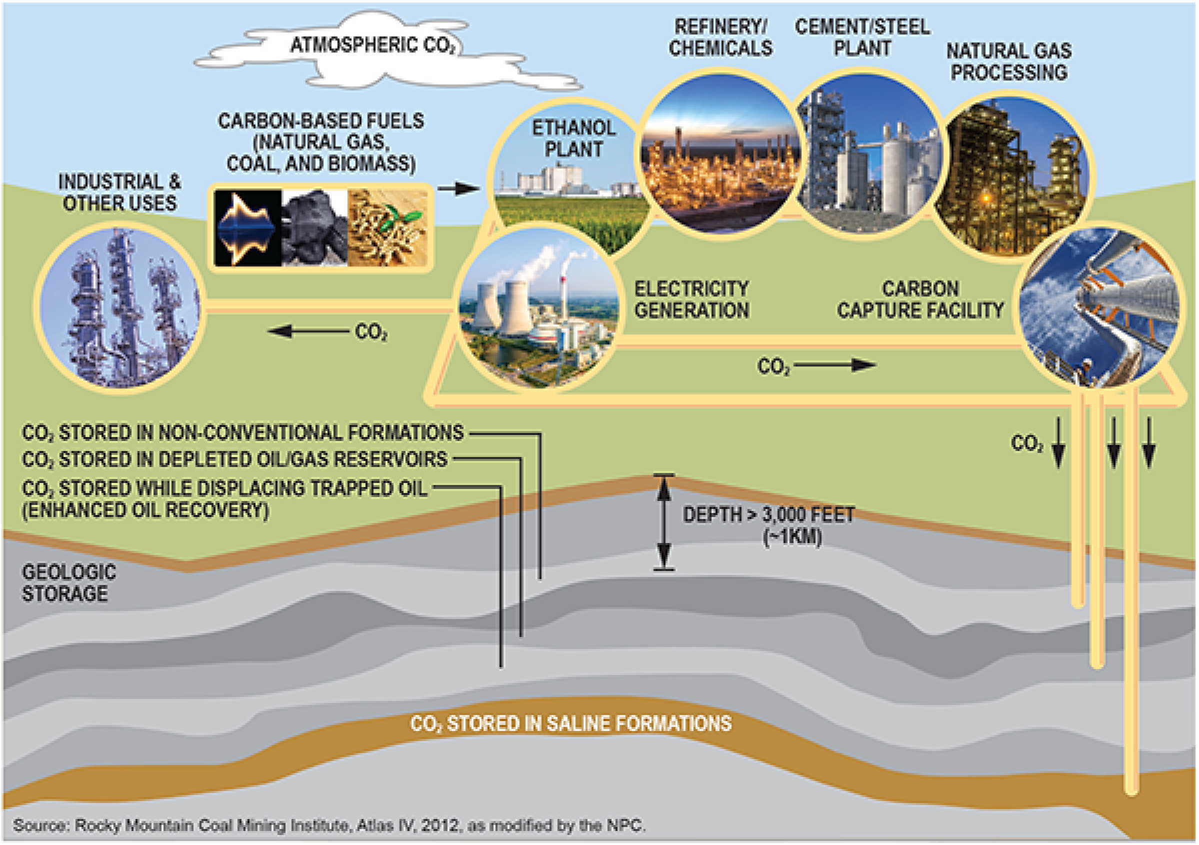


Figure 1-4. *Supply Chain for Carbon Capture, Use, and Storage*

Although CCUS supply chains can have many forms, the building blocks are generally described as follows:

Capture. CO_2 is produced in combination with other gases during industrial processes, including hydrocarbon-based power generation. CO_2 capture involves the separation of the CO_2 from these other gases. This separation can be accomplished using many different technologies, the most common of which is amine absorption. Once the CO_2 is separated, it is typically compressed or refrigerated so that it behaves like a liquid, making it ready for transport and storage.

Transport. In most cases, captured CO_2 will need to be transported from the capture location to a different location where it can be used or stored. This transport is typically accomplished using pipelines operating at a pressure that enables the CO_2 to remain compressed into a dense liquid phase. This compressed CO_2 can also be transported by rail, truck, ship, and barge.

Use. Although the majority of captured CO_2 is stored, it can also be used to create other products, such as building materials and carbon fiber tubes. Despite the relatively small amount of captured CO_2 that is used for other purposes, market and technology development might provide several economically viable opportunities to increase its use.

Storage. Safe, secure, and permanent storage of compressed CO_2 occurs by injecting it into carefully selected subsurface geologic formations. These are usually saline formations, depleted oil and gas reservoirs, and un-mineable coal seams. CO_2 is also used to produce oil via a process called enhanced oil recovery (EOR). Operational experience indicates that approximately 99% of the CO_2 used in EOR is ultimately trapped in hydrocarbon-producing geologic formations.

V. THE ROLE OF CCUS

CCUS is an essential element in the portfolio of solutions needed to change the emissions trajectory of the global energy system. In its *Fifth Assessment Report,* the IPCC concluded that the costs for achieving atmospheric CO_2 levels consistent with holding average global temperatures to 2°C above preindustrial levels—referred to as a “2°C world”—will be more than twice as expensive without CCUS.[15]

In support of that report, the Energy Modeling Forum 27 at Stanford University evaluated various scenarios with specific stabilization targets consistent with a 2°C world that would, for example, limit atmospheric CO_2 to 450 ppm.[16] As part of that work, Figure 1-5 presents potential outlooks for global energy-related CO_2 emissions under different stabilization scenarios (assessed 2°C scenarios) relative to baseline scenarios that represent pathways with limited change in policy.

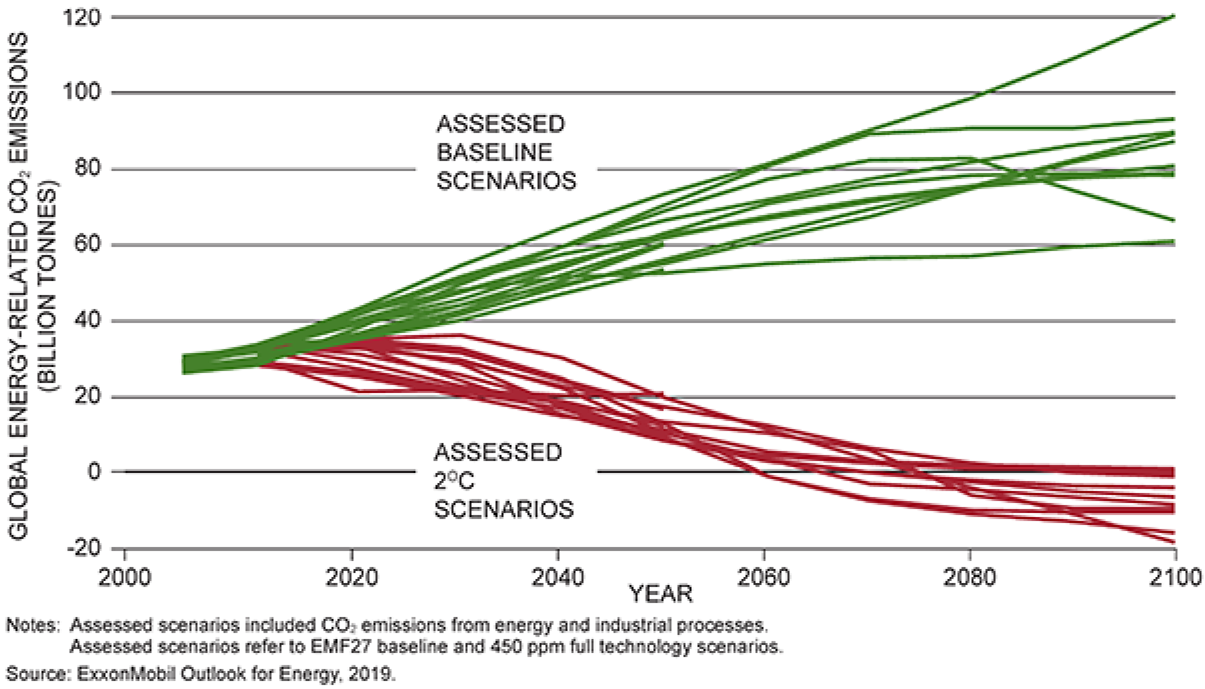


Figure 1-5. *Comparison of Assessed Baseline and Assessed 2°C Scenarios to Achieve Global Net-Zero Emissions by 2100*

The set of baseline scenarios shows CO_2 emissions growing steadily until 2100. The assessed 2°C scenarios show that global CO_2 emissions must decline to zero and, in most cases, become negative in the second half of the century. To achieve these reductions, the assessed 2°C scenarios require processes that remove CO_2 from the atmosphere. These CO_2 removal technologies enable "negative emissions."

Bioenergy with CCUS (BECCS) and direct air capture (DAC) are two negative emissions processes that could be applied to achieve a 2°C world. The BECCS process converts biomass, which extracts CO_2 from the atmosphere as it grows, to energy and the resulting CO_2 is captured and geologically stored. The DAC process captures CO_2 from the air to create purified CO_2 for use or storage.

The IEA forecasts the role of CCUS in its Sustainable Development Scenario (SDS). Figure 1-6 depicts the difference in global emissions projections between the IEA STEPS and SDS. In the SDS, CCUS contributes 9% of cumulative emissions reductions globally by 2050, making it a vital part of the mix of solutions needed to reach SDS targets.[17]

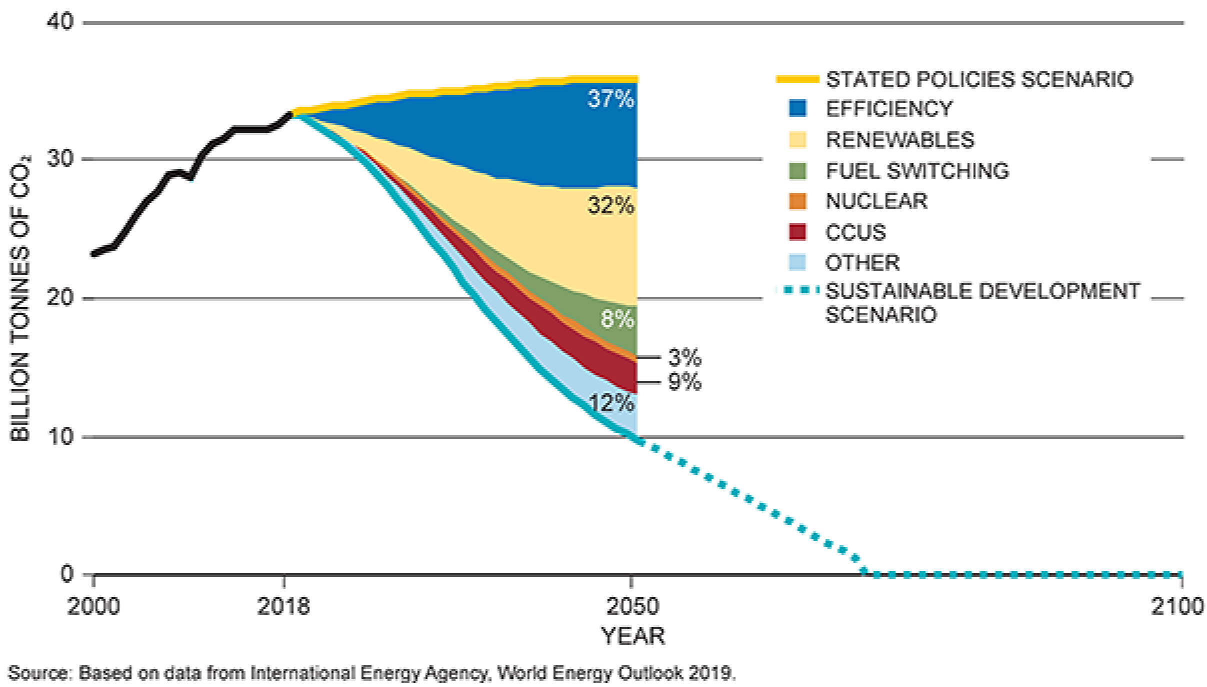


Figure 1-6. *Global Emissions Projections for the IEA's Stated Policies Scenario and Sustainable Development Scenario*

As the IEA explained in 2017, “Our analysis consistently shows that CCUS is a critical part of a complete clean energy technology portfolio that provides a sustainable path for mitigating greenhouse gas emissions while ensuring energy security.”[18] The rationale supporting CCUS as a part of a global clean energy technology portfolio is related, in part, to historical energy demand and expected energy demand growth in Asia. In September 2019, German environmental organization Urgewald estimated that China and India would account for more than half of new planned coal-fired power plants around the world.[19,20] Without retrofitting CCUS to these long-lived energy assets (up to 40 to 50 years[21]), achieving the SDS goals may require premature retirement of these facilities.

VI. NEW MARKETS ARE EMERGING AS THE WORLD TRANSITIONS TO A LOWER-CARBON ENERGY SYSTEM

The Industrial Revolution in the late 18th and early 19th centuries sparked technological breakthroughs and created new industries. As manufacturing expanded and innovation improved, labor-intensive processes, energy demand, and GDP per capita soared. The advancements in energy delivery and utility—unlocked by fossil fuel combustion—transformed the global energy system.

More than 200 years later, fossil fuels are deeply woven into the current energy and consumer product supply chains, accounting for about 80% of both the United States and global fuel mix. Beyond heat, light, and mobility, fossil fuels are the building blocks for a vast array of petrochemical products such as plastics, lubricants, and fabrics. They also enable the production of key building materials like cement and steel.

Figure 1-7 illustrates global primary energy demand by share. In the chart, the label “other renewables” includes solar, wind, and geothermal. Hydropower and traditional biofuels are listed in separate categories. Throughout history, it has taken decades for new energy sources to achieve a substantial market share. However, to meet the dual challenge, the world will need a greatly accelerated transition to a lower-carbon energy system.

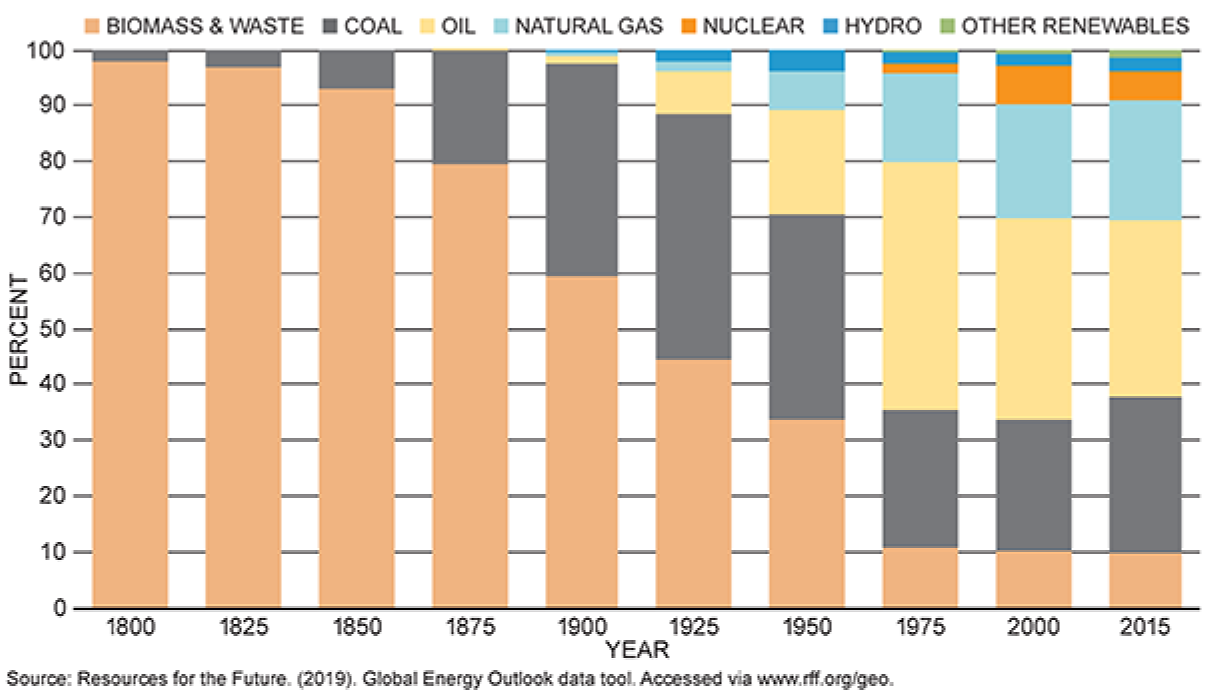
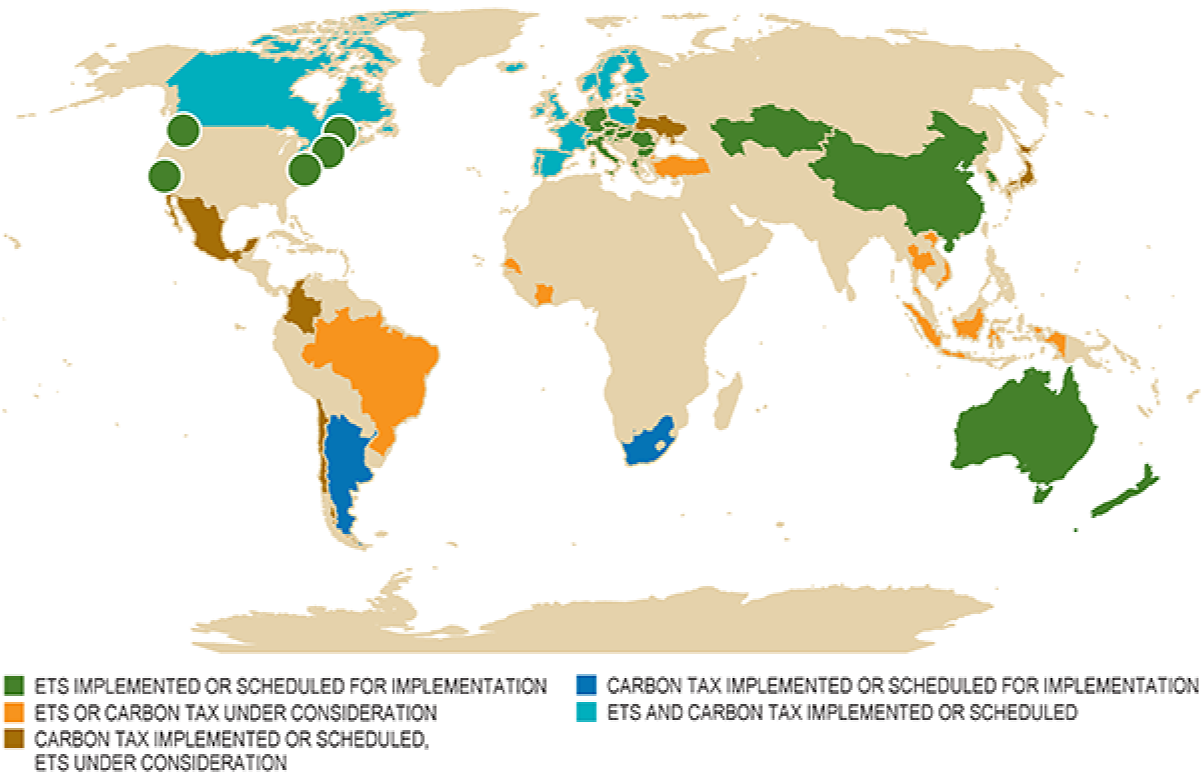


Figure 1-7. *Global Primary Energy Demand by Share*

Until the mid-20th century, availability and cost were the primary drivers for consumers’ energy choices. Over time, the environmental impacts of energy production and consumption have become a concern. In the 1980s, air and water pollution became a concern in the United States when smog and acid rain caused adverse impacts. Government and industry collaborations, combined with government regulations, yielded successful reductions in those pollutants.

Over the past few decades, the public has placed greater emphasis on the environment and climate change. In response, many governments have enacted policies to reduce emissions, leading to widespread deployment of lower CO_2-intensive technologies. In the United States, durable policy frameworks helped create markets for energy sources with lower emissions. In 2018, wind, biofuels, and solar accounted for 5.5% of U.S. primary energy consumption.[22]

Some governments have embraced carbon pricing to reduce emissions. As of September 2019, there were 57 carbon pricing initiatives—comprising both emissions trading systems (ETS) and carbon taxes—implemented or scheduled for implementation worldwide (Figure 1-8) that address 11 gigatonnes of CO_2 equivalent, or about 20% of global GHG emissions per year. Furthermore, in the Nationally Determined Contributions (NDCs) under the Paris Agreement, 100 countries consider carbon pricing to meet their emissions reduction ambitions.[23] Beyond carbon pricing, 13 entities—including China, Japan, and the European Union—have incorporated CCUS in their NDCs/low-carbon road maps.[24] Some governments are looking to standards, mandates, and financial incentives to decarbonize.



Note: The circles on the map represent cooperation initiatives on carbon pricing between subnational jurisdictions.

Source: The World Bank, Carbon Pricing Dashboard, August 1, 2019.

Figure 1-8. *Countries That Have Implemented or Scheduled Implementation of Carbon Pricing*

Some governments recognize the potential for CCUS to decarbonize heavy industry.[25] Countries in the European Union have identified industrial clusters suitable for CCUS deployment, including the Port of Rotterdam's CO_2 Transport Hub and Offshore Storage (PORTHOS) project in the Netherlands, Northern Lights in Norway, and five low-carbon clusters in the United Kingdom—Humber, Merseyside, North East Scotland, South Wales, and Teesside.

Lower carbon markets continue to emerge in the United States. Figure 1-9 illustrates the policies and incentives promoting energy efficiency and renewable energy by state. This activity demonstrates the country's broad interest in addressing the risks of climate change through mechanisms, including renewable energy, low-carbon fuel standards, and energy efficiency. One of the most recent and impactful policies implemented at the federal level is the 45Q tax credit. In total, there are more than 3,500 policies and incentives at the local, state, and federal levels. Chapter 3, "Policy, Regulatory, and Legal Enablers," outlines the details of various policy mechanisms.

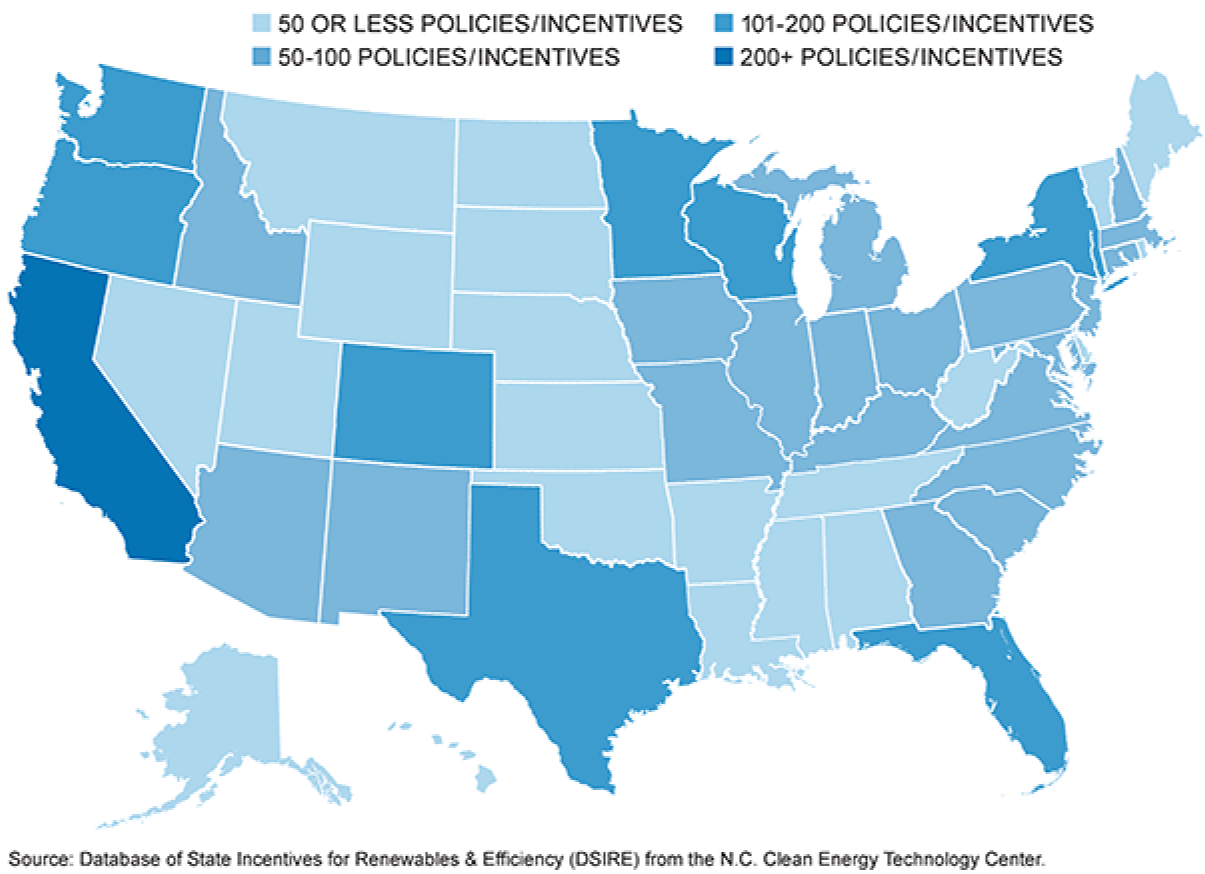


Figure 1-9. *Clean Energy Policies and Incentives by State in November 2019*

Sustained societal expectations and government action to lower GHG emissions will continue to create opportunities for technology development and new markets, particularly for CCUS. International collaboration will be key as global interest and markets grow. For example, the United States, United Kingdom, Norway, and Saudi Arabia established a CCUS initiative under the Clean Energy Ministerial process to include CCUS technologies in clean energy discussions on a regular basis. The initiative now has 11 member countries[26] and works to bring governments, industry, and the financial community together to accelerate CCUS project deployment.

The United States is uniquely positioned to compete in this global market by exporting the world-leading technologies and expertise it has already gained through the 10 large-scale CCUS projects within its borders, which is more than any other country in the world. The United States would increase its competitiveness in the global market by continued development of its domestic capabilities and resources through at-scale deployment of CCUS. A description of U.S. leadership in CCUS is described in Chapter 2, “CCUS Supply Chains and Economics.”

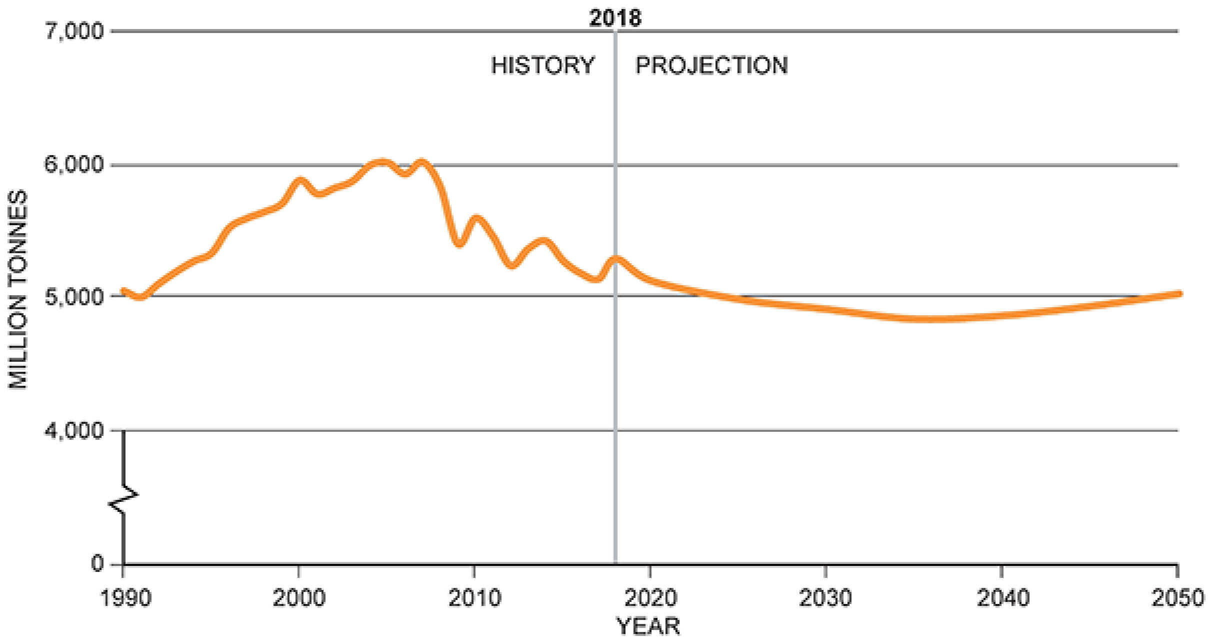
In 2014, EOR projects in the United States used CO_2 to produce approximately 300,000 barrels of oil per day—more than 2% of U.S. oil production.[27] By expanding the use of CO_2 for EOR through further development of domestic resources, the United States can sustain and protect its energy security. Increased production also creates economic benefits for businesses, local communities, and states, and it helps maintain and expand the jobs and capabilities associated with oil and natural gas production. Additionally, EOR has a relatively small environmental footprint because existing infrastructure and brownfields are often used to produce incremental oil. A 2015 study by the IEA estimated that oil produced through EOR is 63% less carbon intensive than oil produced through traditional methods.[28]

There may also be an opportunity for the United States to market its CO_2 storage resources to countries that do not have favorable geology for such storage. Because the volume of subsurface CO_2 storage potential in the United States greatly exceeds the capacity likely to be used by U.S. sources, there could be value in importing and storing CO_2 from countries with insufficient storage resources. For example, CO_2 import and storage along the Gulf Coast could become a parallel market to natural gas exports for liquefied natural gas. This concept is like the Northern Lights project being developed in Norway with a goal to create a CO_2 transport and storage system to receive CO_2 originating from a range of industrial sources.

Other potential opportunities may exist in the development and export of low-carbon and decarbonized products, as well as the use of CO_2 as a feedstock. This market is expected to grow based on what is anticipated to be an increase in consumer demand for low-carbon products. Although many of these new products are still in early stages of development, there is an opportunity for the United States to be a leader in commercializing new uses of CO_2.

VII. CCUS CAN CREATE ENVIRONMENTAL BENEFITS FOR THE UNITED STATES THROUGH CO_2 EMISSIONS REDUCTION

On average, U.S. energy-related CO_2 emissions have declined over the last decade.[29] Switching from coal to natural gas in power generation, increased renewable electricity production, and vehicle efficiency gains have all played a role in emissions reduction. The U.S. EIA projects that U.S. energy-related CO_2 emissions will remain essentially unchanged for the next 30 years under current policies (Figure 1-10). The CCUS process and its technologies provide a solution for reducing stationary, or point-source, emissions—those that originate from single, fixed sources like factories, power plants, and refineries. At-scale deployment of CCUS in the United States can enable a dramatic reduction in emissions.



Source: EIA *Annual Energy Outlook 2019*.

Figure 1-10. *U.S. Energy-Related CO_2 Emissions in AEO2019 Reference Case, 1990 to 2050*

The left side of Figure 1-11 explores U.S. CO_2 emissions by sector. Transportation—travel by air, car, rail, heavy trucking, and shipping—is the largest contributor of U.S. CO_2 emissions.[30] However, these emissions sources are mobile and cannot be significantly decarbonized by current CCUS technologies. This sector is more likely to employ other emissions reduction technologies, such as electrification, efficiency gains, increased use of biofuels, and, potentially, the development of hydrogen as a fuel.[31]

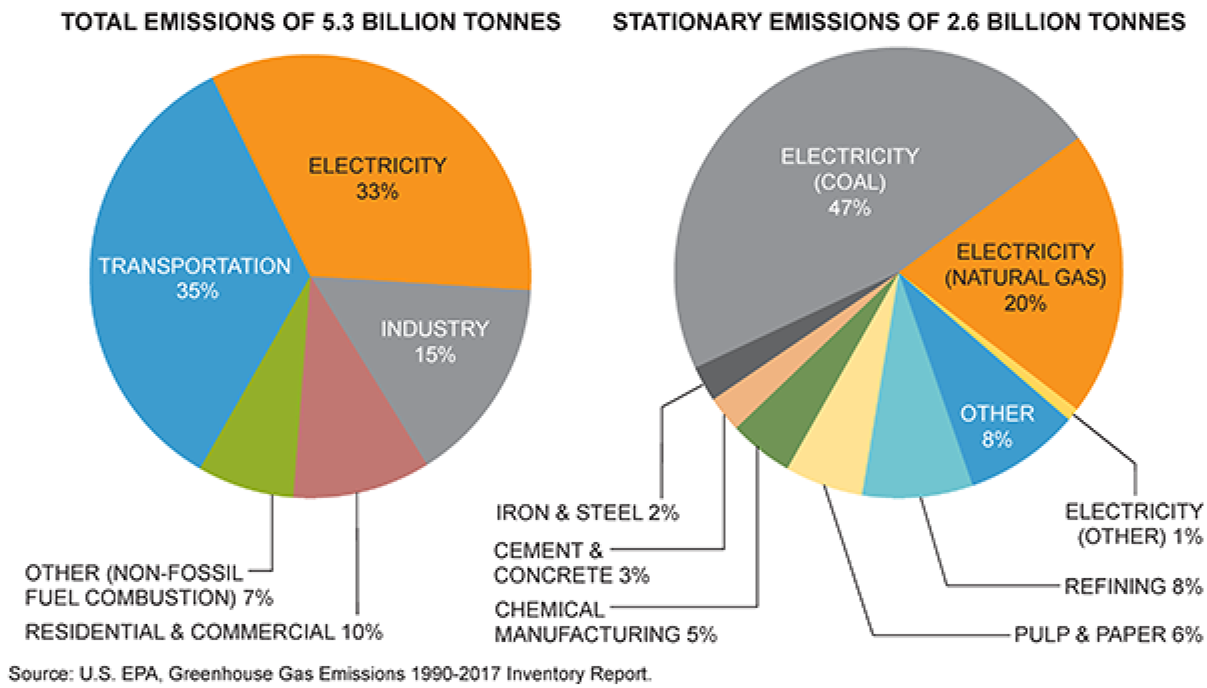


Figure 1-11. *2017 U.S. Energy-Related CO_2 Emissions by Sector (left) and Stationary CO_2 Emissions by Industry Type (right)*

Stationary emission sources from industrial and power generation facilities represent nearly 50% of total U.S. CO_2 emissions. The United States has more than 6,500 large stationary sources emitting approximately 2.6 billion tonnes of CO_2 per year across a range of industries. The right side of Figure 1-11 breaks down U.S. stationary emissions by industry type. Point-source emissions from electricity generation account for more than two-thirds of stationary source CO_2 emissions. Process emissions associated with various industries contribute most of the balance, led by refining and followed by pulp and paper, chemical manufacturing, cement and concrete, and iron and steel manufacturing. These stationary sources are prime candidates for CCUS deployment.

VIII. MANY REGIONS CAN BENEFIT FROM CCUS

The stationary sources are distributed across the country with several clusters of power generation and industrial activity in key geographies: Appalachia (along the Ohio River), the Gulf Coast, Southern and Northern California, and the New Jersey seaboard (Figure 1-12). Many of these CO_2 sources are above, or adjacent to, viable CO_2 storage targets—labeled as saline formations on the map—making them prime candidates for CCUS retrofit.

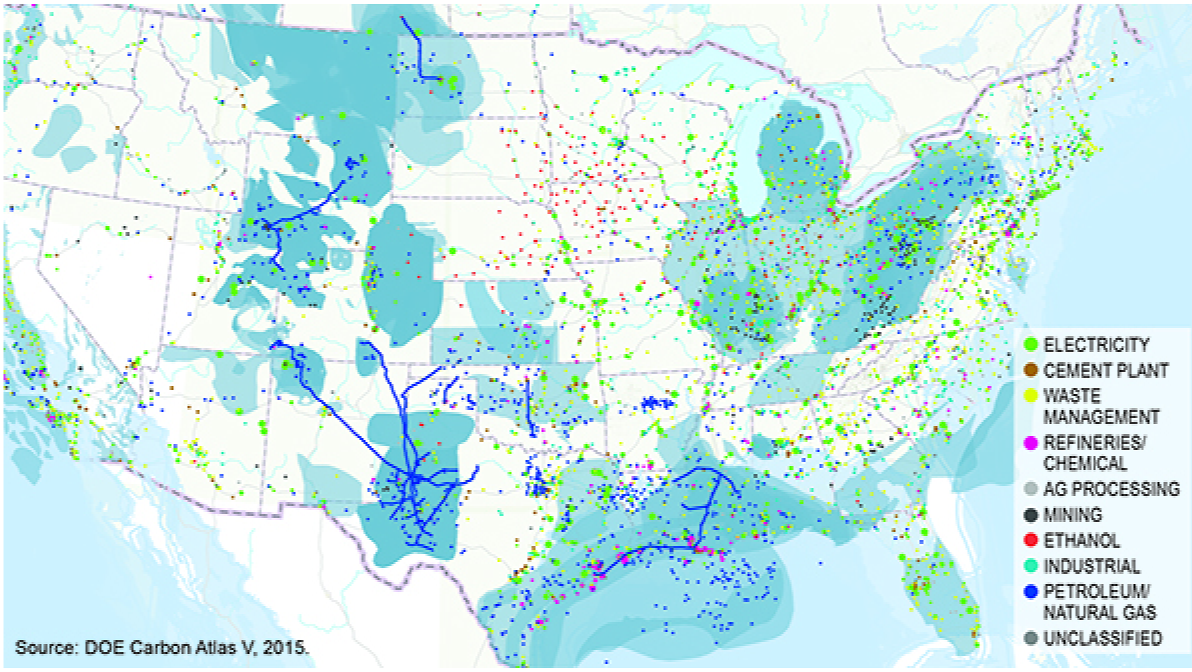
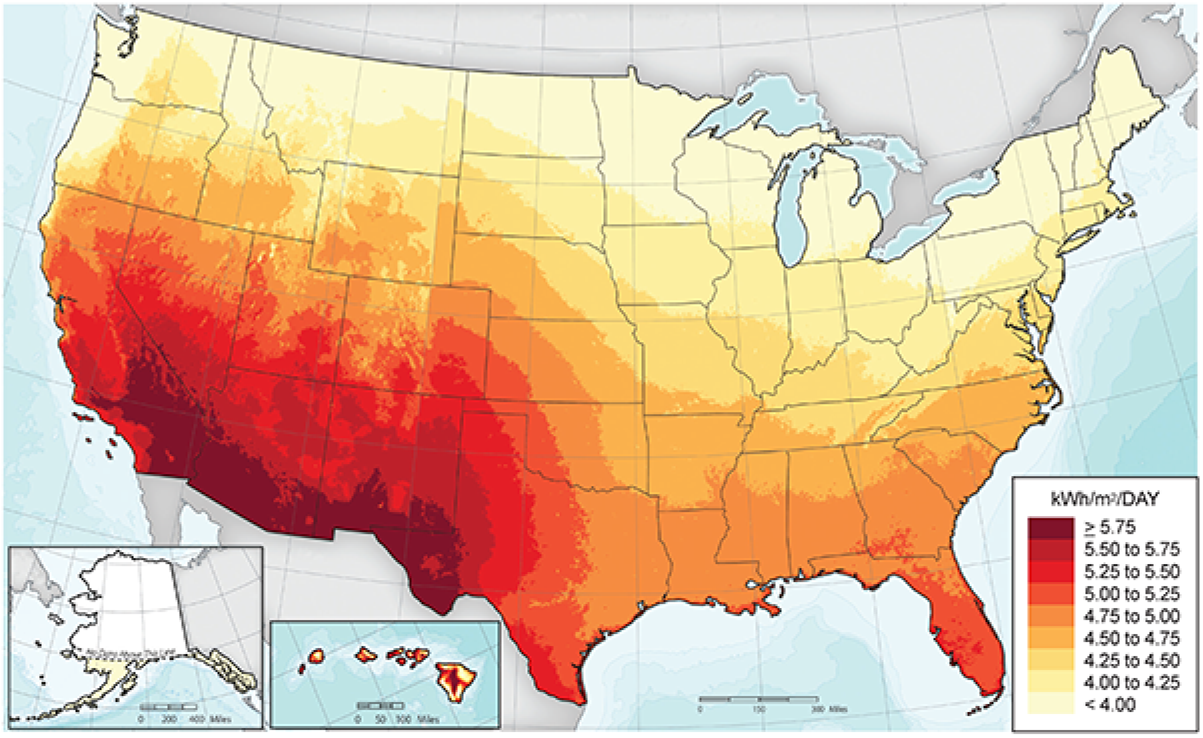


Figure 1-12. *U.S. Stationary Sources of CO_2 Emissions (by Type and Sized by Volume), Saline Formations, and Existing CO_2 Pipelines*

The United States has abundant wind and solar resources, but their availability varies across the country. As shown in Figures 1-13 and 1-14, solar resources are concentrated in the southwest while wind capacity is primarily concentrated in the middle of the country. CO_2 storage resources also vary by region (Figure 1-15) and are well placed to enable decarbonization of nonrenewable energy in areas with limited solar and wind potential.



Source: National Renewable Energy Laboratory, Geospatial Data Science, Solar Maps.

Figure 1-13. *U.S. Average Daily Total Solar Resource, 1998-2016*

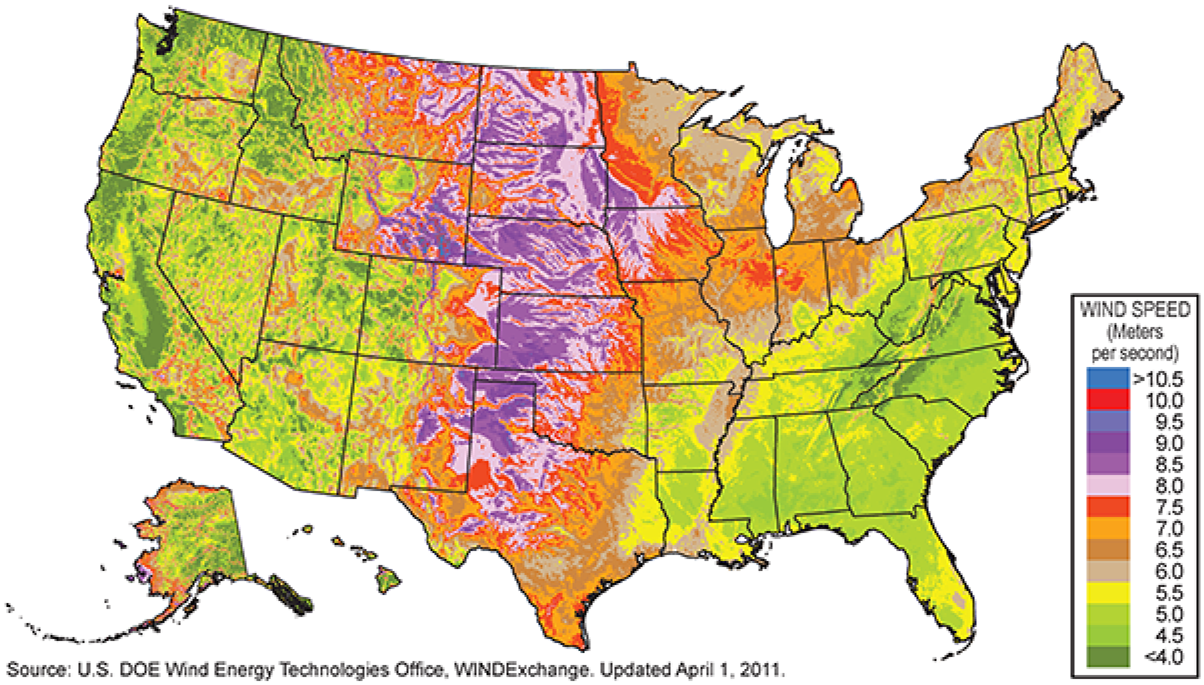


Figure 1-14. *U.S. Average Annual Wind Speed at 80 Meters*

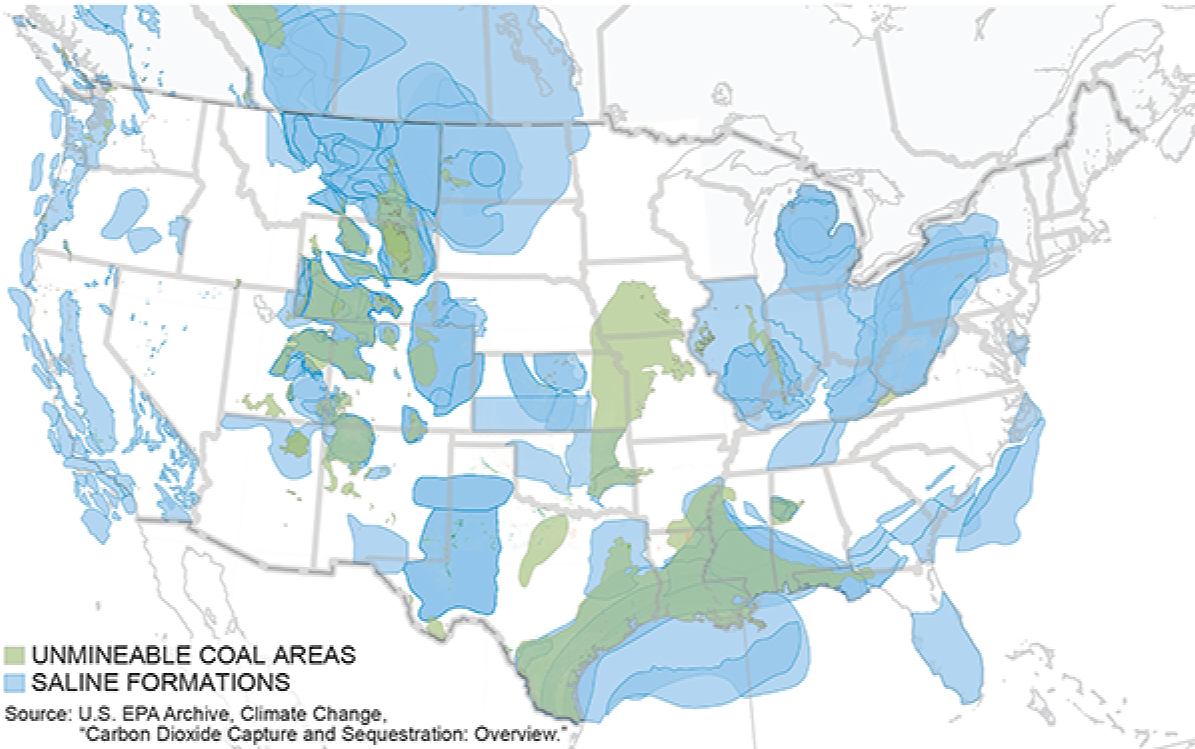


Figure 1-15. *U.S. Assessment of Geologic CO_2 Storage Potential*

IX. CCUS CAN SUPPORT A LOW-CARBON ELECTRICITY SYSTEM

Power generation emits more CO_2 than any other sector around the world and in the United States; it represents the largest opportunity for the application of CCUS. CCUS can enable decarbonization of the power sector by supporting market share growth of variable output renewable energy sources and promoting greater U.S. energy independence and fuel diversity.

Wind and solar energy produce intermittent power—when the wind blows and the sun shines. However, power systems must provide electricity to the grid on demand. For areas without solar and wind capacity, and to increase the deployment and integration of renewables, it is necessary to have additional power sources that can be accessed quickly, reliably, at low cost, and, given increasing environmental concerns, with low-carbon emissions.

On average, in 2019, natural gas with CCUS is considered the lowest cost, high-capacity source of flexible low-carbon power in the United States. Advancements in battery storage have enabled short-term backup (up to four hours) of intermittent renewable energy. For extended periods (more than four hours) with no significant production of wind or solar power, natural gas with CCUS could be a cost-effective and low-CO_2 emission solution to maintain a reliable power supply.[32,33]

X. CCUS CAN ASSIST DECARBONIZATION OF HARD-TO-ABATE SECTORS

Economic sectors that are more costly or difficult to decarbonize are sometimes referred to as "hard to abate."[34] Such sectors include heavy industry—steel, cement, and chemical production—as well as heavy duty transportation such as trucking, shipping, and aviation. Hard-to-abate sectors represent 30% of total CO_2 emissions worldwide and are on the rise.[35]

Decarbonizing these sectors is difficult because of the special operational requirements for heavy industry, including high temperatures (500°C to 1,500°C) and high-capacity factors (24/7 operation). About 30% to 40% of emissions from a typical facility result from heat production, commonly from burning coal, gas, or petroleum coke. These unique requirements cannot currently be met by alternative technologies or fuel options.[36] Furthermore, 20% to 50% of emissions are byproducts of the fundamental industrial chemistry, which is represented by the grey bars in Figure 1-16.[37] An example of these byproducts is the release of CO_2 when limestone is heated to high temperatures to convert it to the key ingredient of cement.

