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

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SUMMARY

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

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, such as a coal-fired power plant, 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. 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). Long-term storage of CO_2 can also occur incidentally through enhanced oil recovery (EOR), a process of injecting CO_2 into an oil or gas reservoir that can significantly increase the amount of oil or gas produced.

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 research on geologic sequestration and EOR, and carries out the Regional Carbon Sequestration Partnerships (RCSP) program—a set of public-private partnerships across the United States to deploy testing and development of CO_2 injection and storage. To date in the United States, nine projects have injected large volumes of CO_2 into underground formations as demonstrations of potential commercial-scale storage. Four of these projects are actively injecting and storing CO_2—one in an underground saline reservoir to demonstrate geologic sequestration and three in oil and gas reservoirs as part of EOR. Currently, while numerous large-scale storage R&D projects are ongoing in the United States, none of the projects injecting CO_2 solely for geologic sequestration are operating in a commercial capacity.

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 geologic sequestration of CO_2 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 in the United States. No state has issued a permit for a Class VI well. CO_2 injection for EOR is conducted using Class II wells (associated with oil and gas production). SDWA also authorizes states to administer UIC programs in lieu of EPA, known as *primacy*. For Class VI CO_2 geologic sequestration wells, only North Dakota has primacy. Most oil and gas producing states have primacy for Class II wells and regulate these wells under their own state programs.

Congress has supported carbon storage via underground injection through recent legislation directing DOE to expand R&D activity and increasing the federal tax credit for underground carbon storage. 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. If Congress were to explore future policy in this area, Members may consider the potential health and environmental risks (beyond any related risks to underground sources of drinking water) not addressed by SDWA. Other issues for Congress include unresolved liability and property rights issues, overall CCS project cost, public acceptance of these sequestration projects and participation in their planning, and the relationship of the growth of underground carbon storage with continuing to burn fossil fuels for generating electricity.

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Introduction

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, such as a coal-fired power plant, and storing it underground instead of releasing into the atmosphere—has been proposed as a technological solution for mitigating emissions while using fossil energy.[1] Federal policies on CCS have received support in recent Congresses, including support for research and development (R&D) and expansion of tax credits for carbon storage.[2] The U.S. Fourth National Climate Assessment, released in 2018, states that "the impacts of global climate change are already being felt in the United States and are projected to intensify in the future—but the severity of future impacts will depend largely on actions taken to reduce greenhouse gas emissions and to adapt to the changes that will occur."[3] This report focuses on federal policy regarding the underground carbon storage stage of CCS.

Underground carbon storage is achieved through geologic sequestration and as an incidental benefit of enhanced oil recovery (EOR), which both use injection by well to place CO_2 into deep subsurface geologic formations. Geologic sequestration involves storing CO_2 by placing it permanently in an underground formation. This process is being tested in the United States and several other countries, including several large-scale late-stage R&D projects.[4] EOR involves injecting CO_2 to produce additional oil and gas from underground reservoirs and has been used in the United States since the 1970s.

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 through supporting R&D activities. Congress has supported carbon storage via underground injection through recent legislation directing DOE to expand R&D activity and increasing the federal tax credit for underground carbon storage. As Congress considers policies on underground carbon storage, including geologic sequestration and EOR, Members may wish to consider 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 and related federal R&D. 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

[1] CCS is one of several acronyms used to describe similar processes of capturing and storing 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 will use "CCS" as a broad reference to all of these types of systems.

[2] The Bipartisan Budget Act of 2018 (P.L. 115-123), among other provisions, increased the federal tax credit for carbon storage through geologic sequestration or enhanced oil or gas recovery.

[3] U.S. Global Change Research Group, Fourth National Climate Assessment Volume II: Impacts, Risks, and Adaptation in the United States, Chapter 1, 2018, https://nca2018.globalchange.gov.

[4] The Energy Independence and Security Act of 2007 (EISA) (§702(a)(2)(C), 42 U.S.C. §17002) defines *large-scale* to mean the "injection of more than 1,000,000 tons of carbon dioxide from industrial sources annually or a scale that demonstrates the ability to inject and sequester several million metric tons of industrial source carbon dioxide for a large number of years." This does not include earlier Department of Energy–sponsored research pilot projects of significantly smaller volumes.

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

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*, by Peter Folger.

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; for solution mining; and, more recently, to inject CO_2 for geologic sequestration. As of 2018, EPA estimated that there were more than 734,000 permitted injection wells in the United States.[7] According to one estimate, approximately 750 billion gallons (2.8 million tons) of oil field brine are injected underground each year in the United States.[8]

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. These wells can reach thousands of feet deep.[9] 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 plant or chemical production facility.[10] Although CO_2 is initially captured as a gas, it is compressed into a supercritical fluid—a relatively dense fluid intermediate to a gas and a liquid—

[6] 40 C.F.R §144.3 and EPA, "Federal Requirements Under the Underground Injection Program for Carbon Dioxide (CO_2) Geological Sequestration (GS) Wells; Proposed Rule," 73 *Federal Register* 43492-43541, July 25, 2008, p. 43493.

[7] EPA, *FY2018 State UIC Injection Well Inventory*, https://www.epa.gov/uic/uic-injection-well-inventory.

[8] Intergovernmental Panel on Climate Change (IPCC), *Carbon Dioxide Capture and Storage, A Special Report of Working Group III*, 2005, p. 212, https://www.ipcc.ch/report/carbon-dioxide-capture-and-storage/.

[9] 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.

[10] 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.

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.[11] Research shows that CO_2 could also be sequestered in deep ocean waters or mineralized.[12] 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.[14] (For more details, see **Appendix A**.) By comparison, U.S. energy-related CO_2 emissions in 2018 totaled 5,269 million tons.[15] 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*, and CRS Report R41325, *Carbon Capture: A Technology Assessment*, by Peter Folger.

