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Updated September 22, 2022

Congressional Research Service
https://crsreports.congress.gov
R46192

CRS REPORT
Prepared for Members and
Committees of Congress

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Injection and Geologic Sequestration of Carbon Dioxide: Federal Role and Issues for Congress

SUMMARY

R46192

September 22, 2022

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For several decades, the federal government has funded efforts to explore the feasibility of mitigating the release of greenhouse gases (GHGs) while burning fossil fuels as a source of energy. Carbon capture and storage (CCS)—the process of capturing manmade carbon dioxide (CO_2) at its source and storing it before its release into the atmosphere—has been proposed as a technological solution for mitigating emissions into the atmosphere while continuing to use fossil energy. Permanent underground carbon storage, known as geologic sequestration, is the long-term containment of a fluid (including gas or liquid CO_2) in subsurface geologic formations. CO_2 may be injected, and a portion incidentally stored, as part of enhanced oil recovery (EOR) operations that increase production from aging oil reservoirs.

The U.S. Department of Energy (DOE) leads the federal government's carbon storage research and development (R&D) as part of the agency's fossil energy programs. The agency conducts CCS research and carries out public-private partnerships for testing and development of CO_2 injection and storage projects. Congress has recently directed DOE to expand its R&D activities to support deployment and commercialization of CCS projects.

The Safe Drinking Water Act (SDWA), administered by the U.S. Environmental Protection Agency (EPA), provides authorities for regulating underground injection of fluids and serves as the framework for regulation of injection of CO_2 for geologic sequestration and EOR. The major purpose of the act's Underground Injection Control (UIC) provisions is to prevent endangerment of underground sources of drinking water from injection activities. EPA has promulgated regulations and established minimum federal requirements for six classes of injection wells. In 2010, EPA promulgated regulations for the underground injection of CO_2 for long-term storage and established UIC Class VI, a new class of wells solely for geologic sequestration of CO_2. The well performance standards and other requirements established in the Class VI Rule are based on the distinctive features of CO_2 injection compared to other types of injection. Two Class VI wells, both in Illinois, are currently permitted by EPA. EOR, including CO_2-EOR, is conducted using Class II wells classified for disposal of fluids associated with oil and gas production. SDWA authorizes states to administer the federal UIC programs in lieu of EPA, known as *primacy*. For Class VI CO_2 geologic sequestration wells, North Dakota and Wyoming have primacy under SDWA. For Class II wells, SDWA authorizes states to regulate these wells under their own state programs, and most oil- and gas-producing states have primacy for Class II wells. Currently in the United States, one geologic sequestration facility, the ADM facility in Illinois, has EPA Class VI permits and is actively injecting CO_2 from an ethanol plant for geologic sequestration. North Dakota has issued two state Class VI permits for geologic sequestration.

Congress has supported carbon storage via underground injection through recent legislation that directs DOE to expand research, development, and deployment activity and expands the federal tax credit for carbon sequestration. A policy challenge that Congress may face with underground carbon storage is balancing protection of underground sources of drinking water with supporting and encouraging the development of cost-effective CCS technology. Other policy issues of congressional interest may include unresolved liability and property rights issues, overall CCS project cost, public acceptance of these projects and participation in their planning, and the relationship of the growth of underground carbon injection and storage with continuing to burn fossil fuels for generating electricity. In addition, Congress may consider potential health and environmental risks (beyond any related risks to underground sources of drinking water) not addressed by SDWA.

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Introduction

For several decades, the federal government has funded efforts to explore the feasibility of mitigating greenhouse gases (GHGs) emitted to the atmosphere from the burning of fossil fuels at power plants and other large industrial facilities. Carbon capture and storage (CCS) is the process of capturing manmade carbon dioxide (CO_2), a GHG, at its source, such as a coal-fired power plant, and injecting and storing it underground instead of releasing into the atmosphere.[1] CCS has been proposed as a technological solution for mitigating emissions while continuing to use fossil energy. In a 2021 report to Congress on CCS, the Council on Environmental Quality (CEQ) noted that in order to meet the Biden Administration's goal of net-zero emissions by 2050, "significant quantities" of CO_2 will likely need to be permanently sequestered.[2] Federal policies on CCS have received support in recent Congresses, including support for research and development and expansion of tax credits for carbon utilization or sequestration.[3] This report focuses on federal policy regarding the underground carbon injection and storage stage of CCS.

Under specific conditions, underground carbon storage can be achieved through geologic sequestration and as a secondary result of enhanced oil recovery (EOR) processes that use CO_2. Both use wells to inject CO_2 into deep subsurface geologic formations. Geologic sequestration involves storing CO_2 by placing it in an underground formation for ultimate permanent storage. A small number of geologic sequestration projects are currently operating with goals of storing over 1 million tons of storage in several countries, typically developed with significant government investment in research and development.[4] EOR involves injecting water or certain chemicals—in some cases CO_2—to produce additional oil from underground reservoirs.

Injection of CO_2 for both geologic sequestration and EOR are regulated under the Safe Drinking Water Act (SDWA) for the purpose of protecting underground sources of drinking water (USDWs).[5] The U.S. Environmental Protection Agency (EPA) and delegated states administer sections of SDWA relevant to underground injection and carbon storage. The U.S. Department of Energy (DOE) also engages in underground carbon storage activities through supporting research, development, and deployment (RD&D) activities.

In recent years, Congress has passed legislation related to carbon storage via underground injection that directs DOE to expand RD&D activity and for the IRS to expand the federal tax credit for carbon sequestration and utilization. As Congress considers further policies on underground carbon storage, including geologic sequestration and EOR, Members may consider

[1] CCS is one of several acronyms used to describe similar processes of capturing and storing or sequestering CO_2 underground. Other commonly used terms include *carbon capture, utilization, and sequestration* and *carbon capture, utilization, and storage*, both referred to as CCUS. This report uses "CCS" as a broad reference to all of these types of systems.

[2] Council on Environmental Quality, *Report to Congress on Carbon Capture, Utilization, and Sequestration*, June 30, 2021. The USE IT Act (Division S, P.L. 116-260, Consolidated Appropriations Act, 2021) directed CEQ, in consultation with other agencies, to submit a report to Congress on permitting requirements and regulatory frameworks for CCS infrastructure and projects.

[3] Congress has amended Section 45Q through the American Recovery and Reinvestment Act (P.L. 111-5), the Bipartisan Budget Act of 2018 (BBA; P.L. 115-123), the Consolidated Appropriations Act, 2021 (P.L. 116-260), and the budgetary measure commonly known as the Inflation Reduction Act of 2022 (IRA; P.L. 117-169).

[4] Consideration of "large-scale" carbon injection and sequestration has evolved in recent years in legislation and federal law. 42 U.S.C. §16293 defines "large-scale" to mean a scale that has a goal of sequestering "not less than 50 million metric tons of carbon dioxide." This does not include earlier DOE-sponsored research pilot projects of significantly smaller volumes.

[5] Safe Drinking Water Act, §§1421-1425; 42 U.S.C. §§300h - 300h-5.

the current regulatory framework and status of federal and federally sponsored activities in this area.

This report provides background on underground injection and geologic sequestration processes, related federal RD&D, and CO_2 injection and storage projects. It then analyzes the federal framework for regulating land-based underground injection of CO_2 both for geologic sequestration and EOR. Finally, it includes a discussion of several policy issues for Congress and recent relevant federal legislation. Not covered in this report are research and management of CCS elements not directly related to underground injection, including carbon capture and the pipeline and transportation infrastructure for captured CO_2. Regulation of geologic sequestration on federal land and offshore geologic sequestration of CO_2 are also beyond the scope of this report. For additional information on the technical aspects of CCS, see CRS Report R44902, *Carbon Capture and Sequestration (CCS) in the United States*.

Underground Carbon Storage Process

Underground Injection

Underground injection has been used for decades to dispose of a variety of fluids, including oil field brines (salty water) and industrial, manufacturing, mining, pharmaceutical, and municipal wastes. Injection wells are also used to enhance oil and gas recovery production; for solution mining; and, more recently, to inject CO_2 for geologic sequestration. As of 2019 (the latest data available), EPA estimated that there were more than 735,000 permitted injection wells across the states and more than 6,900 additional wells on tribal lands.[7]

Key Terms[6]

A *fluid* is "any material or substance which flows or moves whether in a semisolid, liquid, sludge, gas or any other form or state."

Carbon capture and storage (CCS) is the process of capturing CO_2 from an emission source, compressing and transporting it to an injection site, and injecting it into deep subsurface rock formations for long-term storage.

Enhanced oil recovery/enhanced gas recovery (EOR/EGR) is the process of injecting a fluid into an oil- or gas-bearing formation to recover residual oil or natural gas. This report will use the term EOR to refer to both EOR and EGR.

CO_2 injection wells are a type of deep injection well, used for injection into deep, isolated rock formations and can reach thousands of feet deep.[8] More details on specific well types are provided later in this report.

Geologic Sequestration

Geologic sequestration is the long-term containment of a fluid (including a gas, liquid, or supercritical CO_2 stream) in subsurface geologic formations. The goal of geologic sequestration of CO_2 is to trap or transform CO_2 emitted from stationary anthropogenic sources permanently underground and ultimately reduce emissions of GHGs from these sources into the atmosphere. CO_2 for sequestration is first captured from a large stationary source, such as a coal-fired power

[6] 40 C.F.R §144.3 and U.S. Environmental Protection Agency, "Federal Requirements Under the Underground Injection Program for Carbon Dioxide (CO_2) Geological Sequestration (GS) Wells; Proposed Rule," 73 *Federal Register* 43492-43541, July 5, 2008, p. 43493.

[7] EPA, *FY 2019 State UIC Injection Well Inventory and FY2019 Tribal UIC Injection Well Inventory*, accessed September 22, 2022, at https://www.epa.gov/uic/uic-injection-well-inventory.

[8] Most underground injection wells are relatively shallow wells, including wells for disposing of motor vehicle waste, large-capacity cesspools and septic wells, and stormwater drainage wells.

plant or chemical production facility.[9] Although CO_2 is initially captured as a gas, it is compressed into a supercritical fluid—a relatively dense fluid with both gas-like and liquid-like properties—before injection and remains in that state due to high pressures in the underground formation. The CO_2 is injected through specially designed wells into geologic formations, typically a half a mile or more below the Earth's surface. These formations include, for example, large deep saline reservoirs (underground basins containing salty fluids) and oil and gas reservoirs no longer in production.[10] Research shows that CO_2 could also be sequestered in deep ocean waters or mineralized.[11] Impermeable rocks above the target reservoir, combined with high CO_2 pressures, keep the CO_2 in a supercritical fluid state and prevent migration into shallower groundwater or into other formations.

The National Energy Technology Laboratory (NETL) estimates that the total onshore storage capacity in the United States ranges between about 2.6 trillion and 22 trillion metric tons (hereinafter *tons* in this report) of CO_2.[13] (For more details, see **Appendix A**.) By comparison, U.S. energy-related CO_2 emissions in 2020 totaled 4,575 million tons.[14] Theoretically, the United States contains storage capacity to store all CO_2 emissions from large stationary sources (such as power plants), at the current rate of emissions, for centuries. For additional information on the technical aspects of CCS, see CRS Report R44902, *Carbon Capture and Sequestration (CCS) in the United States*.

Physical and Chemical Process of Geologic Sequestration

CO_2 can be sequestered in underground formations in several different ways. CO_2 can be physically trapped in the pore space, trapped through a chemical reaction of the CO_2 with rock and water, dissolved into the existing fluid within the formation, adsorbed onto organic material, or go through other chemical transformations. Researchers expect that geologic sequestration will take place over hundreds of years after injection, which may ultimately result in permanent storage of the CO_2. According to one analysis from the Intergovernmental Panel on Climate Change (IPCC), "For well-selected, designed and managed geological storage sites, the vast majority of the CO_2 will gradually be immobilized by various trapping mechanisms and, in that case, could be retained for up to millions of years."[12]

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[9] An emerging technology that captures CO_2 directly from the atmosphere—called direct air capture—could also provide a source of CO_2 for geologic sequestration or EOR. For more information on carbon capture, see CRS In Focus IF11501, *Carbon Capture Versus Direct Air Capture*, by Ashley J. Lawson.

[10] Researchers and industry are also considering unmineable coal seams as potential target formations.

