THE CHIEF FINANCIAL OFFICER
WASHINGTON, D.C. 20460

December 3, 2024

The Honorable Mike Simpson
Chair, Subcommittee on Interior,
Environment, and Related Agencies
Committee on Appropriations
House of Representatives
Washington, D.C. 20515

The Honorable Chellie Pingree
Ranking Member, Subcommittee on Interior,
Environment, and Related Agencies
Committee on Appropriations
House of Representatives
Washington, D.C. 20515

The Honorable Jeff Merkley
Chair, Subcommittee on Interior,
Environment, and Related Agencies
Committee on Appropriations
United States Senate
Washington, D.C. 20510

The Honorable Lisa Murkowski
Ranking Member, Subcommittee on Interior,
Environment, and Related Agencies
Committee on Appropriations
United States Senate
Washington, D.C. 20510

Dear Chairman, Chair, and Ranking Members:

Enclosed please find the U.S. Environmental Protection Agency's Fiscal Year 2022 Report to Congress, in consultation with the Bureau of Ocean Energy Management, on the Class VI Program's Relevance to Outer Continental Shelf Carbon Capture Projects. The Joint Explanatory Statement accompanying the *Consolidated Appropriations Act, 2022* (Public Law 117-103) instructed the EPA to follow the guidance in House Report 117-83:

> The Committee understands there is strong interest in carbon capture and storage projects that permanently sequester carbon dioxide in geologic formations instead of releasing this pollutant into the air. The Committee provides not less than $4,000,000 for the Agency's work, within the Underground Injection Control program, related to Class VI wells for geologic sequestration to help develop expertise and capacity at the Agency. These funds should be used by the Agency to expeditiously review and process Class VI primacy applications from States and Tribes and to directly implement the regulation as quickly as possible, where States have not yet obtained primacy by working directly with permit applicants. The Committee also directs the Agency, in consultation with the Bureau of Ocean Energy Management, to provide an assessment,

within 180 days of enactment of this Act, of Class VI program's relevance to Outer Continental Shelf {OCS} carbon capture projects.

This report focuses on the coordination and communication efforts with the BOEM, Bureau of Safety and Environmental Enforcement, other federal agencies, foreign countries, and other stakeholders, discussing carbon capture, utilization, and sequestration assessments. Additionally, the report highlights the agency's efforts to adhere to the UIC requirements that govern a Class VI project from permitting and siting through injection, post-injection, and site closure. Finally, the report also briefly describes environmental benefits, potential advantages and disadvantages of storing CO_2, an assessment of carbon storage potential, and the selection of sites with the *Infrastructure Investment and Jobs Act, 2021* (P.L. 117-58), BOEM, and BSEE.

If you have further questions or would like to set up a meeting to discuss this report, please contact Ed Walsh at 202-564-4594 or Walsh.Ed@epa.gov.

Sincerely,

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Enclosure

EPA Class VI Underground Injection Control (UIC) Program Relevance to Outer Continental Shelf Carbon Sequestration Projects Under Department of Interior Authority

Contents

Abbreviations List

AOR: Area of Review
BIL: Bipartisan Infrastructure Law
BOEM: Bureau of Ocean Energy Management
BSEE: Bureau of Safety and Environmental Enforcement
CCS: Carbon Capture and Storage
CDR: Carbon Dioxide Removal
CO_2: Carbon Dioxide
DOE: Department of Energy
DOI: Department of the Interior
EPA: Environmental Protection Agency
GHGRP: Greenhouse Gas Reporting Program
GS: Geologic Sequestration
IIJA: Infrastructure Investment and Jobs Act
IPCC: Intergovernmental Panel on Climate Change
IRA: Inflation Reduction Act
MPRSA: Marine Protection, Research, and Sanctuaries Act
MRV: Monitoring, Reporting, and Verification
OCS: Outer Continental Shelf
OCSLA: Outer Continental Shelf Lands Act
PISC: Post-injection Site Care
SDWA: Safe Drinking Water Act
TDS: Total Dissolved Solids
UIC: Underground Injection Control
USDW: Underground Sources of Drinking Water
USGS: United States Geological Survey

Introduction

Background

Climate change may be one of the most urgent and complex issues facing the United States and the world at large. The negative impacts that communities across the country are already facing are only expected to worsen in the absence of significant action. Federal agencies and international partners have identified an array of potential mitigation measures, and in the last several years, they have been implementing comprehensive strategies, policies, and legislation to facilitate and incentivize greater adoption of such measures, including Carbon Capture and Storage (CCS) and Carbon Dioxide Removal (CDR) technologies.

CCS technologies typically operate to capture carbon dioxide (CO_2) from point source emissions or directly from the air and transport, compress, and inject it into deep geologic formations in the earth's subsurface for long-term storage. The process of injection into the subsurface is known as geologic sequestration (GS) (U.S. EPA, 2022). Safe, successful, and widespread deployment of CCS and CDR technologies (e.g., direct air capture and sequestration, bioenergy generation with carbon capture and sequestration), requires effective and efficient permitting and regulatory frameworks (U.S. EPA, 2022).

Achieving Net-Zero Emissions

The Biden Administration's 2021 *Long-Term Strategy of the United States: Pathways to Net-Zero Greenhouse Gas Emissions by 2050* (U.S. Department of State and the U.S. Executive Office of the President, 2021) references GS as one of several processes that can help advance the nation towards the goal of reaching net-zero emissions by 2050. Net-zero emissions by 2050 was identified by the International Energy Agency and Intergovernmental Panel on Climate Change (IPCC) as necessary for limiting global warming rise to 1.5ºC (IEA, 2022a; IPCC, 2018). Achieving this goal may require the cumulative sequestration of 350 billion to one trillion metric tons of CO_2 (CEQ, 2021) and the IPCC has noted that "the technical geological CO_2 storage capacity is estimated to be…more than the CO_2 storage requirements through 2100 to limit global warming to 1.5°C" (IPCC, 2023).

If GS projects are well designed, carefully operated, and properly monitored, they can provide significant environmental benefits (U.S. EPA, 2022). However, the IPCC notes that "global rates of CCS deployment are far below those in modelled pathways limiting global warming to 1.5°C to 2°C. Enabling conditions such as policy instruments, greater public support, and technological innovation could reduce these barriers" (IPCC, 2023).

Since 2021, Congress has provided significant additional funding for the development, deployment, and regulation of CCS technologies, including GS. For example, funding for GS under the Infrastructure Investment and Jobs Act (IIJA), also known as the Bipartisan Infrastructure Law (BIL), includes:

- $50 million for the U.S. Environmental Protection Agency (EPA) to support states, Tribes, and territories in obtaining primary enforcement responsibility, or primacy, for Underground Injection Control (UIC) Class VI wells and implementing Class VI programs under the Safe Drinking Water Act (SDWA). Funding recipients must demonstrate that they are integrating environmental justice and equity considerations into their Class VI programs.
- $25 million to the EPA for the permitting of Class VI wells ($5 million per year for Fiscal Years 2022 through 2026).

- $2.5 billion for the Department of Energy (DOE) to develop "new or expanded commercial large-scale carbon sequestration projects and associated carbon dioxide transport infrastructure" (U.S. DOE, 2021).