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, or absorbed onto organic material or go through other chemical transformations. Researchers expect that geologic sequestration will take place over hundreds of years after injection, ultimately resulting in permanent storage of the CO_2. According to one analysis from the Intergovernmental Panel on Climate Change (IPCC), almost all of the CO_2 will remain in the formation for 1,000 years after injection.[13]

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

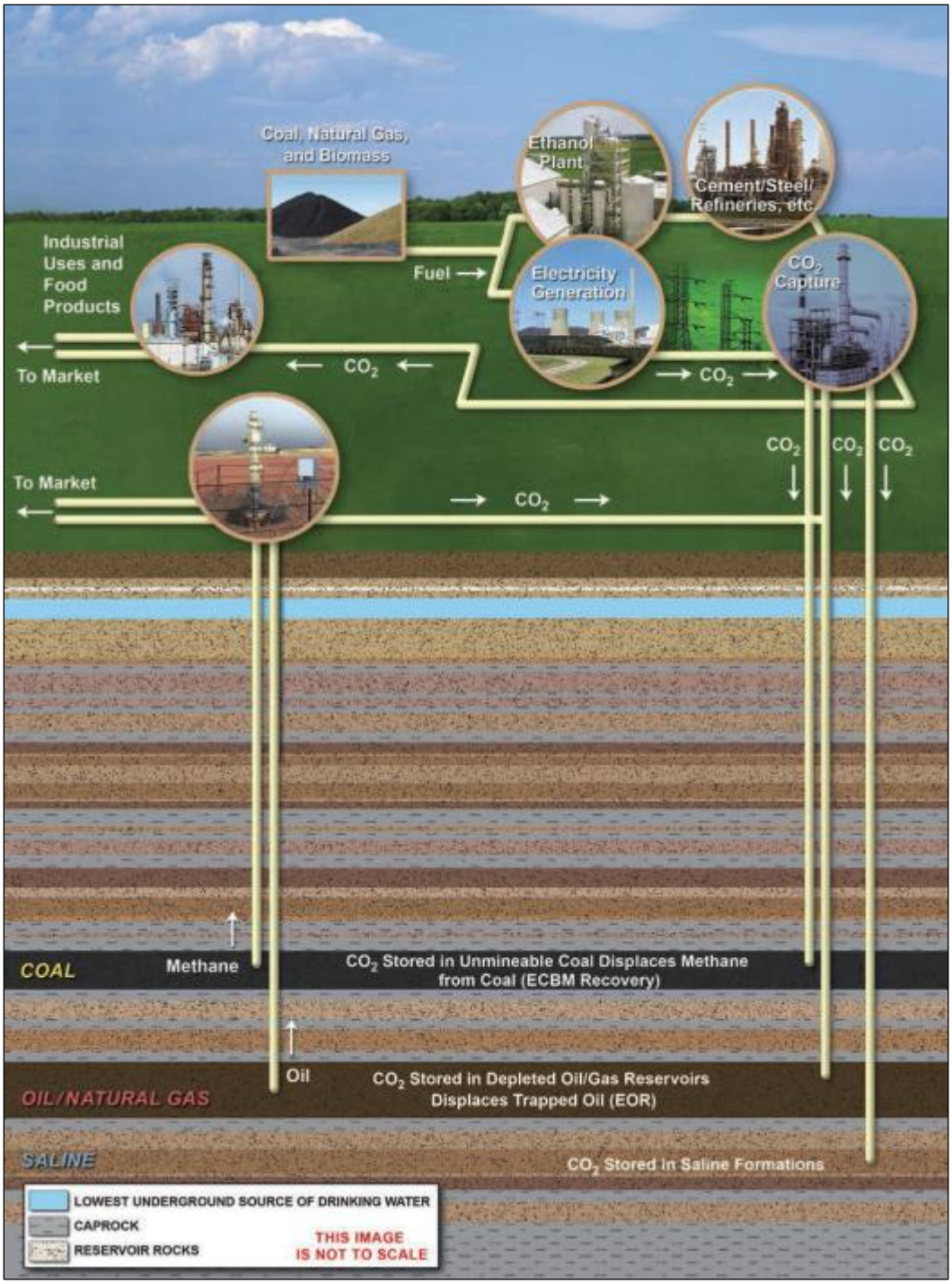
[12] In addition to geologic sequestration in underground reservoirs, R&D is underway on technologies for ocean sequestration, where CO_2 is injected directly into deep waters or below the seabed, and mineral carbonation, a process where CO_2 is converted into solid inorganic carbonates through chemical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

[13] IPCC, *Carbon Dioxide Capture and Storage*, p. 14.

[14] NETL, *Carbon Utilization and Storage Atlas*, 5th ed., 2015, pp. 18-20.

[15] U.S. Energy Information Agency, "Frequently Asked Questions," https://www.eia.gov/tools/faqs/faq.php?id=75&t=11. *Energy-related emissions* refers to emissions from the coal, natural gas, petroleum, and electricity sectors.

Figure 1. The CCS Process



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.

EOR

Use of wells to inject CO_2 builds on known processes. Much of the technology is adopted from well-established experience in the oil and gas industry, which as of 2014, injected approximately 68 million tons of CO_2 underground each year in a process known as EOR.[16] Enhanced recovery is also used occasionally in natural gas development. EOR can significantly increase the amount of oil or gas produced from a reservoir.[17] CO_2 is the most common injection agent used in EOR projects.