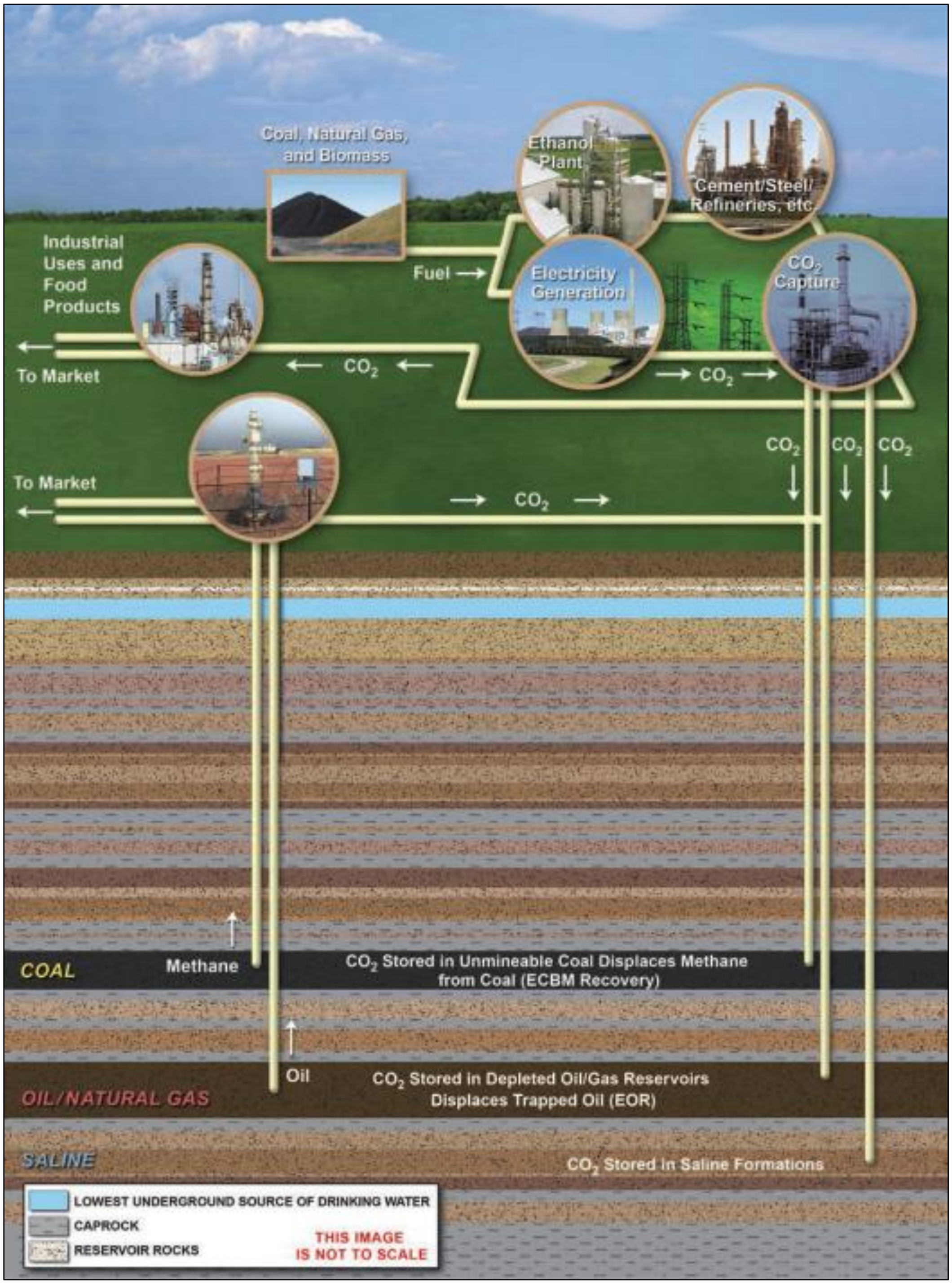
[11] In addition to geologic sequestration in underground reservoirs, research and development is under way on technologies for ocean sequestration, where CO_2 is injected directly into deep waters or below the seabed, and mineral carbonation, a process where CO_2 is converted into solid inorganic carbonates through chemical reactions.

[12] IPCC 2005, p. 14.

[13] U.S. Department of Energy, National Energy Technology Laboratory, *Carbon Utilization and Storage Atlas*, 5th ed., 2015, pp. 18-20 (hereinafter U.S. Department of Energy 2015).

[14] U.S. Energy Information Agency, "U.S. Energy-Related Carbon Dioxide Emissions, 2020," accessed May 24, 2022, at https://www.eia.gov/environment/emissions/carbon/. Energy-related emissions are generally those associated with fossil fuel combustion. Other sources of emissions include agriculture, forestry, and waste (e.g., landfills).

Figure 1. Examples of Carbon Capture, Injection, Storage, and Utilization



Source: U.S. Department of Energy, Office of Fossil Energy, "Carbon Utilization and Storage Atlas," 4th ed., 2012, p. 4.

Notes: *EOR* is enhanced oil recovery; *ECMB* is enhanced coal bed methane recovery.

Enhanced Oil Recovery (EOR)

Injecting substances to increase production from oil-bearing formations is a process known as *enhanced oil recovery*, or EOR.[15] The EOR process involves use of recovery wells (separate from production wells) to inject brine, water, steam, polymers, or CO_2 into oil-bearing formations. EOR, which is also known as *tertiary recovery,* can significantly increase the amount of oil or gas produced from a reservoir.[16]

CO_2 is the most common gas injection agent used in EOR projects.[17] The use of wells to inject CO_2 builds on known industrial processes used by the oil and gas industry since the 1970s. CO_2 injected for EOR is most commonly extracted from naturally occurring underground CO_2 reservoirs, but may also be captured from anthropogenic sources, such as natural gas production, ammonia production, and coal gasification facilities.[18] In many cases, the CO_2 is transferred from the source to the injection site by pipeline. The CO_2 is typically injected into depleted oil or gas reservoirs using the existing well infrastructure from the original production process. The injected CO_2 travels through the pore spaces of the formation, where it combines with residual oil. The mixture is then pumped to the surface, where the CO_2 is separated from other fluids, recompressed, and reinjected. Through repeated EOR cycles, some CO_2 can be gradually stored in the reservoir. NETL reports that generally, 30%-40% of the CO_2 is stored in each injection cycle, depending on the reservoir characteristics, through what it terms "incidental storage."[19] This portion of the CO_2 "will be contained indefinitely within the reservoir," according to NETL.[20]

In 2017 (the latest data available), commercial CO_2-EOR projects were operating in 80 oil fields in the United States, primarily located in the Permian Basin of western Texas.[21] For 2020, EOR facilities reported receiving a total of 35.2 million tons of CO_2 for EOR.[22]

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[15] As of 2014. See Vello Kuuskraa and Matt Wallace, "CO_2-EOR Set for Growth as New CO_2 Supplies Emerge," *Oil and Gas Journal*, vol. 112, no. 4 (April 7, 2014), p. 66. Oil recovery consists of three stages. In *primary recovery*, the natural difference in pressure causes oil to rise through a well and to the surface of the reservoir, or artificial lift methods are used to move the oil. In *secondary recovery*, water or gas is injected through injection wells to move the oil toward the production wells and to the surface. *Tertiary recovery* involves the use of thermal methods, gas injection, or chemical flooding to recover additional oil. EOR is sometimes referred to as *tertiary recovery*. Enhanced recovery is also used occasionally in natural gas production

[16] NETL, "Enhanced Oil Recovery," accessed November 20, 2019, at https://netl.doe.gov/oil-gas/oil-recovery.

[17] NETL, "Enhanced Oil Recovery."

[18] U.S. Environmental Protection Agency, "Federal Requirements Under the Underground Injection Program for Carbon Dioxide (CO_2) Geological Sequestration Wells," 75 *Federal Register* 77230-77303, December 10, 2010, p. 77234.

[19] NETL, *CO_2 Leakage During EOR Operations—Analog Studies to Geological Storage of CO_2*, January 2019, p. 17, at https://www.netl.doe.gov/projects/files/CO2LeakageDuringEOROperationsAnalogStudiestoGeologicStorageofCO2_013019.pdf.

[20] NETL, *CO_2 Leakage During EOR Operations*, 2019, p. 17.

[21] IEA, "Commentary: Whatever Happened to Enhanced Oil Recovery," November 28, 2018 (embedded dataset). In 2020, 70 facilities reported receiving CO_2 for EO under EPA's Greenhouse Gas Reporting Program, discussed later in this report.

[22] U.S. Environmental Protection Agency, "Supply, Underground Injection, and Geologic Sequestration of Carbon Dioxide," accessed on May 24, 2022 at https://www.epa.gov/ghgreporting/supply-underground-injection-and-geologic-sequestration-carbon-dioxide.

Some analysts project that the federal tax credit for carbon utilization and sequestration and the potential increased supply of CO_2 from carbon capture could lead to expansion in both the number and locations of CO_2 injection for EOR operations.[23]

Federal Research and Development for Underground Carbon Storage

Over the last decade, the focus of federal carbon storage RD&D efforts, including geologic sequestration and EOR, has shifted from small demonstration projects to exploration of the technical and commercial viability for injecting and storing large volumes of captured CO_2.

DOE leads the federal government's underground carbon storage RD&D as part of the agency's fossil energy programs implemented in the Office of Fossil Energy and Carbon Management. DOE's work includes conducting laboratory research on wells, storage design, geologic settings, and monitoring and assessment of the injected CO_2. In 2003, DOE created the Regional Carbon Sequestration Partnerships (RCSP) program—a set of public-private partnerships across the United States to characterize, validate, and develop large-scale field testing of CO_2 injection and storage methods. Projects supported through the RCSP include potential carbon storage through geologic sequestration and EOR, conducted through partnerships with the petroleum and chemical industries and public and private research institutions. These projects were scheduled to end by July 2022.[24]

In September 2019, DOE announced four new projects awarded funding through the department's Regional Initiative to Accelerate CCUS Deployment.[25] The regionally based projects are intended to support commercial-scale deployment through activities such as identifying challenges with CCUS technology and CO_2 transportation, evaluating regional CO_2 infrastructure, developing CCUS readiness indicators, and identifying geologic storage sites.[26]

DOE's Carbon Storage Assurance Facility Enterprise (CarbonSAFE) initiative, launched in 2016, promotes the development of geologic sequestration sites capable of storing over 50 million tons of CO_2 from industrial sources.[27] Through the initiative, DOE has funded 13 pre-feasibility (Phase I) projects, 6 feasibility (Phase II) projects, and 5 site characterization and permitting (Phase III) projects.[28] The Phase II projects focus on storage complex feasibility, and Phase III projects include activities such as site characterization, obtaining EPA permits to construct CO_2 injection wells for geologic sequestration, CO_2 capture assessments, and activities related to obtaining a National Environmental Policy Act determination.[29] Future Phase IV projects would include

[23] NETL, *CO_2 Leakage During EOR Operations*, 2019, p. 10.

[24] Based on CRS discussions with DOE, September 26, 2019.

[25] U.S. Department of Energy, "FOA 2000: Regional Initiative to Accelerate CCUS Deployment," accessed September 22, 2020, at https://www.energy.gov/fe/foa-2000-regional-initiative-accelerate-ccus-deployment.

[26] U.S. Department of Energy, "FOA 2000: Regional Initiative to Accelerate CCUS Deployment," accessed September 22, 2020, at https://www.energy.gov/fe/foa-2000-regional-initiative-accelerate-ccus-deployment.

[27] NETL, "CARBONSAFE," accessed September 22, 2020, at https://www.netl.doe.gov/coal/carbon-storage/storage-infrastructure/carbonsafe.

[28] U.S. Department of Energy, "Carbon Management Webinar," December 1, 2021, at https://www.energy.gov/fecm/articles/1201-carbon-management-webinar-presentation.

[29] NETL, "CarbonSafe Initiative," accessed July 19, 2022, at https://netl.doe.gov/carbon-management/carbon-storage/carbonsafe.

obtaining an EPA permit for CO_2 injection for geologic sequestration and construction of a CO_2 storage complex.[30] The projects are managed by NETL.

CO_2 Injection and Storage Projects

In the United States, most CO_2 injection and storage projects have been developed and operated through collaborations among DOE, industry, and local research institutions.[31] These projects include the smaller research and development projects administered by DOE and designed to test various methodologies and technology and demonstrate technical feasibility, as well as the first larger-scale injection and storage projects, which some designate as a "commercial" project.[32] As explained later in this report in the "History of Congressional Action on Injection and Storage of CO2," Congress has recently directed DOE to expand its RD&D activities to support commercialization of CCS projects.

To date in the United States, nine research and development projects funded, or partially funded, by DOE have injected large volumes of CO_2 into underground formations for intended geologic sequestration or EOR-related storage RD&D projects (see **Appendix B**). Three of these projects have involved injection into saline formations for geologic sequestration (for demonstration purposes), five have involved injection for EOR purposes, and one has involved both sequestration and EOR.

One of these projects, the ADM project, in Decatur, IL, is actively injecting CO_2 for geologic sequestration.[33] ADM is injecting CO_2 from its ethanol production plant into an onsite sandstone formation and has injected 2 million metric tons of CO_2 between 2016 and 2020 (the most recent injection data available).[34]

At least two other DOE-funded CCS projects are currently capturing and injecting CO_2 as part of EOR operations. The Air Products Carbon Capture Project in Port Arthur, TX, has been injecting CO_2 captured from steam methane reformers since 2013 as part of EOR operations. The Michigan Basin Project in Otsego County, MI, is injecting CO_2 from a natural gas facility for EOR. The Petra Nova facility in Texas was the first operating coal-fired electricity generating plant with a CCS system in the United States. Now idled, this facility injected CO_2 for EOR from 2017 through May 2020.[35] The ADM, Air Products, and Petra Nova projects received funds from the American Recovery and Reinvestment Act of 2009 (P.L. 111-5). DOE provided partial funding for Michigan Basin project through the RCSP program.

[30] U.S. Department of Energy, *Overview of the COE CCUS R&D Program*, August 2020.

[31] An additional project, the FutureGen Alliance project in Jacksonville, IL, planned to retrofit a power plant to capture emissions and inject CO_2 for geologic sequestration. The project was originally conceived by the George W. Bush Administration and revived under the Obama Administration as FutureGen 2.0 with $1 billion in ARRA funding. The project was cancelled in 2016 due to a variety of technical and financial challenges.

[32] For example, the Global CCS Institute (GCCSI) has defined a *commercial facility* as "a facility capturing CO_2 for permanent storage as part of an ongoing commercial operation that generally has an economic life similar to the host facility whose CO2 it captures, and that supports a commercial return while operating and/or meets a regulatory requirement."

[33] This project is also referred to as the Illinois Industrial Carbon Capture and Storage Project.

[34] EPA FLIGHT database, accessed February 16, 2022.

[35] The owner and operator, NRG, idled Petra Nova's carbon capture equipment in May 2020 in response to lower oil prices caused, in part, by the COVID-19 pandemic (NRG Energy, "Petra Nova Status Update," accessed September 14, 2020, at https://www.nrg.com/about/newsroom/2020/petra-nova-status-update.html).

From 2009 to 2021, five other projects were implemented through the RCSP program as large-scale field tests of larger volumes of CO_2 storage.[36] The projects included injection into various underground formations for geologic storage and injection associated with EOR, with volumes of CO_2 injected and stored ranging from a few hundred tons to nearly 5 million tons (at the time, DOE considered over 1 million tons to be commercial-scale).[37] In total, according to DOE, RCSP projects resulted in the injection and storage of more than 11 million tons of CO_2.[38] Five of these projects have completed injection and are now in the post-injection monitoring phase.[39] See **Appendix B** for project details.