Furthermore, the Inflation Reduction Act (IRA) of 2022 enhances the "45Q" tax credit. These enhancements include increasing the per-ton incentives for GS, expanding the definition of qualified facilities, extending the window for projects to begin construction, and other actions that incentivize CCS. The IRA also significantly expands incentives for direct air capture projects and provides additional funding in the form of loan guarantees for carbon management projects (IEA, 2022b; The White House, 2023a).

Report Purpose and Scope

In House Report 117-83, the Committee on Appropriations "directs [the EPA], in consultation with the Bureau of Ocean Energy Management [BOEM], to provide an assessment…of [the] Class VI program's relevance to Outer Continental Shelf (OCS) carbon capture projects." The EPA and BOEM have developed this report in response to this requirement.

The EPA has statutory authority under the SDWA to regulate Class VI injection activities onshore, whereas BOEM and the Bureau of Safety and Environmental Enforcement (BSEE) have statutory authority for activities (including drilling wells) related to minerals, energy production, and carbon sequestration on the OCS under the Outer Continental Shelf Lands Act (OCSLA). Where the EPA's SDWA authority applies, CO_2 injection wells for GS would be considered Class VI wells regulated under the UIC program.

The OCS is defined as all submerged lands lying seaward of state coastal waters that are under U.S. jurisdiction (Figure 1). The UIC Class VI program does not apply to the OCS. The Class VI regulations, however, are specifically designed to prevent the movement of fluids into any unintended zones as part of a CO_2 injection project. As such, some aspects of the Class VI program may be instructive to GS projects on the OCS.

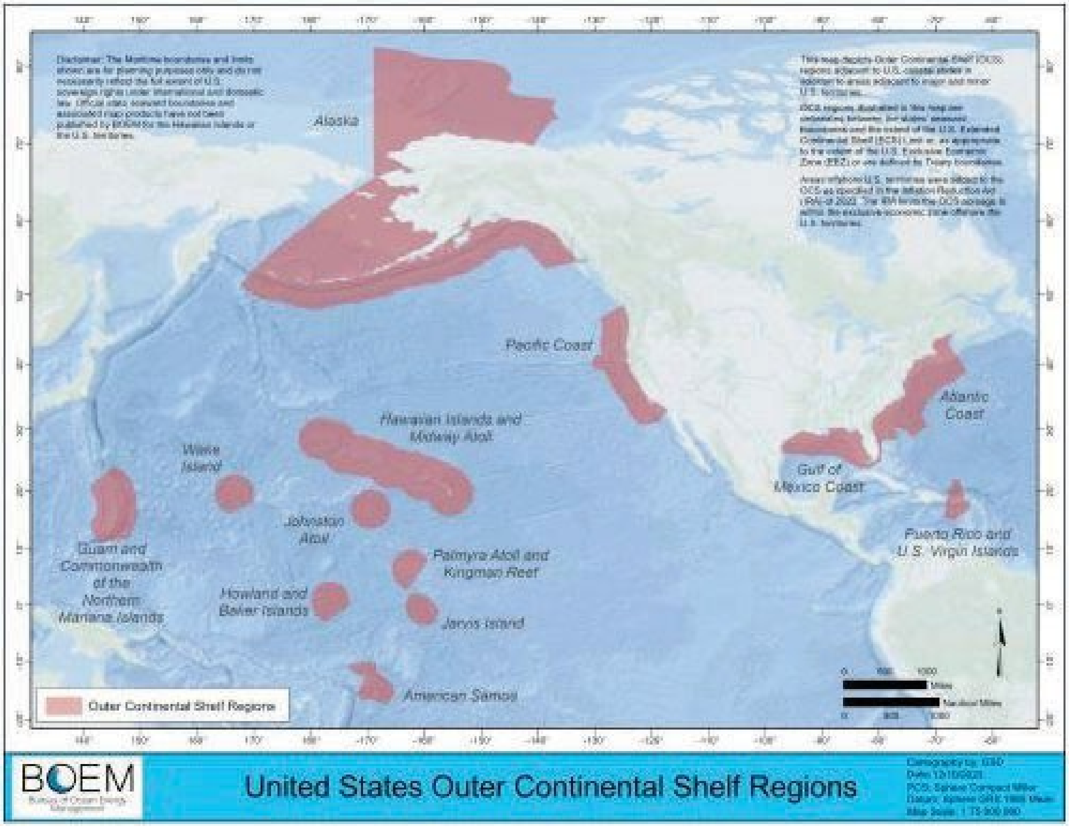

Figure 1. Outer continental shelf in regions of the United States
(Source: BOEM, n.d.)

Carbon Capture and Storage Overview

The most common approach to CCS (and GS-based CDR) entails compressing captured CO_2 from a gaseous state to a supercritical fluid,[1] transporting it to an approved GS site, and injecting it into a suitable geologic formation (U.S. EPA, 2022). Deep permeable geologic formations with highly saline groundwater (saline formations) can be especially attractive for GS operations. These formations tend to be laterally and/or vertically extensive, have large storage capacities, allow for high injection rates due to high porosity and permeability, have potentially greater capabilities for withstanding pressure increases associated with injection, and are frequently located in geological sequences where thick clay or shale formations can serve as confining zones (Kumar et al., 2020; Benson & Cook, 2005). Onshore storage in saline formations was assessed, tested, and validated as part of DOE's Regional Carbon Sequestration Partnerships (NETL, n.d.-a.). For offshore storage in saline formations, DOE-supported GoMCarb and SECARB-Offshore Partnerships have been characterizing offshore storage resources in state and federal waters since 2017 (Gulf Coast Carbon Center, 2023; Southern States Energy Board, 2023).

Deep saline formations are not the only type of geological formation that may be suitable for GS. Both the DOE and the United States Geological Survey (USGS) published storage resource assessments that provide estimates of the onshore carbon storage resources in a number of formation types within the United States (NETL, n.d.-b; USGS, 2013). Among them are depleted oil and gas reservoirs, which have the advantage of having been well characterized and have potentially useful existing infrastructure. While commercial-scale CO_2 injection into basalts has not yet been demonstrated, these formations also have

[1] Supercritical fluid is a fluid above its critical temperature (31.1°C for CO_2) and critical pressure (73.8 bar for CO_2). Supercritical fluids have physical properties intermediate to those of gases and liquids (U.S. EPA, 2010).

potential for both on- and offshore GS as evidenced by the DOE-supported Wallula Basalt Project (a 2013 pilot project) and Iceland's 2012 Carbfix pilot project (Raza et al., 2022). The Wallula Basalt Project injected approximately 1,000 metric tons of supercritical CO_2 into a natural basalt formation in eastern Washington State (PNNL, n.d.). The Carbfix project injected CO_2-saturated water (CO_2 dissolved in water) into porous basalt rock at an underground test site in southwest Iceland (Carbfix, 2023). Analyses at both projects during two years post-injection suggested rapid incorporation of the injected CO_2 into new carbonate minerals (McGrail et al., 2017; Matter et al., 2016). At the Carbfix site, it was estimated that greater than 95 percent of the CO_2 had been mineralized (Matter et al., 2016).

Overview of the EPA's Regulations for Geologic Sequestration

Underground Injection Control

UIC regulations and the EPA's UIC program ensure protection of underground sources of drinking water (USDWs) from risks posed by underground injection. The UIC regulations specifically address the various pathways through which injected fluids or native formation fluids can migrate to USDWs, including: (1) through faulty injection well casing, (2) via the annulus between the casing and the well bore, (3) migration through confining layers from the injection zone, (4) vertical migration through improperly abandoned and completed wells, (5) lateral migration from within the injection zone into a protected portion of a USDW, or (6) direct injection of fluids into or above a USDW (see Figure 2). Protective measures in the UIC regulations cover the siting, well construction, operation, and closure of underground injection wells. The injection well owner or operator must comply with the UIC regulations to ensure that the injection project does not pose a threat to USDWs, even after the injection well has been plugged and abandoned.