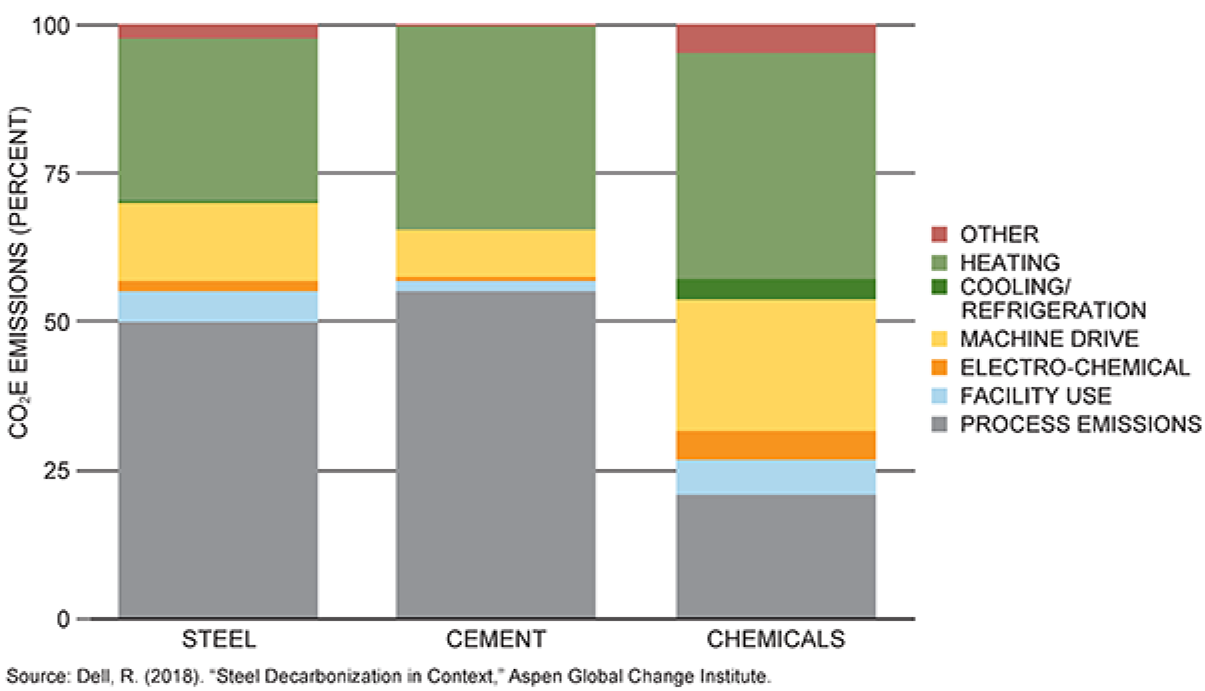


Figure 1-16. *CO_2 Equivalent Emissions Associated with the Production of Steel, Cement, and Chemicals*

CCUS is a key technology to mitigate the carbon intensity of heavy industry, especially for steel, cement, and chemicals production. The chemicals and petrochemicals sector represent the largest source of capturable CO_2 from industrial processes. CCUS can help decarbonize the production of hydrogen, ammonia, and methanol as well as high-value chemicals like ethylene, propylene, and aromatics. The role of CCUS in heavy industry is pivotal, and it grows over time as deeper emissions cuts are needed and other options are exhausted or uneconomic.[38]

XI. CCUS CAN LEVERAGE EXISTING INFRASTRUCTURE

CCUS technologies can be retrofitted to reduce emissions from long-lived energy assets such as power plants, industrial boilers, and refineries.[39] Continued use of this existing infrastructure could preserve jobs and avoid costs when compared with the costs of premature retirement and replacement. Without CCUS retrofitted to these facilities, continued operation would significantly slow the reduction in CO_2 emissions.

XII. CONCLUSION

CCUS is an essential element in the portfolio of solutions needed to meet the dual challenge—delivering reliable energy while addressing the risks of climate change—at the lowest cost over the long term. Governments around the world are already making policy decisions to reduce CO_2 emissions, and the United States is positioned to lead implementation because of its unique combination of technical expertise, CCUS experience, and geologic capacity to store CO_2. By using a combination of technologies to decrease the amount of CO_2 emissions from stationary sources, CCUS deployment can help advance progress on climate targets by removing CO_2 from the energy system, as well as removing CO_2 from carbon-intensive processes, and supporting increased use of lower-carbon energy sources. To remain a leader in CCUS, and to realize the potential economic and environmental benefits from its deployment, the United States will need continued investment in technology and a durable regulatory and legal framework that provides the clarity and certainty to create markets and encourage private investment.

Chapter 2 of this report, "CCUS Supply Chains and Economics," describes the CCUS supply chains, associated costs, and enablers for future projects. It also details the United States' leadership in CCUS and explains the factors that uniquely position the U.S. for continued leadership in emerging CCUS markets.

Chapter 3, "Policy, Regulatory, and Legal Enablers," outlines the CCUS policy, regulatory, and legal landscape and provides detailed recommendations to enable deployment. To achieve at-scale deployment, CCUS must overcome substantial hurdles to financing and regulatory clarity and certainty. A durable policy and legal framework can provide the clarity and certainty needed to create markets and encourage private investment.

Chapter 4, "Building Stakeholder Confidence," underscores the critical role that stakeholders play in enabling at-scale deployment of CCUS, and offers a set of recommended actions designed to effectively engage all stakeholders and build confidence. At present, awareness of CCUS among the general public is low; accordingly, the impact CCUS technologies can play to cost-effectively reduce CO_2 is not well-understood. Building the commitment needed to achieve at-scale deployment will require education, transparency and trust.

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1 CCUS includes transport.

2 For the purposes of this study, GHGs include CO_2, methane, nitrous oxide (N_2O), ozone, and chlorofluorocarbons.

3 United Nations, Department of Economic and Social Affairs, Population Division. (2019). *World Population Prospects 2019,* Online Edition. Rev. 1.

4 *BP Energy Outlook*. (2019). London, UK: BP p.l.c., https://www.bp.com/content/dam/bp/business-sites/en/global/corporate/pdfs/energy-economics/energy-outlook/bp-energy-outlook-2019.pdf.

5 The OECD average excludes Iceland because it was not included in the data set.

6 *BP Energy Outlook* (2019); ExxonMobil, Outlook for Energy (2019); International Energy Agency, *World Energy Outlook 2019,* Stated Policies Scenario.

7 "Previously known as the New Policies Scenario, it has been renamed to underline that it considers only specific policy initiatives that have already been announced. The aim is to hold up a mirror to the plans of today's policy makers and illustrate their consequences, not to guess how these policy preferences may change in the future." Source: International Energy Agency. (2019). *World Energy Outlook,* Executive Summary, p. 23.

8 "STEPS: the Stated (Energy) Policies Scenario." Source: International Energy Agency (2019) *World Energy Outlook,* Introduction, p. 29.

9 International Energy Agency. (2019). *World Energy Outlook,* https://www.iea.org/weo/weomodel/steps/.

10 On page 6 of *Facing the Hard Truths about Energy Executive Summary* (2007), the National Petroleum Council noted that, "Policies aimed at curbing CO_2 emissions will alter the energy mix, increase energy-related costs, and require reductions in demand growth." This point is also supported by the Intergovernmental Panel on Climate Change, IEA, and other global entities.

11 *Data Snapshots: Reusable Climate Maps,* National Oceanic and Atmospheric Administration, Climate.gov, https://www.climate.gov/maps-data.

12 From *Merriam-Webster*—anthropogenic (adjective): of, relating to, or resulting from the influence of human beings on nature.

13 IPCC, 2013: *Climate Change 2013: The Physical Science Basis. Working Group I Contribution to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change* [Core Writing Team, R.K. Pachauri and L.A. Meyer (eds.)]. IPCC, Geneva, Switzerland, p. 17.

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15 IPCC, 2014: *Climate Change 2014: Synthesis Report. Contribution of Working Groups I, II and III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change* [Core Writing Team, R.K. Pachauri and L.A. Meyer (eds.)]. IPCC, Geneva, Switzerland, 151 pp. in IPCC ARS Synthesis Report website.

16 *2019 Outlook for Energy: A Perspective to 2040*. Irving, TX: ExxonMobil Corporation, 2019, https://corporate.exxonmobil.com/-/media/Global/Files/outlook-for-energy/2019-Outlook-for-Energy_v4.pdf.

17 The SDS "sets out the major changes that would be required to reach the key energy-related goals of the United Nations Sustainable Development Agenda. These are:

An early peak and rapid subsequent reductions in emissions, in line with the Paris Agreement (Sustainable Development Goal [SDG] 13).

Universal access to modern energy by 2030, including electricity and clean cooking (SDG 7).

A dramatic reduction in energy-related air pollution and the associated impacts on public health (SDG 3.9)."

18 International Energy Agency. (2017). "IEA and China Host High-Level Gathering of Energy Ministers and Industry Leaders to Affirm the Importance of Carbon Capture," https://www.iea.org/newsroom/news/2017/june/iea-and-china-host-high-level-gathering-of-energy-ministers-and-industry-leaders.html.

19 Planned coal-fired power plants tallied 579 gigawatts (GW) of which China and India planned 226 GW and 92 GW, respectively.

20 Witkop, N., "China behind Bulk of World's Coal Growth Plans – Report." Montel News, September 19, 2019. https://www.montelnews.com/en/story/china-behind-bulk-of-worlds-coal-growth-plans--report/1044193.

21 "Why Is China Placing a Bet on Coal?" *Morning Edition: NPR*. Washington, D.C.: National Public Radio, April 29, 2019,

https://www.npr.org/2019/04/29/716347646/why-is-china-placing-a-global-bet-on-coal.

22 *2019 Annual Energy Outlook with Projections to 2050*, Washington, D.C.: U.S. Energy Information Administration, 2019, https://www.eia.gov/aeo.

23 2019 United Nations Framework Convention on Climate Change: "What does the Paris Agreement say on carbon pricing? https://unfccc.int/about-us/regional-collaboration-centres/the-ci-aca-initiative/about-carbon-pricing#eq-7.

24 2019 United Nations Framework Convention on Climate Change, "The Paris Agreement and NDCs": https://unfccc.int/process/the-paris-agreement/nationally-determined-contributions/ndc-registry.

25 International Energy Agency. (2019). "Transforming Industry through CCUS," IEA, Paris, https://www.iea.org/publications/reports/TransformingIndustrythroughCCUS/.

26 Members include Canada, China, Japan, Mexico, Netherlands, Norway, Saudi Arabia, South Africa, United Arab Emirates, UK, and the United States.

27 Kuuskraa, V., and Wallace, M., "CO_2 – EOR set for growth as new CO_2 supplies emerge." *Oil & Gas Journal,* Pennwell, April 7, 2014, https://www.adv-res.com/pdf/CO2-EOR-set-for-growth-as-new-CO2-supplies-emerge.pdf.

28 International Energy Agency, Insights Series – 2015, Storing CO_2 through Enhanced Oil Recovery, November 3, 2015.

29 It is noteworthy that in 2018 emissions rose, indicating that emissions reduction is not inevitable and may prove difficult.

30 U.S. EPA's Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2017, https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks.

31 Energy Transitions Commission, *Mission Possible: Report Summary,* November 2018, p. 10, http://www.energy-transitions.org/sites/default/files/ETC_MissionPossible_ReportSummary_English.pdf.

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33 Boston, A., Bongers, G., and Byrom, S. (2018). "Renewables and the NEM: What are the limits and what else is needed to go zero?," Gamma Energy Technology, P/L, Brisbane Australia, https://anlecrd.com.au/wp-content/uploads/2019/02/Rpt-2-Final-web.pdf.

34 Powell-Tuck, R., *In Focus: Hard to Abate Sectors,* https://radar.sustainability.com/issue-20/in-focus-hard-to-abate-sectors/.

35 Energy Transitions Commission, *Mission Possible: Report Summary, November 2018,* p. 7, http://www.energy-

transitions.org/sites/default/files/ETC_MissionPossible_ReportSummary_English.pdf.

36 International Energy Agency. (2019). "Transforming Industry through CCUS," IEA, Paris, https://www.iea.org/publications/reports/TransformingIndustrythroughCCUS/.

37 Dell, R. (2018). "Steel Decarbonization in Context," Aspen Global Change Institute, https://www.agci.org/sites/default/files/pdfs/lib/main/Dell_11_12_1400_Dell_2018-11-12.pdf.

38 Dell, R. (2018); and Energy Transitions Commission. (2018). "Mission Possible: Reaching Net-Zero Carbon Emissions from Harder-to-Abate Sectors by Mid-Century," Report Summary, p. 18.

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Chapter Two

CCUS SUPPLY CHAINS AND ECONOMICS

I. CHAPTER SUMMARY

Carbon capture, use, and storage (CCUS) is an essential element in the portfolio of solutions needed to meet the dual challenge of providing affordable and reliable energy while addressing the risks of climate change. The CCUS supply chain involves the capture—separation and purification—of carbon dioxide (CO_2) from stationary sources so it can be transported to a suitable location where it is used to create products or injected deep underground for safe, secure, and permanent storage. Stationary CO_2 emissions are generated at fixed points and include sources such as power generation and industrial processes.

This chapter will describe the CCUS supply chain and relevant deployments in the United States. The focus on the United States will continue by describing CCUS supply chain enablers as well as the costs associated with at-scale deployment.

In 2019, there were 19 large-scale CCUS projects operating around the world with a total capacity of about 32 million tonnes per annum (Mtpa) of CO_2.[1] Ten of these projects are in the United States with a total capture capacity of about 25 Mtpa.

Six of the U.S. projects were enabled by market factors that included availability of a low-cost CO_2 supply and a demand for CO_2 by enhanced oil recovery (EOR) and food industries. The four remaining projects required significant policy support to be economically viable.

This chapter will provide a brief description of each U.S. project and what enabled its deployment, as well as the level of incentive needed to achieve at-scale deployment of CCUS in the United States. The United States has a history of developing the legal and regulatory framework needed to enable CCUS projects. Although this chapter mentions that framework, a more detailed discussion about what is required to support at-scale deployment in the United States appears in Chapter 3, "Policy, Regulatory, and Legal Enablers."

In 2019, the United States had more than 6,500 large stationary sources emitting approximately 2.6 billion tonnes of CO_2 per year across multiple industrial sectors. These sources represent nearly 50% of the total U.S. CO_2 emissions. Although these sources are distributed across the country, many are located near geologic formations suitable for CO_2 storage.

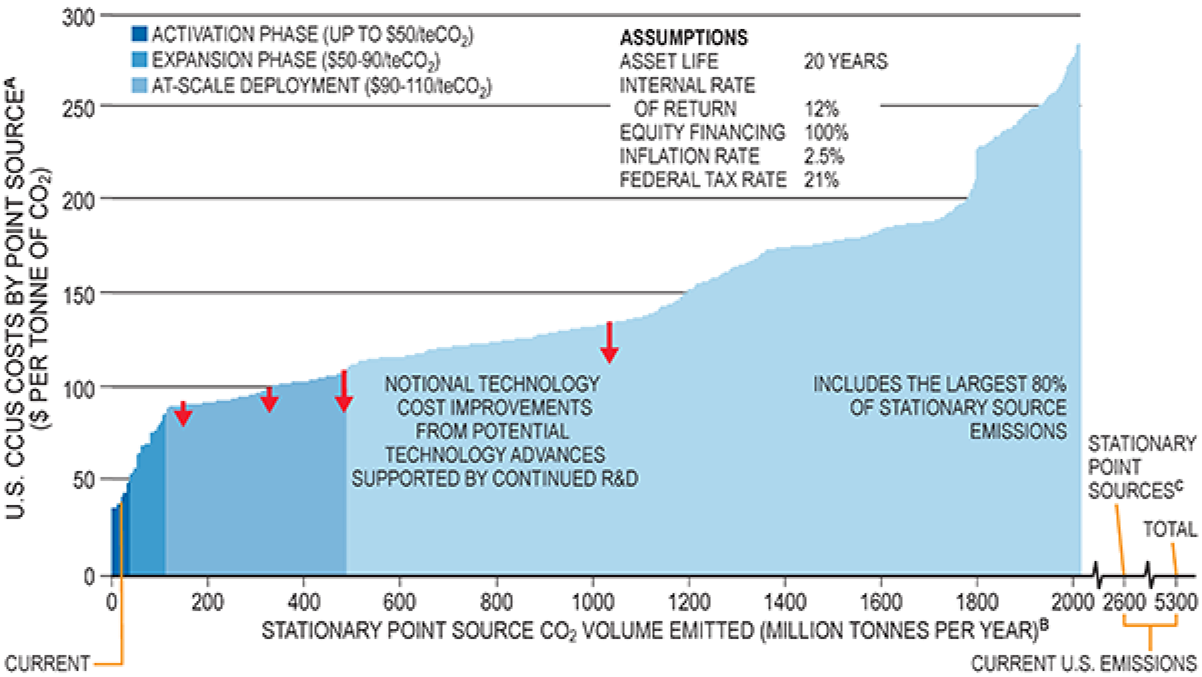
The United States has one of the largest known CO_2 geological storage capacities in the world. Most states in the continental United States possess some subsurface CO_2 storage potential. Though estimates vary, experts generally agree that the geologic resource would be able to store hundreds of years of CO_2 emissions from U.S. stationary sources.

In 2019, there were more than 5,000 miles of CO_2 pipelines transporting more than 70 Mtpa of CO_2 from both natural and anthropogenic sources. With approximately 85% of the world's CO_2 pipelines and 80% of the world's CO_2 capture capacity, the United States has established itself as the world leader in CCUS deployment. However, the 25 million tonnes of CCUS capacity in the United States represents an application to less than 1% of the CO_2 stationary sources. Accordingly, the potential for further deployment is significant.

As discussed in Chapter 1, "The Role of CCUS in the Future Energy Mix," U.S. stationary sources of CO_2 emissions include power plants, refineries and petrochemical plants, pulp and paper production, natural gas processing, ammonia production, industrial hydrogen production, industrial furnaces (including steel blast furnaces), cement plants, and the ethanol industry. For many of these source types, CCUS is a viable solution to enable emissions reduction.

There must be an economic incentive for all participants in a CCUS supply chain—from emission source and capture to transport and storage—to establish a CCUS project. Creating a supply chain will require significant capital investment and ongoing operating expenses. Furthermore, the costs at each stage are dependent on supply chain-specific circumstances that vary with each CCUS project. Capture costs vary with CO_2 concentration, while transport costs vary based on the volume, distance, and terrain over which CO_2 is transported. Storage costs also vary depending on location and nature of the storage formation. The variety of CO_2 sources, capture processes, transportation methods, and end uses makes many supply chain configurations possible.

This National Petroleum Council (NPC) study assessed the costs to capture, transport, and store CO_2 emissions from 80% of the largest U.S. stationary sources. These results are presented in a CO_2 cost curve (Figure 2-1), where the cost to capture, transport, and store one tonne of CO_2 from each of the largest 80% of stationary sources is plotted against the volume of CO_2 abated from that source. This chapter provides a detailed description of the assumptions used to develop the cost curve and the types of CCUS projects that could be enabled in the future by implementing the recommendations of this study.



Cost Curve Notes:

A. Includes project capture costs, transportation costs to defined use or storage location, and use/storage costs; does not include direct air capture.

B. This curve is built from bars each of which represents an individual point source with a width corresponding to the total CO_2 emitted from that individual source.

C. Total point sources include ~600 Mtpa of point sources emissions without characterized CCUS costs.

Figure 2-1. *U.S. CCUS Cost Curve with CO_2 Capture Volume by Phase*

There are three transition points on the cost curve that align with three phases of CCUS deployment projected to occur over a 25-year period to achieve at-scale deployment in the United States. The activation phase requires clarification of existing policies and regulations with current financial incentives of about $50/tonne of CO_2 to enable an additional 25 Mtpa to 40 Mtpa, doubling existing U.S. CCUS capacity within the next 5 to 7 years. The expansion phase broadens existing policies and increases financial incentives to $90/tonne of CO_2. Combining greater financial incentives with a durable regulatory and legal environment could enable an additional 75 Mtpa to 85 Mtpa within the next 15 years. The at-scale phase requires increasing the level of incentives up to about $110/tonne of CO_2, which could drive total U.S. CCUS capacity to approximately 500 Mtpa within the next 25 years.

Although the NPC does not expect CCUS will be applied to all U.S. stationary sources, achieving 500 Mtpa of U.S. CCUS deployment means that CCUS would be deployed on nearly 20% of U.S. stationary emissions, which is a level the NPC has defined as widespread or “at-scale” deployment. It is also worth noting that at an incentive of about $150/tonne, CCUS could be economically applied to about 1.2 billion tonnes of CO_2 emissions, which is just under half of all U.S. stationary emissions and nearly a quarter of total U.S. CO_2 emissions.

The specific policy and regulatory improvements and types of stakeholder engagement needed to deploy CCUS within each of the defined phases are detailed in Chapters 3 and 4 respectively.

II. THE CCUS SUPPLY CHAIN

The CCUS supply chain involves the capture (separation and purification) of CO_2 from stationary emissions sources so that it can be transported to a suitable location where it is converted into useable product or injected deep underground for safe, secure, and permanent storage (Figure 2-2).

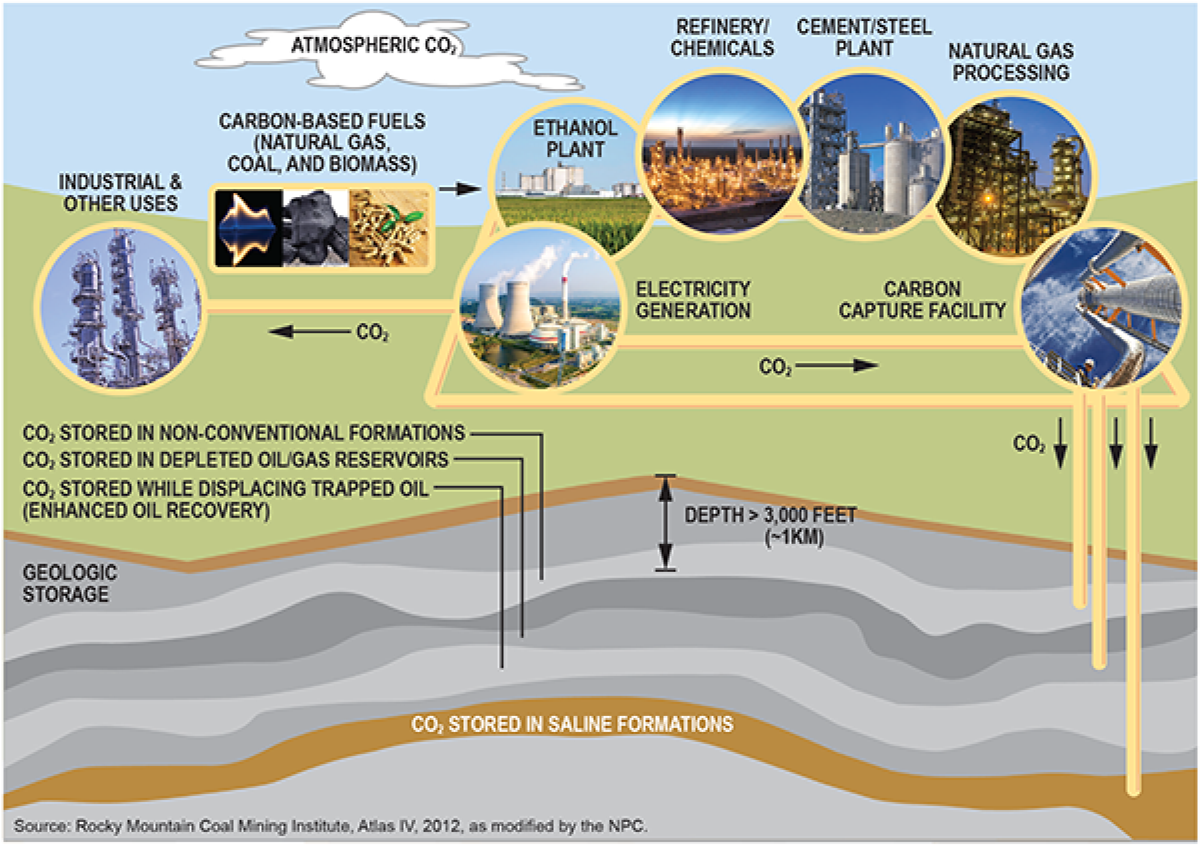


Figure 2-2. *Supply Chain for Carbon Capture, Use, and Storage*

The CCUS supply chain can take many forms depending on the emissions source, capture technology, transport option, and use or storage disposition. Figure 2-3 uses a Sankey flow diagram to show the breadth of supply chain combinations that can occur with CCUS. A Sankey diagram is a directional flow chart where the width of the streams is proportional to the quantity of flow, and where the flows can be combined, split, and traced through a series of events or, in this case, elements of the supply chain. In this diagram, the width of each link is an illustrative proportion of each component of the existing supply chain. This diagram is intended to show the possible supply chain configurations and does not account for future, or low technology readiness level (TRL), capture technologies currently in development.

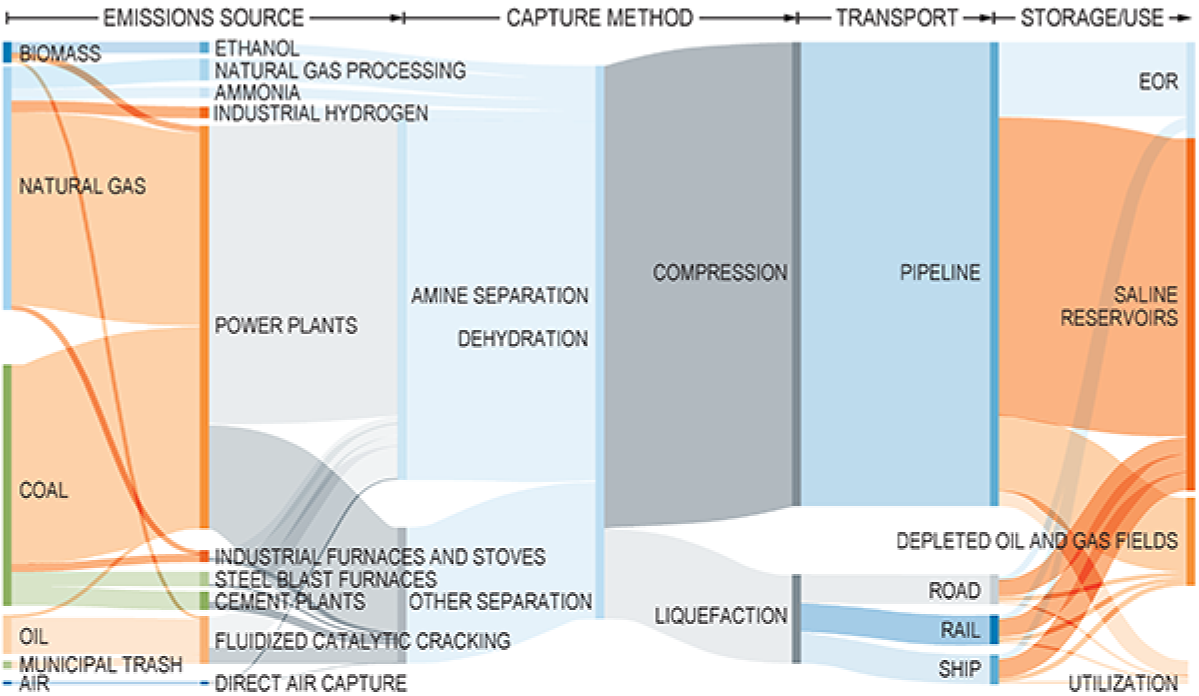


Figure 2-3. *Illustrative Sankey Diagram of CCUS Supply Chain*

While Figure 2-3 shows the possibility of many different supply chain configurations that could be developed to achieve at-scale deployment of CCUS, it also highlights that many of the components have already been demonstrated in the United States.

A description of each step in the CCUS supply chain follows.

A. Source

CO_2 is emitted from a wide range of sources across a broad range of industries. The original source of the carbon in the CO_2 is the carbon present in a wide variety of feedstocks used in natural and industrial processes to create and supply the products necessary for modern life. These industrial processes release some or all of the CO_2 generated.

- Biomass absorbs carbon from the air as it grows and can be used to generate liquid fuels, such as ethanol, or burned to create heat and power.
- Natural gas is produced and then processed (natural gas processing) to remove CO_2 to meet use specifications. Natural gas can be:
  - Used to generate electricity in power plants
  - Used to provide heat and energy in industrial furnaces and stoves
  - Separated to make hydrogen for use in industrial processes and refining, and for the creation of chemicals such as ammonia
  - Used in the production of cement.
- Coal is predominantly burned in power plants to generate electricity, although it is also used to provide high temperature heat to industrial furnaces, steel furnaces, and cement plants.
- Crude oil is processed at refineries to generate gasoline and other hydrocarbon-based products.
- Municipal trash can be burned to generate electricity or gasified and converted to liquid fuels such as diesel and jet fuel.

- CO_2 is released from limestone as it is heated to produce cement.
- CO_2 is also present in ambient air. This CO_2 can be removed from the air through direct air capture technologies.

In these sources, industries, and processes, CO_2 is produced in a variety of volumes and concentrations. Some processes, such as natural gas processing, ethanol fermentation, and ammonia production, create streams that have concentrations of 95% to 100% CO_2. The concentrated streams produced from these facilities typically require no separation and only dehydration and compression before transport.

Most of the other processes considered in this study produce lower concentration streams that will require further separation before dehydration and preparation for transport. Typical CO_2 concentrations are as follows:

- Industrial hydrogen plants: 15% to 95%
- Steel blast furnaces: ~26%
- Cement plants: ~20%
- Refinery fluidized catalytic crackers: ~16%
- Coal power plants: ~13%
- Industrial furnaces: ~8%
- Natural gas power plants: ~4%.

B. Capture

CO_2 is produced in combination with other gases during industrial processes, including hydrocarbon-based power generation. CO_2 capture involves the separation of the CO_2 from these other gases. This step, which can represent around 75% of the cost of the CCUS supply chain for low concentration streams, presents the largest opportunity to apply technological innovation to help reduce overall cost. Oil and natural gas producers have decades of experience in separating CO_2 from hydrocarbons, and other industries are making progress in separating CO_2 from their own process streams.

The separation of CO_2 can be accomplished through the application of four main CO_2 capture technologies:

- Absorption, which is the uptake of CO_2 into the bulk phase of another material
- Adsorption, which is the uptake of CO_2 onto the surface of another material
- Membranes, which selectively separate CO_2 primarily based on differences in solubility or diffusivity
- Cryogenic processes, which chill the gas stream to separate CO_2.

Each technology offers advantages and challenges associated with implementation in different industries. Absorption has been utilized as the primary means of separating CO_2 from gas mixtures for more than 40 years and is by far the most widely applied of the main capture technologies today. As a result, absorption is substantially more mature than other capture technologies and is expected to be the primary choice for separation in the near- to mid-term.

The appropriate carbon capture technology to use in an industrial application depends on the size (i.e., volume) of the source gas stream to be handled, the concentration of CO_2 and the contaminants in the gas mixture, the pressure and temperature of the mixture, the percent of CO_2 to be captured, and the purity of the CO_2 desired downstream of the capture process. Each of these considerations will influence determination of the optimum technology, and the associated costs of CO_2 capture.

A summary of the industries for which the four separation/capture methods may be employed is provided in Table 2-1. Absorption has the widest range of applicability given the decades of deployment experience that exist with absorption technologies (especially amine scrubbing). Adsorption and membrane technologies offer potential solutions for some industries, although application to date is generally less mature. Finally, cryogenic CO_2 capture is at the earliest stage of application but does have potential across several industries.

Separation Process	Absorption	Adsorption	Membranes	Cryogenic	Compress and Dehydrate
Electric Power Generation	X		R	T	X
Petroleum and Coal Products	X		Z	T	X
Pulp and Paper	R			T	X
Cement Manufacturing	X		R	T	X
Chemical Manufacturing	X	Z		T	X
Iron and Steel	X		Z	T	X
Oil and Natural Gas Processing	X	Z	Z	T	X
Pesticide, Fertilizer, Agricultural Chemical Manufacturing	X	Z			X
Bioethanol Fermentation					X

Key: X = primary, Z = secondary, R = research/demo, T = theoretical.

Table 2-1. *Application of Various Separation/Capture Processes in Selected Industries*

C. Transport

In most cases, captured CO_2 will need to be transported from the capture location to a location where it can be stored or utilized. Typical modes of transportation are as follows:

- Pipelines are generally the most cost-effective method of transporting large volumes of any fluid, including CO_2. In most cases, CO_2 is compressed into a dense phase, referred to as a supercritical fluid, before entering a pipeline system. In this state, CO_2 can be pumped like other liquids
- Railcars may be cost effective for small to medium volumes of CO_2 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 for very small volumes of CO_2 traveling short distances. Like rail, trucking can take advantage of existing infrastructure, but also like rail, liquefaction facilities may be needed at the point of origin
- Ship and barge transport is technically feasible but has only been demonstrated in isolated instances. Ship transport of CO_2 could potentially move large volumes of CO_2 from source locations with limited storage capacity to locations with ample storage capacity located near waterways that can accommodate such vessels.

D. Use

While most CO_2 captured over the next few decades will likely be stored, it can also be used to produce valuable products. Due to the limits of existing technology, CO_2 use will likely be an outlet for only a small fraction of the captured CO_2.

CO_2 use technologies convert CO_2 into valuable products like fuels, chemicals, and materials through chemical reactions and/or biological conversions. There are four primary technology pathways for CO_2 use and conversion:

1. Thermochemical CO_2 conversion

2. Electrochemical and photochemical CO_2 conversion

3. Carbonation (carbon mineralization) of CO_2

4. Biological CO_2 use.

Overall, CO_2 use is the least mature component in the CCUS technology chain. Yet it presents significant opportunities and multiple technology pathways for the development of processes to convert CO_2 from captured emissions and waste CO_2 into useful products.

E. Storage

While there are multiple pathways to geologic storage, most of them involve the injection of CO_2 into carefully selected subsurface geologic formations for safe, secure, and permanent storage.

1. Geologic Storage

Safe and secure geologic storage of CO_2 requires that the injection formation have enough pore space, or porosity, within which CO_2 can be contained. The formation must also have enough pathways connecting this pore space, which defines its permeability, so that CO_2 can be injected and move within the formation. The storage formation also needs to have a geologic seal—an overlying layer of nonporous, impermeable rock that prevents the injected CO_2 from leaving the formation. To ensure that the CO_2 is stored as a supercritical fluid, which has benefits for storage security and efficient storage space utilization, formations need to be at a depth of about 1 km or more.

Examples of subsurface formations include saline formations, oil and natural gas reservoirs, and un-mineable coalbeds. Globally, there are more than 20 years of experience with CO_2 injection for large-scale (more than 1 Mtpa) geologic storage, such as the Sleipner gas field in the

Norwegian sector of the North Sea. In the United States, small-scale projects have been operating for nearly as long, while the large-scale Illinois Industrial Carbon Capture and Storage Project has been operating since 2017.

2. Enhanced Oil Recovery

CO_2 can also be used to produce oil in a process known as enhanced oil recovery. During this process, CO_2 is injected into an oil reservoir and mixes with remaining oil, enabling it to flow more easily to a production well. Some of the injected CO_2 does not mix with the oil and becomes trapped in the reservoir. As the mixture of oil and CO_2 is produced, the mixed CO_2 is recovered from the oil and reinjected into the reservoir to repeat the closed-loop cycle. This process is repeated multiple times, with a portion of CO_2 being trapped within the reservoir during each cycle. Approximately 99% of the CO_2 used in EOR is ultimately trapped in hydrocarbon-producing geologic formations. Further details about each of the CCUS technologies described here can be found in Chapters 5 through 9 in Volume III of this report.

III. EXISTING CCUS SUPPLY CHAINS IN THE UNITED STATES

In 2019, 19 large-scale CCUS projects were operating worldwide with a total capacity of ~32 Mtpa of CO_2. Ten of these projects totaling ~25 Mtpa of CO_2 are located in the United States and represent ~80% of global capacity. These projects span a range of CCUS supply chains from multiple industries, including natural gas processing (~17 Mtpa), synthetic natural gas production (~3 Mtpa), fertilizer production (~2 Mtpa), coal-fired power generation (~1 Mtpa), hydrogen production (~1 Mtpa), and ethanol production (~1 Mtpa). The Global CCS Institute estimates that these U.S. projects have captured and stored approximately 160 million tonnes of CO_2.

Table 2-2 provides data for the 10 large-scale projects operating in the United States as of 2019. In addition to the projects listed in Table 2-2, there are also numerous pilot- and demonstration-scale projects that are operational in the United States.

Plant Name	Start Up Year	State	Operator	Capacity (million tonnes/ year)	CO_2 Source	Pipeline Connection (miles)	CO_2 Sink	Govt. Fund
Terrell Gas Processing	1972	TX	Occidental Petroleum	0.5	Natural Gas Processing	220	EOR	
Enid Fertilizer	1982	OK	Koch Nitrogen Company	0.7	Fertilizer Production	120	EOR	
Shute Creek Gas Plant	1986	WY	ExxonMobil	7.0	Natural Gas Processing	142	EOR	
Great Plains Synfuels	2000	ND	Dakota Gasification	3.0	Coal Gasification	205	EOR	$1.6B*
Century Plant	2010	TX	Occidental Petroleum	8.4	Natural Gas Processing	100	EOR	
Air Products SMR	2013	TX	Air Products	1.0	Hydrogen Production	13	EOR	$235M
Coffeyville Gasification	2013	KS	Coffeyville Resources	1.0	Fertilizer Production	68	EOR	
Lost Cabin Gas Plant	2013	WY	ConocoPhillips	0.9	Natural Gas Processing	232	EOR	
Illinois Industrial CCS	2017	IL	ADM	1.0	Ethanol Production	2	Saline	$141M
Petra Nova	2017	TX	NRG	1.4	Power Generation	80	EOR	$190M

* Government funding was for construction of the synfuels plant, not CO_2 capture.

Table 2-2. *Ten Large-Scale CCUS Projects Operating in the United States as of 2019*

Of the 10 projects, six were driven exclusively by market factors, including the availability of a low-cost CO_2 supply and demand for CO_2 from the EOR industry. For these six projects, a high concentration stream of CO_2 is produced as part of fertilizer production or natural gas processing. Accordingly, only dehydration, compression, and pipeline facilities are generally required to deliver CO_2 to EOR sites, greatly reducing the capital and operating costs. The remaining four projects involved more complex and costly

CO_2 capture. As a result, all four projects required significant financial support through government policies.

The following is a brief description of the 10 U.S. large-scale projects, with a focus on the commercial drivers that enabled development. Additional details about each of the projects can be found in Appendix C, "CCUS Project Summaries," at the back of this report.

A. Terrell Natural Gas Processing, 1972

Located in Terrell County in the Permian Basin in western Texas, Occidental Petroleum's Terrell natural gas processing facility processes methane that contains between 18% to 53% of CO_2. This CO_2 must be removed from the methane to meet pipeline specifications. Since 1972 the plant has supplied CO_2 to EOR operations via a 220-mile pipeline linking the facility to a network of CO_2 pipelines in the Permian. To date about 20 million tonnes of CO_2 have been prevented from reaching the atmosphere through storage associated with the EOR process.

B. Enid Fertilizer, 1982

ARCO began CO_2 injection into a portion of the Sho-Vel-Tum field in Oklahoma in 1982, and expanded operations in 1998. This demand for CO_2 incentivized the construction of capture equipment at the Farmland Industries fertilizer facilities in Enid, Oklahoma. The production of nitrogen fertilizers results in a high concentration CO_2 stream that requires cooling, dehydration, and compression to be ready for pipeline transport. About 0.6 million tonnes of CO_2 is captured and transported each year.

C. Shute Creek Gas Plant, 1986

The ExxonMobil Shute Creek Treating Facility in Wyoming processes natural gas production from the LaBarge field with CO_2 concentrations up to 66%. The CO_2 is removed using physical absorption solvent trains to meet pipeline specifications for natural gas transport. The facility was commissioned in 1986 and undertook major debottlenecking activities to increase gas production in 2004 and 2005. In 2008, an $86 million expansion brought the total capacity up to 7 Mtpa. Around 0.5 Mtpa of the separated CO_2 is injected back into the LaBarge field. The remaining CO_2 is transported through pipelines to a series of oil fields in Wyoming, Colorado, and Montana for EOR operations.

D. Great Plains Synfuels, 2000

The Great Plains Synfuels plant near Beulah, North Dakota, produces methane by gasification of a low-quality coal called lignite. The facility was constructed between 1981 and 1984. The project cost $2 billion and was funded by a federal loan guarantee of up to $2 billion to encourage the development of alternative fuel sources. By mid-1985, natural gas prices had dropped so much that the project was abandoned. Dakota Gasification Company was formed in 1988 and purchased the plant from Department of Energy for $85 million and a share of future profits.

The project is currently the only commercial-scale coal gasification plant in the United States. The lignite is gasified at high temperature to produce a mixture of methane, CO_2, and other gases. The gas is then cooled, which separates a highly concentrated stream of CO_2.

E. Century Plant, 2010

The Occidental Petroleum Century Plant gas processing facility is located in Pecos Country in the Permian Basin of Texas. It processes natural gas from nearby fields in the Val Verde sub-basin that contain up to 65% CO_2. Since 2010, the plant has supplied CO_2 to EOR operations via a 100-mile pipeline linking the facility to the CO_2 distribution hub in Denver City, Texas. The plant was designed in 2008 with a maximum capacity of 5 Mtpa and brought online in 2010. An expansion in 2012 increased capacity to 8.4 Mtpa.

F. Air Products Steam Methane Reformer, 2013

Air Products operates two Steam Methane Reformer (SMR) units to produce hydrogen for the Valero Refinery in Port Arthur, Texas. In 2010, Air Products was awarded $253 million by DOE through the American Recovery and Reinvestment Act to retrofit CO_2 capture equipment onto the units. The total project cost was $431 million, and the project began operations in May 2013. The output from the SMR units is separated through vacuum swing adsorption, purified, dehydrated, and compressed to make a 97% pure, pipeline-ready CO_2 stream due to the SMR units capturing more than 90% of the CO_2.

Denbury constructed and operates a 13-mile pipeline to transport the CO_2 to Denbury Onshore for use in an EOR project at the West Hastings Field. The maximum capture capacity from both units is about 1 Mtpa, and more than 4 million tonnes has been stored through EOR since the project began.

G. Coffeyville Gasification, 2013

The Coffeyville nitrogen fertilizer plant was built in 2000 by Farmland Industries, and sold to Coffeyville Resources in 2004. It uses a petroleum coke gasification process to produce hydrogen for use in the manufacture of ammonia for fertilizer. The CO_2 is separated from the hydrogen through pressure swing adsorption, and although some captured CO_2 was used for urea synthesis, the majority was vented to the atmosphere.

In 2011, Chapparal Energy entered into a commercial agreement with Coffeyville Resources to construct a compressor and a 68-mile pipeline to link oil fields in North Burbank and northeastern Oklahoma to the fertilizer plant. The project came online in 2013, with a capacity to deliver 1 Mtpa for EOR. Chapparal sold their interest to Perdure Petroleum in 2017.

H. Lost Cabin Gas Plant, 2013

The Lost Cabin Gas Plant in Fremont County, Wyoming, was constructed by Louisiana Land and Exploration in 1995. It processes natural gas production from the nearby Madden field with a CO_2 concentration of 19%. The CO_2 was originally vented to the atmosphere. In 2006, Conoco-Phillips took over operatorship of the plant. The Lost Cabin Gas plant has the capacity to produce about 1 Mtpa of CO_2.

In 2010, Denbury entered into an agreement to take the CO_2 from ConocoPhillips, which subsequently constructed the capture facility. Denbury constructed a 232-mile pipeline to transport the CO_2 to the Bell Creek oil field. To date the CO_2 EOR operations have injected over 10 million tonnes of CO_2. The total amount of CO_2 that will be trapped in the field at the end of operations is estimated to be about 12 million tonnes. Denbury is currently extending the pipeline another 110 miles northeastward into Montana to commence EOR.

I. Illinois Industrial CCS, 2017

The Illinois Industrial Carbon Capture and Storage (IL-ICCS) project is the only saline reservoir carbon storage project in the United States. The project is located at the Archer Daniels Midland Company (ADM) agricultural processing and biofuels complex in Decatur, Illinois, where a highly concentrated stream of CO_2 from the ethanol fermentation process is captured, dehydrated, compressed, and injected into the Mount Simon Sandstone reservoir adjacent to the facility. The project has a capacity of about 1.1 Mtpa, and has stored about 2 million tonnes since injection began in April 2017. This project’s main objectives are to demonstrate an integrated system for collecting CO_2 from biofuel production and compressing, transporting, and injecting the CO_2 into a saline formation.

In October 2009, the DOE selected the IL-ICCS project for Phase 1 funding ($141 million) under the Industrial Carbon Capture and Storage program, funded by the American Recovery and Reinvestment Act of 2009. Under this program, ADM was able to secure a grant and structure the project’s nonfederal cost-share obligation in a way that reduced the amount of upfront capital and associated risk.

Following 2018 expansion of the Section 45Q tax credit, ADM began claiming the credits in 2019.

J. Petra Nova, 2017

The Petra Nova project is the world's largest operational, post-combustion capture system applied to power generation. It was retrofitted to a unit of the W.A. Parish coal-fired power plant near Houston, Texas, and began operations in January 2017. It has the capacity to capture 1.4 Mtpa, which is transferred through an 80-mile pipeline to Hilcorp's West Ranch oil field for storage through EOR. The project uses proprietary amine scrubbing absorption technology to capture the CO_2 from power plant flue gas. Total project cost was about $1 billion.

Although the project is in an oil and natural gas producing region where many oil fields would benefit from EOR, the price for CO_2 for EOR did not support the investment in the capture plant. The Petra Nova project solved this problem by combining the EOR activity with the CO_2 capture facility project, creating a financial structure with enough return from the integrated CCS-EOR project.

NRG initially planned for a 60-Megawatts-electric (MWe) capture system but ultimately increased the system capacity to 240 MWe, enabling use of technology from Mitsubishi Heavy Industries America, Inc., which already had a successful demonstration plant capturing CO_2 from coal-fired flue gas. The DOE provided $190 million in grant funding. In May 2013, JX Nippon purchased 50% of Petra Nova, bringing much needed capital and access to debt financing for project funding.

IV. ENABLERS OF U.S. CCUS SUPPLY CHAINS

The United States has become the world leader in CCUS by:

- Executing successful CO_2 capture projects
- Investing in CO_2 pipeline infrastructure
- Establishing a supportive regulatory framework
- Enacting world-leading policy support
- Investing in research, development, and demonstration (RD&D).

A. CO_2 Pipeline Infrastructure

In addition to possessing approximately 80% of the world's capture capacity, the energy industry has constructed more than 5,000 miles of CO_2 pipelines in the United States (Figure 2-4), representing approximately 85% of the total CO_2 pipeline mileage in the world.[2] The CO_2 transported through this pipeline network is a mix of anthropogenic and natural CO_2 and is primarily used for EOR.

Figure 2-4. *Schematic Map of CO_2 Pipelines in the United States*

B. EOR and Storage Potential

The U.S. oil industry leads the world in CO_2 EOR deployment and has been safely injecting CO_2 underground for nearly 50 years, extending the life of older fields and maximizing the value of U.S. hydrocarbon resources. Today, more than 95% of U.S. anthropogenic CO_2 is used in EOR. It is expected that EOR will continue to be the prominent disposition for anthropogenic CO_2 for at least the next decade, though its potential to store CO_2 is relatively small when compared to the total U.S. onshore CO_2 storage resource including saline formations.