While no uniform definition of "commercial" CCS project exists, some CCS stakeholders track projects and report data on projects with certain commercial characteristics and projects under various stages of planning and development. According to one set of data collected by the Global CCS Institute (GCCSI) as of December 2021, 12 commercial CCS projects were operating in the United States that both capture CO_2 and inject it into underground formations, including the ADM and Air Products projects. [40]

In addition to these projects, in early 2022, Red Trail Energy in Richardton, ND, began injecting CO_2 from an ethanol production plant into a nearby saline formation. The project, regulated by North Dakota, is expected to inject a total of 3.7 million tons of CO_2 over the lifetime of the project.[41] In 2022, North Dakota also granted a Class VI permit to Minnkota Power (also known as Project Tundra) for injection of CO_2 captured from a coal-fired power plant.

Worldwide, several CO_2 geologic sequestration projects are operating in diverse regions, primarily developed through public-private partnerships. In Norway, facilities at the Sleipner Gas Field in the North Sea and Snohvit in the Barents Sea conduct offshore sequestration under the Norwegian continental shelf.[42] The Quest CCS facility in Canada has stored over 5 million tons of CO_2 since 2015.[43] Chevron's Gorgon Injection Project, a natural gas production facility in Australia, began operating in 2019 and is expected to store a total of 100 million tons of CO_2.[44] In Qatar, a project injecting CO_2 for geologic sequestration from a natural gas processing facility has been operating since 2019.[45]

For more information on CCS projects, see CRS Report R44902, *Carbon Capture and Sequestration (CCS) in the United States*.

[36] U.S. Department of Energy 2015, p. 4.

[37] Based on CRS discussions with DOE, September 21, 2020. A seventh project never reached the injection stage due to technical challenges.

[38] Based on CRS discussions with DOE, 2020.

[39] Based on CRS discussions with DOE, 2020.

[40] Global CCS Institute, *Global Status Report 2021*, December 1, 2021. GCCSI does not include a definition of "commercial" in its 2021 report. Two additional CCS facilities injecting CO_2 for EOR suspended operations in 2020.

[41] North Dakota Industrial Commission, NDIC Case No. 28848 -Draft Permit Fact Sheet and Storage Facility Permit Application," accessed on February 16, 2022, at www.dmr.nd.gov/oilgas/GeoStorageofCO2.asp. This injection well is permitted by North Dakota.

[42] IPCC 2005, p. 201.

[43] Shell, "Quest CCS Facility Captures and Stores Five Million Tonnes of CO_2 Ahead of Fifth Anniversary," accessed September 25, 2020, at https://www.shell.ca/en_ca/media/news-and-media-releases/news-releases-2020/quest-ccs-facility-captures-and-stores-five-million-tonnes.html.

[44] Chevron, "Gorgon," accessed September 23, 2020, at https://www.chevron.com/projects/gorgon.

[45] Global CCS Institute, *Global Status Report 2021*, December 1, 2021.

Federal Framework for Regulating Injection of CO_2

This section provides an overview of the federal framework for regulating underground injection of CO_2 for both geologic sequestration and EOR. It describes the primary federal statute for underground injection control (UIC), the general federal and state roles in developing and implementing UIC regulations, and the UIC well classes. The section analyzes the differences between wells used solely for geologic sequestration and wells used for EOR. It also outlines the regulatory requirements for transitioning from EOR wells to geologic sequestration wells.

Safe Drinking Water Act (SDWA)

SDWA is the primary federal statute governing underground injection activities in the United States, including those associated with geologic sequestration of CO_2. SDWA Section 1421 directs EPA to promulgate regulations for state UIC programs to protect underground sources of drinking water and prohibits any underground injection activity except when authorized by a permit or rule.[46] The statute defines underground injection as "the subsurface emplacement of fluids by well injection."[47]

Preventing Endangerment of USDWs From Underground Injection

SDWA states that UIC regulations must "contain minimum requirements for effective programs to prevent underground injection which endangers drinking water sources." The statute defines endangerment as the following: "Underground injection endangers drinking water sources if such injection may result in the presence in underground water which supplies or can reasonably be expected to supply any public water system of any contaminant, and if the presence of such contaminant may result in such system's not complying with any national primary drinking water regulations or may otherwise adversely affect the health of persons." Endangerment applies to both current and potential USDWs.[48]

Federal and State Roles

EPA issues regulations for underground injection, issues guidance to support state program implementation, and in some cases, directly administers UIC programs in states.[49] The agency has established minimum requirements for state UIC programs and permitting for injection wells. These requirements include performance standards for well construction, operation and maintenance, monitoring and testing, reporting and recordkeeping, site closure, financial responsibility, and for some types of wells, post-injection site care. Most states implement the day-to-day program elements for most categories of wells, which are grouped into "classes" based on the type of fluid injected. Owners or operators of underground injection wells must

[46] SDWA §1421; 42 U.S.C. §300h. EPA defines *underground source of drinking water* as an "aquifer or its portion which supplies any public water system or which contains a sufficient quantity of ground water to supply a public water system; and currently supplies drinking water for human consumption; or contains fewer than 10,000 mg/l total dissolved solids; and which is not an exempted aquifer" (40 C.F.R. §146.3). In addition to the provisions described above, Sections 1421 and 1447 establish that injections by federal agencies or injections on property owned or leased by the federal government are subject to the state UIC requirements. Section 1423 sets forth enforcement standards and procedures for the UIC program, including civil and criminal penalties.

[47] SDWA §1421(d)(1); 42 U.S.C. §300h.

[48] SDWA §1421; 42 U.S.C. §300h.

[49] 40 C.F.R. §§144-147.

follow the permitting requirements and standards established by the UIC program authority in their state.

SDWA authorizes EPA to delegate primary enforcement authority for UIC programs, known as *primacy*, to individual states (see **Figure 2**). Section 1422 mandates that states seeking primacy adopt and implement UIC programs that meet all minimum federal requirements under Section 1421.[50] For wells other than certain oil- and gas-related injection wells, states must adopt laws and regulations at least as stringent as EPA regulations and meet other statutory requirements to be granted primacy. EPA grants a state primacy through a federal rulemaking process for one or more classes of wells. If granted primacy for a class of wells, a state administers that UIC program, develops its own requirements, and allows well injection by state rule or by issuing permits. If a state's UIC plan has not been approved, or the state has chosen not to assume program responsibility, SDWA requires that EPA directly implement the program in that state.[51]

UIC Well Classes

Under SDWA authority, EPA has established six classes of underground injection wells based on similarity in the fluids injected.[52] Construction, injection depth, design requirements, and operating techniques vary among well classes. Some wells are used to inject fluids into formations *below* USDWs, while others involve injection *into* or *above* USDWs. EPA regulations set out specific permitting and performance standards for each class of wells. In 2010, EPA issued the first federal rule specific to underground injection of CO_2, *Federal Requirements Under the Underground Control (UIC) Program for Carbon Dioxide (CO_2) Geological Sequestration* (Class VI Rule).[53] In the rule, the agency promulgated regulations for underground injection of CO_2 for long-term storage and established UIC Class VI, a new class of wells for geologic sequestration of CO_2. Prior to the Class VI Rule's effective date in January 2011, injection of CO_2 was permitted under Class II if used for EOR, or Class V if the well was experimental (e.g., DOE-supported research wells). **Table 1** lists the classes of UIC wells.

Table 1. UIC Well Classes and Estimated Wells

Class	Estimated Number of EPA Permitted Wells	Percentage of Total Wells	Type of Fluid Injected
Class I	903	0.12%	Injection of hazardous and non-hazardous wastes into deep, isolated rock formations
Class II	156,547	21.29%	Injection of fluids associated with oil and natural gas production (including injection of CO_2 for enhanced recovery and produced water disposal)
Class III	28,465	3.87%	Injection of fluids for solution mining (e.g., extracting uranium or salt)

[50] SDWA §1422(b). For Class II wells (used for oil- and gas-related injections), a state may exercise primacy under either SDWA Section 1422 or Section 1425. To receive primacy under 1425, a state must demonstrate that it has an effective program that prevents endangerment of underground sources of drinking water from underground injection.

[51] SDWA §1422.

[52] *Injection well* means a well into which "fluids" are being injected (40 C.F.R. §144.6). EPA UIC regulations are codified at 40 C.F.R. §§144-148.

[53] U.S. Environmental Protection Agency, "Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration Wells; Final Rule," 75 *Federal Register* 77230-77303, December 10, 2010.

Class	Estimated Number of EPA Permitted Wells	Percentage of Total Wells	Type of Fluid Injected
Class IV	169	0.02%	Injection of hazardous or radioactive wastes through shallow wells into or above formations that contain a USDW (these wells are banned unless authorized under a federal or state groundwater remediation project)
Class V	549,322	74.70%	Any well used to inject non-hazardous fluids underground that does not fall under the other five classes, including storm water drainage wells, septic system leach fields, aquifer storage and recovery wells, and experimental wells; most Class V wells are used for injection of wastes into or above USDWs
Class VI	2	Less than .01%	Injection of CO_2 into geologic formations for long-term storage or geologic sequestration
TOTAL	**735,408**		

Sources: 40 C.F.R. §144.6; EPA, *FY 2019 State UIC Injection Well Inventory*, accessed September 22, 2022.

Notes: Estimates based on 2019 EPA data (latest available). New York and New Jersey did not submit data for these estimates. This table does not include tribal wells, which include Class 1, Class II, and Class V wells (totaling 6,945 wells, according to EPA's *FY 2019 Tribal UIC Injection Well Inventory*). The two Class VI wells are both located at one site. Class VI estimate does not include two wells permitted by North Dakota in 2022.

EPA has delegated UIC program primacy for well Classes I-V to 32 states (see **Figure 2**). EPA has delegated primacy for all six well classes to two states, North Dakota and Wyoming.[54] Seven states and two tribes have primacy for Class II wells only. Including those states, a total of 40 states have primacy for Class II.[55]

EPA shares UIC implementation responsibility with seven states and two Indian tribes, and implements the UIC program for all well classes in eight states.

For Class VI, EPA has delegated primacy to two states and has direct implementation authority in 48 states and all territories.[56] EPA requires that state primacy for Class VI wells would be implemented under SDWA Section 1422. Additional states are pursuing Class VI primacy; for example, Louisiana is in a completeness determination phase and West Virginia and Arizona are in a pre-application phase for all six well classes.[57] As with regulations for other well classes, the Class VI Rule allows states to apply for primacy for Class VI wells without applying for primacy for other well classes.

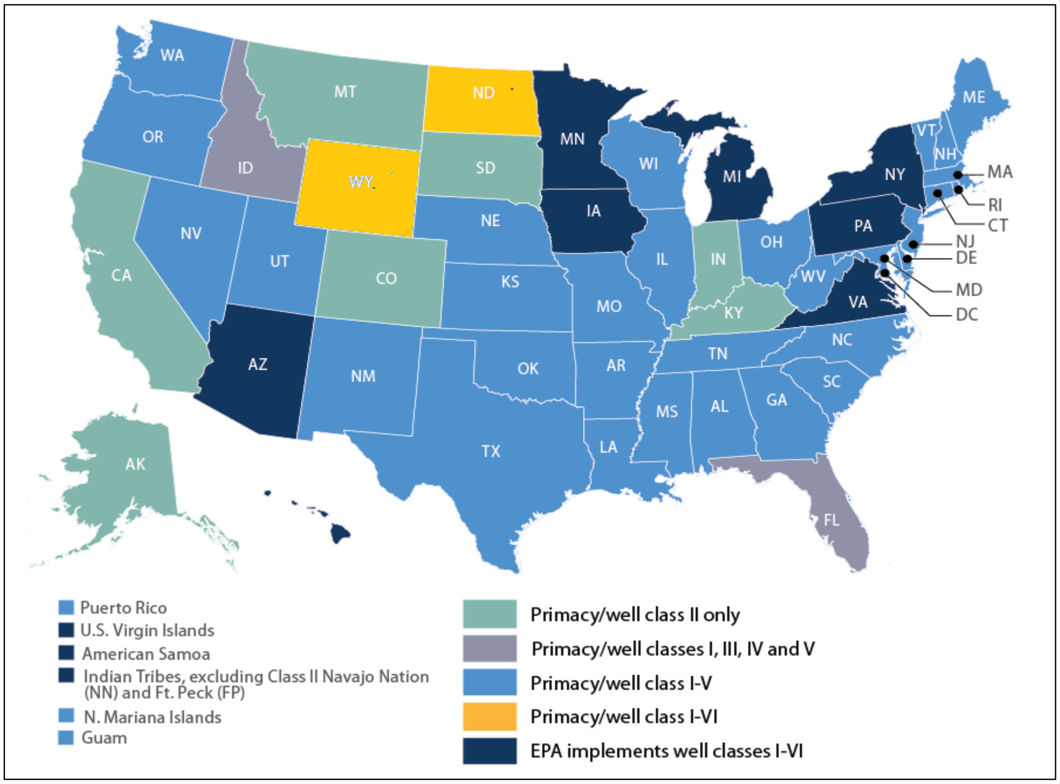
[54] EPA granted Class VI primacy to North Dakota in 2018 and to Wyoming in 2020.

[55] States may request primacy for Class II oil- and gas-related injection operations programs under SDWA Section 1422 or Section 1425 (see "Class II Oil and Gas Related Wells" in this report).

[56] EPA retains direct implementation authority for Class II wells in Florida and Idaho, with those states having primacy over Classes I, III, IV, and V.

[57] U.S. Environmental Protection Agency, "Primacy Enforcement Authority for the Underground Injection Control Program," accessed on September 22, 2022, at https://www.epa.gov/uic/primary-enforcement-authority-underground-injection-control-program-0.

Figure 2. State UIC Primacy Map



Source: CRS, from EPA, "Primary Enforcement Authority for the Underground Injection Control Program," accessed on September 22, 2022, at https://www.epa.gov/uic/primary-enforcement-authority-underground-injection-control-program-0, accessed on September 22, 2022.

Note: North Dakota and Wyoming have primacy for all well classes, including Class VI**.** EPA implements the Class VI program for all other states, territories, and tribes.