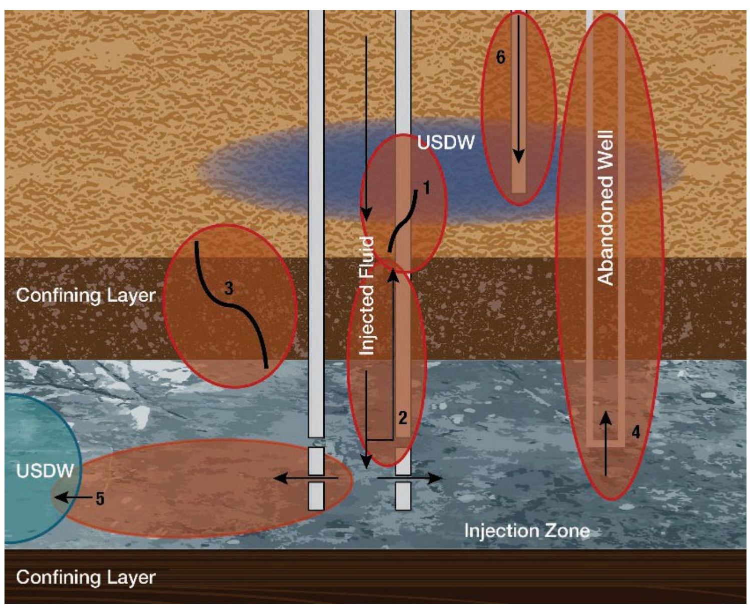

Figure 2. Pathways through which injected fluids or native formation fluids can migrate to USDWs

Under 40 CFR 144.3, a USDW is defined as an aquifer or its portion that supplies any public water system or that contains a sufficient quantity of groundwater to supply a public water system and either currently supplies drinking water for human consumption or contains fewer than 10,000 mg/L total dissolved solids (TDS). Thus, USDWs include aquifers that are currently used for drinking water as well as those that could reasonably be expected to serve as drinking water sources in the future.

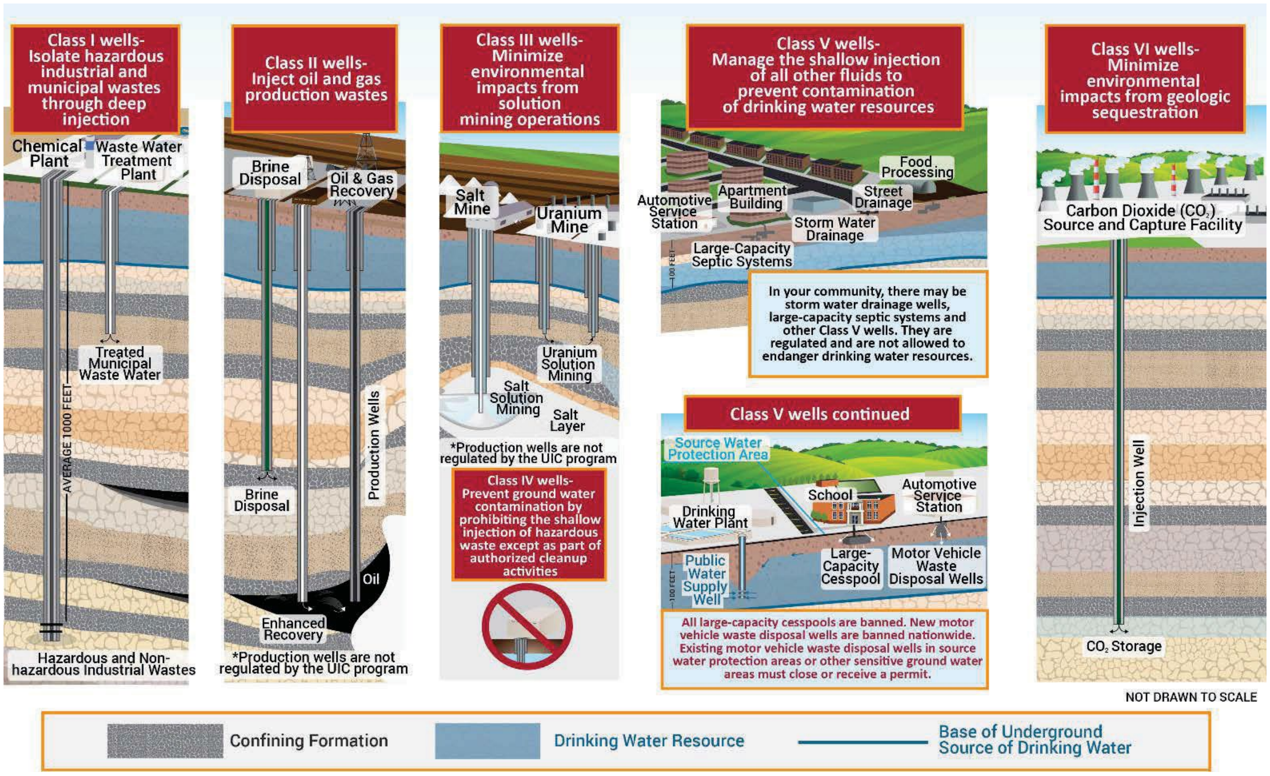

Figure 3. UIC injection well classes. Injection well Classes I, II, III, IV, and V were established as part of the EPA's 1980 UIC rulemaking and through a subsequent 1999 Class V addition. The EPA established well Class VI in a 2010 rulemaking. (Source: U.S. EPA, 2022)

The EPA regulates six classes of underground injection wells used to emplace fluids, such as water, brine, or CO_2, into deep, porous geological formations (see also Figure 3):

- Class I: used for injection of hazardous and non-hazardous wastes for disposal into deep, isolated geological formations
- Class II: used for injection of fluids related to oil and natural gas production
- Class III: used for injection of fluids related to mineral extraction
- Class IV: used for injection of hazardous or radioactive wastes into or above a formation containing a USDW (banned since 1984)
- Class V: used for injection of non-hazardous fluids, often above and sometimes into a USDW
- Class VI: used for injection of CO_2 into deep geological formations for carbon sequestration

States, Tribes, and territories may apply to the EPA to be the UIC permitting authority in their jurisdiction and, if approved, receive primary enforcement authority (primacy). If the state, Tribe, or territory has not obtained primacy, the EPA is the UIC permitting authority.

The Class VI Rule

The EPA's Class VI Rule was promulgated in 2010 and establishes federal requirements for Class VI well permitting, siting, construction, operation, monitoring, and site closure. These requirements address the unique nature of CO_2 injection. In putting the regulation in place, the EPA recognized the significant potential for CCS as a greenhouse gas mitigation strategy, the evidence of the considerable risks that climate change poses to human health and the environment, and the need to proactively ensure that GS wells could be safely operated without posing a risk to USDWs.