The United States also has one of the largest known CO_2 geologic storage capacities in the world, with much of the continental U.S. possessing some subsurface CO_2 storage potential, as shown in Figure 2-5. While estimates of U.S. storage resource vary, most indicate that this resource is adequate to store hundreds of years of CO_2 emissions from U.S. stationary sources. Studies also suggest that offshore storage capacity in the United States may be as large as the onshore potential.[3]

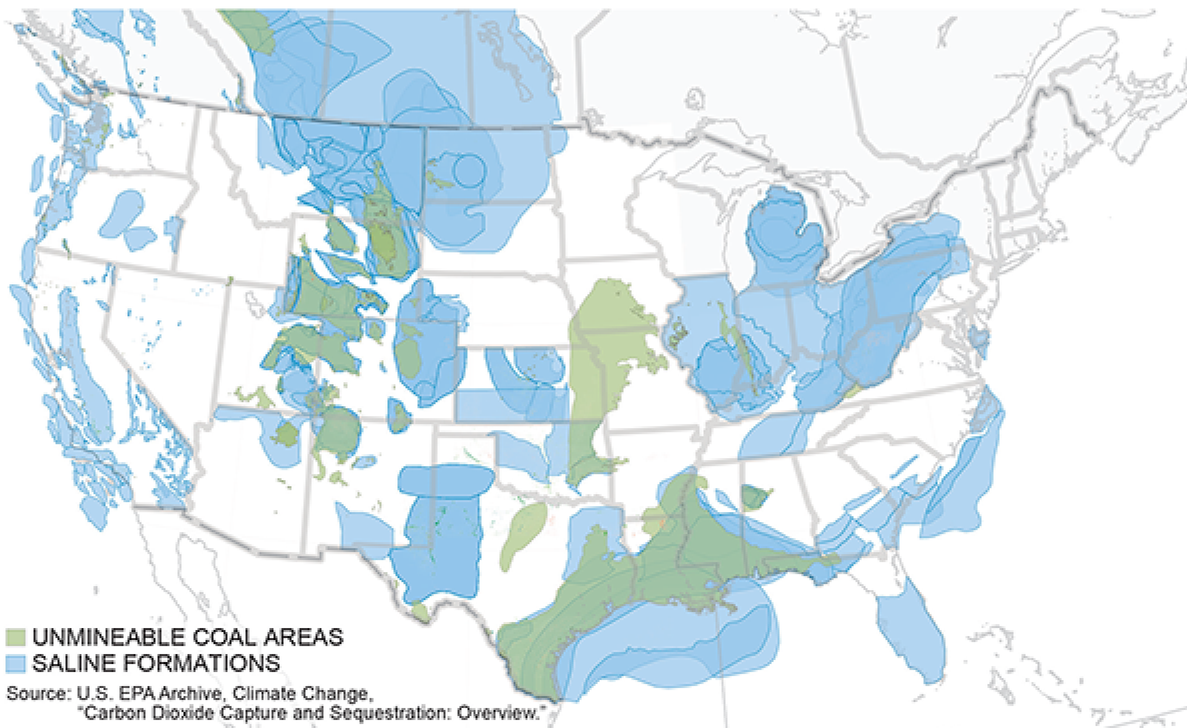


Figure 2-5. *U.S. Assessment of Geologic CO2 Storage Potential*

C. U.S. Regulatory Framework

Beyond action taken by commercial entities, the U.S. government has actively pursued the establishment of a strong regulatory framework to assure safe and secure transport and storage of CO_2. The Environmental Protection Agency (EPA) has developed specific regulatory and permitting frameworks under the Safe Drinking Water Act (SDWA) to protect underground sources of drinking water during injection operations. These include the Class II (oilfield injection) and Class VI (saline formation storage of CO_2) permitting programs for CO_2 injection wells. The EPA also maintains the Greenhouse Gas Reporting Program and has developed accounting protocols under the Clean Air Act for the injection of CO_2 for geologic storage. The CO_2 pipelines are regulated by the Pipeline and Hazardous Materials Safety Administration within the Department of Transportation, which sets the standards for permitting and operation. A number of policy, regulatory, and legal actions are needed to enable at-scale deployment of CCUS, as described in Chapter 3, "Policy, Regulatory, and Legal Enablers," and the United States is well positioned to take these next steps.

D. Financial Support: Demonstration Projects

As noted earlier, four of the 10 large-scale projects in the United States required significant policy support to be economically viable. In 2009, the American Recovery and Reinvestment Act (Recovery Act; P.L. 111-5) provided the U.S. DOE $3.4 billion for CCUS[4] projects and activities. The large and rapid influx of funding for industrial-scale CCUS projects was intended to accelerate development and demonstration of CCUS in the United States. As described earlier in this chapter, three projects that are currently in operation, the Air Product Steam Methane Reformer CO_2 capture project, the ADM Illinois Industrial CCS project, and the NRG Petra Nova CO_2 capture project, all greatly benefited from this funding. The fourth project, the Great Plains Synfuels project, was, as noted earlier, initially constructed from 1981 to 1984 with major financial support from the U.S. government to encourage the development of alternative fuel sources. In 2000, following the construction of an international CO_2 pipeline and entry into a supply agreement, the facility began delivering CO_2 to two oil fields in Canada.

E. Financial Support: Broad Policies

CCUS has also benefited from federal tax policy as well as state and regional incentives. The 2018 FUTURE Act amended Section 45Q of the U.S. tax code for operators of carbon capture equipment, increasing the tax credit from \$20 to \$50 per tonne of CO_2 stored in dedicated geologic storage and from \$10 to \$35 per tonne for CO_2 stored through EOR or used. The legislation also removed some limits on the size of projects that can qualify and the total amount of credits that can be claimed. It is worth noting that the International Energy Agency (IEA) has estimated that the amended 45Q could "trigger new capital investments of as much as \$1 billion for CCUS over the next six years."[5] Although no final investment decisions have been announced since the revision of Section 45Q was enacted, the NPC expects multiple projects will be incentivized by this revision, assuming the tax policy and regulatory clarifications recommended in the activation phase, as detailed in Chapter 3, are addressed.

F. U.S. DOE Leadership

The United States has benefited from more than 20 years of DOE leadership, funding support, and public-private partnerships between government, academia, and industry. Since 1997, the DOE has invested more than $4.5 billion in CCUS RD&D programs. This funding has been a major contributing factor to the United States becoming the world leader in CCUS technology and deployment capability.

Much of this development was accomplished through the DOE's Regional Carbon Sequestration Partnership program, which includes 40 states and four Canadian provinces. The regional partnerships combined academic, research, and industrial experience to deliver 27 small-scale CO_2 injection pilots and seven large-scale CO_2 injection test projects delivering more than 11 million tonnes of CO_2 storage. To date, more than 20 million tonnes of CO_2 have been stored through DOE supported CCUS projects.

V. COST TO DEPLOY CCUS IN THE UNITED STATES

As part of this study, the costs to capture, transport, and store CO_2 emissions from the largest 80% of U.S. stationary sources were assessed. The purpose of this assessment was to understand the level of incentive needed to enable the creation of a multi-hundred-billion-dollar CCUS industry in the United States (e.g. wide-scale deployment). The analysis comprises approximately 850 U.S. stationary sources of CO_2 emissions. The largest 80% of emitting sources in the 2018 EPA Facility Level Information on GreenHouse gases Tool

(FLIGHT) database, which tracks and reports U.S. CO_2 emissions, are included. In addition, fermentation emissions from ethanol plants larger than 100,000 tonnes/year that are not reported in the EPA FLIGHT database were added to the sources and are included in the curve.[6] In total, the curve includes approximately 850 U.S. stationary sources of CO_2 emissions.

The results are presented as a CO_2 cost curve (Figure 2-6), where the total cost to capture, transport, and store one tonne of CO_2 from stationary sources is plotted against the volume of CO_2 abatement it could provide. The curve is arranged in a marginal cost manner, such that the sources with the lowest combined cost to capture, transport, and store CO_2 from each source (shortest bars) are to the left of the curve and sources with the highest combined cost (tallest bars) are to the right of the curve. The cost per tonne gives an indication of the minimum financial revenue or benefit needed to incentivize supply chain development. Today, these incentives come from revenue generated through the sale of CO_2 and from CO_2 tax credits.

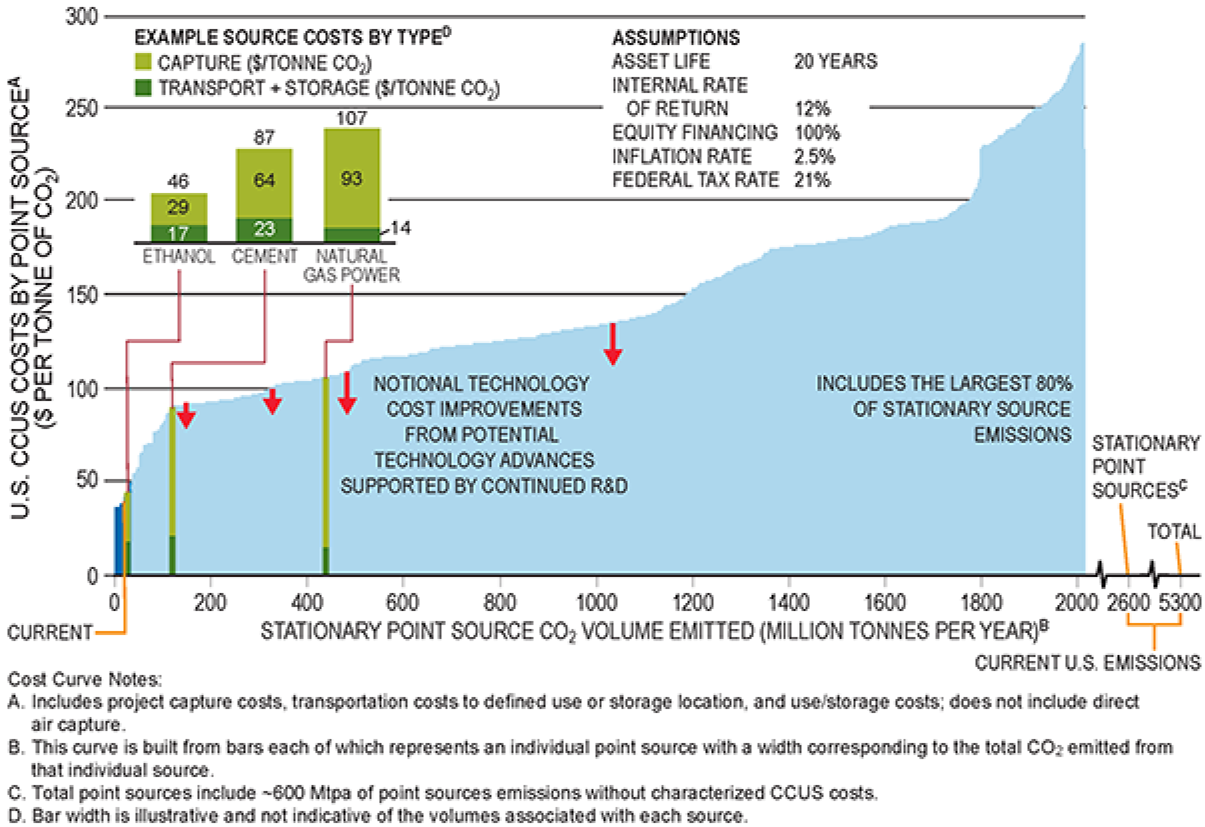


Figure 2-6. *U.S. CCUS Cost Curve*

The cost curve shown in Figure 2-6 was developed using costs associated with currently available and deployed technologies. The red down arrows in the curve represent an illustrative view of notional 10% to 30% cost improvements that could be expected over the next 20-30 years based on technology advances supported by continued research and development.[7] Although the cost curve is not time based, the length of the red arrows represents the notional cost reductions in the context of the phases of deployment described in this report.

The results of the curve are highly dependent upon the assumptions used in the analysis. Using "reference cases" and standard economic assumptions was essential to developing the cost curve, formulating recommendations, and assessing the potential impact of those recommendations on CCUS deployment at a national level. Costs for individual projects will vary based on location factors and the economic assumptions specific to each project.[8]

In order to provide a useful public resource and ensure transparency of this work, the cost assessment tool, created by Gaffney, Cline & Associates, has been made available.[9] The tool will allow interested parties to change the cost and financial assumptions to generate their own view of costs.

Each of the largest 80% of U.S. CO_2 emissions from the EPA FLIGHT data, about 850 sources, is included in the cost curve depicted in Figure 2-6 with the X-axis representing the combined volume of each source. The Y-axis represents the total estimated cost to capture, transport and store the CO_2 emissions from each source. The costs presented in this study are based upon a variety of project types across a broad spectrum of industries in the United States. A significant driver of variation in capture costs is the concentration of CO_2 in the total gas stream for each emissions source. For example, point sources with high CO_2 concentration (e.g., ethanol, natural gas processing, etc.) will typically have relatively small capture costs and are seen in the lower cost area of the curve (i.e., left side). However, for most CO_2 emissions sources, capture will account for the majority of the overall cost of CCUS. Figure 2-7 provides an illustrative view of the combined cost for capture, transport, and storage for a single source of emissions. These costs vary by source type, distance from facility to storage location, and characteristics of the storage location.

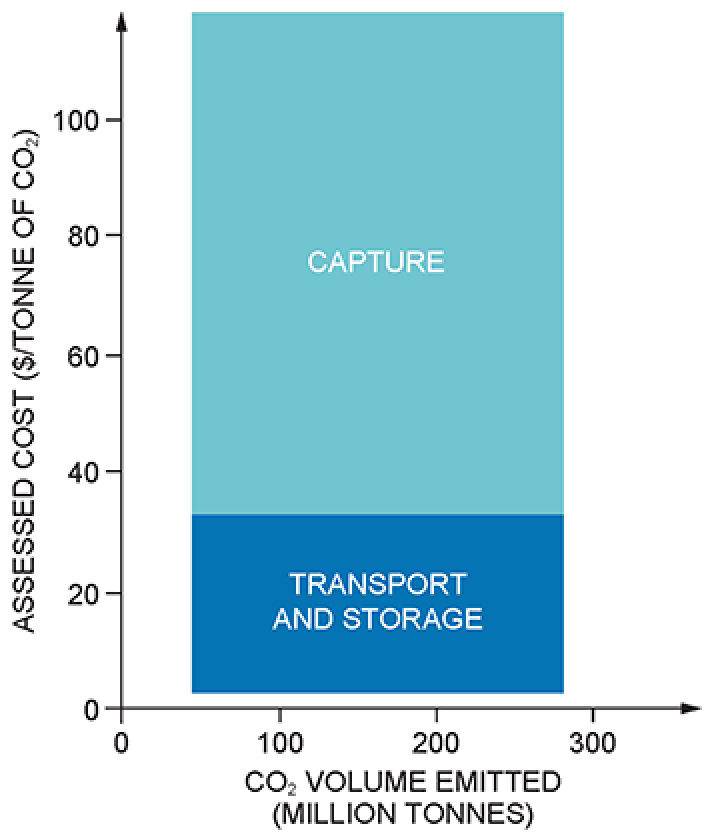


Figure 2-7. *Cost Associated with CCUS for a Single Source of CO_2 Emissions*

A. Financial Assumptions

The total calculated cost of each source comprises a capture, transport, and storage component. Each of the components was assessed using a cash flow model with the following assumptions:

Asset Life	20 years

Internal Rate of Return (after tax)	12%
Equity Financing	100%
Tax Rate	21%
Inflation	2.5%
Depreciation	7-year MACRS[10]

These financial assumptions reflect the collective view of the study participants regarding the conditions that need to exist to incentivize widespread deployment of CCUS in the United States over the next two decades. The IRR of 12% was selected as the level required for large-scale implementation of CCUS in the United States, considering the inherent financial risks of these types of projects. This level of return was deemed by the study team to be adequate to attract investment from corporate equity investors, independent equity investors, and non-governmental (unsubsidized) debt sources. It was also recognized that these assumptions would likely not be appropriate to assess individual CCUS project opportunities, as individual project circumstances can vary widely. While these financial assumptions were applied uniformly in the cost analysis, capital investment, fixed operating cost, and variable operating cost including energy were individually assessed based on industry type and location. As discussed in the next section, capture costs vary as a function of the circumstances in which the technologies are employed. As previously noted, the model used to develop this cost curve has been made publicly available, giving the user the opportunity to change the financial assumptions to reflect alternative views.

B. Capture Costs Assessment

Capture costs were estimated based on specific industrial process conditions and the capture technologies applied. In general, CO_2 capture systems include three major processes, (1) separation of CO_2 from other gases, (2) removal of water from CO_2, which is generally referred to as dehydration, and (3) compression of CO_2 to a supercritical phase, making it ready for transport. The cost assessment assumes the application of currently available capture systems to existing large-scale CO_2 emissions sources. On that basis, the capture costs developed reflect retrofits to existing facilities and includes the purchase of electricity and natural gas necessary to run the capture equipment and prevent any significant parasitic load reducing output.

Costs were estimated for each industry sector, taking into consideration the unique processes and other conditions associated with the facility type deemed most relevant. To assess costs, a reference plant size and capacity utilization were identified for each industry in an effort to portray a typical facility. For each reference plant within the facility type, an exhaust volume and an associated molar CO_2 concentration was assumed. For facility types with an exhaust CO_2 molar concentration greater than 95%, no separation costs were included—only dehydration and compression costs were assumed. For facility types with an exhaust CO_2 molar less than 95%, separation costs were estimated based on the application of amine absorption technology, with dehydration and compression facilities assumed for the reference plant size.

The costs developed for this model were based on an assessment of historical studies, published industry experience, and insights from a wide range of industry experts who reliably design, construct, and operate such large-scale, technically challenging, commercially complex, and capital-intensive energy and industrial projects. The range of capture costs (e.g., low to high) developed for this model is intended to reflect differences in the economies of scale between individual facilities, the various ways to integrate power and heat requirements within existing facilities, and a range of equipment delivery and labor costs.

Table 2-3 lists the key capture cost variables within each assessed industry. For each reference plant within a facility type, capital and operating costs were estimated based on the key variables described in the following sections.

Facility Type	Reference Plant Size	Capacity Utilization %	Stream Flowrate (tonnes/ hour)	CO_2 in Exhaust %	CO_2 Separation Technology	CO_2 Volume Captured (tonnes/ year)	Separation Notes
Natural Gas Processing	140 MMCF/D	85	21	95-100	None	24,000	Vented only, not combustion
Ethanol Production	150 million gal/yr	85	49	95-100	None	342,000	Vented only, not combustion
Ammonia Production	907,000 tonnes/yr	85	53	95-100	None	389,000	Vented only, not combustion
Hydrogen Production	87 MMCF/D	85	59	45	Amine	340,000	Process only, not combustion
Cement Plants	1 million tonnes/yr	85	431	21	Amine	842,000	Both process and combustion
Refinery Fluidized Catalytic Cracking (FCC) Plants	60,000 barrels/day	85	272	16	Amine	374,000	Process only, not combustion
Steel/Iron Plants	2.54 million tonnes/yr	85	1,381	26	Amine	3,324,000	Both process and combustion
Coal Power Plants	550 MW net	85 55 35	2,829	13	Amine	3,089,000 1,999,000 1,272,000	Combustion
Industrial Furnaces (refining/ chemicals)	4x150 MMBTU/hr	85	247	8	Amine	220,000	Combustion
Natural Gas Power Plants	560 MW net	85 55 35	3,707	4	Amine	1,279,000 827,000 527,000	Combustion

Table 2-3. *Cost Curve Assessed Industries with Key Capture Cost Variables*

1. Capital Costs

As previously noted, the process to separate CO_2 from other exhaust gases generally uses amine absorption separation technology. This technology is effective over a wide range of CO_2 concentrations and pressures. However, the level of capital and operating costs will vary significantly based on the concentration of CO_2 versus other gases. Figure 2-8 illustrates the size and complexity of the equipment needed for CO_2 capture at the NRG/JX Petra Nova project near Houston, Texas. The facility uses post-combustion amine absorption technology to capture approximately 90% of the CO_2 in the processed flue (vent) gas stream from one of the facility's four coal-fired units.

Source: NRG Energy Case Studies, *Petra Nova, Carbon capture and the future of coal power.*

Figure 2-8. *The NRG/JX Petra Nova CO_2 Capture Project Near Houston, Texas*

Amine absorption involves the molecules of CO_2 being dissolved into the bulk of a liquid solvent. Flue (vent) gas, which can contain a range of CO_2 concentrations, and the liquid solvent contact each other in a column called an absorber tower or unit. The tower provides an interface area between the gas and liquid phases. The separation of CO_2 from flue gas primarily occurs through the high solubility of CO_2 in the solution relative to that of other flue gas constituents. The CO_2-rich solution is then sent to a regenerator, also called a stripper tower. In the stripper tower, the solution is typically heated to liberate CO_2 from the solution. The warm, CO_2-lean solution is then cooled in a heat exchanger and recycled back to the absorber tower for reuse, and the process continues. Amine solvent systems (e.g., amine acid gas scrubbing systems) are often used in industries such as natural gas processing and fertilizer manufacture.

While the application of amine absorption technology is similar for most applications, separating CO_2 at lower concentrations generally increases costs. The absorption of CO_2 in solvent occurs in a packed column. The diameter (area) of the column is determined by the limiting velocity of the gas containing the CO_2 moving through the packed column. The packed column is proportionally larger for dilute gas streams because more gas must move though the column for the same amount of CO_2 in these dilute gas streams than for the same amount of CO_2 in a more concentrated stream. In addition, the ducts and fans that bring the gas containing CO_2 to the packed column must also be larger for more dilute streams. The increase in equipment size for the more dilute streams adds additional costs. Because the fans used to move the gas to the absorber are larger, they also consume more energy than for more concentrated streams. Generally, the cost per tonne of CO_2 captured from a natural gas combined cycle plant with a 4% CO_2 concentration in the flue gas is approximately 20% greater than the cost per tonne of CO_2 captured from a coal-fired power plant at 13% concentration in the flue gas. Note that in this comparison, both gas streams are near atmospheric pressure.[11]

In addition to the deployment of amine absorption, the cost associated with ancillary facilities was considered for the purposes of this study. These costs do not include any additional impurity cleanup costs that may be required in some applications of the CO_2 capture process to meet transport or storage/use specifications. The following provides examples of other capital investment considerations:

- Ducting to move exhaust gases from the vent stacks to the inlet of the capture system
- Cooling systems to cool exhaust gas
- Pre-treatment systems if the inlet gas contains contaminants
- Water treatment systems
- Storage bins and tanks for materials, including reserves of solvent.

Capital costs for separation, dehydration, and compression were estimated for each reference plant within a facility type based on an assessment of historical studies, published industry experience, and insights from a wide range of industry experts. All new projects were assumed to have a 3-year construction period, with 20% of the required capital spent in the first year, 50% in year 2 and 30% in year 3. Table 2-4 provides the capital investment costs that were estimated for each facility type assessed.

Facility Type	Reference Plant Size	Capacity Utilization %	CO_2 Volume Captured (tonnes/year)	Capital Cost Low-High ($ millions)	Unit Capital Cost 20-Year Life Low-High ($/tonne)
Natural Gas Processing	140 MMCF/D	85	24,000	17-28	7-12
Ethanol Production	150 million gal/yr	85	342,000	21-36	6-10
Ammonia Production	907,000 tonnes/yr	85	389,000	24-41	6-11
Hydrogen Production	87 MMCF/D	85	340,000	59-98	19-33
Cement Plants	1 million tonnes/yr	85	842,000	148-247	17-29
Refinery Fluidized Catalytic Cracking (FCC) Plants	60,000 barrels/day	85	374,000	136-227	43-72
Steel/Iron Plants	2.54 million tonnes/yr	85	3,324,000	805-1342	26-44
Coal Power Plants	550 MW net	85	3,089,000	891-1485	33-55
		55	1,999,000		54-91
		35	1,272,000		89-149
Industrial Furnaces (refining/chemicals)	4x150 MMBTU/hr	85	220,000	92-153	49-83
Natural Gas Power Plants	560 MW net	85	1,279,000	399-666	34-58
		55	827,000		57-95
		35	527,000		92-155

Table 2-4. *Estimated Capital Investment Costs for Reference Plants by Facility Type*

2. Operating Costs

Operating costs associated with CO_2 capture facilities are divided into four major categories:

- Annual fixed costs (taxes, insurance, overhead, general plant salaries)

- Semi-variable costs (major and minor repairs, maintenance, overhauls)
- Variable non-energy costs (replacement of process chemicals, water, water treatment, etc.)
- Variable energy costs (electricity to drive compressors, motors, pumps and fans; steam to strip CO_2-laden solvent).

Considering that the deployment of a similar separation technology (amine absorption) was assumed for all facilities within an industrial sector, fixed, semi-variable and non-energy variable annual operating costs were estimated as a percentage of capital investment (CAPEX) for an industrial sector.

Table 2-5 depicts the non-energy operating cost assumptions.

Facility Type	CO_2 Volume Captured (tonnes/year)	Non-energy O&M % of CAPEX
Natural Gas Processing	24,000	6%
Ethanol Production	342,000	7%
Ammonia Production	389,000	5%
Hydrogen Production	340,000	5%
Cement Plants	842,000	7%
Refinery Fluidized Catalytic Cracking (FCC) Plants	374,000	4%
Steel/Iron Plants	3,324,000	5%
Coal Power Plants	3,089,000	4%
	1,999,000	
	1,272,000	
Industrial Furnaces (refining/chemicals)	220,000	4%
Natural Gas Power Plants	1,279,000	5%
	827,000	
	527,000	

Table 2-5. *Estimated Non-energy Operating Costs for Different Facility Types*

Energy costs associated with operating amine absorption equipment were estimated based on industry experience and a survey of recent studies. A list of the relevant assumptions related to energy use requirements and pricing follows:

- Electricity required for compression and dehydration was assumed to be 0.1 MWh per tonne of CO_2.

- Electricity required to operate an amine system was assumed to be 0.05 MWh per tonne of CO_2, with minor differences dependent on facility type.
- Electricity prices were assumed at $50/MWh. For reference, the EIA average price for February 2019 was $51.80 per MWh of electricity for industrial customers in West South Central (AR, LA, OK, and TX).
- Fuel required to operate the amine system was assumed to be 2.5 to 3.5 MMBTU per million tonnes of CO_2, dependent on facility and solvent type.

Table 2-6 provides the specific energy use assumptions used for each facility type.

Facility Type	Reference Plant Size	Electricity & Gas	
		MWh/ tonne CO_2	MMBTU/ tonne CO_2
Natural Gas Processing	140 MMCF/D	0.10	0.0
Ethanol Production	150 million gal/yr	0.12	0.0
Ammonia Production	907,000 tonnes/yr	0.10	0.0
Hydrogen Production	87 MMCF/D	0.18	2.6
Cement Plants	1 million tonnes/yr	0.16	2.6
Refinery Fluidized Catalytic Cracking (FCC) Plants	60,000 barrels/ day	0.14	2.6
Steel/ Iron Plant	2.54 million tonnes/yr	0.16	2.6
Coal Power Plants	550 MW net	0.16	2.6
Industrial Furnaces (refining/ chemicals)	4x150 MMBTU/ hr	0.16	2.6
Natural Gas Power Plants	560 MW net	0.16	2.8

Table 2-6. *Amount of Electricity and Fuel Required for Reference Plants by Facility Type*

By adding the calculated capital and operating costs described, Table 2-7 provides a summary of estimated annualized capture costs per tonne of CO_2 captured for each reference plant within a facility type. High and low ranges are provided to reflect potential differences within a facility type or industry. For example, the range provided for coal power and natural gas combined cycle (NGCC) reference plants are intended to reflect the potential differences in capacity utilization of various plants, ranging from 35% to 85%, with a midpoint of 55%. The ranges for the other sources reflect regional variations in construction costs, labor costs, and commodities transport. For most sources, midpoint of the range was used to assess costs.

Facility Type	Reference Plant Size	CO_2 Volume Captured (tonnes/year)	Unit Capital Cost 20-Year Life Low-High ($/tonne)	Unit Non-Energy Cost 20-Year Life Low-High ($/tonne)	Unit Energy Operating Cost ($/tonne)	Unit Total Cost 20-Year Life Low-High ($/tonne)
Natural Gas Processing	140 MMCF/D	24,000	7-12	8-13	9	23-35
Ethanol Production	150 million gal/yr	342,000	6-10	8-13	11	24-34
Ammonia Production	907,000 tonnes/yr	389,000	6-11	6-10	9	21-30
Hydrogen Production	87 MMCF/D	340,000	19-33	15-26	28	61-88
Cement Plants	1 million tonnes/yr	842,000	17-29	22-37	28	64-95
Refinery Fluidized Catalytic Cracking (FCC) Plants	60,000 barrels/day	374,000	43-72	28-47	29	97-150
Steel/Iron Plants	2.54 million tonnes/yr	3,324,000	26-44	22-38	29	75-113
Coal Power Plants	550 MW net	3,089,000	33-55	22-37	30	83-124
		1,999,000	54-91	35-59	26	113-178
		1,272,000	89-149	57-95	23	166-268
Industrial Furnaces (refining/chemicals)	4x150 MMBTU/hr	220,000	49-83	33-55	31	110-171
Natural Gas Power Plants	560 MW net	1,279,000	34-58	29-49	31	93-140
		827,000	57-95	47-79	26	122-192
		527,000	92-155	75-126	23	179-290

Note: The addition of unit CAPEX and OPEX costs in the above table may result in rounding errors when compared to actual unit total costs provided.

Table 2-7. *Total Estimated Capture Cost ($/tonne) for Reference Plants by Facility Type*

Several publicly available studies on the cost of CCUS were considered during development of the capture cost assumptions and, where appropriate and supported by data, the assumptions were used as the basis to develop the costs shown in Table 2-7.[12]

The capture costs presented in this chapter are commonly referred to as the total spent costs. There are other ways to express capture costs, including “avoided costs,” which considers the total amount of CO_2 emissions avoided and includes the costs and CO_2 impact of the energy required to operate the capture process to produce the same level of useful energy. These costs are frequently described in terms of a cost per unit of energy produced (e.g., per MWh of electricity). It is worth noting that when capture costs for coal and natural gas are compared, the avoided cost for natural gas power plant can be lower due to lower fuel costs and higher rates and conversion efficiency of fuel to power. For purposes of determining the level of incentives needed to achieve widespread CCUS deployment, this study uses total spent costs.

C. Transport Cost Assessment

Transport costs were estimated based on the assumption that a pipeline system is generally the most economical means of moving CO_2 from sources to storage locations (sinks). Transportation from source to sink was assessed for the largest 80% of emitting sources in the 2018 EPA FLIGHT database. In total, approximately 900 source-to-sink combinations were assessed. It was assumed that if the combined volume from multiple sources within 0.5-degree latitude by 0.5-degree longitude grid was greater than 2 Mtpa, a pipeline was justified. Truck or rail transport was assumed for the remaining sources. As previously noted, although not included in the 2018 EPA FLIGHT database, ethanol plants with emissions greater than 100,000 Mtpa were included in this study. These emissions were calculated by state and assumed to originate from a single point within that state.

A pipeline network was designed that connected sources to the nearest sink assuming the shortest distance between source and sink. A factor of 20% was added to those distances to account for routing the pipelines around obstacles, away from populated areas, and along existing rights-of-way. Some segments of the local pipelines naturally fell into logical routes for trunk lines (larger diameter pipelines that connect a number of smaller pipelines). Those segments were therefore upsized into three trunk lines located in the Midwest, South Central, and Eastern parts of the United States.

Individual pipeline segment diameters were sized according to the CO_2 flow rate to be transported. The resultant pipeline diameters were rounded up to the nearest inch. The cost to construct the pipeline segments was estimated on an inch-mile basis formulated from historical construction costs, with pumping station spacing built into the regional pipeline cost. For purposes of modeling the cost, the United States was divided into four longitudinal regions—Western, Rockies, Central, and Eastern. Pipeline costs within each region were estimated using a regional construction cost basis. The longitudinal division between each region, and the estimated costs to construct pipelines within the regions, are shown in Table 2-8.

Region	Longitude		Pipeline Cost ($ Thousands/ inch-mile)
	min	max	
Western		-114.75	120
Rockies	-114.75	-102.50	150
Central	-102.50	-85.75	80
Eastern	-85.75		100
Midwest Trunk line	80		
South-Central Trunk line	80		
Eastern Trunk line	100		

Table 2-8. *Estimated CO_2 Pipeline Costs by Region*

Installed costs for trunk lines were estimated based on historic data with the Midwest and South-Central lines costing $80 thousand/inch-mile and the Eastern trunk line being more expensive, at $100 thousand/inch-mile. Each of the trunk lines was designed with a capacity of 100 Mtpa.

The transport cost for each point source was estimated by multiplying the straight-line distance between each source and its associated sink by the capacity needed to transport the source CO_2 volume on a cost per tonne-mile basis. This transport cost ranges between $2 and $38 per tonne for a 20-year project.

To address the modeling assumption that CO_2 pipelines are instantly present at a given source and have a large enough diameter to transport the emissions, an additional $5 per tonne cost was added to the first 100 Mtpa of pipeline capacity. This reflects the estimation of a $500 million incentive for the upfront investment needed to start installation of the CO_2 pipeline infrastructure.

D. Storage Cost Assessment

Storage cost assumptions were based upon the September 2017 version of the National Energy Technology Laboratory's FE/NETL CO_2 Saline Storage Cost Model (FE/NETL Model).[13,14] The 684 individual subsurface formations in the FE/NETL Model were aggregated into five storage regions as shown in Figure 2-9.

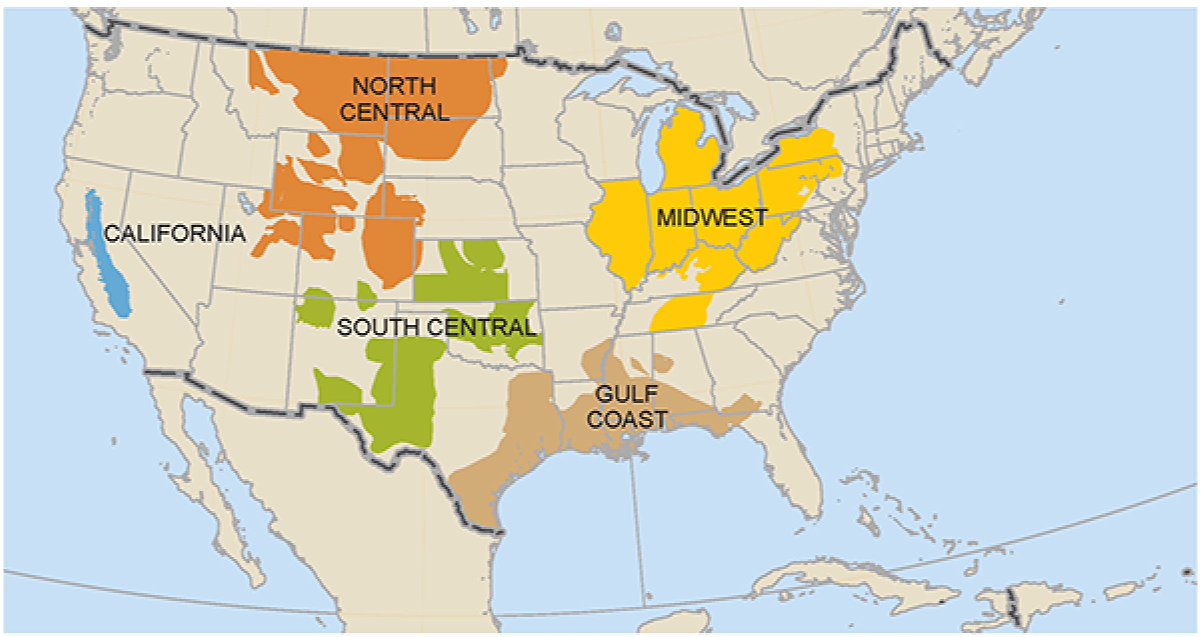


Figure 2-9. *Regional Groupings of Select USGS Basins*

The FE/NETL Model assumes that captured CO_2 would be directed to the lowest cost storage formations within each region. For purposes of this study, that resulted in four regions with a storage cost threshold of $15/tonne, and one region North Central, with a threshold of $22/tonne, due to higher overall costs associated with that region. Formations with costs higher than the defined thresholds were excluded, as were formations along the Atlantic coast and in South Florida because they are unlikely locations for significant volumes of CO_2 storage. According to the FE/NETL Model, 620 gigatonnes of total U.S. storage capacity is potentially available in formations with estimated storage cost at, or below, the threshold costs, which is adequate to accommodate future captured CO_2 volumes.

Storage volume-weighted average costs were calculated for each region using the FE/NETL Model assumptions, but included the following exceptions:

- The ratio of monitoring wells to injection well was reduced to 2:1 from 9:1. The study assumed that on average, each injection well has one in-zone well and one above-zone well to measure pressure and saturation, and that the two monitoring wells would need to be placed at different locations optimized to address site-specific risk.
- The number of seismic surveys was reduced to six (one for site selection and characterization, three during operations, and two during post-injection site care [PISC]) from 16 (one for site selection and characterization, six during operations, and 10 during PISC).

These adjustments to the FE/NETL Model assumptions were made on the basis that injection projects target the best-quality lowest-risk sites. As a result, sites that the FE/NETL Model assumed would require monitoring would likely be excluded during initial site selection and characterization in the model presented here. These adjustments to the assumptions had the effect of reducing the cost of storage by approximately 50% compared with the FE/NETL Model assumptions as well as reducing the total available U.S. storage capacity.

Table 2-9 summarizes the volume-weighted average storage cost calculated for each region using these assumptions. Because limited work has been done to identify specific storage sites within each storage region, these average storage costs were assumed to apply uniformly throughout each region. Some sites will be more expensive, and some sites will be less expensive within a region, so an average cost is uniformly applied to the entire region.

Region	Average Cost ($/tonne)	Storage Volume (gigatonnes)
California	$7	11
Midwest	$7	54
North Central	$11	85
Gulf Coast	$7	135
South Central	$8	129
Overall Average/ Total	$8	413

Table 2-9. *Volume-Weighted Storage Cost by Region*

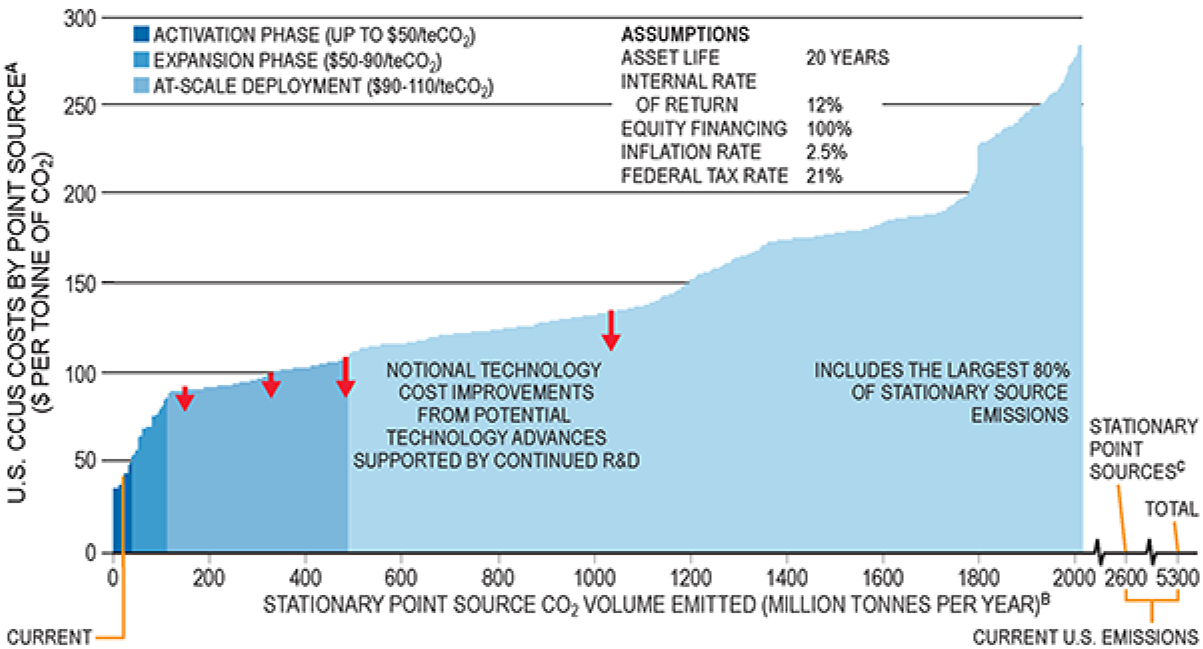
E. Additional Considerations and Assumptions

The long-term nature of a CCUS investment suggests that financiers will require assurance that the source of CO_2 will be available for the entire financing period (i.e., 20 years). For industries, less likely to invest in CCUS on their own, it is envisaged that a long-term CO_2 offtake agreement between the emitter and the industries that are willing to invest in the CCUS equipment and capture the emissions may be required. The offtake agreement commits the emitter to providing CO_2 volumes for that financing period. These emitters will likely require an incentive as compensation for entering into the long-term commitment of a CO_2 offtake agreement and having capture equipment adjacent to their facilities. For purposes of the cost curve modeling, an emitter incentive (CCUS cost) of $5 per tonne was applied to all industry emitters other than oil, natural gas, and power generation.

For power plants, the capture cost per tonne is affected by the power plant utilization. As power plant utilization rates decline, primarily due to increased use of renewable forms of energy, the effective cost to capture and separate CO_2 increases. To account for this, each third of total power plant capacity was assumed to be running with utilizations of 85%, 55%, and 35%.

VI. ENABLING FUTURE CCUS PROJECTS

As described earlier, at-scale deployment of CCUS in the United States will require an economic incentive for all participants in the supply chain—from emission source and capture to transport and storage. Creating these supply chains will require significant capital investment as well as ongoing operating expenses. Figure 2-10 depicts the estimated cost to deploy CCUS, assuming a 12% return on investment as shown in Figure 2-6.



Cost Curve Notes:

A. Includes project capture costs, transportation costs to defined use or storage location, and use/storage costs; does not include direct air capture.

B. This curve is built from bars each of which represents an individual point source with a width corresponding to the total CO_2 emitted from that individual source.

C. Total point sources include ~600 Mtpa of point sources emissions without characterized CCUS costs.

Figure 2-10. *U.S. CCUS Cost Curve with CO2 Capture Volume by Phase*

Within the cost curve, three transition points were identified and denote three phases of CCUS deployment projected to occur over a 25-year period—activation, expansion, and at-scale. A set of actions has been identified for each phase of implementation to enable the growth of CCUS in the United States over the next 25 years. The phases are based upon enabling the lowest cost supply chains first, with consideration given to ease and speed of implementation.

- Activation Phase — Aligns existing policies and regulations with existing incentives of up to $50/tonne enabling an additional 25 Mtpa to 40 Mtpa, doubling existing CCUS capacity within the next 5 to 7 years. It is important to note that under existing policies, capacity in this phase will likely remain at the lower end of the range, primarily due to the 12-year life of the Section 45Q tax incentive.

- Expansion Phase — Extends and broadens existing policies, bringing total incentives up to $90/tonne and enabling an additional 120 Mtpa within the next 15 years. This phase also requires developing a durable regulatory and legal environment.
- At-Scale Phase — Brings total CCUS capacity to ~500 Mtpa, enabled by incentives of about $110/tonne.

While the NPC does not expect CCUS will be applied to all U.S. stationary sources, at this level, CCUS would be deployed on nearly 20% of U.S. stationary emissions, which is a level the NPC has defined as at-scale deployment. It is also worth noting that at an incentive of ~$150/tonne, CCUS could be economically applied to about 1.2 billion tonnes of CO_2 emissions, which is just under half of all U.S. stationary emissions and nearly a quarter of total U.S. CO_2 emissions. Achieving that level of CCUS deployment, when combined with continued RD&D and infrastructure development, will drive down technology costs and could also create other carbon management pathways including greater use of hydrogen, bioenergy with CCS, and direct air capture.

Put into context, 500 Mtpa of CCUS capacity is roughly equivalent to 14 million barrels of oil, which is larger than the volume of U.S. domestic production in 2019. Achieving CCUS deployment at that level will require a total cumulative investment over 25 years of approximately $680 billion, of which about $28 billion is for CO_2 pipeline infrastructure development. This level of investment and infrastructure development has the potential to generate $21 billion in annual GDP and support 233,000 annual jobs.[15]

Chapter 3, "Policy, Regulatory, and Legal Enablers," describes the existing policy and regulatory framework in the United States for CCUS and explains the challenges it presents for further deployment. It details the specific policy driven financial incentives and the regulatory improvements that will be needed to enable deployment across the three phases of implementation: activation, expansion, and at-scale. The chapter also describes the critical role that RD&D plays in improving performance, reducing costs, and advancing alternative CCUS technologies, making the case for continued investment by both government and industry to decrease the cost of CO_2 capture technology and to identify and characterize suitable large-scale storage locations.

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1 Large-scale as defined by the Global CCS Institute.

2 IEAGHG, "CO_2 Pipeline Infrastructure," 2013/18, December 2013. https://ieaghg.org/docs/General_Docs/Reports/2013-18.pdf.

3 Sweatman, R. E., Crookshank, S., and Edman, S. (January 1, 2011). "Outlook and Technologies for Offshore CO_2 EOR/CCS Projects," Offshore Technology Conference, doi:10.4043/21984-MS.

4 Folger, P. (2016). "Recovery Act Funding for DOE Carbon Capture and Sequestration (CCS) Projects," Congressional Research Service, February 18, 2016, 24 pp. https://fas.org/sgp/crs/misc/R44387.pdf.

5 IEA Tracking Clean Energy Progress, CCUS in power. (May 24, 2019). https://www.iea.org/tcep/power/ccus/. Accessed November 19, 2019.

6 These ethanol plants report only combustion emissions to the EPA. To estimate the ethanol fermentation CO_2 emissions, the yearly output of ethanol for each plant was multiplied by the stoichiometric conversion factor of ethanol to CO_2 to arrive at CO_2 emissions.

7 IEAGHG. (2019). “Further Assessment of Emerging CO_2 Capture Technologies for the Power Sector and their Potential to Reduce Costs,” p. 278.

8 Examples of differences for individual projects include:

Costs for individual projects will be different based on specific scale and local market conditions for labor and equipment supply and can therefore result in alternative economic results for individual projects.

Operating costs for individual projects will be different based on their ability to integrate with existing operations and can therefore result in alternative economic results for individual projects.

Financing for individual projects will be different based on specific risks and market conditions. For example, the National Engineering Technology Laboratory (NETL) baseline cost estimates for coal and gas power (Revision 4) assume an IRR of ~8% for 45% equity and an interest rate of ~3% for 55% debt financing and can therefore result in alternative economic results for these types of projects.

9 Cost assessment tool can be found at https://www.gaffneycline.com/carbon-capture-use-and-storage-ccus-project-evaluations.

10 Modified Accelerated Cost Recovery System is the current tax depreciation system in the United States.

11 Comparisons with other gases at high pressure or temperature (>200°C) are not appropriate.

12 Studies reviewed include (among others):

National Energy Technology Laboratory and Booz Allen, “Cost of Capturing CO_2 from Industrial Sources,” https://www.netl.doe.gov/projects/files/CostofCapturingCO2fromIndustrialSources_011014.pdf.

U.S. Department of Energy, National Energy Technology Laboratory. (2016). “Eliminating the Derate of Carbon Capture Retrofits,” https://www.netl.doe.gov/energy-analysis/details?id=2886.

International Energy Agency. (June 2019). “The Future of Hydrogen: Seizing Today’s Opportunities,” https://www.iea.org/reports/the-future-of-hydrogen.

Kuramochi, T., Ramirez, A., Turkenburg, W. C., and Faaij, A. (2012). “Comparative Assessment of CO_2 Capture Technologies for Carbon-Intensive Industrial Processes,” *Progress in Energy and Combustion Science* 38(1):87-112, https://www.researchgate.net/publication/251576085_Comparative_assessment_of_CO2_capture_technologies_for_carbon-intensive_industrial_processes.