Class VI Geologic Sequestration Wells

Underground injection for the purpose of long-term geologic sequestration of CO_2 is subject to SDWA UIC regulations for Class VI wells. Class VI requirements may also apply to CO_2 injection for EOR using Class II wells when EPA or the delegated state determines that there is an increased risk to USDWs.[58]

Two Class VI wells, both in Illinois, are currently permitted by EPA in the United States. EPA issued these final permits in 2017 for two wells injecting CO_2 into a saline aquifer at the ADM ethanol plant in Illinois. As of February 2022, EPA is reviewing 26 Class VI permit applications for wells in the pre-construction phase.[59]

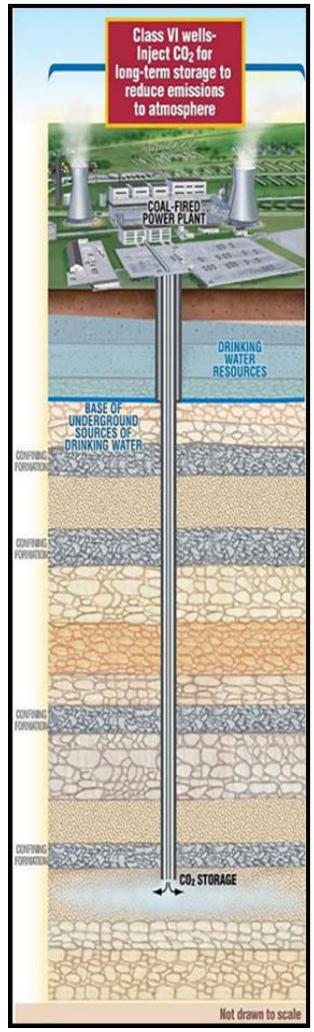
In 2015, EPA issued a final Class VI permit for the FutureGen project, but the permit expired after the project was cancelled without any CO_2 injection taking place.[60]

North Dakota has issued two Class VI permits, for injection of CO_2 captured from an ethanol production facility and from a coal-fired power plant.[61]

Unique Class VI Requirements

When developing minimum federal requirements for Class VI wells, EPA generally built upon Class I hazardous waste requirements. The agency added new requirements to address the unique properties of CO_2 and geologic sequestration in the Class VI Rule. In the preamble to the Class

Figure 3. Conceptual Class VI Well Diagram



Source: EPA, https://www.epa.gov/uic/class-vi-wells-used-geologic-sequestration-co2.

[58] U.S. Environmental Protection Agency, "Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration Wells; Final Rule," 75 *Federal Register* 77230-77303, December 10, 2010, p. 77245.

[59] U.S. Environmental Protection Agency, "Class VI Wells Permitted by EPA," accessed on September 14, 2022, at https://www.epa.gov/uic/class-vi-wells-permitted-epa.

[60] The FutureGen Alliance project in Jacksonville, IL, planned to retrofit a power plant to capture emissions and inject CO_2 for geologic sequestration. The project was originally conceived by the George W. Bush Administration and revived under the Obama Administration as FutureGen 2.0 with $1 billion in ARRA funding. The project was cancelled in 2016 due to a variety of technical and financial challenges.

[61] North Dakota Oil and Gas Division, "Class VI Wells," accessed on February 14, 2022, at https://www.dmr.nd.gov/oilgas/GeoStorageofCO2.asp; and Project Tundra, "Minnkota Received CO2 Storage Permit from NDIC," accessed on February 14, 2022, at www.projecttundrand.com/post/minnkota-receives-co2-storage-permit-from-ndic.

VI Rule, EPA noted that "the Agency has determined that tailored requirements, modeled on the existing UIC regulatory framework, are necessary to manage the unique nature of CO_2 injection for geologic sequestration."[62] EPA bases the regulation of CO_2 injection as a separate class of wells on several unique risk factors to USDWs:

- the large volumes of CO_2 expected to be injected through wells;
- the relative buoyancy of CO_2 in underground geologic formations;
- the mobility of CO_2 within subsurface formations;
- the corrosive properties of CO_2 in the presence of water that can effect well materials; and
- the potential presence of impurities in the injected CO_2 stream.[63]

Due to all of these properties, Class VI requirements establish a larger injection site "area of review" compared to requirements for other classes. The area of review for Class VI wells "includes the subsurface three-dimensional extent of the carbon dioxide plume, associated area of elevated pressure, and displaced fluids, as well as the surface area above that delineated region."[65] The requirements also obligate well owners or operators to track, model, and predict CO_2 plume movement. The monitoring and post-injection site care requirements in the regulations are based on estimates that commercial-scale CO_2 injection projects are expected to operate between 30 and 60 years. **Appendix C** compares the major permitting requirements and technical standards for Class II wells related to oil and gas production, which are used for

Human Health and Environmental Considerations of CO_2 and Use of Wells for Geologic Sequestration

CO_2 itself is not federally regulated as a toxic or hazardous substance. The "CO_2 stream," the full stream of fluid injected for geologic sequestration, however, is not likely to be pure CO_2. Depending on its source, CO_2 streams may contain substances that could be harmful to humans or the environment and subject to applicable regulations.

EPA and other analysts have identified several potential risks associated with injection and geologic sequestration of CO_2:

- contamination of shallower groundwater formations, including drinking water sources, through vertical migration of CO_2 in the subsurface;
- movement of salty water (brine) into drinking water sources caused by injection pressure;
- gradual leaks into the air from the injection well components or monitoring wells;
- sudden large accidental releases that could raise CO_2 concentration above safe levels for humans;
- elevated CO_2 concentrations in soils that could affect plant and animals;
- elevated CO_2 concentrations in the subsurface that could affect microbial populations;
- effects on the minerals in the geologic formation; and
- earthquakes induced by injection pressure.[64]

[62] U.S. Environmental Protection Agency, "Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration Wells; Final Rule," 75 *Federal Register* 77230-77303, December 10, 2010, p. 77233.

[63] U.S. Environmental Protection Agency, "Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration Wells; Final Rule," 75 *Federal Register* 77230-77303, December 10, 2010, p. 77234.

[64] U.S. Environmental Protection Agency, "Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration Wells; Proposed Rule," 73 *Federal Register* 43492-43541, July 25, 2008, p. 43497; IPCC 2005, pp. 245-250; and Interagency Task Force on Carbon Capture and Storage, *Report of the Interagency Task Force on Carbon Capture and Storage*, 2010, pp. 246-250.

[65] 40 C.F.R. §146.81.

EOR, and Class VI wells for geologic sequestration of CO_2.

To assist states and owner operators with the permitting process, EPA has also issued 11 technical guidance documents on Class VI wells. These documents are not legally enforceable, but provide additional information on site characterization, area of review, construction, reporting and recordkeeping, site closure, financial responsibility, and other permit elements.

Class II Oil and Gas Related Wells

Class II wells are used to inject fluids associated with oil and gas production, including wastewater disposal wells (disposal wells) and wells injecting water, brine, steam, CO_2, or other chemicals for EOR (recovery wells). EOR wells are the most common type of Class II wells. As of 2019, there were approximately 156,500 permitted Class II wells, approximately 119,500 (76%) of which were recovery wells.[66] Most of these wells are located in California, Texas, Kansas, Illinois, and Oklahoma. The remaining approximately 20% of Class II wells are disposal wells and hydrocarbon storage wells.

States may request primacy for Class II oil- and gas-related injection operations programs under SDWA Section 1422 or Section 1425. Section 1422 mandates that state programs meet EPA requirements promulgated under Section 1421 and prohibits underground injection that is not authorized by permit or rule.[67] EPA regulations under Section 1421 specify requirements for siting, construction, operation, monitoring and testing, closure, corrective action, financial responsibility, and reporting and recordkeeping.[68] Sixteen states and three territories have Class II primacy under Section 1422.

Section 1425 allows states to administer their own Class II UIC programs using state rules in lieu of EPA regulations, provided a state demonstrates that it has an effective program preventing any underground injection that endangers drinking water sources.[69] To receive approval under Section 1425's optional demonstration provisions, a state program must include permitting, inspection, monitoring, and record-keeping and reporting requirements. Twenty-four states and two tribes have Class II primacy under Section 1425. Most oil- and gas-producing states have primacy for Class II under this section. Overall, nearly 99% of EOR wells are located in states with primacy under Section 1425.[70] In the 10 states without Class II primacy, the District of Columbia, and for most tribes, EPA directly implements the Class II program, and federal regulations apply.[71]

While both Class II CO_2-EOR wells and Class VI wells involve injection of CO_2 into underground reservoirs, the purposes and regulations of these two classes are different. Class II EOR wells inject primarily into oil or gas fields for the purposes of enhancing production from an underground oil and gas reservoir. In Class II wells, only some of the CO_2 stays in the reservoir during each recovery cycle, gradually increasing the total volume of CO_2 stored. In Class VI wells, all of the injected CO_2 is intended to remain in the reservoir for sequestration. CO_2 injection through Class VI wells generally involves higher injection pressures, larger expected

[66] EPA, *FY19 State UIC Injection Well Inventory*.

[67] SDWA §1422.

[68] SDWA §1421.

[69] Section 1425 requires a state to demonstrate that its UIC program meets the requirements of Section 1421(b) for inspection, monitoring, recordkeeping, and reporting, and represents an effective program to prevent underground injection that endangers underground sources of drinking water (SDWA §1425 (a)).

[70] EPA, *FY19 State UIC Injection Well Inventory*.

[71] 40 C.F.R. §142.

fluid volumes, and different physical and chemical properties of the injection stream compared to Class II CO_2-EOR wells.

Given these differences between the two well classes, EPA Class II regulations specify different requirements than Class VI regulations. Generally, EPA Class II requirements impose less comprehensive performance requirements and provide longer time periods between mandatory testing and reporting, compared to EPA Class VI requirements. Unlike EPA Class VI requirements, EPA Class II requirements do not include providing seismicity information, continuous monitoring of the injection pressure and CO_2 stream, monitoring of the CO_2 plume and pressure front, or monitoring of groundwater quality throughout the lifetime of the project.[72] EPA Class II requirements also do not impose post-injection site care or emergency and remedial response requirements, which are included in EPA Class VI requirements.[73] Class II wells can be granted a permit or authorized by rule by either a primacy state or EPA, while Class VI wells cannot be authorized by rule.[74] See **Appendix C** for more information on EPA Class II well requirements.

Transition of Wells from Class II to Class VI Wells

Class II CO_2-EOR wells have a different primary purpose than Class VI wells and must transition to a Class VI permit under certain conditions. EPA has determined that, "owners or operators of Class II wells that are injecting carbon dioxide for the primary purpose of long-term storage into an oil or gas reservoir must apply for and obtain a Class VI permit where there is an increased risk to USDWs compared to traditional Class II operations."[75] EPA recognizes that there may be some CO_2 trapped in the subsurface at EOR operations. However, if the Class VI UIC Program Director (either EPA or the primacy state) has determined that there is no increased risk to USDWs, then these operations would continue to be permitted under the Class II requirements.[76] To date, no Class II wells have been transitioned to Class VI.

Other Federal Authorities

Regulations promulgated under most other federal environmental statutes have generally not applied to underground injection or geologic sequestration of CO_2. If the well owner or operator constructs, operates, and closes the injection well in accordance with a UIC Class II or Class VI permit, the injection and storage would typically not be subject to other federal air quality, waste management, or environmental response authorities and related liability. For example, a release of a hazardous substance in compliance with a UIC permit would be exempt as a "federally permitted release" from liability and reporting requirements of the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA).[77] Such federally permitted releases

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[72] 40 C.F.R. §§144 and 146.

[73] 40 C.F.R. §§144 and 146.

[74] SDWA §1422.

[75] 40 C.F.R. §144.19(a). This section specifies nine criteria that the UIC Program Director must consider in the determination of risk to USDWs.

[76] EPA, *Geologic Sequestration of Carbon Dioxide; Draft Underground Injection (UIC) Program Guidance on Transitioning Class II Wells to Class VI Wells*, p. 1.

[77] Section 107(j) of CERCLA (42 U.S.C. §9607(j)) exempts federally permitted releases of hazardous substances from liability under the statute. Section 103(a) of CERCLA (42 U.S.C. §9603(a)) also exempts such releases from reporting to the National Response Center. Section 101(10)(G) of CERCLA (42 U.S.C. §9601(10)(G)) defines a "federally permitted release" to include underground injection of fluids authorized under the Safe Drinking Water Act, including permits issued by states with authorities delegated under that statute. For a discussion of liability and response

would also be exempt from emergency notification requirements of the Emergency Planning and Community Right-to-Know Act (EPCRA).[78]

During the development of the UIC Class VI final rule, some stakeholders in the CCS industry asked EPA for clarification on how hazardous waste requirements, established under the Resource Conservation and Recovery Act (RCRA), may apply to CO_2 streams that are geologically sequestered. In response, EPA promulgated a rule excluding CO_2 from RCRA's hazardous waste management requirements when injected into UIC Class VI wells.[79] As a result, when injected in compliance with a UIC Class VI well permit, CO_2 streams are not separately subject to RCRA requirements applicable to the management of hazardous waste.

Certain federal regulations may apply to CCS processes or facilities that support CO_2 injection and sequestration, such as carbon capture and CO_2 transportation and compression. The regulatory frameworks of these activities are beyond the scope of this report.

Clean Air Act Greenhouse Gas Reporting Program

In the Consolidated Appropriations Act, 2008 (P.L. 110-161), Congress provided $3.5 million for EPA to promulgate a greenhouse gas reporting rule that would "require mandatory reporting of greenhouse gas emissions above appropriate thresholds in all sectors of the economy of the United States."[80] Under its Clean Air Act (CAA) authorities, EPA requires certain sources of GHGs to report emissions data.[81] In 2010, EPA promulgated a rule to include injection of CO_2 for EOR and geologic sequestration in the GHGRP. In this rule, the agency explained that facilities that inject CO_2 for long-term sequestration and all other facilities that inject CO_2 underground fall within the GHGRP covered source categories.[82] Therefore, reporting requirements apply to both Class VI wells and Class II wells that inject CO_2. EPA's purpose for collecting this information is two-fold—to track CO_2 emissions and to quantify the amount of CO_2 being sequestered.