CO_2 injected for EOR most commonly comes from natural sources, such as underground CO_2 reservoirs, but some is also 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, CO_2 is gradually stored in the reservoir. NETL reports that generally, between 30% and 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, 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] Some analysts project that the federal tax credit for carbon storage 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.[22]

Federal Research and Development for Underground Carbon Storage

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

DOE leads the federal government's underground carbon storage R&D as part of the agency's fossil energy programs. DOE's work includes conducting fundamental laboratory research on wells, storage design, geologic settings, and monitoring and assessment of the injected CO_2. In

[16] 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.

[17] NETL, "Enhanced Oil Recovery," https://netl.doe.gov/oil-gas/oil-recovery.

[18] EPA, "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, https://www.netl.doe.gov/projects/files/CO2LeakageDuringEOROperationsAnalogStudiestoGeologicStorageofCO2_013019.pdf.

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

[21] International Energy Agency, "Commentary: Whatever Happened to Enhanced Oil Recovery," November 28, 2018 (embedded dataset).

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

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. The RCSP program supports these R&D projects, which include carbon storage through geologic sequestration and EOR, through partnerships with the petroleum and chemical industries and public and private research institutions.

Congress has supported DOE's carbon storage work through appropriations and, beginning in 2005, through enacting legislation directing DOE to establish programs in this area. The Energy Policy Act of 2005 (EPAct, P.L. 109-58), Section 963, directed DOE to carry out a 10-year carbon capture R&D program to develop technologies for use in new and existing coal combustion facilities.[23] 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 continue R&D work through carbon sequestration partnerships.[24] EPAct Section 354 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 sequestration R&D and demonstration. 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.[25] Subtitle A 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.[26] Subtitle B directed DOE to conduct a national assessment for onshore capacity for CO_2 sequestration.[27]

To date in the United States, nine DOE-supported projects have injected large volumes of CO_2 into underground formations as part of CCS systems or related EOR R&D projects (see **Appendix B**). Three of these active projects involve injection into saline formations for geologic sequestration (for demonstration purposes), five involve injection for EOR purposes, and one involves both sequestration and EOR. Four of these projects are currently injecting and/or storing CO_2.[28] The Petra Nova facility in Texas is the first operating industrial-scale coal-fired electricity generating plant with a CCS system in the United States. The captured CO_2 is transported by pipeline to an oil field where it is injected for EOR. The project is jointly owned by several energy companies and was partially funded by DOE. In Decatur, IL, ADM is injecting CO_2 from its ethanol production plant into an onsite sandstone formation for geologic sequestration.[29] 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. Each of these projects received funds from the American Recovery and Reinvestment Act (ARRA, P.L. 111-5). The Michigan Basin Project in Otsego County, MI, is injecting CO_2 from a natural gas facility for EOR. DOE provides partial funding for this project through the RCSP program. All of the projects operate through collaborations among DOE, industry, and local research institutions.

[23] EPAct §963; 42 U.S.C. §16293.

[24] EPAct §963; 42 U.S.C. §16293.

[25] EISA §§702-705; 42 U.S.C. §§17001-17253.

[26] EISA §702(a)(2)(C); 42 U.S.C. §17001.

[27] EISA §711; 42 U.S.C. §17271.

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

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

Five other projects that injected CO_2 were implemented through the RCSP program.[30] The projects included sequestration into various underground formations and storage associated with EOR with volumes of CO_2 injected and stored ranging from a few hundred tons to over 1 million tons (considered commercial-scale).[31] The RCSP program is currently in the development phase, which DOE defines as large-scale field testing of high volumes of CO_2 storage.[32] These projects have completed injection and are now in the post-injection monitoring phase.[33] All of the existing RCSP projects are scheduled to end by July 2022, but DOE is in the process of selecting additional projects for the program.[34] In the United States, while numerous large-scale storage R&D projects are ongoing, none of the projects injecting CO_2 solely for geologic sequestration are operating in a commercial capacity.

Worldwide, public-private partnerships have implemented several CO_2 geologic sequestration projects in diverse regions. There are two active projects, both in Norway, where facilities at the Sleipner Gas Field in the North Sea and Snohvit in the Barents Sea conduct offshore sequestration under the Norwegian continental shelf.[35] Chevron's Gorgon Injection Project, a natural gas production facility in Australia, plans to begin sequestering CO_2 in 2020 and store a total of 100 million tons of CO_2.[36] Canada, Japan and Algeria have carried out smaller-scale CCS projects with sequestration in saline reservoirs.

Federal Framework for Regulating Geologic Sequestration of CO_2 and EOR

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.

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

[30] 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.

[31] NETL, *Carbon Utilization and Storage Atlas*, p. 4.

[32] A seventh project never reached the injection stage due to technical challenges.

[33] Based on CRS discussions with DOE, 2019.

[34] Based on CRS discussions with DOE, 2019.

[35] IPCC, *Carbon Dioxide Capture and Storage*, p. 201.

[36] Chevron, "Fact Sheet: Gorgon Carbon Dioxide Injection Project," https://australia.chevron.com/-/media/australia/publications/documents/gorgon-co2-injection-project.pdf.

permit or rule.[37] The statute defines *underground injection* as "the subsurface emplacement of fluids by well injection."[38]

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.[39]

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.[40] 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 follow the permitting requirements and standards established by the UIC program authorities in their states.

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.[41] 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.[42]

[37] 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.

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

[39] SDWA §1421; 42 U.S.C. §300h.

[40] 40 C.F.R. §§144-147.

[41] 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 USDWs from underground injection.

[42] SDWA §1422.

UIC Well Classes

Under SDWA authority, EPA has established six classes of underground injection wells based on similarity in the fluids injected.[43] 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).[44] 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

Class	Estimated Number of Permitted Wells	Percentage of Total Wells	Type of Fluid Injected
Class I	781	0.11%	Injection of hazardous and non-hazardous wastes into deep, isolated rock formations
Class II	177,763	24.22%	Injection of fluids associated with oil and natural gas production (including injection of CO_2 for enhanced recovery and produced water disposal)
Class III	26,714	3.64%	Injection of fluids for solution mining (e.g., extracting uranium or salt)
Class IV	103	0.01%	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	528,300	72.00%	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 (both wells at one site)
TOTAL	**733,663**		

Sources: 40 C.F.R. §144.6; EPA, *FY18 State UIC Injection Well Inventory*.