The Class VI permitting process is extensive and UIC regulations for Class VI wells require significant site characterization prior to permitting and stringent monitoring during and after injection. Permit applications must contain comprehensive information about the geological characteristics of the proposed injection site, computational modeling (simulations) of the area of review (AoR),[2] the proposed design for well construction, an injection and post-injection phase testing and monitoring plan, and an emergency response plan. Permitting also entails a demonstration of financial responsibility. Once a permit has been issued, the well owner or operator can construct the well (or modify an existing well) and complete pre-injection testing. Pre-injection test results must be submitted to the permitting authority before CO_2 injection is authorized and can commence.

In 2022, the EPA submitted a Report to Congress on Class VI permitting that provides a summary of all requirements associated with Class VI wells; it also includes recommendations to improve permitting procedures (U.S. EPA, 2022). This report, and additional detailed information on the EPA's Class VI permitting process, can be found on the EPA's Class VI website.[3]

Greenhouse Gas Reporting

Under the authority of the Clean Air Act, the EPA's Greenhouse Gas Reporting Program (GHGRP) requires that all facilities that inject CO_2 underground report data annually to the EPA. All wells permitted as Class VI under the UIC program, and any other wells used for GS, are required to report under subpart RR of the GHGRP and submit for approval an associated Monitoring, Reporting, and Verification plan (MRV plan). Facilities subject to subpart RR are required to annually report information on the amount of CO_2 received for injection; the amount of CO_2 produced; the amount of CO_2 lost through surface leaks, equipment leaks, and vented emissions; and the net amount of CO_2 sequestered in the subsurface formation. These facilities are also required to submit an annual monitoring report containing a narrative history of the monitoring efforts conducted and a description of any surface leakages of CO_2. Subpart RR is applicable to both onshore and offshore facilities, and in a May 2023 rulemaking (Fed. Reg., 2023), the EPA proposed a definition for the term "offshore" to clarify this distinction for the purposes of greenhouse gas reporting.[4] This air emissions data reporting program is separate from the UIC program.

Offshore Geologic Sequestration

Benefits, Risks, and Uncertainties of Offshore Geologic Sequestration

The OCS sub-seabed provides significant storage potential in the United States. Offshore GS risks may involve many of the same geologic conditions and risk factors associated with onshore GS (e.g., well integrity, leakage issues). Risks related to possible effects of induced seismicity on populated areas are

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[2] The AoR is the area surrounding a GS project where USDWs may be affected by the injection activity. The AoR is defined at 40 CFR 144.3 as "the area surrounding an injection well described according to the criteria set forth in §146.6."

[3] https://www.epa.gov/uic/class-vi-wells-used-geologic-sequestration-carbon-dioxide

[4] Defined as ''seaward of the terrestrial borders of the United States, including waters subject to the ebb and flow of the tide, as well as adjacent bays, lakes or other normally standing waters, and extending to the outer boundaries of the jurisdiction and control of the United States under the Outer Continental Shelf Lands Act.'' (Fed. Reg., 2023)

reduced in comparison to onshore projects. There is, however, the added possibility of impacts on the marine environment.

To date, no USDWs have been documented on the OCS, although the potential for low-salinity groundwater on the continental shelf has been explored. USGS has modeled the extents of regional North Atlantic Coastal Plain aquifers out to where the chloride content reaches 10,000 mg/L (not TDS) (Pope et al., 2016), with some extending into the OCS. Another study notes that low-salinity groundwater (TDS content not specified) has been found within continental shelves in various regions. The study presents geophysical data suggestive of a submarine aquifer system extending tens of kilometers off the shore of the U.S. Atlantic (Gustafson et al., 2019); these findings have not been confirmed via drilling. At this time, the existence, extents, and salinities of potential low-salinity aquifers on the OCS remain uncertain. To date, the authors of this report are unaware of any reports of USDWs on the OCS during the course of offshore drilling operations.

The management of GS projects onshore may fall under split estate or multiple-resource ownership regimes, particularly regarding subsurface pore space. This could introduce complications not applicable to projects in federal waters. However, in offshore environments, well and facility operation may be more expensive and complex due to the unique challenges associated with offshore activities.

The extensive geological and geophysical resource evaluation data and information available for the Gulf of Mexico—a region critical to the United States' energy transition—have allowed BOEM to estimate a preliminary sub-seabed CO_2 storage capacity for the OCS in the region, which contains potential GS sites in both depleted oil and gas reservoirs and saline formations.

Examples of areas that are in need of more development and analysis include: assessing methods for long-term monitoring of the CO_2 plume and pressure front within offshore formations and the surrounding environment, including the seafloor; optimizing lease spacing and multiple uses of the sub-seabed and water column above the injection formation (the formation into which CO_2 is injected); developing appropriate emergency response and contingency plans; and understanding the potential impacts of spilled or leaked CO_2 on the marine environment.

Finally, while there are notable long-term projects in Norway, and while considerable prior research has been competed on sub-seabed GS, no sub-seabed GS projects are yet operational in the United States.

For a successful offshore GS project, safeguards need to be developed to protect against accidental releases of the captured CO_2 during transportation as well as during and after operation. The same operational safeguards also would protect against any potential leakage of formation fluids. In addition, clarifying and communicating relationships between regulatory regimes across marine spaces will be necessary to ensure transparency of roles and responsibilities within the whole-of-government approach to compliance.

Interest from Industry

There is growing and considerable industry and government interest in sub-seabed GS. Wood Mackenzie reports six projects in development or planning phases in the Gulf of Mexico (Wood Mackenzie, 2022). For example, Chevron, TotalEnergies, and Carbonvert aim to be among the first offshore carbon sequestration project operators in the United States by developing a hub in Bayou Bend in Texas state waters (Chevron, 2022; TotalEnergies, 2024). Cox Energy subsidiary, Carbon-Zero US, LLC, and Repsol are also evaluating carbon sequestration opportunities in Louisiana state waters and the OCS (Davis, 2022). Furthermore, ExxonMobil is exploring the implementation of carbon sequestration projects in and around Houston, including offshore in the Gulf of Mexico (ExxonMobil, 2022).

In addition to industry-led efforts, DOE is funding the Gulf Coast Carbon Center and the Southern States Energy Board to study offshore carbon storage in the sub-seabed of the Gulf of Mexico. The Gulf Coast Carbon Center, which resides in the Bureau of Economic Geology at the University of Texas at Austin, conducts research and provides advisory, educational, technical, and informational services for GS with a focus on enabling the private sector to develop an economically viable industry for GS in the Gulf Coast area. The Southern States Energy Board is an interstate compact aiming to enhance economic development and the quality of life in the South through innovations in energy and environmental policies, programs, and technologies. The DOE-funded projects are characterizing and mapping the sub-seabed geology for potential GS sites, as well as evaluating transportation and infrastructure needs, performing risk assessments and identifying applicable monitoring technology, and educating the public. Similarly, DOE continues to fund research to characterize the sub-seabed geology for potential GS sites along the Mid-Atlantic coast from the Georges Bank Basin through the Long Island Platform to the southern Baltimore Canyon Trough.

Financial Incentives

Several public initiatives such as tax credits and subsidies at the federal and state levels have been created to encourage CCS and CDR. Building off the existing Carbon Storage Assurance Facility Enterprise (CarbonSAFE) initiative, DOE is expanding CarbonSAFE with $2.5 billion under the BIL to develop "new or expanded commercial large-scale carbon sequestration projects and associated carbon dioxide transport infrastructure." This new dedicated funding to carbon storage may impact industry interest in developing projects both onshore and offshore. DOE funding opportunities are focused on accelerating the development of new or expanded commercial-scale GS projects and associated CO_2 transport infrastructure, through a focus on detailed site characterization, permitting, and construction stages of project development. DOE is expecting to fund both onshore and offshore projects with BIL funding. As of May 2024, DOE has selected 25 CarbonSAFE projects from rounds 1 and 2 under FOA2711 (U.S. DOE, 2023a, 2023b).