Under the GHGRP Rule Subpart RR, facilities that inject a CO_2 stream for long-term containment (i.e., geologic sequestration) must develop and implement a monitoring, reporting, and verification (MRV) plan.[83] The purpose of the MRV plan is to verify the amount of CO_2 sequestered and collect data on any CO_2 surface emissions from geologic sequestration facilities.[84] Any facility holding an EPA Class VI permit would be subject to Subpart RR and be

authorities of CERCLA, see CRS Report R41039, *Comprehensive Environmental Response, Compensation, and Liability Act: A Summary of Superfund Cleanup Authorities and Related Provisions of the Act*, by David M. Bearden.

[78] Section 304(a) of EPCRA (42 U.S.C. §11004(a)) exempts CERCLA federally permitted releases from emergency notification requirements for reporting to state and local emergency response officials. For a discussion of EPCRA emergency notification requirements, see CRS Report R44952, *EPA's Role in Emergency Planning and Notification at Chemical Facilities*, by Richard K. Lattanzio and David M. Bearden.

[79] U.S. Environmental Protection Agency, "Hazardous Waste Management System: Conditional Exclusion for Carbon Dioxide (CO_2) Streams in Geologic Sequestration Activities," 79 *Federal Register* 350-364, January 3, 2014.

[80] The Consolidated Appropriations Act, 2008, P.L. 110-161, provided funding for EPA to develop and finalize a rule to "require mandatory reporting of GHG emissions above appropriate thresholds in all sectors of the economy of the United States." Congress directed EPA to issue a final rule no later than 18 months after the date of enactment. EPA promulgated the GHGRP under the authority in Clean Air Act Sections 114 and 208.

[81] Clean Air Act §114 (for stationary sources) and §208 (for mobile sources).

[82] U.S. Environmental Protection Agency, "Mandatory Reporting of Greenhouse Gases: Injection and Geologic Sequestration of Carbon Dioxide; Final Rule," 75 *Federal Register* 75060-75089, December 1, 2010.

[83] 40 C.F.R. §98, Subpart RR.

[84] U.S. Environmental Protection Agency, "Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration Wells; Final Rule," 75 *Federal Register* 77230-77303,

required to report the mass of CO_2 that is received, injected into the subsurface, produced, emitted by surface leakage, emitted by leaks in equipment, and emitted by venting.[85] Facilities also must report the mass of CO_2 sequestered in subsurface geologic formations.[86]

Subpart UU of the rule applies to Class II wells used to inject CO_2 for EOR and for small and experimental sequestration projects exempted under Subpart RR. Subpart UU does not require an MRV plan and sets forth different and fewer requirements for monitoring and reporting.[87]

For GHGRP reporting year 2020, 70 facilities reported receiving CO_2 for EOR and 6 facilities reported injecting CO_2 for geologic sequestration.[88] For addition information, see CRS Report R46757, *Reporting Carbon Dioxide Injection and Storage: Federal Authorities and Programs*, by Angela C. Jones.

History of Congressional Action on Injection and Storage of CO_2

For over a decade, Congress has supported DOE's carbon storage-related RD&D activities and EPA's UIC Class VI program through passage of legislation, oversight, and agency appropriations.

The Energy Policy Act of 2005 (EPAct05; P.L. 109-58) Section 963 originally directed DOE to carry out a 10-year carbon capture RD&D program to develop technologies for use in new and existing coal combustion facilities and has since been amended. Among the specified objectives of this program, Congress directed DOE, "in accordance with the carbon dioxide capture program, to promote a robust carbon sequestration program" and to continue RD&D work through carbon sequestration partnerships.[89] Section 354 of the act directed the agency to establish a demonstration program to inject CO_2 for the purposes of EOR while increasing the sequestration of CO_2.

The Energy Independence and Security Act of 2007 (EISA; P.L. 110-140) amended EPAct Section 963 and expanded DOE's work in carbon storage RD&D. EISA Title VII, Subtitle A, directed DOE to conduct fundamental science and engineering research in carbon capture and sequestration, and to conduct geologic sequestration training and research. Subtitle A of the act also specifically directed DOE to carry out at least seven large-scale projects testing carbon sequestration systems in a diversity of formations, which could include RCSP projects. Subtitle B directed DOE to conduct a national assessment for onshore capacity of CO_2 sequestration.

In 2008, the Energy Improvement and Extension Act (P.L. 110-343) authorized federal tax credits for carbon sequestration. This act added Section 45Q to the Internal Revenue Code (I.R.C.), which established tax credits for CO_2 disposed of in "secure geologic storage" or through EOR

December 10, 2010, p. 77236.

[85] 40 C.F.R. §98, Subpart RR. EPA defines *surface leakage* as "the movement of the injected CO_2 stream from the injection zone into the surface, and into the atmosphere, indoor air, oceans, or surface water" (40 C.F.R. §98.449).

[86] 40 C.F.R. §98, Subpart RR.

[87] 40 C.F.R. §98, Subpart UU.

[88] U.S. Environmental Protection Agency, "Supply, Underground Injection and Sequestration of Carbon Dioxide," accessed on February 28, 2022, at https://www.epa.gov/ghgreporting/supply-underground-injection-and-geologic-sequestration-carbon-dioxide. Of the six sequestration reporters, one facility has a Class VI permit and the others voluntary report under Subpart RR.

[89] EPAct05 §963.

with "secure geologic storage."[90] Over time, Congress has amended Section 45Q through the American Recovery and Reinvestment Act (P.L. 111-5), the Bipartisan Budget Act of 2018 (BBA; P.L. 115-123), the Consolidated Appropriations Act, 2021 (P.L. 116-260), and the budgetary measure commonly known as the Inflation Reduction Act of 2022 (IRA; P.L. 117-169). See "Carbon Sequestration Tax Credits" below for more information on the Section 45Q tax credit and associated issues for Congress. See also the CRS In Focus IF11455, *The Tax Credit for Carbon Sequestration (Section 45Q)*, by Angela C. Jones and Molly F. Sherlock.

Recently Enacted Legislation

Energy Act of 2020

In recent years, Congress has provided additional funding for DOE and directed the department to continue and expand RD&D activities for CO_2 storage and sequestration. In the Energy Act of 2020 (Division Z of the Consolidated Appropriations Act, 2021, P.L. 116-260), enacted in December 2020, Congress reauthorized the general DOE CCS research program through amendments to EPAct05.[91] The act characterizes relevant DOE activities as "Carbon Storage Validation and Testing" rather than "research, development and deployment" referred to in EISA. The Energy Act of 2020 specifically directs DOE to establish a large-scale carbon storage program that would develop geologic sequestration mapping and monitoring tools, assess sequestration safety, and other activities at a variety of geologic settings. In Section 4003, the act defines *large-scale carbon sequestration* as a project scale that demonstrates geologic sequestration of CO_2 and has a goal of sequestering at least 50 million metric tons of CO_2 over a 10-year period.[92] The act directs DOE to establish a large-scale demonstration program intended to provide information on the cost and feasibility of these projects. The act also supports efforts toward commercialization of carbon storage projects through DOE activities to transition large-scale storage demonstration projects to "integrated commercial storage complexes," including site identification and assessment of technical and commercial viability of the sites.[93]

USE IT Act

In the Utilizing Significant Emissions with Innovative Technologies Act (USE IT Act, Division S, §102) enacted as part of the Consolidated Appropriations Act, 2021 (P.L. 116-260), Congress directed EPA and CEQ to undertake several activities related to geologic sequestration and related CCS infrastructure, among other provisions related to carbon utilization, project permitting, and CCS infrastructure. The act directed EPA, in consultation with DOE and other relevant federal agencies, to submit a report to Congress on "deep saline formations" that addresses potential risk and benefits to project developers, recommendations for managing these risks, and recommendations for potential legislation and federal policy in these areas.[94] The USE IT Act also directed CEQ, in consultation with EPA, DOE, and other agencies, to submit a report to Congress regarding the permitting and review of CCS projects and CO_2 pipelines.[95] Among other CCS topics, the report was to include information on federal permitting and authorities for sequestration projects and "gaps in the current federal regulatory framework" for sequestration

[90] 26 U.S.C §45Q. P.L. 115-123 expanded the tax credit to carbon oxides, which includes CO_2.

[91] P.L. 116-260, Division D §4003.

[92] The definition was altered in 2021 by P.L. 117-58 to remove the 10-year time frame (42 U.S.C. §16293).

[93] P.L. 116-260, Division Z §4003.

[94] P.L. 116-260, Division.S §102(b).

[95] P.L. 116-260, Division.S §102(b).

projects, capture and utilization projects, and CO_2 pipelines. The act also directed CEQ to issue a guidance to federal agencies based on this report that facilitates reviews and supports the development of CCS projects and CO_2 pipelines. See "CEQ 2021 CCS Report to Congress and 2022 CCS Guidance" later in this report for a discussion of CEQ's report and guidance in response to these directives.

Other Relevant Provisions in P.L. 116-260

In Division G of the Consolidated Appropriations Act, 2021, Congress directed EPA to submit a report and provide a briefing to Congress on recommendations to "improve Class VI permitting procedures."[96] In the act, Congress also extended the start of construction deadline for projects seeking the federal tax credit for carbon sequestration, also known as the "Section 45Q" tax credit by two years, to 2026.[97]

Infrastructure Investment and Jobs Act

The Infrastructure Investment and Jobs Act (IIJA; P.L. 117-58), enacted in November 2021, expanded some of the DOE large-scale carbon storage activities authorized in the Energy Act of 2020 and adds "commercialization" of projects as a focus of the agency's carbon storage program. Specifically, IIJA Division D, Title III, directed DOE to establish a new "large-scale carbon storage commercialization program" for geologic sequestration projects. IIJA also changes the definition of "large-scale carbon sequestration," removing the 10-year time frame for sequestering 50 million tons enacted in the Energy Act of 2020.[98] In Division J of IIJA, Congress also provided $2.5 billion in total supplemental appropriations to DOE for carbon storage, validation, and testing activities for FY2022-FY2026.

For EPA, IIJA directed the agency to establish a grant program for states that have been granted Class VI program primacy by EPA. Division J of the act provides $50 million in supplemental appropriations to EPA for grants to states that have or are working toward Class VI primacy, and an additional $25 million to the agency for Class VI permitting administration, both for FY2022.

The Inflation Reduction Act of 2022

In the budgetary measure commonly known as the Inflation Reduction Act of 2022 (IRA; P.L. 117-169), Congress amended Section 45Q in numerous ways. The IRA changed existing provisions and added new provisions that revised the tax credit amounts, lowered the amounts of CO_2 facilities are required to capture each year to qualify for the credit, and extended the deadline for when a facility must start construction, among other changes.[99] For more information on the Section 45Q tax credit, see "Carbon Sequestration Tax Credits" later in this report.

Issues for Congress

If Congress were to address carbon storage through underground injection, there are a variety of policy issues Members may consider. Several policy issues relate to the current SDWA UIC regulatory framework and what elements of CO_2 injection are covered under the statute's purpose

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[96] P.L. 116-260, Division G, Title II, Environmental Protection Agency.

[97] P.L. 116-260, Division EE, the Taxpayer Certainty and Disaster Relief Act of 2020, Title I, §121.

[98] P.L. 117-58, Division D §40305 (42 U.S.C. §16293).

[99] P.L. 117-169, §13104. Application of tax credit amounts, construction deadlines, and other Section45Q provisions depend on when capture equipment is placed in service.

and approach. Congress may also wish to consider other issues that may have implications for CO_2 injection and storage policy, including current pathways of federal support for CCS and underground carbon storage, project cost, and stakeholder perspectives on CCS and fossil fuels. In addition, in 2021, as directed by Congress, CEQ provided a report on CCS that contains additional issues for consideration.

Scope of the SDWA UIC Regulatory Framework

SDWA currently serves as the major federal authority for regulating injection of CO_2 for geologic sequestration, and carbon storage in general. However, the major purpose of the act's UIC provisions is to prevent endangerment of public water supplies and sources from injection activities. In the preamble to the proposed Class VI Rule, EPA states, "While the SDWA provides EPA with the authority to develop regulations to protect USDWs from endangerment, it does not provide authority to develop regulations for all areas related to GS [geologic sequestration]."[100] The agency identified specific policy areas related to geologic sequestration that are beyond the agency's authority, including, but not limited to, capture and transport of CO_2, managing human health and environmental risks other than drinking water endangerment, determining property rights, and transfer of liability from one entity to another.[101]

The agency acknowledges the challenge of balancing SDWA goals with broader efforts to support geologic sequestration. In the preamble to the Class VI Rule, EPA noted that "[t]his rule ensures protection of USDWs while also providing regulatory certainty to industry and permitting authorities and an increased understanding of GS through public participation and outreach."[102]

Potential Environmental Risks of Injection and Geologic Sequestration of CO_2

Federal agencies, external analysts, and other stakeholders have expressed a variety of viewpoints on the potential risks associated with injection and geologic sequestration of CO_2. EPA, the Interagency Task Force on Carbon Capture and Storage (Task Force), and others have recognized that CO_2 injection and sequestration activities may convey risks to the environment and human health.[103] Some of these risks involve potential endangerment of USDWs that would be covered

[100] U.S. Environmental Protection Agency, "Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration Wells; Proposed Rule," 73 *Federal Register* 43492-43541, July 25, 2008, p. 43495.

[101] U.S. Environmental Protection Agency, "Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration Wells; Proposed Rule," 73 *Federal Register* 43492-43541, July 25, 2008, p. 43495.

[102] U.S. Environmental Protection Agency, "Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration Wells; Final Rule," 75 *Federal Register* 77230-77303, December 10, 2010, p. 77279.

[103] In its 2010 report, the U.S. Interagency Task Force on Carbon Capture and Storage stated, "Because [the] SDWA is focused on the protection of drinking water sources, it may require clarification to support actions to address or remedy ecological or non-drinking water human health impacts arising from the injection and sequestration of CO_2" (Interagency Task Force on Carbon Capture and Storage, *Report of the Interagency Task Force on Carbon Capture and Storage*, 2010). In another report, a coalition of academic experts, the CCSReg Project, stated, "Because of the constraints of its statutory mandate, the UIC program cannot comprehensively manage all potential issues that arise in connection with geologic sequestration operations, and, because it places protection of drinking water aquifers (independent of quantity or depth) above all other objectives, it cannot address tradeoffs between risk to groundwater and risks from climate change" (CCSReg Project, *Carbon Capture and Sequestration: Framing the Issues for Regulation*, 2009).

by SDWA. Other potential impacts, however, are not covered by SDWA or the UIC implementing regulations.