Rubin, E. S., Herzog, H. J., and Davison, J. E. (2015). “The Cost of CO_2 Capture and Storage,” *International Journal of Greenhouse Gas Control* 40, https://www.researchgate.net/publication/282489683_The_cost_of_CO2_capture_and_storage.

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Carbon Utilization Council. (July 25, 2018). “Making Carbon a Commodity: The Potential of Carbon Capture RD&D,” http://www.curc.net/webfiles/Making Carbon a Commodity/180724 Making Carbon a Commodity FINAL with color.pdf.

13 Grant, T. and Morgan, D., “FE/NETL CO_2 Saline Storage Cost Model: Model Description and Baseline Results,” DOE/NETL-2014/1659, July 18, 2014.

14 National Energy Technology Laboratory. (2017). “FE/NETL CO_2 Saline Storage Cost Model.” U.S. Department of Energy. Last Update: September 2017 (Version 3), https://edx.netl.doe.gov/dataset/fe-netl-co2-saline-storage-cost-model-2017.

15 See ERM memo, Appendix D.

Chapter Three

POLICY, REGULATORY, AND LEGAL ENABLERS

I. CHAPTER SUMMARY

The U.S. federal and several state governments have a long history of enacting policy, legislation, and regulations intended to support the development and deployment of carbon capture, use, and storage (CCUS). As noted in Chapter 2 of this report, four of the ten existing CCUS projects in the United States received significant levels of financial policy support, in various forms, to enable their development. This world-leading policy support includes a 20-year history of Department of Energy (DOE) leadership and funding in leading CCUS research, development, and demonstration (RD&D) programs and projects, including support for industrial-scale demonstration projects like Petra Nova, Great Plains, ADM, Air Products, and hundreds of small-scale R&D projects involving various CCUS technologies.

This chapter explains the existing policy and regulatory framework in place in the United States for CCUS and describes the current challenges it presents for CCUS development and deployment. It then details, across three proposed phases of implementation, the changes that will be needed to enable CCUS deployment at scale within the next 25 years. This chapter also describes the critical need for RD&D and provides detailed recommendations for its increased support.

CCUS deployment has been supported by federal tax policy as well as state and regional incentives. For example, the Energy Improvement and Extension Act of 2008 (amended 2009) provides a tax credit to operators of carbon capture equipment for the capture and storage of up to 75 million tonnes of CO_2 (Section 45Q). To date, approximately 85% of those tax credits have been claimed.[1] The Bipartisan Budget Act of 2018 (BBA) amended Section 45Q, significantly expanding the value, duration, and eligibility of the credits.

A strong regulatory and legal framework has also been developed to ensure safe and secure transportation and storage of CO_2. Agencies such as the Environmental Protection Agency (EPA), Department of the Interior (DOI), and the Pipeline and Hazardous Materials Safety Administration (PHMSA), among others, have established regulations, guidance, and orders that underpin federal CCUS policy. For example, the EPA has developed specific regulatory frameworks under the Safe Drinking Water Act (SDWA) to protect underground sources of drinking water (USDW), and maintains the accounting protocols under the Clean Air Act Greenhouse Gas Reporting Program for the injection of CO_2 into geologic storage; while PHMSA sets and regulates the standards for design, construction, and operation of CO_2 pipelines.

Originally driven by businesses that use natural sources of CO_2 for enhanced oil recovery (EOR), the United States has successfully developed ~80% of the world's CO_2 capture capacity[2] and ~85% of the world's CO_2 pipelines, establishing itself as the world leader in CCUS project deployment. However, today's ~25 million tonnes per annum (Mtpa) of CCUS capacity represents less than 1% of U.S. stationary emissions. As described in the previous chapter, currently only a small volume of CO_2 can be economically captured, transported, and stored. Achieving at-scale CCUS deployment (e.g., 20% of U.S. stationary emissions) will require establishing adequate financial incentives through government policy underpinned by a durable regulatory and legal framework, the implementation of which should occur through a series of phases and prioritized based on deployment economics and ease of implementation.

The activation phase is designed to enable high-concentration CO_2 sources located close (~50 miles) to suitable storage or existing CO_2 pipeline—the most financially attractive projects—and offers recommendations that clarify existing policies and regulations and can be implemented quickly, without Congressional action. The expansion phase is focused on enhancing and expanding existing policies and developing a durable regulatory framework to enable additional CCUS capacity. This additional capacity is likely to be deployed where large high-concentration CO_2 sources can be connected to suitable economically accessible storage locations and in certain circumstances, where lower-concentration CO_2 sources can take advantage of infrastructure that has been developed because of high-purity source CCUS deployments. These CO_2 sources are generally more expensive to capture, transport, and store than those in the first phase. While this phase leverages existing policies and regulations, the recommendations include amendments that will require Congressional action. The third phase, at-scale deployment, intends to unlock a much larger volume of low-concentration CO_2 sources, including industries such as power generation, refining, chemicals, cement, and steel. Enabling capture at these sources will require substantially increased support driven by national policies that will require time to develop and enact. As a result of the significant allocation of resources needed to reach this level of deployment (i.e., ~500 Mtpa), the policies developed should be thoroughly evaluated and as economically efficient as possible.

II. EXISTING POLICY AND REGULATORY FRAMEWORK

The U.S. federal and several state governments have a long history of enacting policy, legislation and regulations intended to support the development and deployment of CCUS. Many of the financial incentives that have been implemented in the United States fall into two major categories: those that provide tax relief or support, and those that provide direct funding or funding support. Financial incentives that provide tax relief or support include mechanisms such as investment tax credits, production tax credits, tax-exempt financing, and tax advantaged corporate structures. Financial incentives that provide funding or funding support include mechanisms such as direct funding, loans, and loan guarantees. Additionally, the United States has a strong regulatory framework to ensure safe and secure transportation and storage of CO_2. From capture through transport and ultimately to storage, various U.S. federal and state agencies have developed specific regulatory and permitting requirements to ensure the safety of, and address the risks associated with, CCUS.

A. Financial Incentives

A range of federal tax credits exist today to incentivize emissions reduction technology and energy programs. To date, the tax incentives that support CCUS have taken the form of either Production Tax Credit (PTC) or Investment Tax Credit (ITC). A PTC provides a tax rebate based on the annual activity of the eligible project: this could be electric generation in the case of an electric project or annual tonnage of CO_2 stored underground for a carbon capture project. The most widely known PTC used to date is the PTC to incentivize wind generated power based on a per kilowatt hour of generation. An ITC is another tax credit incentive for businesses designed to encourage capital investment; but in the case of an ITC, the rebate is based on the cost of the equipment purchased for the project—rather than on the annual activity as in a PTC. The result is a reduction in the tax burden for the business, minimizing the amount of taxes owed.

1. Production Tax Credit (Section 45Q)

The Section 45Q tax credit is a form of PTC for an amount of CO_2 captured by the taxpayer at a qualified facility and is either “disposed of by the taxpayer in secure geologic storage”[3] or is “used by the taxpayer as a tertiary injectant in a qualified enhanced oil or natural gas recovery project and disposed of by the taxpayer in secure geological storage”[4] or “utilized by the taxpayer”[5] through fixation, chemical conversion or “for any other purpose for which a commercial market exists.”[6] This program began under the Energy Improvement and Extension Act of 2008 (amended 2009). In 2018, Congress increased the value of the credit, eliminated the 75 million metric ton (tonne) cap but set a defined period in which the credit could be claimed, and extended the tax credit to include utilization beyond EOR.

As amended, in 2009, Section 45Q provided a credit for capturing CO_2 and disposing of the CO_2 in secure geological storage within the United States in accordance with the following terms:

1. A credit of $10 per tonne of CO_2 that is captured by a taxpayer at an industrial facility and used as a tertiary injectant in an enhanced oil or gas recovery project, and disposed of in secure geological storage
2. A credit of $20 per tonne of CO_2 that is captured by a taxpayer at an industrial facility and disposed of in secure geological storage
3. A cap on the amount of credit claimed of 75 million tonnes of CO_2
4. A requirement that the “The Secretary [of Treasury], in consultation with the Administrator of the Environmental Protection Agency, the Secretary of Energy, and the Secretary of the Interior, shall establish regulations for determining adequate security measures for the

geological storage of carbon dioxide... such that the carbon dioxide does not escape into the atmosphere."

In February of 2018, Congress passed the Bipartisan Budget Act of 2018, which increased the amount of the credit, provided a 12-year period to claim the credit, expanded the definition of qualifying utilization projects beyond EOR, and allowed direct air capture to be eligible for the credit. Figure 3-1 shows the level of tax credit available under the amended 45Q. Key provisions of the 2018 statute include:

- Increasing the tax credit over a 10-year period to \$35/tonne for CO_2 used as a tertiary injectant for EOR or natural gas recovery and disposed of in secure geological storage
- Increasing the tax credit over a 10-year period to \$50/tonne for CO_2 disposed of in secure geological storage
- Applying the credit for a 12-year period beginning on the date new carbon capture equipment is originally placed in service at a qualified facility
- Requiring construction of new carbon capture equipment to begin before January 1, 2024
- Establishing minimum capture requirements for categories of facilities (volumes detailed in Figure 3-1) to receive the tax credit
- Allowing a credit for utilization that can be shown, based upon an analysis of life-cycle greenhouse gas (GHG) emissions, to have been captured and permanently isolated from the atmosphere, or displaced from being emitted into the atmosphere

- Allowing for the recapture of the credit for any CO_2 that ceases to be captured, disposed of, or used as a tertiary injectant
- Allowing the tax credit to be transferred from the equipment owner to the party that disposes of, uses, or utilizes the CO_2
- Repeating the requirement that the Internal Revenue Service (IRS), after consultation with EPA, DOE, and DOI, promulgate regulations defining "secure geological storage."

	MINIMUM SIZE OF ELIGIBLE CARBON CAPTURE PLANT BY TYPE (KILOTONNES OF CO_2/YR)			RELEVANT LEVEL OF TAX CREDIT IN A GIVEN OPERATIONAL YEAR ($/T$CO_2$)									
TYPE OF CO_2 STORAGE/ USE	POWER PLANT	OTHER INDUSTRIAL FACILITY	DIRECT AIR CAPTURE	2018	2019	2020	2021	2022	2023	2024	2025	2026	BEYOND 2026
DEDICATED GEOLOGICAL STORAGE	500	100	100	28	31	34	36	39	42	45	47	50	INDEXED TO INFLATION
STORAGE VIA EOR	500	100	100	17	19	22	24	26	28	31	33	35	
OTHER UTILIZATION PROCESSES[1]	25	25	25	17[2]	19	22	24	26	28	31	33	35	

[1] Each CO_2 source cannot be greater than 500 kilotonnes of CO_2 (KTCO_2) per year.
[2] Any credit will only apply to the portion of the converted CO_2 that can be shown to reduce overall emissions.

Source: Energy Futures Initiative, 2018.

Figure 3-1. *Section 45Q Tax Credit Value for Different Sources and Uses of CO_2*

The Section 45Q tax credit is earned by the taxpayer who owns the carbon capture equipment at a qualified facility and applies to every tonne of qualified carbon oxides[7] captured during the 12-year period beginning on the date the carbon capture equipment is placed in service. The taxpayer who earns the credit may transfer the credit to the entity that disposes of the qualified carbon oxide, uses it for EOR, or utilizes it in another way. Credit transferability enhances the options for a project to fully monetize the value of the tax credit and to secure financing.

Although the 2018 amendments to Section 45Q significantly expanded the value, duration and eligibility of these tax credits, clarifications regarding the access and use of the credits has not yet occurred, creating significant uncertainty for those considering investment. On June 5, 2019, the IRS issued Notice 2019-32 stating that the U.S. Department of the Treasury (Treasury) and IRS intend to issue regulations under Section 45Q and solicited public comments on many aspects of the credit, including the start of construction, transferability, recapture, and secure geologic storage, which are top priorities identified by this study. As of the date of this report, regulations had not yet been issued.

2. Enhanced Oil Recovery Production Tax Credit (Section 43C)

The EOR production tax credit under Section 43 of the Internal Revenue Code was put into place to incentivize EOR projects when oil prices fall below a reference price. The EOR tax credit offers a 15% federal tax credit on qualified costs of projects implemented or expanded after 1990. The credit is applicable to specific project costs, both capital expenditure and operating expense, and reduces the overall tax burden for the owner of the working interest. Because the credit was put in place during a period of relatively low oil prices, its value is based on reference price for oil price of $28 per barrel (adjusted for inflation). Once the reference price exceeds the original $28 per barrel of oil (adjusted for inflation), the credit is reduced. The credit is fully phased out once the reference price exceeds the inflation adjusted price by $6. Based on 2019 oil prices, the credit is not available. In 2019, the reference price of $61.41 exceeds the inflation adjusted oil price of $48.54 by more than $6, resulting in a complete phase out of the credit for 2019.

3. Investment Tax Credit (Section 48)

Policy support in the form of investment tax credits for CCUS to date has emphasized demonstrations of CCUS at coal plants. These policies included Section 48A investment tax credits for coal plants with CCUS (26 U.S. Code § 48A) and Section 48B investment tax credits for industrial gasification (26 U.S. Code § 48B).

In 2005, Congress established the “Credit for Investment in Clean Coal Facilities” in the Energy Tax Incentives Act (ETIA). ETIA authorized $1.3 billion in tax credits to support advanced coal-based generation technology designed to incentivize the construction of new, highly efficient coal units, and to incentivize projects at existing units to improve their efficiency. In 2008, Congress provided an additional $1.25 billion in tax credits through the Energy Improvement and Extension Act, which increased the value of the tax credit to 30% of the eligible investment and imposed a new requirement to capture and store at least 65% of the CO_2 in order to be eligible for the tax credits. As part of the BBA, Sections 48A and 48B of the American Recovery and Reinvestment Tax Act of 2009 were amended and authorized by Congress for $3.15 billion.

The tax credit is available to the investor the year qualifying equipment is placed into service whether it is a newly constructed unit, retrofit, or equipment that was acquired if the original use of the property commences with the taxpayer. The tax credit is available to integrated gasification combined cycle (IGCC) projects and advanced coal-based generation technologies. The amount of the tax credit is 20% for IGCC, up to $800 million, and 15% and 30% for advanced coal projects, based on when the equipment is placed into service, with limits of $500 million and $1.2 billion respectively.

4. Other Tax Incentives

In addition to tax credits, other tax-related instruments and structures can provide incentives for CCUS deployment. For example, master limited partnerships (MLPs) and private activity bonds (PABs) could provide incremental incentives to CCUS projects. Historically, MLPs have been crucial to building infrastructure and pipeline networks by allowing a lower effective tax rate for investors. PABs can lower the cost of debt and provide incremental incentives for potential CCUS projects. Currently, CCUS projects do not have the ability to use MLP structures or issue PABs.

An MLP is a partnership that is publicly traded and listed on a national securities exchange. Its two defining features are the ability to pass through gains and losses to partners without corporate double taxation, while at the same time being able to access public stock markets in a way not normally available to partnerships. For a corporation or C-corp., income is subject to corporate-level income taxes, and any shareholder would additionally be subject to income tax on dividends received. In contrast, MLPs and other types of partnerships, and limited liability corporations, pay no income tax at the partnership level for income derived from qualified sources, as defined in 26 U.S. Code § 7704(d), and instead pass through to their limited partner unitholders their pro rata share of taxable income. Typically, the benefits of avoiding double taxation in a partnership are partly counteracted by U.S. laws that generally prohibit partnerships from accessing the public stock markets—but MLPs are the exception to that restriction on public fundraising. These structures have the effect of reducing the overall costs of financing projects. MLPs have historically been used for oil and natural gas exploration and for coal mining, transportation, and processing. The challenge with the existing MLP structure is that it is only applicable to qualifying income from depleting resources such as natural gas, oil, and naturally occurring CO_2. The Master Limited Partnership Parity Act, introduced in Congress in 2019, would allow a broad range of clean energy and renewable projects, including carbon capture projects, to be eligible for MLP structuring and tax treatment—combining the benefits of avoiding double taxation and ready access to the public stock markets.

5. Tax-Exempt Bond Financing

Private Activity Bonds are a form of tax-exempt debt issued by a U.S. state or local government entity “on behalf of” certain Congressionally authorized categories of privately owned or privately used industrial development, transportation, or pollution control projects. That is, Congress sometimes allows tax-exempt bonds—normally only allowed to be issued for traditional government projects—to be used for certain special types of private projects. They are essentially corporate bonds that have the benefit of lower interest rates paid on tax free municipal bonds. The rules by which, and purposes for which, such PABs can be issued were substantially overhauled by the Tax Reform Act of 1986. “The federal government currently allocates to the states permission to issue approximately $33 billion of PABs annually.”[8] The transactions involve the sale of bonds to investors by the government agencies, which then loan the bond proceeds to the privately owned project. The loan to the private company mirrors exactly the terms of the bond issued to the public, and repayment of that public bond is based solely on cash flows from the loan. Because investors pay no tax on the interest income, they require a lower interest rate from the company than would be the case for taxable debt.

PABs could be used to attract investment in CCUS projects if Congress amends the portion of the tax code that lists the types of projects permitted to use PABs to include CCUS projects.[9] The benefit to the company is the lower cost of borrowing due to the tax-exempt status of the bonds. PABs provide projects that might not otherwise qualify for debt financing with access to long-term bond financing.

6. Cost-Share Grants and Cooperative Agreements

Grants are financial awards given by the government to partially fund a project. The U.S. government has a long history of providing competitively awarded, cost-share grants as a mechanism to fund ideas and projects that provide public services. Cost-share grants and cooperative agreements are often used to stimulate the economy during recessions, fund infrastructure development, or support innovative research into new technologies.[10] Because they are funded by tax dollars, they are subject to a number of compliance and reporting processes to ensure the use of the funds is consistent with the purpose of the grant.

In 2009, the American Recovery and Reinvestment Act (Recovery Act; P.L. 111-5) provided DOE $3.4 billion for CCUS projects and activities.[11] The large and rapid influx of funding for industrial-scale CCUS projects was intended to accelerate development and demonstration of CCUS in the United States. Table 3-1 shows the allocation of Recovery Act funding to CCS projects. Approximately $1.4 billion of the $3.4 billion allocated for CCUS activities was unspent by the 2015 spending deadline because six of the nine major development projects were cancelled or withdrawn. Various issues, including lengthy Underground Injection Control (UIC) Class VI permitting periods, court challenges, poor development planning, ownership structures lacking large project implementation experience, and lawsuits, prevented projects like those listed in Table 3-1 from moving forward prior to the spending deadline.

Project	Type	Amount of Recovery Act Award ($)	Amount Unspent at Sept. 30, 2015 Deadline ($)	Net Recovery Act Spent ($)	% Spent	% Returned
FutureGen—Capture	Stand-Alone	589,744,000	(473,077,241)	116,666,759	20%	80%
FutureGen—Transport & Storage	Stand-Alone	404,985,000	(321,716,380)	83,268,620	21%	79%
FutureGen Total		**994,729,000**	**(794,793,621)**	**199,935,379**	**20%**	**80%**
Hydrogen Energy California	CCPI Round III	275,000,000	(122,171,564)	152,828,436	56%	44%
Summit Texas Clean Energy	CCPI Round III	211,097,445	(104,223,677)	106,873,768	51%	49%
NRG Energy/Petra Nova	CCPI Round III	167,007,179		163,007,179	100%	0%
AEP Mountaineer	CCPI Round III	146,493,376	(129,613,108)	16,880,268	12%	88%
CCPI Totals		**795,598,000**	**(356,008,349)**	**439,589,651**	**55%**	**45%**
Leucadia Energy, LLC	ICCS Large Demo	261,382,000	(248,623,661)	12,758,339	5%	95%
Archer Daniel Midlands	ICCS Large Demo	141,405,945		141,405,945		
Air Product & Chemicals, Inc.	ICCS Large Demo	284,012,496		284,012,496		
Research Triangle Institute	ICCS Advanced Gasification	168,824,716		168,824,716		
ICCS Large Project Totals		**855,625,157**	**(248,623,661)**	**607,001,496**	**71%**	**29%**
All Other ICCS Projects	ICCS	630,751,232		630,751,232		
ICCS Totals		**1,486,376,389**	**(248,623,661)**	**1,237,752,728**	**83%**	**17%**
Grand Totals		**3,276,703,389**	**(1,399,425,631)**	**1,877,277,758**	**57%**	**43%**

Source: Congressional Research Service, *Recovery Act Funding for DOE Carbon Capture and Sequestration (CCS) Projects*, February 18, 2016.

Table 3-1. *DOE CCS Projects with Recovery Act Funding (nominal dollars)*

DOE provided the unspent $1.4 billion in funding for 785 RD&D projects. Recovery Act funding was intended, in part, to help DOE achieve its RD&D goals as outlined in the department's 2010 Carbon Dioxide Capture and Storage RD&D Roadmap.[12] About 90% of the 785 RD&D projects involved coal technologies, such as coal gasification, which is the conversion of carbon-containing material into synthetic natural gas.

7. Loans and Loan Guarantee Programs

a. Transportation Infrastructure Finance and Innovation Act

One federal loan program is the Transportation Infrastructure Finance and Innovation Act (TIFIA) program, which was enacted in 1998 as part of the Transportation Equity Act for the 21st Century (TEA-21). TEA-21, as extended and expanded in subsequent law, provides credit assistance to major transportation investments in the form of direct loans, loan guarantees, and lines of credit. TIFIA provides credit assistance for qualified projects of regional and national significance. Many large-scale, surface transportation projects including highway, transit, railroad, intermodal freight, and port access are eligible for assistance. Eligible applicants include state and local governments, transit agencies, railroad companies, special authorities, special districts, and private entities. The government assumes the default risk associated with extending credit to project sponsors, which can include private firms. Loans typically are made at rates based on the U.S. Treasury’s cost of long-term borrowing, which in most cases will be substantially less than alternative borrowing rates. The TIFIA credit program offers three distinct types of financial assistance designed to address the varying requirements of projects throughout their life cycles:

- Secured (direct) loan — Offers flexible repayment terms and provides combined construction and permanent financing of capital costs; maximum term of 35 years from substantial completion; repayments can start up to 5 years after substantial completion to allow time for facility construction and ramp-up

- Loan guarantee — Provides full-faith-and-credit guarantees by the federal government and guarantees a borrower's repayments to nonfederal lender; loan repayments to lender must commence no later than 5 years after substantial completion of project
- Standby line of credit — Represents a secondary source of funding in the form of a contingent federal loan to supplement project revenues, if needed, during the first 10 years of project operations; available up to 10 years after substantial completion of project.

The amount of federal credit assistance may not exceed 33% of total reasonably anticipated, eligible project costs. The exact terms for each loan are negotiated between the U.S. Department of Transportation (DOT) and the borrower, based on the project economics, the cost and revenue profile of the project, and any other relevant factors. For example, DOT policy does not generally permit equity investors to receive project returns unless the borrower is current on TIFIA interest payments. TIFIA interest rates are equivalent to Treasury rates. Depending on market conditions, these rates are often much lower than what most borrowers can obtain in the private markets. Unlike private commercial loans with variable rate debt, TIFIA interest rates are fixed. Overall, borrowers benefit from improved access to capital markets and potentially achieve earlier completion of large-scale, capital intensive projects that otherwise might be delayed or not built at all because of their size and complexity and the market's uncertainty over the timing of revenues.[13] For CO_2 pipeline projects to be TIFIA eligible, Congress would need to enact new legislation providing budget authority for an expanded program and modify current statutory provisions.

b. DOE and USDA Loans and Loan Guarantee Programs

A loan guarantee is a contractual obligation between the government, private creditors, such as banks and other commercial loan institutions, and a borrower that obligates the federal government to cover the borrower's debt obligation in the event that the borrower defaults. The U.S. government has been providing financial assistance through loan guarantees since the 1930s. In some instances, instead of private parties providing loans that are then federally guaranteed, the U.S. government lends to the project directly from the U.S. Treasury's Federal Financing Bank. Because loan guarantees and direct loans generally accomplish the same purpose, the two terms are often used interchangeably.

Government loan guarantees help protect lenders against defaults, making it viable for commercial lenders to offer loans to borrowers who may not qualify for a loan on the open market. In 2005, Section 1703 of Title XVII of the Energy Policy Act created DOE's Loan Guarantee Program. DOE's loan guarantees are designed to facilitate the commercial introduction of new technologies through projects that are not yet financeable with private loans or debt investment, and, in doing so, promote the development of private debt sources.[14] By statute, DOE loan guarantees can be used to finance up to 80% of eligible project costs. One of the various solicitations currently available under the Innovative Energy Loan Guarantee Program is for Advanced Fossil Energy Projects, which has $8.5 billion of loan guarantee authority available. To qualify for the program, a project must avoid, reduce, or sequester air pollutants or greenhouse gases, employ a new or significantly improved technology, and provide a reasonable prospect of repayment.

To date, DOE has issued one conditional commitment for an Advanced Fossil Energy project and up to $2 billion has been approved for the Lake Charles Methanol Project that utilizes carbon capture technology for enhanced oil recovery. The Loan Program Office (LPO) administers a two-part application process under the Innovative Energy Loan Guarantee Program. Under Part I, an applicant provides basic project information for the LPO to determine if the project meets key eligibility criteria under the program. Under Part II, an applicant provides more detailed information for the LPO to conduct its due diligence and determine the overall terms of the financing. For the Part I application, a fee of $50,000 is required. For the Part II application, fees are tiered based on the amount of debt a project is seeking from DOE. Projects seeking less than $150 million in debt are responsible for paying $150,000, and projects seeking more than $150 million in debt are responsible for paying $350,000. In addition, the borrower pays a facility fee equal to 0.5% of the principal amount of the loan, and a $500,000 maintenance fee annually once the loan is approved.[15] The LPO continues to focus on CCUS projects under the Section 1703 program and is available for no-cost pre-application consultations with potential applicants.

Loan guarantees are available today from the U.S. Department of Agriculture (USDA) to projects under the Consolidated Farm and Rural Development Act. These loan guarantees are for economic development in rural areas. They can be used to purchase and develop land, easements, rights-of-way, buildings or facilities, and for business and industrial acquisitions when the loan will create or save jobs. To date, this program has not been utilized for a CCUS project.

B. Regulatory Framework for CCUS

The United States has a strong regulatory framework to assure safe and secure transportation and storage of CO_2. From capture through transport, and ultimately to storage, various U.S. federal and state agencies have developed specific regulatory and permitting requirements to ensure the safety of, and address the risks associated with, CCUS. The EPA has developed specific regulatory and permitting frameworks under the SDWA to protect USDW during injection and geologic storage operations. The EPA has developed accounting protocols under the Clean Air Act Greenhouse Gas Reporting Program for the injection of CO_2 into geologic storage. The CO_2 pipelines are regulated by the PHMSA within the DOT, which sets the standards for construction and operation.

1. EPA Underground Injection Control Program

The EPA established requirements for the injection of fluids into the subsurface under the SDWA through the UIC program. The statutory mandate for the UIC program is protection of USDW and that goal is fundamentally achieved by ensuring safe, long-term containment of the injected CO_2 streams and displaced formation fluid. With respect to CO_2 injection, these requirements include regulations for Class II wells used for EOR and Class VI wells used for geologic storage of CO_2 in saline formations. The UIC program in both cases is designed to prevent impacts to USDWs from the operation of injection wells and to confine injected fluids to the permitted formation(s). The Class II regulations were established as part of the original federal UIC program in 1980. Approximately 180,000 Class II wells are in operation in the United States of which approximately 80% inject fluids including water or CO_2 for the purpose of EOR.[16]

a. Class II Well Program

The Class II program is specific to oil and gas related injection wells used to inject fluids associated with oil and natural gas production including disposal wells (e.g., oil and natural gas wastewater disposal), EOR wells, and hydrocarbon storage wells other than natural gas. Many aspects of well design and operation are identified and documented as part of the Class II permitting process, including well design and construction, injection pressure, fracture pressure, injection fluid volumes, identification of confining strata, area of review, monthly fluid injection reports, and a plan for plugging and abandonment.

Most states with oil and natural gas activity have obtained Class II primacy and administer the UIC Class II program for permitting. It generally takes states an average of 90 days or less[17] to process a permit application for a Class II well.

This report does not recommend any changes to the Class II program. The EPA has recognized "CO_2 storage associated with Class II wells is a common occurrence and CO_2 can be safely stored where injected through Class II-permitted wells for the purpose of enhanced oil or gas-related recovery."[18]

b. Class VI UIC Well Program

In 2010, EPA developed a Class VI UIC program, with well design and permitting processes, for the injection of CO_2 for storage in saline formations. The program was developed to provide near-term regulatory certainty for CO_2 geologic storage, promote consistent permitting approaches, and ensure that permitting agencies are able to meet their demands. The elements of the rulemaking were based on the existing UIC regulatory frameworks, with modifications to address the unique nature of CO_2 injection for geologic storage. Class VI sets minimum technical criteria for the permitting, geologic site characterization, area of review (AoR) and corrective action, financial responsibility, well construction, operation, mechanical integrity testing, monitoring, well plugging, post-injection site care (PISC), and site closure. As demonstrated by ongoing commercial-scale projects, the injection of large volumes of CO_2 into deep saline formations can result in safe, secure, and permanent geologic storage.

Class VI permitting is a procedural process that initially involves submitting a permit application to the EPA. The rule also establishes specific procedural requirements to provide the opportunity for public participation in the permitting process. EPA then reviews and comments or issues a permit with authorization to drill an injection well. After the injection well has been drilled and construction completed, EPA reviews consistency with the permit application and any new information that is developed and ultimately authorizes injection. The permit process is made up of the steps shown in Figure 3-2.

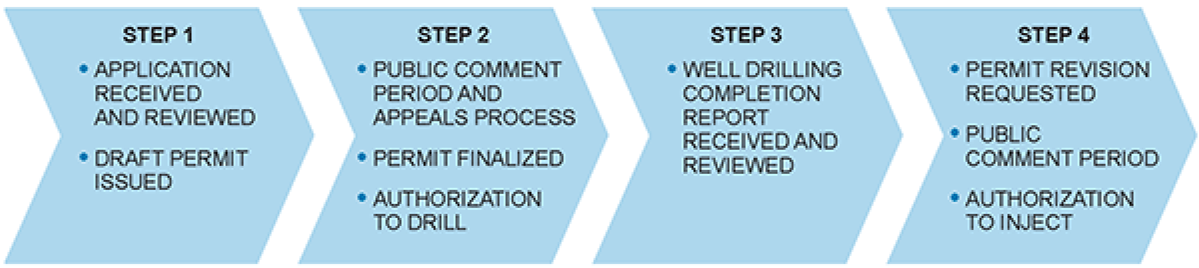


Figure 3-2. *Class VI Well Permitting Process Flow*

The period between issuance of the Authorization to Drill and Authorization to Inject is highly variable and dependent upon several factors including:

- The length of time it takes to drill the well
- The geology and its resemblance to that described in the permit application
- The modeling of area of review, which may need to be revised if geology is significantly different than anticipated
- The possibility of EPA requesting additional information or modeling, resulting in changes to permit, triggering a major modification.

In the permitting process, the operator provides their plan to meet these performance standards, based on site- and project-specific conditions. Examples of these plans include injection well construction procedures, a preoperational formation testing program to follow construction, any well stimulation program, injection operation procedures, an AoR delineation and corrective action plan, financial assurance, a testing and monitoring strategy, an emergency and remedial response plan, an injection well plugging plan, and a post-injection site care and site closure plan. The Class VI rule requires geologic storage project developers to apply for and obtain a permit for each individual CO_2 injection well even for projects involving multiple injection wells.

As noted above, the Class VI permit application requires estimation of an AoR, defined as the region surrounding the project where USDWs may be endangered by the injection activity. In practice, the area (footprint) of the free-phase CO_2 plume around an injection well is much smaller than the area of the elevated pressure, which could allow upward movement of formation fluids (e.g., brine). However, the density differences between buoyant free-phase CO_2 and heavier brine create different risks of upward leakage. This suggests that the total AoR can be defensibly subdivided into different areas with different regulatory requirements depending on whether the concern is buoyant free-phase CO_2 or pressure-driven dense brine migration. Currently, the Class VI regulations do not reflect this.

Permits are issued for the life of the project and can cover any period of time, but the default PISC period established in regulation is 50 years with the potential to be shortened through a computational modeling demonstration to support an alternative PISC timeframe or by demonstrating during the PISC period that the project “no longer poses a risk of endangerment to USDWs.” This timeframe is at the higher end of other related monitoring requirements for similar programs. For example, the default post-closure care period for Resource Conservation and Recovery Act Subtitle C hazardous waste management facilities is 30 years, with provisions for adjusting the default period (40 CFR 264/265.117). In addition, in implementing the European Union's Directive 2009/31/EC, the European Commission recommends a 20-year post-closure monitoring period as a default because the actual length of the post-closure period cannot be predicted in advance. (Implementation of Directive 2009/31/EC on the Geological Storage of Carbon Dioxide, Guidance Document 4, Article 19 Financial Security and Article 20 Financial Mechanism.)

The Class VI UIC program restricts the geologic formations into which CO_2 can be injected. Injection must be into an injection zone that is below the lower-most USDW unless the applicant can demonstrate, via an injection depth waiver process, that any lower USDWs will be protected against endangerment. For other UIC classes, EPA has a process for exempting aquifers from the definition of USWD if they have "no real potential to be used as drinking water sources." (40 CFR §144.1(g)) However, the use of exempted aquifers was not extended to Class VI. This prohibition has already prevented the permitting of at least one important scientific research project designed to further the development of CCUS technologies.

As of mid-2019, only two Class VI well permits with permission to inject have been issued by EPA. These two permits each took 6 years. This timeframe presents an obstacle for the development of future CCUS projects especially those trying to take advantage of the 45Q tax credit.

By default, EPA is the regulatory authority under the UIC program, but states can apply for primacy to obtain state permitting authority. States must submit to EPA an application for primacy to implement the UIC program. For the Class VI program, the state must demonstrate under Section 1422 of the SDWA that its program is “at least as stringent as” the federal requirements. For Class II, which is under Section 1425 of the SDWA, a state must demonstrate that its program is equally effective as the federal program.

Whereas many states have obtained primacy for other well classes, only North Dakota has successfully sought and obtained primacy for Class VI permitting. Wyoming submitted its first application for primacy in January 2018. EPA action is anticipated in fall 2020.

2. EPA Greenhouse Gas Reporting Program[19]

On November 22, 2010, the EPA issued final rules that require facilities that conduct geologic sequestration of carbon dioxide and all other facilities that inject CO_2 underground to report GHG data to EPA annually.

Subpart RR requires reporting of quantities of CO_2 securely stored from facilities that inject CO_2 underground for geologic sequestration. Subpart RR requires facilities conducting geologic sequestration of CO_2 to develop and implement an approved EPA site-specific monitoring, reporting, and verification plan, and to report the amount of sequestered CO_2 using a mass balance approach. This rule is complementary to the Class VI program for geologic storage wells and permits participation by Class II wells.

Under Subpart UU, all facilities that inject CO_2 underground for any reason, including EOR, are required to report basic information on CO_2 received for injection, and it allows EPA to evaluate data obtained on CO_2 received for injection in conjunction with data obtained from Subpart PP on CO_2 supplied to the economy. EOR operators are also subject to reporting requirements under subparts W and C (if applicable) for above ground equipment leaks.

3. Pore Space Access

Additionally, when developing CO_2 storage projects, project developers need to ensure they have rights to the applicable contiguous pore space. In many countries, subsurface pore space is owned by the federal government or a sovereign. In the United States, mineral rights and water rights belong to landowners or to those who purchase them from landowners. Under common law, oil and natural gas operators have the right to use a surface owner’s pore space as reasonably necessary to produce the minerals on the property. Therefore, the pore space owner’s rights are not violated when the CO_2 remains in the pore space. Among the three states (Montana, North Dakota, and Wyoming) that have clarified pore space ownership, all have recognized that pore space rights generally belong to the surface owners. Operators may need to pursue acquisition of both surface and mineral rights, which requires a time and monetary commitment.

In some cases, pore space access might require agreements with many parties. Some states allow forced unitization of mineral resources, in which case if some percentage of owners agree, the remaining owners can be forced to participate. Yet, it is unclear if and how these laws extend to pore space. The challenges that accompany obtaining the rights to pore space will also likely require legislative or legal clarification for each state. For example, North Dakota has adopted a statute that allows for amalgamation of pore space rights, which has much in common with the unitization model.

a. Pore Space — Federal Lands

The Federal Land Policy and Management Act authorizes the Secretary of the Interior to issue leases, permits, and easements for the use, occupancy, and development of public lands. The regulations implementing this authority are at 43 CFR 2920. The statute and regulations are sufficiently broad to allow for a variety of authorizations related to geologic storage and related activities while sufficiently flexible in form and terms to accommodate many different actions and activities, including surface and subsurface rights-of-way and leases for subsurface storage.

The Mineral Leasing Act (MLA) allows the Secretary of the Interior to approve the subsurface storage of gas, regardless of whether the gas is produced on federally owned lands or the lands are leased, in order to promote conservation of resources. Such gas storage agreements are used today for the temporary storage of produced natural gas in order to balance production rates and address delivery issues. However, the broad language of the MLA could be modified to allow for the use of gas storage agreements to authorize long-term geologic storage of CO_2.

The MLA also allows for lessees to join together and collectively operate under a cooperative or unit plan of development where it is determined by the Secretary of the Interior to be necessary or advisable in the public interest. CO_2 EOR operations are conducted today under unit plans of development and could serve as a model for long-term geologic storage of CO_2.

b. Pore Space — Private Lands

Prior to injection, the operators seeking to undertake storage operations must either own the pore space, have permission from the owner, or have statutory or common law right to use the pore space that avoids potential liability or exposure to trespass and nuisance claims. In the United States, the law concerning private property rights is a basic responsibility of the state rather than the federal government. In most states, the surface estate owns the pore space except to the extent pore space rights have been conveyed away.

This ownership is subject to a right of the mineral estate to make reasonable use of the surface estate as necessary to produce minerals from the tract. The right of use would include the right to inject substances, such as CO_2, for EOR. The fact that CO_2 injection might also result in the long-term sequestration of CO_2 should not alter the right of the mineral estate owner to engage in CO_2 injection for enhanced recovery.

However, with respect to CO_2 sequestration in formations that do not include the minerals, the right to inject CO_2 solely for storage would most likely be held by the surface owner.

The Interstate Oil and Gas Compact Commission has recommended that operators hold “the necessary and sufficient property rights” for construction and operation of a CO_2 storage project, which is defined to encompass the project in its entirety including “all surface and subsurface infrastructure” and “the reservoir used” for injection and storage operations.[20]

Three states (Montana, Wyoming, and North Dakota) have enacted legislation clarifying ownership of pore space for CO_2 sequestration. These three states clarified that the subsurface pore space belongs, at least presumptively, to the surface owner. Montana and Wyoming allow pore space to be transferred as a separate property from the surface and North Dakota established that pore space belongs to the owner and cannot be separated from the owners of the overlying property, although it can be leased.[21]

Although state law generally supports surface owner title, the question of whether the surface estate or mineral estate owns the private property interest in the pore space for geologic storage of CO_2 is not clearly settled. Statutory and regulatory clarity may be needed with respect to geologic storage of CO_2.

4. Federal and State Waters

Regulation of offshore CO_2 storage differs depending on where it occurs. The federal government administers the submerged lands, subsoil, and seabed in a specified zone of exclusive U.S. federal jurisdiction beyond state-owned waters (typically 3 nautical miles from the shoreline) and up to 200 nautical miles or more from the U.S. coastline, which is known as the Outer Continental Shelf (OCS). In Texas and Florida, state waters include those waters from the coast to three leagues (approximately 10.36 miles). For an example, see text box "Texas Creates Framework for Offshore Storage." Neither federal nor state agencies have authority over the high seas (areas greater than 200 nautical miles offshore).

TEXAS CREATES FRAMEWORK FOR OFFSHORE STORAGE

Texas is an example of a state that has anticipated offshore storage, creating a statutory framework for subsurface geologic repository for the storage of anthropogenic CO_2 in state waters.[1] The law required that the Bureau of Economic Geology (BEG) at the University of Texas at Austin study state-owned submerged land to identify potential locations for a CO_2 repository. The law also required the Land Commissioner and the Texas School Land Board to determine suitable locations and issue requests for proposals for the lease of the land for the construction of any necessary infrastructure for the transportation of CO_2 to be stored in the repository. The board could accept CO_2 for storage at a fee. The Texas Commission on Environmental Quality establishes standards for measuring, monitoring, and verification of the permanent storage status of the CO_2 and the BEG performs the measuring, monitoring, and verification. After verification of permanent storage, the board acquires title to the CO_2 stored in the repository. On the date the state acquires the right, title, and interest in CO_2, the producer of the CO_2 is relieved of liability for any act or omission regarding the CO_2 in the repository. However, transfer of title to the state does not relieve a producer of CO_2 of liability for any act or omission regarding the generation of the stored CO_2 occurring before the CO_2 was stored.[2]

1 2009 HB 1796.

2 Texas Legislature, 2009, Offshore geologic storage of carbon dioxide: 81st Texas Legislature, Regular Session, House Bill 1796, Chapter 1125, https://texashistory.unt.edu/ark:/67531/metapth148377/m1/1/.

The principle legislation governing activity within the OCS, including CO_2 storage, is the Outer Continental Shelf Lands Act (OCSLA).[22] Under the OCSLA, the Secretary of the Interior is responsible for the administration of mineral exploration and development of the OCS and has authority to grant leases for mineral development. The statutory authority for regulating CO_2 injection on the OCS originates from the OCSLA. DOI has statutory authority under the OCSLA to permit the use and sequestration of CO_2 for EOR activities on existing oil and natural gas leases on the OCS. DOI has the statutory authority to permit the geologic sequestration of CO_2 for activities that “produce or support production, transportation, or transmission of energy from sources other than oil and gas.” Specifically, under Section 8(p)(1)(C) of the OCSLA (43 U.S.C. 1337)(p)(1)(C)), DOI’s Bureau of Ocean Energy Management (BOEM) may issue leases, easements, and rights-of-way for these types of projects.

In addition, Section 8(p)(1)(C) allows BOEM to issue leases for sub-seabed CO_2 sequestration. This includes sub-seabed storage of CO_2 generated as a byproduct of electricity production from an onshore coal-fired power plant. BOEM’s interpretation of this language is that the agency would only be able to issue leases for CO_2 storage in the OCS for CO_2 generated as a byproduct of onshore coal-fired power production, but not from CO_2 generated as a byproduct from other industrial activities, such as refining, chemical manufacturing, natural gas power generation, or nonenergy related industries (e.g., steel or cement production).[23]

Although there is an argument that other language in the OCSLA could authorize DOI to grant leases for offshore storage of CO_2, supporting the “exploration, development, production, or storage of oil or natural gas,” this language is something less than explicit for that purpose and would not apply to CO_2 from nonoil and natural gas-related industries.[24] This ambiguity will continue to hinder investment, development, and deployment of offshore CCUS opportunities.

Another issue that needs to be addressed is the Marine Protection, Research and Sanctuaries Act of 1972, also referred to as the “Ocean Dumping Act,” which regulates the transportation and dumping of any material into ocean waters. The Act requires the issuance of permits for the disposal of waste and other matter at sea, including industrial waste. Although not explicitly named in the Act, the term “industrial waste” has commonly been interpreted to include CO_2 generated through industrial processes. Under such an interpretation, CO_2 on the OCS would require a permit from EPA, subject to public comment and hearings, to evaluate the environmental impact of such activity. This regulation is duplicative of the environmental impact assessment procedures that already apply to BOEM OCS leasing program. The international community has recognized this unintentional barrier to offshore storage of CO_2 and explicitly exempted CO_2 from the list of prohibited materials for disposal in the OCS.[25]

5. Regulatory Authority for Permitting of CO_2 Pipelines

The ability to transport very large volumes of CO_2 by pipelines, or a network of interconnected pipelines, from sources to sequestration sites will be crucial to the deployment of CCUS at-scale. Existing pipeline infrastructure will need to be expanded at least ten-fold to accommodate the volume of CO_2 transport at that level. Beyond any financial support that might be needed from the government to offset early deployment costs, nonfinancial incentives, such as streamlining and/or expediting permitting applicable to both power and industrial CCUS projects, can play an important role.

Although the Federal Energy Regulatory Commission (FERC) has jurisdiction to regulate the transmission and sale of natural gas for resale in interstate commerce under the Natural Gas Act, it has disclaimed jurisdiction to regulate CO_2 based on a finding that CO_2 is not a natural gas under the Natural Gas Act. The Surface Transport Board (STB), which is an independent federal administrative agency within the DOT, is responsible for economic regulation of certain common carrier interstate transportation, primarily related to railroad transportation, but also including interstate transportation of pipeline commodities “other than water, gas, or oil” with the term “gas” undefined. However, the STB’s predecessor agency, the Interstate Commerce Commission, found that CO_2 is a gas and therefore nonjurisdictional under the Interstate Commerce Act when transported by pipeline. If STB followed this precedent, it would not regulate CO_2 pipelines either. However, they have neither disclaimed jurisdiction in the same manner as FERC, nor asserted jurisdiction over CO_2 pipelines to date.

At present, the only federal agency that has exercised any sort of authority over CO_2 pipelines siting and rates is the Bureau of Land Management (BLM), which is one of the federal agencies with authority to grant right-of-way across federal land. BLM imposes the equivalent of a common carrier obligation on CO_2 pipelines crossing federal lands on the basis that CO_2 is a natural gas within the meaning of the Mineral Leasing Act.

6. Long-Term Liability

Two of the most important questions that must be answered if CCUS is to become a large-scale commercially viable technology are:

- What will be the liability of CCUS operators for personal injury, property damage, trespass, and nuisance claims that could arise over the lifetime of a geologic storage project, which could be measured in centuries?
- What is the appropriate institutional framework for managing CCUS sites after closure?

Generally, operators are potentially liable until the statutes of limitations expire, and regulatory requirements cease to apply. Beyond ongoing responsibilities for monitoring, potential liabilities associated with a CO_2 storage facility may include responsibility for mitigation and remediation of any leaks; recapture of incentives associated with CO_2 that ceases to be stored; risks of subsurface trespass that entails migration to pore space for which storage rights were not acquired; and potential litigation for personal or property damage. These may result from situations in or out of the operator's control and are similar to those encountered during typical oil and natural gas operations.

A key distinction between EOR operations and CO_2 storage operations is that, whereas oil and natural gas operators may or may not be required to cover liabilities after operations cease, a CO_2 storage operation has obligations imposed by regulation during the post-injection site care period even though the fluid pressures are greatest, and the CO_2 is most mobile (and potentially able to escape quickly) during the injection of CO_2. Over time, the CO_2 dissolves, precipitates, or becomes trapped and the pressure dissipates, which implies that proper monitoring and injection design is needed for the duration of the project, but not necessarily long afterwards.[26] When operations cease, the operator generally maintains responsibility for overseeing a site for some amount of time and remains liable for legal violations until statutes of limitations expire. For example, under Class VI permitting for saline storage, the default requirement for monitoring is 50 years, or at the discretion of the EPA administrator, whereas under California's Low-Carbon Fuel Standard CCS Protocol, the default requirement is 100 years. These potential long-term liabilities and responsibilities can have a detrimental effect on project development. Thus far, there are no insurance products available to appropriately cover these long-term, low-risk scenarios.

Several options have been proposed to address long-term liability concerns. Some have advocated that long-term liabilities should be handed over to state or other governmental agencies once it has been demonstrated the plume is stable. Others have advocated for only partial transfer of liability. Today, only a few states have defined a process to manage some initial, limited liability for CO_2 injection, including long-term liability (described in more detail below). However, because no commercial storage operations in the United States have entered the post-injection site care phase, long-term liability transfers have yet to be tested, so questions remain regarding the evolution of the current legal standards for post-injection site closure and liability management.