Section 45Q of the Internal Revenue Code was enacted under the Energy Improvement and Extension Act of 2008 to provide a tax credit for sequestration of carbon oxide. Section 45Q(f)(2) provides that the Secretary of the Treasury, in consultation with the Administrator of the EPA, the Secretary of Energy, and the Secretary of the Interior, must establish regulations for determining adequate security measures for the geological storage of qualified carbon oxide under Section 45Q(a) such that the qualified carbon oxide does not escape into the atmosphere. The 2022 IRA enhancements to the "45Q" tax credit include increasing the per-ton incentives for GS, expanding the definition of qualified facilities, extending the window for projects to begin construction, and other actions that significantly expand incentives for industry to pursue the development of CCS and CDR projects. This builds on previous enhancements introduced under the 2018 Bipartisan Budget Act that expanded the scope, qualifying requirements and thresholds, and eligibilities for the credits.

Department of the Interior's Role

Section 40307 of the 2021 BIL amended the OCSLA to authorize the Secretary of the Interior to grant a lease, easement, or right-of-way on the OCS for activities that "provide for, support, or are directly related to the injection of a CO_2 stream into sub-seabed geologic formations for the purpose of long-term carbon sequestration" (U.S. Congress, 2021). As directed in the BIL, BOEM and BSEE are jointly developing regulations for GS on the OCS.

The BIL also specifically excluded the application of the Marine Protection, Research, and Sanctuaries Act (MPRSA), through which the EPA regulates the transportation and disposition of any material into ocean waters, to sub-seabed GS on the OCS. The London Convention and London Protocol treaties have established an international regulatory framework and have developed international guidance for sequestration of CO_2 streams in sub-seabed geologic formations in the sub-seabed beneath the ocean water column. The United States is a party to the London Convention and has signed, but not yet ratified the London Protocol.

OCS Geologic Sequestration Regulations Pending

As noted above, BOEM and BSEE are working diligently on a joint proposed rule on OCS carbon sequestration to implement the Department of the Interior's (DOI's) authority provided in the BIL and develop an OCS carbon sequestration program. The bureaus are leveraging both their existing expertise and extensive outreach to experts in other federal agencies, foreign regulatory agencies, academia, industry, non-governmental organizations, and others to develop the joint proposed rule.

Interagency Collaboration on Geologic Sequestration

There are multiple avenues of interagency collaboration on offshore GS. The Carbon Dioxide Capture, Utilization, and Sequestration Federal Lands Permitting Task Force and the Outer Continental Shelf Permitting Task Force, comprised of representatives from the energy sector, state and federal government, Congress, non-governmental organizations, and other stakeholder organizations, provide input on the responsible development of CCS (The White House, 2023b). Furthermore, DOI, DOE, the EPA, and other agencies hold regular interagency meetings on CCS, which include, but are not limited to, discussions on the offshore environment. In addition, there is potential for future interagency collaboration on scientific research, such as between DOI and the EPA on water quality impacts. Finally, given the varying authorities across space, from the coast to areas beyond national jurisdiction, agencies will need to work together to assess opportunities to coordinate regulatory frameworks.

Class VI Rule Requirements and Considerations for the OCS

The UIC Class VI criteria and standards can be found at 40 CFR Part 146, Subpart H, which contains requirements for the entire lifecycle of a GS project, from required information for permit application through well construction, injection, post-injection, and eventual site closure. The Class VI Rule also provides criteria for circumstances requiring particular considerations, such as injection depth waivers and transitioning from a Class II permit for enhanced hydrocarbon recovery to a Class VI permit.

An important consideration that offshore GS projects face is the potential risk of leakage to the seafloor. This is a primary concern because CO_2 can affect seawater chemistry and marine habitats and biota (LP, 2007). The overall goals for a safe and viable GS project involve careful well siting, construction, and operations so that CO_2 is injected into a suitable storage reservoir, as well as monitoring throughout the life of the project to demonstrate non-endangerment of USDWs and verify the CO_2 remains permanently and securely stored. The Class VI requirements incorporate many best practices for site characterization, well construction, well plugging, monitoring, and other aspects of a GS project. Additionally, major components of the Class VI regulations require permitting authority–approved and enforceable plans that can be updated during the project's lifetime.

The EPA supports Class VI well owners/operators and permitting authorities through a series of technical guidance documents and quick reference guides that could be adapted for DOI GS regulations (U.S. EPA, 2023a, 2023b). The EPA also has recently developed a suite of tools and strategies for streamlining the permitting process and facilitating and promoting awareness of it; these could also serve as examples for DOI. The tools and strategies address topics including early engagement, regulator training, permit application outline and template, and tutorials for use of the EPA's Geologic Sequestration Data Tool (U.S. EPA, 2022). These resources and tools are publicly available on EPA's Class VI website.

Below are descriptions of key aspects of the regulations that may inform the bureaus as they develop regulations for the review of offshore GS projects on the OCS. These key aspects are applicable to all Class VI UIC GS projects.

Pre-Construction Requirements

Site Characterization

The materials submitted for a UIC Class VI permit application must collectively meet minimum criteria for project siting (40 CFR 146.83). These basic criteria are applicable to all GS projects.

- The well site must have suitable geology, with an injection zone that is large enough and has the appropriate properties (porosity and permeability) to receive and contain the total anticipated volume of the CO_2 that will be injected (40 CFR 146.83(a)(1)).
- The injection zone must also have an overlying impermeable confining zone with sufficient areal extent and integrity to prevent vertical movement of the CO_2 or displaced formation fluids (40 CFR 146.83(a)(2)).
- The confining zone must be free of any faults or fractures that could allow fluid movement, and it must be able to withstand the proposed injection pressures and volumes without either fracturing or propagating existing fractures (40 CFR 146.83(a)(2)).
- The permitting authority may require the owner or operator to identify and characterize any additional zones in the geology that could serve as secondary confining zones (40 CFR 146.83(b)).

The Class VI Rule at 40 CFR 146.82 specifies required permit application information to demonstrate that the project site is suitable for GS, with a large injection zone that can receive and store the CO_2 and a confining zone free of faults and fractures that will prevent leakage (40 CFR 146.83). Details for the elements in 40 CFR 146.82 are given in other sections of 40 CFR 146.

A map is required (40 CFR 146.82(a)(2)) with detailed surface and subsurface features in the AoR. For example, owners or operators must identify existing wells (injection wells; producing wells; abandoned, plugged, or dry wells; stratigraphic test wells) and faults in the AoR. Identification of existing wells and faults and their characteristics is needed to demonstrate the suitability of the site, as these can compromise storage if they allow movement of CO_2 or fluids out of the injection zone.

Owners or operators must submit extensive geologic and hydrogeologic information to characterize the proposed project site. This includes rock types (lithologies), structure, areal extent, thickness, and porosity and permeability, among other information (40 CFR 146.82(a)(3)). This information is used to confirm that the proposed injection formation can receive and contain the amount of CO_2 the owner or operator intends to inject.