For groundwater-related risks, EPA has noted that expansion of CO_2-EOR and associated CO_2 storage could increase the risk of endangerment to USDWs due to increased injection zone pressures and the large number of wells in oil and gas fields that could serve as leakage pathways.[104] Injected CO_2 could also force brine from the target formation into USDWs, which could affect drinking water.[105] To address potential releases or leakage that could endanger USDWs, in the Class VI Rule, EPA included monitoring, reporting, and record-keeping requirements specific to CO_2 injection.[106] Class VI construction and testing requirements, which are generally more stringent than Class II requirements for EOR, are also intended to prevent USDW endangerment.[107]

Regarding other types of risk from improperly managed projects, EPA identified risks to air quality, human health, and ecosystems as potential concerns not addressed by SDWA authorities.[108] In its 2010 report, the Task Force concluded that SDWA's limited application to only those groundwater formations that meet the specific statutory definition of USDWs may "require clarification to support actions to address or remedy ecological or non-drinking water human health impacts arising from the injection and sequestration of CO_2."[109] The Task Force also stated that an accidental large release could result in risks to surface water, local ecology, and human health.[110] (See text box **Human Health and Environmental Considerations of CO_2 and Geologic Sequestration**.)

An additional concern with injection and sequestration of CO_2 is the increased potential for earthquakes associated with deep-well injection. Earthquakes induced by CO_2 injection could fracture the rocks in the reservoir, or more importantly, the caprock above the reservoir.[111] Class VI well regulations require that information on earthquake-related history be included in the permit application and that owners or operators not exceed injection pressure that would induce seismicity or initiate fractures.[112]

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[104] U.S. Environmental Protection Agency, "Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration Wells; Final Rule," 75 *Federal Register* 77230-77303, December 10, 2010, p. 77244. Most CO_2-EOR is regulated by states under SDWA Section 1425 rather than regulated directly by EPA.

[105] IPCC 2005, p. 248.

[106] 40 C.F.R. §146.90 and §146.91.

[107] 40 C.F.R. §146.86-§146.90.

[108] U.S. Environmental Protection Agency, "Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration Wells; Proposed Rule," 73 *Federal Register* 43492-43541, July 25, 2008, p. 43497.

[109] Interagency Task Force on Carbon Capture and Storage, *Report of the Interagency Task Force on Carbon Capture and Storage*, 2010, p. 106.

[110] Interagency Task Force on Carbon Capture and Storage, 2010 p. 42. Such as a release due to well damage or failure, or certain circumstances where the injected CO_2 could migrate in an unexpected way (IPCC 2005, p. 247).

[111] Mark D. Zoback and Steven M. Gorelick, "Earthquake Triggering and Large-Scale Geologic Storage of Carbon Dioxide," *PNAS*, vol. 109, no. 26 (June 26, 2012), pp. 10164-10168.

[112] U.S. Environmental Protection Agency, "Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration Wells; Proposed Rule," 73 *Federal Register* 43492-43541, July 25, 2008, p. 43498.

In a 2005 CCS report, the IPCC notes that data on physical leakage from geological storage sites are "very limited," and "physical leakage rates are estimated to be very small for geological formations chosen with care."[113]

NETL and other stakeholders offer other perspectives on potential health and environmental risks. Regarding the risks of CO_2 leakage, NETL outlines several case studies on leakage related to underground carbon storage in a 2019 report.[114] The report states that use of EOR in the United States "has demonstrated that large volumes of gas can be stored safely underground and over long timeframes when the appropriate best-practices are implemented."[115] According to the report, "Despite over 40 years of operating CO_2 EOR projects, leakage events have rarely been reported"; although the report also notes that "there has been no official mechanism for reporting leaks of CO_2 until recently."[116] Other stakeholders have also commented that even given potential health and environmental risks, the benefits of CO_2 sequestration in reducing GHG emissions as part of climate change mitigation efforts outweigh such risks.[117]

Liability and Property Rights Issues

In the Class VI Rule, EPA acknowledged stakeholder interest in liability and long-term stewardship, but noted that that the agency does not have the authority to determine property rights or transfer liability from one owner or operator to another.[118] In its report, the Task Force also identified that "the existing [f]ederal framework largely does not provide for a release or transfer of liability from the owner/operator to other persons" and noted that some stakeholders view these issues as a barrier to future CCS project deployment.[119] Specific policy questions regarding property rights include who owns and controls the subsurface formations (known as the pore space) targeted for CO_2 storage, if and how such property can be transferred or aggregated, and how underground reservoirs that cross state and tribal boundaries should be regulated. State laws and contractual property arrangements, similar to those established for oil and gas development, may address some of these questions, but some analysts identify the need for more clarity.[120]

Issues of financial liability and long-term stewardship of injection sites and storage reservoirs also remain largely unresolved. Analysts have raised questions such as (1) who is responsible for the site and reservoir after the 50-year mandated post-injection site care period; (2) what is the role of the federal or state government in assisting site developers and operators with managing the risks associated with sequestration activities; and (3) whether the federal government should be involved in taking on some or all financial responsibility during the life-cycle of sequestration projects.[121] Large-scale commercial geologic sequestration projects would likely require unique

[113] IPCC 2005, pp. 371.

[114] NETL, *CO_2 Leakage During EOR Operations*, 2019, pp. 104-109.

[115] NETL, *CO_2 Leakage During EOR Operations*, 2019, p. 2.

[116] NETL, *CO_2 Leakage During EOR Operations*, 2019, pp. 104 and 110.

[117] CCReg Project 2009, p. 83.

[118] U.S. Environmental Protection Agency, "Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration Wells; Proposed Rule," 73 *Federal Register* 43492-43541, July 25, 2008, p. 43495, and U.S. Environmental Protection Agency, "Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration Wells; Final Rule," 75 *Federal Register* 77230-77303, December 10, 2010, p. 77272.

[119] Interagency Task Force 2010, p. 109.

[120] CCReg project 2009, p. 95, and Interagency Task Force 2010, p. 71.

[121] Interagency Task Force 2010, p. 68, and CCReg Project 2009, p. 58.

liability and stewardship structures that address issues such as the particular characteristics of CO_2, the entire life-cycle of sequestration projects—from site selection to periods beyond site closure—and the geologic time frame (hundreds or thousands of years) over which sequestration occurs. For more information on legal issues, see CRS Report RL34307, *Legal Issues Associated with the Development of Carbon Dioxide Sequestration Technology*, by Adam Vann and Paul W. Parfomak.

Other Policy Considerations

Research, Development, and Deployment

EPA has stated that, "a supporting regulatory framework for the future development and deployment of [carbon storage] technology can provide the regulatory certainty needed to foster industry adoption of CCS, which is crucial to supporting the goal of any climate change legislation."[122] Even with the completion of several large-scale demonstration field projects, analysts recognize uncertainties regarding wide-spread commercial CCS operation in the United States. These include uncertainties in operations, such as how much CO_2 would be injected, CO_2 sources, availability of appropriate locations, and the exact constituents of CO_2 injection streams.[123] A lack of existing infrastructure for CCS systems—from capture technology to pipelines to transport CO_2—may also act as barriers to future CCS deployment.[124]

As noted earlier in this report, recent legislative directives from Congress to DOE and CEQ, as well as appropriations to DOE for carbon storage RD&D, demonstrate increased attention to supporting research and development activities that further technical knowledge and facilitate deployment of CCS projects.[125] The Energy Act of 2020, the USE IT Act, and IIJA expanded DOE's CCS activities in research and demonstration of geologic sequestration technologies and assessments of sequestration sites. Congress provided $2.5 billion in IIJA to DOE for carbon storage, validation, and testing activities. Congress has also directed DOE to prepare reports on CCS RD&D.[126] Overall, in recent years congressional attention has moved toward supporting larger-scale projects and the technology and programs needed to move these projects from demonstrations toward deployment and commercial operation.

Project Cost

The cost of constructing and operating a new CCS system or retrofitting an existing facility, such as a coal-fired or natural gas power plant, with CCS, is likely to play a major role in the future deployment of commercially viable sequestration projects. Costs for large-scale geologic sequestration or EOR include expenses directly related to injection and storage, as well as costs of investing in sufficient carbon capture and transportation infrastructure and maintaining ongoing facility operations. Regarding regulatory costs associated with geologic sequestration, in the

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[122] U.S. Environmental Protection Agency, "Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration Wells; Proposed Rule," 73 *Federal Register* 43492-43541, July 25, 2008, p. 43496.

[123] Interagency Task Force 2010, pp. C-5-C-9.

[124] Interagency Task Force 2010, p. 48.

[125] See Divisions S and Z of P.L. 116-260 and Divisions D and J of P.L. 117-58.

[126] Division Z of P.L. 116-260, §4003 (42 U.S.C §16293).

preamble to the Class VI Rule, EPA specified the agency's intention that the rule would not impede geologic sequestration:

> Should this rule somehow impede GS from happening, then the opportunity costs of not capturing with the benefits associated with GS could be attributed to this regulation; however the Agency has tried to develop a rule that balances risk with practicability, site specific flexibility and economic considerations and believes the probability of such impedance is low.[127]

Analysts expect that the costs of CCS, whether new system or retrofitting of an existing facility, are likely to total more than a billion dollars per project, which could act as a barrier to future CCS deployment without the continuation of federal subsidies for development.[128] According to Enchant Energy, a company planning to retrofit power generation facilities in New Mexico and North Dakota, the projects are expected to cost $1.3 billion and $1 billion, respectively.[129] Minnkota Power estimates that a CCS project in North Dakota, Project Tundra, will require $1 billion in capital investment.[130] The project is in the early development stages and would install carbon capture at a coal-fired power plant and inject CO_2 into a nearby formation for geologic sequestration.

Examples of completed commercial-scale CCS operations and associated costs are limited, causing some uncertainty regarding future investments and the scale of project deployment in the coming decades. In a 2019 report, NETL indicated that "the potential costs of commercial-scale CCS are still not fully understood, particularly from a fully integrated (capture, transportation, and storage) perspective."[131] Costs could vary greatly due to a variety of site-specific factors. The type of capture technology is the largest component of costs, possibly accounting for as much as 80% of the total.[132] The variations in the geology of storage formations also make predicting future geologic sequestration costs particularly difficult. In one set of estimates reported by the National Petroleum Council, storage costs in the United States range from $7 to $11 per ton of CO_2, depending on the storage location.[133]

Projects that inject some or all the CO_2 for EOR (with incidental carbon storage) involve different cost implications and economic factors from projects injecting solely for permanent CO_2 sequestration. These factors could influence future deployment of these types of projects, as facility owners and operators may consider cost implications when deciding whether to invest in EOR or when deciding between investing projects for EOR or permanent geologic sequestration. EOR operations typically use the existing injection infrastructure in place from earlier oil and gas production activities; thus, the well exploration and construction costs are "sunk costs." Unlike geologic sequestration projects, these expenses may not be included in total project cost

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127 U.S. Environmental Protection Agency, "Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration Wells; Final Rule," 75 *Federal Register* 77230-77303, December 10, 2010, p. 77279. EPA's cost estimates apply to injection activities only and do not include capture and transport of CO_2.

128 See IPCC 2005, p. 347, and Jeffrey Rissman and Robbie Orvis, "Carbon Capture and Storage: An Expensive Option for Reducing U.S. CO_2 Emissions," *Forbes*, May 3, 2017.

129 Carlos Anchondo and Edward Klump, "Petra Nova is Closed: What It Means for Carbon Capture," *Energywire*, September 22, 2020.

130 Project Tundra, "Project Tundra," accessed on February 28, 2022, at https://www.projecttundrand.com.

131 NETL, *Class I Injection Wells-Analog Studies to Geologic Storage of CO_2, January* 2019, p. 75, at https://www.netl.doe.gov/projects/files/UICClassIInjectionWellsAnalogStudiestoGeologicStorageofCO2_013019.pdf.

132 Steve Furnival, "Burying Climate Change for Good," *Physics World*, September 1, 2006.

133 National Petroleum Council, *Meeting the Dual Challenge*, updated June 5, 2020, p. 2-24.

calculations, resulting in comparatively lower costs for injecting and storing the CO_2. In addition, for EOR projects, overall project costs could be influenced by revenue for the owner or operator from additional oil and gas production. EOR project costs may also be subject to variability and uncertainty, however. NETL notes that the price of oil and the cost and availability of CO_2 are key drivers in the economics of CO_2 EOR.[134]

Federal tax credits for carbon sequestration, available since 2009 for both EOR and geologic sequestration, may also play a role in underground injection and storage of CO_2 project costs and investment decisions. These credits are discussed later in this report.

Public Acceptance and Participation

In the preamble to the proposed Class VI Rule, EPA noted that "GS of CO_2 is a new technology that is unfamiliar to most people, and maximizing the public's understanding of the technology can result in more meaningful public input and constructive participation as new GS projects are proposed and developed."[135] EPA also stated that "the agency expects that there will be higher levels of public interest in GS projects than for other injection activities."[136] In the Class VI Rule, EPA adopted the existing UIC public participation requirements, which require permitting authorities to provide public notice of pending actions, hold public hearings if requested, solicit and respond to public comments, and involve a broad range of stakeholders.[137]

At least two cases involving Class VI permits have come before EPA's Environmental Appeals Board.[138] The first case involved the permit for the FutureGen facility, which was never constructed. The second case involved ADM's Illinois facility, currently operating and permitted in Illinois. Public concerns centered on safety and environmental protection issues, including air quality, groundwater quality, and protection of endangered species. Local landowners claimed that the permits did not adequately address how the facility will ensure these protections in the event of leakage or well failure. They also raised concerns about property rights (including mineral rights), potential decreases in property value, and increased traffic associated with the facilities.[139]

Continued Use of Fossil Fuels

In EPAct05 and EISA, Congress recognized connections between injection of CO_2 and the continued use of fossil fuel as a major energy source for electric power in the United States.

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[134] NETL, *Carbon Dioxide Enhanced Oil Recovery*, pp. 14-20, https://www.netl.doe.gov/sites/default/files/netl-file/CO2_EOR_Primer.pdf.

