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Fundamentals of Carbon Capture and Sequestration

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TABLE OF CONTENTS

Fundamentals of Carbon Capture and Sequestration

by Thomas M. Weber and Paul R. Tough[1]

I. Introduction

Recent changes in federal tax law may finally make development and implementation of commercial-scale carbon capture and sequestration ("CCS") a reality. Effective January 13, 2021, the Internal Revenue Service ("IRS") adopted amendments to its regulations that expanded existing federal tax credits for the capture and secure geological sequestration of, or authorized use of, carbon oxides. These credits are commonly referred to as the "45Q tax credit."[2] The expanded 45Q credit makes investment in CCS projects economically more attractive and creates new business opportunities for the oil and gas industry—especially given the industry's technical expertise gained through decades of implementing carbon dioxide ("CO_2") pipeline transportation, enhanced oil recovery ("EOR"), and acid gas injection ("AGI") projects. Despite this experience, many questions remain including questions about the scope of the credit, how to navigate an evolving federal and state regulatory framework, and how to best manage risk given the uncertainties associated with pore space ownership in Texas. Notwithstanding these uncertainties, a new industry is emerging as dozens of CCS projects move forward in Texas.

II. Federal 45Q Tax Credits

In 2018, Congress enacted the Bipartisan Budget Act of 2018 expanding the existing 45Q tax credit. The IRS then amended its regulations implementing the expanded credit and provided additional clarity on the scope of the credit and the mechanics for claiming it. The expanded tax credit creates a potentially significant economic incentive for developing CCS projects. It is important, therefore, to understand how the credit works, who and what qualifies for the credit, and how to demonstrate and implement the key regulatory requirement of "secure geological storage."

a. Breaking Down the Credit[3]

To qualify for the 45Q tax credit, owners of "qualified carbon capture facilities" placed into service on or after February 9, 2018, are required to capture anthropogenic carbon oxides that would otherwise be released to the atmosphere and either (a) dispose of the carbon oxides into "secure geological storage," (b) inject the carbon oxides as "tertiary injectant" as part of qualifying

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[2] 86 Fed. Reg. 4728 (Jan. 15, 2021).

[3] Subsections (i) through (vii) highlight key provisions of the expanded tax 45Q tax credit but are not intended as a comprehensive summary of potentially applicable IRS regulations.

EOR project, or (c) "utilize" the captured carbon oxide in ways that conform with section 45Q(f)(5) of the IRS Code.[4]

i. The Tax Credits

The 45Q tax credit is claimed on a dollar per-metric-ton basis so long as the volume of carbon oxides captured exceeds certain threshold levels that are dependent on the type of facility where the carbon oxides are captured. The credit can be claimed over a **12-year period beginning on the date the carbon capture equipment is placed into service**.[5] Table 1 shows the applicable credit available by year for carbon capture equipment placed in service on or after February 9, 2018.[6]

Table 1: Expanded 45Q Tax Credit by Use ($ per metric ton of carbon oxide)[7]

Taxable Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Disposal In Secure Storage	22.66	25.70	28.74	31.77	34.81	37.85	40.89	43.92	46.96	50.00
EOR or Utilization	12.83	15.29	17.76	20.22	22.68	25.15	27.61	30.07	32.54	35.00

The amount of the credit varies based on how the carbon oxide is used. A higher credit is available for a taxpayer that disposes of carbon oxide in secure geological storage whereas a lower credit is available for carbon oxides that are either injected in a qualified EOR project or utilized by the taxpayer in a manner authorized under IRS Code § 45Q(f)(5) (e.g., use of carbon oxide for some commercial purpose, that converts carbon oxide into a material or chemical compound that "secures" it , or the "fixation" of carbon oxide by growing bacteria or algae). After 2026, the credit increases according to an inflation adjustment factor.[8]

ii. Who May Claim the Credit?

The taxpayer entitled to claim the credit is the owner of the qualified carbon capture equipment that either physically or contractually ensures that the captured carbon oxides are (1)

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[4] 26 U.S.C.A. § 45Q(f)(5). This paper does not focus on utilization of carbon oxide in commercial processes but rather focuses on injection of carbon oxides for sequestration in Class VI or Class II injection wells as such classification are defined below.

[5] 26 C.F.R. § 1.45Q-1(c).

[6] Lower credits are available for carbon capture equipment placed into service at a qualified facility prior to February 9, 2018. 26 C.F.R. § 1.45Q-1. Credits for carbon capture equipment placed into service before February 9, 2018, are subject to an alternative inflation adjustment factor under 26 C.F.R. § 1.45-Q1(b)(2). In the case of carbon capture equipment at a qualified facility placed in service before February 9, 2018, for which additional or modified carbon capture equipment is placed in service on or after February 9, 2018, IRS rules allow allocation of the lower pre-expansion credits and the higher post-expansion credits. 26 C.F.R. § 1.45Q-1(g).

[7] 26 C.F.R. § 1.45Q-1(d).

[8] *Id*.

disposed of into secure geologic storage, (2) injected into a qualified EOR project, or (3) utilized in an authorized manner. The owner of the carbon capture equipment, however, is not required to own the industrial facility at which the qualified carbon capture equipment is located.[9] IRS rules also allow multiple owners of qualified carbon capture equipment held through partnerships to claim and allocate the credit pursuant to a partnership agreement.[10]

If contracting to dispose of, inject for EOR, or utilize carbon oxides, then IRS rules impose minimum contract standards including that the contract be written, contain "commercially reasonable terms" (without expressly defining that phrase), require compliance with applicable regulations (e.g., regulations relating to secure geologic storage), provide notice of and information relevant to a possible "recapture" event (discussed further below), and contain other minimum requirements.[11] The contract may not limit damages to "a specified amount (for example, through use of a liquidated damages provision)."[12] With regard to limiting damages, § 1.45-1(h)(2)(i) states that "a contractual provision that limits damages to an amount equal to at least five percent of the total contract price will not be treated as limiting damages to a specified amount."[13] IRS rules also require that certain information related to the contract be reported annually.[14]

The taxpayer entitled to claim the credit can also elect, on an annual basis, to transfer the credit to the party that contractually performs the activities described in (1) through (3) above.[15] For example, IRS rules expressly state that the taxpayer electing to transfer the credit may transfer it to "the party that obtains the permit to dispose of the qualified carbon oxide in secure geological storage."[16] IRS rules provide additional flexibility by allowing the electing taxpayer to transfer the credit to multiple transferees proportional to the amount of carbon oxide disposed of, injected for EOR, or utilized.[17]

iii. Qualified Carbon Oxide

The 45Q tax credit is only available for the capture and disposal of, injection for EOR, or utilization of "qualified carbon oxides."[18] Qualified carbon oxides are those that are captured at "qualified facilities" (including "industrial sources" or "direct air capture facilities") and that (1) would otherwise be released into the atmosphere as an industrial emission of greenhouse gas, and (2) are measured at the capture source and "verified at the point of disposal, injection, or utilization."[19] With regards to "direct air capture" facilities, qualified carbon oxides includes any carbon oxide that is captured directly from ambient air and that is measured at the capture source and verified at the point of disposal, injection, or utilization.[20] Finally, the "initial deposit" of

[9] 26 U.S.C.A. § 45Q(f)(3)(ii).
[10] 26 C.F.R. § 1.45Q-1(h)(3).
[11] 26 C.F.R. § 1.45Q-1(h)(2).
[12] 26 C.F.R. § 1.45Q-1(h)(2)(i).
[13] *Id*.
[14] 26 C.F.R. § 1.45Q-1(h)(2)(v).
[15] 26 C.F.R. § 1.45Q-1(h)(3).
[16] *Id*.
[17] *Id*.
[18] Carbon oxides includes carbon dioxide (CO_2) and other carbon oxide. Carbon oxides and CO_2 are used interchangeably throughout this paper.
[19] 26 U.S.C.A. § 45Q(c)-(d).
[20] 26 U.S.C.A. § 45Q(c)(1)(C).

carbon oxides captured from industrial sources that are permanently sequestered in an EOR project also qualifies for the credit but not carbon oxides that are "recaptured, recycled or re-injected" as part of an EOR project.[21]

IRS regulations define the term "industrial source" as "an emission of carbon oxide from an industrial facility." The term "industrial facility" is defined as:

> "…a facility, including an electricity generating facility, that produces a carbon oxide stream from a fuel combustion source or fuel cell, a manufacturing process, or a fugitive carbon oxide emission source that, absent capture and disposal, injection, or utilization, would otherwise be released into the atmosphere as industrial emission of greenhouse gas or lead to such release."[22]

IRS rules define the term "manufacturing process" as:

> "…a process involving the manufacture of one or more products, other than carbon oxide, that are intended to be sold at a profit, or are used for a commercial purpose (other than producing carbon oxide). All facts and circumstances with respect to the process and products are to be taken into account."[23]

By way of example, refineries and natural gas processing plants which extract anthropogenic CO_2 as part of a manufacturing process constitute industrial sources for purposes of 45Q. As discussed below, the nature of the source is also important in determining the type of well into which carbon oxides may be injected.

iv. Qualified Carbon Capture Facilities and Equipment; Threshold Volumes

To qualify for the expanded 45Q tax credit, the qualifying carbon oxide must be captured at either an industrial source or direct-capture facility where "construction begins"[24] before January 1, 2026, and either (a) construction of the capture equipment begins before that date, or (b) the "original planning and design" for the facility called for installation of carbon capture equipment.[25] A qualified facility must also meet annual minimum carbon capture threshold volumes set out in 26 U.S.C.A § 45Q(d)(2). The minimum annual capture thresholds are linked to the type of facility:

[21] 26 U.S.C.A. § 45Q(c)(2).
[22] 26 C.F.R. § 1.45Q-2(d). Note: "An industrial facility does not include a facility that produces carbon dioxide from carbon dioxide production wells at natural carbon dioxide-bearing formations or a naturally occurring subsurface spring. For purposes of section 45Q, a carbon dioxide production well at natural carbon dioxide-bearing formations or a naturally occurring subsurface spring means a well that contains 90 percent or greater carbon dioxide by volume (90 percent test)." 26 C.F.R. § 1.45Q-2(d)(1).
[23] 26 C.F.R. § 1.45Q-2(d)(3).
[24] IRS Notice 2020-12, sects. 4-6, pp. 7-15 (Feb. 2020), for guidance on determining when "construction begins."
[25] 26 C.F.R. § 1.45Q-2(g). Note, the phrase "original planning and design" was not defined in the statute and the IRS elected not to define the term in its rules. 86 Fed. Reg. 4728, 4736 (Jan. 15, 2021).