Other required information pertains to the stability of the site, including seismic history, strength of the formation lithologies, and information about any faults in the AoR. The data can include field- and laboratory-based information and is required to be presented in standard formats (e.g., maps and cross-sections).

40 CFR 146.82(a)(6) requires baseline geochemical data on subsurface formations in the AoR. Geochemical data are needed to determine how the CO_2 injectate will interact with the lithologies and fluids in the injection formation and as a baseline in the event of unanticipated geochemical changes during injection. This extensive site characterization is a key aspect of permit application information and supports a demonstration that the injection well will be constructed in an appropriate location. Similarly, the tabulation of existing wells and their characteristics (construction, depth, completion or plugging) is

intended to support a demonstration that existing wells in the AoR will not compromise storage of the CO_2.

Proposed Well Operations (40 CFR 146.82(a)(7))

The Class VI Rule at 40 CFR 146.82(a)(7) describes required information about proposed operations during injection—average and maximum daily rate and volume and/or mass and total anticipated volume and/or mass of the CO_2 stream (40 CFR 146.82(a)(7)(i)); average and maximum injection pressure (40 CFR 146.82(a)(7)(ii)); CO_2 stream source(s) (40 CFR 146.82(a)(7)(iii)); and analysis of the chemical and physical characteristics of the CO_2 stream (40 CFR 146.82(a)(7)(iv)). These basic parameters are important to define for the operation of any GS project and are set according to site-specific information (e.g., geology of the site, geomechanical properties of the injection formation, and the specific CO_2 source).

Area of Review and Corrective Action (40 CFR 146.84)

The determination of the AoR is a key component of permitting for all UIC wells. It delineates the area for identifying risks (e.g., subsurface wells) and planning the project's monitoring program. The proposed AoR is presented in the initial permit application. The AoR is a term associated with the UIC program (multiple well classes), identifying the area in the subsurface that will be affected by injection activities.

AoR determination for GS requires sophisticated computational modeling to simulate how the injected CO_2 will migrate and how pressure in the injection formation will increase. 40 CFR 146.84 provides requirements for this modeling. The regulations require the modeling supporting the AoR to be periodically updated during operation as monitoring data are collected.

The term "corrective action" refers to the use of permitting authority–approved methods to ensure that wells within the AoR do not serve as conduits for the movement of fluids out of the injection formation (leakage). When existing wells with deficiencies (e.g., improper plugging) are identified, it may be necessary for them to be remediated. Corrective action is important for ensuring containment of CO_2 and fluids within the injection zone.

Financial Responsibility (40 CFR 146.85)

Under 40 CFR 146.85, the owner or operator must demonstrate and maintain financial responsibility. These requirements ensure that the private costs of GS, including possible costs after the injection well has been plugged, are not passed along to the public. Well owners or operators must provide documentation to the permitting authority showing that they have established a financial instrument with a third party or have self-insurance. 40 CFR 146.85(a)(2) and (3) require that the financial instrument be sufficient to cover costs of corrective action, injection well plugging, post-injection site care (PISC; the period after injection stops), closure, and emergency and remedial response. Issues that could arise may involve physical problems with the well or other infrastructure and other compliance problems requiring investigation and possible remedial activities. The regulations include a specific list of acceptable financial instruments and other conditions of the financial responsibility coverage.

Injection Well Construction Requirements (40 CFR 146.86)

Class VI injection wells must be constructed to high industry and operations standards to ensure the wells can withstand the pressures and environment in which it will be operated. Well construction requirements at 40 CFR 146.86 are intended to prevent fluids from moving into any unauthorized zones. For all injection wells, preventing movement of injectate or formation fluids into other, unplanned geologic formations or the surface (land surface or seabed) is important for safe and effective operation. GS injection well construction uses the principle of multiple barriers, with layers of casing and cement to prevent migration of CO_2 outside of the well or up and down along the well bore.

Under the requirements in 40 CFR 146.86(a)(2), wells must be constructed to allow for the use of testing devices and workover tools. Wells also will be subject to continuous monitoring of the annular space between tubing and casing (40 CFR 146.86(a)(3)); appropriate monitoring equipment should be chosen based on the project and its environment.

Requirements under 40 CFR 146.86(b)(1), 40 CFR 146.86(b)(5), and 40 CFR 146.86(c)(2) and (3) address well materials (cement, casing, packer), which must last for the life of the project and be compatible with the fluids to which the materials will be exposed. Materials must meet or exceed industry standards (American Petroleum Institute, American Society for Testing and Materials, or comparable). Such standards are not specific to the UIC program. The requirements for Class VI well materials are focused on function, and owners or operators in an offshore environment can propose materials appropriate for the conditions their wells will experience. For example, the materials and equipment near the top of an offshore well will have continuous exposure to seawater.

For cementing, 40 CFR 146.86(b)(4) notes a cement emplacement method (staging) but allows the permitting authority to approve an alternative method as long as the owner or operator can demonstrate that the cement will not allow fluid to move up along the outside of the casing. Additionally, 40 CFR 146.86(b)(5) requires the owner or operator to verify the quality (integrity) and location of the cement and the locations of any channels in the cement, although the specific methods are not specified. Evaluating cement quality is necessary for keeping geological formations isolated and ensuring that fluid does not migrate along the well.

Pre-Operational Testing Requirements

At 40 CFR 146.82(a)(8), the Class VI Rule requires the owner or operator to submit a proposed pre-operational testing program; the specific types of information that must be gathered through the testing are described in 40 CFR 146.87. Tests are done during and after well installation and take place after the owner or operator has received authorization to drill. The Class VI Rule provides a list of specific tests to be done at several stages: during drilling (146.87(a)(1)), before and upon installation of the surface casing (146.87(a)(2)), before and upon installation of the long string casing (146.87(a)(3)), and upon completion of the injection well(s) (146.87(a)(4)).

The pre-operational testing confirms the characteristics of the project site and its suitability for GS, provides accurate and site-specific data to ensure conformance with well construction requirements, provides data to finalize operating parameters (e.g., maximum injection pressure), and establishes an accurate site-specific baseline for future monitoring. The lists of well logs and checks, sampling, and other analyses to be conducted at each stage reflect comprehensive testing as routinely done during drilling and completion of deep wells.

During Drilling (40 CFR 146.87)

Examples of the types of data acquired during drilling include well logging and other downhole measurements to confirm the sequence of rock types and the pressure, temperature, and pH in the injection formation (40 CFR 146.87(a)(3); 40 CFR 146.87(c)). The regulations at 40 CFR 146.87(a)(5) allow some flexibility in how data are collected; the permitting authority can approve alternative methods. This allows for selection of the optimal methods for the site-specific project conditions.

Cores and formation fluid samples are collected for laboratory analysis (40 CFR 146.87(b)), although the permitting authority can accept such information from cores from other nearby wells if cores cannot be retrieved when drilling the injection well. These support characterization of physical and chemical characteristics of the injection and confining zone(s) (40 CFR 146.87(b)(2)) and of the formation fluids in the injection zone(s) (40 CFR 146.87(d)(3)). Confirmation of the physical and chemical characteristics of the lithology and fluids in the injection and confining zone(s) is needed to anticipate reactions between the injected CO_2 and the minerals and fluids in the formation. This compatibility is important for understanding whether changes due to injection can cause minerals to dissolve or precipitate, thereby affecting the ability to inject CO_2.