An example of options to address long-term liability for geologic storage of CO_2 is a "layered approach" as described in Eames and Anderson.[27] This approach creates cooperative agreements between operators and the government, which are used to pool resources, and sets up a layered responsibility approach, with each layer having set limits. In the event of an incident requiring remediation, the operator/site owner has the first layer of responsibility at any point in the site life, up to a per-incident dollar limit. If this is exceeded, the second layer cost is shared by those in the cooperative agreements. The third layer is backstopped by the government, and any remaining fourth layer costs are borne by the site owner/operator. This proposal is intended to limit liability during the formative stages of the CCUS industry while leaving operators with enough potential liability to encourage responsible behavior.

A recent paper by the Global CCS Institute[28] discusses the common perceptions regarding risk and approaches adopted by different jurisdictions that have been used globally and finds “the availability and benefits of transfer provisions in some jurisdictions have proven particularly significant, with some proponents highlighting their beneficial impact upon project investment decisions.” The paper also highlights the mechanisms that have been employed to date including CCUS under existing liability schemes, transfer of liability to a governmental body, and upfront detailed requirements on site selection, monitoring, and verification. They also identify the need for further engagement of the insurance sector for the development of effective and affordable products for entities that cannot self-insure as an option for handling long-term liability.

There are some policies that allow long-term liability to be transferred to the government after a period of time. This has been adopted by four states: Texas (for state-owned offshore acreage), Illinois (for the FutureGen project to the extent damages exceed $100 million), North Dakota, Louisiana, and some federal governments of other countries. For example, Australia provides for a statutory indemnity. The Commonwealth must indemnify against liability if the formation was specified under the GHG license, a site closing certificate is in force, a closure assurance period (CAP) has been declared, and if: the liability is a liability for damages; the liability is attributable to an act done, or omitted to be done, in the carrying out of operations authorized by the license in relation to the formation; and the liability is incurred or accrued after the end of the CAP. If the CAP has been declared and the license holder subsequently ceases to exist, the Crown assumes liability for damage and losses, for which it would have indemnified the former licensee. These policies generally transfer stewardship, monitoring, and remediation requirements to a government entity, with the operator paying a fee into a trust or stewardship fund throughout the operations and/or at the time of liability transfer to defray the government's expenses. Assuming trust fund requirements are not excessive or too low, these liability transfers are beneficial because they put the site in the hands of a government entity that can assure the stewardship responsibilities are met, whereas private entities may or may not exist in perpetuity and/or the long time frames associated with CO_2 storage.

However, even these transfers may not protect an operator from damage claims in perpetuity. Due to societal unfamiliarity with the risks and benefits of CO_2 storage, litigation risks pose a threat to operators regardless of the validity of damage claims.

7. Power Market Challenges

CCUS will be needed in the power sector to achieve rapid, large-scale, and cost-effective decarbonization of the electric system without sacrificing reliability.[29] Fossil fired generation with CCUS can provide low-carbon emissions reliability services in the form of system inertia, black start capability, and ability to load follow as a result of fluctuations in power generation from renewables.

The power sector is highly complex. Each state is effectively a unique market with its own laws and regulations. In a few states, power remains fully regulated. Other states have deregulated power markets, known as competitive markets, and some states have a blend of the two types of markets. Overlaid on the states in which generation participates in a competitive market are independent system operators, which add a layer of unique rules, from wholesale market design to plant dispatch algorithms. Additionally, the federal government, through FERC, oversees the wholesale markets as well as interstate transmission. When deciding how best to achieve deployment of CCUS in the power sector, all of these differences need to be considered. For purposes of this report, a simplifying assumption has been made—electricity markets are either fully regulated (i.e., a monopoly utility that owns/operates its own facilities and makes its own investment decisions with state regulatory oversight) or deregulated (i.e., generation competes in a wholesale market and investment decisions are not made by utilities with primarily federal regulatory oversight).

Regulated markets are simpler to understand, yet difficult for the federal government to change. Fully regulated utilities remain outside of the independent system operators' involvement and largely beyond FERC regulation. Some regulated markets also have generation technologies imposed upon them via their state's legislature, most commonly in the form of Renewable Portfolio Standards (RPS). An RPS mandates how much of the power generation mix must be renewable. In addition to RPS, states have also enacted "must run" policies that require all energy from renewables to be prioritized over other forms of power generation. A recent trend is for states to dramatically increase the required amount of power supplied from renewables to reach targets of 50% or higher. However, without adequate energy battery storage, which comes at a cost, or fossil fired generation to back up renewables, the reliability of the grid will be jeopardized.

Deregulated markets are more complex. They are generally within the purview of the federal government, making implementation of any federal policy more straightforward.[30] The wholesale markets commonly pay power generators for: (1) the generation of energy (the commodity), (2) the generation capacity (the right to use that capacity),[31] and (3) reliability services needed to maintain the grid. For example, in addition to energy and capacity, PJM[32] also pays for reserves, regulation, and black start service. Renewables generally cannot provide reliability services, whereas fossil fuel plants are ideally suited for this purpose. The energy payment to a specific plant depends upon whether the plant is dispatched by the independent system operators in any given period, which is driven by the plant's bid. If the plant is not dispatched, it does not generate electricity and therefore does not get paid nor generate revenue. Similarly, the capacity payment depends upon whether the plant's capacity is selected in a capacity auction. This requires bidding the plant's capacity in at a price no higher than the highest bidder selected. Similar to energy, if the plant is not selected in the auction, it does not collect a capacity payment. (Note that capacity auctions address no more than a few years at a time.)

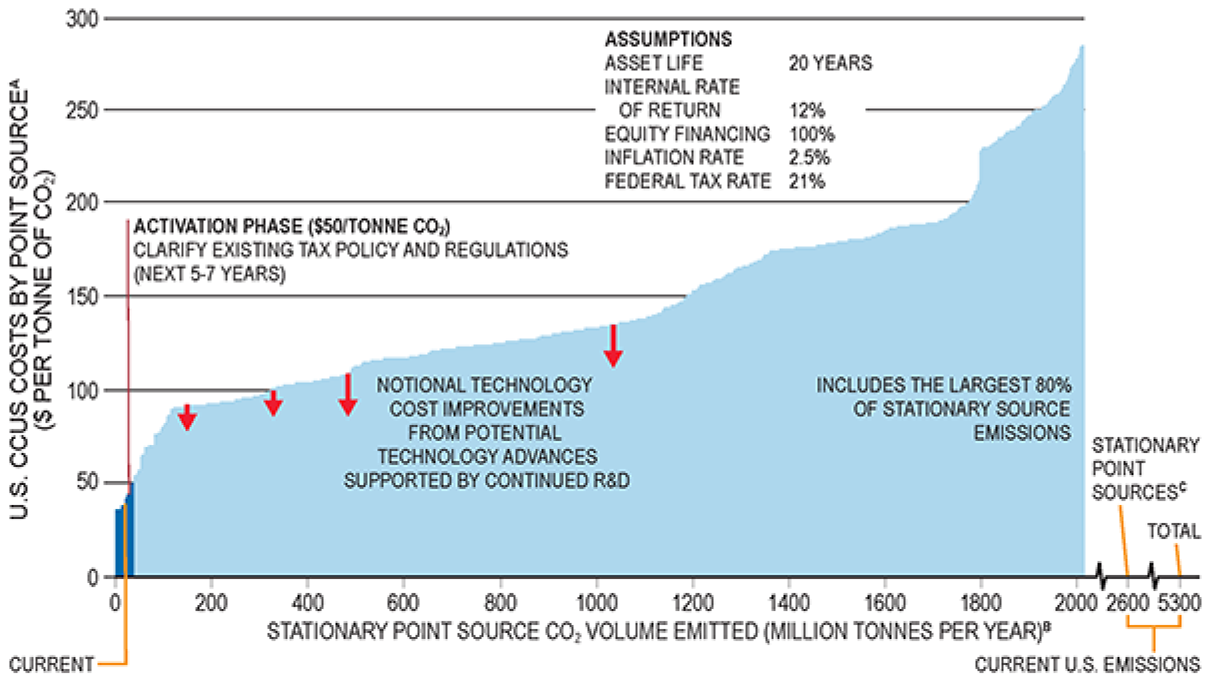
The two challenges to achieving rapid decarbonization in the power sector regardless of the market structure are (1) the need to do so at a reasonable cost while (2) maintaining the high reliability of the grid. These challenges become even more critical when considering the goals of electrification of parts of other sectors of the economy that rely on fossil fuels today (e.g., transportation). Wind and solar energy sources create new operational requirements. They do not contribute to meeting demand when there is no wind or sun but can lead to over-generation when they are abundant. Their variations need to be managed. Plants with CCUS can help meet these challenges. An existing fossil plant retrofitted with CCUS is significantly less expensive than installing a mix of solar generation with long-term battery storage.[33] CCUS plants can also be dispatched as needed, thereby compensating for the weather dependency of renewables while simultaneously adjusting output for the fluctuations of load, they also provide long-term (months) of support that batteries cannot.

III. ENABLING WIDESPREAD CCUS DEPLOYMENT

Achieving widespread deployment of CCUS will require establishing an adequate level of financial incentives through government policy underpinned by a durable regulatory and legal environment. A policy and regulatory framework should be implemented in a phased approach, based on economic efficiency and ease of implementation. The following three phases of implementation (activation, expansion, and at-scale) are intended to detail the policy and regulatory improvements needed to enable increasing levels of CCUS deployment, with a goal of achieving at-scale deployment (i.e., ~500 Mtpa) within 25 years.

A. Activation Phase—Clarifying Existing Tax Policy and Regulations

The United States currently has approximately 25 Mtpa of CCUS capacity. Clarification of existing tax policy and regulations could drive an additional 25 to 40 Mtpa of CCUS capacity deployment within the next 5 to 7 years, as illustrated in Figure 3-3. These improvements could be achieved without Congressional action. It is important to note, however, that because the cost curve assumes a 20-year project life, capacity potential in this phase may be optimistic. Deployment will likely remain limited to the lower end of the range in this phase as a result of the current 12-year duration of the Section 45Q tax credit.



Cost Curve Notes:
A. Includes project capture costs, transportation costs to defined use or storage location, and use/storage costs; does not include direct air capture.
B. This curve is built from bars each of which represents an individual point source with a width corresponding to the total CO_2 emitted from that individual source.
C. Total point sources include ~600 Mtpa of point sources emissions without characterized CCUS costs.

Figure 3-3. *CCUS Cost Curve Highlighting Activation Phase Deployment Volume*

As described in Chapter 2, "CCUS Supply Chains and Economics," this near-term additional capacity is likely to be deployed where large high-concentration CO_2 sources are in reasonable proximity to suitable storage locations or an existing CO_2 pipeline.

Clarification within three key areas—45Q tax policy, access to federal and state lands, and Class VI well permitting—could quickly enable projects to move forward and potentially double the existing CCUS capacity in the United States. In addition, opportunities to leverage the existing loans available under the DOE Advanced Guarantee Loan Program, and loans available under the USDA Consolidated Farm and Rural Development Act, should be explored.

1. Clarifying 45Q Tax Credits

A significant issue in implementing the 45Q tax credit revolves around the demonstration of “secure geological storage.” To date, the IRS has yet to establish regulations as required by the original Energy Improvement and Extension Act of 2008 (amended 2009) and the BBA of 2018 for determining secure geologic storage. This has led to confusion, uncertainty, and controversy in the application of the 45Q tax credit. IRS clarifications, through guidance or regulations, could provide investors certainty in the near term.

Since its original enactment in 2008, Section 45Q has included a requirement that the Treasury, in consultation with the EPA, DOE, and DOI, issue regulations related to claiming these tax credits. The Treasury issued guidance in 2009 but has not yet issued regulations. As a result, the requirements necessary to access the 45Q tax credits have been unclear. On June 5, 2019, the IRS issued Notice 2019-

32 stating that the Treasury and IRS intend to issue regulations under Section 45Q and solicited public comments on many aspects of the credit, including secure geological storage, start of construction, transferability, recapture, and “economic substance doctrine” which were top priorities identified by this study.

For example, clarity has been needed since 2009 on options for demonstrating “secure geological storage” for CO_2 used in EOR. This concern continues post-BBA and requires a flexible framework that can be implemented by taxpayers as documentation on the amount of CO_2 being securely stored during EOR operations. The International Standards Organization (ISO) Technical Committee 265 on CCUS has issued an international standard on CO_2-EOR, published in January 2019, ISO 27916. This standard provides a sound basis for demonstrating secure geologic storage. To implement this path forward, the American National Standards Institute (ANSI) has authorized the creation of an American Standard using the ISO 27916. Utility of the standard for 45Q purposes has more to do with implementation than with the substance of the standard.

Clarification is also needed regarding how credits can be transferred between parties, what constitutes “beginning construction,” and recapture of tax credits. As noted previously, the 45Q tax credit is earned by the taxpayer who owns the carbon capture equipment. The ability to obtain financing for such projects requires some certainty regarding the value and duration of the tax credits. In most cases, however, the owner of the capture equipment is not the entity that utilizes or stores the CO_2. Lack of clarity regarding the transfer of credits between parties and recapture provision has the potential to create a barrier to financing for the owner of the capture equipment. The tax credit should be transferable, in full or in part, to any party that has a vested interest in the capture project including project developer, the party capturing the CO_2, or the entity that stores the CO_2. Further investment also requires that the tax credit cannot be subject to recapture for a time period inconsistent with IRS audit requirements or similar to the recapture period for other tax credits, i.e., no longer than 3 years[34] after the time of injection. The recapture terms should require that the taxpayer continues to comply, either directly or by contract, with a Treasury recognized method for demonstrating secure geologic storage and has a plan to remediate leaks of CO_2 should they occur.

In order to obtain maximum value for the credit, the term “beginning construction” should be defined to be consistent with accepted precedents for wind and solar tax credits while acknowledging the size and complexity of CCUS projects. Additionally, carbon capture projects may be economically attractive when tax credits are considered, but may have negative operating profits in the absence of consideration of tax credits, thus creating a challenge unless the IRS clarifies that its “economic substance doctrine” does not apply.[35] Resolving these requirements through new rules provided by the IRS will reduce uncertainty for investors, helping to enable the development of CCUS projects needed to begin widescale deployment.

The NPC recommends that the IRS clarify the Section 45Q requirements, specifically:

1. Establish that “beginning construction” is satisfied when the taxpayer has spent or incurred 3% of the expected total expenditure and construction continues without interruption for 6 years.
2. Clarify options for demonstrating secure geological storage as it relates to CO_2 via EOR. One potential option that has attracted significant stakeholder interest is ISO 27916. Utility of the standard for 45Q purposes has more to do with implementation than with the substance of the standard. The IRS should assess implementation issues and potential utility of this standard.
3. Make credit transferable to encourage tax equity investment. The tax credit should be transferable, in full or in part, to any party that has a vested interest in the capture project including project developer, the party capturing the CO_2, or the entity that stores the CO_2.
4. Provide that the tax credit will not be subject to recapture for longer than 3 years[36] after the time of injection, to encourage financing and investment, with the requirement that the taxpayer continues to comply, either directly or by contract, with a Treasury recognized method for demonstrating secure geologic storage and has a plan to remediate leaks of CO_2 should they occur.
5. Clarify that additional carbon dioxide capture capacity placed in service after the BBA should be based on the delta between the new capacity and the average of the amount of CO_2 captured in the 3 years prior to the enactment of the BBA or the facility’s nameplate annual capacity.

6. The IRS should also specifically provide that the economic substance doctrine and provisions of Section 7701(o) will not be deemed relevant to a transaction involving the 45Q credit that is consistent with the congressionally mandated purpose of the credit, capture, and geological storage or utilization of CO_2.

The NPC recommends that DOE, with EPA and Treasury, begin to develop a robust life-cycle analysis framework with common parameters to support technology development and direct RD&D funding.

2. Access to Pore Space on Federal and State Lands

Access to pore space on federal and state lands will be important in early deployment of CCUS. Federal and state lands can have a significant advantage over privately owned lands because large areas of land are owned by one party. Federal lands have long been used for commercial activities such as oil and natural gas production, mining, farming, logging, livestock grazing, and public recreation. Accordingly, government statutes and regulations have been developed to manage these activities. There are, however, no current government mechanisms to grant access to, and use, of pore space rights on federal or state lands, except in Montana, North Dakota, and Wyoming. Formulating these regulations is critical to unlocking much of the CO_2 storage capacity in the United States.

As noted previously, the United States has vast CO_2 geologic storage potential. However, access to this storage, especially for saline formations, can be challenging due to the complexity of securing the rights to use the pore space from multiple property owners. In most of the United States, the land (surface) owner also owns the subsurface pore space in which CO_2 can be stored. For saline formation CO_2 storage projects, securing access rights to a large subsurface storage area might require agreement from hundreds if not thousands of landowners.

The NPC recommends that DOI and individual states adopt regulations to enable access to, and use of, pore space for geologic storage of CO_2 on federal and state lands similar to the approach under the Mineral Leasing Act where parties can join together and collectively operate under a cooperative or unit plan of development where it is determined by the Secretary of the Interior to be necessary or advisable in the public interest.

3. Class VI Well Program

As described earlier in this chapter, the Class VI permit process shown in Figure 3-2 requires numerous steps, from submission of a complete application, issuance by EPA of authority to drill under a Final Permit, submission by the permittee of a Well Completion Report, and finally, issuance by EPA of an Authorization to Inject.

As of mid-2019, EPA had issued only six Class VI well permits (Permits to Drill) and only two Authorizations to Inject. The time it took to receive a final Permit to Drill was ~3 years for the two active Illinois wells and 18 months for the four inactive permits (also in Illinois). The process from drilling the well to the issuance of an Authorization to Inject took an additional 2 to 3 years for the two wells that have injected CO_2 for a total of 6 years.[37] Four permits were issued in 18 months for the FutureGen 2.0 project but were never used because the project ran out of time to use federal funding.

The Class VI permitting process poses significant project risk because there is a high degree of variability in how long the timing will be between submission of a complete Class VI application and issuance of an Authorization to Inject, which may not be able to be determined up front. The Class VI wells are not as routine as other classes of wells because: (1) the Class VI requirements are more complicated than other classes, and (2) the Area of Review calculation is significantly different than other classes. Industry can help to reduce the time required for permitting by submitting complete applications and well-characterized geologic storage reservoirs. EPA can help reduce the timing by implementing program improvements noted in the recommendations.

When the Class VI regulations were promulgated, EPA acknowledged the limited information available at that time and emphasized the benefit of having "an adaptive approach" to enable EPA "to incorporate new research, data, and information about geologic storage and associated technologies (e.g., modeling and well construction)." To use this information, EPA announced its "plans, every six (6) years, to review the rulemaking and data on GS projects to determine whether the appropriate amount and types of information and appropriate documentation are being collected, and to determine if modifications to the UIC Class VI requirements are appropriate or necessary."[38]

As discussed in the Storage Cost Assessment section of Chapter 2, "CCUS Supply Chains and Economics," it is assumed that after its 6-year review, the EPA adopts the following recommendation of moving to a site-specific, performance-based approach to the ratio of monitoring to injection wells and number of seismic surveys (versus the NETL CO_2 Saline Storage Cost Model).

The time required to complete the process would be improved through clear and consistent procedures for reviewing permit applications, improved interactive communications with applicants, and more efficient resolution/dispensation of comments and/or challenges to the permit applicants.

The NPC recommends that the EPA undertake the planned periodic review of the Class VI rules, guidance, and implementation so that they are aligned with a site-specific and performance-based approach. Specifically, EPA should use the experiences and learnings since the program was promulgated to:

- Consider how the program could be modified to better incorporate a site-specific, performance-based approach
- Review guidance documents to be sure they reflect the latest technical and financial information, and they are consistent with the regulations. Include clarity regarding which aspects of the guidance documents are requirements versus recommendations.

This program review should be done in consultation with DOE, a national association of state groundwater agencies like the Ground Water Protection Council, the Interstate Oil and Gas Compact Commission (IOGCC), and relevant industry partners, including former and prospective Class VI permit applicants.

The NPC recommends that the EPA issue a Permit to Drill within six months. The NPC further recommends that upon receipt of a Well Completion Report, the EPA should review, make any necessary modifications, and issue a Permit to Inject within six months.

The NPC further recommends that Congress, through its agency oversight process, emphasize to the EPA the importance of accelerating the review of states' applications seeking primacy to implement the Class VI program.

Under the Class VI UIC regulations, computational modeling must be performed to support reduction in the default 50-year PISC period. In the final rule, the EPA established an option for demonstrating "an alternative post-injection site care timeframe other than the 50-year default" based on extensive additional data collection, technical analysis, and computational modeling. Although these expectations were designed for large, commercial projects, the EPA has applied it universally. As a result, smaller research and development projects have incurred significant redirection of financial and technical resources to make such demonstrations.

The NPC recommends that the EPA adjust its computational modeling requirements for post-injection site care requirements with respect to small demonstration projects to make them fit for purpose.

4. R&D for Class V CO_2 Injection

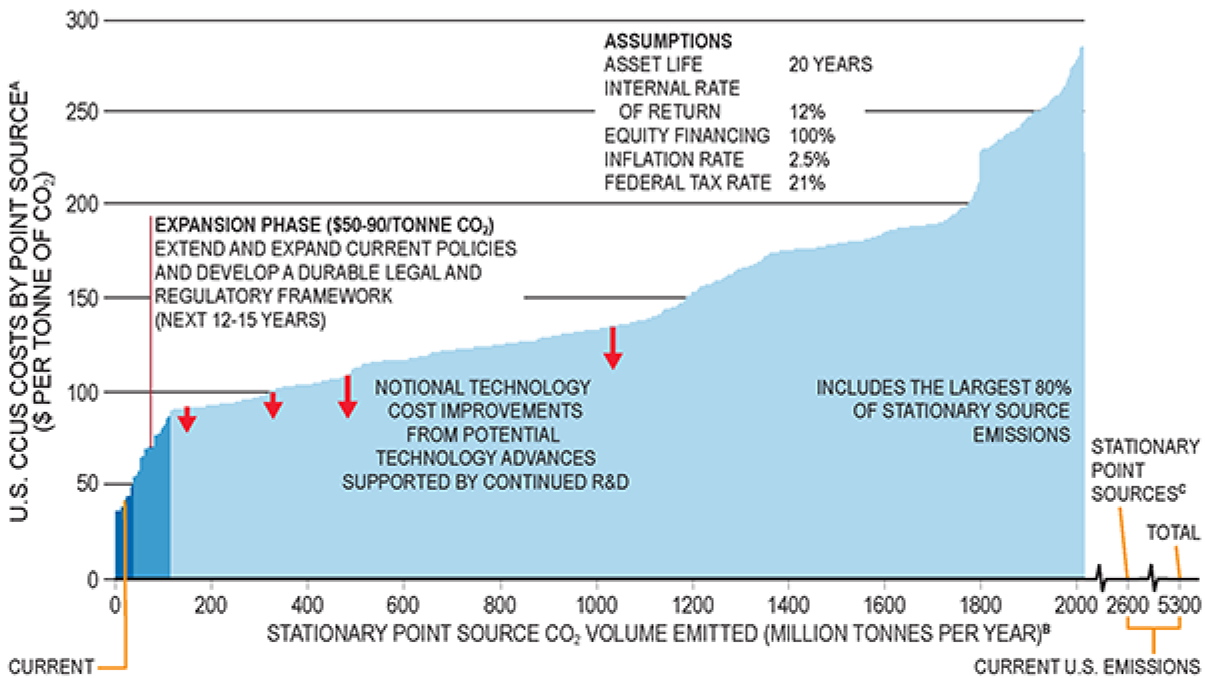
The effort to apply the Class VI provisions to smaller scale R&D projects has imposed permitting and regulatory compliance costs that far exceed any real or potential benefits in terms of environmental protection. In particular, the administrative and permitting costs have limited the scientific content of projects on fixed budgets to the long-term detriment of advances in scientific knowledge and CCUS technologies.

The NPC recommends that the EPA amend the regulation to allow pilot and demonstration projects to be permitted under the UIC Class V program as experimental technology wells, which give the agency much greater flexibility to tailor permit requirements to the individual project. DOE should consult with the EPA to determine what additional research is needed to allow the EPA to better define the scale of research projects that can be permitted as Class V experimental.

B. Expansion Phase—Expanding Policies and Addressing Regulatory Needs

By the end of the activation phase, Treasury should have completed Section 45Q tax credit regulations governing secure geologic storage, start of construction, transferability, and recapture, and developed a robust life-cycle analysis framework to allow taxpayers to claim credits for utilization of CO_2 so that these are no longer barriers. As shown in Figure 3-4, extending and expanding current policies to achieve a combined level of ~$90/tonne and further developing a durable legal and regulatory framework would incentivize an additional 75 to 85 Mtpa of capacity, bringing the total U.S. capacity to approximately 150 Mtpa.

This deployment level could be achieved in the next 15 years. These policy changes will likely require congressional action as well as rulemaking by U.S. federal agencies.



Cost Curve Notes:

A. Includes project capture costs, transportation costs to defined use or storage location, and use/storage costs; does not include direct air capture.

B. This curve is built from bars each of which represents an individual point source with a width corresponding to the total CO_2 emitted from that individual source.

C. Total point sources include ~600 Mtpa of point sources emissions without characterized CCUS costs.

Figure 3-4. *CCUS Cost Curve Highlighting Expansion Phase Deployment Volume*

This additional capacity is likely to be deployed where large high-concentration CO_2 sources can be connected to suitable storage locations that are economically accessible and, in certain circumstances, where lower-concentration CO_2 sources can take advantage of infrastructure that has been developed because of high-purity source CCUS deployments.

1. Financial Incentives

a. Extend and Expand 45Q Tax Credits

Under the current 45Q tax credit, the deadline to begin construction by January 1, 2024, will limit the near-term deployment of CCUS projects. In general, the time needed to identify, prove, plan, acquire access to and permit a CCUS project is more than 3 years. The project development timeline might be longer if there are complex commercial arrangements between multiple parties, a need for tax equity, pore space negotiations, and the structuring of insurance and liabilities. Unless a project was already in some stage of development when the Bipartisan Budget Act of 2018 passed, it will be challenging for CCUS project developers to accomplish the necessary tasks in time to qualify for the deadline.

Over the next decade, 45Q tax credits will need to be extended and expanded. As currently designed, the amount and the length of the tax credits are likely insufficient to encourage significant deployment. Qualified projects are eligible to receive the credit for a 12-year period from the date the capture equipment is originally placed in service. In most cases, the total value of the tax credit during this period will be insufficient to incentivize investment. In addition, approximately 56% of electricity-generation units, and 27% of industrial sources, do not generate sufficient CO_2 each year to meet their respective minimum size requirements for 45Q as currently written.

Recommendations on other aspects are discussed below.

The NPC recommends that Congress amend Section 45Q such that it will:

1. Extend the deadline (January 1, 2024) for beginning construction to 2030.
2. Lengthen the duration the credit pays out to a project from 12 to 20 years.
3. Lower the project size thresholds to 25,000 tonnes for industrial facilities, 100,000 tonnes for power plants, and 1,000 tonnes for use per year per site to accommodate smaller installations that may not qualify for the credit.
4. Increase the value of the credit for storage and use applications by notionally $5 per tonne as the current value of the credit is often less than the costs for such projects. The actual adjustment should be based on economic conditions at the time of reassessment.

b. Amend Section 43 Tax Credit

The Internal Revenue Code Section 43 EOR credit was put in place to incentivize investment in EOR projects during periods of low activity (e.g., periods of low oil price). At current oil prices, with the current reference price of $28 per barrel (adjusted for inflation), the credit will be phased out for 2019. Because EOR is an important near-term pathway for CCUS deployment, incentivizing new EOR projects that securely store anthropogenic sources of CO_2 with a 15% tax credit for qualified costs can help drive additional capacity in the near term. Amending Section 43 by raising the reference price to a level sufficient to activate the tax credit (e.g., $50 per barrel) for projects that securely store anthropogenic CO_2, especially when stored in conjunction with the existing Section 45Q incentive, will incentivize new EOR projects.

The NPC recommends that Congress amend the IRS Section 43 tax credit by raising the reference price to a value greater than $50 per barrel of oil for CO_2 EOR projects that securely store anthropogenic CO_2.

c. Expand Other Financial Incentives to CCUS

Currently, the Section 48A and 48B tax credits are only available to coal-based power generation technologies and integrated gasification combined cycle projects, and requirements for the existing program create challenges. Expanding access to investment tax credits like Section 48 to all CCUS projects would likely incentivize multiple projects that currently remain uneconomic with current policy.

The NPC recommends that Congress enact legislation to expand Section 48 of the tax code to create 48C for industrial sources and natural gas fired electricity generating technologies.

As noted earlier in the chapter, private activity bonds are a way to provide financial support for projects that are deemed to be in the public good.

The NPC recommends that legislation be enacted to allow CCUS projects access to private activity bonds.

Current MLPs are not allowed to own and receive single-taxation benefit on the income from carbon capture projects. Even if all CO_2 capture projects were deemed qualified, it still may not make sense for an MLP to own CCUS assets. This is because MLP unitholders likely could not benefit from the full value of Section 45Q tax credits. The value of a Section 45Q tax credit would be limited to the taxable income generated by the partnership that could be offset, before being passed through to unitholders. Said otherwise, in the event the tax credit exceeded the partnership's taxable income, unitholders would not be able to apply the excess credit against their taxable income. Addressing this issue would make MLPs an attractive vehicle for CCUS investment and an ideal mechanism to disburse the 45Q tax credits.

The NPC recommends that Congress enact legislation providing CCUS projects access to the use of master limited partnership structures and that the MLP be structured in a way that allows the Section 45Q tax credit to be passed through and applied toward an individual's income.

To advance CCUS, a substantial amount of CO_2 pipeline infrastructure will need to be built. An option for the government to support infrastructure needs for CCUS would be to expand the TIFIA program to include CO_2 pipeline infrastructure.

The NPC recommends that Congress enact legislation to allow CO_2 pipelines to qualify under TIFIA and provide the budget authority for the expanded program.

2. Regulatory Improvements

a. Underground Injection Control Program and Class II Transition to Class VI

In the expansion phase, traditional EOR operators or others may be interested in considering how to optimize CO_2 storage versus conducting EOR operations for the primary purpose of producing oil. Some may be interested in exploring CO_2 storage in depleted oil fields where it is no longer economical to produce oil and natural gas with current methods. Any optimization of CO_2 storage by design and intent that does not result in a more efficient recovery of hydrocarbons would also need to be properly vetted to ensure that the mineral estate and the surface estate interests are both considered.

The question of whether a well should transition from Class II to Class VI should not focus on the activity but rather on the physical parameters of the proposed operating regime and associated risk. As stated by the EPA, “The most direct indicator of increased risk to USDWs is increased pressure in the injection zone related to the significant storage of CO_2. Increases in pressure should first be addressed using tools within the Class II program. Indirect methods that could indicate such a pressure increase or show the movement of the CO_2 plume may also be used. Transition to Class VI should only be considered if the Class II tools are insufficient to manage the increased risk.”[39] Given the complexities of determining when such a transition is appropriate, it is important that the decision rest with the state primacy agency because they have the greatest familiarity with the relevant information about the reservoir characteristics, the pressure and volume of CO_2 injected, and the production rates for EOR processes in a given field.

The NPC recommends that the EPA, in consultation with DOE, academics, Class II state directors, the IOGCC, nongovernmental organizations (NGOs), and industry develop a process for determining maximum pressure threshold or ratio, and/or maximum injection rates or volumes, above which the risk is such that the injection should transition from Class II to Class VI. At a minimum, EPA should codify the statements in its memo to Regional Directors "Key Principles in EPA Underground Injection Control Program Class VI Rule Related to Transition of Class II Enhanced Oil or Gas Recovery Wells to Class VI" April 2015.

b. Class VI Program Review

i. Risk-Based Approach to Endangerment

EPA's regulations limit even inconsequential migration of fluids and constituents into a USDW. The SDWA defines endangerment in terms of health-based considerations, and EPA has recognized that an endangerment standard is inherently linked to the assessment and management of risk.[40] Such an approach facilitates a far more realistic and scientific assessment, as well as management, of public health risks related to geologic storage operations.

The NPC recommends that the EPA apply a risk-based approach when implementing the standard for endangerment and in the implementation of all aspects of the Class VI program.

ii. Flexibility with Risk-Based Monitoring

Under the Class VI regulations, monitoring is required to track the injected CO_2 plume. However, determining the exact location of the CO_2 plume may not be the most efficient way to determine containment, and monitoring strategies should evolve as the project evolves. Additionally, the requirement for in-zone monitoring may be interpreted as an additional well, requiring penetration of the reservoir cap rock and creating an additional potential leakage pathway. The Class VI regulations allow indirect methods of monitoring the extent of the CO_2 plume and the presence of the associated pressure front, but only in addition to direct methods. Careful site selection and indirect monitoring can be adequate to monitor the extent of the carbon dioxide plume and the presence of the associated pressure front, while avoiding the unnecessary penetrations into the injection zone created by direct methods. The director should have the necessary flexibility to allow the use of indirect monitoring methods only, when appropriate.

The NPC recommends that the Class VI regulations be amended to allow indirect monitoring through perimeter and above zone monitoring of storage reservoirs to ensure containment.

iii. Financial Responsibility

The Class VI regulations base financial responsibility on the applicant's "detailed written estimate, in current dollars, of the cost of performing corrective action on wells in the area of review, plugging the injection well(s), post-injection site care and site closure, and emergency and remedial response."[41] Yet EPA review of Class VI permit applications has imposed prescriptive approaches to estimating costs. A risk assessment/management approach should be allowed for both scaling to fit the size of the project and for consideration of site-specific factors.

The NPC recommends that the EPA, in consultation with experts in the field and stakeholders, clarify what information, including financial estimates for emergency and remedial response, should be provided to support a risk-based approach when evaluating financial responsibility.

iv. Post-Injection Site Care

The Class VI permittee is required to petition for site closure via a non-endangerment finding by the delegated regulatory agency. Although the default PISC period specified in the regulation is 50 years, guidance has been provided by EPA that includes considerations and recommendations to help owners or operators petition for an alternate PISC during permitting, to revise the PISC time frame during the injection operation, and to make a non-endangerment demonstration for revision of the PISC and Site Closure Plan at the discretion of the EPA administrator. The default 50-year PISC period is overly conservative and longer than it needs to be for some well-chosen sites and imposes a substantial burden for permit applicants. This flexibility should be included in UIC permits so that shorter PISC time frames can be specified with the possibility of adjustment depending on actual site conditions.

The NPC recommends that the EPA amend the UIC Class VI regulations to allow the PISC time frames to be set based on actual site conditions by using a risk-based approach for the duration of the PISC period.

v. Area of Review

Revising the AoR framework would reduce the cost of regulatory compliance while ensuring that the objective of protecting USDWs is preserved. Separating the AoR into subareas would lead to a tiered AoR definition in which the projected region of CO_2 plume extent would have appropriately focused regulatory standards regarding site characterization, monitoring, and corrective action than the larger pressure plume: (1) the region of CO_2 plume extent would have the highest regulatory standards regarding site characterization, monitoring, and corrective action, and (2) the pressure plume part of the AoR would focus on major pathways for brine leakage, such as unplugged wellbores and transmissive faults. Alternatively, the AoR reevaluation could be conducted pursuant to certain performance-based triggers derived from monitoring and operating conditions rather than according to a rigid fixed schedule.

The NPC recommends that the Class VI regulations be amended to allow the Area of Review to be separated into different subareas that are focused on whether the primary concern is free-phase CO_2 or pressure-driven upward brine leakage.

vi. Class VI Primacy

Under the UIC program, EPA established “minimum requirements for effective programs to prevent underground injection which endangers drinking water sources” with states intending to adopt and administer UIC programs that meet these requirements. States that receive approval to implement primary enforcement responsibility of their UIC programs are called “primacy” states. State primacy for Class VI implementation can be a more effective means for advancing CCUS in states that have existing CO_2 management and natural resource conservation programs.

To obtain primacy for the Class VI UIC program, a state is required to demonstrate that its program is “at least as stringent as” the federal requirements, although the regulations also specify that “States need not implement provisions identical to the[se] provisions.” EPA provided for state primacy for the Class VI UIC program separate from primacy for the other classes of injection wells. EPA has outlined a process for states seeking UIC primacy. North Dakota was the first state to receive Class VI UIC program in April 2018. The process from application submittal to approval took almost 5 years.

The NPC recommends that, to facilitate state primacy for the Class VI program, Congress enact statutory changes for approval of state primacy of the Class VI program under the Section 1425 standard of equal effectiveness, similar to the Class II UIC program.

vii. Funding for UIC Class Program

Increased project activity as a result of increased deployment of CCUS with respect to both Class II and Class VI will require additional funding. The level of federal funding for the UIC program has remained at approximately $10.5 million for the past 16 years, and has, in effect, been diminished by inflation. During that time, the EPA and state agencies responsible for the UIC program have faced increased compliance and reporting requirements and significantly more program implementation expenses.

The NPC recommends that Congress increase the funding to EPA and the states by $20 million for UIC Class II and $50 million for Class VI to support EPA’s and the states’ anticipated increase in workload in the expansion phase to review permit applications, to provide any additional training, and support state Class VI primacy applications and EPA’s review of those primacy applications.

viii. Flexibility with Aquifer Exemption

The SDWA directed EPA to develop regulations "to prevent underground injection which endangers drinking water sources."[42] To implement the SDWA, EPA promulgated the UIC program regulations authorizing state UIC program directors to "identify aquifers and portions of aquifers which are actual or potential sources of drinking water" by applying criteria relating to the ability of a geologic formation to produce water that can reasonably be expected to supply a "public water system" as defined by rule.[43] The UIC regulations established a two-part process under which the term "underground source of drinking water" is defined (1) by using broad criteria to identify aquifers that may potentially be capable of producing water for drinking, and then (2) by using the process for identifying exempted aquifers to exclude such aquifers from the definition if they have no real potential to be used as a drinking water source. Class VI prohibits the use of the two-part test established under the UIC regulations. As a result, two DOE-funded projects failed to obtain Class VI permits. These provisions appear in 40 CFR §§144.7(a) and 146.4. In both cases, the normally applicable criteria for designating exempted aquifers might have confirmed that such formations are not USDWs. This provision undercuts the carefully designed process for identifying USDWs and exempted aquifers built into the original UIC regulations. EPA's Class VI regulations also limit the use of aquifer exemptions available to wells transitioning from Class II to Class VI. This prohibition has already prevented the permitting of at least one important scientific research project designed to further the development of CCUS technologies.

The NPC recommends that the EPA amend the UIC Class VI regulations to allow the use of the UIC two-part process for exempting aquifers.

c. Storage in Federal Waters

One of the largest opportunities for saline storage in the United States can be found offshore in federal and state waters, particularly in the Gulf of Mexico. Offshore formations are typically not near underground sources of drinking water, the pore space rights are not dispersed among large numbers of owners (as is typical onshore), and the leasing, permitting, and regulation could be managed by a single entity (i.e., DOI). For these reasons, among others, there could be significant advantages to offshore storage.

However, as noted previously, the OCSLA language bars the storage of CO_2 on the OCS from the majority of industrial sources of CO_2, which would be a major impediment to widespread deployment of CCUS. Although there is an argument that other language in the OCSLA could authorize DOI to grant leases for offshore storage of CO_2 supporting the "exploration, development, production, or storage of oil or natural gas," this language is something less than explicit for that purpose and would not apply to CO_2 from non-oil and natural gas-related industries.[44] This ambiguity will continue to hinder investment, development, and deployment of offshore CCUS opportunities.

Similarly, the interpretation of CO_2 as industrial waste with respect to the Ocean Dumping Act has resulted in the unintended consequence of creating a barrier to offshore storage of CO_2.

The NPC recommends that Congress amend the OCSLA or enact a separate statute explicitly authorizing the issuance of leases, easements, and rights-of-way for facilities used to transport and inject CO_2 in the OCS without respect to the origin of the CO_2. Further, the DOE, Bureau of Ocean Energy Management, and Bureau of Safety and Environmental Enforcement should establish processes to enable access to pore space in federal waters and regulate CO_2 storage in those waters.

The NPC recommends that Congress amend the Ocean Dumping Act to explicitly exempt CO_2 from the list of prohibited materials for disposal in the OCS.

d. Regulating CO_2 Pipelines

In an optimal situation, buildout and access to future CO_2 pipeline capacity would be driven by the market. If common carrier pipelines are constructed with private funds, it seems logical the project will be developed with source and sink well understood, and contract terms for capacity and length identified upfront. In this situation, reservation of capacity by various shippers would not leave a lot of spare capacity for new shippers. Those who commit to the project early, which is the economic backbone of the pipeline, must have assurance that the pipeline will have space to move their captured CO_2 volumes to the sink.

However, open access on CO_2 pipelines could eventually lead to venting from all sources using the pipeline in the event of over subscription for service (proration). Under both scenarios, transportation rates for "cost of service" should be fairly straightforward using in-service cost, capacity, annual operating expense, rate of return, and project life for economic payout.

In addition, deployment of CCUS at scale will require significant expansion of CO_2 pipeline infrastructure, which will require access to the necessary property for pipeline construction, sometimes through eminent domain. Eminent domain is the power of government to take private land for public use. This power is limited by the federal Constitution and by state constitutions. In the United States under the Fifth Amendment to the Constitution, the owner of any appropriated land is entitled to reasonable compensation, usually the fair market value of the property. Eminent domain has been used traditionally to facilitate transportation, supply water, construct public buildings, and aid in defense readiness. Although federal Fifth Amendment protections apply to all exercises of the power of eminent domain, each state has its own laws and regulations that govern takings within the state. State governments have delegated the power of eminent domain to their political subdivisions, such as cities and counties. In some states, eminent domain is delegated to certain public and private companies, typically utilities, such that they can bring eminent domain actions to run telephone, power, water, or gas lines. Eminent domain law and legal procedures vary, sometimes significantly, between jurisdictions.

Both the interstate and intrastate pipeline permitting processes are complex and can involve multiple federal, state, and local agencies, as well as the public. An applicant may be required to comply with other federal regulations, such as the Clean Air Act, Clean Water Act, National Historical Preservation Act, and Endangered Species Act. In addition, projects may be subject to the National Environmental Policy Act (NEPA), which may require the preparation and coordination of extensive environmental impact assessments. And, the applicant may be required to comply with various state regulations.

In addition, several factors can affect the time frame for the permitting process of a given project, including different types of federal permits or authorizations, delays in the reviews needed by governmental stakeholders, and incomplete applications. For example, state and local permitting and review processes can affect federal decision-making time frames because some federal agencies cannot issue their permits until state and local governments have completed their own permitting processes.

The need for pipelines to be built to connect sources of CO_2 to EOR or storage locations in the activation phase, and to ultimately achieve widescale deployment, makes this recommendation of critical importance.

The NPC recommends that DOE create a CO_2 pipeline working group to study how to: harmonize federal/state/local permitting processes; establish tariffs, grant access, and administer eminent domain; establish the authority to issue certificates of public convenience and necessity; and to facilitate corridor planning. The working group should be made up of relevant federal and state regulatory agencies such as FERC, the IOGCC, or the Environmental Council of the States, representatives of local governments and communities, industry, and interested NGOs. The working group should be established concurrently with the activation phase.

e. Addressing Long-Term Liability

During CO_2 injection operations—which may last for a period of 10 years to more than 60 years—the operator generally holds and provides financial assurance for liabilities. These financial assurance mechanisms may cover responsibility for monitoring, mitigation, and remediation of any leaks; paying back incentives associated with CO_2 that ceases to be stored; risks of subsurface trespass, which entails migration to pore space for which storage rights were not acquired; and potential litigation for personal or property damage.

When operations cease, the operator generally maintains responsibility for overseeing a site for some amount of time and remains liable for legal violations until statutes of limitations expires. These potential long-term liabilities and responsibilities have a detrimental effect on project development. Some have advocated that long-term liabilities should be handed over to state or other governmental agencies once it has been demonstrated that storage is secure. Others have advocated for only partial transfer of liability. Today, only a few states have defined a process to manage liability for CO_2 injection, including long-term liability. However, because no commercial storage operations in the United States have entered the post-injection site care phase, long-term liability transfers have yet to be tested, so questions remain regarding the evolution of the current legal standards for post-injection site closure and liability management.

The NPC recommends that DOE convene an industry and stakeholder forum to develop a risk-based standard to address long-term liability. The forum should be established concurrently with the activation phase. Options to be considered for resolving long-term liability should include:

- Applicability and limitations of private insurance
- Government assumption of liability for early mover project to incentivize and de-risk market creation[45]
- Transfer of liability risk and oversight to the government when secure geologic storage is demonstrated, likely with operators paying a fee into a stewardship or trust fund
- Layered responsibility approach for risk pooling among operators and government
- When evaluating damage claims, consider the societal benefit of CO_2 storage.

f. Pore Space Access — Private Lands

In the longer term, to progress secure geologic storage at levels necessary to achieve widespread deployment of CCUS, it will become important for projects to access pore space on privately held land. As such, commercial viability of CCUS may depend on whether and how property rights issues are resolved.

The NPC recommends that state policymakers enact legislation enabling access to storage resources on private lands, including pore space ownership, setting a threshold and process for forced unitization and fair compensation.

g. Power Market Incentives

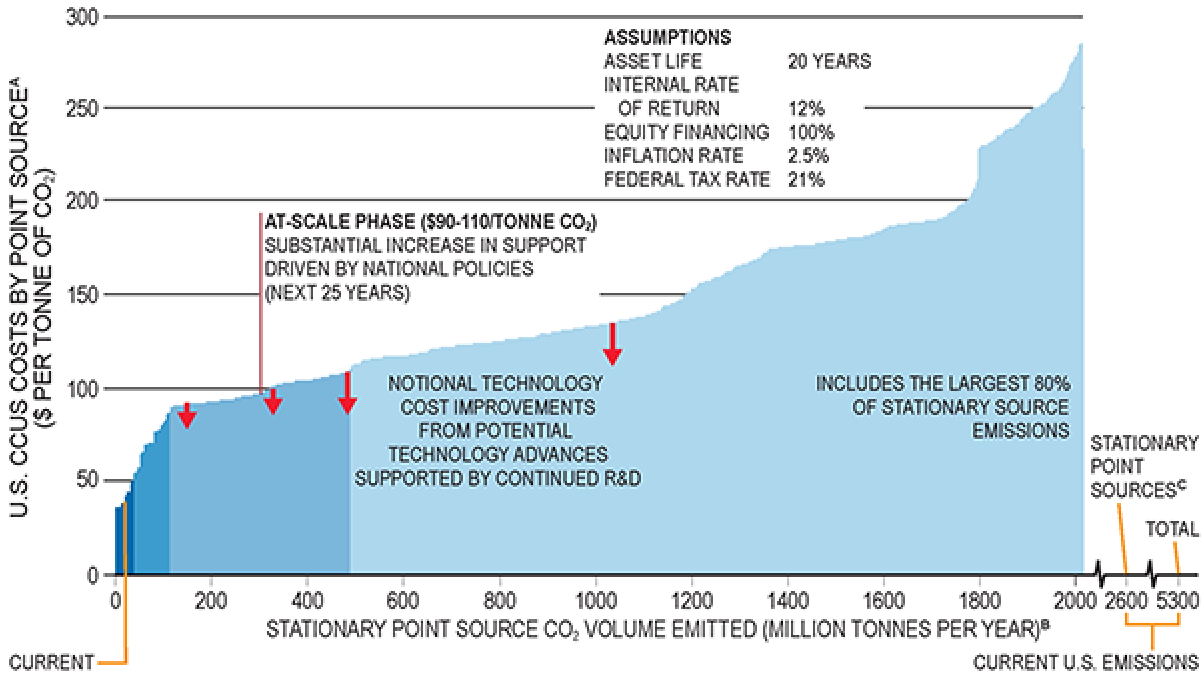
Investments in power plants with CCUS will remain economically challenged unless there are some changes in public policy both at the state and federal level. Mandates and subsidies of non-fossil favored supply resources, and the failure to charge the market for all relevant costs, are generating distorted market outcomes and producing negative economic impacts that disproportionately suppress economic incentives to deploy fossil-fueled generation resources with CCUS.