(a) for industrial facilities and electric generating facilities that emit no more than 500,000 metric tons per year of carbon oxide that capture and "utilize" the carbon oxides under 26 U.S.C.A § 45Q(f)(5), the annual capture threshold is at least 25,000 metric tons;

(b) for electric generating facilities that emit more than 500,000 tons per years of carbon oxides, the annual capture threshold is at least 500,000 metric tons; or

(c) for any direct air capture facility and all other electric generating or industrial facilities (i.e. those not covered by (a) or (b) above), the annual capture threshold is at least 100,000 metric tons.[26]

To account for partial years when carbon oxides are captured, these minimum volumes can be annualized (or ratioed) for the first or last year of the 12-year period in which the credit can be claimed.[27] In some instances, taxpayers may also "aggregate" emissions from multiple qualified carbon capture facilities if they are part of a "single project" to meet the annual minimum threshold volumes. IRS Notice 2020-12, section 8, lists eight (8) factors for determining whether the multiple facilities meet the "single project" test.[28]

As stated previously, the owner of the "carbon capture equipment" is the taxpayer entitled to claim the credit. Under the 45Q regulations, "carbon capture equipment" is defined as equipment installed after February 9, 2018, that is required to capture, compress, treat, process, liquefy, and pump qualified carbon oxides. It also includes the gathering lines that collect captured carbon oxides at a qualified facility or from qualified facilities that constitute a "single project." Carbon capture equipment generally does not include pipelines and other equipment used for transporting carbon oxide for disposal in secure geologic formation, for injection in an EOR project, or for qualified utilization projects.[29] The IRS also recognizes that some facilities constructed before February 9, 2018, may be retrofitted to install new or additional carbon capture equipment to take advantage of the expanded tax credit.[30] The retrofit could result in some equipment having been installed prior to, and some after, February 9, 2018, or some equipment being "used" rather than "new." The rules provide that a facility retrofit or upgrade will qualify for the expanded credit if the fair market value of the used equipment comprises 20% or less of the total market value of the carbon capture equipment (the so-called "80/20 Rule" with new equipment comprising at least 80% of the total value).[31]

v. Secure Geological Storage

To qualify for a 45Q tax credit by disposing of qualified carbon oxides, the taxpayer must arrange for disposal of qualified carbon oxide in "secure geological storage" in a manner that prevents its escape to the atmosphere. Section 1.45Q-3(a) states that secure geological storage

[26] *See* 26 U.S.C.A § 45Q(d)(2); *see also* 26 C.F.R. § 1.45Q-2(g)(1).
[27] 26 C.F.R. § 1.45Q-2(g)(3).
[28] IRS Notice 2020-12, sect. 8, pp. 18-26 (Feb. 2020).
[29] *See* 26 C.F.R. § 1.45Q-2(g)(5) re: application of 80/20 rule to "new pipelines" to transport carbon oxides captured at qualified facility that would otherwise be emitted to the atmosphere.
[30] 26 C.F.R. § 1.45Q-2(g)(5).
[31] *See Id.*; *see also* 86 Fed. Reg. 4728, 4736-4737 (Jan. 15, 2021).

"includes, but is not limited to, storage at deep saline formations, oil and gas reservoirs, and unminable coals seams."[32] The 45Q regulations distinguish between injection into wells utilized for tertiary injection (e.g., an enhanced oil recovery project) and those that do not. Section 1.45Q-3 states:

> "**(b)** ***Requirements for secure geological storage.*** For purposes of the section 45Q credit, qualified carbon oxide is considered disposed of by the taxpayer in secure geological storage such that the qualified carbon oxide does not escape into the atmosphere if the qualified carbon oxide is -
>
> **(1)** Injected into a well that
>
> **(i)** Complies **<u>with applicable Underground Injection Control or other regulations</u>**, located onshore or offshore under submerged lands within the territorial jurisdiction of States or federal waters, and
>
> **(ii)** Is **<u>not used as a tertiary injectant</u>** in a qualified enhanced oil or natural gas recovery project, in compliance with applicable requirements under 40 CFR part 98 subpart RR; or
>
> **(2)** Injected into a well that
>
> **(i)** Complies with applicable Underground Injection Control or other regulations, is located onshore or offshore under submerged lands within the territorial jurisdiction of States or federal waters, and
>
> **(ii)** Is **<u>used as a tertiary injectant</u>** in a qualified enhanced oil or natural gas recovery project and stored in compliance with applicable requirements under 40 CFR part 98 subpart RR, or the International Organization for Standardization (ISO) standards endorsed by the American National Standards Institute (ANSI) under CSA/ANSI ISO 27916:2019, Carbon dioxide capture, transportation and geological storage - Carbon dioxide storage using enhanced oil recovery (CO2-EOR) (CSA/ANSI ISO 27916:2019)."[33] (emphasis added)

As discussed in greater detail below, there are two UIC injection well classifications relevant to commercial-scale CCS projects: Class II and Class VI wells. While most of the comments submitted and discussion included in the rule-making process focused on Class VI storage wells and Class II EOR wells, it is important to note that §1.45Q-3 does not expressly reference a specific class of Underground Injection Control ("UIC") well that must be used for secure geological sequestration. Instead, it merely references injection into "a well" that complies with "applicable [UIC] or other regulations."

The primary focus of the UIC program is protection of underground sources of drinking water ("USDWs"). Class II and Class VI wells are two of the six types of UIC well classifications

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[32] 26 C.F.R. § 1.45Q-3(a).
[33] 26 C.F.R. § 1.45Q-3(b).

established by the EPA under Section 1421 of the Safe Drinking Water Act for the purpose of protecting USDWs from endangerment.

EPA rules define Class II wells as wells that inject fluids:

> "(1) **Which are brought to the surface in connection with** natural gas storage operations, or **conventional oil or natural gas production and may be commingled with waste waters from gas plants which are an integral part of production operations**, unless those waters are classified as a hazardous waste at the time of injection.
>
> (2) **For enhanced recovery of oil or natural gas**; and
>
> (3) For storage of hydrocarbons which are liquid at standard temperature and pressure."[34] (emphasis added)

Class II wells encompass not only EOR wells but also wells used to dispose of produced water and acid gas injectors ("AGIs) used to dispose of hydrogen sulfide ("H_2S") and other fluids removed in natural gas processing such as CO_2.

Class VI wells are defined as:

> "wells that are "not experimental in nature **that are used for geologic sequestration of carbon dioxide beneath the lowermost formation containing a USDW**; or, wells used for geologic sequestration of carbon dioxide that have been granted a waiver of the injection depth requirements pursuant to requirements at § 146.95 of this chapter; or, wells used for geologic sequestration of carbon dioxide that have received an expansion to the areal extent of an existing Class II enhanced oil recovery or enhanced gas recovery aquifer exemption pursuant to §§ 146.4 of this chapter and 144.7(d)."[35] (emphasis added)

The reference to UIC wells "not used for tertiary" injection in section 1.45Q-3(b)(1) clearly includes Class VI wells used to sequester carbon dioxide. However, the reference in section (b)(1) to UIC wells "not used for tertiary" injection also likely encompasses (and under a strict interpretation would encompass) more than just Class VI wells; it would also include Class II injectors "not used for tertiary injection" such as traditional AGIs which are often used to dispose of a mixture of H_2S, CO_2, and other fluids. This is important for two reasons: (1) it suggests that the expanded 45Q tax credit applies to wells beyond Class VI wells and Class II EOR wells injecting CO_2; and (2) few states (only Wyoming and North Dakota) currently have primacy to permit and regulate Class VI wells, whereas most states have primacy to permit and regulate Class II wells. On this second point, EPA's Class VI permitting process is widely considered to be more technically demanding and time consuming than state-administered Class II permitting programs and, therefore, more risky and costly. Furthermore, at the time this paper was written, EPA Region 6 has not issued any Class VI permits, though there are four pending Class VI applications

[34] 40 C.F.R. § 144.6(b).

[35] 40 C.F.R. § 144.6(f).

currently under review with several more applicants in the process of submitting data (or "populating modules") using EPA's Geologic Storage Data Tool ("GSDT")—EPAs' electronic platform for uploading the required elements of an application and supporting data. By contrast, the Railroad Commission of Texas ("RRC") has permitted 200+/- AGIs over the last several decades through its Class II program. The mechanics of permitting Class VI and Class II wells and applicable regulations are discussed below in sections III and IV respectively.

Additional support for the proposition that the 45Q tax credit applies to non-EOR Class II wells injecting oil and gas fluids "brought to the surface in connection with oil and gas operations" (such as AGIs) can be found in language contained in the Federal Register at the time the IRS adopted amendments to its rules implementing the expanded 45Q tax credit. In the preamble to the IRS's adoption of the rule amendment in a section entitled "Secure Geological Storage," it states:

> "Injection of carbon oxide into any underground reservoir, onshore or offshore under submerged lands within the territorial jurisdiction of States, requires the operator to comply with Underground Injection Control (UIC) program regulations under the Safe Drinking Water Act and to obtain the appropriate UIC well permits. Under 40 CFR 146.5 (Classification of injection wells), **Class II may be an appropriate UIC well permit for wells that inject fluids (including carbon dioxide) brought to the surface in connection with conventional oil or natural gas production and may be commingled with waste waters from gas plants that are an integral part of production operations**, unless those fluids are classified as a hazardous waste at the time of injection, and for wells which inject fluids (including carbon oxides) for enhanced recovery of oil or natural gas."[36] (emphasis added)

Further, as discussed below, UIC staff at both EPA Region 6 and the RRC have within the last year issued draft or preliminary guidance recognizing Class II AGIs as potential vehicles for geological storage/CO_2 disposal. In fact, there are several projects underway across Texas involving Class II AGIs planning to inject CO_2 and claim the tax credit.

vi. Subpart RR and MRV Plans

In addition to injecting qualified carbon oxides in compliance with UIC standards, §1.45Q-3 of the IRS's rules states that qualified carbon oxides also must be injected in compliance with EPA's greenhouse gas ("GHG") reporting requirements contained in 40 CFR Part 98, Subpart RR (entitled "Geologic Sequestration of Carbon Dioxide"). Subpart RR requires facilities that are engaged in geological sequestration to report information regarding the amount of CO_2 received and injected, the amount of CO_2 lost through equipment leakage or from surface leakage, and related information. Importantly, Subpart RR also requires submission and approval of a Monitoring, Reporting and Verification ("MRV") plan under 40 CFR § 98.448 as part of demonstrating secure geological storage.[37] EOR wells injecting qualified carbon oxides are afforded additional flexibility under IRS rules and can demonstrate secure geologic storage by

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[36] 86 Fed. Reg. 4728, 4740 (Jan. 15, 2021).
[37] 26 C.F.R. § 1.45Q-3(b).

either complying with Subpart RR or with the International Organization for Standardization ("ISO") standards endorsed by the American National Standards Institute ("ANSI").[38]

GHG emissions must be reported under 40 CFR Part 98 according to the type of facility or "source category." The Subpart RR source category is comprised of "any well or group of wells that inject a CO_2 stream for long-term containment in subsurface geologic formations."[39] Section § 98.440(b) then specifically identifies Class VI wells as being part of the source category. However, § 98.440(c) states that Class II EOR wells injecting CO_2 are not part of the source category unless either: (1) the owner or operator of the well injects CO_2 for "long-term containment" in a geologic formation and chooses to submit an MRV Plan for approval by EPA; or (2) the well is permitted as a Class VI well under the UIC program.[40] Other Class II wells injecting CO_2 (such as AGIs) are not specifically addressed but are encompassed within the "any well" language employed by 40 CFR § 98.440(a).