[135] U.S. Environmental Protection Agency, "Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration Wells; Proposed Rule," 73 *Federal Register* 43492-43541, July 25, 2008, p. 43523.

[136] U.S. Environmental Protection Agency, "Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration Wells; Final Rule," 75 *Federal Register* 77230-77303, December 10, 2010, p. 77273.

[137] U.S. Environmental Protection Agency, "Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration Wells; Final Rule," 75 *Federal Register* 77230-77303, December 10, 2010, p. 77273.

[138] UIC Appeal No. 114-68; 14-69; 14-70; 14-71 (Consolidated), (Environmental Appeals Board United States Environmental Protection Agency 2014) and UIC Appeal No. 17-05 (Environmental Appeals Board United States Environmental Protection Agency 2017).

[139] "EAB Dismisses Challenge to Second SDWA Permit Issued for CCS Project," *EnergyWashingtonWeek*, December 17, 2014.

Consistent with Congress's directives, DOE's CCS research identifies that the purpose of its CCS research, technology development, and testing is "to benefit the existing and future fleet of fossil fuel power generating facilities by creating tools to increase our understanding of geologic reservoirs appropriate for CO_2 storage and the behavior of CO_2 in the subsurface."[140] In the preamble to the proposed Class VI rule, EPA stated that, "the capture and storage of CO_2 would enable the continued use of coal in a manner that greatly reduces the associated CO_2 emissions while other safe and affordable energy sources are developed in the coming decades."[141]

Some stakeholders have argued for further research, development and deployment of CCS (when coupled with negative carbon technology, such as direct air capture) as a method for achieving the negative emissions trajectories modeled by the IPCC.[142] Some of these stakeholders state that CCS is an appropriate transitional technology to reduce CO_2 emissions from electricity generation and other industrial sources while expanding the capacity of low or zero-carbon power sources, such as renewable energy.[143] Research on the net emissions reductions of CO_2 associated with EOR is ongoing, although large variations exist in the current literature regarding EOR emissions life cycle analysis methodologies and parameters.[144]

In contrast, other stakeholders have argued that CO_2 storage could create a disincentive to reduce fossil-fuel-based power plant emissions or shift to renewable energy sources.[145] For example, in its 2021 draft recommendations to the Biden Administration, the White House Environmental Justice Advisory Council included CCS projects in its list of "examples of the types of projects that will not benefit a community."[146] In particular, some stakeholders note that injecting CO_2 for EOR may actually increase net GHG emissions, as it produces additional oil and gas to be burned as fuel.[147] CCS systems also require energy to compress, transport, and inject the CO_2, which, if derived from fossil fuel combustion, could detract from the net GHG reduction benefits of carbon storage.

Carbon Sequestration Tax Credits

Federal tax credits for carbon sequestration were first authorized in 2008 with the enactment of the Energy Improvement and Extension Act (P.L. 110-343). This act added Section 45Q to the Internal Revenue Code (I.R.C.), which established tax credits for CO_2 disposed of in "secure

[140] U.S. Department of Energy 2015, p. 9.

[141] U.S. Environmental Protection Agency, "Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration Wells; Proposed Rule," 73 *Federal Register* 43492-43541, July 25, 2008, p. 43498.

[142] *Net negative carbon* is a type of negative emission technology, which the IPCC defines as the "removal of greenhouse gases from the atmosphere by deliberate human activities" (IPCC, *Global Warming of 1.5ºC, A Special Report on the Impacts of Global Warming of 1.5ºC Above Pre-industrial Levels*, 2018, Glossary).

[143] Natural Resources Defense Council, "Capturing Carbon Pollution While Moving Beyond Fossil Fuels," accessed on November 27, 2019, at https://www.nrdc.org/experts/david-doniger/capturing-carbon-pollution-while-moving-beyond-fossil-fuels.

[144] For example, an International Energy analysis concluded that under certain conditions and within certain parameters, injecting CO_2 for EOR results in negative net CO_2 emissions per barrel of oil produced (International Energy Agency, *Storing CO_2 Through Enhanced Oil Recovery*, 2015, p. 30).

[145] Carlos Anchondo, "Industry Warns Lawmakers of CCS Threats," *Energywire*, November 25, 2019; and Richard Conniff, "Why Green Groups Are Split on Subsidizing Carbon Capture Technology," *YaleEnvironment360*, April 9, 2018, YaleEnvironment360, April 9, 2018.

[146] White House Environmental Justice Advisory Council, *Draft Recommendations on: Justice 40 Climate and Economic Justice Screening Tool & E.O. 12898*, May 13, 2021.

[147] Conniff, 2018.

geologic storage" or through EOR with "secure geologic storage."[148] For EOR, only the initial CO_2 injected as a tertiary injectant qualifies for the tax credit; CO_2 recaptured, recycled, or reinjected does not qualify.[149]

Provisions in Section 45Q establish the amount of the tax credit per ton of carbon oxide captured and disposed of, annual CO_2 capture minimums, deadlines for beginning facility construction, and credit claim periods; and direct the U.S. Department of the Treasury (Treasury) to issue 45Q regulations, among other provisions. Credit rates, capture minimums, and other provisions differ depending on when the facility or capture equipment was placed in service in relation to the Bipartisan Budget Act of 2018 (BBA) and IRA enactment. As noted previously in this report, Congress has amended Section 45Q through several legislative measures, such as the BBA, IIJA, and the IRA. The BBA expanded the tax credit to "carbon oxides" captured and to carbon oxides utilized in a qualified manner (in addition to EOR), as defined in the act.[150]

In 2022, the IRA amended 45Q to revise the credit amounts and extend the start of construction deadline, among other changes. For facilities or equipment placed in service after December 31, 2022, and that meet prevailing wage and registered apprenticeship requirements, the tax credit amount is $85 per ton of CO_2 disposed of in "secure geologic storage" and $60 per ton of CO_2 used for EOR and disposed of in "secure geologic storage," or utilized in a qualified matter.[151] Different credit rates apply to equipment placed in service between the enactment of the BBA on February 9, 2018, and December 31, 2022, and to equipment placed in service prior to BBA enactment.[152]

In the IRA, Congress established a separate set of credit amounts for CO_2 captured using direct air capture (DAC), an emerging technology designed to remove CO_2 directly from the atmosphere rather than from a point source of CO_2 emissions. For DAC facilities or equipment placed in service after December 31, 2022, and that meet prevailing wage and registered apprenticeship requirements, the credit is $180 per ton for CO_2 captured using DAC and disposed of in "secure geologic storage," and $130 per ton for CO_2 captured using DAC that is used for EOR and disposed of in "secure geologic storage," or utilized in a qualified manner.[153]

To qualify for these tax credits, a point source facility or DAC facility must begin construction by December 31, 2032.[154]

The IRA also established a lower amount of CO_2 that certain facilities must capture each year to qualify for the credit, compared to what had previously been required. For facilities that begin

[148] 26 U.S.C §45Q. P.L. 115-123 expanded the tax credit to carbon oxides, which includes CO_2.

[149] 26 U.S.C §45Q (c)(2). *Tertiary injectant* refers to the injection of CO_2 for enhanced oil recovery (also known as tertiary recovery). For the purposes of §45Q, tertiary injectant has the same meaning as used in 26 U.S.C §193.

[150] 26 U.S.C §45Q (a). For more information on Section 45Q, please see CRS In Focus IF 11455, *The Tax Credit for Carbon Sequestration (Section 45Q),* by Angela C. Jones and Molly F. Sherlock. Carbon oxide refers to any of the three oxides of carbon: carbon dioxide, carbon monoxide, and carbon suboxide.

[151] P.L. 117-169, §13104(b). For facilities that do not meet prevailing wage and apprenticeship requirements, the base credit amount is $17 per ton for secure geologic storage and $12 per ton for EOR or other qualified use. Credit amounts are adjusted for inflation after 2026.

[152] 26 U.S.C §45Q (a).

[153] P.L. 117-169, §13104(c). Prior to the IRA amendments, eligible taxpayers disposing of CO_2 captured through DAC would receive the credit amount for the type of disposal used, either geologic sequestration or EOR/utilization. For facilities or equipment placed in service after December 31, 2022, the base credit amount is $36 per ton for CO_2 captured using DAC and geologically sequestered and $26 per ton for CO_2 captured using DAC that is used for EOR or utilized in a qualified manner.

[154] P.L. 117-169, §13104(a).

construction after August 16, 2022, DAC facilities must capture at least 1,000 tons of CO_2 per year.[155] Electricity generating facilities must capture at least 18,750 tons of CO_2 per year and have a capture design capacity at least 75% of the unit's baseline carbon oxide production; and other facilities must capture at least 12,500 tons of CO_2 per year.[156]

In January 2021, the IRS issued final Section 45Q regulations that include requirements for demonstrating the "secure geological storage" of carbon oxides in underground formations needed to qualify for 45Q tax credits.[157] The rule adds new I.R.C. Section 1-45Q-3, which establishes that compliance with relevant provisions of the EPA's Mandatory Reporting of Greenhouse Gases Rule satisfies the 45Q secure storage demonstration requirements.[158] In addition, the regulations require that carbon oxides must also be injected into a well that complies with applicable EPA UIC regulations to be considered secure geological storage.[159] For more information, see CRS In Focus IF11639, *Carbon Storage Requirements in the 45Q Tax Credit*, by Angela C. Jones.

Treasury estimates that for FY2023, the credit will reduce federal income tax revenue by $720 million.[160] Over the FY2022-FY2031 budget window, Treasury estimates that the tax credit will reduce federal income tax revenue by a total of $20.1 billion.[161] As of June 2020 (the latest data available), the amount of stored carbon oxide claimed for 45Q credits (for projects in service before February 9, 2018) since 2011 totaled 72,087,903 tons.[162] In a November 2021 notice, Treasury did not provide an updated total of claimed credits, but noted that it is not certifying that the total has reached 75 million tons.[163]

CEQ 2021 CCS Report to Congress and 2022 CCS Guidance

In response to the USE IT Act, CEQ in 2021 provided Congress with a report on carbon capture, utilization, and sequestration.[164] One of several reports required by Congress in the Consolidated

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[155] P.L. 117-169, §13104(a).

[156] P.L. 117-169, §13104(a). For equipment placed in service after the enactment of the BBA on February 9, 2018 and before January 1, 2023, the annual capture requirements are: (1) in the case of a facility that emits no more than 500,000 metric tons of carbon oxide, capture at least 25,000 metric tons of carbon oxide that is either fixated through the growing of algae or bacteria, chemically converted into a material or chemical compound in which the carbon oxide is stored, or used for another commercial purpose (other than a tertiary injectant); (2) in the case of an electricity generating facility not described in (1), capture at least 500,000 metric tons of carbon oxide per year; or (3) in the case of a direct air capture facility not described in (1) or (2), capture at least 100,000 metric tons of carbon oxide. For equipment placed in service before February 9, 2018, the capture requirement is 500,000 tons per year.

[157] Internal Revenue Service, "Credit For Carbon Oxide Sequestration," 86 *Federal Register* 4728-4773, January 15, 2021.

[158] 29 C.F.R. Part 1 §1-45Q-3.

[159] 29 C.F.R. Part 1 §1-45Q-3.

[160] U.S. Department of the Treasury, "FY 2023 Tax Expenditures," accessed February 17, 2022, at https://home.treasury.gov/policy-issues/tax-policy/tax-expenditures.

[161] U.S. Department of the Treasury, "FY2023 Tax Expenditures," accessed February 17, 2022, at https://home.treasury.gov/policy-issues/tax-policy/tax-expenditures.

[162] Internal Revenue Service Notice 2020-40, "Credit for Carbon Dioxide Sequestration 2020 45Q Inflation Adjustment Factor," June 15, 2020. This applies to tax credits for geologic sequestration and EOR.

[163] Internal Revenue Service Notice 2021-35, "Credit for Carbon Dioxide Sequestration 2021 45Q Inflation Adjustment Factor," November 15, 2021.

[164] CEQ, *Council on Environmental Quality Report to Congress on Carbon Capture, Utilization, and Sequestration*, https://www.whitehouse.gov/wp-content/uploads/2021/06/CEQ-CCUS-Permitting-Report.pdf. The report to Congress is required by P.L. 116-260, Division S, §102.

Appropriations Act, 2021 (P.L. 116-260), this report provides information on federal permitting and regulations for CCS projects and examines technical, financial, and policy-related issues for project deployment. In its key findings, CEQ states that "the Federal Government has an existing regulatory framework that is rigorous and capable of managing permitting and review actions while protecting the environment, public health, and safety as CCUS projects move forward."[165] CEQ also finds that with the complex nature of CCS projects, there are opportunities for improvement in the federal regulatory framework to "ensure that CCUS is responsibly scaled in a timely manner that is aligned with climate goals."[166] CEQ identifies two specific areas of improvement related to CO_2 injection and sequestration—EPA UIC Class VI program capacity and resolving questions of underground pore space ownership and liability. For the EPA Class VI program, CEQ recommends increasing staff capacity and training to process and administer the potential increase in Class VI permit applications and the number of states seeking Class VI program primacy.[167] Regarding pore space, CEQ recommends that EPA, the Department of the Interior, the Department of Agriculture, and possibly other federal agencies, develop regulations to clarify property rights and pore space ownership on federal lands.[168] CEQ also recommends that the agencies should also specify the process for leasing pore space for geologic sequestration on federal lands.[169]

CEQ released an interim guidance, "Carbon Capture, Utilization, and Sequestration Guidance," in February 2022, also as directed by Congress in the USE IT Act.[170] The interim guidance includes recommendations for federal agencies that would support "the efficient, orderly, and responsible development and permitting of CCUS projects at an increased scale in line with the Administration's climate, economic, and public health goals."[171] Related to CO_2 injection and geologic sequestration, CEQ provides guidance on the processes for permitting and review of CCUS projects and CO_2 pipelines, public engagement, and assessing environmental impacts of CCUS projects.

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[165] CEQ CCS Report, p. 8.

[166] CEQ CCS Report, p. 8.

[167] CEQ CCS Report, p. 39.

[168] CEQ CCS Report, p. 42.

[169] CEQ CCS Report, p. 42.