Note: This table does not include tribal wells, which include Class I, Class II, and Class V wells (totaling 6,528 wells, according to EPA's *FY18 Tribal UIC Injection Well Inventory*).

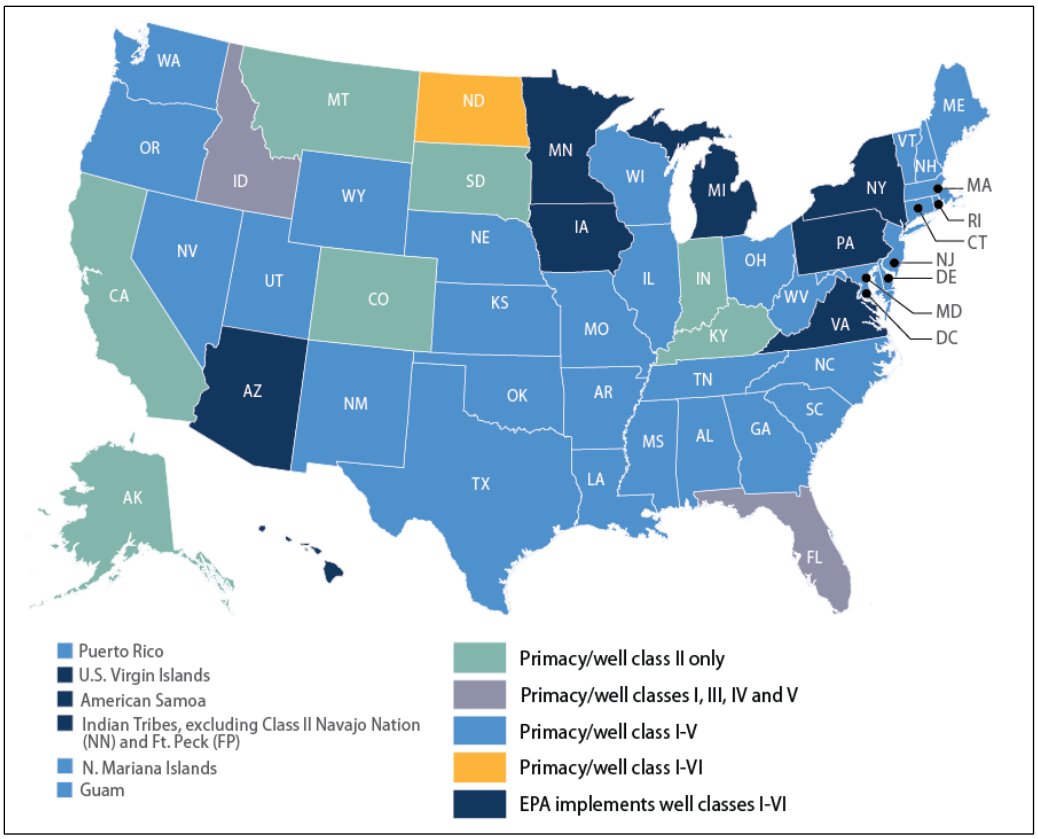
[43] *Injection well* means a well into which "fluids" are being injected (40 C.F.R. §144.6). EPA UIC regulations are codified at 40 C.F.R. §§144-148.

[44] EPA, "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.

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 one state, North Dakota. 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.[45] For Class VI, EPA has direct implementation authority in 49 states and for all territories. For Classes I, III, IV and V only, the agency has delegated primacy for two states.[46] EPA shares UIC implementation responsibility with seven states and two Indian tribes and implements the UIC program for all classes in eight states.

Additional states are pursuing Class VI primacy: EPA is reviewing Wyoming's application for Class VI primacy, and Louisiana is in a pre-application phase. 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.

Figure 2. State UIC Primacy Map



Source: CRS, from EPA, https://www.epa.gov/uic/primary-enforcement-authority-underground-injection-control-program.

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

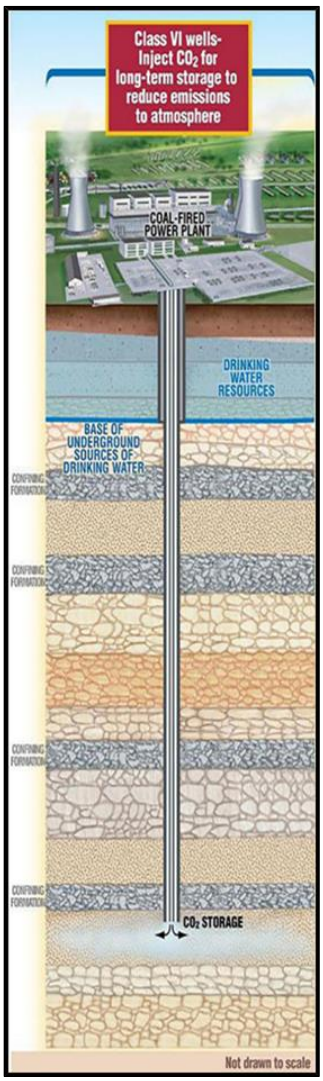
[45] States may request primacy for Class II oil- and gas-related injection operations programs under SDWA Section 1422 or Section 1425 (see "Class II Oil and Gas Related Wells" in this report).

[46] 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.