Subpart RR MRV Plans are reviewed by EPA's Greenhouse Gas Reporting ("GHGR") branch, whose primary focus is on GHG releases to the atmosphere and related reporting requirements (whereas EPA-administered or state-administered UIC programs focus on the protection of groundwater). As discussed in detail below, the Class VI permitting process also requires compliance with Subpart RR and preparation of an MRV Plan. Class II wells injecting CO_2, however, typically report GHG emissions under Subpart UU and are not required to adopt an MRV Plan. But to qualify for the 45Q tax credit, Class II wells currently reporting under Subpart UU would need to obtain EPA approval of an MRV Plan, and once approved, begin reporting under Subpart RR. To date, most of the MRV plans processed by EPA have been for EOR projects where injection of some portion of the injected CO_2 is permanently stored. But there are examples of MRV Plans that have been submitted and approved for Class II AGI wells—one each in New Mexico and Wyoming with at least one pending for a project in Texas.[41] Note, the RRC's UIC department recently requested in calls with the authors that Texas Class II well applicants who obtain approved MRV Plans submit a copy to the RRC.

EPA guidance broadly identifies the primary components of an MRV Plan to include the following:

- Delineation of the maximum monitoring area ("MMA") and active monitoring area ("AMA").

- Identification of potential pathways for CO_2 to leak to the surface.

- A strategy for detecting and quantifying any surface leakage of CO_2.

- A strategy for establishing the expected baselines for monitoring CO_2 surface leakage.

- A summary of how the facility will calculate site-specific variables for the mass

[38] 26 C.F.R. § 1.45Q-3(b)(2).
[39] 40 C.F.R. § 98.440(a) (emphasis added).
[40] *See* 40 C.F.R. § 98.440(b) and (c); *see also* 40 CFR § 144.19 (entitled "Transitioning from Class II to Class VI").
[41] https://www.epa.gov/ghgreporting/subpart-rr-geologic-sequestration-carbon-dioxide.

> balance equation, such as considerations for calculating equipment leakage and vented emissions between flow meters and wells, and considerations for calculating CO_2 in produced fluids.

The MMA is defined as the area expected to contain the free-phase CO_2 plume until the CO_2 plume has stabilized, plus an all-around buffer zone of at least one-half mile. The AMA is defined in Subpart RR as:

> "Active monitoring area is the area that will be monitored over a specific time interval from the first year of the period to the last year in the period (t). The boundary of the active monitoring area is established by superimposing two areas:
>
> > (1) The area projected to contain the free phase CO2 plume at the end of year t, plus an all around buffer zone of one-half mile or greater if known leakage pathways extend laterally more than one-half mile.
> >
> > (2) The area projected to contain the free phase CO2 plume at the end of year t + 5."[42]

The first period for an AMA begins on the date selected by the applicant in the MRV Plan and extends through the date at which the plan calls for the first expansion of the monitoring area. The length of each monitoring period can be any time interval chosen by the applicant that is greater than 1 year.[43] The following figure, taken from EPA guidance, helps demonstrate the distinction between the MMA and AMA.

[42] 40 C.F.R. § 98.449.

[43] 40 C.F.R. § 98.448(a)(1).

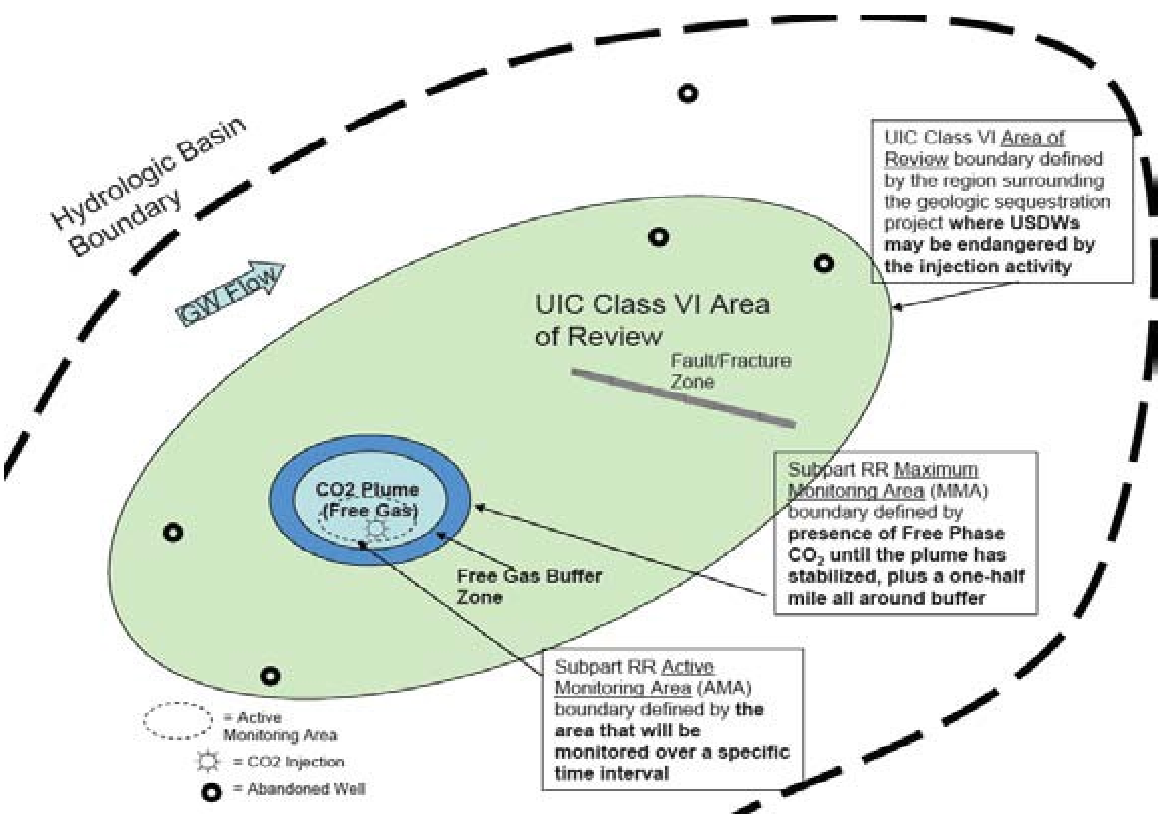

Figure 1: Monitoring Areas Under UIC Class VI and Subpart RR Requirements[44]

Note that wellbores penetrating the injection zone within these areas must be accounted for in the MRV Plan and may require corrective action (e.g., the re-entering and re-plugging of improperly plugged wells) to ensure that they cannot act as pathways for migration of CO_2 to USDWs or the surface—a key to ensuring "secure" geologic storage.

The timing for submitting an MRV Plan is critical and dependent, in part, on the type of facility for which the plan is being submitted. For most onshore facilities, a proposed MRV Plan must be submitted to EPA within 180 days of receiving a final UIC permit authorizing CO_2 injection. For an offshore facility that is not subject to the Safe Drinking Water Act, a proposed MRV Plan mut be submitted to EPA within 180 days of receiving authorization to begin geologic sequestration of CO_2.[45] EPA rules authorize one extension for plan submission for up to an additional 180 days.[46] If CO_2 is injected into a subsurface geologic formation for EOR purposes, and the wells are not permitted as Class VI, then an MRV Plan can be submitted at any time. Other filing deadlines and program requirements are also addressed in Subpart RR.[47]

[44] *Technical Support Document for Injection and Geologic Sequestration of Carbon Dioxide: Subparts RR and UU.* U.S. Environmental Protection Agency, Office of Air and Radiation, GHG Reporting Program, Figure 5-1 (November 2010).
[45] 40 C.F.R. § 98.448(b)(2).
[46] *Id.*
[47] 40 C.F.R. § 98.448(b)(3).

vii. Recapture

Why is it important that the geologic storage be "secure?" One obvious answer is that the 45Q tax credit applies only to carbon oxides that do not escape to the atmosphere. Likewise, under UIC standards, carbon oxides must be contained in the target injection formation and cannot be allowed to escape or threaten contamination of USDWs. An equally obvious answer is to avoid common law claims such as for trespass or groundwater contamination. However, there is also a provision within 45Q itself that emphasizes the importance of ensuring that geologic storage be secure.

Section 45Q-5(a) provides that previously claimed tax credits can be "recaptured" by the federal government if carbon oxides injected for secure geological storage are released to the atmosphere. It states in relevant part:

> "A recapture event occurs when qualified carbon oxide for which a section 45Q credit has been previously claimed ceases to be disposed of in secure geological storage (as described in § 1.45Q-3(b)), or used as a tertiary injectant during the recapture period."[48]

The extent of the credit recapture is tied to the amount of carbon oxides leaked to the atmosphere that is in excess of the amount securely stored or injected into a qualifying EOR project during a tax year. Section 45Q-5(g)(1) states:

> "… If the leaked amount of qualified carbon oxide does exceed the amount of qualified carbon oxide securely stored in the taxable year reported, then the taxpayer must add the recapture amount to the amount of tax due in the taxable year in which the recapture event occurs."

The volume of leaked carbon oxides is calculated and reported according to Subpart RR standards or, in the case of wells used for tertiary injectant, according to either Subpart RR or ISO/ANSI standards. IRS rules state that capture amounts are calculated on a last-in-first-out ("LIFO") basis, such that the leaked amount of qualified carbon oxide is deemed attributable first to the prior taxable year, then to the taxable year before that, and then up to a maximum of a third preceding year.

The period during which the taxpayer is subject to recapture is limited by the IRS regulations themselves. It begins on the date of first injection in the year the credit was claimed and ends on the earlier of "three years after the last taxable year in which the taxpayer claimed a section 45Q credit or was eligible to claim a credit" or "the date monitoring ends" under the requirements of Subpart RR or the ISO/ANSI standards.[49]

Subsection (i) provides for "limited exceptions" for when a recapture event is <u>not</u> triggered, stating that recapture will not result "in the event of a loss of containment of qualified carbon oxide resulting from actions not related to the selection, operation, or maintenance of the

[48] 26 C.F.R. § 1.45Q-5(a).
[49] 26 C.F.R. § 1.45Q-5(f).

storage facility, such as volcanic activity or terrorist attack."[50] This force majeure-type provision stands out primarily because of what might appear to be a limited number of excepted events—volcanic activity or terrorist attack. But in EPA's response to comments published in the Federal Register at the time the 45Q expansion rules were adopted, EPA made clear that those listed events were purely "illustrative."[51]

b. What Does "Secure" Storage Really Mean?

A critical determination for CCS project developers planning to claim 45Q tax credits, or for third parties planning to contract with tax credit claimants to inject their qualified carbon oxides for storage, is whether the storage will be "secure" as required under 26 CFR 1.45Q-3. Under 45Q, achieving secure geological storage would appear, on its face, to mean compliance with UIC regulations and an EPA-approved MRV plan (or, for an EOR project, either complying with an approved MRV plan or with ISO/ANSI standards). However, achieving secure storage requires a more complicated analysis and is perhaps best divided into three categories: **(1) geologic or geophysical security; (2) mechanical security; and (3) title security**.

Ensuring "secure geological storage" is not only important in a 45Q context but it is also an essential consideration in permitting Class VI and Class II UIC wells and in obtaining MRV plan approval. While the UIC and GHGR programs do not use that precise term, the concept of secure storage or containment is a fundamental regulatory underpinning of both the UIC and GHGR programs. From a project development perspective, the need to establish secure geologic storage requires careful siting of a CCS project and a detailed, up-front investigation of the local geology including localized faulting and seismic activity. A common question raised by CCS project developers is whether 2-D or 3-D seismic data is required for approval of a UIC injection permit or an MRV plan. With regard to Class II UIC approval in Texas and MRV plan approval under EPA's GHGR program, the answer is "no" but seismic data is clearly a helpful tool in establishing geologic security. In discussions with the authors, both RRC's UIC staff and EPA's GHGR branch confirmed that seismic data is not a required element of either a Class II injection permit application or an MRV plan. However, both stated that the applicant must provide sufficient technical support to prove containment of injected fluids for protection of USDWs (per UIC staff) and for prevention of leakage to the atmosphere (by EPA GHGR staff) and that seismic data could be beneficial in meeting that burden. While seismic analysis is not the only available tool for establishing geologic security, it may be one of the best—albeit a potentially costly one.