The Class VI Rule under 40 CFR 146.87(a)(1) through (4) also requires tests to verify the quality of the cement and the overall mechanical integrity of the well. This information is needed for all GS wells to make sure the well functions as designed and does not become a conduit for leakage of CO_2 or formation fluids.

Under 40 CFR 146.87(d)(1), the owner or operator must determine the pressure at which the rock in the injection zone(s) begins to fracture (i.e., "fracture pressure"). This property is crucial for setting operational parameters as it is used to calculate a safe maximum allowable injection pressure. The goal is to avoid induced fractures and migration of CO_2 beyond the intended storage area. Setting a maximum allowable injection pressure is required of all UIC wells and would be appropriate for all GS wells.

After Well Completion (40 CFR 146.87(e))

Under 146.87(e), upon completion of the well but before operation, the owner or operator must complete certain tests (e.g., a pressure fall-off test, and pump test or injectivity tests) to verify the hydrogeologic properties of the injection zone(s). All injection well sites need some form of formation testing to verify the hydrogeologic properties and to demonstrate that the injection zone(s) can receive the injected CO_2.

Injection Well Operation (40 CFR 146.88)

Under 40 CFR 146.88(a), the owner or operator must ensure that the injection pressure does not create leakage by generating new fractures, increasing existing fractures in the injection zone(s) and confining zone(s), or causing fluids to migrate. To maintain safe operations, the maximum injection pressure cannot exceed 90 percent of the fracture pressure of the injection zone as determined during pre-operational testing (40 CFR 146.87(d)(1)).

Additional provisions in 40 CFR 146.88(b), (c), and (d) address other aspects of well operation (e.g., no injection between the outermost casing and the wellbore, maintaining correct pressure on the annulus between the tubing and casing, maintaining the mechanical integrity of the well). In 40 CFR 146.88(c), the Class VI Rule requires continuous recording of injection pressure, CO_2 flow rates, and CO_2 volumes. These measures are intended to maintain safe operations and prevent movement of CO_2 or fluids outside of the injection zone due to malfunction or poor condition of the well.

Mechanical Integrity Testing (40 CFR 146.89)

Before injection starts, and periodically throughout the life of the project, the well is tested for structural soundness. This is called mechanical integrity testing (40 CFR 146.89(c), (d), and (e)). Under 40 CFR 146.89(a), a well is determined to have mechanical integrity if: (1) there is no significant leak in the casing, tubing, or packer; and (2) there is no significant fluid movement through channels adjacent to the injection well bore. Maintaining a well's mechanical integrity is crucial to ensuring the injection well does not allow CO_2 or formation fluids to migrate along the well to other formations or to the surface.

As noted above, the Class VI requirements (40 CFR 146.89(b)) include continuous monitoring of operational parameters (injection pressure, rate, injected volumes, and others). The Class VI Rule also requires annual tests for possible fluid movement along the outside of the casing (40 CFR 146.89(c)). While specific tests are included in the Class VI regulatory language (e.g., tracer survey, temperature, or noise log), the permitting authority can also require other tests and at other frequencies to demonstrate mechanical integrity (40 CFR 146.89(d), (e), and (g)). The Rule notes under 40 CFR 146.89(f) that the methods and standards used must be generally accepted in the industry. The goal of these requirements is to ensure robust mechanical integrity testing of the injection well. Similar requirements would be appropriate for all GS wells, with the jurisdiction presumably setting methods and schedules deemed appropriate for the project and setting.

Testing and Monitoring (40 CFR 146.90)

40 CFR 146.90 requires several types of monitoring during the injection and post-injection phases. Detailing the monitoring program, including its goals and methods, is a crucial best practice for any GS project.

The owner or operator is required to fully document their monitoring procedures by preparing and maintaining an enforceable testing and monitoring plan to verify that the project is operating as permitted. This plan is required under 40 CFR 146.90 and initially submitted with permit application materials under 40 CFR 146.82(a)(15). The owner or operator also is required to periodically review the testing and monitoring plan (40 CFR 146.90(j)), ensuring that the specifics of the testing and monitoring can be adapted as needed as the project proceeds and data are collected. Additionally, a quality assurance and surveillance plan is required for all testing and monitoring requirements (40 CFR 146.90(k)).

Required testing and monitoring comprises several types of monitoring that collectively track the injectate, operational parameters, downhole pressure and water quality, and well integrity:

- **Carbon dioxide stream analysis** (40 CFR 146.90(a)): Analysis of the CO_2 stream "with sufficient frequency to yield data representative of its chemical and physical characteristics" is appropriate for any GS operation, as impurities in the CO_2 can degrade well components.
- **Continuous recording of operational parameters** (40 CFR 146.90(b)): The Class VI Rule requires continuous monitoring of injection pressure, rate, volume, pressure on the annulus between the tubing and long string casing, and volume added. These are expected operational parameters for an injection well.
- **Corrosion monitoring** (40 CFR 146.90(c)): The Class VI Rule requires monitoring of the well materials on a quarterly basis for cracking, pitting, or other signs of corrosion. The regulations note two specific methods (coupons or a loop constructed of well materials) and allow for an alternate, permitting authority–approved method. For both onshore and offshore GS wells, corrosion monitoring is crucial in routine evaluation of well integrity because of anticipated pH changes downhole. A variety of methods are used in industry for corrosion monitoring of wells in the offshore environment, and regulations can allow for appropriate flexibility in choosing the most appropriate method(s) and monitoring frequency.
- **Groundwater quality monitoring above the confining zone** (40 CFR 146.90(d)): This monitoring is recommended (but not required under Class VI regulations) to be done in the first permeable formation overlying the confining zone but could be conducted in another formation. The monitoring data can provide early warning signs of any changes that could be related to CO_2 movement through the confining zone or along the well.
- **External mechanical integrity testing** (40 CFR 146.90(e)): Once per year, the owner or operator must conduct testing to demonstrate the external mechanical integrity of the well as per 40 CFR 146.89(c), and the permitting authority may also require a casing inspection log at a frequency to be determined (see discussion above on mechanical integrity testing).

- **Pressure fall-off testing** (40 CFR 146.90(f)): This form of testing examines how pressure declines when the well is shut in (closed off and monitored). It is necessary to test for hydrogeologic changes during injection that could affect how readily the formation receives the CO_2 and the overall performance of the project.
- **Plume and pressure tracking** (40 CFR 146.90(g)): The plume and pressure must be tracked for GS projects to determine if they are behaving as anticipated (e.g., if the plume is moving as expected, and if the pressure increase is in line with expectations). The Class VI Rule requires that this tracking be done both directly (by taking measurements in the injection formation with monitoring wells) and indirectly from the surface (by using seismic surveying to obtain images of the subsurface, or by other methods). However, the regulations allow permitting authority discretion regarding the appropriateness of indirect methods depending on site geology. Some form of tracking the plume and pressure is necessary for GS projects; methods may need to be flexible according to the environment.
- **Additional monitoring** (40 CFR 146.90(i)): The Class VI Rule allows other types of monitoring to be required by the permitting authority in order to support, upgrade, and improve the computational modeling used for the AoR evaluation (required under 40 CFR 146.84(c)) and to determine compliance with standards under 40 CFR 144.12. This provides flexibility in ensuring that the owner or operator will have the data needed to make their modeling as robust as possible. It also allows for monitoring methods to be chosen so as to be appropriate for the project and its environment.