Class VI Geologic Sequestration Wells

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

Figure 3. Conceptual Class VI Well Diagram



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.[47]

Two Class VI wells, both in Illinois, are currently permitted 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. 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.[48] No state has issued a permit for a Class VI well. EPA requires that state primacy for Class VI wells would be implemented under SDWA Section 1422.

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 VI rule, EPA noted that "tailored requirements, modeled on the existing UIC regulatory framework, are necessary to manage the unique nature of CO_2 injection for geologic sequestration."[49] 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;

[47] EPA, "Final Rule," p. 77245.

[48] 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.

[49] EPA, "Final Rule," p. 77233.

- 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.[51]

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."[52] 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 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.

Human Health and Environmental Considerations of CO_2 and 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.[50]

Class II Oil and Gas Related Wells

Class II wells are used to inject fluids associated with oil and gas production, including wells injecting CO_2 for EOR. EOR wells are the most common type of Class II wells. As of 2018, there were approximately 178,000 permitted Class II wells, approximately 135,600 (76%) of which were recovery wells.[53] Most of these wells are located in California, Texas, Kansas, Illinois, and

[50] EPA, "Proposed Rule," p. 43497; IPCC, *Carbon Dioxide Capture and Storage*, pp. 245-250; and *Report of the Interagency Task Force on Carbon Capture and Storage*, August 2010, pp. 246-250.

[51] EPA, "Final Rule," p. 77234.

[52] 40 C.F.R. §146.81.

[53] EPA, *FY18 State UIC Injection Well Inventory*.

Oklahoma. 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 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.[54] EPA regulations under Section 1421 specify requirements for siting, construction, operation, monitoring and testing, closure, corrective action, financial responsibility, and reporting and recordkeeping.[55] 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 that prevents underground injection that endangers drinking water sources.[56] To receive approval under Section 1425's optional demonstration provisions, a state program must include permitting, inspection, monitoring, and recordkeeping 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.[57] For the 10 states without Class II primacy, the District of Columbia, and most tribes, EPA directly implements the Class II program, and federal regulations apply.[58]

While both Class II and Class VI wells involve injection of CO_2 into underground reservoirs, the purposes and regulations of these two classes are different. Class II 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 sequestration in Class VI wells generally involves higher injection pressures, larger expected fluid volumes, and different physical and chemical properties of the injection stream compared to Class II 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.[59] 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.[60] Class II wells can be granted a permit or authorized by rule by either a primacy state or EPA, while Class VI wells

[54] SDWA §1422.

[55] SDWA §1421.

[56] 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 USDWs (SDWA §1425 (a)).

[57] EPA, *FY18 State UIC Injection Well Inventory*.

[58] 40 C.F.R. §142.

[59] 40 C.F.R. §§144 and 146.

[60] 40 C.F.R. §§144 and 146.

cannot be authorized by rule.[61] See **Appendix C** for more information on EPA Class II well requirements.

Transition of Wells from Class II to Class VI Wells

Class II 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."[62] 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.[63] 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).[64] Such federally permitted releases would also be exempt from emergency notification requirements of the Emergency Planning and Community Right-to-Know Act (EPCRA).[65]

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.[66] As a result, when

[61] SDWA §1422.

[62] 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.

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

[64] 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 *federally permitted release* to include underground injection of fluids authorized under the SDWA, including permits issued by states with authorities delegated under that statute. For a discussion of liability and response 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.

[65] 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.

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

geologically sequestered 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

The Greenhouse Gas Reporting Program (GHGRP) established by EPA under the authority of the Clean Air Act, requires certain sources of GHGs to report emissions data.[67] In 2010, EPA promulgated a rule to include injection and geologic sequestration of CO_2 in the GHGRP. In this rule, the agency determined 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.[68] 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 plan.[69] The purpose of this plan is to verify the amount of CO_2 sequestered and collect data on any CO_2 surface emissions from geologic sequestration facilities.[70] Any facility holding a Class VI permit would be subject to Subpart RR and be 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.[71] Facilities must also report the mass of CO_2 sequestered in subsurface geologic formations.[72]

Subpart UU of the rule applies to Class II wells—for the injection of CO_2 for EOR and for small and experimental sequestration projects exempted under Subpart RR. Subpart UU does not require a monitoring, reporting, and verification plan and sets forth different requirements for monitoring and reporting.[73]

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 and approach. Congress may also wish to consider other issues that may have implications for

[67] The Consolidated Appropriations Act, 2008 (P.L. 110-161), authorized 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." EPA promulgated the GHGRP under the authority in Clean Air Act Section 114.

[68] EPA, "Mandatory Reporting of Greenhouse Gases: Injection and Geologic Sequestration of Carbon Dioxide; Final Rule."

[69] 40 C.F.R. §98, Subpart RR.

[70] EPA, "Final Rule," p. 77236.

[71] 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).

[72] 40 C.F.R. §98, Subpart RR.

[73] 40 C.F.R. §98, Subpart UU.

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.

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]."[74] 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.[75]

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 the 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."[76]

Potential Environmental Risks of 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, and others have recognized that CO_2 injection and sequestration activities may convey risks to the environment and human health.[77] Some of these risks involve potential endangerment of USDWs that would be covered 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.[78] Injected CO_2 could also force brine from the target formation into USDWs, which could affect drinking water.[79] To address potential releases or leakage that could endanger

[74] EPA, "Proposed Rule," p. 43495.

[75] EPA, "Proposed Rule," p. 43495.

[76] EPA, "Final Rule," p. 77279.

[77] In its 2010 report, the Task Force 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." (*Report of the Interagency Task Force*, p. 106). 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).

[78] EPA, "Final Rule," p. 77244. Most CO_2-EOR is regulated by states under SDWA Section 1425 rather than regulated directly by EPA.

[79] IPCC, *Carbon Dioxide Capture and Storage*, p. 248.