Another key element of secure storage is mechanical integrity. This primarily involves investigating wellbores that penetrate the injection zone within the MMA and analyzing the casing, cementing, and/or plugging history of those wells. Wells that penetrate the injection formation that do not have adequate casing and cement, that were improperly plugged, or where those protections are likely to have degraded due to time or corrosion, may compromise secure storage and might require corrective action including the re-entry of existing wellbores to ensure that they are not avenues for fluid migration to USDWs or the surface (see more detailed discussion below regarding corrective action in the Class VI permitting process). From an MRV plan approval perspective, it also means accounting for potential leakage from equipment located between the

[50] 26 C.F.R. § 1.45Q-5(i).
[51] 86 Fed. Reg. 4728, 4750.

wellhead and upstream flow meters.[52] Likewise, the monitoring plan required for Class VI and MRV plan approval is also a key element of ensuring sustained secure storage over the life of a CCS project.

A third, key element of establishing secure storage relates to record title or the ownership of the real property interests where the storage project is located. A good working knowledge of the title to the surface and mineral rights is crucial early in project development. While acquiring fee title to the lands encompassed by the MMA would be ideal, it is likely a CCS project unicorn for obvious practical and economic reasons. Locating a single large tract, or several contiguous relatively large tracts, with few penetrations of the injection zone within the MMA is probably the best one can expect for onshore projects. Locating such tracts in relatively close proximity to industrial sources is not easy—especially near large population centers. More onshore options are likely available near industrial sources in south and west Texas (but see discussion regarding Seismic Response Areas below). Offshore storage might prove a better option along the Gulf Coast. However, offshore CCS development involves higher costs, unique technical challenges, and longer project timelines.

In Texas, with its long history of mineral development, there are often competing uses of the subsurface pore space. As discussed in greater detail in section V below, Texas courts have typically found that the pore space is owned by the surface estate. Anecdotally and based on the authors' personal experience, it appears that most CCS project developers initially acquire an option to lease the storage rights (typically from the surface estate owners) with the intent to exercise the option to lease upon obtaining regulatory approval of their storage projects. The acquisition of storage rights becomes more legally and technically complicated where storage involves injection into minerally productive geologic formations, where there are minerally productive formations below the target storage zone, where there are existing injection wells competing for pore space, and/or for Class VI projects that have a bifurcated permitting process where drilling must be authorized and undertaken before a permit to operate is approved (see Class VI well permitting discussion below). Though they can be an extremely valuable source of data for geologic characterization of the target zone and related overlying and underlying confining zones, existing penetrations of the target storage zone can pose difficult well-permitting challenges. Ensuring those wells are properly cased, cemented and/or plugged is obviously important and part of the Class II permit, Class VI permit, and MRV plan regulatory review and approval process. Further, some historic penetrations will require corrective action (e.g., re-entry and re-plugging) and/or monitoring. There could also be active production from, or injection into, deeper formations and, if those deeper wells are not properly cased and cemented through the storage zone, then they could be pathways for escape of the stored fluids and thus potentially jeopardize "secure" geologic storage.

[52] For instance, 40 CFR § 98.448(a)(5) requires: "A summary of the considerations you intend to use to calculate site-specific variables for the mass balance equation. This includes, but is not limited to, considerations for calculating CO2 emissions from equipment leaks and vented emissions of CO2 between the injection flow meter and injection well and/or the production flow meter and production well, and considerations for calculating CO2 in produced fluids."

Even more challenging problems are posed by the possible need to account for future deep mineral development or future competing injection projects. Acquiring deep rights (storage and mineral rights in the storage zone and deeper horizons) is likely the best option second only to acquiring fee title but, like the acquisition of fee title, it is not always an available option. Another approach is to acquire the right to impose a deed restriction that limits mineral development of, or the use of (for injection, storage operations or otherwise), deeper formations or that at least impose casing, cementing and plugging requirements on parties drilling through the injection zone.

There are also regulatory tools that can provide an element of security such as: (1) adopting field rules at the RRC for the storage zone which alerts prospective oil and gas producers and injection well operators of existing storage operations and can impose casing, cementing and plugging requirements for wells completed in those zones; or (2) relying on RRC Rule 13 which offers some similar (though somewhat less comprehensive) protection as adopting field rules. RRC Rule 13 requires oil and gas operators to set steel casing and cement across and above all formations permitted for injection under RRC Rule 9, or immediately above all formations permitted for injection under Rule 46, for any well proposed within a one-quarter mile radius of an injection well.[53] Rule 13 also requires operators to case and cement across and above all potential flow zones and/or zones with corrosive formation fluids.[54] The RRC maintains a list of such known zones by RRC district and county and provides that list with each drilling permit it issues. If CO_2 is injected along with H_2S into a Class II AGI well, then designating the field as an H_2S and/or CO_2 storage field is likewise an option.

III. Federal Regulation of Class VI Wells

There are six classes of injection wells under the Safe Drinking Water Act's UIC program.[55] As mentioned above, Class VI is the newest classification and covers carbon sequestration wells.

a. Applicability and Class VI Classification Defined

The Class VI classification is for "[w]ells that are not experimental in nature that are used for geologic sequestration of carbon dioxide beneath the lowermost formation containing a USDW; or, wells used for geologic sequestration of carbon dioxide that have been granted a waiver of the injection depth requirements pursuant to requirements at § 146.95 of this chapter; or, wells used for geologic sequestration of carbon dioxide that have received an expansion to the areal extent of an existing Class II enhanced oil recovery or enhanced gas recovery aquifer exemption pursuant to §§ 146.4 of this chapter and 144.7(d)."[56]

The catch-all Class V classification, which is for shallow and/or complex injection wells not included in Class I, II, III, IV, or VI, cannot be used for geologic sequestration.[57] Geologic

[53] 16 TAC. § 3.13.
[54] *Id*.
[55] 40 CFR § 144.6.
[56] 40 CFR § 144.6(f).
[57] 40 CFR § 144.15 ("The construction, operation or maintenance of any non-experimental Class V geologic sequestration well is prohibited). 40 CFR §§ 144.6(e) and 144.80(e) ("Injection wells not included in Class I, II, III, IV, or VI.")

sequestration means the long-term containment of a gaseous, liquid, or supercritical carbon dioxide stream in subsurface geologic formations.[58]

Additionally, Class VI wells cannot be authorized by rule to inject carbon dioxide.[59] The owners or operators of Class VI wells must obtain a permit.

b. Permitting

At the time this paper was authored, there are only two Class VI wells permitted by EPA and both were in Region 5. A number of Class VI permit applications were pending but only four in Region 6 and none in Texas.[60] Early estimates from EPA and industry consultants suggest that the path to a Class VI permit to construct (or permit to drill) will take approximately two years. The permitting discussion that follows does not cover every aspect or element of a Class VI permit application as that would make this paper far more detailed than the regulations themselves. This paper is intended to highlight some of the more significant parts of the Class VI permit application process.

The Class VI permitting process is bifurcated where the applicant first obtains a construction permit for the well and then approval to inject into and operate the well.[61]

In the construction permitting phase of the process, the area of review dictates most of the information requirements.

i. Area of Review

The area of review ("AOR") is the region surrounding the geologic sequestration project where USDWs may be endangered by the injection activity.[62] The AOR is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide stream and is based on available site characterization, monitoring, and operational data.[63] The regulations do not identify the type of models that are acceptable. However, 2013 EPA guidance, though somewhat dated, does contain a non-exhaustive list of models that have been evaluated for use on carbon sequestration projects.[64]

The modeling is used to predict the projected lateral and vertical migration of the carbon dioxide plume and formation fluids in the subsurface. Then, based on that defined area, the applicant must identify all penetrations, including active and abandoned wells and underground mines, that may penetrate the confining layers of the injection zone. The applicant is required to determine which abandoned wells in the AOR have been plugged in a manner that prevents the movement of carbon dioxide or other fluids that may endanger USDWs, including use of materials

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[58] 40 CFR § 144.3; 40 CFR § 146.81(d). Geologic sequestration does not apply to carbon dioxide capture or transport.
[59] 40 CFR § 144.18.
[60] Only administratively complete applications appear in EPA's Table of Class VI Wells, of which only one application was administratively complete in Region 6 at the time of the paper.
[61] 40 CFR § 146.82(a) and (c).
[62] 40 CRF § 146.84.
[63] 40 CFR § 146.84(a).
[64] https://www.epa.gov/sites/default/files/2015-07/documents/epa816r13005.pdf at section 2.6.

compatible with the carbon dioxide stream.[65] The AOR analysis is perhaps the single most defining feature of a CCS project because it impacts so many aspects of the permitting process. For example, it dictates or affects any corrective action, geologic review, financial responsibility, and post-injection site care and site closure plan. So potential applicants should prioritize site selection to avoid existing wells or future penetrations.

ii. Corrective Action

Correction action must be performed on all wells within the AOR that need corrective action using methods designed to prevent the movement of fluid into or between USDWs.[66]

Corrective action is defined to mean "the use of Director-approved methods to ensure that wells within the area of review do not serve as conduits for the movement of fluids into underground sources of drinking water."[67] Corrective action might include plugging or re-plugging a nearby well, performing remedial cementing (e.g., perf and squeeze), or testing to determine well integrity. Importantly the corrective action plan must include information on how site access will be guaranteed for future corrective action.[68] Ensuring site access for the life of a Class VI well and the post-injection period is an important overall consideration when planning a project.

The owner or operator of a Class VI well must prepare, maintain, and comply with a plan to delineate the AOR for a proposed geologic sequestration project, periodically reevaluate the delineation, and perform corrective action as required.[69]

A couple of key points – the AOR can and will likely change over time as will any required corrective action plan. The minimum frequency at which the owner or operator is required to reevaluate its AOR is every five years.[70] All modeling inputs and data used to support AOR reevaluations must be retained for 10 years.[71]

iii. Financial Responsibility

Prior to issuance of the Class VI permit, the Regional Director must consider and approve the financial responsibility demonstration for all the phases of the geologic sequestration project.[72] The owner or operator of a Class VI well must demonstrate and maintain financial responsibility in the form of a financial instrument (e.g., bond or letter of credit) to cover the cost of (1) corrective action, (2) injection well plugging, (3) post injection site care and closure, and (4) emergency and remedial response. Written cost estimates of (1) through (4) must be based on the costs to the

[65] 40 CFR § 146.84(c)(3).
[66] 40 CFR § 146.84(d).
[67] 40 CFR § 146.81(d).
[68] 40 CFR § 146.84(b)(2)(iv).
[69] 40 CFR § 146.84(b).
[70] 40 CFR § 146.84(b)(2)(i).
[71] 40 CFR § 146.84(g).
[72] 40 CFR § 146.85(a)(5)(i).

regulatory agency of hiring a third party to perform the required activities (i.e., not a party who is within the corporate structure of the owner or operator).[73]

The owner or operator is under a continuing duty to provide updated information related to their financial responsibility instrument on an annual basis and to notify the agency of any adverse financial conditions that may affect the ability to carry out injection well plugging, post-injection site care, and site closure.[74]

Additionally, the owner or operator must maintain financial responsibility and resources until approved site closure, including approved completed post-injection site care and site closure plan.[75] The long duration of some Class VI projects, in particular the long post-injection timeframe, may pose challenges, at the time of permitting, for securing a financial instrument for the duration of a particular phase of the project or for the project as a whole.[76] For phases of the project that occur far into the future, the applicant may also try to establish an interim financial instrument to meet the financial responsibility requirements at the time of permitting if it is not possible to secure the specific instrument at that time.[77]

iv. Injection Well Construction

Applicants must submit proposed schematics and construction procedures for the injection well. This is to ensure that the well is constructed and completed to: (1) prevent the movement of fluids into or between USDWs or into any unauthorized zones; (2) permit the use of appropriate testing devices and workover tools; and (3) permit continuous monitoring of the annulus space between the injection tubing and long string casing.[78]

Federal UIC regulations require that surface casing extend through the base of the lowermost USDW and be cemented to surface.[79] That differs from RRC surface casing requirements, which are tied to the base of usable quality water and not the USDW.