A wide range of possibilities could be considered to address this issue including legislated capacity markets, portfolio standards similar to RPSs that include CCUS, Clean Energy Standards, feed-in-tariffs, contracts for differences,[46] or some other form of long-term market construct such as those described in a publication by Energy Innovation[47] including offtake agreements and power purchase agreements. Recently, the UK CCUS Advisory Group (CAG) released a report on various business models to underpin investment in CO_2 capture in power and energy intensive industries along with CO_2 transport and infrastructure.[48] The various business models are designed to provide options for managing risks. For the power sector, the CAG focused on variants of a contract for difference (CFD). In terms of power, the report recommended a new “dispatchable CFD,” which would include fixed and variable payments and would be designed to bring forward investment in dispatchable low-carbon power generation capacity. The design of the dispatchable CFD is intended to ensure that electricity plants with CCUS would dispatch ahead of unabated gas-fired plants, but behind renewables and nuclear generation. Note in the United States, the states still retain authority to make their own independent generation technology choices, which could work against any federal policy. As discussed here, multiple policies will likely need to be implemented to adequately incentivize the building and operation of power plants with CCUS. The options presented are just a few of the possibilities. Since the options that will be selected have important and long-lived implications, further focused study is strongly recommended to advance the thinking. Encouraging the generation mix to be the most economically reliable is the proper focus.

The NPC recommends that DOE conduct a study exploring the range of options to determine how to address CCUS dispatch and available capacity in the most cost-effective manner with input from Electric Power Research Institute, Edison Electric Institute, independent system operators, NGOs, FERC, National Association of Regulatory Utility Commissioners, the utilities, and independent power investors and industry. The study should begin concurrently with the activation phase.

C. At-Scale Phase—Achieving At-Scale CCUS Deployment

Achieving at-scale CCUS deployment will require substantially larger economic incentives than those recommended in the activation and expansion phases. As shown in Figure 3-5, policies that support financial incentives of ~$110/tonne, could enable an additional 350 to 400 Mtpa of CCUS capacity within 25 years, bringing total U.S. capacity to ~500 Mtpa. At this level, CCUS would be deployed on nearly 20% of current U.S. stationary emissions, which is a level the NPC defines as at-scale deployment.



Cost Curve Notes:

A. Includes project capture costs, transportation costs to defined use or storage location, and use/storage costs; does not include direct air capture.

B. This curve is built from bars each of which represents an individual point source with a width corresponding to the total CO_2 emitted from that individual source.

C. Total point sources include ~600 Mtpa of point sources emissions without characterized CCUS costs.

Figure 3-5. *CCUS Cost Curve Highlighting At-Scale Phase Deployment Volume*

At this level of incentives, the additional CCUS capacity could be deployed in industries such as power generation, refining and chemical manufacturing, and cement and steel. As described in Chapter 2, “CCUS Supply Chains and Economics,” these industries typically have low concentrations of CO_2 (e.g., less than 15%) and, as a result, the highest cost to capture and separate. Achieving this level of deployment will also require substantial industry support for, and investment in, pipeline and storage infrastructure.

The following section describes three broad policy frameworks that have been implemented at the federal and state level in the United States and globally to address GHG emissions reductions:

- Standards and mandates (e.g., renewable portfolio standards)
- Financial incentives (e.g., tax incentives)
- Market-based mechanisms (e.g., carbon tax or cap and trade).

Each of the three policy frameworks applies a different methodology for addressing CO_2 emissions. Standards and mandates, such as efficiency standards and technology mandates, establish a set of required actions or technologies designed to reduce emissions. Financial incentives provide value, usually in the form of tax benefits, to individuals or companies for implementing or using certain technologies designed to reduce emissions. A market-based mechanism, such as a carbon tax or cap-and-trade system, places either a cost or a cap on CO_2 emissions, and requires an emitter to either pay the cost of their emissions or meet certain emissions levels, respectively. Although any policy framework can be implemented effectively, the ultimate success or failure of an emissions control program depends upon the basic design and the details of implementation.

1. Standards and Mandates

The U.S. government and many states have implemented some combination of standards and mandates that require certain products and technologies be used and/or establish a performance standard that certain technologies must achieve. For example, the federal Renewable Fuel Standard requires that specified volumes of biofuels be blended into U.S. transportation fuels. Figure 3-6 shows the current U.S. states and territories with renewable and clean energy standards and goals.

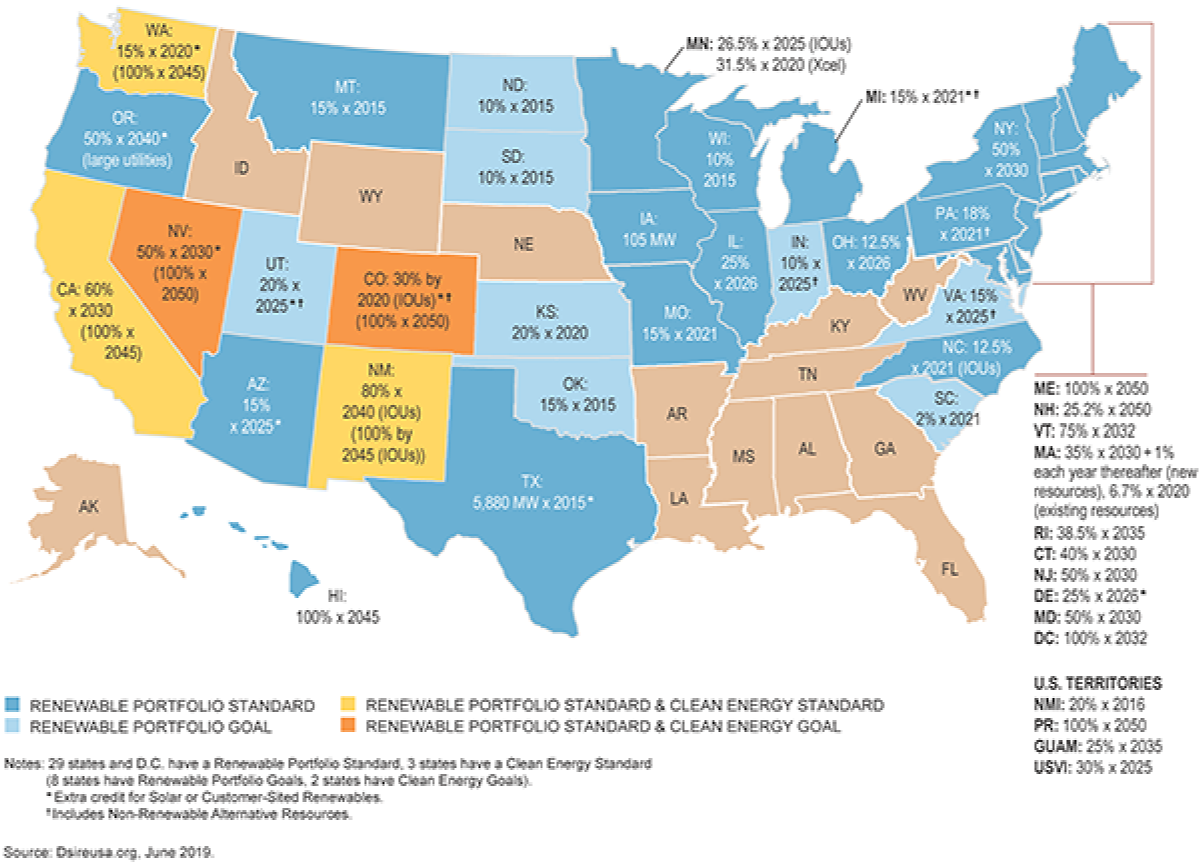


Figure 3-6. *U.S. Map of Renewable and Clean Energy Standards, June 2019*

At the state level, a range of policies have been put in place to drive emissions reductions. One of the most common state policies is a renewable portfolio standard

(RPS) requiring that certain amounts of electric capacity come from renewable sources or alternative energy sources. Twenty-nine U.S. states, Washington, D.C., and three territories have adopted an RPS, while eight states and one territory have set renewable energy goals. RPS mandates have created strong demand for renewable power. It is estimated that 58% of all renewable capacity in the United States installed from 1998 to 2014 is being used to meet RPS targets (excluding hydropower).[49] Currently, electric power associated with CCUS technology is not eligible under RPS policies.

While these approaches can be effective at driving deployment of targeted technologies, they can also be economically inefficient. According to a recent study by the Energy Policy Institute at the University of Chicago, RPS policies “come at a very high cost to consumers and are inefficient at reducing carbon emissions.”[50] The study concluded that although the RPS had the intended effect of increasing renewable power generation, and thereby reducing the carbon intensity of the electricity generation, the estimated impact on consumers is a 17% increase in retail electricity prices over a period of 12 years, and across the 29 states studied, a cumulative effect of $125 billion more for energy than they would have paid in the absence of the policy, with an average cost of $130 per tonne of CO_2 abated.

A similar study was published in 2018 by the National Bureau of Economic Research in conjunction with Yale and Harvard Universities that assessed the cost of a range of policies designed to reduce greenhouse gas emissions. By compiling and analyzing a number of other economic studies that looked at the cost per tonne of CO_2 abated, the report estimates the range of policies to be between \$10 and \$1,000 per tonne, with most standards and mandates policies ranging from \$50 to \$500 per tonne of CO_2.[51]

Fundamentally, a standards and mandates approach will likely be the most difficult to implement in a manner that yields the most emissions reduction for the least cost. This is because in a complex system, it is difficult for the standard-setter to be able to identify and then specify the precise economic optimum and to continually update the standards as technology develops, market conditions change, or to adjust for other factors in the economy.

2. Financial Incentives

As shown in the cost curve in Figure 3-5, CCUS deployment in the at-scale phase will require incentives at a greater level than has been provided to date. The activation and expansion phases focus primarily on clarifying and then extending and expanding access to existing financial incentives that have been detailed in the previous two sections of this chapter. This third phase of deployment will require an increase in the absolute value of such incentives.

As described earlier in the chapter, there are three types of policy driven financial incentives available to CCUS projects—investment incentives, production or operations incentives, and financing support. By increasing the value of the existing incentives, a broader range of CCUS projects become economic, making them more attractive to investment. For many projects, it will be necessary to combine available incentives to make a project viable. The amount of incentive and level of support needed will vary based on each company's ability to finance and take advantage of certain tax credits, gain access to pipelines, generate revenue from the sale of CO_2, and other factors. Ultimately, that combined level of incentives needs to reach approximately $110/tonne to achieve at-scale deployment of CCUS.

The renewable energy industry provides an example of how policy can incentivize at-scale deployment of technology. Between 2005 and 2015, the federal government provided $51.2 billion in financial incentives in support of solar and wind power development, and tax incentives provided 90% of that amount. Those financial incentives, when combined with a range of renewable energy standards and other supportive policies at the federal and state level, helped established the renewable energy industry. Today, more than 7% of U.S. electricity is supplied by wind and solar energy.

However, financial incentives have similar limitations to those described in the standards and mandates framework in that they place government in the position of choosing which technologies to incentivize (i.e., picking winners and losers). One risk of relying solely on financial incentives to drive CCUS deployment is the uncertainty regarding the life of the incentive. As governments and societal expectations change, policy priorities and programs will change. Uncertainty is a key issue for project developers and investors.

3. Market-Based Mechanisms

For more than a decade, there has been considerable discussion in the United States regarding a national price on

CO_2 emissions to incentivize deployment of lower emissions technologies. Putting a price on CO_2 emissions is generally referred to as a price on carbon. There are two main types of carbon pricing: carbon taxes and emissions trading systems (e.g., cap and trade). In the United States, several states and regions have cap-and-trade programs in place, including California, Massachusetts, and 10 Northeast and Mid-Atlantic states participating in the Regional Greenhouse Gas Initiative.

Both cap-and-trade and tax programs attempt to overcome the difficulty of identifying and specifying the economic optimum by employing market mechanisms, which in theory combine the knowledge of many participants and evolve over time. Both systems function by establishing a cost for emitting. A tax program has a theoretical advantage over cap and trade for reducing GHG emissions because a tax should produce a more predictable price and has broader application and provides a stable planning basis for the large capital investments necessary to make a significant reduction in GHG emissions over many decades. A cap-and-trade system conversely subjects the participants to more price volatility and is less transparent to the public. Under either approach, studies suggest that the most effective system would impose a gradually increasing real carbon cost over time.

One market-based policy approach that could incentivize CCUS is the implementation of a Clean Energy Standard (CES). A CES typically refers to a technology-neutral portfolio standard that requires that a certain percentage of utility sales be met through clean zero- or low-carbon resources, such as renewables, nuclear energy, coal or natural gas fitted with carbon capture, and other technologies. Similar to an RPS, eligible technologies are awarded credits per MWh of generation that can be traded, which provides an efficient, market-based solution to meet a standard.[52] The CESs that exist today are at the state level and do not recognize CCUS as a low-carbon technology. However, federal CES legislation has been proposed recognizing CCUS as a low-carbon resource.

A CES offers the potential to achieve an equivalent level of emissions reductions as an RPS at lower cost. Having a greater number of technologies in competition to reduce emissions can increase market efficiency and lower overall compliance costs for a given level of emissions reduction. In addition, the inclusion of a broad range of zero- and low-emitting technologies as compliance options for a clean energy standard can also increase ambition with respect to emissions reductions.

Previous research done by Resources for the Future, an independent research nonprofit organization, suggests that further efficiency gains are possible by using a credit system based on emissions rates rather than technology type. This credit system would encourage emissions reductions through changes in dispatch or investments at a facility, consequently further reducing emissions and lowering costs by allowing low-carbon technologies to participate.[53]

In the near-term, incentives will likely be a more effective way to drive deployment. In the long-term, however, a market-based approach is likely a much more economically efficient way of reducing CO_2 emissions than standards and mandates or financial incentives. Various articles have been written detailing the benefits and drawbacks of incentive-driven programs versus market-based approaches. Most economists agree that a market-based approach is a more effective approach for reducing emissions and more efficient for the overall economy.

The NPC recommends that to achieve at-scale deployment of CCUS, congressional action should be taken to implement economic policies amounting to about $110 per tonne. The evaluation of these policies should occur concurrently with the expansion phase.

IV. RESEARCH, DEVELOPMENT, AND DEMONSTRATION FUNDING

The United States has benefited from a more than 20-year history of DOE leadership, funding support, and public-private partnerships between government, academia, and industry. Between 2012 and 2018, Congress provided more than $4 billion in appropriations for CCUS R&D through DOE's Office of Fossil Energy. In addition, since 2010, $60 million per year of funding has been provided for technological advances in CO_2 EOR in unconventional reservoirs. As a result, the United States is currently the leader in CCUS technology and deployment capability. To retain this leadership position, RD&D funding must continue and, in some cases, increase to continue driving technology forward and costs to levels that will incentivize widespread deployment of CCUS. Increased RD&D will unlock opportunities by helping to enable the development of lower cost technologies, thus reducing investment uncertainty and the financial incentives necessary to enable substantial deployment of CCUS.

Commitment to research and development and expansion of academic and industry research for carbon capture across multiple innovation pathways is required to enable continued cost reductions, create competition, and help accelerate innovation. As noted in Chapter 5, “CO_2 Capture,” in Volume III of this report, capture technologies have been demonstrated at several commercial projects. Many of these projects were successful in part because of governmental support through, among other things, research funding. For example, Petra Nova received up to $190 million in cost share from DOE, and Air Products received a $284 million contribution from DOE.

The DOE Office of Fossil Energy is responsible for research, development, and demonstration efforts on CCUS, among other areas of power generation. Current federal CCUS research and development is housed in two main areas: DOE’s Office of Fossil Energy and the Advanced Research Project Agency–Energy (ARPA-E). The Fossil Energy Research and Development (FER&D) program offices advance transformative science and innovative technologies that enable the reliable, efficient, affordable, and environmentally sound use of fossil fuels. FER&D conducts R&D on advanced fossil energy systems, crosscutting fossil energy research, and CCUS technologies, including CO_2 EOR on unconventional reservoirs.[54] DOE’s research and development efforts over the last eight years (2012 to 2019) are outlined in Table 3-2.

FER&D Coal Program Areas	Program/ Activity	FY2012 ($1,000)	FY2013 ($1,000)	FY2014 ($1,000)	FY2015 ($1,000)	FY2016 ($1,000)	FY2017 ($1,000)	FY2018 ($1,000)	FY2019 ($1,000)
Coal CCS and Power Systems	Carbon Capture	66,986	63,725	92,000	88,000	101,000	101,000	100,671	100,671
	Carbon Storage	112,208	106,745	108,766	100,000	106,000	95,300	98,096	98,096
	Advanced Energy Systems	97,169	92,438	99,500	103,000	105,000	105,000	112,000	129,633
	Cross-Cutting Research	47,946	45,618	41,925	49,000	50,000	45,500	58,350	56,350
	Supercritical CO_2 Technology				10,000	15,000	24,000	24,000	23,430
	NETL Coal R&D	35,011	33,338	50,011	50,000	53,000	53,000	53,000	54,000
	Transformational Coal Pilots							35,000	25,000
Subtotal Coal		**359,320**	**341,864**	**392,202**	**400,000**	**430,000**	**423,800**	**481,117**	**488,180**

Source: U.S. Department of Energy.

Table 3-2. *Funding for DOE Fossil Energy RD&D Program Areas*

A. Technology Readiness and Maturity

Technology maturity levels provide a helpful indicator by which to assess the potential for continuing development and application of CCUS technologies to offer potential for cost reductions, efficiency gains, and performance improvements over time.

Figure 3-7 describes the range of technology readiness levels (TRL) for all of the CCUS technologies described in this study, using the U.S. Department of Energy TRL definitions[55] and assessment from NPC CCUS Technology Task Group members. Each technology is assigned a technology readiness level 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 the TRL level (i.e., >8), the closer a technology is to commercial readiness and deployment.

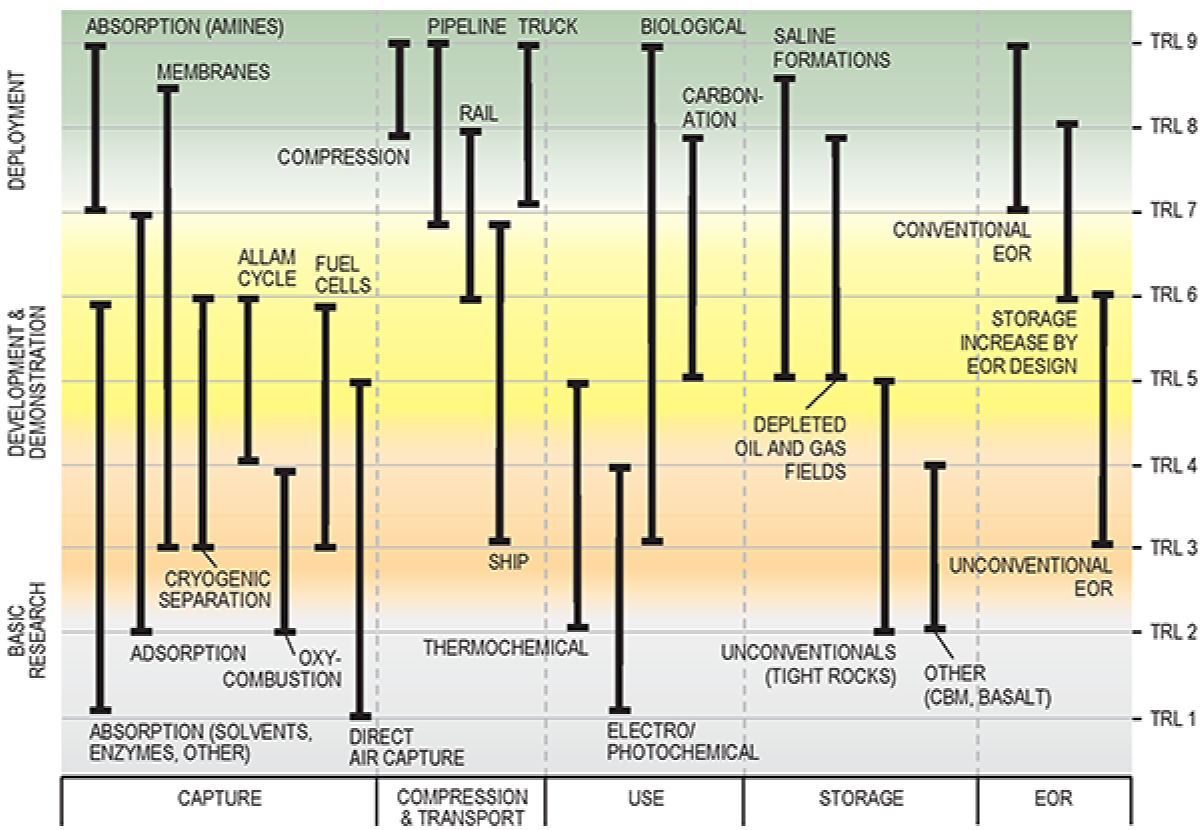


Figure 3-7. *Technology Readiness Level (TRL) Ranges for CCUS Technologies*

Chapter 2, "CCUS Supply Chains and Economics," highlights several CCUS technologies that are quite mature, well understood, and have been deployed safely at large-scale in commercial projects for many years. These technologies include absorption capture (via amine scrubbing), CO_2 compression and transport by pipeline, geologic storage in saline formations as well as CO_2 injection, and trapping during Enhanced Oil Recovery, among others. These technologies have TRL ranges in the upper (green) portion of Figure 3-7.

These established technologies have benefited from, decades of research and development, application and deployment, and associated learning-by-doing. As a result, most have experienced reductions in cost and improvements in efficiency and performance. Each of these technologies remains available for further application and deployment as part of future CCUS projects across a range of industries today. However, as a result of their maturity, further cost reductions are expected to be limited.

Figure 3-7 also includes a number of newer CCUS technologies in earlier stages of development (TRL 6 and below). These less mature and emerging technologies offer the greatest potential for a step change in performance and cost reductions, and, through continued public and private investment in RD&D, are likely to deliver the greatest return on that investment.

The technology chapters and appendices in Volume III of this report include an assessment of the maturity of each component technology today and describe what is needed for each to achieve their future potential. As experience and expertise develop, and the market for CCUS matures, existing technologies may move up the TRL scale. In addition, new technologies may be introduced into this portfolio.

B. R&D Policy Parity

Appropriations language in the federal budget provides guidance regarding the allocation of funds for CCUS projects across various industries. From 2017 through 2019, the appropriations language has directed DOE to “use funds from Coal CCS and Power Systems for both coal and natural gas research and development as it determines to be merited, as long as such research does not occur at the expense of coal research and development.”[56] And although the language does not prohibit funds to be used for natural gas RD&D, it may be interpreted that way. As a result, relatively little funding has gone into natural gas RD&D. In addition, as shown in Table 3-2, the Fossil Energy program does not have a designated industrial carbon capture program. However, some of the technologies in development through DOE’s carbon capture program have either evolved from industrial carbon capture process technologies or can be used in industrial applications. Revising the federal budget appropriations language to allow for all sources and fuel types could encourage broader research and development into new technologies.

The NPC recommends that Congress amend appropriations language to allow for all CO_2 sources and fuel types in the allocation of RD&D funding for CCUS.

C. Increasing Federal Research, Development, and Demonstration Funding

In conjunction with the recommended policy and regulatory support described in this chapter, continued investment in RD&D for existing and emerging technologies will be critically important. Increased RD&D will unlock opportunities by helping to enable the development of lower cost technologies, thus reducing the level of financial incentives needed to enable substantial deployment of

CCUS. Achieving more substantive cost reductions and improving the performance of existing technologies for CCUS deployment requires a substantially increased and continued investment in the RD&D of emerging technologies. Table 3-3 details the level of RD&D support needed over the next 10 years across all technology areas. A more detailed description of the specific research and development priorities for each technology follows the table. The NPC recognizes that these funding recommendations represent a substantial increase from current RD&D funding levels. A phase-in over one to two years could provide a pathway to the ultimate levels of support NPC recommends.

Technology	R&D (including pilot programs)	Demonstrations	Total	10-Year Total
Capture (including negative emissions technologies)	$500 million/year	$500 million/year	$1.0 billion/year	$10 billion
Geologic Storage	$400 million/year		$400 million/year	$4 billion
Nonconventional Storage (including EOR)	$50 million/year		$50 million/year	$500 million
Use	$50 million/year (first 10 years)		$50 million/year	$500 million
Total	**$1.0 billion/year**	**$500 million/year**	**$1.5 billion/year**	**$15 billion**

Table 3-3. *10-Year RD&D Funding Levels Recommended by NPC Study on CCUS*

The NPC recommends that Congress appropriate the level of RD&D funding detailed in Table 3-3 ($1.5 billion per year) over the next 10 years to enable the continued development of new and emerging CCUS technologies and demonstration of existing CCUS technologies.

This section describes the critical role RD&D has in improving performance, reducing costs, and advancing alternative CCUS technologies, making the case for continued investment by both government and industry in capture technology and methods for identification and characterization of suitable large-scale storage locations. It is anticipated, as with experiences in other areas, that as more CCUS projects are deployed, nominal cost improvements will occur as industry learns by doing. Examples of this may include developing a better understanding of how to integrate new CO_2 capture facilities with existing equipment already on site, and of how to link more effectively to new downstream components of the CCUS chain (e.g., new pipelines to new storage or EOR sites).

1. CO_2 Capture Research and Development

Over the next decade-plus, a combined public/private partnership will be required, which is estimated at $1.6 billion per year. The projected federal R&D investment averages around $1.0 billion per year. Current funding levels from the FY19 enacted budget are $101 million for CO_2 capture and $129 million for advanced energy systems such as pressurized oxy combustion, chemical looping combustion, supercritical CO_2 cycles, and hydrogen generator systems. The proposed capture technology RD&D has the following emphasis:

- Adjust to handle differences between coal flue gas, natural gas flue gas, and industrial CO_2 gas sources, and atmospheric source

- Advance development in solvents, sorbents, membranes, and cryogenic processes for gas separation as well as new energy cycles that would inherently capture CO_2 for storage or utilization
- Develop a baseline against which improvements can be benchmarked and evaluated openly
- Lower the overall cost of capture including capital, operating, and maintenance costs
- Focus on flexibility of operations of the CO_2 capture systems to accommodate ramping cycles
- Test partial capture to find the low-cost minimum for the technologies and sectors to which partial capture would be most applicable.

Specifically, average annual public-private investment into CO_2 capture, including negative emissions technologies, over the next 10+ years are recommended below and detailed in Chapter 5, "CO_2 Capture."

- R&D (includes basic science and applied research, bench-scale, and small pilots): $300 million per year at an 80% federal cost share (i.e., $250 million) for a minimum of 10 years on CO_2 capture and advanced power cycles system development. Typically, the cost share is 80% federal.
- Pilot programs: $300 million per year at 80% federal cost share (i.e., $250 million) over a minimum of 10 years is needed for a large-scale pilot program[57]
- Demonstrations: $1.0 billion annually at a total 50% federal cost share (i.e., $500 million) over 10 years to support the needed CCUS technology demonstrations.

This type of aggressive RD&D program with a focus on demonstration will enable market driven deployment of CO_2 capture projects in addition to other actions recommended in the activation and expansion phases, to reduce the need for additional environmental regulations or mandates.

a. Industrial Capture R&D

As of the time of this report, the DOE Fossil Energy program did not have a designated industrial CO_2 capture program. However, some of the technologies in development through DOE's CO_2 capture program have either evolved from industrial CO_2 capture process technologies or can be applied to industrial applications. One example of this is the pre-combustion CO_2 capture work that DOE has supported for several years. As many industrial processes require CO_2 to be removed from the gas stream in order to be used or to produce other products, DOE has had a dedicated R&D program to develop new and improved gas processing technologies that are widely used in many different industries. DOE has also supported R&D on air separation systems, which are widely used by industrial gas companies for purifying gas streams.

Some industrial applications of CO_2 capture are complex in that they have more than one exhaust stream resulting from both combustion and process streams from chemical reactions, so the approach to capture is not well defined.

The NPC recommends that DOE undertake a study for industrial CCUS RD&D to determine a uniform approach for addressing CO_2 removal from industrial systems and prioritizing R&D pathways. As part of the effort, DOE should identify how federal investments in CO_2 capture technologies currently in the DOE R&D portfolio can be leveraged with industrial applications of those technologies.

b. Demonstration Programs

The Clean Coal Power Initiative (CCPI) provided direct grants at 50-50 cost share for commercial-scale demonstrations of coal plants with CO_2 capture technologies. The American Recovery and Reinvestment Act of 2009 resulted in almost $1 billion of funding for the CCPI. It was through the CCPI program that the Petra Nova project received a $190 million grant to develop the project. Federal funding has not been appropriated to this program since the 2009 Recovery Act. Continuing to fund CCUS commercial-scale demonstration projects, across all fuel sources, through a direct grant program similar to CCPI, is critical to progressing at-scale deployment.

The NPC recommends that the CCPI program be expanded to include all fuel sources or that Congress authorize a new commercial-scale demonstration program with a new set of criteria to be established and robust federal funding provided.

2. CO_2 Storage — Research and Development

Ramping up CO_2 storage in geologic formations to the gigatonne/year scale is an enormous task. To put this into perspective, 1 gigatonne/year globally (a scale equivalent to approximately 40% of U.S. stationary source CO_2 emissions) would require about a 15-fold increase from the combined existing CO_2-EOR and storage operations taking place globally today. Based on the know-how developed through more than 100 years of oil and natural gas operations and the 20+ years of experience with CO_2 storage, there is enough knowledge today to continue expanding geologic storage projects in both oil and natural gas reservoirs and saline formations. Scale-up will take place gradually with learning-by-doing acting as a key component of capacity building and knowledge generation.

However, if this technology is to expand to achieve at-scale CCUS deployment and beyond, much more intensive use of existing storage resources will be necessary. This will require better information to assess risks, characterize sites, match CO_2 sources with potential sinks, and provide assurances that storage will be safe and effective. Several recent assessments, including the 2018 National Academy of Sciences report on CO_2 Removal and Secure Sequestration and the 2017 Mission Innovation Workshop on CO_2 Capture and Sequestration, detail the research needs. This report focuses on the research and development needs to support the rapid scale-up of CO_2 storage in geologic formations within the United States.

Today a significant amount of experience exists with CO_2 storage projects on the scale of 1 million tonnes/year, and even more with smaller scale pilot tests. As described above, the projects have conformed to performance expectations and as anticipated in the 2005 IPCC Special Report on Carbon Dioxide Capture and Storage, “With appropriate site selection informed by available subsurface information, a monitoring program to detect problems, a regulatory system, and the appropriate use of remediation methods to stop or control CO_2 releases if they arise, the local health, safety and environment risks of geological storage would be comparable to risks of current activities such as natural gas storage, EOR, and deep underground disposal of acid gas."[58]

Challenges associated with larger-scale projects needed to efficiently achieve rapid deployment of CCUS over the coming decades are driven by several factors, including larger quantities of CO_2 injected in hub-scale projects; the presence of multiple CO_2 storage projects in a single basin that may interact with each other through overlapping pressure buildups and potentially, plume co-mingling; choosing new sites in regions with less existing data available to support site characterization; and the need to consider the potential for CO_2 storage in unconventional formations.

To address the challenges, research priorities include:

- Increasing the effectiveness of site characterization and selection methods
- Increase pore space utilization by improving confidence in CO_2 plume immobilization mechanisms and accelerating their speed in immobilizing CO_2
- Improving coupled models for optimizing and predicting CO_2 flow and transport, geomechanics, and geochemical reactions—including leveraging capabilities in the oil and natural gas industry
- Lowering the cost and increasing the reliability of monitoring
- Quantifying and managing the risks of induced seismicity

- Investigating the feasibility of million tonnes/year storage in alternatives to sandstone and carbonate reservoirs, including ultramafic rocks (e.g., basalt) and low permeability rocks (e.g., shale)
- Social sciences research for improving community engagement and informing the public about the need, opportunity, risks, and benefits of CO_2 storage in geologic formations.

Existing R&D programs address both the basic and applied science of storage and field deployment with drilling, site characterization, and pilot- and demonstration-scale CO_2 injection projects. These field projects, supported by basic and applied science R&D, will be most impactful to industry to advance storage technology to widespread deployment. These projects also provide valuable infrastructure used in R&D phases for use in commercial-scale deployment.

Kick-starting CCUS projects through early engagement and characterization is intended to help lower or eliminate project risks and demonstrate the technical and commercial feasibility of CCUS, thus accelerating widespread deployment. Sustaining and increasing support of CarbonSAFE, the Regional Initiative to Accelerate CCUS Deployment, similar initiatives, and other storage-oriented efforts, is vital to facilitating rapid deployment. Increasing support for development and refinement of monitoring techniques will also further reduce implementation cost.

The NPC recommends that Congress increase R&D funding for geologic storage to $400 million per year for the next 10 years. The funding should be allocated as follows:

$100 million to the Regional Initiative to Accelerate CCUS Deployment; $100 million for characterization of geologic storage formations, including offshore, that have scale potential through the CarbonSAFE program or similar initiatives; and $200 million per year to enable field-scale projects that collect data and geologic samples used to advance the basic and applied science of long-term storage security.

3. Nonconventional Storage (including CO_2 EOR) Research and Development

CO_2 EOR is a mature and well understood process that has been successfully practiced for over 40 years. The first CO_2 EOR floods in the early 1970s operated with a combination of high CO_2 costs and low oil prices.[59] Combined with a limited capability to monitor and control the subsurface movement of the injected CO_2, these circumstances encouraged operators to inject relatively small volumes of CO_2. Advances in monitoring and control techniques, and more readily available volumes of affordable CO_2, have led to the use of larger volumes of CO_2. These injected CO_2 volumes are monitored and controlled to ensure that they contact, displace, and recover oil, rather than simply circulating CO_2 through higher permeability zones of the reservoir.

In addition to larger volumes of injected CO_2, the implementation of tapered water alternating gas injection schemes has become common practice to better control CO_2 mobility, improve conformance and sweep efficiency, and avoid bypassing areas of the reservoir that contain residual oil. These control measures, along with the application of more advanced well drilling and completion strategies to better contact bypassed oil, have led to steady improvements in residual oil recovery efficiencies in today's state-of-the-art CO_2 EOR projects.[60]

To a large degree, the impact of technology on expanding the application of CO_2 EOR in conventional reservoirs will most likely not be through the development of entirely new tools or technologies, but rather through refinement of existing state-of-the-art methods and their broader application to a larger number of reservoirs within basins with existing CO_2 EOR projects and in basins where CO_2 EOR has not yet been implemented.

Two state-of-the-art CO_2 EOR technologies that can benefit from research are (1) vertical and horizontal conformance controls to maximize sweep efficiency, and (2) advanced compositional modeling techniques to better predict and enhance performance.

Unconventional reservoirs account for 50% of U.S. crude oil production. These unconventional reservoirs have ultra-low permeability, which limits a conventional CO_2 flooding process where CO_2 and water are injected into dedicated wells to create a mobile oil bank that travels to producer wells.

The NPC recommends that Congress fund $100 million over the next 10 years for research into methods that can be used to improve effective application of CO_2 EOR for purposes of enhancing storage of CO_2 in conventional residual oil zone reservoirs, for application to unconventional CO_2 EOR reservoirs, and to storage in unmineable coal deposits and basalts. This is needed so that widespread CO_2 EOR in these reservoirs can begin within 5 to 10 years.

4. CO_2 Use — Research and Development

In the United States, funding levels for CO_2 utilization have been relatively small and an increase in funding is necessary to achieve CCUS at scale. Synergies may exist between the R&D needs of other federal agencies and the use of CO_2. Until recently, CO_2 use (with the exception of EOR) has received very little attention. Over the last 10 years, potentially marketable CO_2 use technologies have been developed with the assistance of government support. Several companies are exploring mechanisms for incorporating CO_2 emission streams for use in manufacturing. Existing commercial uses for CO_2 include the production of methanol, urea, carbonate salts, polycarbonates, and other specialty chemicals. These technologies currently do not sequester CO_2 on the order of magnitudes required for CCUS at scale but have shown promise at a small scale. These technologies can play an important role in emerging energy technologies, such as in the manufacture of electrodes used in batteries and fuel cells.

Fundamental research funding would be very important to advance science and engineering related to these technological areas by providing sufficient government support. Both multi-PI funding and center grants focused on scientific discoveries should be created. Interdisciplinary research is very important for CO_2 technologies since they require expertise in a wide range of fundamental areas including materials, catalysis, and reaction engineering as well as systems engineering. Collaborations between academia and industry should be encouraged via center grants. An earlier version of “ARPA-E type” funding for the acceleration of tech-to-market transitions can provide support for academic researchers to work with industrial partners and the “New ARPA-E type” funding can be given to startup companies.

Among the focus areas for research and development, “the Office of Fossil Energy seeks to develop novel, marketable products using CO_2 or coal as a feedstock. Projects are sought for technologies that show a positive life-cycle analysis; the potential to generate a marketable product; and significant advantages when compared to traditional products.”[61]

The NPC recommends that Congress provide $500 million in R&D funding over 10 years for support to basic science. This is particularly important for CO_2 use technologies since many of them are still in low TRL. The design of R&D funding structure should also be unique to the program.

The NPC further recommends that Congress provide an additional $500 million in years 10 to 15 for pilots, demonstration projects, and early deployment support. In order to do so, it is recommended that projects need to be field deployed to at least the level of National Carbon Capture Center, Wyoming Integrated Test Center, or similar practical demonstration environments that use real flue gas from coal and NGCC sources, in an industrial environment.

D. Sharing RD&D Information

When researchers and technology providers work together to share information on their research designs, process, and outcomes, while maintaining intellectual property protections, all parties benefit, and RD&D is more effective. Two means of accomplishing this are furthering public-private partnerships that integrate government, academia, and industry, and embracing the concept of open-source technology development. These options to maximize RD&D investment efficiency should be explored.

The NPC recommends that DOE promote public-private partnerships and consider open source approaches to the development of CCUS technologies as appropriate.

V. CONCLUSIONS

As described in Chapter 2, “CCUS Supply Chains and Economics,” the United States has had remarkable success to date in deploying CCUS technology. And although the United States leads the world in CCUS today, further deployment opportunities remain limited. Achieving widespread deployment of CCUS will require greater policy support, further development of a clear and durable legal and regulatory framework, and significant increases in funding for research and development. By implementing the recommendations detailed in this chapter and in the “Roadmap to At-Scale Deployment of CCUS for the United States” developed as part of this study, the United States has the opportunity to achieve widespread deployment of CCUS within 25 years and remain the global leader in technology and deployment. Implementing the recommendations in this chapter will depend upon engaging all stakeholders, including policymakers, coalitions, industry and the general public to achieve commitment and support. Chapter 4, “Stakeholder Engagement,” describes the process for engaging all stakeholders to enable widespread deployment, and details recommended actions to achieve that commitment and support.

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45 Under the Anti-Deficiency Act, the United States may not agree to open-ended indemnification arrangements absent specific Congressional authorization. See 31 U.S.C. 1341(a)(1)(B). Such authorizations have rarely

been granted due to their inherent open-ended risk to the federal government and taxpayers. Accordingly, sound public policy and legislative precedent counsel that authority to indemnify be strictly limited to activities of absolutely vital national security interests, and then only when private insurance is unavailable (e.g., agreements indemnifying Department of Energy contractors for liability arising out of nuclear incidents; and agreements indemnifying certain Department of Defense contractors). See Pub. L. No. 85-804 (codified as 50 U.S.C. § 1431 et seq.); the Price-Anderson Act, 42 U.S.C. § 2210; and Hercules Inc. v. United States, 516 U.S. 417, 426-29 & n.11 (1996).

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Chapter Four

BUILDING STAKEHOLDER CONFIDENCE

I. CHAPTER SUMMARY

Wide-scale deployment of carbon capture, use, and storage (CCUS), including transport, as described throughout this report, will remain limited without public commitment and support.

At present, awareness of CCUS among the general public is low, primarily because a limited cross section of stakeholders has direct interaction with CCUS projects. As a result, the role that CCUS can play in effectively addressing key issues, such as climate change, energy security, and economic growth, is not well understood by the public. Additionally, knowledge and opinions about CCUS vary widely among those who do have a working knowledge of CCUS. This working knowledge is often directly associated with coal and, to a lesser degree, oil and natural gas. Gaining public confidence in, and support for, CCUS will require significantly improving its understanding of CCUS and multiple demonstration projects to illustrate that CCUS is safe and its operations are environmentally sound.

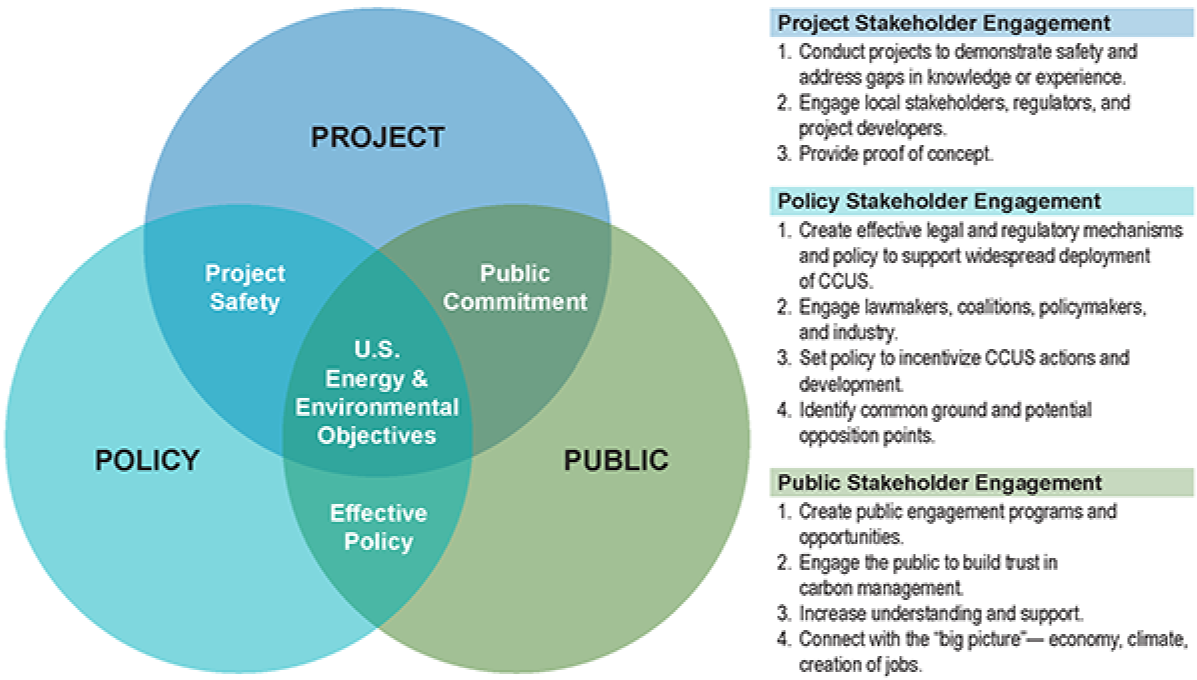
CCUS project-specific stakeholder engagement is well established in the United States, in part because of the U.S. Department of Energy's (DOE) Regional Carbon Sequestration Partnerships (RCSP), which has refined successful project-based public outreach and consultation programs. However, building widespread commitment and support through individual CCUS projects continues to be challenging. Although CCUS engagement on its own cannot guarantee success, when it is done well, it can be a significant enabler. In contrast, poor CCUS engagement can, and has, prevented CCUS projects from moving forward.

The level of action needed to enable wide-scale deployment of CCUS is substantial and requires the support of a broad range of stakeholders, including policymakers, nongovernmental organizations (NGOs), and various industry groups. Federal, state, and local policymakers will need to understand the leading role CCUS can play to cost-effectively address carbon dioxide (CO_2) emissions in both the near and long term. Coalitions, independent organizations, and NGOs will need to work closely with industry, policymakers, labor organizations, and NGOs to educate and inform the public and support policies that will enable wide-scale deployment of CCUS.

It is also critical to clearly communicate the concept of CCUS and signify its objective by using terminology that is more accessible to the public. For example, replacing use of the acronym "CCUS" with "carbon capture" or "carbon management" would go a long way to advancing public understanding and discourse. The amount of technical details provided to explain a more easily identifiable concept can then be tailored for each type of stakeholder while ensuring the overall objective is explained and understood by all stakeholders.

II. INTRODUCTION

Stakeholders are those individuals and entities who perceive that they have a stake, or direct interest, in a project or program.[1] The CCUS stakeholder landscape is complex and engagement occurs in three primary spheres: project, policy, and public (Figure 4-1). Collectively, these are known as the “spheres of engagement.” For example, CCUS stakeholders include, but are not limited to, residents of a community, landowners directly impacted by projects, local and regional officials, regulators, civic groups (such as chambers of commerce), politicians, media, and other opinion leaders. For broader national and international policy audiences, stakeholders may include NGOs, regulatory agencies, such as the U.S. Environmental Protection Agency, state agencies, federal agencies, such as DOE and the U.S. Department of the Interior, industry, financial organizations, and elected officials. Environmental action organizations are stakeholders with interests that intersect all three of the primary spheres.



Source: Greenberg, S., information from stakeholder focus groups conducted for the NPC study, unpublished, 2019.

Figure 4-1. *CCUS Spheres of Stakeholder Engagement*

As shown in Figure 4-1, stakeholder engagement happens simultaneously within each sphere and overlaps between the three spheres of engagement. U.S. energy and environmental objectives are at the epicenter of the overlapping spheres. The primary outcomes shared between the spheres, where they overlap with one another, are project safety, effective policy, and public commitment. Gaining stakeholder confidence and support requires engagement in all three spheres of engagement. Successful engagement enables the nation to voice its energy and environmental concerns while providing an opportunity to build trust with stakeholders.

Engagement processes vary between the stakeholder groups, and each has specific needs. Engagement can also vary depending on stakeholders' geographic proximity to projects with national, regional, and site-specific boundaries. When engaging stakeholders, it is important to understand their level of understanding and ability to influence projects or policies, either positively through support or negatively through opposition. Engagement with each group is the foundation for creating a broad and diverse stakeholder base. For example, public engagement programs need to understand and characterize stakeholder perceptions. Identifying potential common ground and opposition points is key to building trust and productive stakeholder relationships.

Trust requires that stakeholders are properly engaged and cultivated over time, creating relationships that can facilitate wide-scale deployment of CCUS. Open and positive engagement in the project sphere has proven to be critical in addressing the deeply held concerns of local stakeholders and has created an atmosphere of trust in which project developers can demonstrate that CCUS is safe and effective. Similarly, engagement is needed in the policy sphere to ensure local, state and national groups, lawmakers, industry, and other policymakers who define or influence the local or national energy agenda consider CCUS to be a safe and effective means to meet clean energy and environmental objectives. Once engagement in the project and policy sphere is well established and objectives and momentum have aligned, the process of engaging the public becomes more effective and widespread. However, even with a foundation of trust, it may take years to cultivate supportive relationships.

III. PUBLIC PERCEPTION AND CCUS

Public attitudes concerning the safe generation and use of energy are inextricably linked to environment, climate change, and renewable energy technologies. Those who are aware of CCUS often associate the technology with fossil fuels such as coal and, to a lesser degree, oil and natural gas. CCUS is a relatively unknown or misunderstood technology, and its positive role in addressing climate change, energy security issues, and economic growth is not fully understood.[2,3]

The connection between CCUS and industrial emissions has recently begun to be recognized, especially in the area of bioenergy carbon capture and storage. When considering cleaner forms of energy, renewables such as wind and solar are currently preferred by the public, despite their limited potential for meeting current and future energy demands.[4] Public opinion about coal or natural gas power generation with CCUS lags far behind nearly all renewable energy sources. CCUS awareness also registers lower in the public mind than do natural gas and nuclear options as a means of achieving low-carbon energy generation.[5] CCUS does not currently have the positive public profile needed to garner consideration among these options, which could impact acceptance of wide-scale CCUS deployment.[6]

Despite successful project deployment and significant advances that demonstrate the ongoing safety of the storage component of CCUS, broad fears persist in the consciousness of the American public. A relatively small number of individuals and groups have had direct interaction with CCUS, usually through projects, policy development, or the local media. One barrier for public support of CCUS is an ongoing perception of the risk of catastrophic failure of the storage process.[7]

Proponents of the technology often argue that CCUS is an important integration of advanced technologies for addressing greenhouse gas emissions in a material and cost-effective manner. CCUS supporters cite these technologies as (1) a necessary component of climate models to reach 1.5°C greenhouse gas reduction targets, (2) having the greatest potential to safely store large volumes of CO_2, (3) serving as a bridge to cleaner energy technologies, (4) a means to commoditize CO_2 through both enhanced oil recovery (EOR) and non-EOR activities, (5) the only technology available for reducing emissions in the industrial sector, and (6) a component of the all-of-the-above energy portfolio.