USDWs, in the Class VI rule, EPA included monitoring, reporting, and recordkeeping requirements specific to CO_2 injection.[80] Class VI construction and testing requirements, which are generally more stringent than Class II requirements for EOR, are also intended to prevent USDW endangerment.[81]

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.[82] 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."[83] The Task Force also stated that an accidental large release could result in risks to surface water, local ecology, and human health.[84] (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.[85] 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.[86]

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.[87] 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."[88] According to the report, "Despite over 40 years of operating CO_2 EOR projects, leakage events have rarely been reported,"[89] although the authors also note that "there has been no official mechanism for reporting leaks of CO_2 until recently."[90] 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.[91]

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[80] 40 C.F.R. §146.90 and §146.91.

[81] 40 C.F.R. §146.86-§146.90.

[82] EPA, "Proposed Rule," p. 43497.

[83] *Report of the Interagency Task Force*, p. 106.

[84] *Report of the Interagency Task Force*, 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, *Carbon Dioxide Capture and Storage*, p. 247).

[85] 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.

[86] EPA, "Proposed Rule," p. 43498.

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

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

[89] NETL, *CO_2 Leakage During EOR Operations*, p. 104.

[90] NETL, *CO_2 Leakage During EOR Operations*, p. 110.

[91] CCSReg Project 2009, p. 83.

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.[92] In its report, the Task Force also identified that "the existing Federal 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.[93] Specific policy questions regarding property rights include who owns and controls the subsurface formations (known as the pore space) targeted for CO_2 sequestration, 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.[94]

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.[95] Large-scale commercial geologic sequestration projects would likely require unique 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 sequestration 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 and Development

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."[96] 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 technical issues 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

[92] EPA, "Proposed Rule," p. 43495; and EPA, "Final Rule," p. 77272.

[93] *Report of the Interagency Task Force,* pp. 109.

[94] CCSReg Project, p. 95, and *Report of the Interagency Task Force,* p. 71.

[95] *Report of the Interagency Task Force,* p. 68; and CCSReg Project, p. 58.

[96] EPA, "Proposed Rule," p. 43496.

injection streams.[97] 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.[98]

Congress has directly supported federal activities in both geologic sequestration of CO_2 and EOR through the EPAct in 2005 and EISA in 2007, directing DOE to carry out R&D activities to further technical knowledge and deployment of CCS.[99] Several bills in the 116th Congress—including H.R. 1166/S. 383, H.R. 3607, and S. 1201—would continue or expand DOE's CCS programs, including carbon storage programs. Some of these bills would direct EPA to conduct CCS research and/or direct DOE to develop and implement R&D programs related to geologic sequestration methods, storage siting, and assessment of potential impacts. Provisions in some of these bills would also direct DOE to continue its partnership programs for large-scale sequestration demonstration projects. Other relevant provisions include provisions that would require actions from the Council on Environmental Quality, such as publishing guidance and submitting reports to Congress on CCS research and development.

Project Cost

The cost of constructing and operating a new CCS system or retrofitting an existing facility, such as a coal-fired 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 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.[100]

Analysts expect that the costs of CCS, whether new system or retrofitting of an existing facility, are likely to total several billion dollars per project, which could act as a barrier to future CCS deployment without the continuation of subsidies.[101] Recently, Public Service Company of New Mexico reportedly estimated that retrofitting a 500-megawatt coal-fired power plant with CCS technology could cost between $5 billion and $6 billion.[102] The company reportedly stated that its evaluations showed that it would be more cost effective to switch to another source of energy (such as renewable energy) rather than continue to use coal with the addition of CCS.

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

[97] *Report of the Interagency Task Force,* pp. C-5–C-9.

[98] *Report of the Interagency Task Force,* p. 48.

[99] See EPAct §§354 and 963 and EISA §702.

[100] EPA, "Final Rule," p. 77279. EPA's cost estimates apply to injection activities only and do not include capture and transport of CO_2.

[101] See IPCC, *Carbon Dioxide Capture and Storage*, 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.

[102] Edward Klump, "CCS at Coal Plant Could Add $1.3B-Utility," *Energywire*, November 26, 2019.

CCS are still not fully understood, particularly from a fully integrated (capture, transportation, and storage) perspective."[103] 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.[104] The variations in the geology of storage formations also make predicting future geologic sequestration costs particularly difficult.

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 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.[105]

Federal tax credits for carbon storage, 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."[106] EPA also stated that "the agency expects that there will be higher levels of public interest in GS projects than for other injection activities."[107] 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.[108]

At least two cases involving Class VI permits have come before EPA's Environmental Appeals Board.[109] 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

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

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

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

[106] EPA, "Proposed Rule," p. 43523.

[107] EPA, "Final Rule," p. 77273.

[108] EPA, "Final Rule," p. 77273.

[109] 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).

quality, groundwater quality, and protection of endangered species. Local landowners claimed that the permits do 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.[110]

Continued Use of Fossil Fuels

In the EPAct in 2005 and EISA in 2007, Congress recognized connections between geologic sequestration of CO_2 and the continued use of fossil fuel as a major source of electricity in the United States. 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."[111] 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."[112]

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.[113] 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.[114]

In contrast, other stakeholders have argued that CO_2 sequestration could create a disincentive to reduce fossil-fuel-based power plant emissions or shift to renewable energy sources.[115] 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.[116] 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 sequestration.

Carbon Storage Tax Credits

Federal tax credits for carbon storage were first enacted in 2008 by the Energy Improvement and Extension Act (P.L. 110-343). This act added Section 45Q to the Internal Revenue Code, which

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

[111] NETL, *Carbon Utilization and Storage Atlas*, p. 9.

[112] EPA, "Proposed Rule," p. 43498.