[170] Council on Environmental Quality, "Carbon Capture, Utilization, and Sequestration Guidance," 87 *Federal Register* 8808-8811, February 16, 2022. The CEQ guidance is required by P.L. 116-260, Division S, §102.

[171] Council on Environmental Quality, "Carbon Capture, Utilization, and Sequestration Guidance," 87 *Federal Register* 8808-8811, February 16, 2022, p. 8809.

Appendix A. Estimates of U.S. Storage Capacity for CO_2

Table A-1. Estimates of U.S. Storage CO_2 Capacity

(in billions of metric tons)

Formations	Low	Medium	High
Oil and Natural Gas Reservoirs	186	205	232
Unmineable Coal Seams	54	80	113
Saline Formations	2,379	8,328	21,978
Total	2,618	8,613	22,323

Source: U.S. Department of Energy, National Energy Technology Laboratory, *Carbon Utilization and Storage Atlas*, 5th ed., August 20, 2015, at https://www.netl.doe.gov/sites/default/files/2018-10/ATLAS-V-2015.pdf (data current as of November 2014).

Notes: The low, medium, and high estimates correspond to a calculated probability of exceedance of 90%, 50% and 10% respectively, meaning that there is a 90% probability that the estimated storage volume will exceed the low estimate and a 10% probability that the estimated storage volume will exceed the high estimate. Numbers in the table may not add precisely due to rounding.

Appendix B. Department of Energy Funded Large Scale Injection and Geologic Sequestration of CO_2 Projects in the United States

Table B-1. Large Scale CO_2 Injection Projects in the United States (RCSP and Recovery Act Funded) as of 2021

Project	CO_2 Source	Type	Injection Status	Volume Injected for Storage (in tons)	Funding Source and Amount
Illinois Industrial Carbon Capture and Storage Project (Archer Daniels Midland Facility) *Decatur, IL*	Ethanol fermentation plant	Saline storage	Active injection and sequestration	1.8 million (as of July 2020)	ARRA $141,405,945 (funding includes Illinois Basin Project)[a]
Air Products Project *Port Arthur, TX*	Steam methane reformers	EOR	Active injection	6.8 million (as of July 2020)	ARRA $284,000,000[b]
Michigan Basin Project *Otsego County, MI*	Natural gas processing plant	EOR	Active injection	1,638,692[c]	RCSP $1,019.414[d]
Petra Nova Plant *Thompsons, TX*	Coal-fired power plant	EOR	Idled[e]	1.4 million per year (through 2019)	ARRA $167,000,000 and FY2016 Consolidated Appropriations Act $23,000,000 ($190,000,000 total)[f]
Citronelle Project *Citronelle, AL*	Coal-fired power plant	Saline storage	Completed Sept. 2014; post-injection monitoring	114,104	RCSP $76,981.260[g]
Illinois Basin Decatur Project (Archer Daniels Midland Facility) *Decatur, IL*	Ethanol fermentation plant	Saline storage	Completed Nov. 2014; post-injection monitoring	999,215	RCSP $141,405,945 (funding includes Illinois Industrial Project)[h]
Cranfield Project *Natchez, MS*	Natural	EOR with saline storage	Completed Jan. 2015; post-injection monitoring	4,743,898	RCSP $76,981.260[i]

Project	CO_2 Source	Type	Injection Status	Volume Injected for Storage (in tons)	Funding Source and Amount
Bell Creek Field Project *Crook County, WY*	Natural gas processing plant	EOR	Completed; post-injection monitoring	2,982,000	RCSP $95,453,751[j]
Farnsworth Unit *Ochitree County, TX*	Ethanol and fertilizer production plant	EOR	Completed; post-injection monitoring	791,593	RCSP $65,618,315[k]
Kevin Dome Project *Toole County, MT*	None	Saline storage	Project suspended	0	RCSP $67,000,000[l]

Sources: For Project, CO_2 Source, Type, Injection Status and Volume Injected: DOE, *Carbon Utilization and Storage Atlas 2015*; based on CRS discussions with DOE, September 26, 2019, and September 21, 2020; NETL, "Petra Nova Parish Holdings," accessed October 25, 2019, at htpps://www.netl.doe.gov/sites/default/files/netl-file/Petra_Nova.pdf; NETL, "Recovery Act: CO_2 Capture from Biofuels Projection and Sequestration into the Mt. Simon Sandstone Reservoir," accessed October 25, 2019, at https://www.netl.doe.gov/project-information?p=FE0001547.

Notes: ARRA is the American Recovery and Reinvestment Act (P.L. 111-5); RSCP is the Regional Carbon Sequestration Partnership.

a. NETL, "Recovery Act: CO2 Capture from Biofuels Projection and Sequestration into the Mt. Simon Sandstone Reservoir," accessed October 25, 2019, at https://www.netl.doe.gov/project-information?p=FE0001547.

b. NETL, "Demonstration of Carbon Capture and Sequestration of Steam Methane Reforming Process Gas Used for Large-Scale Hydrogen Production," accessed October 25, 2019, at https://www.netl.doe.gov/sites/default/files/netl-file/2012-10-18-PCC-Presentation-APCI—Zinn-Rev1.pdf.

c. Total as of December 2019. Although injection continues, DOE is no longer collecting stored CO_2 data on this facility.

d. NETL, "Northern Michigan Basin CarbonSAFE Integrated Pre-Feasibility Project," accessed October 25, 2019, at https://www.netl.doe.gov/project-information?p= FE0029276.

e. NRG idled Petra Nova's carbon capture equipment in May 2020, in response to lower oil prices (NRG Energy, "Petra Nova Status Update, accessed September 14, 2020, at www.nrg.com/about/newsroom/2020/petra-nova- status-update.html).

f. NETL, "Petra Nova—W.A. Parish Project," accessed October 25, 2019, at https://www.energy.gov/fe/petra-nova-wa-parish-project.

g. SECARB, "Phase III Anthropogenic CO2 Injection Field Test," accessed October 25, 2019, at http://www.secarbon.org/files/anthropogenic-test.pdf.

h. NETL, "Recovery Act: CO2 Capture from Biofuels Projection and Sequestration into the Mt. Simon Sandstone Reservoir," accessed October 25, 2019, at https://www.netl.doe.gov/project-information?p=FE0001547.

i. SECARB, "Phase III Early CO2 Injection Field Test at Cranfield," accessed October 25, 2019, at http://www.secarbon.org/files/early-test.pdf.

j. DOE, "Federal Investments in Coal as Part of A Clean Energy Innovation Portfolio," accessed October 25, 2019, at https://www.energy.gov/sites/prod/files/2016/06/f32/Federal%20Investments%20in%20Coal%20as%20Part%20of%20a%20Clean%20Energy%20Portfolio.pdf.

k. DOE, "Federal Investments in Coal as Part of A Clean Energy Innovation Portfolio," accessed October 25, 2019, at https://www.energy.gov/sites/prod/files/2016/06/f32/Federal%20Investments%20in%20Coal%20as%20Part%20of%20a%20Clean%20Energy%20Portfolio.pdf.

l. Big Sky Sequestration Partnership, "Kevin Dome Storage Project Fact Sheet," accessed October 25, 2019, at https://www.bigskyco2.org/sites/default/files/outreach/KevinProjectMediaKit_071511.pdf.

Appendix C. Comparison of Class II and Class VI Wells

Table C-1. Minimum EPA Requirements for Class II and Class VI Wells

Class II Requirements Apply to 10 States Where EPA Administers the Class II Program and 16 States with Class II Primacy Under Section 1422

Requirements	Class II[a]	Class VI
General Permit Information	The permit applicant must provide basic facility information, a listing of permits under other federal programs, a topographic map of the property including injection well sites and water bodies within a ¼ mile of the facility boundary, land records, and a plugging and abandonment plan.	Class II requirements plus detailed information on the CO_2 stream, baseline geochemical data on subsurface formations, including all USDWs in the area of review and more detailed information on the geologic structure and hydrogeologic properties of the storage site and overlaying formation.
Siting Criteria	New wells must be sited so that they inject into a formation separated from any USDW by a confining zone that is free of known open faults or factures within area of review.	The permit applicant must demonstrate that within the geologic system: the injection site is in a suitable geologic formation for geologic sequestration; the injection zone can receive the total anticipated volume of the CO_2 stream; and the confining zone is free of faults or fractures and of sufficient extent and integrity to contain the injected CO_2 stream and displace formation fluids at the proposed maximum pressures and volumes without initiating or propagating fractures.
Permit Required	Yes, except for existing EOR wells authorized by rule.	Yes; cannot be authorized by rule.
Seismicity Information	None.	Provide information on seismic history of the site; demonstration that the formation's confining zone (which limits fluid movement) is free of faults or fractures and can contain the injected CO_2 and other formation fluids (e.g., brine) without initiating or propagating fractures in the formation.
Area of Review (AOR) and Corrective Action	For new wells, a ¼ mile fixed radius or radius of endangerment. For new wells, must identify the location of all known wells within the injection well's AOR which penetrate the injection zone, or in the case of Class II wells operating over the fracture pressure of the injection formation, all known wells within the AOR penetrating formations affected by the increase in pressure. For improperly sealed, completed, or abandoned wells, must submit a corrective action plan.	Designates a larger AOR that accounts for the physical and chemical properties of CO_2, including how CO_2 injection plumes flow through underground formations. Owner/operator must review the AOR every five years. Corrective action on all wells in the area of review that are determined to need corrective action, using methods designed to prevent the movement of fluid into or between USDWs, including use of materials compatible with the CO_2 stream, where appropriate.

Requirements	Class II[a]	Class VI
Financial Responsibility	Financial assurances (bond, letter of credit, or other adequate assurance) that the owner or operator will maintain financial responsibility to properly plug and abandon the wells.	Financial responsibility instruments to cover corrective action, injection, well plugging, post-injection site care, and any emergency and remedial response that meets the regulatory requirements of those actions.
Well Construction	Casing and cementing are adequate to prevent movement of fluids into or between USDWs.	Class II requirements plus must also use materials and performance standards suitable for long-term contact with CO_2 for the life of the project.
Logging, Sampling, and Testing Prior to Operation	New wells must be tested for mechanical integrity prior to operation.	Class II requirements plus more specific requirements to determine or verify the characteristics of formation fluids in all relevant geologic formations. Specific tests required to demonstrate mechanical integrity. Specific requirements for testing and recording of the physical and chemical characteristics of the injection zone.
Operating Requirements	Injection pressure shall not exceed a calculated maximum or cause the movement of injection or formation fluids into a USDW.	Class II requirements plus more specific limits on injection pressure and continuous monitoring of injection pressure and CO_2 stream. In no case may injection pressure initiate fractures in the confining zone(s) or cause the movement of injection or formation fluids that endangers a USDW.
Mechanical Integrity	Internal—pressure test at least once every five years. External—adequate cement records may be used in lieu of logs.	Specific standards for when a Class VI well demonstrates mechanical integrity, including the requirement for annual testing to determine the absence of significant fluid movement.
Testing and Monitoring	Annual fluid chemistry and other tests as needed/required by permit. Injection pressure, flow rate, and cumulative volume observed weekly for disposal and monthly for enhanced recovery.	The testing and monitoring plan must verify that the project is operating as permitted and is not endangering USDWs. Analysis of CO_2 stream at sufficient frequency. Continuous monitoring of the CO_2 injection pressure, rate, and volume. Testing and monitoring of the underground CO_2 plume and pressure front both during injection and for a period following injection.[b] Quarterly corrosion monitoring of well materials. Periodic monitoring of groundwater quality throughout the lifetime of the project. The UIC director may require air and/or soil gas monitoring.
Well Plugging and Site Closure[c]	Well must be plugged with cement in a manner that will not allow the movement of fluids into or between USDWs.	Class II requirements plus more specific well plugging and site closure requirements for testing, notification, and reporting. Technical and management requirements to prevent CO_2 leakage from the entire site after operation ceases.

Requirements	Class II[a]	Class VI
Reporting and Recordkeeping	Required annually. Retain records of all monitoring information. Reporting of noncompliance which may endanger health or the environment.	Required semiannually. Class II requirements plus reporting of more specific information on injection fluid stream and pressure data. Owners/operators must report within 24 hours "evidence that the injected carbon dioxide stream or associated pressure front may cause an endangerment to a USDW."[d] Records must be retained for all data collected under Class VI permit applications for the life of the project and 10 years following side closure; monitoring data must be retained for 10 years after collected.
Post-injection Site Care	None.	Continue monitoring of the CO_2 plume and pressure front to prevent endangerment of USDWs after injection. 50-year period of monitoring after final injection.[e]
Emergency and Remedial Response	None.	Submit an emergency and remedial response plan to prevent endangerment of a USDW. Notification and plan implementation in the event of a CO_2 release.
Permitting Period	Specific period, may be for the life of well. Existing Class II recovery or hydrocarbon storage injection wells are authorized by rule for the life of the project. UIC program directors must review each permit at least once every five years.	Sets a longer permitting period, including the lifetime of the facility plus a 50 year post-injection period. UIC program directors must review each permit at least once every five years.
Area Permits	Generally allowed.	Not allowed.

Source: EPA, "Technical Program Overview: Underground Injection Control Regulations," EPA 816-R-02-025, December 2002, pp. 11 and 67; 40 C.F.R. §144.36; 40 C.F.R. §144; 40 C.F.R. §146.81.

a. Most oil and gas production occurs in states with primacy (program oversight and enforcement authority) for Class II wells under SDWA Section 1425. These states regulate Class II wells under their own state programs, rather than the EPA regulations discussed here.

b. *Pressure front* means the zone of elevated pressure that is created by the injection of CO_2 into the subsurface; can refer to the pressure sufficient to cause the movement of injected fluids or formation fluids into a USDW (40 C.F.R. §146.81(d)).

c. *Closure* means the point in time when the facility owner or operator is released from post-injection site care responsibilities, as determined by the UIC program director (40 C.F.R. §146.81(d)).

d. 40 C.F.R. §146.91(c)(1).

e. Other well classes have post-closure monitoring periods as determined by the UIC Director.

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Acknowledgments

CRS Research Librarians Kezee Procita, Rachel Eck, and L.J. Cunningham made significant contributions to this report.

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