Those who oppose CCUS cite (1) its cost, (2) the lack of a successful long-term track record, (3) its role in extending the use of fossil fuels, and (4) the investment tradeoff that prevents more deployment of renewable energy. CCUS opponents often argue that the window for widespread CCUS deployment has passed, and the focus should be on renewables and other clean energy options. Controversy may continue even when CCUS is well understood because benefits are accrued to the global community, but the impacts affect a local community.

In a 2019 study by the Global CCS Institute, policy influencers were surveyed to better understand their perceptions about CCS.[8] The study surveyed 100 federal policy influencers (50 public and 50 private). Only about half of those polled recognized the term CCS. Among those who knew what CCS was, the majority said they believe it is safe but have specific concerns about seismic activity or leakage. They also expressed support of government efforts to deploy CCS. And, while CCS is perceived by policy influencers as prolonging the use of fossil fuels, they recognize that it has environmental and energy benefits. The policy influencers believe carbon utilization increases support for public investment in CCS and that direct air capture leads to greater support for public investment. There was overwhelming agreement that the United States should pursue lower-carbon technologies.[9]

Listening sessions and roundtable meetings were also conducted for this study to gain insight into a cross section of views within the environmental NGOs, oil and natural gas industry, and the financial sector. The environmental NGOs that participated see CCUS as essential to meeting near-zero emissions goals by 2050. They expressed concerns about integrating CCUS into the broader infrastructure, passing on costs to consumers, and impacts on wildlife. Perceived risks associated with storage include leakage, accounting for stored CO_2, accurate reporting of data, and the efficacy of monitoring technologies. Industrial CCUS is seen as a critical component and as important as decarbonizing the power sector. The environmental NGOs also see a need for transparency and engagement that helps envision the infrastructure and timelines associated with CCUS. These groups want to continue to be engaged in listening and learning, staying current on issues and the messages around CCUS. One participant summarized future activities by saying there is a “need to advance the conversation—we are narrative creatures and respond as such.”

Financial stakeholders consider enabling factors such as international markets, debt financing, certainty in the technology, the presence of a clear legal framework, and economics. These stakeholders see the state of public understanding as a critical factor. Banks are interested in exploring CCUS and begin investing but need an integrated approach to reduce risk, noting that they face a steep learning curve. Key topics of interest to these groups are information about technology and liability, a broader conversation to address social issues, and balancing pressure by investors regarding funding fossil fuel companies.

The study also engaged a group of oil and natural gas companies to discuss perceptions of issues and challenges associated with the deployment of CCUS. These companies see access to capital and resources and capital allocation as issues related to developing CCUS. Large companies have resources and experience, while smaller companies may be flexible and act more quickly when establishing CCUS projects. Long-cycle projects are increasingly difficult to support. Pore-space ownership, long-term liability, durability of financial instruments, and time to permit were all cited as areas of risk and uncertainty. Oil and natural gas companies also expressed concern about reasonable rates of return for shareholders, durable funding mechanisms, stable legal and regulatory frameworks, and fiduciary responsibility. They are seeing a change in shareholder expectations that now include environmental, social, and governance and governmental actions. They also see a need for clear and basic communication that is consistent, delivered at the appropriate level, and contains facts and examples while accounting for emotions.

Additional listening and discussion sessions with multiple stakeholder groups will be important to expand the understanding of stakeholder perspectives and broaden the spheres of engagement. Key factors shaping stakeholder perceptions on CCUS include the following:

Historical views on issues of environmental protection and climate change. Many stakeholders do not perceive CCUS as a viable climate change technology, or they care more about other environmental issues, such as pollution control. In some cases, concern about climate change is so strong that CCUS is perceived as a technology that cannot help in a meaningful time frame because it prolongs the use of fossil fuels and delays the deployment of renewable energy generation.[10] Conversely, other stakeholders are unconcerned with climate change and believe CCUS is not worth the investment.

Personal impact and competing resource utilization. Stakeholders who have some understanding of CCUS raise concerns about the potential personal impacts of CCUS projects. Common views include “not in my backyard” (NIMBY) or “not under my backyard” (NUMBY) because a significant number of citizens do not want any type of energy infrastructure—wind, solar, CCUS, power plants, or industrial facilities—located nearby. Controversy exists even when storage sites are identified that meet NIMBY or NUMBY expectations. For example, saline storage has the potential to generate demand for compensation for use of pore space and the land surface itself. In other cases, there are concerns about the risk of adverse impacts on the use of pore space as a shared resource. Concern has also been expressed about storage hubs and large storage projects that receive CO_2 from multiple sources, because public perception is that the site is a dumping ground. Additional economic concerns exist that natural gas and CO_2 could potentially be mixed in the subsurface if preexisting natural gas storage sites and the large-scale saline storage footprint share pore space.

Political leadership. Historically, CCUS has received bipartisan support because it has both environmental and economic benefits. Thus, government and industry support for CCUS can and should play a major role in increasing awareness and acceptance of CCUS projects. Leadership can vary within the U.S. political system, especially in regard to climate change, which can drive shifts in public attitudes. Climate change and the role of CCUS as a mitigation or solution technology are increasingly part of the political dialogue.[11] Legislative efforts continue to emerge that reflect current CCUS policy and potentially drive public opinion about CCUS. These types of efforts should be studied to honestly and responsibly improve public support for CCUS. Political leadership and the policy sphere can find common ground by creating a balanced energy portfolio that includes CCUS as part of an all-of-the-above solution in combination with renewables.

Trust in government institutions and corporations. Local experience with regulators, environmental management, and project developers plays a key role in building trust and shaping public attitudes. One example of a positive public perception experience is the public/private partnership of the Illinois Industrial Sources CCS project. ADM, the main employer in Decatur, Illinois, had community trust, worked with trusted partners such as the Illinois State

Geological Survey and Richland Community College, and worked closely with DOE to actively engage stakeholders in their CCUS project.[12] Conversely, the Barendrecht project in the Netherlands is an example of a negative public perception experience that resulted from the local government's lack of trust for a corporation that led to strong local public opposition.[13] When building trust, public and private organizational integrity and competence remain paramount.

Socioeconomic considerations. The background conditions, needs, and resources of impacted communities play a significant role in a project's success. CCUS projects can potentially introduce jobs, training, and other community benefits, as well as draw on local resources such as community colleges and development efforts. Being able to clearly describe all the potential benefits along with a realistic assessment of risk that a CCUS project brings to a community can influence the level of support received. Understanding local environmental concerns is also critical to addressing the questions associated with planned CCUS activities. For example, communities with traditional water quality issues need to see reliable evidence that a CCUS project will not impact local water quality or access.

Environmental justice. Environmental justice is ensuring that all people have access to fair treatment and the opportunity for involvement regardless of race, ethnicity, national origin, or income around the development, implementation, and enforcement of environmental laws, regulations, and policies. Environmental justice is best achieved when there are equal degrees of protection from environmental and health hazards, and there is equal access to the environmental policy and decision-making process.[14]

Familiarity with the fossil fuel or energy industries. In geographic regions where the production of fossil fuels or hydrocarbon energy production exists, local stakeholders tend to have a deeper understanding of how CCUS technologies can lower carbon emissions.[15] In these areas, it is important to understand whether the public perceives the fossil fuel and energy industries as having a critical role in the local economy and a positive impact on the environment, or perceives them as a threat to the community and its environment.

IV. DEFINING STAKEHOLDERS

A. Project Stakeholders and Engagement

Globally, there are examples of both successful and failed CCUS projects. The basis for success and failure varies and sometimes may be attributed to poor stakeholder engagement. Carbon storage projects can fail or falter when public stakeholders perceive that project and/or policy stakeholders (proponents) are withholding important information about the project or changing the parameters of a project without input from those directly affected.[16] Several CCUS projects have shown that responsible stakeholder engagement leads to successful implementation of those CCUS projects, particularly when there is alignment between government and project developers, social benefit, and communication mixed with a good measure of flexibility.[17] Successful public engagement does not guarantee successful projects, but projects rarely proceed without first creating an opportunity for input from local citizens. To be transparent and open to input and influence, engagement processes must be understood by all stakeholders. For example, the failed Barendrecht project in the Netherlands demonstrated that local stakeholders believed decisions about the project, particularly the location of storage, had been made without consultation and that engagement was conducted as an afterthought to inform residents of previously determined details.[18]

The United States and Canada are both leaders in successful stakeholder engagement for projects, including the Illinois Basin–Decatur Project, Illinois Industrial Sources CCS, Wallula, Bell Creek, FutureGen, FutureGen 2.0, Quest, Boundary Dam, and Petra Nova. Lessons learned from these and other projects provide valuable insights for addressing local stakeholder concerns and building trust. This success is, at least in part, because of the development of DOE's seven RCSPs in the early 2000s. The RCSP projects resulted in not only geologic lessons learned, but also lessons from the public outreach and consultation programs. As a result of these lessons learned, processes and strategies were further refined, contributing to the development of best practices publications that included DOE's *Best Practices for Public Outreach and Education for Carbon Storage Projects*.[19]

The RCSPs established a collaborative environment that drew together industry, government, NGOs, academia, and project operators. The regional approach stitched together key stakeholders that then began a national discussion while remaining rooted in the geology and economics of specific regions. This programmatic approach to stakeholder engagement shows a successful example of project-based engagement supporting and providing evidence-based information for policy and regulatory developments, as well as supporting public education. The Plains CO_2 Partnership is a good example of working with local public television to create a series of informative videos on CCUS that were widely viewed. The Southeast Regional Partnership Carbon Sequestration partnership, the Midwest Regional Carbon Sequestration Partnership, and the Midwest Geological Sequestration Consortium created effective models of stakeholder engagement and school curricula that were shared throughout their regions. By way of example, each of the partnerships was able to leverage project experiences for engagement opportunities at local, state, national, and international levels, which proved to be a powerful mechanism to explain and demonstrate the how and why of CCUS to a broad audience.

The resulting group of stakeholder engagements created by the DOE partnerships enabled the project proponents and its trained professionals to expand their international network of colleagues involved in CCS/CCUS projects and research in Australia, North America, Europe, and Asia. As a result, these DOE partnerships have refined CCS/CCUS stakeholder engagement practices and processes. International knowledge-sharing and collaboration has continued to accelerate the deployment of CCUS globally and served to build confidence among government, project stakeholders, and the general public. A wealth of knowledge currently exists among this network of engagement and subject matter experts from early CCUS demonstration projects; leveraging the knowledge and best practices from these experts can successfully guide new CCUS projects in understanding what to do and what not to do when engaging stakeholders.

CCUS has learned many technological lessons from the oil and natural gas industry and may also gain insight from successful stakeholder engagements currently underway in this sector. Although the underground injection control Class II permitting process for oil and natural gas wells does not require a significant amount of public engagement, the industry has begun engaging communities through project-specific processes because environmental concerns have escalated. Infrastructure (wells, refineries, pipelines) or site development and monitoring (seismic surveys, ground water sampling) may require repeat public interaction. Local engagement by industry is often driven by infrastructure, production, and maintenance, as well as the fact that many employees live in the community, or the industry may be a major force in the local economy.

For example, as oil and natural gas companies expand CO_2 EOR projects, engagement is typically focused on regulators and owners of the subsurface pore space and mineral rights. As policies to support CO_2 capture have been promoted, many in the oil and natural gas industry have engaged policymakers to share information about the benefits of ancillary CO_2 storage from CO_2 EOR. In another example, stakeholders continue to express concerns over the impacts of hydraulic fracturing and the potential for induced seismicity as a function of shale gas development. Activities related to the subsurface are often not well understood by public and policy stakeholders, which can lead to general concern and reluctance. These interactions have led to an increase in engagement in the policy sphere and may lead to more locally driven engagement as well as change in permitting processes or societal expectations.[20] As these types of projects continue to develop, it is important to understand the extent to which they may be viewed differently than conventional oil and natural gas operations and in conjunction with saline storage.

Another source of project-level experience is in the power sector, where significant large and long-lived infrastructure decisions are made that have significant local impact. These kinds of projects tend to draw a full range of active stakeholders and spur healthy debate. Power companies also consider their long-term role in providing power and jobs in the communities they serve. Historically, power companies have looked for multiple ways to build community relationships and to be ready to respond to accidents, investments, and other major activities. Power companies involved in CCUS projects, such as those conducted by Southern Company at the Barry and Kemper plants, have often front-loaded public engagement to build awareness and support and to assess project viability.

Beyond the direct value or impact of a project's success, project experiences also provide policymakers with evidence and information about the specific enhancements or improvements needed to enable widespread deployment of CCUS. Projects provide the public with opportunities to see and experience CCUS for themselves, understand how it works, and recognize that it can safely and effectively capture and store CO_2.

Given the limited number of projects in the United States today, project experience alone is not enough to bridge the awareness gap associated with CCUS. For most of the public, CCUS remains a relatively unknown concept with very little connecting it to energy production or the environment. The more projects that can be successfully implemented, the greater the opportunity to more broadly demonstrate to the public the benefits of CCUS.

B. Lessons Learned from Early CCUS Projects

Successful CCUS demonstration projects have shown that providing a reliable and trusted local point of contact (face of the project) is just as important as the message being communicated. For example, the oil and natural gas or power industries often may have a good rapport with stakeholders within their local regions as the result of being an employer of many stakeholders and contributing to the local economy. In these areas, companies involved with CCUS projects should begin communication from within by educating employees about the project and by answering their questions and concerns. Knowledgeable employees can become project experts or informal spokespersons who are proud to share factual and relevant information when asked by friends and neighbors in the communities where they live and work.

Identifying groups and individuals within a local community who may be affected by the project's development, implementation, and operation is key for successful engagement, particularly in communities unfamiliar with subsurface activities.[21] An effective engagement process must allow stakeholders to influence, respond to, and feel heard in the development of the project, regardless of their position. This type of interactive engagement process creates a meaningful platform that assures stakeholders their input is respected and can influence or impact the project. Recognizing that a community or location may never be willing to engage or accept a proposed project must be accepted as a potential outcome of the engagement process. Regardless of outcome, an engagement strategy should not be contingent on convincing a population of stakeholders about a predetermined outcome. Instead, engagement activities should be designed to establish trust, paths of communication, and, when reasonable and feasible, a willingness to adapt or change a project to accommodate stakeholder perspectives and concerns.

To achieve this, engagement for a CCUS project should begin as early as possible, definitely when site selection is underway, and should include a range of engagement mechanisms and tools such as one-on-one conversations with landowners, project presentations at community-led events, open houses for the wider community, social media information campaigns, and, where possible, organization of site tours of the relevant facilities for interested members of the local public, media, and government officials.[22]

Engagement activities should be designed to provide consistent, continuous, and open collaboration and communication among internal project managers, risk managers, outreach team managers, and policy and public stakeholders. To mitigate potentially sharing mistakes or incorrect information with project or stakeholder communities, two-way respectful communication is essential—sharing project information, explaining what the information means, listening to community concerns and potential misconceptions, and answering questions using easy-to-understand terminology and imagery. Communication should also be conducted through as many channels as possible, because stakeholders vary where they get information and what information they trust.[23]

C. Policy Stakeholders and Engagement

Stakeholders in this sphere include federal and state legislators, regulators, NGOs, and industry associations. Policy engagement relies on the same principles as projects, but with a broader scope, and draws on evidence of successful CCUS projects. Stakeholders in this sphere may consider a project in relation to its impact on policy rather than the specific local impacts of the project, but they may also be active in a community where a project is planned.

Engagement in the policy sphere generally focuses on specific legal, regulatory, or policy mechanisms that impact CCUS deployment. A group advocating for a new or changed policy will identify concerns among various stakeholders so they can be proactively addressed. Because this is a diverse group of decision-makers with varying levels of knowledge about energy, the environment, and CCUS technologies, engagement with this category includes stakeholders who need varying levels of information about how CCUS works, why it is important, and its potential economic and environmental benefits. Understanding the audience and preparing materials specifically crafted to provide the depth of information needed by this diverse group is an important factor at this stage. Engaging at the policy level may also require reaching out to the far wings of the political spectrum and illustrating how different factions, from those seeking aggressive climate change mitigation to those who support CCUS, can find common ground.

One example of an effective and still-evolving effort is the Carbon Capture Coalition, formerly the National EOR Initiative, which was formed after broad U.S. climate legislation failed. Convened by the Center for Climate and Energy Solutions and the Great Plains Institute, the Carbon Capture Coalition has brought together leaders from industry, the environmental community, labor organizations, and state governments, to build support for policies that enable greater CO_2 storage through EOR. The initial focus was to advocate for extending and expanding the existing Section 45Q tax incentive for carbon capture projects. Working together across a broad group of stakeholders, the Carbon Capture Coalition and the Carbon Utilization Research Council helped drive the expansion of the 45Q tax credits to include utilization options beyond EOR, address minimum eligibility storage requirements to meet the needs of industry and demonstration projects, gain new understanding of the importance of saline storage to some environmental groups, and refine the message to reinforce the value of EOR for both increasing domestic energy independence and addressing the risk of climate change. In fact, CCUS may be experiencing a broader appeal because of its potential to create benefits across the political spectrum. A combination of largely Democratic support for addressing climate change, Republican support for the use of captured CO_2 in EOR, and bipartisan recognition of the potential for using CO_2 in the manufacture of everything from shoes to cement was key to passing the tax incentive.

California’s Air Resource Board (ARB) provides yet another example of how existing engagement processes influence policy and regulation. The ARB was instrumental in developing recently adopted quantification methodologies (QMs) used for specifying how captured CO_2 can be eligible for credits within the state’s low-carbon fuel standard. Prior to drafting regulations, the state held eight workshops to solicit input from stakeholders between February 2016 and May 2017. The workshops addressed a range of topics, including site selection, monitoring, well mechanical integrity, and accounting protocols. At the conclusion of these workshops and meetings, the ARB drafted proposals that were open to public comment. Throughout the process, the ARB reached out to diverse stakeholders in the state, including environmental justice groups, academics, and industry. The QMs were formally adopted in September 2018.

D. Public Stakeholders

Advancing CCUS deployment depends on public understanding of the role CCUS plays and confidence that technologies across the value chain are safe and reliable and effectively reduce CO_2 emissions at a rate that will inhibit climate change and benefit society. Not surprisingly, the most challenging area for project and policy stakeholders is engagement with the public sphere. Success with this group of stakeholders will require creating explanatory, approachable, and straightforward processes and materials that can resonate with a broad range of perspectives. It is important to distill concepts to facilitate communication, but not to oversimplify to the extent that mistrust results.[24] This type of engagement will influence overall stakeholder perceptions and needs to expand as deployment of CCUS progresses. It is important to recognize, however, that as CCUS is deployed more broadly, the engagement and education process will need to continue and will remain an explanatory challenge. Thus, having a comprehensive and clear energy and environmental policy, along with successful demonstrations of projects, is necessary to ensure the general population understands the role of CCUS as a carbon mitigation technology that is important for the U.S. environment, economy, and energy security.

It is also important to encourage and empower the public to play a role in CCUS deployment, providing it with ample opportunities to ask questions and raise concerns, engage with elected officials and project developers to understand impacts and benefits, and to take part in discussions about energy, climate, and societal expectations.

One of the most important roles of stakeholder engagement is establishing the opportunity to bridge the entire CCUS value chain and create an interface between the three spheres of engagement—project, policy, and public—while continuing to refine and deliver the message that CCUS is safe and necessary.

The multitude of perspectives and opinions across stakeholders reinforces the importance of understanding popular attitudes in the stakeholder engagement process. Despite specific factors that may influence perception, experience has shown that a consistent set of questions is asked by all stakeholders regarding CCUS,[25] including:

- What is CCUS? What is carbon capture?

- How does it work?
- Is it safe?
- Will it impact my property value?
- Who pays for it?
- Who is responsible for CO_2 once it is stored?
- Will it cause earthquakes?
- What happens when you have an earthquake?
- Will it damage my groundwater/drinking water?
- Is it a ploy to continue to use fossil fuels at the expense of renewables?
- Is this process taking oxygen out of the atmosphere? Is it harmful?
- How many carbon capture plants are operating today?

It is critical that, at a minimum, any stakeholder engagement in any of these spheres addresses these questions and provides a basis for which all stakeholders can begin to understand the role of CCUS in substantially reducing the emissions associated with a broad range of industries.

V. DEPLOYING STRATEGIC STAKEHOLDER ENGAGEMENT

A robust stakeholder engagement process involving all stakeholders in the spheres of engagement considers the sociopolitical landscape, develops effective means of communication with critical stakeholders, aligns with local objectives and government policy, and is transparent and adaptive.[26] All engagement requires listening to stakeholder input to help shape the project parameters required to reconcile objectives and stakeholders' needs and concerns. Furthermore, the development of messages that will resonate with stakeholders is critical. Equally important is developing responses to address opposition.

The key to successful engagement is identifying and planning for the who, what, when, where, how, and why associated with the engagement goal. The strategy developed should consider the timing of engagement strategies; the importance of gaining knowledge about the community; the identification and communication of the project's local benefits; an understanding of how, when, and what to communicate and engage; and how best to use appropriate sources of information.[27] Many resources and tools are available to inform the engagement process. Methods draw from social science assessments and include surveys, one-on-one interviews, media reviews, and other methods to identify and understand public opinion and important stakeholder groups.[28]

A. Social Site Characterization

Experience indicates that stakeholder perceptions of CCUS projects tend to be more strongly influenced by socioeconomic factors than the technical details of any given project.[29] Efforts must be made to gain a preliminary understanding of the physical, environmental, and social characteristics of a project or policy. It is equally important to understand local and regional economic considerations.

Social site characterization is a process that draws its reference from the critical role of geological site characterization for CCUS projects. However, social site characterization suggests that in addition to assessing the technical and/or physical characteristics of a site, the social or human characteristics or impacts should be considered when selecting and designing projects.[30]

Social site characterization and stakeholder identification are intertwined and employ "the common steps of stakeholder identification, mapping, and response."[31] Social site characterization includes an analysis of the project context and proposed location, identification and mapping of stakeholders (including identifying concerns, local factors such as economic, political, environmental, social, and project-related issues that could arise), and the development of a stakeholder engagement plan based on an analysis of project-related issues.[32]

Social site characterization becomes even more important as widespread industrial deployment of CCUS occurs. As CCUS is increasingly put forward as an option in addressing emissions from industries that are not associated with energy production (i.e., cement and steel manufacturing), CCUS proponents making decisions about stakeholder engagement put projects at risk if they do not complete social site characterization work on communities in and around the siting of such projects, particularly in regions without an active oil and natural gas industry.

B. CCUS Communication Strategies

Although engagement at the project level has been successful in many instances, messaging around CCUS has historically been overly technical, decentralized, and inconsistent, enabling misconceptions to form about the technology. Some of the most persistent misconceptions about CCUS are: it does not work; the technology is too expensive and not deployable at commercial scale; it, or related activities such as storage, is not safe; it is not needed to meet climate goals; and it only enables continued use of fossil fuels.

Three key aspects will drive future communication strategies for CCUS: framing, messaging, and messengers.

CCUS stakeholder communication and education have traditionally focused on explaining the complex technologies in detail and providing specifics about subsurface activities, which are often challenging and misunderstood. More recently, simplifying the message has increased understanding and gained public support at the project level. Instead of using a technical approach that defines sources and storage sinks, value chains, and climate models, CCUS policies and deployment would benefit from a simplified nontechnical approach that describes how CCUS is a technology that can be applied to all energy-intensive industries and is therefore neutral to the carbon management process.

Successful acceptance of CCUS requires complete, strong, and consistent messages delivered by a variety of messengers who are well versed in CCUS technologies and the role these technologies can have in meeting U.S. energy and environment objectives. One advantage of CCUS is that it lends itself to flexible messaging and can encompass many benefits, ranging from climate management to energy security. This flexibility should be leveraged while striving for consistent messaging.

The engagement activities and materials used can have a significant effect on stakeholder understanding of CCUS. Communication materials that incorporate multiple views and are authored by diverse groups (industry, NGOs, government, and academia) are often trusted more than overly polished approaches that may even cause mistrust.[33] It is important to remember that NGOs and environmental activist organizations are an integral part of the spheres of engagement. They have a persuasive voice within the public and policy spheres. It is critical to have open dialogue with these groups to ensure that all sectors in the spheres of engagement are included in the communication process.

C. Consistent and Accessible Messaging

Accessible education and communication concepts need to be developed and distributed to increase understanding of CCUS. A broad range of advocates and climate scientists have supported a rebranding of CCUS focused on using an easier-to-understand name that matches efforts to demystify the technology. Creating a more easily recognizable name, such as carbon capture or carbon management, provides an opportunity to shift public perception of the technology from expensive and not ready to an existing technology and critical to addressing global climate goals.[34] The amount of technical details included when discussing the general concept can be adjusted to suit specific stakeholders while allowing for the overall concepts to be understood or explained.

Additionally, focused communications about technologies that enable carbon use beyond EOR, and terms like “carbon removal” can be a helpful entry point to discussing carbon capture across the political spectrum. Climate advocates are often more comfortable with carbon removal and the economic potential of carbon use beyond EOR, and these simpler but accurate terms can appeal to conservatives. Describing the economic benefits will often resonate with all parties.

ClearPath, an NGO that supports carbon capture within its larger mission to promote clean and reliable power, convened a small bipartisan focus group of congressional staffers in early 2017 and found that most had not moved beyond the negative associations with expensive projects that have failed. This congressional staff focus group produced a set of findings and recommendations that remain relevant and should be considered for implementation in future stakeholder communications.

The focus group found that acronyms do not work. Almost all the staffers referred to the technology as “carbon capture” in public outreach. As one staffer noted, “We’d use carbon capture with our bosses, but CCS amongst ourselves.” Some staff members noted that carbon capture technically only references one-third of the use case for the technology by omitting the utilization and storage/sequestration benefits, citing this as a challenge to the nomenclature used for the technology. But the same could be said for the common shortening of concentrated (or photovoltaic) solar power to simply solar power.

The most popular single message emerging from the 2017 focus group was that carbon capture is a technology that the United States will be able to sell around the world, helping our economy and trade balance and addressing growing coal use in developing nations and natural gas use more broadly. The opportunity for the United States to play a key role in addressing the global climate issue through development and exportation of technology is a message that resonated with staffers. Opinions about CCUS will continue to change as policy drivers are put in place. Therefore, continued listening sessions and research will be needed to understand changing perceptions among policymakers and other stakeholders.

Policy influencers from the 2019 Global CCS Institute study recommend framing CCS as an effective tool to address climate change and achieve the goal of carbon emission reduction, addressing concerns about costs, highlighting increased commercial interest and investment in carbon utilization and direct air capture, and addressing lingering concerns over safety.[35]

In a similar approach, the Carbon XPRIZE, along with Carbon180, Circular Carbon Network, and CO_2 Value Europe conducted a survey to better understand "terminology, messaging, perceptions, challenges, and opportunities" around carbon utilization outside of EOR. Their report, *Communicating the Value of CO_2*, found that the most popular terms for the technology were "carbon capture and utilization" and "carbon tech." The report also emphasized that respondents believed these technologies should be framed as complementary to, and not competitive with, renewables.

Although recent efforts like those described above have begun shifting stakeholder perceptions, there remains a clear need for more accessible CCUS terminology and for experts and advocates to be thoughtful about messaging. It is important to be mindful of the language used in stakeholder engagement to ensure messages are clear, understandable, and make sense for the target audience.

D. Skilled Messengers

Another challenge for stakeholder engagement is the alignment of messenger, message, and stakeholder needs. This is necessary when determining the engagement strategy needed for commercial deployment. Gaining support for CCUS requires the explanation of complex technical information to audiences with minimal understanding of key technology concepts.

In the project sphere, engagement programs need to identify credible sources of information from the stakeholders' point of view. Stakeholders often seek information from people and sources they trust, even if those sources are not experts on topics related to CCUS. The most credible sources of information for community engagement must be identified on a site-specific basis. Such individuals may be local sports heroes, business leaders, social networkers, or other messengers with the potential to connect with stakeholders. It will vary in each community. The assessment of credibility is based on stakeholders' perceptions of a person's motivations, knowledge, and relationship to the project and the community. In areas where potential negative perceptions are likely, it is important to find good communications partners and to focus on building local relationships in the community.[36]

In the policy sphere, engagement programs should leverage industry, academia, coalitions, and advocacy groups with good communication skills to explain and build support for CCUS. Policymakers may not have the most comprehensive knowledge or understanding about CCUS, so involving a broad range of participants can help to educate policymakers and lead to better and more effective policy design. The oil and natural gas industry and other industries provide relevant examples of how successful outreach efforts with policymakers has led to greater understanding of and support for the benefits created for both the communities where they operate and for the nation as a whole.

A challenge for CCUS messengers will be the successful use of digital communications, such as social media, to engage stakeholders. These types of communications play an increasingly important role in mobilizing public attitudes toward CCUS projects. Finding ways to effectively engage various stakeholder groups through a range of communications platforms will be key to reaching a broad and diverse group of stakeholders going forward.

VI. CONCLUSIONS

Building support for a comprehensive U.S. commitment to CCUS requires broad stakeholder engagement among and within the three spheres of engagement—project, policy, and public. The CCUS stakeholder engagement process would benefit from, and should support, clear and comprehensive policies to promote widespread deployment of CCUS that drive greater domestic energy security and address the risks of climate change by substantially lowering U.S. CO_2 emissions.

Engagement for CCUS deployment enables public discourse about the United States' existing energy infrastructure, the decarbonization of energy intensive industries, securing jobs, and ensuring national energy security and global competitiveness. Additionally, the United States can reinforce its position as a technology leader in CCUS by becoming an exporter of CCUS technological expertise. Conducting meaningful engagement, clarifying messaging, demonstrating societal benefits, and creating educational opportunities and social research are the keys to building trust and lasting stakeholder relationships.

A robust stakeholder engagement process considers the sociopolitical landscape, develops effective means of communication with critical stakeholders, aligns with local objectives and government policy, and is transparent and adaptive. All engagement requires listening to stakeholder input to help shape the project parameters that are required to reconcile objectives and stakeholders' needs and concerns. In addition, development of messages that resonate with stakeholders is critical and responses developed to address opposition are important. CCUS is a complex system that requires clearly defining the technology, costs and benefits, and risks in an easily understood format.

Consistent and high-quality CCUS stakeholder engagement is essential, but it is not the silver bullet to achieving deployment at scale. CCUS will continue to face opposition, and effective strategies need to be in place to engage, listen, and work across issues, lean into opposition, and create opportunities for finding common ground.

VII. RECOMMENDATIONS

A. Conduct Meaningful Engagement

- All members in the spheres of engagement should be engaged early in a series of national discussions on CCUS that includes federal and state government, industry, policy and environmental stakeholders, and the public to meet the dual challenge of providing energy while reducing environmental impacts. Discussion formats could include town hall meetings, policy briefings, focus groups, online interaction, and workshops.
- CCUS policy and projects require systems thinking across CO_2 emitters, transporters, and users, each often having different risk profiles, return expectations, and contracting strategies and structures. All stakeholder levels should better utilize and expand the stakeholder engagement process to:
  - Address legal and regulatory issues, such as IRS clarification of the Section 45Q tax credit, use of federal land, and long-term liability
  - Create and facilitate mechanisms, such as policy discussion events around this report, that encourage frank conversations about energy and emissions
  - Create an ongoing series of listening sessions and conduct research to understand changing perceptions among policymakers and other stakeholders
  - Continue demonstrating to the public that CCUS projects have environmental integrity and will sequester material amounts of CO_2 from the atmosphere

  - Engage with financial institutions on the technical details and risks associated with CCUS, better understand shareholder concerns, and advance a broader conversation to address social issues.
- Educate consumers on the merits of CCUS to enable consumer demand for low-carbon products.
- Industry and NGOs should create coalitions and utilize trade organizations to work together to educate and engage internal and external stakeholders.
- DOE should increase and sustain federal and state crossover engagement opportunities and linkages through the Regional Partnership Initiative, state working groups, and other similar organizations.
- Industry, RD&D coalitions, and DOE should continue to demonstrate leadership in international carbon capture and storage government, industry, and nongovernmental agency international forums, such as the IEA CCS Unit, IEA Greenhouse Gas R&D Programme (IEAGHG), Carbon Sequestration Leadership Forum, Oil and Gas Climate Initiative, and Clean Energy Ministerial.
- DOE should work with other agencies to formalize the interagency CCS work group to meet regularly, generate interagency reports, and provide materials suitable for stakeholder engagement that can facilitate integration of technical, economic, and societal aspects of CCUS.
- All stakeholder spheres should continue to require funded CCUS programs and projects to prioritize stakeholder engagement at the project level using best practices.

B. Clarify Messaging

- Multiple stakeholder groups should work together to simplify the language used to discuss CCUS and agree upon an easy-to-understand and recognizable moniker.
- A program for training communication champions and empowering stakeholders should be developed, including assessments to measure impact toward advanced deployment.
- The National Petroleum Council should create engagement opportunities using the NPC CCUS study as a platform, create talking points, and create summary materials that outline a clear set of recommendations of how to apply CCUS study findings to policy.
- Create events that share lessons learned and result in the continuation of deploying best practices for influencer and project-level stakeholder engagement efforts.

C. Demonstrate Societal Benefits

- Industry, academia, and DOE should support mechanisms for evaluating and demonstrating CCUS social benefits and impacts, including a set of common metrics for tabulating the benefits of CCUS projects.
- Congress should expand DOE's authorization and appropriations to fund research on social and economic drivers of CCUS through organizations such as the IEAGHG Social Research Network.
- DOE should commission a national economic development and jobs research study to better understand the potential for CCUS-specific economic impacts jobs.

D. Fund Engagement Research and Education Opportunities

- DOE should provide dedicated funding for CCUS education and research on stakeholder engagement processes and impacts, and require integrated analyses, results sharing, and joint work products, as part of new CCUS projects and programs.
- DOE should collaborate with other agencies, such as the National Science Foundation and Department of Education, to consider new funding models for education and engagement that align with emerging technologies and support continued research, development, and demonstration.

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APPENDICES

Appendix C:
CCUS Project Summaries

Appendix D:
ERM MEMO: *Economic Impacts of CCUS Deployment*

Appendix C

CCUS PROJECT SUMMARIES

I. CCUS LARGE-SCALE FULL-VALUE CHAIN PROJECTS

As of October 2019, there were 19 large-scale carbon capture, use, and storage (CCUS) projects operating around the world, with a total capacity of about ~32 million tonnes (Mt) of CO_2 per year.[1] Ten of these projects are in the United States, with a total storage capacity of about ~25 Mt per year. The other nine are located around the world, in Canada (2), Brazil (1), Norway (2), Saudi Arabia (1), United Arab Emirates (UAE) (Abu Dhabi) (1), China (1), and Australia (1). In addition, there were two Alberta Carbon Trunk Line (ACTL) projects under construction and expected to be operating by year-end 2019. Those projects are also included here for information in anticipation of their near-term start-up.

The next two sections of this appendix provide summary information on each of these 21 CCUS projects.

A. Top 10 U.S. CCUS Value Chain Projects (in order of operational date)

The 10 large-scale CCUS projects located in the United States include:

- Terrell Natural Gas Processing
- Enid Fertilizer
- Shute Creek Gas Plant
- Great Plains Synfuel
- Century Plant
- Air Products SMR
- Coffeyville Gasification
- Lost Cabin Gas Plant
- Illinois Industrial CCS
- Petra Nova (WA Parish).

These 10 projects have a total storage capacity of about ~25 Mt per year, representing ~80% of global capacity. They span a range of CCUS supply chains from multiple industries, including natural gas processing (~17 million tonnes per annum [Mtpa]), synthetic natural gas production (~3 Mtpa), fertilizer production (~2 Mtpa), coal-fired power generation (~1 Mtpa), hydrogen production (~1 Mtpa), and ethanol production (~1 Mtpa). The Global CCS Institute estimates that these U.S. projects have captured and stored approximately 160 Mt of CO_2.

A map showing the location of each project across the United States is provided in Figure C-1. Individual summary descriptions of each project are provided in the tables that follow.

Figure C-1. *Map of Top 10 U.S. Full-Value Chain Projects*

Terrell Natural Gas Processing, Fort Stockton, Texas	
Operator	Occidental Petroleum
Start Date	1972
Size	0.5 Mtpa
CO_2 Source	Natural gas processing
Transportation	220-mile Val Verde pipeline
Oil Field EOR Storage Site	Fields in West Texas Permian Basin
Key Highlights	The Terrell natural gas processing facility is the oldest operating industrial CCS project in the United States. The Terrell facility processes methane that contains between 18% to 53% of CO_2. This CO_2 must be removed from the methane to meet pipeline specifications. Since 1972, the plant has supplied CO_2 for enhanced oil recovery operations via a 220-mile pipeline linking the facility to a network of CO_2 pipelines in the Permian Basin.
References	Global CCS Institute Facilities Database, https://co2re.co/FacilityData. Occidental communication with NPC CCUS Study, 2019.

Enid Fertilizer, Oklahoma	
Operator	Koch Nitrogen Company
Start Date	1982
Size	0.7 Mtpa
CO_2 Source	Koch Nitrogen's Enid Fertilizer Plant
Transportation	120-mile pipeline
Oil Field EOR Storage Site	Northeast Purdy and the Brady Unit of the composite Golden Trend Field, as well as the Sko-Vel-Tum field, both south of Oklahoma City
Key Highlights	ARCO began EOR in a portion of the Sho-Vel-Tum field in 1982 and expanded in 1998. CO_2 from Enid Fertilizer has been used since 2003, when Koch Nitrogen Company bought the Enid facility. Operations were expanded in 2010.
References	Howard Herzog. Carbon Capture and Sequestration Technologies Program, MIT, CCS Project Database, http://sequestration.mit.edu/tools/projects/enid_fertilizer.html. Vandewater, Bob. "ARCO hunts hard-to-get state oil with gas injection," *The Oklahoman*, June 6, 1982, https://oklahoman.com/article/1986087/arco-hunts-hard-to-get-state-oil-with-gas-injection.

Shute Creek Gas Plant, La Barge, Wyoming	
Operator	ExxonMobil
Start Date	1986
Size	7 Mtpa
CO_2 Source	Natural gas stream from fields in Wyoming, including LaBarge field
Transportation	142-mile pipeline
Oil Field EOR Storage Site	A series of fields in Wyoming, Colorado, and Montana
Key Highlights	Production of natural gas from LaBarge field began in 1986, which is processed at the Shute Creek Treating facility, where it is separated into CO_2, methane, and helium for sale and removing hydrogen sulfide for disposal. A concentrated acid gas stream of about 60% hydrogen sulfide and 40% CO_2 is injected into a section of the same reservoir from which it was produced, safely disposing of the hydrogen sulfide and CO_2. In 2008, an expansion of the CO_2 capture facility brought the capacity up to 7 Mtpa.
References	Howard Herzog. Carbon Capture and Sequestration Technologies Program, MIT, CCS Project Database, http://sequestration.mit.edu/tools/projects/la_barge.html. Gearino, Jeff. "ExxonMobil reduces emissions in Wyo, sends more CO_2 for oil production," *Billings Gazette*, December 15, 2010, https://billingsgazette.com/news/state-and-regional/wyoming/exxonmobil-reduces-emissions-in-wyo-sends-more-co-for-oil/article_96837618-aa96-5465-aedf-fe431fc0e161.html. U.S. Environmental Protection Agency. "ExxonMobil Shute Creek Treating Facility SubPart RR Monitoring, Reporting and Verification Plan," February 2018, https://www.epa.gov/sites/production/files/2018-06/documents/shutecreekmrvplan.pdf.

Great Plains Synfuels Plant, Beulah, North Dakota	
Operator	Dakota Gasification Company
Start Date	2000
Size	3 Mtpa
CO_2 Source	Coal gasification
Transportation	205-mile pipeline across border into Saskatchewan, Canada
Oil Field EOR Storage Site	Weyburn and Midale Fields in Saskatchewan for EOR and CO_2 storage
Key Highlights	The Synfuels Plant produces methane by gasification of a low-quality coal called lignite. The plant captures more CO_2 from coal conversion than any facility in the world. Dakota Gas captures about two-thirds of the readily available CO_2 when running at full rates. Since 2000, CO_2 emissions at the Synfuels Plant have been reduced by about 45%. The plant has captured and transported nearly 38 Mt of CO_2 for geologic sequestration since 2000.
References	Dakota Gasification Company website, CO_2 Capture and Storage page, https://www.dakotagas.com/about-us/co2-capture-and-storage. Basin Electric Power Conservative website, https://basinelectric.com/sites/CMS/files/files/pdf/Fact-Sheets-Media-Kit/DGC-fact-sheet-8-19.pdf.

Century Plant, Pecos County, Texas	
Operator	Occidental Petroleum
Start Date	2010
Size	8.4 Mtpa
CO_2 Source	Natural gas processing
Transportation	100-mile pipeline
Oil Field EOR Storage Site	Permian Basin Fields
Key Highlights	Century Plant gas processing facility is the largest single industrial source CO_2 capture facility in North America. It processes natural gas from nearby fields in the Val Verde sub-basin that contain up to 65% CO_2. Since 2010, the plant has supplied CO_2 for enhanced oil recovery operations via a 100-mile pipeline linking the facility to the CO_2 distribution hub in Denver City, Texas. The plant was designed in 2008 with a maximum capacity of 5 Mtpa and brought online in 2010. An expansion in 2012 increased capacity to 8.4 Mtpa.
References	Howard Herzog. Carbon Capture and Sequestration Technologies Program, MIT, CCS Project Database http://sequestration.mit.edu/tools/projects/century_plant.html Occidental communication with NPC CCUS Study, 2019.

Air Products SMR, Port Arthur, Texas	
Operator	Air Products
Start Date	2013
Size	1.0 Mtpa
CO_2 Source	Existing steam-methane reformers
Transportation	13-mile pipeline
Oil Field EOR Storage Site	EOR in West Hastings and Oyster Bayou oil fields, Texas
Key Highlights	CO_2 capture units were retrofitted to Air Product's two steam methane reformers located within the Valero Port Arthur refinery. This is the first-ever commercial-scale steam methane reformer (SMR) hydrogen production facility incorporating vacuum-swing adsorption carbon capture gas separation technology.
References	Howard Herzog. Carbon Capture and Sequestration Technologies Program, MIT, CCS Project Database, http://sequestration.mit.edu/tools/projects/port_arthur.html. Carolyn Preston, "The Carbon Capture Project at Air Products' Port Arthur Hydrogen Production Facility,"14th Greenhouse Gas Control Technologies Conference, Melbourne 21-26 October 2018, https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3365795.

Coffeyville Gasification, Kansas	
Operator	Coffeyville Resources
Start Date	2013
Size	1.0 Mtpa
CO_2 Source	Fertilizer
Transportation	68-mile pipeline
Oil Field EOR Storage Site	North Burbank Unit in Osage County, Oklahoma
Key Highlights	The Coffeyville Resources Nitrogen Fertilizer plant was built in 2000 by Farmland Industries. It uses a petroleum coke gasification process to produce hydrogen for use in the manufacture of ammonia for fertilizer. The CO_2 is separated from the hydrogen through pressure swing adsorption, which originally was either used for urea synthesis or vented to the atmosphere. Since 2013 the plant has been delivering compressed CO_2 to the North Burbank Oil Unit for enhanced oil recovery.
References	Howard Herzog. Carbon Capture and Sequestration Technologies Program, MIT, CCS Project Database, http://sequestration.mit.edu/tools/projects/coffeyville.html.

Lost Cabin Gas Plant, Fremont County, Wyoming	
Operator	ConocoPhillips
Start Date	2013
Size	0.9 Mtpa
CO_2 Source	Lost Cabin natural gas processing facility
Transportation	232-mile Denbury pipeline
Oil Field EOR Storage Site	Denbury's Belle Creek oil field in Montana
Key Highlights	In 2010, Denbury acquired the Bell Creek field with the intention of rejuvenating the once robust field by switching from water to CO_2 injection. The injection site is the Bell Creek integrated CO_2 EOR and Storage Project, a collaboration between Denbury and the Plains CO_2 storage associated with a commercial scale EOR operation. To date the CO_2 EOR operations have injected more than 10 Mt of CO_2. Denbury is currently extending the pipeline another 110 miles northeastward into Montana to commence EOR.
References	Bleizeffer, Dustin. "Deep into Wyoming," *Casper Star Tribune*, March 9, 2003, https://trib.com/business/deep-into-wyoming/article_c1b3467a-4853-53dc-8e83-ba5351679f73.html. Howard Herzog. Carbon Capture and Sequestration Technologies Program, MIT, CCS Project Database, http://sequestration.mit.edu/tools/projects/lost_cabin.html.

Illinois Industrial CCS (ADM), Decatur, Illinois	
Operator	Archer Daniels Midland
Start Date	2017
Size	1.1 Mtpa
CO_2 Source	Ethanol production
Transportation	2-mile pipeline
Geologic Storage Site	Geological storage – Mount Simon sandstone
Key Highlights	The ADM agricultural processing and biofuels complex produces a highly concentrated stream of CO_2 from the ethanol fermentation process is captured, dehydrated, compressed and injected into the Mount Simon Sandstone reservoir adjacent to facility. This project is the only saline reservoir carbon storage project in the United States. The project has stored about 2 Mt since injection began in April 2017.
References	Howard Herzog. Carbon Capture and Sequestration Technologies Program, MIT, CCS Project Database, http://sequestration.mit.edu/tools/projects/illinois_industrial_ccs.html.

Petra Nova (WA Parish), Houston, Texas	
Operator	NRG Energy
Start Date	2017
Size	1.4 Mtpa
CO_2 Source	Coal-fired power generation
Transportation	80-mile pipeline
Oil Field EOR Storage Site	Hilcorp Energy’s West Ranch Oilfield
Key Highlights	Petra Nova is the world’s largest operational post-combustion CO_2 capture facility and the first commercial-scale power sector CCS project in the U.S. It is the first instance of an independent power producer (NRG) investing in all parts of the CCS value chain. The project captures CO_2 using technology from Mitsubishi Heavy Industries America on a 240-megawatt slipstream of flue gas from WA Parish Unit 8. Within 10 months of operational startup in January 2017, the plant has captured more than 1 Mt of CO_2 and boosted oil production by 1,300%.
References	Howard Herzog. Carbon Capture and Sequestration Technologies Program, MIT, CCS Project Database, http://sequestration.mit.edu/tools/projects/wa_parish.html. NRG website. Petra Nova: Carbon capture and the future of coal power case study, https://www.nrg.com/case-studies/petra-nova.html. Armpriester, Anthony. W.A. Parish Post Combustion CO_2 Capture and Sequestration Project Final Public Design Report. United States: N.p., 2017, https://www.osti.gov/servlets/purl/1344080. The Shand CCS Feasibility Study Public Report, https://ccsknowledge.com/pub/documents/publications/Shand%20CCS%20Feasibility%20Study%20Public%20_Full%20Report_NOV2018.pdf.

B. Major International CCUS Value Chain Projects (in order of operational date)

The nine large-scale CCUS projects operating worldwide (outside the United States) as of October 2019 include: • Sleipner CO_2 storage project, Norway (offshore) • Snøhvit CCS project, Norway (offshore) • Petrobras Santos Basin EOR Project, Brazil (offshore) • Boundary Dam Coal-Fired Power and CCS Project, Canada • Quest Project, Canada

• Uthmaniyah Project, Saudi Arabia • Emirates Steel CCS Project, United Arab Emirates • Jilin Oil Field CO_2 EOR Project, China • Gorgon LNG and CCS Project, Australia.

Two new large-scale CCUS projects are expected to start up by end of 2019, both in Canada and associated with the Alberta CO_2 Carbon Trunk Line. Project summaries of these two projects are also included below in anticipation of their existence by the time this report is published: 1. Alberta Carbon Trunk Line with Sturgeon Refinery CO_2 Stream, Canada 2. Alberta Carbon Trunk Line with Agrim CO_2 stream, Canada Individual summary descriptions of each project follow.