Importantly the injection well must be constructed with cement and cement additives that are compatible with the carbon dioxide stream and subsurface chemistry.[80]

c. Pre-Operations and Operations

i. Logging, sampling, and testing prior to injection well operations

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[73] 40 CFR § 146.85(c)(1).
[74] 40 CFR §§ 146.85(a)(5)(ii) and 146.85(d).
[75] 40 CFR § 146.85(b)(1).
[76] https://www.epa.gov/sites/default/files/2018-01/documents/implementation_manual_508_010318.pdf at p. 4-27.
[77] *Id*.
[78] 40 CFR § 146.86(a).
[79] 40 CFR § 146.86(b)(2).
[80] 40 CFR § 146.86(b)(5).

Applicants must submit a proposed pre-operational formation and well-testing program that describes how they will test the well and analyze the chemical and physical characteristics of the injection and confining zones.[81] This plan must be approved before the well is drilled.[82]

During the drilling and construction of a Class VI well, the owner or operator must run appropriate logs, surveys, and tests to determine or verify the depth, thickness, porosity, permeability, and lithology of, and the salinity of any formation fluids in, all relevant geologic formations. This is to ensure conformance with the injection well construction requirements under Section 146.86 and to establish accurate baseline data against which future measurements may be compared.[83] The federal UIC logging, sampling, and testing requirements of a Class VI well are substantial and go well beyond what is typically run or required for Class II wells.

a. Surface Casing

Before and upon installation of the surface casing, the applicant must run resistivity, spontaneous potential, and caliper logs.[84] A cement bond and variable density log and temperature log must be run after surface casing is set and cemented.[85]

b. Long String Casing

Before and upon installation of the long string casing, the applicant must run resistivity, spontaneous potential, porosity, caliper, gamma ray, fracture finder logs, and any other logs that the EPA Regional Director may require (to the extent any others exist).[86] Just as with the surface casing, a cement bond and variable density log, and a temperature log must be run after the long string casing is set and cemented.[87]

Additionally, the rules require that the applicant run a series of tests to demonstrate the internal and external mechanical integrity of the injection well, including pressure tests with liquid or gas, a tracer survey (e.g. oxygen-activation logging), a temperature or noise log, and a casing inspection log.[88]

c. Cores and Sampling

The applicant must take whole cores or sidewall cores of the injection zone and confining system and formation fluid samples from the injection zone.[89] The applicant must also record the

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[81] 40 CFR § 146.82(a)(8).
[82] If the well has already been constructed (i.e., converting an existing well) then the applicant must provide documentation of prior logs, mechanical integrity tests, or other tests to inform a demonstration that the well was engineered and constructed to meet the goals of 40 CFR § 146.86.
[83] 40 CFR § 146.87(a).
[84] 40 CFR § 146.87(a)(2)(i).
[85] 40 CFR § 146.87(a)(2)(ii).
[86] 40 CFR § 146.87(a)(3)(i).
[87] 40 CFR § 146.87(a)(3)(ii).
[88] 40 CFR § 146.87(a)(4).
[89] 40 CFR § 146.87(b). The Regional Director has the discretion to accept information on cores from nearby wells if the owner or operator can demonstrate that core retrieval is not possible and that such cores are representative of conditions at the well. The Regional Director may also require cores from other formations.

fluid temperature, pH, conductivity, reservoir pressure, and static fluid level of the injection zone.[90] A determination of the fracture pressure of the injection and confining zones must also be made by the applicant.[91]

Upon completion, but prior to operation, the applicant must conduct a pressure fall-off test and either a pump test or injectivity test. Additional testing may include seismic monitoring to determine if seismic activity may impact the confining zone.[92]

At this point the owner or operator must obtain approval for the operation of the Class VI well.[93] Operation of the well requires consideration of the final AOR based on modeling and the site-specific data collected during the logging, testing, and sampling phase.

ii. Well Operating Requirements

The Class VI permitting process also includes reviewing the proposed injection pressure, annulus pressure, and planned down-hole shut-off systems to ensure that injection rates and volumes are appropriate to the site geology and the well's construction. Injection pressure in a Class VI well may not exceed 90 percent of the fracture pressure of the injection zone to ensure that injection does not initiate new fractures or propagate existing fractures within the injection zone.[94] Injection pressure may not also initiate fractures in the confining zones or cause the movement of injection or formation fluids that endangers a USDW.[95] Any stimulation plan must be approved as part of the permit application and incorporated into the permit.[96]

The annulus (the space) between the tubing (injection through tubing is required) and the long-string casing must be filled with a non-corrosive fluid and pressure on that annulus must exceed the operating injection pressure of the injection well.[97] This is a way to avoid leaking of injection fluid from the tubing into the annulus.

The applicant must also provide for continuous monitoring, alarms, automatic surface shut-off systems (onshore wells), and automatic down-hole shut-off systems (offshore wells). There are also notification requirements when there is a loss of mechanical integrity indicated by the monitoring.[98]

A Class VI well has mechanical integrity if there is no significant leakage in the casing, tubing, or packer, and there is no significant fluid movement into an USDW through channels adjacent to the injection well bore.[99] Proof of mechanical integrity comes in the form of continuous

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[90] 40 CFR § 146.87(c).
[91] 40 CFR § 146.87(d).
[92] https://www.epa.gov/sites/default/files/2018-01/documents/implementation_manual_508_010318.pdf at p. 4-35.
[93] 40 CFR § 146.82(c).
[94] 40 CFR § 146.88(a).
[95] 40 CFR § 146.88(a).
[96] 40 CFR § 146.88(a).
[97] 40 CFR § 146.88(c). There are exceptions if the Regional Director determines that maintaining a higher annulus pressure would harm the integrity of the well or endanger USDWs.
[98] 40 CFR §§ 146.88(e) and (f).
[99] 40 CFR § 146.89(a).

monitoring of injection pressures, rates, injected volumes, annulus pressures, and annulus fluid volumes.[100]

At least once per year, the owner or operator must determine the absence of significant fluid movement by running an approved tracer survey (such as an oxygen-activation log), or a temperature or noise log.[101] It may also become necessary to run a casing inspection log to determine whether there is corrosion in the long-string casing.[102]

In addition to the pre-operating testing requirements, there are significant operating testing and monitoring requirements. The rules require applicants to develop and implement a comprehensive testing and monitoring plan that includes injectate monitoring, corrosion monitoring of the well's tubular, mechanical, and cement components, mechanical integrity testing, pressure fall-off testing, groundwater quality monitoring, carbon dioxide plume and pressure front tracking, and at the discretion of the UIC Program, surface air and/or soil gas monitoring.[103]

iii. Reporting

Reporting requirements are in Section 146.91, which notably requires semi-annual reporting of any changes to the physical, chemical, and other characteristics of the carbon dioxide stream from the proposed operating data. This is to confirm that the stream's composition remains consistent with the permit and the information on which predictions of no adverse interaction between the injectate and well materials or formation fluids were based. Other operational data (e.g. pressure, rate and volume) and descriptions of any events that exceed certain operating parameters or trigger shut-off devices must be included in the semi-annual report.[104]

iv. Emergency and Remedial Response Plan

The Emergency and Remedial Response Plan ("ERRP") is a part of the Class VI permit application. It must address movement of the injection or formation fluids that may cause an endangerment to a USDW during construction, operation, and post-injection site phases.[105] The owner or operator of the well is required to take specific actions if it obtains evidence that the injected carbon dioxide stream and associated pressure front may cause an endangerment to a USDW. Those actions include immediately ceasing injecting, identifying and characterizing any release, notifying the EPA Regional Director within 24 hours, and implementing the ERRP.[106]

d. Post-Injection

During the post-injection phase, after injection has ceased, Class VI well owners or operators must conduct monitoring to confirm project behavior over time. Also during this phase,

[100] 40 CFR § 146.89(b).
[101] 40 CFR § 146.89(c).
[102] 40 CFR § 146.89(d).
[103] 40 CFR § 146.90
[104] 40 CFR § 146.91(a).
[105] 40 CFR § 146.94(a).
[106] 40 CFR § 146.94(b).

the owner or operator must plug the injection well and monitoring wells to ensure they do not become conduits for fluid movement that could endanger USDWs.

i. Plugging

A well plugging plan is part of the Class VI well construction permit application. The plugging requirements, include flushing the Class VI well with a buffer fluid, determining the bottomhole reservoir pressure, and performing a final external mechanical integrity test.[107]

ii. Post-Injection Site Care and Site Closure

This plan addresses activities that occur following cessation of injection. The owner or operator must continue to monitor the site for 50 years following the cessation of injection, or for an approved alternative timeframe, until it can be demonstrated that no additional monitoring is needed to ensure that the project does not pose an endangerment to USDWs ("Non-Endangerment Demonstration"). The Non-Endangerment Demonstration must be based on monitoring and other site-specific data and should verify that (1) the carbon dioxide plume and pressure front are behaving as predicted and (2) the pressures within the subsurface area dissipating.

Once it is determined by the EPA Regional Director that no additional monitoring is needed to ensure that the geologic sequestration project does not pose an endangerment to USDWs, then site closure can be authorized.[108] After site closure is authorized by the Regional Director, the owner or operator must plug all monitoring wells.[109]

Within 90 days of site closure, the owner or operator must submit a site closure report that includes: (1) documentation of appropriate well plugging and a copy of a survey plat which has been submitted to the local zoning authority designated by the Regional Director;[110] (2) documentation of appropriate notification and information to such other authorities (e.g. RRC) that have authority over drilling activities to enable such authorities to impose appropriate conditions on subsequent drilling activities that may penetrate the injection and confining zones; and (3) records reflecting the nature, composition, and volume of the carbon dioxide stream.[111]

Finally, the owner or operator of the Class VI well must record a notation on the deed to the facility property or any other document that are normally examined during a title search that will, in perpetuity, provide any potential purchaser of the property the following information: (1) the fact that the land has been used to sequester carbon dioxide; (2) the name of the State agency, local authority, and/or Tribe with which the survey plat was filed, as well as the address of the EPA Regional Office to which it was submitted; and (3) the volume of fluid injected, the injection zone into which it was injected, and the period over which injection occurred.[112]

[107] 40 CFR § 146.92(a).
[108] 40 CFR § 146.93(b)(3).
[109] 40 CFR § 146.93(e).
[110] The plat must indicate the location of the injection well relative to permanently surveyed benchmarks. 40 CFR § 146.93(f)(1).
[111] 40 CFR § 146.93(f).
[112] 40 CFR § 146.93(g).