[113] Negative carbon technology is a type of negative emission, which is defined by the IPCC 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)

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

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

[116] Conniff, "Why Green Groups Are Split on Subsidizing Carbon Capture Technology."

established tax credits for CO_2 storage through both EOR and geologic sequestration.[117] For EOR, only the CO_2 that is used as tertiary injectant and remains in the reservoir qualifies for the tax credit. CO_2 recaptured or recycled does not qualify.[118] The Bipartisan Budget Act of 2018 (BBA) amended Section 45Q to increase the amount of these tax credits from $22.66 to $50 per ton over time for sequestered CO_2 and from $12.83 to $35 per ton over time for CO_2 used in EOR.[119] The BBA also removed a 75-million-ton cap on total qualified CO_2 captured or injected but required the relevant taxpayer to claim the credit over a 12-year period after operations begin. Additionally, eligible facilities must be operating or must begin construction before 2024. The U.S. Department of the Treasury is currently considering comments on proposed implementing regulations for the BBA tax credit provision and has not released a final rule. In response to the 2019 Internal Revenue Service notice requesting comments on carbon credits for future regulations and guidance, some oil and gas industry commenters expressed concerns with Treasury's proposed approach to measuring "secure geological storage" and other requirements, which they assert would impact their ability to plan and invest in CCS projects.[120]

In the meantime, the tax credit as authorized in the BBA is available to qualified entities. Treasury estimates that in FY2019, the credit will reduce federal income tax revenue by $70 million.[121] Over the FY2020-FY2029 budget window, Treasury estimates that the tax credit will reduce federal income tax revenue by a total of $2.3 billion.[122] As of May 2019, the amount of stored carbon oxide[123] claimed for 45Q credits since 2011 totaled 62,740,171 tons.[124]

In legislation pending in the 116th Congress, H.R. 5156 would extend the deadline for the start of construction of a qualified facility to January 1, 2025. S. 2263 would revise the requirements for the secure geologic storage of carbon oxide for EOR and sequestration.

Recent CCS Legislation

Table 2, below, lists legislation introduced in the 116th Congress that includes provisions relating to geologic sequestration of CO_2 (as of date of report publication). Legislation in the 116th Congress has focused on research and development of CCS, including carbon storage through EOR and geologic sequestration, and adjustments to the 45Q carbon storage tax credit.

[117] 26 U.S.C §45Q.

[118] Internal Revenue Service Notice 2009-83, "Credit for Carbon Dioxide Sequestration Under Section 45Q," November 2, 2009, p. 588. This notice set forth interim guidance, pending the issuance of regulations, for 45Q tax credits, including guidance on measuring the amount of qualified CO_2 (presumed to be the difference of the amount measured at capture and the amount verified at disposal or injection).

[119] P.L. 115-123, §41119.

[120] Comments of the Energy Advance Center on IRS Notice 2019-32—Credit for Carbon Oxide Sequestration, July 3, 2019. Section 45Q (f)(2) specifies that DOE, in consultation with other agencies, "shall establish regulations for determining adequate security measures for the geological storage of qualified carbon oxide" (26 C.F.R. 45(Q)(f)(2).

[121] U.S. Department of the Treasury, "Tax Expenditures," https://home.treasury.gov/policy-issues/tax-policy/tax-expenditures.

[122] U.S. Department of the Treasury, "Tax Expenditures."

[123] Carbon oxide refers to any of the three oxides of carbon: carbon dioxide, carbon monoxide, and carbon suboxide.

[124] Internal Revenue Service Notice 2019-31, "Credit for Carbon Dioxide Sequestration 2019 45Q Inflation Adjustment Factor," May 13, 2019, p. 1182. This applies to tax credits for geologic sequestration and EOR.

Table 2. Carbon Sequestration Related Legislation in the 116th Congress

Bill Number	Short Title	Major Carbon Sequestration Related Provision
H.R. 1166	USE IT Act	Would amend the Clean Air Act by directing EPA to conduct certain carbon capture research activities. Would require DOE to submit a report to Congress on the potential risks and benefits to project developers associated with increased storage of CO_2 in deep saline formations and recommendations for federal policy changes to mitigate identified risks. Would direct the Council on Environmental Quality (CEQ) to prepare a report including information on permitting and review of CCS projects and issue guidance on development of CO_2 pipelines and storage projects.
H.R. 3607	Fossil Energy Research and Development Act of 2019	Would amend the Energy Policy Act of 2005 to direct DOE to carry out a program of R&D and demonstration for CCS. Would direct DOE to conduct large-scale carbon sequestration partnerships through RCSP.
H.R. 5156	Carbon Capture and Sequestration Extension Act of 2019	Would amend Section 45Q of the Internal Revenue Code to extend the deadline for the start of construction of a qualified facility to January 1, 2025.
S. 383	USE IT Act	Would amend the Clean Air Act by directing EPA to conduct certain carbon capture research activities. Would require DOE to report to Congress on the potential risks and benefits to project developers associated with increased storage of CO_2 in deep saline formations and recommendations for federal policy changes to mitigate identified risks. Would direct CEQ to prepare a report including information on permitting and review of CCS projects and issue guidance on development of CO_2 pipelines and storage projects.
S. 1201	EFFECT Act	Would amend the Energy Policy Act of 2005 to direct DOE to carry out CCS research and development programs. Program requirements would include conducting research to support sites for large volume storage of CO_2 and accompanying infrastructure and continuation of a demonstration program for large-scale carbon storage validation and testing. Would require DOE to submit a report to Congress on CCS activities. Would establish an optional program to transition large-scale carbon sequestration demonstration projects into integrated commercial storage complexes.
S. 1790	National Defense Authorization Act for FY 2020	As passed in the Senate, would amend the Clean Air Act by directing EPA to conduct certain carbon capture research activities. Would require DOE to report to Congress on the potential risks and benefits to project developers associated with increased storage of CO_2 in deep saline formations and recommendations for federal policy changes to mitigate identified risks. Would direct CEQ to prepare a report including information on permitting and review of CCS projects and issue guidance on development of CO_2 pipelines and storage projects. These provisions were not included in the final version of the legislation (P.L. 116-92.)
S. 2302	America's Transportation Infrastructure Act	Would amend the Clean Air Act by directing EPA to conduct certain carbon capture research activities. Would require DOE to report to Congress on the potential risks and benefits to project developers associated with increased storage of CO_2 in deep saline formations and recommendations for federal policy changes to mitigate identified risks. Would direct CEQ to prepare a report including information on permitting and review of CCS projects and issue guidance on development of CO_2 pipelines and storage projects.