Sleipner CO_2 Storage, Offshore North Sea, Norway	
Operator	Statoil
Start Date	1996
Size	1 Mtpa
CO_2 Source	Natural gas processing
Geologic Storage Site	Utsira saline formation
Key Highlights	Sleipner is the world's first offshore CCS facility. CO_2 from the nearby Alfa Nord and Gudrun fields is also separated here.
References	Scottish Carbon Capture & Storage, Global CCS Map, http://www.sccs.org.uk/expertise/global-ccs-map.

Snøhvit, Norway	
Operator	Equinor
Start Date	2008
Size	0.7 Mtpa
CO_2 Source	Natural gas – LNG facility on the island of Melkøya
Geologic Storage Site	Snøhvit field offshore
Key Highlights	The Snøhvit CO_2 storage facilities form part of the development of gas fields in the Barents Sea, offshore Norway. The CO_2 is captured at an LNG facility on the island of Melkøya, northern Norway, where the offshore sourced gas stream is processed. The captured CO_2 is transported via pipeline back to the Snøhvit field offshore where it is injected into an offshore storage reservoir, more than 4 million tonnes of CO_2 has been stored to date since 2008.
References	Global CCS Institute, Facilities database, https://co2re.co/FacilityData.

Petrobras Santos Basin Pre-Salt Oil Field, Brazil	
Operator	Petrobras
Start Date	2013
Size	1 to 3 Mtpa
CO_2 Source	Natural gas
Oil Field EOR Storage Site	Lula, Sapinhoa, and Lapa fields
Key Highlights	Ten CO_2 separation and injection systems aboard floating production, storage, and offloading vessels anchored in the Santos Basin, off the coast of Rio de Janeiro. This is the first application of CO_2 EOR in an offshore oil field.
References	Oil and Gas Climate Initiative, 2019 Annual Report, https://oilandgasclimateinitiative.com/policy-and-strategy/#annual-report.

Boundary Dam, Saskatchewan, Canada	
Operator	SaskPower (owned by Government of Saskatchewan)
Start Date	2014
Size	1 Mtpa
CO_2 Source	Coal-fired power
Oil Field EOR Storage Site	Weyburn Oil Unit
Key Highlights	It is the world's first post-combustion CO_2 capture process on a coal power plant at Boundary Dam Unit 3. CO_2 sold to Cenovus for use in EOR. Unit 3 at the Boundary Dam coal-fired power station completed a refurbishment program in October 2014 that included retrofitting CO_2 capture facilities with a capture capacity of approximately 1 Mtpa of CO_2. The majority of the captured CO_2 is transported via pipeline and used for enhanced oil recovery at the Weyburn Oil Unit, also in Saskatchewan. A portion of the captured CO_2 is transported via pipeline to the nearby Aquistore Project for dedicated geological storage.
References	Sask Power. "2030 Emission Reduction Goal Progressing," news release July 9, 2018, https://www.saskpower.com/about-us/media-information/news-releases/2030-emission-reduction-goal-progressing. Scottish Carbon Capture & Storage, Global CCS Map, http://www.sccs.org.uk/expertise/global-ccs-map. Global CCS Institute, Facilities database, https://co2re.co/FacilityData.

Quest, Fort Saskatchewan, Alberta, Canada	
Operator	Athabasca Oil Sands Project – JV between Canadian Natural Resources (70%), Chevron (20%), Shell (10%) and Operator.
Start Date	2015
Size	1 Mtpa
CO_2 Source	Process gas streams from hydrogen manufacturing units
Geologic Storage Site	Basal Cambrian Sands saline formation
Key Highlights	Quest is the world's first oil sands CCS project. It captures and stores about one third of the CO_2 emissions from the Shell-operated Scotford Upgrader which turns oil sands bitumen into synthetic crude that can be refined into fuel and other products.
References	Scottish Carbon Capture & Storage, Global CCS Map, http://www.sccs.org.uk/expertise/global-ccs-map. Shell communication with NPC CCUS Study, 2019.

Uthmaniyah, Saudi Arabia	
Operator	Saudi Aramco
Start Date	2015
Size	0.8 Mtpa
CO_2 Source	Natural gas
Oil Field EOR Storage Site	Ghawar oil field
Key Highlights	Uthmaniyah CO_2 – EOR Demonstration compresses and dehydrates CO_2 from the Hawiyah NGL natural gas liquids recovery plant in the Eastern Province of the Kingdom of Saudi Arabia. The captured CO_2 is transported via pipeline to the injection site in Ghawar oil field a small flooded area in the Uthmaniyah production unit for enhanced oil recovery.
References	Global CCS Institute, Facilities database, https://co2re.co/FacilityData.

Abu Dhabi CCS – Emirates Steel Industries, UAE	
Operator	ADNOC
Start Date	2016
Size	0.8 Mtpa
CO_2 Source	Steel production
Oil Field EOR Storage Site	Various ADNOC oil reservoirs
Description	Abu Dhabi CCS is the world's first fully commercial CCS facility in the iron and steel industry and involves the capture of CO_2 via a new build CO_2 Compression Facility using high purity CO_2 produced as a by-product of the direct reduced iron-making process at the Emirates Steel Industries factory in Mussafah. The captured CO_2 is transported via pipeline to Abu Dhabi National Oil Company ADNOC oil reservoirs for enhanced oil recovery.
References	Global CCS Institute, Facilities database, https://co2re.co/FacilityData.

CNPC Jilin Oil Field CO_2 EOR, China	
Operator	CNPC
Start Date	2018
Size	0.6 Mtpa
CO_2 Source	Natural gas
Oil Field EOR Storage Site	Jilin oil field
Key Highlights	This facility injects CO_2 for EOR in low permeability reservoirs of the Jilin oil field in northeast China. The CO_2 is captured from a nearby natural gas processing plant at the Changling gas field and transported by pipeline. After 12 years of pilot and demonstration tests, the commercial operation, as Phase III, began in 2018, reaching 600,000 tonnes CO_2 per annum. Cumulative CO_2 injection of 1.12 million tonnes for pilot and demonstration scale operation was reached in the 2017.
References	Global CCS Institute, Facilities database, https://co2re.co/FacilityData.

Gorgon, Australia	
Operator	Chevron
Start Date	2019
Size	3.4 to 4.0 Mtpa
CO_2 Source	Natural gas
Geologic Storage Site	Saline formation beneath Barrow Island
Key Highlights	Gorgon CO_2 Injection is part of the wider Gorgon gas development project offshore Western Australia. Reservoir CO_2 would be separated and compressed at facilities located on Barrow Island and then piped a short distance to CO_2 injection wells on the Island where the CO_2 would be injected deep in the subsurface.
References	Global CCS Institute, Facilities database, https://co2re.co/FacilityData.

The following two ACTL projects are planned to be operating by year-end 2019 after ACTL construction is completed. The projects are listed here for information in anticipation of their near-term start-up. However, they are not included in the count of 19 large-scale CCUS full-value chain projects in operation at the time of this report's preparation.

Alberta Carbon Trunk Line with Sturgeon Refinery CO_2 Stream, Canada	
Operator	Enhance Energy and North West Redwater Partnership
Start Date	2019
Size	1.2 to 1.4 Mtpa
CO_2 Source	Petcoke gasification plants for hydrogen
Oil Field EOR Storage Site	Devonian carbonate in a depleted oil field near Red Deer in central Alberta
Key Highlights	The initial sources of CO_2 for the ACTL includes the new build North West Redwater NWR Partnerships Sturgeon Refinery. The refinery includes a new CO_2 compression and cooling facility owned by Enhance Energy that will be able to capture 1.2 to 1.4 Mtpa CO_2 for transport via ACTL. The ACTL aims to transport CO_2 from a number of sources in Alberta's Industrial Heartland, near Redwater, to declining oil fields in Central Alberta for the purpose of enhanced oil recovery.
References	Global CCS Institute, Facilities database, https://co2re.co/FacilityData.

Alberta Carbon Trunk Line with Agrim CO_2 Stream, Canada	
Operator	Enhance Energy and Agrium
Start Date	2019
Size	0.3 to 0.6 Mtpa
CO_2 Source	Agrium fertilizer plant
Oil Field EOR Storage Site	Devonian carbonate in a depleted oil field near Red Deer in central Alberta
Key Highlights	The initial sources of CO_2 for the ACTL include the existing Agrium fertilizer plant. The plant will have a CO_2 recovery facility retrofitted by Enhance Energy that will be able to capture 0.3 to 0.6 Mtpa CO_2 for transport via ACTL. The ACTL aims to transport CO_2 from a number of sources in Alberta's Industrial Heartland, near Redwater, to declining oil fields in Central Alberta for the purpose of enhanced oil recovery.
References	Global CCS Institute, Facilities database, https://co2re.co/FacilityData.

1 Large-scale projects are defined as those integrated projects that store at least 80,000 tonnes of CO_2 per year from a coal-based facility or at least 400,000 tonnes of CO_2 per year from other sources.

Appendix D

ERM MEMO:

ECONOMIC IMPACTS OF CCUS DEPLOYMENT

The National Petroleum Council retained ERM (Environmental Resource Management), a leading global provider of environmental, health, safety, risk, social consulting services and sustainability related services to conduct an economic analysis of deploying carbon capture, use, and storage (CCUS) at scale. This memo summarizes the potential total economic impacts of the investments in CCUS deployment as described in Chapter 2, Volume II, of the NPC report. The at-scale deployment of CCUS technology could involve 379 facilities, which will have direct impacts on jobs, gross domestic product (GDP), income, and tax revenues. These investments will have additional "multiplier" effects that will create additional economic impacts (i.e., indirect and induced impacts).

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Memo

To	National Petroleum Council
From	Doug MacNair Ryan Callihan
Date	November 20, 2019
Subject	Economic Impacts of CCUS Deployment

1. EXECUTIVE SUMMARY

This memo summarizes the potential total economic impacts of the investments in Carbon Capture Use and Storage (CCUS) deployment as described in Chapter 2 of the NPC Report. The At-scale deployment of CCUS technology could involve 379 facilities, which will have direct impacts on jobs, gross domestic product (GDP), income, and tax revenues. These investments will have additional "multiplier" effects that will create additional economic impacts (i.e. indirect and induced impacts).

Chapter 2 of the NPC Report describes three phases of CCUS deployment: Activation, Expansion, and At-scale using a cost curve analysis. The investments by the facilities in each phase form the basis for this economic impact analysis.

The economic impacts result from two types of investments or expenditures:

- One-time:

- Carbon capture capital costs for each facility, and
- Pipeline infrastructure costs for connecting sources to sinks.

■ On-going:

- Facility annual operating and maintenance (O&M) costs (facilities including fuel and power),
- Incremental oil production from CO_2 enhanced oil recovery (EOR) activities and,
- Storage activities associated with operating Class VI injection wells.

Table ES-1 summarizes the *incremental* investments in CCUS for the three phases. The estimated 23 facilities that would deploy CCUS technology during the Activation Phase would invest $50.6 billion over 20 years. During the Expansion Phase, an estimated 47 additional facilities would deploy CCUS technology, leading to an additional $124.4 billion in investments over 20 years. By the time the At-scale CCUS deployment occurs, an additional 309 facilities would be participating and the investment would be $504.7 billion over 20 years.

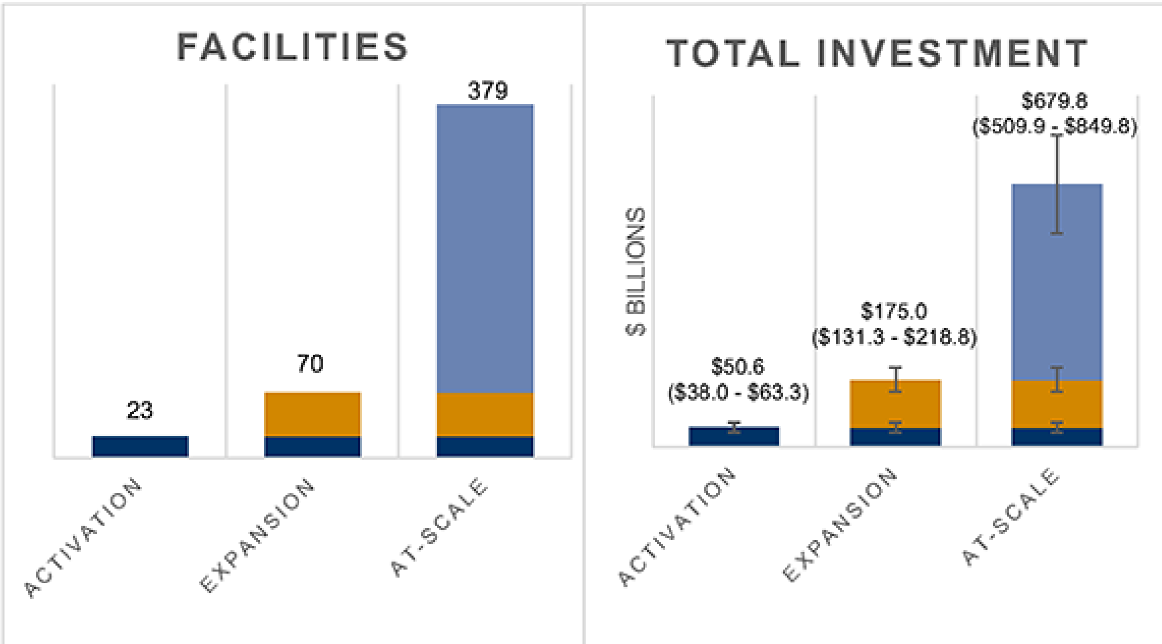
Table ES-1: Incremental On-going and One-Time Investments ($2018)

Phase	Number of Incremental Facilities	One-time Incremental Investment ($billions)	On-going Incremental Investment ($billions)	Total Incremental Investment ($billions)
Activation	23	$3.8	$46.8	$50.6
Expansion	47	$15.6	$108.8	$124.4
At-scale	309	$118.9	$385.8	$504.7

Note: One-time includes capital for carbon capture equipment and pipeline cost. On-going costs include spending on EOR, O&M and saline storage over 20 years. Facility counts include those deploying CCUS technology, not well-operators benefiting from EOR.

Figure ES-1 shows the *cumulative* investment for the three phases along with the uncertainty range of 25 percent for the total investment. Each phase of investment is in addition to the previous phase creating a total investment at the At-scale Phase for 379 facilities and $679.8 billion in investment. The uncertainty range of 25 percent on the total investment At-scale ranges from $509.9 billion to $849.8 billion[1].

Figure ES-1: Cumulative Facilities and Investment ($2018)



Note: Investments at each facility include one-time costs and on-going costs over 20 years

The economic impacts from the CCUS investments are estimated using IMPLAN, a well-accepted model for conducting economic impact studies. The IMPLAN model is discussed in more detail in Section 2.

Table ES-2 summarizes the *incremental* average annual economic impacts for each of the three phases, while Figure ES-2 provides a graphical summary for the estimated *cumulative* jobs and GDP impacts. These economic impacts result from the investment spending described in Table ES-1.

In the Activation Phase, the CCUS investment and the multiplier effects of that investment will support 9,000 jobs annually. Additional investments by facilities that deploy CCUS technology in the Expansion Phase will support an additional 33,000 jobs and $3.2 billion to GDP, annually. At-scale deployment will support an additional 194,000 annual jobs and $16.3 billion in annual GDP.

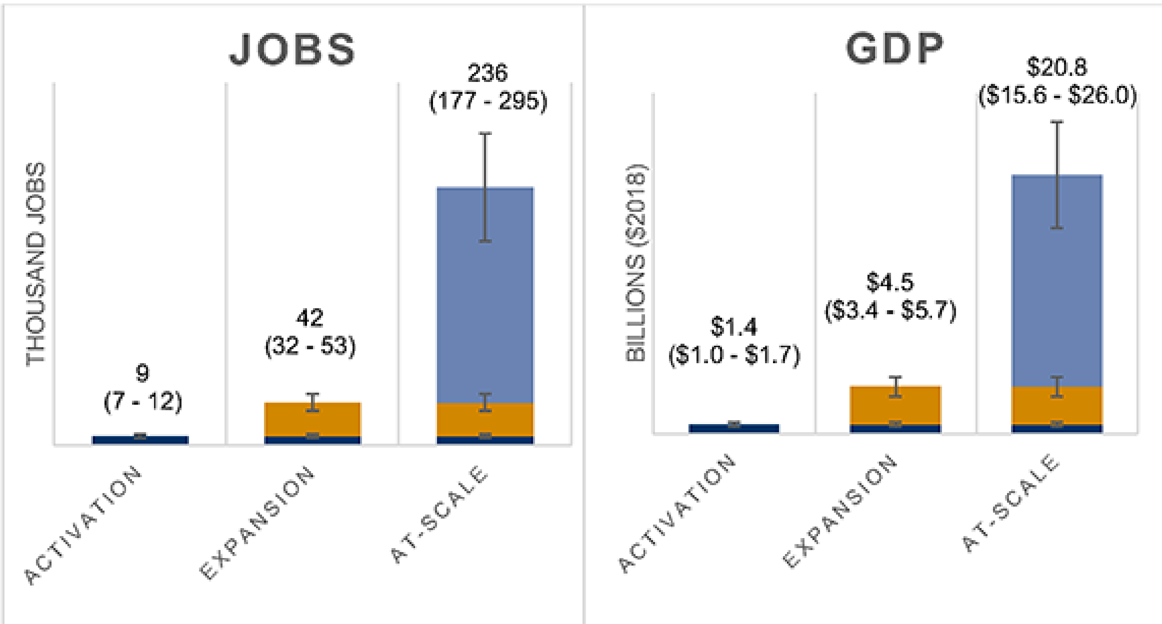
Table ES-2: Incremental Average Annual Economic Impacts ($2018)

Phase	Incremental Jobs (thousands)	Incremental GDP ($billions)	Incremental Labor Income ($billions)	Incremental Federal Taxes ($billions)	Incremental State and Local Taxes ($billions)
Activation	9	$1.4	$0.6	$0.1	$0.2
Expansion	33	$3.2	$2.0	$0.4	$0.3
At-scale	194	$16.3	$11.0	$2.2	$1.3

Notes: Averages are for a 20-year period.

Figure ES-2 shows the cumulative economic impact from the three phases and the uncertainty range at 25 percent. During the At-scale Phase, the annual economic impact from the investment in CCUS supports 236,000 jobs, with a range between 177,000 and 295,000 jobs. It will also generate $20.8 billion in annual GDP, with a range between $15.6 billion and $26.0 billion.

Figure ES-2: Cumulative Annual Job and GDP Impacts



Note: Averages are for a 20-year period.

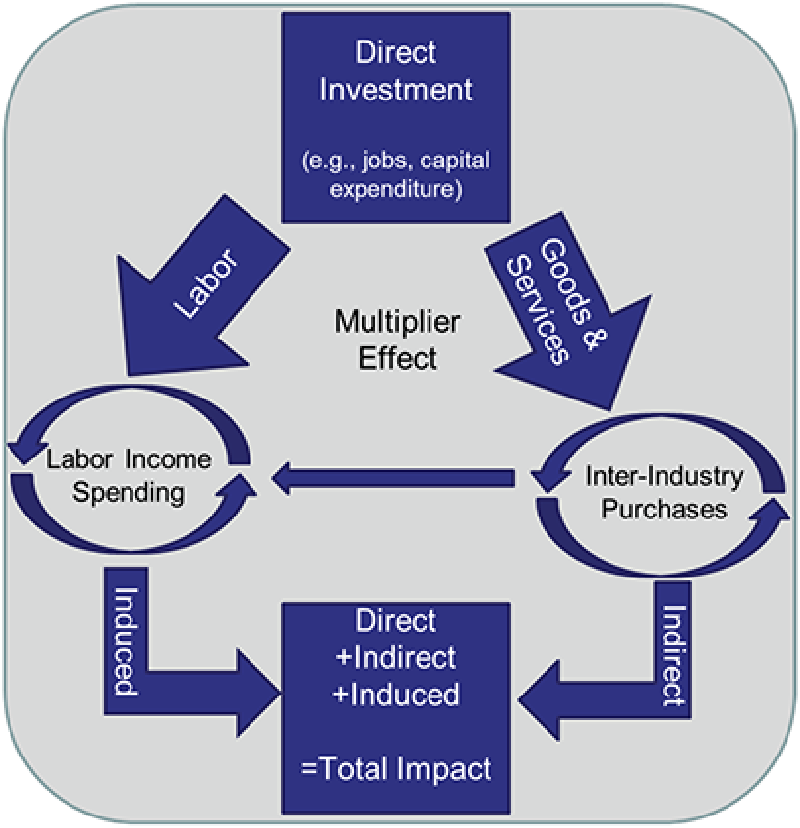
2. IMPLAN

This section describes the methodology and model used for the economic impact analysis that provides the estimates of change in economic activity from deploying CCUS technology. Input-output models (I-O) are used for estimating the total change in demand for goods and services (in this case, demand for CCUS technology one-time and ongoing expenditures).[2] They quantify the inter-industry relationships within an economy (i.e., how output/activity from one sector becomes an input in another sector of the economy and their inter-industry effects).

IMPLAN, the I-O model used in this analysis, relies on multipliers (Figure 1), which quantify interactions between firms, industries, and social institutions within a local economy. Each industrial or service activity within the economy (i.e., agriculture, mining, manufacturing, trade, services, etc.) is assigned to an economic sector.[3] The model starts with a ‘shock’ to the economy. The shock can be expressed as either a change in the number of jobs in an industry (e.g., 100 jobs for construction of a pipeline) or a change in expenditures (e.g., the dollar amount spent on construction). A change in expenditures (e.g. an investment) can be broadly divided into the purchase of goods and services and the purchase of labor. Both types of investment set off repeated rounds of economic activity (the multiplier effect). The additional jobs, GDP, income, and taxes generated by the inter-industry spending is called the indirect effect, while the impact from household spending is the induced effect.

The sum of the direct, indirect, and induced impacts equals the total economic impact. The multipliers vary by location and sector depending on the makeup of the local economy. The model treats the CCUS spending as a “shock”, or a new source of spending, and estimates how each of the affected industries responds in terms of additional value added (GDP), jobs, income and taxes.

Figure 1: Economic Impact Model



IMPLAN estimates three types of impacts:

- **Direct impact** – the initial change in the value of the output, employment, and labor earnings from the CCUS investments.
- **Indirect impact** – the increase in the output, employment, and labor earnings in the industries supporting the CCUS investments.
- **Induced impact** (or household spending impact) – the increase in the spending of workers in the direct and indirect industries.

The IMPLAN results include the direct, indirect, induced, and total economic impacts for the following four categories.

- **Jobs** – Jobs are measured in "job years" and reflect one year of employment.
- **GDP** – GDP is the monetary or market value of all the finished goods and services produced in a year.
- **Labor Income** – All forms of annual employment income, including employee compensation (wages and benefits) and proprietor income.
- **Taxes** – Annual tax revenue generated at the local, state, and federal levels.

IMPLAN estimates the distribution of economic impacts on local economies and industrial sectors. It is important to note that IMPLAN results are not a benefit-cost analysis and do not evaluate whether a project provides an overall net benefit to society. IMPLAN does not estimate the impact of any changes in prices, such as electricity prices from power plants investing in CCUS, which may affect production, output and jobs in other industries. In addition, IMPLAN does not evaluate the opportunity costs of the private investment or public funds.[4]

IMPLAN is widely used by academics, government agencies, and private sector business to understand the economic impacts of spending on the local economy. The U.S. Environmental Protection Agency (EPA) uses economic impact analysis to look at distributional impacts of spending by entities directly affected by regulations.[5] The Department of Energy (DOE) also applies this approach (using IMPLAN) and recently analyzed the economy-wide impacts of the American Recovery and Reinvestment Act of 2009 (Recovery Act or ARRA) funding for Smart Grid project deployment in the United States.[6]

Table 1 provides additional examples of studies using IMPLAN conducted in the United States by government agencies, interest groups, and private companies. It represents a small sample of the total body of analysis and research using this modelling software.

Table 1: IMPLAN Study Examples

DOE (2013). "Economic Impact of Recovery Act Investments in the Smart Grid"
DOI (2016). "Economic Contributions of Outdoor Recreation on Federal Lands"
EPA (2018). "Estimating the Economic Benefits of Energy Efficiency and Renewable Energy."
ICF (2017) "U.S. Oil and Gas Infrastructure Investment through 2035" Prepared for API
Massachusetts Division of Energy Resources (2007) "Energy from Forest Biomass: Potential Economic Impacts in Massachusetts". Prepared by University of Massachusetts, Department of Resource Economics
NREL (2007) "Energy, Economic, and Environmental Benefits of the Solar America Initiative"
PWC (2017) "Impacts of the Oil and Natural Gas Industry on the US Economy in 2015" Prepared for API

Other economic input-output methods have been used recently in other studies that look at the benefits of carbon capture technology. A study in the United Kingdom (UK) concluded that CCUS could play a key role in sustaining direct jobs in the on-shore support industry that have traditionally been associated with oil and gas, as well as supply jobs associated with this industry and the emerging offshore renewables sectors.[7] A study by Orion Innovation in the UK showed that CCUS could create thousands of annual jobs by 2030 due to increases in construction employment and ongoing O&M.[8]

An economic impact analysis by Patrizio et al. (2018) assessed the potential effects of reducing emissions in the coal industry.[9] The results show that deployment of carbon capture technology will not only reduce job losses from coal plant retirements, but also increase employment through construction and O&M jobs along with further multiplier effects.[10]

3. FACILITIES, PHASES AND INVESTMENTS

This section summarizes the investments by the three phases described in Chapter 2. As described in the Chapter, the CCUS cost curve (Figure 2) depicts the total cost to capture, transport and store CO_2 from stationary sources, plotted against the volume of CO_2 that is abated from those sources. The curve is arranged from lowest combined cost to highest combined cost. The cost curve provides the basis for the inputs into the economic model for each phase.

Figure 2: U.S CCUS Cost Curve

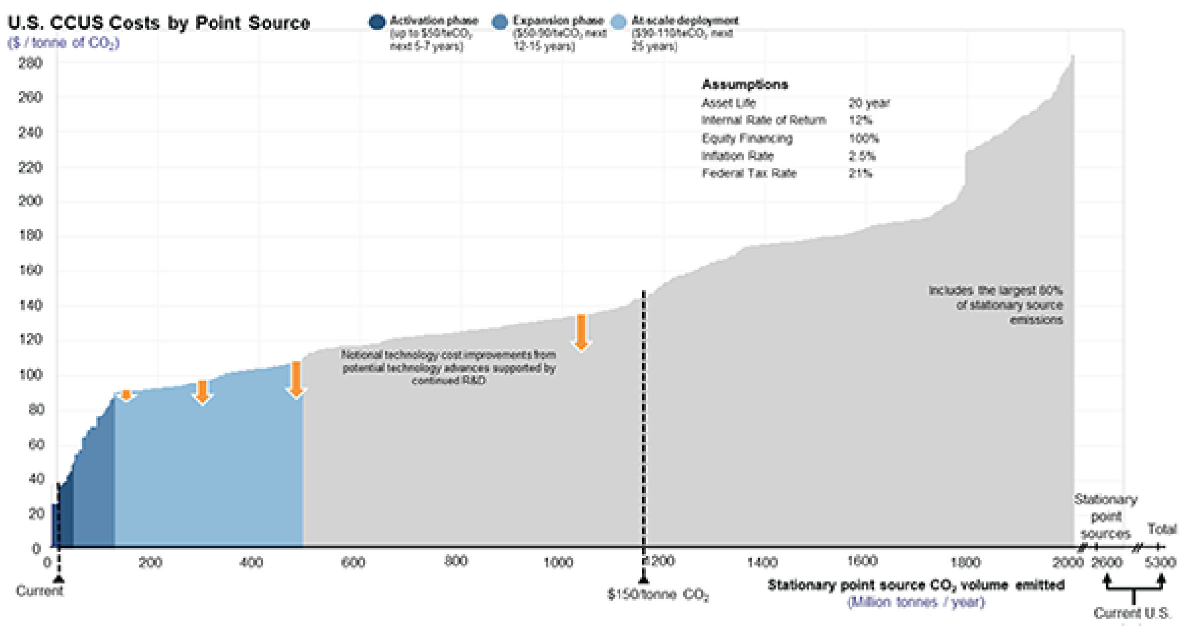


Table 2 summarizes the inputs for the economic model for each of the three phases. The number of facilities and total investment increases significantly from the Activation Phase to the At-scale Phase.

Table 2: Profile of Investments in CCUS

	Activation Phase	Expansion Phase	At-scale Phase
Number of Facilities	23	47	309
Annual Captured Emissions ($MtCO_2$/year)	35	75	380
One-time costs			
Carbon Capture Costs ($ billion)	$1.9	$7.4	$98.3
Pipeline ($ billion)	$1.9	$6.4	$20.2
On-going costs			
Annual Incremental Oil Revenue from EOR ($ billion/year)	$2.3	$4.7	$2.1
Annual O&M Costs ($ billion/year)	$0.3	$1.3	$12.5
Annual Storage Costs ($ billion/year)	$0.1	$0.2	$2.9

Carbon capture capital costs are calculated by multiplying the estimated industry specific per-ton capture costs (Table 3) by facility specific annual $MtCO_2$/year per year based on EPA data. The estimated costs range from $71/tonne CO_2 for ethanol and ammonia facilities and up to $472/tonne CO_2 for industrial furnaces. The O&M costs are a percent of the total capital expenditures by facility type. O&M costs include the non-energy O&M while the energy cost include natural gas and electricity costs.

The incremental revenue from EOR is estimated using an approach suggested by Cook (2012). This study looked specifically at economic impacts from incremental oil revenue. The EOR revenue estimate assumes one additional barrel of oil is produced per metric ton of CO_2 used. The revenue estimate is based on a projected $86 per barrel of oil, which is the average projected price of West Texas Intermediate between 2020 and 2040 (EIA Annual Energy Outlook 2019).[11] EOR does not represent an industry in IMPLAN, as a proxy we use the oil and gas industry spending pattern. Some of the standard IMPLAN parameters have been altered to reflect unique characteristics of the EOR oil revenue. The employment per dollar of revenue and labor income per employee ratios are modified to match the results from Cook (2012). Since EOR is not an industry in IMPLAN, using the literature to inform the methodology provides an accepted approach to estimate the economic impact in this sector.[12]

Table 3: One-time and On-going Input Costs by Industry

Facility Type	Carbon Capture Capital Cost (US$/tonne)	Non-Energy O&M (Percent of Total Capital Expenditures)	Energy Cost* ($/tonne)
Ethanol	71	7%	6
Ammonia	71	5%	5
Natural Gas Processing (low)	80	6%	5
Natural Gas Processing (high)	276	6%	5
Cement	199	7%	17
Hydrogen	196	5%	18
Steel/Iron	275	5%	17
Coal Power Plant	327	4%	17
Refinery-FCC	412	4%	16
Natural Gas Power Plant	354	5%	18
Industrial Furnaces	472	4%	17

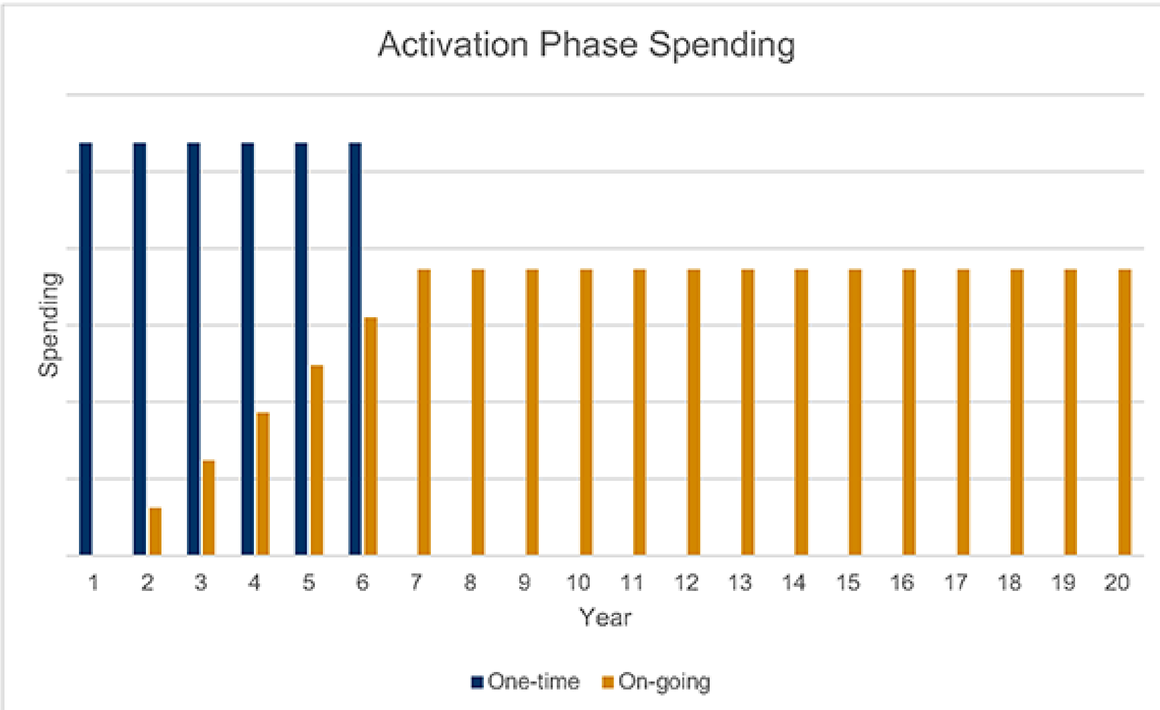
*Energy costs consist of both gas and electricity costs

The direct investments described have ripple effects that create additional impacts throughout the economy (i.e., indirect and induced impacts), which are captured by the IMPLAN multipliers. The annual economic impacts are averaged over a 20-year horizon during which the one-time investments occur over several years. In the analysis, the timeframes associated with these investments are consistent with the durations outlined in the NPC Report. In the Activation Phase, the one-time investment spend profile is assumed to occur equally over six years (between year 1 and year 6) (i.e., 1/6th of the estimated total one-time investment occurs during each of the first six years of the 20-year period). Similarly, for the Expansion Phase the one-time investments occur over the first nine years and At-scale Phase over the first ten years.

On-going investments begin a year later following the one-time investments and ramp up proportionately over the one-time investment period until full capital deployment occurs. These costs then remain constant for the remaining years of the 20 year period. The economic impact values are averaged over the 20 year period.

Figure 3 illustrates the investment spending timeframe for the Activation Phase. The one-time investment is spread out equally over the first six years. The on-going investment begins in year 2 and continues for the rest of the 20 year period. Summing all of the bars and dividing by 20 yields the average annual investment over the Activation Phase. The same approach is used for the other two phases.

Figure 3: Accounting for Timing of the Impacts



4. IMPLAN RESULTS - EMPLOYMENT

Figure 4 presents the cumulative employment impacts by investment source (one-time and on-going) and impact type (direct, indirect, and induced) for each of the three phases. Table 4 summarizes the incremental job impacts for the three phases. The At-scale Phase totals 236,000 jobs per year, which consist of 127,000 direct, 17,000 indirect, and 50,000 induced jobs per year. The At-scale Phase has a longer construction period so a greater percentage of the impacts come from one-time expenditures relative to the other two phases. The 25 percent range parallels the results from Chapter 2 and account for the uncertainty in the input assumptions. At-scale deployment has a range of 177,000 – 295,000 thousand jobs cumulatively per year. This figure includes the job estimates from the previous two phases.

Figure 4: Annual Cumulative Employment Impacts by Investment Source and Impact Type

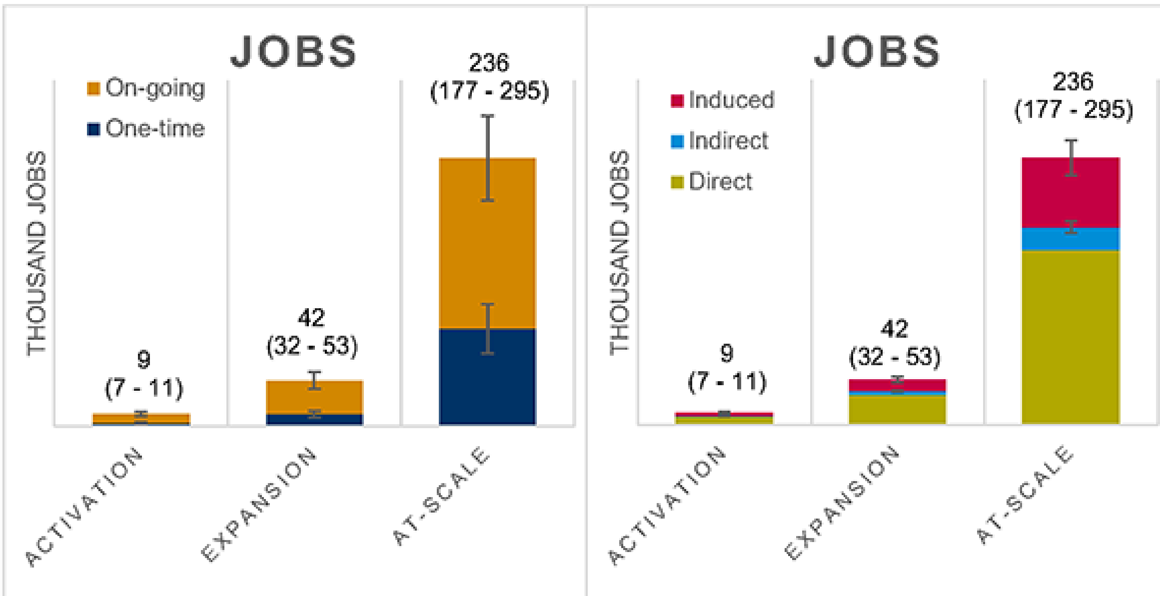


Table 4: Annual Average Employment Impacts by Phase (Thousands)

Impact	Activation Phase	Expansion Phase	At-scale Phase
Direct	4	14	118
Indirect	3	10	27
Induced	3	9	48
Total	9	33	194
Uncertainty Factor (+/- 25%)	7 – 11	25 – 42	145 - 242

5. IMPLAN RESULTS – GDP, INCOME, AND TAXES

Table 5, 6, and 7 show the annual *incremental* monetary economic impacts of the CCUS activities for each of the phases. As shown in Table 7, during the At-scale Phase, *incremental* CCUS investments result in an annual GDP impact of $16.26 billion. These investments also yield annual tax revenues of $1.25 billion at the state and local level and $2.25 billion at the federal level.

The uncertainty factor accounts for a plus and minus 25 percent range in the cost of the CCUS inputs for the IMPLAN model. The total incremental economic impacts At-scale range between $12.19 billion and $20.24 billion in GDP annually.

Table 5: Activation Phase Incremental Average Annual Economic Impacts

Impact	GDP ($ billions)	Labor Income ($ billions)	Federal taxes ($ billions)	State and Local taxes ($ billions)
Direct	0.79	0.28	0.07	0.11
Indirect	0.34	0.21	0.04	0.03
Induced	0.25	0.13	0.03	0.03
Total	1.39	0.62	0.15	0.16
Uncertainty Factor (+/- 25%)	1.04 – 1.74	0.46 – 0.77	0.11 – 0.18	0.12 – 0.21

Note: Average annual values over 20 years

Table 6: Expansion Phase Incremental Average Annual Economic Impacts

Impact	GDP ($ billions)	Labor Income ($ billions)	Federal taxes ($ billions)	State and Local taxes ($ billions)
Direct	1.51	0.95	0.19	0.14
Indirect	0.94	0.64	0.13	0.08
Induced	0.71	0.40	0.09	0.07
Total	3.15	1.99	0.41	0.29
Uncertainty Factor (+/- 25%)	2.37 – 3.94	1.49 – 2.48	0.31 – 0.52	0.22 – 0.37

Note: Average annual values over 20 years

Table 7: At-scale Phase Incremental Average Annual Economic Impacts

Impact	GDP ($ billions)	Labor Income ($ billions)	Federal taxes ($ billions)	State and Local taxes ($ billions)
Direct	9.53	7.05	1.38	0.59
Indirect	2.74	1.68	0.36	0.26
Induced	4.00	2.23	0.50	0.40
Total	16.26	10.96	2.25	1.25
Uncertainty Factor (+/- 25%)	12.19 – 20.24	8.22 – 13.70	1.69 – 2.81	0.94 – 1.56

Note: Average annual values over 20 years

1 The uncertainty range of 25 percent is based on range used in Chapter 2 to derive cost estimates.

2 Bess, R., & Ambargis, Z. O. (2011, March). Input-output models for impact analysis: suggestions for practitioners using RIMS II multipliers. In 50th Southern Regional Science Association Conference (pp. 23-27). Southern Regional Science Association Morgantown WV.

3 IMPLAN uses data from the U.S. Bureau of Economic Analysis, Bureau of Labor Statistics, U.S. Census Bureau, and other sources. IMPLAN also uses detailed U.S. Department of Commerce information that relates the purchases of goods and services each industry makes from other industries to the value of output in each industry. As such, IMPLAN describes the supply chain of each industry in terms of output, value-added, labor income, employment levels, and state and local tax revenue. The latest version of IMPLAN data currently includes 536 sectors and regional detail at the state, county, and ZIP code level.

4 The opportunity cost refers to the value of the next-highest-valued alternative use of that resource. Although investments in CCUS create economic benefits, the economic impacts do not take into account the next best use of those funds which presumably provides economic benefits in the absence of CCUS activities.

5 EPA (2010). "Guidelines for Preparing Economic Analyses" Available at: https://www.epa.gov/environmental-economics/guidelines-preparing-economic-analyses

6 DOE (2013). "Economic Impact of Recovery Act Investments in the Smart Grid". Smart Grid Investment Grants Program; Available at: https://www.smartgrid.gov/document/economic_impact_recovery_act_investments_smart_grid.html

7 Turner, Karen and Alabi, Oluwafisayo and Low, Ragne and Race, Julia (2019) Reframing the Value Case for CCUS: Evidence on the Economic Value Case for

CCUS in Scotland and the UK (Technical Report).

8 Orion Innovation (2013). “A UK Vision for Carbon Capture and Storage”. Available at: https://issuu.com/orion_innovations/docs/a_uk_vision_for_carbon_capture_and_

9 The study used the JEDI input-output model, developed by the National Renewable Energy Laboratory.

10 Patrizio, P., Leduc, S., Kraxner, F., Fuss, S., Kindermann, G., Mesfun, S.& Lundgren, J. (2018). Reducing US coal emissions can boost employment. Joule, 2(12), 2633-2648.

11 The economic contributions from EOR is based on the approach used in Cook, B. R. (2012). The Economic Contribution of CO2 Enhanced Oil Recovery in Wyoming.

12 The Cook ratios are 2.6 direct jobs per $10 million in incremental oil revenue and $115,000 in labor income per job.

ACRONYMS AND ABBREVIATIONS

ADM	Archer Daniels Midland Company
ANSI	American National Standards Institute
AoR	Area of Review
ARB	Air Resource Board (California)
ARPA-E	Advanced Research Projects Agency of the Department of Energy
BBA	Bipartisan Budget Act (2018)
BCF/D	billion cubic feet per day
BECCS	bioenergy carbon capture and storage
BEG	Bureau of Economic Geology (University of Texas)
BF	blast furnace
BOF	basic oxygen furnace
BLGCC	black liquor integrated gasification combined cycle
BLM	Bureau of Land Management
BOEM	Bureau of Ocean Energy Management
BOF	basic oxygen furnace
BSCF/D	billion standard cubic feet per day
BSEE	Bureau of Safety and Environmental Enforcement
BTU	British thermal unit
$CaCO_3$	calcium carbonate
CAG	CCUS Advisory Group
CAP	closure assurance period

CCPI	Clean Coal Power Initiative
CCS	carbon capture and storage
CCU	carbon capture and use
CCUS	carbon capture, use, and storage
CES	Clean Energy Standard
CFD	contract for difference
CFR	Code of Federal Regulations
CHP	combined heat and power
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
COG	coke oven gas
CRI	Carbon Recycling International
DAC	direct air capture
DOE	Department of Energy
DOI	Department of the Interior
DOT	Department of Transportation
EAF	electric arc furnaces
EEZ	exclusive economic zone
EIA	Energy Information Administration
EOR	enhanced oil recovery
EPA	Environmental Protection Agency
ESP	Energy Saving Process
ETIA	Energy Tax Incentives Act
ETS	emissions trading systems
FCC	fluid catalytic cracking
FER&D	Fossil Energy Research and Development
FERC	Federal Energy Regulatory Commission
FLIGHT	Facility Level Information on Greenhouse gases Tool

FUTURE	Furthering carbon capture, Utilization, Technology, Underground storage, and Reduced Emissions Act
GDP	gross domestic product
GHG	greenhouse gas
GJ	gigajoule
GOM	Gulf of Mexico
GOR	gas oil ratio
GS	geologic storage
Gt	gigatonnes
H_2	hydrogen
HCPV	hydrocarbon pore volume
IEA	International Energy Agency
IEAGHG	IEA Greenhouse Gas R&D Programme
IGCC	integrated gasification combined cycle
IL-ICCS	Illinois Industrial Carbon Capture and Storage
IPCC	Intergovernmental Panel on Climate Change
IRS	Internal Revenue Service
ISO	International Standards Organization
ITC	Investment Tax Credit
K	Kelvin
kJ	kilojoule
kJ/mol	kilojoules per mole
LED	light-emitting diode
LNG	liquefied natural gas
LPG	liquefied petroleum gas
LVC	lean vapor compression
MDEA	methyldiethanolamine
MEA	monoethanolamine

MES	microbial electrosynthesis
μm	micrometer
MLA	Mineral Leasing Act
MLP	master limited partnerships
MMB/D	million barrels per day
MMBTU	million British thermal units
MMCF/D	million cubic feet per day
MMP	minimum miscibility pressure
MMscf	million standard cubic feet
MOF	metal-organic frameworks
MPRSA	Marine Protection, Research, and Sanctuaries Act
Mt	million tonnes
Mtpa	million tonnes per annum
MTR	Membrane Technology and Research, Inc.
MW	megawatts
MWe	megawatts-electric
MWh	megawatt hour
NASEM	National Academies of Sciences, Engineering, and Medicine
NCCC	National Carbon Capture Center
NEPA	National Environmental Policy Act
NETL	National Energy Technology Laboratory
NGCC	natural gas combined cycle
NGO	nongovernmental organizations
NIMBY	not in my backyard
NPC	National Petroleum Council
NPS	New Policies Scenario
NRAP	National Risk Assessment Partnership
NUMBY	not under my backyard

OCS	Outer Continental Shelf
OCSLA	Outer Continental Shelf Lands Act
OECD	Organisation for Economic Co-operation
OOIP	original oil in place
PCC	precipitated calcium carbonate
PEM	proton exchange membrane
PHMSA	Pipeline and Hazardous Materials Administration
PIM	porous inorganic membranes
PISC	post-injection site care
ppm	parts per million
PSA	pressure swing adsorption
psi	pounds per square inch
psig	pounds per square inch gauge
PTC	production tax credit
R&D	research and development
RCP	reinjection compression plant
RCSP	DOE’s Regional Carbon Sequestration Partnerships
RD&D	research, development, and demonstration
ROZ	residual oil zone
RPS	renewable portfolio standard
RTO	regional transmission organization
SACROC	Scurry Area Canyon Reef Operators
SDS	Sustainable Development Scenario
SDWA	Safe Drinking Water Act
SMR	steam methane reforming
SOA	state-of-the-art
SOE	solid-oxide reactor
SSEB	Southern States Energy Board

STB	Surface Transport Board
STEPS	Stated (Energy) Policies Scenarios
TCF	trillion cubic feet
TCM	Technology Centre Mongstad
TIFIA	Transportation Infrastructure Finance and Innovation Act
TRL	technology readiness level
TSA	temperature swing adsorption
UF	utilization factor
UIC	underground injection control
USDA	U.S. Department of Agriculture
USDW	underground sources of drinking water
USGS	U.S. Geological Survey
VSA	vacuum swing adsorption
WAG	water alternating gas