Reporting Requirements (40 CFR 146.91)

40 CFR 146.91 provides the requirements for reporting results of monitoring and testing to the permitting authority. The Rule requires semi-annual reports that include all relevant data (operational, mechanical integrity, testing, and monitoring, as described in 40 CFR 146.90). The Rule also specifies the need to report within 24 hours any incidents of non-compliance with a permit condition, any well system malfunction, and any evidence of possible endangerment to a USDW. Reporting requirements are important for all permitted activities, GS or other, to ensure that important information gets communicated, vetted, and retained. GS projects in all settings could produce comprehensive monitoring data; semi-annual reporting allows for routine synthesis of monitoring data, summary of the status of the project, and ready comparison to previous reports and data. The requirement to report emergent incidents within 24 hours ensures mobilization of appropriate resources and rapid notification of potentially affected stakeholders or agencies.

Injection Well Plugging (40 CFR 146.92)

The Class VI Rule at 40 CFR 146.92 describes the process for injection well plugging, during which final measurements are made (e.g., bottomhole pressure, mechanical integrity). During the permitting process, the owner or operator will have submitted a well plugging plan as required at 40 CFR 146.82(a)(16), specifying the types and numbers of plugs that will be placed in the well, as well as the cement types to be used and the method of emplacement. The purpose of these requirements is to ensure that the plugs will prevent migration of CO_2 or fluids into an unintended formation or to the top of the well. When the owner or operator wishes to plug the well, they must indicate if changes have been made to the plugging plan and provide a revised plan.

Post-Injection Site Care and Site Closure (40 CFR 146.93)

40 CFR 146.93 sets the conditions and process for PISC, followed by eventual site closure. The owner or operator's plan for the post-injection period needs to include information on how much the pressure in the injection zone(s) has increased due to injection, and an update of the predicted position of the CO_2 plume

and area of increased pressure. This prediction is an update of the modeling done to inform the determination of the AoR. The goal is to demonstrate that the injected CO_2 will not pose a risk to USDWs over the long term.

Monitoring continues during the PISC period. The default PISC timeframe is 50 years, but the permitting authority may require an extension to the monitoring period if conditions warrant. A shorter timeframe can be approved if the owner or operator can demonstrate that the site does not pose a risk to USDWs. This demonstration is based on information that includes all monitoring data, the results of the AoR computational modeling, and estimates of how long it will take for plume migration to stop and pressure to decrease.

Under 40 CFR 146.93(b)(3), if the owner or operator has successfully demonstrated to the permitting authority that the project no longer poses an endangerment to USDWs, they may then notify the permitting authority of their intent to close the site. Demonstrating suitability for site closure involves showing stability of the pressure and plume and immobilization of the CO_2 through physical and chemical processes (e.g., trapping and mineralization). This is done through up-to-date numerical modeling, supported by monitoring data. Other submissions could include characterization of potential conduits (e.g., fractures, faults, wells) or any other site-specific information relevant to the demonstration (U.S. EPA, 2010, 2016). The permitting authority then authorizes site closure, monitoring wells are plugged, and the owner or operator must submit all appropriate documentation to the UIC Program Director; these records must be retained by the owner or operator for 10 years following site closure (40 CFR 146.93 (d) through (h)). If non-endangerment has not been successfully demonstrated, additional monitoring will be required (40 CFR 146.93(b)(4)).

Emergency and Remedial Response (40 CFR 146.94)

A UIC Class VI permit application must include a proposed emergency and remedial response plan (40 CFR 146.82(b)(19), 40 CFR 146.94). The plan identifies how the owner or operator would detect a leak, well failure, or other problem, and it must describe actions the owner or operator would take in the event of an incident (i.e., cease injection, identify and characterize the release, notify the permitting authority within 24 hours, and implement a permitting authority–approved remedial response plan). Events that would require emergency and remedial response include unexpected changes in injection formation pressure, loss of well integrity as identified by continuous monitoring, triggering of a shutdown device, and evidence of change in water quality, among others. Examples of mitigation actions may include remedial cementing of the well to repair compromised cement, repair of surface equipment, or (in the worst case) well plugging and abandonment. Emergency and remedial response plans should be site and project specific. For offshore projects, plans may need to consider the logistics associated with response in an offshore environment (e.g., infrastructure, mobilization of resources, conducting repairs).

Class II to VI Transition (40 CFR 144.19)

In addition to establishing Class VI criteria and standards, the Class VI Rule also provides considerations for transitioning other UIC wells to Class VI. Owners or operators injecting CO_2 into an oil or gas reservoir for enhanced recovery operate under a UIC Class II permit. CO_2 injection can proceed under a Class II permit as long as the primary purpose of the project is oil or gas recovery. If the owner or operator is injecting CO_2 into an oil or gas reservoir for the primary purpose of long-term storage, they must apply for and obtain a Class VI permit if there is an increased risk compared to Class II operations (U.S. EPA, 2015).

The Class VI requirements at 40 CFR 144.19(b) list several factors to consider in determining if there is an increased risk. A primary indicator is increased pressure in the injection zone(s). Other factors to consider are whether CO_2 injection rates will increase and production will decrease; the suitability of the Class II AoR determination; the quality of abandoned well plugs within the AoR; the owner's or operator's plan for recovery of CO_2 at the cessation of injection; the source and properties of injected CO_2; and any additional site-specific factors as determined by the permitting authority. If Class II requirements are inadequate for managing this increased risk, then the project would need to transition to a Class VI permit.

Cross-Boundary Project Considerations

The AoRs for Class VI wells can be larger and more variable than those for other well classes due to the unique nature of CO_2 injection. This increases the possibility that the AoR for a project sited close to a jurisdictional boundary may cross that boundary. For example, the AoR for a project in state waters, where DOI does not have authority, may cross into the OCS, where DOI has authority. Alternatively, a project sited on the OCS may have an AoR that crosses into state waters. In either case, coordination will be needed between regulatory entities. Cross-jurisdictional cooperation would necessitate establishing formal procedures for communication and sharing of information. Another scenario that should be considered is that two or more projects sited near each other could experience pressure interference across the AoR boundaries of the individual projects.

Conclusion

Summary of Assessment

GS is a strategic process that can help advance the United States towards net-zero emissions by 2050, and GS has promise for considerable environmental benefits. There are several potential advantages to storing CO_2 in the sub-seabed of the OCS as compared to onshore GS projects under UIC regulation, including: (1) the lack of known USDWs in the OCS, (2) federal management of the OCS, and (3) reduced risks to populated areas. A potential disadvantage is the possible risks to the marine environment. As directed in the BIL, BOEM and BSEE are jointly developing regulations for GS on the OCS. BOEM and BSEE have conducted and will continue to pursue extensive outreach with other federal agencies, foreign countries, industry, non-governmental organizations, and other stakeholders. BOEM's regional offices are conducting an assessment of carbon storage potential on the Atlantic, Pacific, Alaska, and Gulf of Mexico OCS. Additionally, BOEM's Gulf of Mexico regional office is identifying and characterizing specific sites that may be suitable for carbon sequestration.

The broader goals and many aspects of the UIC regulations may inform the regulations currently under development for the OCS. The UIC requirements govern a Class VI project from permitting and siting through injection, post-injection, and site closure. These include proper site characterization and computational modeling, rigorous well siting and construction requirements, setting safe operational parameters, a well-designed testing and monitoring program, and effective emergency and remedial response, all of which are aspects of the Class VI Rule that could have applicability to GS projects on the OCS (U.S EPA, 2010).

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