Bill Number	Short Title	Major Carbon Sequestration Related Provision
S. 2263	CO_2 Regulatory Certainty Act	Would amend the Internal Revenue Code, Section 45Q, to revise the requirements for the secure geologic storage of carbon oxide for the purpose of the tax credits for sequestration and enhanced oil recovery. Would require the Treasury Department to establish regulations setting out these requirements, including compliance with federal environmental statutes and regulations and other measures to prevent carbon oxide from escaping into the atmosphere.

Sources: Congress.gov and CRS analysis.

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: NETL, *Carbon Utilization and Storage Atlas*, 5th ed., August 20, 2015, 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. 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

Project	CO_2 Source	Type	Injection Status	Volume Injected (in tons)	Funding Source and Amount
Illinois Industrial Carbon Capture and Storage Project (ADM Facility) Decatur, IL	Ethanol fermentation plant	Saline storage	Active injection and sequestration	1.3 million	ARRA $141,405,945 (funding includes Illinois Basin Project)[a]
Air Products Project Port Arthur, TX	Steam methane reformers	EOR	Active injection	5 million	ARRA $284,000,000[b]
Michigan Basin Project Otsego County, MI	Natural gas processing plant	EOR	Active injection	1.5 million	RCSP $1,019.414[c]
Petra Nova Plant Thompsons, TX	Coal-fired power plant	EOR	Active injection	1.4 million per year	ARRA $167,000,000 and FY2016 Consolidated Appropriations Act $23,000,000 ($190,000,000 total)[d]
Citronelle Project Citronelle, AL	Coal-fired power plant	Saline storage	Completed Sept. 2014; post-injection monitoring	110,000	RCSP $76,981.260[e]
Illinois Basin Decatur Project (ADM Facility) Decatur, IL	Ethanol fermentation plant	Saline storage	Completed Nov. 2014; post-injection monitoring	1 million	RCSP $141,405,945 (funding includes Illinois Industrial Project)[f]
Cranfield Project Natchez, MS	Natural	EOR with saline storage	Completed Jan. 2015; post-injection monitoring	4.7 million	RCSP $76,981.260[g]

Project	CO_2 Source	Type	Injection Status	Volume Injected (in tons)	Funding Source and Amount
Bell Creek Field Project Crook County, WY	Natural gas processing plants	EOR	Completed; post-injection monitoring	3 million	RCSP $95,453,751[h]
Farnsworth Unit Ochitree County, TX	Ethanol and fertilizer production plants	EOR	Completed; post-injection monitoring	800,000	RCSP $65,618,315[i]
Kevin Dome Project Toole County, MT	None	Saline storage	Project suspended	No injection	RCSP $67,000,000[j]

Sources: For project, CO_2 source, type, injection status, and volume injected: DOE, *Carbon Utilization and Storage Atlas 2015*, based on CRS discussions with Mark Ackiewicz, Director of Carbon Capture and Storage Research and Development, DOE, September 26, 2019; NETL, "Petra Nova Parish Holdings," 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," https://www.netl.doe.gov/project-information?p=FE0001547.

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

a. NETL, "Recovery Act: CO_2 Capture from Biofuels Projection and Sequestration into the Mt. Simon Sandstone Reservoir," 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," https://www.netl.doe.gov/sites/default/files/netl-file/2012-10-18-PCC-Presentation-APCI—Zinn-Rev1.pdf.

c. NETL, "Northern Michigan Basin CarbonSAFE Integrated Pre-Feasibility Project," https://www.netl.doe.gov/project-information?p=FE0029276.

d. NETL, "Petra Nov—W.A. Parish Project," https://www.energy.gov/fe/petra-nova-wa-parish-project.

e. SECARB, "Phase III Anthropogenic CO_2 Injection Field Test," http://www.secarbon.org/files/anthropogenic-test.pdf.

f. NETL, "Recovery Act: CO_2 Capture from Biofuels Projection and Sequestration into the Mt. Simon Sandstone Reservoir," https://www.netl.doe.gov/project-information?p=FE0001547.

g. SECARB, "Phase III Early CO_2 Injection Field Test at Cranfield," http://www.secarbon.org/files/early-test.pdf.

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

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

j. Big Sky Sequestration Partnership, "Kevin Dome Storage Project Fact Sheet," 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 a determination that, if seismic sources are identified, the seismicity would not interfere with containment.
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 that 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 assurances 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. The financial responsibility instrument(s) must be sufficient to address endangerment of underground sources of drinking water.
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. Monitoring of the CO_2 stream, the CO_2 plume, and pressure front both during injection and for a period following injection.[b] Monitor 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. 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	Annually. Retain records of all monitoring information. Reporting of noncompliance which may endanger health or the environment.	Semi-Annually. 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 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.

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

Notes:

a. States with primacy (program oversight and enforcement authority) for Class II wells under SDWA Section 1425 regulate these wells under their own state programs rather than the EPA regulations discussed here. State programs may vary.

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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