Overall, the Class VI permitting process is an iterative process that evolves over time as more data and information is gathered. Owners and operators are required to continuously monitor and update the various plan components of the permit to ensure that USDWs are protected throughout the life of the project and the 50-year post-injection period.

e. Acid Gas Injectors and Transitioning from Class II to Class VI

Additional insight to the question of whether the 45Q tax credit applies to Class II AGIs can be found in recently issued <u>draft</u> guidance. At the time of the authoring of this paper, EPA had issued the following draft guidance as it relates to AGIs.

> "Acid Gas Wells
>
> In 2015, EPA issued a memorandum titled "Key Principles in EPA's Underground Injection Control Program Class VI Rule Related to Transition of Class II Enhanced Oil or Gas Recovery Wells to Class VI." The Memorandum provides high level guidance in the form of six key principles related to the transitioning of Class II Enhanced Recovery (ER) wells that store CO2 from Class II operations to the Class VI. The Office of Ground Water and Drinking Water, in consultation with the Office of General Counsel, interprets the Memorandum's key principles related to the transition of Class II ER wells to the Class VI program as applicable to Class II-D acid gas wells. Such an interpretation is legally consistent with the UIC Class VI Well Regulations, specifically 40 CFR 144.19.
>
> If the purpose of injecting CO2 and/or sour gas is permanent storage, it is by definition sequestration."

EPA's draft guidance, if formally adopted, would take EPA's rules for transitioning operations from Class II to Class VI injection that have historically been applied to Class II EOR injection of anthropogenic CO_2 and extend them to Class II AGIs. 40 CFR § 144.19 (entitled "Transitioning from Class II to Class VI") provides:

> (a) Owners or operators that are injecting carbon dioxide for the primary purpose of long-term storage <u>**into an oil and gas reservoir**</u> must apply for and obtain a Class VI geologic sequestration permit when there is <u>**an increased risk to USDWs**</u> compared to Class II operations. (emphasis added)

Subsection (b) states that the UIC "Director" shall determine whether there is "an increased risk to USDWs" posed by Class II injection operations and whether a Class VI permit is required. As referenced above, additional guidance for transitioning EOR wells injecting anthropogenic CO_2 from Class II to Class VI is provided in a 2015 EPA memo.[113] That memo makes clear that the "Director" charged with analyzing the increased risk to USDWs is the state UIC director for those states, like Texas, that have primary enforcement responsibility under the Class II UIC program. In the memo, EPA "encourages" state Class II directors to coordinate with EPA's Class VI

[113] https://www.epa.gov/sites/default/files/2020-08/documents/class2eorclass6memo_0.pdf

directors when the state director "believes that the risk has changed as a result of significant storage of CO2 in the reservoir."[114] As discussed below in section IV.b.ii, the RRC, in coordination with EPA Region 6, has likewise recognized in draft guidance the concept that Class II AGI operations may be required to transition to Class VI operations with the "key factor" being whether there is an "increased risk to USDWs" where the "regulatory tools of the Class II program cannot successfully manage the risk."

i. No Increased Risk to USDWs

EPA's transition rule lays out nine factors that the UIC Director must consider in determining whether there is "an increased risk to USDWs" posed by Class II injection operations that would require transition to Class VI for purpose of long-term storage of anthropogenic CO_2.[115] Those factors are:

(1) Increase in reservoir pressure within the injection zone(s);

(2) Increase in carbon dioxide injection rates;

(3) Decrease in reservoir production rates;

(4) Distance between the injection zone(s) and USDWs;

(5) Suitability of the Class II area of review delineation;

(6) Quality of abandoned well plugs within the area of review;

(7) The owner's or operator's plan for recovery of carbon dioxide at the cessation of injection;

(8) The source and properties of injected carbon dioxide; and

(9) Any additional site-specific factors as determined by the Director.[116]

Clearly, these factors make sense in an EOR context where the primary focus is shifting from flooding operations for enhancing production to injecting CO_2 for long-term storage. However, as evidence by EPA's and the RRC's recent draft guidance, it appears that EPA and state UIC programs likely will now apply these factors to Class II AGIs disposing of CO_2 captured from oil and gas production. In fact, the RRC has indicated that, for Class II wells injecting CO_2 for disposal, it plans to require additional data to be submitted as part of the Class II application process or as permit conditions to ensure no increased risk to USDWs including step-rate tests ("SRTs"), post-permitting bottom-hole pressure monitoring and reporting, and possibly plume modeling.

[114] *Id*.
[115] 40 CFR § 144.19(b).
[116] *Id*.

IV. State Regulation of Class VI & Class II Wells

a. Class VI Wells

Currently, only two states have obtained primacy to administer a Class VI well program: Wyoming and North Dakota. Louisiana is expected to obtain approval of its primacy application in 2022 or 2023. Until Texas obtains primacy, developers of CCS projects in Texas that plan to store CO_2 from industrial sources by injecting into Class VI wells (i.e. CO_2 that is not brought to the surface in connection with oil and gas production operations) must file Class VI permit applications with EPA Region 6 in Dallas.

Texas' journey to obtain primacy can be traced back to 2009 when the Texas Legislature established a legal framework for regulating geologic storage of anthropogenic CO_2. The Legislature divided regulatory authority between the RRC and the Texas Commission on Environmental Quality ("TCEQ") and charged both agencies with adopting regulations within their respective jurisdiction and with developing programs for the purposes of obtaining primacy over the geologic storage and "associated injection" of anthropogenic CO_2.

In response to this legislation and effective December 10, 2010, the RRC adopted Chapter 5 (entitled "Carbon Dioxide") which generally covers two sets of permitting procedures; the first of which is a detailed permitting regime governing geologic storage operations (under Chapter 5, Subchapter B, of the RRC's rules),[117] and the second of which sets out a certification process for the injection and incidental storage of CO_2 for the purposes of EOR projects (under Chapter, Subchapter C).[118]

Then, during the 2021 legislative session, the Texas Legislature enacted H.B. 1284 which gives the RRC sole authority to regulate Class VI UIC wells once Texas obtains primacy.[119] Concentrating Class VI regulatory authority in the RRC should add consistency to the Class VI program and will take advantage of the RRC's technical expertise developed over several decades of regulating Class II EOR and AGI wells in Texas.

Until Texas obtains primacy over the Class VI program, EPA Region 6 and the RRC will review Class VI permit applications on a "parallel" track. Recently, the RRC posted guidance on its website regarding this parallel permitting process stating:

> "Until RRC receives Class VI primacy, any applicant for geologic storage of anthropogenic CO_2 unrelated to EOR will need to submit an application to both EPA and the RRC. However, RRC staff have been coordinating with EPA to ensure that both agencies perform the application review on a parallel track, using the EPA Geologic Storage Data Tool (GSDT) so that when the RRC receives primacy, the transfer will be as seamless as possible."[120]

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[117] 16 TAC § 5.201 *et seq*.
[118] 16 TAC § 5.301 *et seq*
[119] Tex. H.B. 1284, 87th Leg., R.S. (2021).
[120] https://www.rrc.texas.gov/oil-and-gas/applications-and-permits/injection-storage-permits/co2-storage/

At the time of the authoring of this paper, not all the details of this parallel permitting process had been ironed out. However, until the RRC obtains primacy, EPA Region 6 is the lead permitting authority for Class VI wells in Texas. The RRC has confirmed that, until primacy is obtained, Class VI well applicants in Texas are not required to file a separate storage application with the RRC but they will still have to comply with various other RRC rules including filing a form P-5 Organization Report, obtaining drilling permits, paying associated permit fees, etc. Also, as discussed in greater detail below, Class II EOR applicants that plan to store anthropogenic CO_2 incidental to their EOR operations may still obtain injection authorization under RRC Rule 46.

i. Current Status of RRC Primacy Application

The RRC initiated the primacy approval process for Texas when it began the pre-application process known as a "crosswalk" which is a process for comparing current state rules to EPA's existing regulations in order to identify areas within the state program that require revision to meet minimum federal Class VI requirements. A state seeking primacy typically conducts its "crosswalk" in consultation with EPA before initiating the formal, four-phase process for obtaining primacy. At the time this paper was written, the RRC had completed its internal crosswalk review and was in the process of developing proposed amendments to its rules that would then be submitted to the Railroad Commissioners for review and approval for publication. The rules being amended include RRC geologic storage rules contained in Chapter 5, Subchapter B. The proposed RRC rule amendments would then be published for public comment.

Upon final adoption of the amendments, the RRC will initiate the four-phased primacy application process. In Phase I, the state submits "pre-application" information to EPA including its crosswalk comparison, rule amendments, and other steps the state proposes to take to implement a Class VI program. Phase II ("Completeness Review and Determination") involves state submission and EPA review of the critical elements of the primacy application to make sure the application is complete. In Phase III ("Application Evaluation"), EPA conducts a detailed evaluation of the state's application and proposed Class VI program and includes an opportunity for the public to comment on, and request a public hearing on, the primacy application. Upon reviewing the public's comments, EPA may request additional revisions to the state's primacy application. Finally, in Phase IV ("Rulemaking and Codification"), EPA drafts a final rule approving or disapproving of the state's primacy application and proposed Class VI program and publishes the final rule along with its responses to public comment in the Federal Register.

Primacy application approval is clearly a multi-year process and it is likely to be several years before the RRC obtains final approval of its proposed Class VI program.

b. Class II Wells

Prior to initiating injection operations, an operator must obtain a Class II injection permit under either Rule 9 (entitled "Disposal Wells") or Rule 46 (entitled "Fluid Injection into Productive Reservoirs").[121] The two rules are very similar in terms of the type of information that is submitted in support of the applications, the parties entitled to notice of the application, and the

[121] RRC policy states that a "productive" reservoir is one that is currently or historically productive of oil and gas within 2 miles of the proposed injection well.

RRC's review process. One important difference is that Rule 46 applicants must file RRC forms H-1 and H-1A in support of their application whereas applications under Rule 9 must file form W-14.

Under both Rules 9 and 46, notice of the applications must be mailed or delivered to: (1) the owner of record of the surface tract on which the well is located; (2) each commission-designated operator of any well located within one-half mile of the proposed injection well; (3) the county clerk of the county in which the well is located; and (4) the city clerk or other appropriate city official of any city where the well is located within the corporate limits of the city.[122] If the well is a commercial disposal well, then notice must also be provided to the record owners of each surface tract that adjoins the tract where the injection is or will be located.[123] Notice, on a form approved by the RRC, must also be published once in a newspaper of general circulation in the county where the well is or will be located.[124] Protests by affected parties must be received within 15 days of receipt of the notice or the date notice is published, whichever is later. If no protest is received, then the RRC may issue the permit administratively without holding a hearing.[125] If a protest is received, the applicant can challenge the protestant's standing as an "affected party" which typically occurs at a pre-hearing conference (i.e., at a conference administered by the administrative law judge ("ALJ") held before the hearing on the merits of the application). An affected party is defined in the rules as "a person who has suffered or will suffer actual injury or economic damages other than as a member of the general public or as a competitor and includes surface owners of property on which the well is located and commission designated operators within one-half mile" of the proposed well. If a hearing on the merits is required, then it is presided over by the ALJ and a technical examiner, who make recommendations, and submit a proposed final order, to the elected Commissioners. The Commissioners vote on whether to grant or deny the application in an open meeting. Appeals of the Commission's decision (or final order) are first made to the Travis County district court in Austin, then to the Third Court of Appeals, and ultimately to the Texas Supreme Court.

To obtain an injection permit, the operator must show that injected fluids will not endanger oil, gas, or recoverable hydrocarbons or endanger USDWs. As a practical matter, this requires a showing that injected fluids will be confined to the proposed injection interval. As part of the application, the operator typically must review public data for wells that penetrate the proposed disposal zone within a one-quarter mile radius of the proposed injection well to determine if all wells within that area of review have been properly cased, cemented, or plugged in a manner that will prevent the movement of fluids from the disposal zone into freshwater strata.[126] However, for Class II wells used to inject qualified carbon oxides in "secure geological storage" for purposes of obtaining the 45Q tax credit, the one-quarter mile radius area of review required under Rule 46 is likely far smaller than the MMA (the plume plus one-half mile buffer) analysis required for MRV Plan approval under Subpart RR.

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[122] 16 TAC § 3.9(5)(A); 16 TAC § 3.46(c)(1).

[123] 16 TAC § 3.9(5)(B); 16 TAC § 3.46(c)(2). A commercial disposal well is a well whose owner or operator receives compensation from others for the disposal of oil field fluids or oil and gas wastes that are wholly or partially trucked or hauled to the well, and the primary business purpose for the well is to provide these services for compensation. 16 TAC § 3.9(4); 16 TAC § 3.46 (b)(2).

[124] 16 TAC § 3.9(5)(D); 16 TAC § 3.46(c)(4)

[125] 16 TAC § 3.9(5)(F); 16 TAC § 3.46(c)(6).

[126] 16 TAC § 3.46(e)(1).

Rules 9 and 46 also contain monitoring, testing and reporting requirements for injection wells.[127] The RRC retains authority to revoke, suspend or modify an injection permit when:

> (A) a material change of conditions occurs in the operation or completion of the injection well, or there are material changes in the information originally furnished;
> (B) fresh water is likely to be polluted as a result of continued operation of the well;
> (C) there are substantial violations of the terms and provisions of the permit or of commission rules;
> (D) the applicant has misrepresented any material facts during the permit issuance process;
> (E) injected fluids are escaping from the permitted injection zone;
> (F) for a disposal well permit under this section, injection is likely to be or determined to be contributing to seismic activity; or
> (G) waste of oil, gas, or geothermal resources is occurring or is likely to occur as a result of the permitted operations.[128]

RRC rules also permit an operator to apply for broader, more general authority to conduct injection activity using multiple wells within a specified area by obtaining an "area permit."[129] This provision may be more administratively convenient where an operator seeks to permit numerous injection wells and retain more flexibility in locating injection wells.

i. State Tax Incentives for EOR Operations Injecting Anthropogenic CO_2

Applicants for geologic storage of anthropogenic CO_2 incidental to EOR operations should submit an application to inject under Rule 46. Additionally, an applicant may be entitled to a reduced state severance tax rate under Rule 50 ("RRC Enhanced Oil Recovery Projects")—including the additional state severance tax reductions available for storing anthropogenic CO_2 as part of EOR operations.

Rule 50 provides for a certification process under which operators of EOR projects may obtain the benefits of certain tax exemptions set forth in Texas Tax Code §§ 202.052, .054, and .0545.[130] Pursuant to these tax exemptions, operators of qualifying EOR projects are entitled to a one-half reduction of severance tax on oil from the usual 4.6% of market value to 2.3% of market value.[131] EOR projects using anthropogenic CO_2 that meet certain additional requirements are entitled to an additional 50% reduction.[132]

To qualify under Tax Code § 202.054, the operator of an EOR project must apply to the RRC and obtain RRC approval before injection commences. Therefore, to obtain the substantial tax benefits provided by the Texas Tax Code, it is imperative that the unit operator file and obtain

[127] 16 TAC § 3.46(i), (j).
[128] 16 TAC § 3.46(d) 16 TAC § 3.9(6).
[129] 16 TAC § 3.46(k).
[130] 16 TAC § 3.50.
[131] Tex. Tax Code §§ 202.052 and 202.054.
[132] Tex. Tax Code § 202.0545.

approval of its Rule 50 application *before* injection commences. An application under Rule 50 is initiated by filing form H-12 and required attachments with the RRC.

The requirements for the additional tax abatements for EOR projects injecting anthropogenic CO_2 are set forth in Texas Tax Code § 202.0545. To qualify, the EOR project must use CO_2 that:

(1) is captured from an anthropogenic source in Texas;
(2) would otherwise be released into the atmosphere as industrial emissions;
(3) is measurable at the source of capture; and
(4) is sequestered in one or more geological formations in Texas following the enhanced oil recovery process.[133]

In order to obtain the tax reduction, the operator must apply to the Texas comptroller for the reduction and apply for a certification from the RRC under the RRC's Chapter 5, Subchapter C, regulations.

The RRC may issue the certification only if it finds that there is a reasonable expectation that at least 99 percent of the carbon dioxide will remain sequestered for at least 1,000 years and that the operator's planned sequestration program will include appropriately designed monitoring and verification measures that will be employed for a period sufficient to demonstrate whether the sequestration program is performing as expected.[134] RRC Form H-12A is used to apply for certification.

ii. Acid Gas Injectors Used for CO_2 Disposal and/or Storage

In addition to complying with the requirements of RRC Rules 9 and 46, AGI applicants must also comply with the applicable provisions of Rule 36 (entitled "Oil, Gas, or Geothermal Resource Operation in Hydrogen Sulfide Areas").[135] Even if a Rule 9 or 46 application is not protested by an affected party, Rule 36 may nevertheless require a hearing before the RRC. Rule 36 states in relevant part:

"(10) Injection provision.

(A) Injection of fluids containing hydrogen sulfide shall not be allowed under the conditions specified in this provision unless first approved by the commission **<u>after public hearing</u>**:

(i) where injection fluid is a gaseous mixture, or would be a gaseous mixture in the event of a release to the atmosphere, and where the 100 ppm radius of exposure is in excess of 50 feet and includes any part of a public area except a public road; or, if the 500 ppm radius of exposure is in excess of 50 feet and includes any part of a public road; or if the 100 ppm radius of exposure is 3,000 feet or greater;

[133] Tex. Tax Code § 202.0545(a).
[134] 16 TAC § 3.50.
[135] 16 TAC § 3.36.

(ii) where the hydrogen sulfide content of the gas or gaseous mixture to be injected has been increased by a processing plant operation."[136] (emphasis added)

Notice of an AGI application is provided pursuant to either Rule 9 or Rule 46 depending on the type of formation into which the H_2S is being injected (non-productive versus productive formations). However, the form for publishing notice is different for AGIs than those used for other Class II wells and includes, among other things, information regarding the H_2S radius of exposure ("ROE"). Under current RRC policy, the ROE is calculated using the highly conservative Pasquill-Gifford equation though, in certain rural areas, the RRC will sometimes allow the ROE to be calculated using air modeling. AGI applicants also must comply with other Rule 36 requirements including providing information regarding H_2S monitoring, employee training, emergency response activities, submission of RRC form H-9, and developing a contingency plan in the event of an H_2S release.

Importantly, RRC staff recently provided informal draft guidance regarding the potential for carbon sequestration in Class II AGI wells which is provided here with RRC permission:

"Information concerning the classification of acid gas disposal wells under the Underground Injection Control program can be found on EPA's website at Final Class VI Guidance Documents.

On this webpage, the introduction to EPA's 2015 Memorandum related to Key Principles in EPA's Underground Injection Control Program Class VI Rule Related to Transition of Class II Enhanced Oil or Gas Recovery Wells to Class VI, states that EPA "interprets these key principles as applicable to Class II-D acid gas wells."

Therefore, the following principles apply to Class II-D acid gas wells:

1. Injection of acid gas that contains CO2 and was generated as part of oil and gas processing may continue to be appropriately permitted under the UIC Class II program.

2. **Injection of acid gas containing CO2 does not necessitate a Class VI permit**.

3. Class VI site closure requirements are not required for Class II acid gas injection operations. A Class II-D well that has been used for injection of acid gas containing CO2 and has been operated within its permit conditions can be closed as a Class II well.

4. If acid gas disposal associated with an oil or gas lease, unit, field or gas processing facility is a Class II permitted operation, the key factor in determining the potential need to transition an acid gas disposal well from Class II to Class VI is the **increased risk to USDWs** related to significant storage of CO2 in the reservoir, where the regulatory tools of the Class II program cannot successfully

[136] 16 TAC § 3.36(c)(10).

> manage the risk. The most direct indicator of increased risk to USDWs is increased pressure in the injection zone related to the significant storage of CO2. Increases in pressure with the potential to impact USDWs should first be addressed using tools within the Class II program. Transition to Class VI should only be considered if the Class II tools are insufficient to manage the increased risk.
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> 5. Class II and Class VI directors will work together to address the potential need for transition of any individual operation from a Class II to a Class VI permit. The Class II program director will have the relevant data on pressure and volume of CO2 injected into Class II acid gas disposal wells, which will influence any transition decision.
>
> …
>
> **The Commission may request additional information to assist in the evaluation of acid gas disposal wells permitted as Class II UIC wells, including the source(s) of the CO2, reservoir pressure data, and CO2 monitoring data.**" (emphasis added)

The RRC's draft guidance expressly recognizes the ability to inject CO_2 into an AGI without the necessity of obtaining a Class VI permit. It is important to note, however, that it is unclear at the time this paper was authored whether the RRC will permit a well injecting pure CO_2 that otherwise meets the Class II definition (i.e., injection of fluids brought to the surface as an "integral part" of oil and gas production operations) as a Class II well.

c. West Texas "Seismic Response Areas"

Though not a focus of this paper, it is important to note that the permitting of any new injector is greatly complicated if the proposed injection well is located in an RRC-designated Seismic Response Area ("SRA"). There are currently three SRAs, all located in West Texas, which were formed in response to increased and intensifying seismic activity: (1) the Gardendale SRA; (2) Northern Culberson-Reeves SRA; and (3) the Stanton SRA.[137] While the cause of the increased seismic activity has been a source of much ongoing debate, it is clear that the RRC will not administratively approve new injection applications within the SRAs. In at least one SRA the RRC believes deep injection is the primary source of increased seismic activity. This means that, for at least the immediate future, applications to inject carbon oxides into deep geologic formations will not be approved administratively by the RRC; that is, applicants must first go to hearing to obtain approval, and it is likely that RRC staff will actively pursue denial in those proceedings. Deep injection is typically more attractive when siting a CCS storage project because of the reduced likelihood of existing or future wells penetrating the storage formation, which could be an avenue for leakage if they are inadequately or improperly cased, cemented, or plugged. But given the RRC's decision to create the SRAs and limit approval of future injection permit applications within the SRAs (especially applications for deep injection), CCS project developers should carefully consider whether their proposed location is within an SRA when siting projects in West Texas.

[137] https://www.rrc.texas.gov/oil-and-gas/applications-and-permits/injection-storage-permits/oil-and-gas-waste-disposal/injection-disposal-permit-procedures/seismicity-review/seismicity-response/

According to UIC Program guidance recent, seismicity (natural or induced) near a proposed Class VI site might trigger the need for a passive seismic monitoring system across the area of review even if the project is not within an SRA. Additionally, the Regional Director could require that the Emergency and Remedial Response Plan, which is part of the Class VI permitting process and discussed previously, include an action plan to address seismic events.

V. Practical Hurdles in Developing a CCS Project in Texas

As applicants work through the permitting process and tax implications of carbon sequestration there are several other hurdles to a viable CCS project. The summary below is not intended to be an exhaustive discussion of ownership of pore space or carbon dioxide in Texas, but simply included to highlight them as possible issues when negotiating real property acquisitions and sourcing carbon dioxide. The long timeline associated with permitting and operating CCS projects should also be a factor in those decisions.

a. Storage Space Ownership

In an ideal scenario, an applicant for a CCS well would have ownership or control (e.g., a lease) over the surface and minerals of the area included within the project area including a buffer to account for plume movement over time. However, the likelihood and economic feasibility of acquiring such ownership interests may be slim, so most applicants will need to familiarize themselves with the law surrounding ownership of storage or pore space. The answer to the ownership question is not always the same in every circumstance.

As established by the Texas Supreme Court "although we agree that the surface owner owns and controls the mass of earth undergirding the surface, those rights do not necessarily mean it is entitled to make physical intrusions into formations where minerals are located and remove some of the minerals – as is probable if a well is drilled into or through such formations."[138]

The *Lightning Oil* case helps to clarify and build upon prior cases that suggested that ownership of the surface includes ownership of the subsurface matrix – the pore space. One of those cases was another Texas Supreme Court decision in *Humble Oil & Refining Co. v. West.*[139]

In *Humble Oil*, the Texas Supreme Court held that the surface overlying a leased mineral estate is the surface owner's property, and those ownership rights included the geological structures beneath the surface.[140] Specifically, "Humble, on the other hand, owns the lands in fee simple and this includes not only the surface and mineral estates, but also the matrix of the underlying earth, i.e., the reservoir storage space..." In support, the Court cited the *Emeny* case where a federal court found, citing the language of the underlying oil and gas leases, that the surface owners of lands retained ownership of the "geological structures beneath the surface"

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[138] *Lightning Oil Company v. Anadarko E&P Onshore, LLC*, 520 S.W.3d 39, 47 (Tex. 2017).
[139] *Humble Oil & Refining Co. v. West*, 508 S.W.2d 812 (Tex. 1974).
[140] *Id.* at 815.

together with any such structure that might be suitable for the underground storage of extraneous gas produced elsewhere.[141]

Also cited in *Lightning Oil* was the 2013 *Springer Ranch* case. In *Springer Ranch*, the San Antonio Court of Appeals determined that "ownership of the hydrocarbons does not give the mineral owner ownership of the earth surrounding those substances."[142] *Springer Ranch* cites favorably to *Emeny*.

Lightning Oil also examines an earlier case out of the 5th Circuit, *Dunn-McCampbell*.[143] Here the 5th Circuit was applying Texas law when it noted that the surface estate owner, not the mineral estate owner, "owns all non-mineral 'molecules' of the land, i.e., the mass that undergrids the surface" estate.[144] Based on *Lightning Oil* and these earlier cases, the prevailing view remains that ownership of the surface includes ownership of the pore space.

But there are some exceptions, and the analysis becomes more complicated if the injection formation contains minerals.[145] For example, in *Mapco v. Carter*, the court determined that a subsurface storage area created in a salt dome (i.e., minerals)[146] was owned by the mineral estate. The mineral fee owners "retain a property ownership, right and interest after the underground storage facility – here, a cavern – had been created."[147] The court determined that those same fee mineral owners are "vested with ownership rights, including, of course, entitlement to compensation for the use of the cavern."[148] So at least in the context of a mineral formation used for storage, the mineral owners had an ownership claim.

An applicant looking to sequester CO_2 in a mineral-bearing formation as part of an EOR, AGI, or CCS project needs to recognize the potentially competing interests in the formation and the risk of future development of that formation by third parties. Sequestration in non-mineral-bearing formations deeper than any current or past hydrocarbon production would likely minimize the competing interests of the mineral estate owner and any third-party operators.

In some instances, it may not be possible to acquire all the pore space rights for a particular CCS project. Applicants have little recourse in those instances because while other states have promulgated specific condemnation authority for CCS, that is not yet an option in Texas.[149]

[141] *Emeny v. United States*, 412 F.2d 1319, 188 Ct.Cl. 1024 (1969).
[142] *Springer Ranch, Ltd. v. Jones*, 421 S.W.3d 273, 282 (Tex.App.- San Antonio 2013, no pet.).
[143] *Dunn-McCampbell Royalty Interest, Inc. v. National Park Service*, 630 F.3d 431 (5th Cir. 2011).
[144] *Id.* at 442.
[145] Still the applicant will need some ownership interest in the surface as sequestration is not typically part of a traditional oil and gas lease.
[146] *State v. Parker*, 61 Tex. 265, 268 (Tex. 1884).
[147] *Mapco, Inc. v. Carter*, 808 S.W.2d 262, 274 (Tex.App. – Beaumont 1991), *rev'd on other grounds*, 817 S.W.2d 686 (Tex. 1991).
[148] *Id.*
[149] Louisiana and Wyoming.

b. CO_2 Ownership

It does not appear that any cases specifically address ownership of carbon dioxide in the context of oil and gas production. In oil and gas production, carbon dioxide is typically seen as a waste product that must be removed from the gas before it can be marketed. In EOR projects, however, the injected carbon dioxide is more akin to a product than a waste with some operators paying for the carbon dioxide.[150] Outside of the oil and gas production context, ownership seems clearer and would seem to initially fall on the generator of the carbon dioxide (e.g., power plant or direct air capture facilities). But in the oil and gas production context where the mineral estate is severed from the surface estate, it is not as clear and there will likely be competing interests to the extent the carbon dioxide has value. The Texas legislature has tried to provide some guidance on ownership once the carbon dioxide is actually stored.

The Texas Natural Resources Code Chapter 121, Ownership and Stewardship of Anthropogenic Carbon Dioxide, states the following about ownership:

Section 121.002. Ownership of Anthropogenic Carbon Dioxide

(a) This section does not apply to anthropogenic carbon dioxide injected for the primary purpose of enhanced recovery operations.
(b) Unless otherwise expressly provided by a contract, bill of sale, deed, mortgage, deed of trust, or other legally binding document or by other law, anthropogenic carbon dioxide stored in a geologic storage facility is considered to be the property of the storage operator or the storage operator's heirs, successors, or assigns.
(c) Absent a final judgment of willful abandonment rendered by a court or a regulatory determination of closure or abandonment, anthropogenic carbon dioxide stored in a geologic storage facility is not considered to be the property of the owner of the surface or mineral estate in the land in which the anthropogenic carbon dioxide is stored or of a person claiming under the owner of the surface or mineral estate.
(d) The owner, as designated by Subsection (b) or (c), of the anthropogenic carbon dioxide stored in a geologic storage facility, or the owner's heirs, successors, or assigns, may produce, take, extract, or otherwise possess anthropogenic carbon dioxide stored in the facility.

Essentially, the legislature is recognizing that injection and storage of the carbon dioxide in the subsurface does not equate to abandonment. The 2011 *Occidental Permian* case applies similar non-abandonment reasoning to carbon dioxide injected for enhanced recovery operations (title to the carbon dioxide prior to injection was not at issue).[151] Relying on *Humble Oil* as an analogy, the Court found that "[t]his record does not describe differences in the injection of extraneous CO_2 to enhance oil production and the injection of natural gas for storage to require

[150] *Commissioner of Gen. Land Office of State v. SandRidge Energy, Inc.*, 454 S.W.3d 603 (Tex.App. – El Paso 2014, pet. denied) (Operator paid on royalty of CO_2 sales).
[151] *Occidental Permian Ltd. v. Helen Jones Foundation*, 333 S.W.3d 392 (Tex.App. – Amarillo 2011, pet. denied).

application of a different rule to the dispute before us."[152] The Court added: "Nothing suggests OPL [operator] has an intent to abandon the CO_2 it injects and recovers."[153] While the statute helps to address ownership of stored carbon dioxide, it does not address ownership before storage.

c. Long-Term Sequestration

The Class VI regulations do not define "long-term," but that phrase is a part of the definition of "geologic sequestration" in Chapter 144.[154] Currently the 45Q Tax Credit can be claimed for up to 12 years. That, combined with the 50-year post-injection monitoring period of Class VI wells and the overall goal of long-term permanent sequestration, means that sequestration projects need to plan for future contingencies and long-term access for purposes of post-injection monitoring and emergency response in the event of leakage to the atmosphere.

Under the Texas Tax Code, there is a tax exemption available for enhanced oil recovery projects using anthropogenic carbon dioxide.[155] As discussed above, the RRC may issue a certification that the project qualifies for the incentive only if it finds that at least 99% of the carbon dioxide sequestered will remain sequestered for at least 1,000 years and the operator's planned sequestration program will include appropriately designed monitoring and verification measures that will be employed for a period sufficient to demonstrate whether the sequestration program is performing as expected.[156] While the Class VI regulations do not equate a specific number of years with the phrase "long-term," there is still an overall goal of minimizing plume migration over time.[157]

UIC Program guidance provides some guidance when the plume is predicted to continue to migrate even after 50 years post injection:

> If the plume is predicted to continue migrating at a slow rate (i.e., it would take a significantly long period – on the order of thousands of years – for the plume to reach a potential receptor), confirm the predicted/estimated migration rate and verify that there are no other potential receptors along the plume trajectory.[158]

Anyone thinking about a CCS project must consider how they will plan for ensuring the long-term storage of the carbon dioxide when purchasing fee property, negotiating leases, and arranging for access agreements. That means understanding the size and nature of the injection plume on the

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[152] *Id.* at 410-411.
[153] *Id.* at 411.
[154] 40 CFR § 144.3.
[155] Texas Tax Code § 202.0545.
[156] 16 TAC § 5.301.
[157] If a demonstration can be made, in conjunction with monitoring data, that a vast majority of the injected carbon dioxide stream has been immobilized via trapping mechanisms, this is strong evidence that the potential for USDW endangerment posed by the carbon dioxide plume has decreased. *See* https://www.epa.gov/sites/default/files/2016-12/documents/uic_program_class_vi_well_plugging_post-injection_site_care_and_site_closure_guidance.pdf at p. 49.
[158] https://www.epa.gov/sites/default/files/2018-01/documents/implementation_manual_508_010318.pdf at p. 7-12.

front end of negotiations or running the risk that additional interests or access will need to be negotiated in the future.

VI. Conclusion

The oil and gas industry seems poised to take advantage of its significant knowledge base surrounding injection operations and injection formations. The increased and expanded 45Q tax credit has primed interest in utilizing that knowledge to develop CCS projects across the state. However, carbon sequestration is still subject to a very evolving regulatory arena that will likely continue to evolve as the RRC seeks primacy and existing applicants work through the comprehensive Class VI permitting and MRV Plan approval process or seek alternative means of taking advantage of the 45Q tax credit through Class II EOR or AGI projects. Hopefully, the incentives are enough to make CCS more than just an interesting paper topic and more the norm.